2015
Integrated Resource Plan
Volume I

Let's turn the answers on.

PACIFICORP

Pacific Power
Rocky Mountain Power

March 31, 2015

This 2015 Integrated Resource Plan Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Top to Bottom):
Wind Turbine: *Marengo II*
Solar: *Residential Solar Install*
Transmission: *Populus to Terminal Tower Construction*
Demand-Side Management: *Wattsmart Flower*
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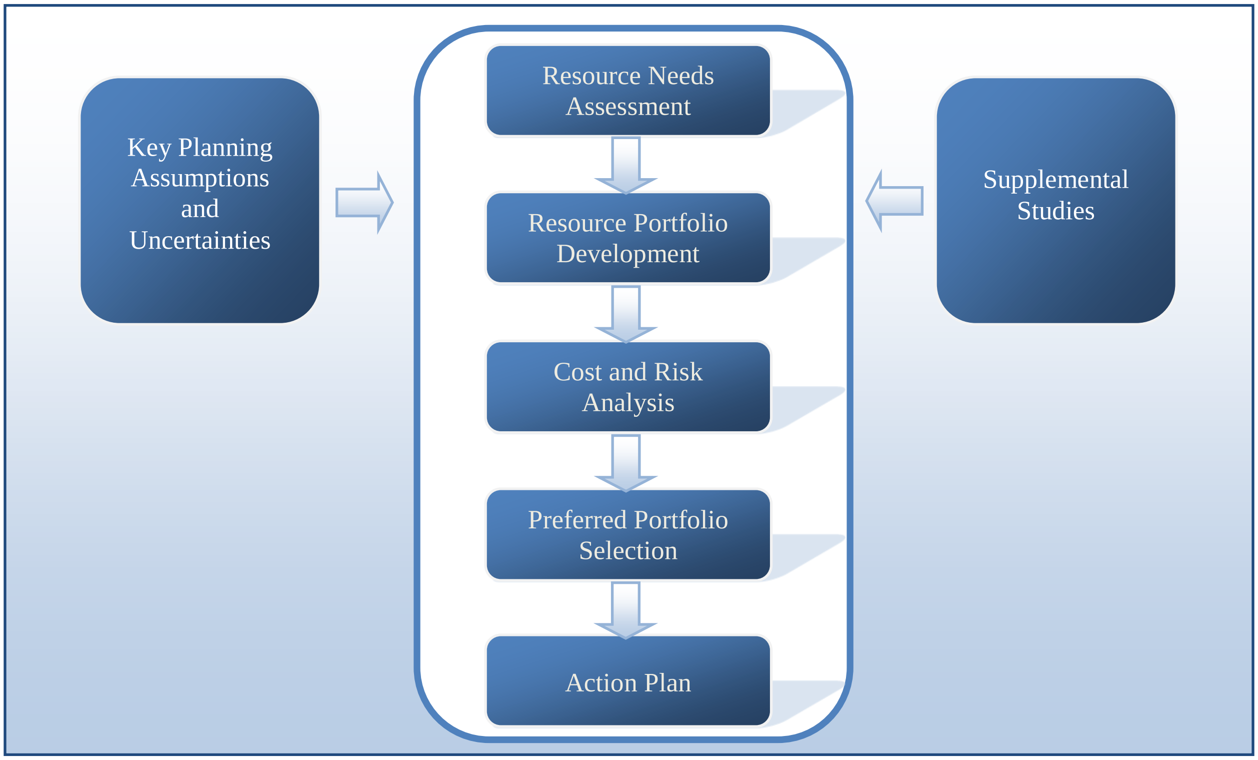
CHAPTER 1 – EXECUTIVE SUMMARY

PacifiCorp's 2015 Integrated Resource Plan (2015 IRP), developed with participation from an active and diverse group of public stakeholders comprised of regulatory staff, advocacy groups, and other interested parties, was initiated with the first public input meeting in June 2014. Over the next nine months, PacifiCorp met with stakeholders in five states, hosted seven public input meetings, and led two technical workshops. Through this process, PacifiCorp received valuable input from its stakeholders and presented findings from a broad range of foundational studies and technical analysis that supports the resource plan presented herein. PacifiCorp's 2015 IRP, representing the 13th plan submitted to state regulatory commissions, identifies future resources needed to provide reliable, reasonable-cost service with manageable risks to its customers and outlines specific resource actions PacifiCorp will implement over the next two to four years.

As depicted in Figure 1.1, PacifiCorp's 2015 IRP was developed by progressing through five fundamental planning steps. A key element of the planning process is to prepare a load and resource balance to quantify resource need over time. In the next planning step, PacifiCorp develops different resource portfolios that meet projected resource needs, each uniquely characterized by the type, timing, and location of new resources in PacifiCorp's system over time. PacifiCorp then performs comparative cost and risk analysis among the different resource portfolio alternatives. This cost and risk analysis informs selection of a preferred portfolio and the associated resource action plan. Throughout this process, PacifiCorp assesses the current planning environment to develop key planning assumptions and to identify key planning uncertainties. Supplemental studies are also completed to support the derivation of specific modeling assumptions.

Figure 1.1 – Key Elements of PacifiCorp's IRP Process



Preferred Portfolio Highlights

Development of the 2015 IRP involved a balanced consideration of cost, risk, uncertainty, supply reliability/deliverability, and public policy goals. Table 1.1 shows that PacifiCorp's resource needs can be met with demand side management (DSM) and low cost short-term firm market purchases, labeled as front office transactions (FOTs), through 2027. The first deferrable thermal resource in the 2015 IRP preferred portfolio is added in 2028, one year later when compared to PacifiCorp's 2013 IRP Update and four years later relative to the 2013 IRP preferred portfolio. By the end of the twenty-year planning horizon, PacifiCorp's 2015 IRP preferred portfolio reflects an assumed reduction in existing owned capacity totaling 2,775 MW. By 2034, it is assumed that approximately 2,800 MW of existing coal generation will either be retired or converted to operate as natural gas-fired generation.

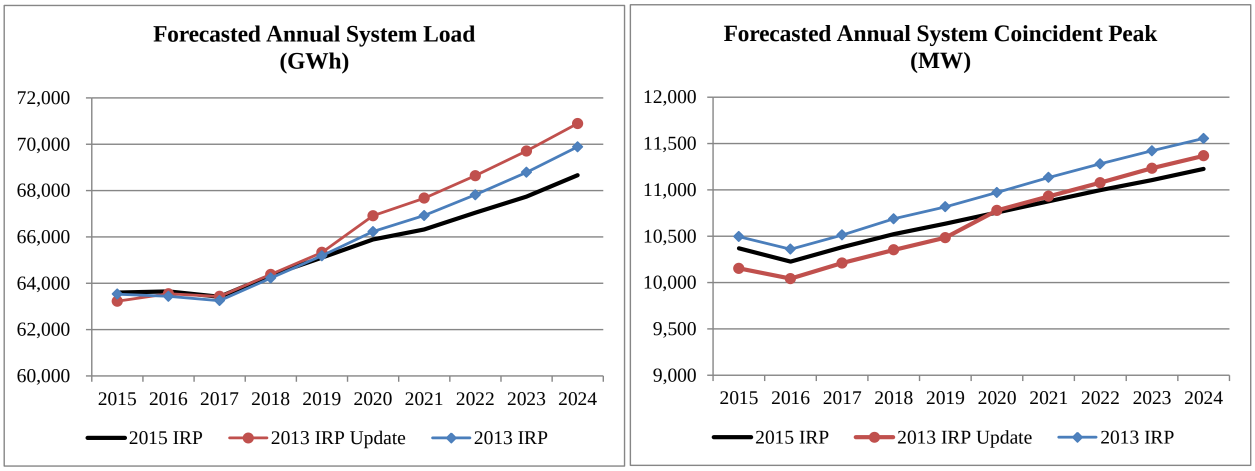
Table 1.1 – 2015 IRP Preferred Portfolio Summary (MW)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
New Resources																					
FOTs	727	937	904	870	935	979	769	791	761	754	771	792	835	1,304	1,167	1,253	1,247	1,411	1,360	1,087	n/a
DSM - Energy Efficiency	133	139	146	146	153	135	137	144	146	149	123	126	130	132	128	125	122	122	122	120	2,678
DSM - Load Control	0	0	0	0	0	0	0	5	11	0	0	11	0	0	11	0	0	0	5	0	42
Natural Gas Combined Cycle	0	0	0	0	0	0	0	0	0	0	0	0	0	423	0	1,159	0	0	635	635	2,852
OR Solar Capacity Standard	0	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7
Existing Unit Changes																					
Reduction in Owned Coal/Gas	(222)	0	0	(280)	0	0	0	0	0	0	(387)	0	0	(762)	0	(807)	(77)	0	(627)	0	(3,162)
Gas Conversion	0	0	0	337	0	0	0	0	0	0	387	0	0	0	0	(337)	0	0	0	0	387
Total Net Change in Resources	638	1,084	1,050	1,073	1,088	1,113	906	941	917	903	893	928	965	1,097	1,305	1,393	1,292	1,533	1,496	1,841	

*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 on the year shown.

Figure 1.2 shows that the Company's load forecast prior to incremental energy efficiency savings and prior to assumed distributed generation penetration levels, is down beyond 2019 in relation to projected loads used in the 2013 IRP and 2013 IRP Update. Forecasted peak falls between the 2013 IRP and 2013 IRP Update through 2019, and drops below the 2013 IRP and 2013 IRP Update beyond 2020. Changes to PacifiCorp's load forecast is driven by reduced residential class load forecast due to increased energy efficiency, including continued phase in of the Energy Independence and Security Act federal lighting standards. In addition, lower energy response to economic growth has lowered system load and coincident peak growth.

Figure 1.2 – Load Forecast Comparison among Recent IRPs



PacifiCorp continues to evaluate DSM as a resource that competes with traditional supply-side resource alternatives when developing resource portfolios that are compared under a range of cost and risk metrics. In preparing its 2015 IRP, PacifiCorp used updated estimates of reasonably achievable DSM resource potential in each year of the planning horizon. Driven by increased cost-effective lighting opportunities followed by cost-effective opportunities in heating, cooling, water heating, appliances and industrial process end-uses, Class 2 DSM, or energy efficiency, savings in the 2015 IRP preferred portfolio exceed energy efficiency savings from the 2013 IRP preferred portfolio by 59 percent by 2024. Over this front ten years of the planning horizon, accumulated acquisition of incremental energy efficiency resources meets 86 percent of forecast load growth from 2015 through 2024. Figure 1.3 compares total energy efficiency savings by state in the 2015 IRP preferred portfolio relative to the 2013 IRP preferred portfolio.

Figure 1.3 – Comparison of Total Energy Efficiency Savings between the 2015 IRP Preferred Portfolio and the 2013 IRP Preferred Portfolio

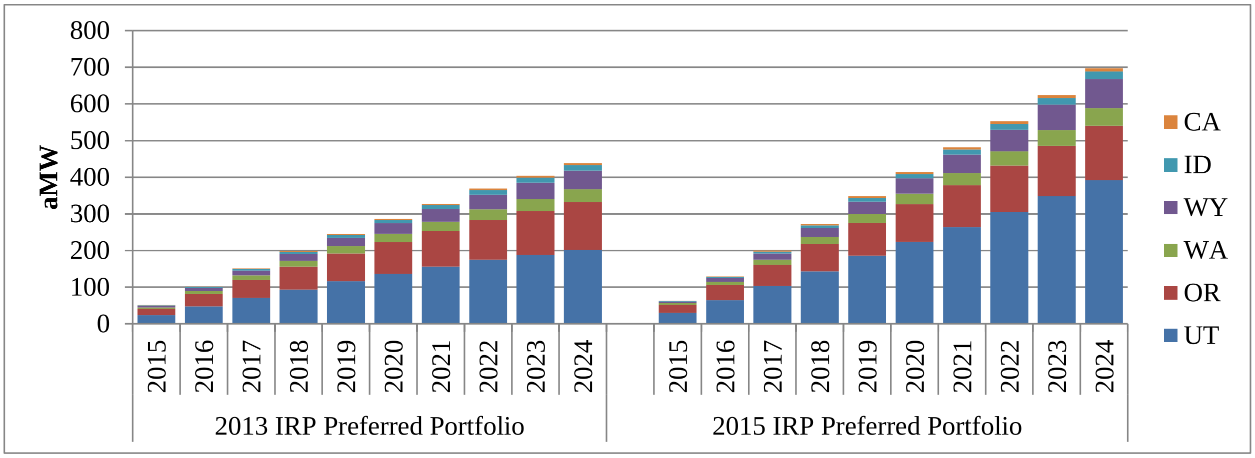


Figure 1.4 shows that base case wholesale power prices and natural gas prices used in the 2015 IRP are significantly lower than the base case market prices used in the 2013 IRP and are more closely aligned with those used in PacifiCorp's 2013 IRP Update. Since the 2013 IRP planning cycle, growth in natural gas supplies, primarily from prolific shale plays in North America, have continued to outpace expectations. With continued declines in forward natural gas prices and reduced regional electric load growth expectations, forward power prices have also declined

significantly since the 2013 IRP. Figure 1.5 compares FOTs from the preferred portfolio among recent IRPs. While market conditions for firm market purchases are favorable, growth in energy efficiency savings mitigate the need for FOTs through the front ten years of the planning horizon. On average 2015 IRP preferred portfolio FOTs are down 16% from the 2013 IRP Update and down 29% when compared to the 2013 IRP preferred portfolio.

Figure 1.4 – Comparison of Power Prices and Natural Gas Prices among Recent IRPs

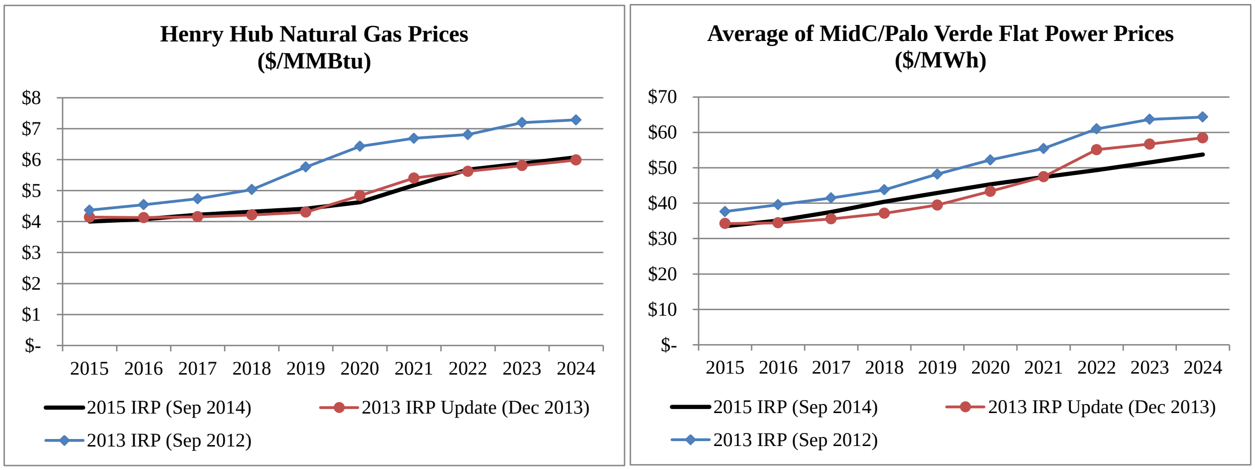
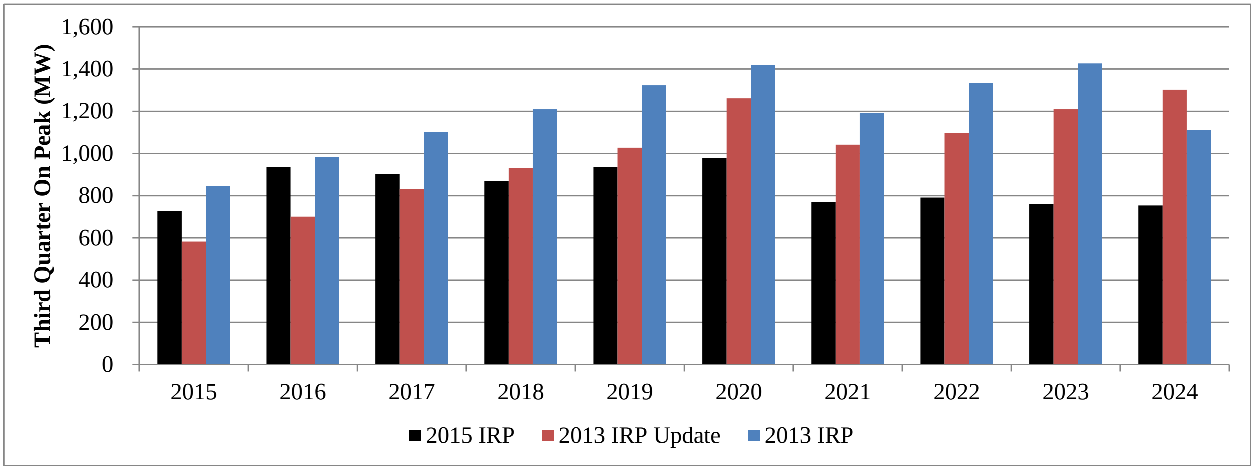
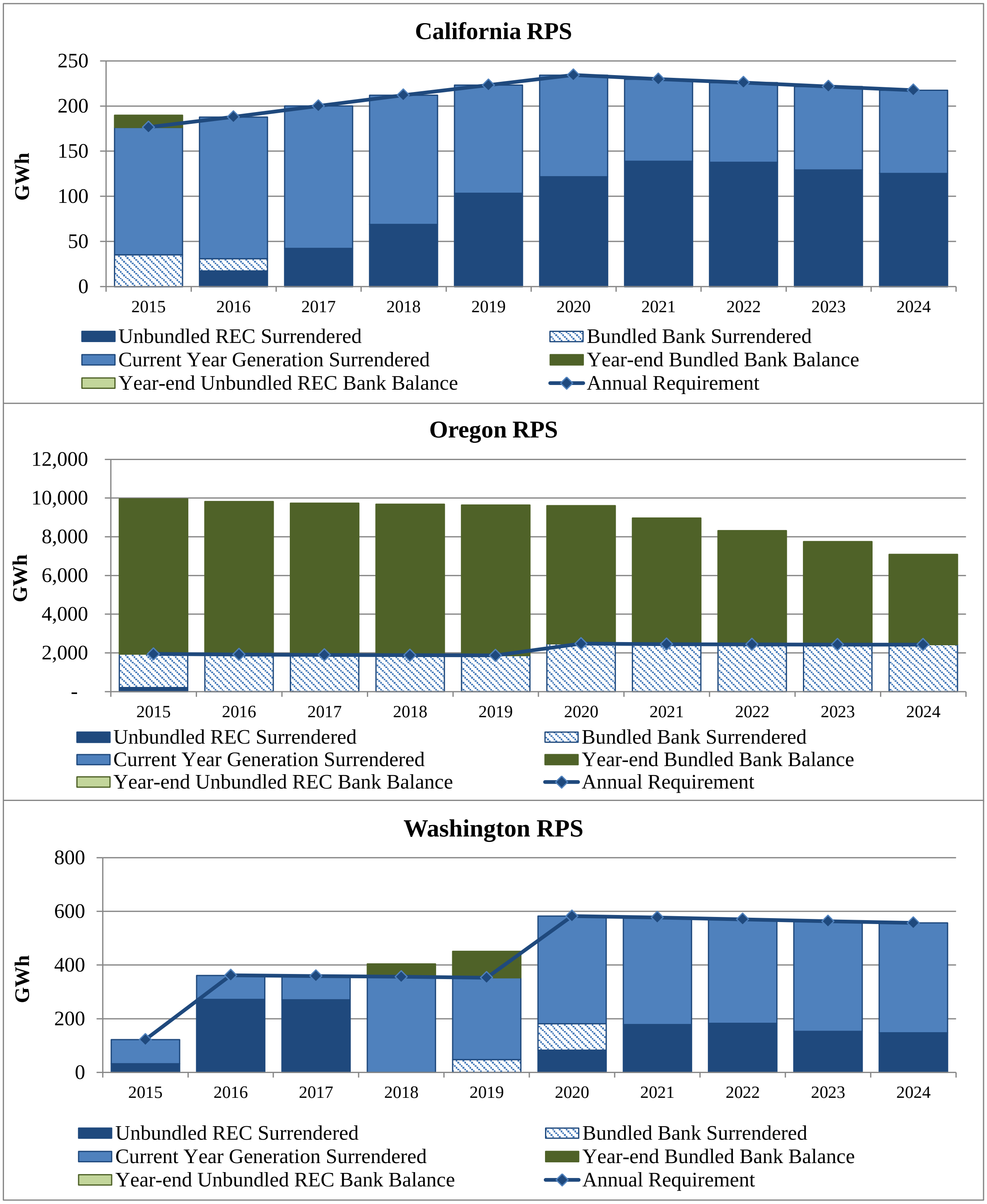


Figure 1.5 – Comparison of FOTs among Recent IRPs



PacifiCorp’s 2015 IRP preferred portfolio is built around a system reflecting the addition of 816 MW of executed wind and solar qualifying facility power purchase agreements from 36 projects having in-service dates by the end of 2016. To mitigate the cost of state renewable portfolio standard (RPS) compliance, analyses in the 2015 IRP continue to support the use of unbundled renewable energy credits (RECs) to meet projected compliance needs through the planning horizon. Figure 1.6 shows PacifiCorp’s RPS compliance forecast for California, Oregon, and Washington covering the period 2015 through 2024. Utah’s RPS goal is tied to a 2025 compliance date, so the 2015 through 2024 position is not shown. However, PacifiCorp meets the Utah 2025 state target of 20%, and has a significant bank to sustain continued future compliance in Utah.

Figure 1.6 – Annual State RPS Position Forecasts



During the 2015 IRP portfolio development process, PacifiCorp considered alternative Regional Haze scenarios, which reflect potential inter-temporal and fleet trade-off compliance outcomes for both known and prospective Regional Haze compliance requirements on existing coal units in PacifiCorp's fleet. Analysis of near-term Regional Haze compliance requirements support converting Naughton Unit 3 to burn natural gas in 2018 and strategies that avoid installation of selective catalytic reduction emissions control equipment at Wyodak, Dave Johnston Unit 3, and Cholla Unit 4, saving PacifiCorp customers hundreds of millions of dollars.

Just as PacifiCorp was initiating its 2015 IRP public process, 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) establishing state emission rate targets for existing resources through application of a best system of emission reduction (BSER). PacifiCorp considered EPA's proposed rule in its 2015 IRP by studying a range of assumed compliance requirements and alternative compliance strategies. The 2015 IRP preferred portfolio meets PacifiCorp's share of state emission rate targets among those states in which PacifiCorp serves retail customers and owns existing fossil generation potentially affected by the proposed rule. PacifiCorp's compliance solution reflects a BSER that is primarily comprised of allocating system renewable generation among states, acquiring energy efficiency resources, and re-dispatching fossil-fired generation resources.

PacifiCorp continues to support transmission permitting efforts for Energy Gateway West (Segments D and E), Energy Gateway South (Segment F), Boardman to Hemingway (Segment H), and a line from Walla Walla to McNary. PacifiCorp will complete construction of the Wallula to McNary project, driven by a customer request for transmission service, with a 2017 expected in-service date.

Supplemental Studies

PacifiCorp's 2015 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 2015 IRP, is provided below.

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

- Distributed Generation Resource Assessment
  New to the 2015 IRP, this supplemental study, prepared by Navigant Consulting, Inc., produced distributed 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 distributed generation penetration forecasts from this study are applied as a reduction to forecasted load throughout the IRP modeling process.

- Anaerobic Digester Resource Assessment
  An anaerobic digester resource assessment, prepared by Harris Group, Inc., reports on the amount of potential electric power generation from dairy waste specific to PacifiCorp's service territory in Washington. Conclusions from the study indicate that economically viable projects would require consolidation of dairies (or dairy waste) to form larger digester facilities. Moreover, alternatives to power generation, such as selling synthetic

natural gas, may be more economically viable. PacifiCorp expects that economic projects would be brought forward through qualifying facility power purchase agreements.

- Energy Storage Screening Study
  HDR Engineering prepared an updated energy storage screening study in support of PacifiCorp's 2015 IRP. The study catalogs commercially available utility scale and distributed scale storage technologies, defines their performance characteristics, and estimates capital and operating costs. The study is used to develop cost and performance data applied during the portfolio development process and supports energy storage sensitivities performed in the 2015 IRP.

- Resource Adequacy Evaluation
  PacifiCorp updated its analysis of regional resource adequacy to support its assumptions for FOT limits. The resource adequacy evaluation presents data from the Western Electricity Coordinating Council's Power Supply Assessment and resource adequacy assessments prepared by the Pacific Northwest Resource Adequacy Forum. PacifiCorp's review of regional resource adequacy continues to support the use of FOTs, representing short-term firm market purchases, as a resource option in the 2015 IRP.

- Planning Reserve Margin Study
  The 2015 IRP was developed targeting a 13% planning reserve margin, which influences the need for new resources and is applied during the portfolio development process. In its updated 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.

- Wind and Solar Capacity Contribution Study
  PacifiCorp updated its wind and solar capacity contribution values for the 2015 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 2015 IRP resource needs assessment and in the portfolio development process.

- Wind Integration Study
  The updated wind integration study, prepared by PacifiCorp in coordination with a technical review committee, estimates the operating reserves required to both maintain system reliability and comply with North American Electric Reliability Corporation reliability standards. Operating reserves estimated from the study are used in cost and risk analysis modeling and estimated wind 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 2015 IRP, an independent consultant prepared updated stochastic parameters.

- <u>Flexible Resource Needs Assessment</u>
  PacifiCorp updated its flexible resource needs assessment, which forecasts flexible resource needs and projected flexible resource supply, based upon the 2015 IRP preferred portfolio. The flexible resource needs assessment shows that PacifiCorp's system has sufficient resources to meet its flexible resource needs throughout the IRP planning horizon.

Resource Needs Assessment

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

Table 1.2 shows the PacifiCorp's annual capacity position for 2015 through 2024, prior to adding any incremental demand side or new supply side resources to the portfolio. Accounting for available FOTs, PacifiCorp exceeds its 13% target planning reserve margin through 2019 and falls just short of its target planning reserve margin in 2020. With the expiration of a legacy exchange contract, available system capacity is increased in the summer of 2021, and PacifiCorp's system once again exceeds its 13% target planning reserve margin through 2022. With continued load growth, PacifiCorp falls 82 MW and 165 MW below its target planning reserve margin in 2023 and 2024, respectively.

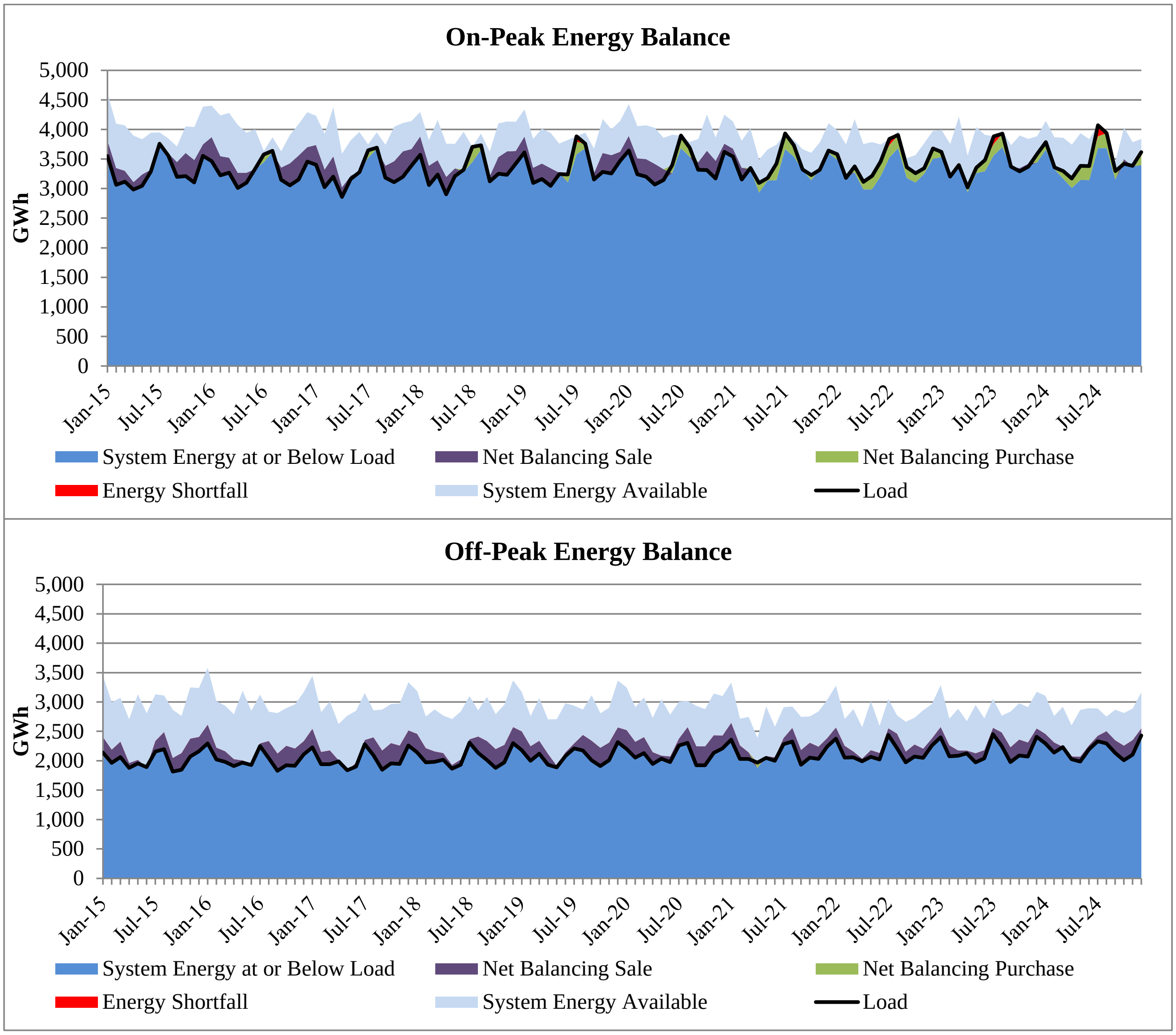
Table 1.2 – PacifiCorp 10-year Capacity Position Forecast (MW)

System	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Existing Resource Capacity Contribution	10,568	10,043	10,143	10,217	10,144	10,124	10,486	10,446	10,458	10,425
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	12,238	11,713	11,812	11,886	11,814	11,794	12,155	12,115	12,128	12,094
Obligation without Incremental DSM	10,104	9,930	10,089	10,225	10,333	10,452	10,569	10,674	10,788	10,832
13% Planning Reserve Margin	1,333	1,310	1,331	1,349	1,363	1,378	1,393	1,407	1,422	1,428
Obligation + 13% Planning Reserves	11,437	11,240	11,420	11,573	11,696	11,830	11,963	12,081	12,210	12,259
System Position with Available FOTs	801	472	393	313	117	(36)	192	34	(82)	(165)
Reserve Margin with Available FOTs	21.1%	18.0%	17.1%	16.3%	14.3%	12.8%	15.0%	13.5%	12.4%	11.7%

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

Figure 1.7 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 assuming no new demand side and supply side resources are added to PacifiCorp's system. At times, system resources are economically dispatched above load levels facilitating net system balancing sales. This occurs more often in off-peak periods than in on-peak periods. At other times, economic conditions result in net system balancing purchases, which occur more often during on-peak periods. Figure 1.7 also shows how much system energy is available from existing resources at any given point in time. Those periods where all available resource energy falls below forecasted loads are highlighted in red, and are indicative of short energy positions absent the addition of any new demand side or supply side resources to the portfolio. During on-peak periods, the first energy shortfall appears in July 2020, totaling 5 GWh. In July 2024, available system energy falls short of monthly loads by 189 GWh. During off-peak periods, there are no energy shortfalls through the 2024 timeframe.

Figure 1.7 – Economic System Dispatch of Existing Resources in Relation to Monthly Load



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

Action Plan

The 2015 IRP action plan identifies specific resource 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 during the development of the 2015 IRP, and other resource activities described in the 2015 IRP. Table 1.3 details specific 2015 IRP action items by category.

Table 1.3 – 2015 IRP Action Plan

Action Item	1. Renewable Resource Actions
1a	**Renewable Portfolio Standard Compliance** • 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.
1b	**Renewable Energy Credit Optimization** • 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.
1c	**Oregon Solar Capacity Standard** • Conclude negotiations with shortlisted bids from the 2013S Request for Proposals (RFP), seeking up to 7 MW_{AC} of competitively priced capacity from qualifying solar systems that will be used to satisfy PacifiCorp's obligation under Oregon's 2020 solar capacity standard.

<table>
<tr><th>Action Item</th><th>2. Firm Market Purchase Actions</th></tr>
<tr><td>2a</td><td><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.

</td></tr>
<tr><th>Action Item</th><th>3. Demand Side Management (DSM) Actions</th></tr>
<tr><td>3a</td><td><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.
</td></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></tr>
<tr><th>Action Item</th><th>4. Coal Resource Actions</th></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.
</td></tr>
</table>

	• 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.
4b	**Dave Johnston Unit 3** • 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 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.
4c	**Wyodak** • 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.
4d	**Cholla Unit 4** • 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.
Action Item	**5. Transmission Actions**
5a	**Energy Gateway Permitting** • Continue permitting for the Energy Gateway transmission plan, with near term targets as follows: – 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.

5b	**Wallula to McNary 230 kilovolt Transmission Line** • 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.

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.

An analytical highlight of the 2015 IRP was to develop a planning framework to address the cost, risk, and uncertainty associated with EPA's proposed rule to regulate CO_2 emissions from existing resources under §111(d) of the Clean Air Act (111(d) rule). New tools were necessary to analyze this policy development, and refinements will be implemented once the rule is finalized and as states begin to develop implementation plans for submittal to EPA. To evaluate EPA's proposed rule, PacifiCorp developed the 111(d) Scenario Maker, a spreadsheet-based tool, to study key 111(d) policy and 111(d) compliance uncertainties. PacifiCorp held two confidential technical workshops, one in Portland, Oregon, and one in Salt Lake City, Utah to demonstrate its use of the 111(d) Scenario Maker to stakeholders.

Another modeling improvement included implementation of an updated version of the Enterprise Portfolio Management (EPM) model which improved the efficiency of the System Optimizer and Planning and Risk (PaR) models.[2] With improved modeling efficiencies, PacifiCorp did not need to evaluate how model performance might be improved by potentially reducing the number of cost bundles used to define demand side management (DSM) supply curves.

Compliance associated with Regional Haze requirements was another area of focus for the 2015 IRP. PacifiCorp developed resource portfolios among four potential Regional Haze scenarios, 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 proposed 111(d) rule as discussed above. Coal-fired units subject to near-term Regional Haze requirements are analyzed in Volume III, which presents financial analysis of compliance alternative for Wyodak, Naughton Unit 3, Dave Johnston Unit 3, and Cholla Unit 4.

Other significant studies conducted to support the 2015 IRP include:

- An updated conservation potential assessment;
- A distributed generation resource assessment for PacifiCorp's service territory;
- An anaerobic digester resource assessment, specific to Washington;
- An energy storage screening study examining utility scale storage potential;
- A planning reserve margin study to determine selection of a planning reserve margin for the 2015 IRP

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[2] EPM refers to ABB's (formerly known as Ventyx) suite of applications. Among the applications, PacifiCorp makes use of both System Optimizer and PaR. These applications use a common database and graphical user interface.

- A western region regional adequacy assessment;
- A wind and solar capacity contribution study;
- An updated wind integration study developed in coordination with a technical review committee;
- Update stochastic parameters; and
- An updated flexible resource needs assessment.

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 2015 IRP, summarizes the role of the IRP, and provides an overview of the public process.

2015 Integrated Resource Plan Components

The basic components of PacifiCorp's 2015 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)
- Resource needs assessment 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 the 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 2015 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.

- Detailed load forecast (Volume II, Appendix A),
- Fulfillment of regulatory compliance requirements, (Volume II, Appendix B),
- Details about the public input process (Volume II, Appendix C),
- DSM analysis and state implementation plans (Volume II, Appendix D),

- Smart Grid discussion (Volume II, Appendix E),
- Flexible resource needs assessment (Volume II, Appendix F),
- Historical plant water consumption data (Volume II, Appendix G),
- Updated wind integration cost study (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),
- Fact sheets for core cases and sensitivities (Volume II, Appendix M),
- Wind, and solar capacity contributions (Volume II, Appendix N),
- Distributed generation (DG) study(Volume II, Appendix O)
- Anaerobic digester study (Volume II, Appendix P),
- Energy storage study (Volume II, Appendix Q), and
- Stochastic parameters (Volume II, Appendix R)

In an effort to improve transparency PacifiCorp is also providing data disks for the 2015 IRP. These disks support and provide additional details for the analysis described within the document. Disks 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."[3] 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 Process

The IRP standards and guidelines for certain states require PacifiCorp to have a public process allowing stakeholder involvement in all phases of plan development. The Company organized five state meetings, held 7 public meetings, some of which spanning two days, and hosted two

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[3] 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.

technical workshops to facilitate information sharing, collaboration, and expectations for the 2015 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. lists the public meetings/conferences and highlights major agenda items covered. Volume II, Appendix C provides more details concerning the public input process.

Table 2.1 – 2015 IRP Public Meetings

Meeting Type	Date	Main Agenda Items
General Meeting	6/5/2014	2015 IRP kickoff meeting
State Meeting	6/10/2014	Washington state stakeholder comments
State Meeting	6/17/2014	Idaho state stakeholder comments
State Meeting	6/18/2014	Utah state stakeholder comments
State Meeting	6/19/2014	Wyoming state stakeholder comments
State Meeting	6/26/2014	Oregon state stakeholder comments
General Meeting (2-Day)	7/17/2014	Environmental Policy, Transmission, Portfolio Development
	7/18/2014	Sensitivities, Demand Side Management and Load Forecast
General Meeting (2-Day)	8/7/2014	Supply-side Resources, Needs Assessment, Distributed Generation
	8/8/2014	Portfolio Development, Wind Integration, Reliability metrics
General Meeting (2-Day)	9/25/2014	Stochastics, Portfolio Development and Selection, Grid efficiencies
	9/26/2014	Anaerobic Digester, Volume 3 modeling, Additional study results
General Meeting	11/14/2014	Energy Imbalance Market Update, Portfolio Results
Confidential Workshop	12/8/2014	111(d) Scenario Maker Model (Salt Lake City)
Confidential Workshop	12/10/2014	111(d) Scenario Maker Model (Portland)
General Meeting (2-Day)	1/29/2015	Confidential Coal Analysis, Preferred Portfolio Overview, PaR Modeling
	1/30/2015	Preferred Portfolio Selection, Sensitivities
General Meeting	2/26/2015	Draft Action Plan, Sensitivity Study Update,

In addition to the public meetings, PacifiCorp used other channels to facilitate resource planning-related information sharing and consultation throughout the IRP process. The Company maintains a public website (http://www.pacificorp.com/es/irp.html), an e-mail "mailbox" (irp@pacificorp.com), and a dedicated IRP phone line (503-813-5245) to support stakeholder communications and address inquiries by public participants. Additionally, a feedback form was used to provide opportunities for stakeholders to submit additional input and ask questions throughout the 2015 IRP public input process. The forms submitted may be found on the comment section of PacifiCorp's IRP website:
(http://www.pacificorp.com/es/irp/irpcomments.html)

CHAPTER 3 – THE PLANNING ENVIRONMENT

CHAPTER HIGHLIGHTS

- Over the last ten years, North American natural gas markets have undergone a remarkable paradigm shift. In 2009 the Marcellus shale play, centered in Pennsylvania and West Virginia, produced 1.5 billion cubic feet per day (BCF/D) of natural gas, by spring 2013 it was producing 8 BCF/D. Today, the Marcellus is producing 15 BCF/D and the Utica, much of which underlies the Marcellus, produces another 1-2 BCF/D, a compound annual growth rate of 48% since 2009. As such, the Marcellus and Utica plays now account for 22% of the nation's gas supply.
- The challenge in gauging uncertainty in natural gas markets will be one of timing. Producers respond to price signals, which usually lag market demand, which then creates periods of asynchronous supply and demand.
- 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. At the same time, EPA issued a proposed rule for modified or reconstructed sources. Comments on the proposed rule were due December 1, 2014, and a final rule is expected summer 2015.
- PacifiCorp signed a memorandum of understanding with the California Independent System Operator (CAISO) February 12, 2013 to outline terms for the implementation of an Energy Imbalance Market (EIM) by October 2014. The EIM between PacifiCorp and CAISO launched at midnight November 1, 2014, following a 30-day test period. The new market provides automated, optimized five-minute security constrained economic dispatch across the combined balancing authority areas. The market immediately began generating benefits for customers with significant economic transfers to California occurring throughout the month of November and December with volumes exceeding 150,000 MWh.
- Near-term procurement activities focused on three areas: natural gas supply and transportation, the purchase and sale of Renewable Energy Credits and Oregon solar resources.

Introduction

Chapter 3 profiles the major external influences that impact PacifiCorp's long-term resource planning as well as recent procurement activities. External influences include events and trends affecting the economy, wholesale power and natural gas prices, and public policy and regulatory initiatives that influence the environment in which PacifiCorp operates.

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

On the government policy and regulatory front, a significant issue facing PacifiCorp continues to be planning for an eventual, but highly uncertain, climate change regulatory regime. This chapter focuses on climate change regulatory initiatives. 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 assuring that resources with the lowest operating cost are serving demand in a region and by providing reliability benefits that arise from a larger portfolio of resources.

PacifiCorp 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 supplies that would go unutilized in all but the most unusual circumstances and would substantially diminish its capability to cost effectively match delivery patterns to the profile of customer demand.

The benefits of being able to access an integrated wholesale market have become even more compelling with the increased penetration of intermittent generation such as solar and wind. Intermittent generation tends to come online and go offline abruptly in congruence with changing weather. For purposes of balancing sub-hourly demand and supply PacifiCorp combined its resources with those of the California Independent System Operator (CAISO). The resulting energy imbalance market (EIM) became operational November 1, 2014. Effective October 1, 2015, it will also include the resources of Nevada Energy, and Puget Sound Energy as of October 2016. The multi-service area footprint brings greater resource and geographical diversity allowing for increased reliability and cost savings in balancing generation with demand using 15-minute interchange scheduling and 5-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 service areas. The EIM is discussed in further detail in a subsequent section of Chapter 3.

As with all markets, electricity markets are faced with a wide range of uncertainties. However, some uncertainties are easier to evaluate than others. Market participants are routinely studying demand uncertainties driven by weather and overall economic conditions. Similarly, there is a reasonable amount of data available to gauge resource supply developments. For example, WECC publishes an annual assessment of power supply and any number of data services are available that track the status of new resource additions. A review of the WECC power supply assessment is provided in Volume II, Appendix J. The latest assessment, published in September 2014, indicates that even when including only existing and under-construction units, WECC as a whole, has ample resources through 2024, the end of the study period (although California and the WECC portion of Mexico[4] only marginally exceed WECC's calculated measure of resource adequacy through 2024). The WECC subregions in which PacifiCorp operates, Northwest Power Pool and Rocky Mountain Reserve Group, are capacity rich through 2024 and 2021, respectively.

There are other uncertainties that are more difficult to analyze and that possess heavy influence on the direction of future prices. One such uncertainty is the evolution of natural gas prices over the course of the IRP planning horizon. Given the increased role of natural gas-fired generation, gas prices have become a critical determinant in establishing western electricity prices, and this trend is expected to continue over the term of this plan's decision horizon. Another critical uncertainty that weighs heavily on the 2015 IRP, as in past IRPs, is the prospect of future greenhouse gas policy. A broad landscape of proposals aiming to curb greenhouse gas emissions continues to widen the range of plausible future energy costs, and consequently, future electricity prices. PacifiCorp's official forward price curve incorporates potential impacts of EPA's proposed 111(d) rule. Other price scenarios developed for the IRP consider impacts of potential future CO_2 emission policies incremental to requirements established in EPA's proposed 111(d) rule. Each of these uncertainties is explored in the cases developed for this IRP and are discussed in more detail below.

Natural Gas Uncertainty

Over the last ten years, North American natural gas markets have undergone a remarkable paradigm shift. Figure 3. shows historical day-ahead prices at the Henry Hub benchmark from January 1, 2005 through December 31, 2014. Over this period, day-ahead gas prices settled at a high of $15.39/MMBtu on December 13, 2005 and at a low of $1.82/MMBtu on April 20, 2012. Prices spiked December 2005 after a wave of hurricanes devastated the Gulf region in what turned out to be the most active hurricane season in recorded history. Prices later topped $13/MMBtu in the summer of 2008 when NYMEX oil futures climbed above $145 per barrel (bbl) in the summer preceding the global credit crisis. By early 2009 slow economic growth coupled with abundant shale gas supplies pressured day-ahead natural gas prices to dip to an average of $3.92/MMBtu. Prices continued to tick down with day-ahead natural gas prices averaging $2.75/MMBtu in 2012 and rebounding to $4.32/MMBtu in 2014. The relative price placidity since 2009, labeled the "Shale Gale", reflects a story of supply – mostly Appalachian supply.[5]

In 2009 the Marcellus shale play, centered in Pennsylvania and West Virginia, produced 1.5 billion cubic feet per day (BCF/D) of natural gas, by spring 2013 it was producing 8 BCF/D. Today, the Marcellus is producing 15 BCF/D and the Utica, much of which underlies the Marcellus, produces another 1-2 BCF/D, a compound annual growth rate of 48% since 2009. As such, the Marcellus and Utica plays now account for 22% of the nation's gas supply. The price spikes that have occurred in the last few years do not reflect commodity shortages, per se, but instead, inadequate take-away capacity, as experienced February 2014 during a prolonged cold snap. As new take-away capacity comes online, coupled with the reversal of key pipeline flows, Appalachian gas displaces eastern-bound Rockies gas, southeastern-bound Henry Hub gas, and

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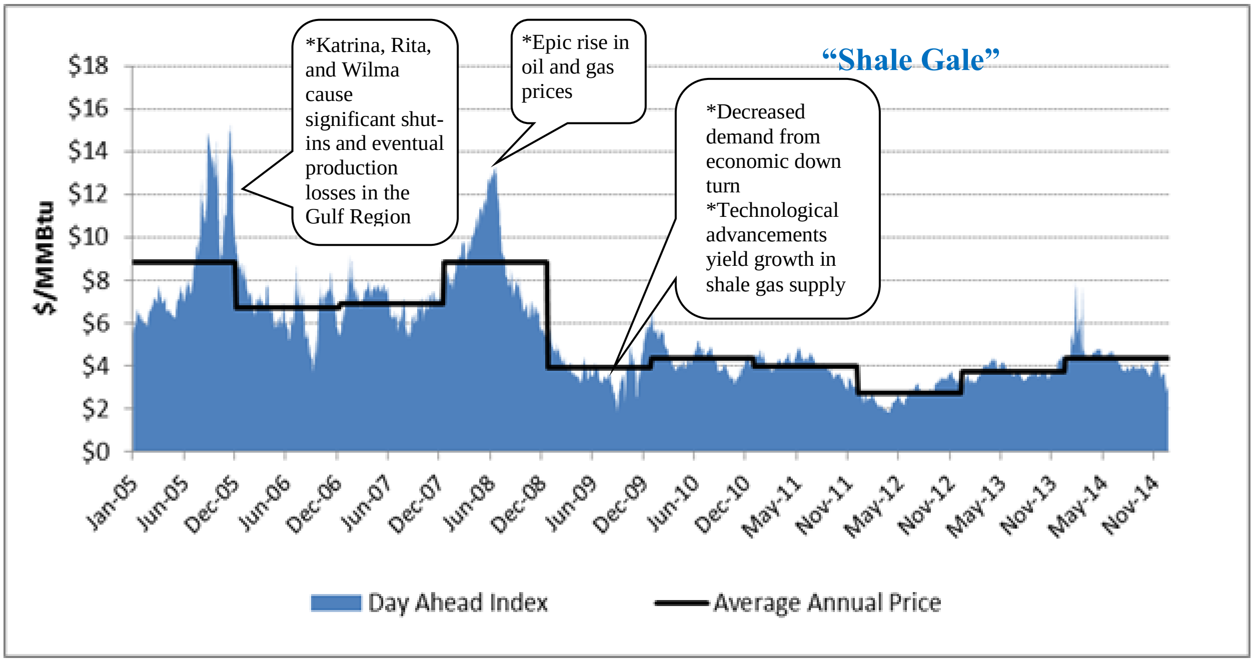
[4] The northern portion of Baja California, Mexico.

[5] Other significant shale gas plays: Eagle Ford (TX); Haynesville (LA/TX); Permian (TX/NM); Niobrara (CO/WY); Bakken (ND/MT).

U.S. northeastern-bound Canadian gas.[6] 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.

Figure 3.1 – Henry Hub Day-ahead Natural 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 and, coupled with reduced demand, sent the average day-ahead 2012 price to $2.75/MMBtu. Prices recovered in 2013-2014 as demand rebuilt but still remained, on average, below $4.50/MMBtu. Figure 3.2 through Figure 3.4 show U.S. natural gas production by source and location.

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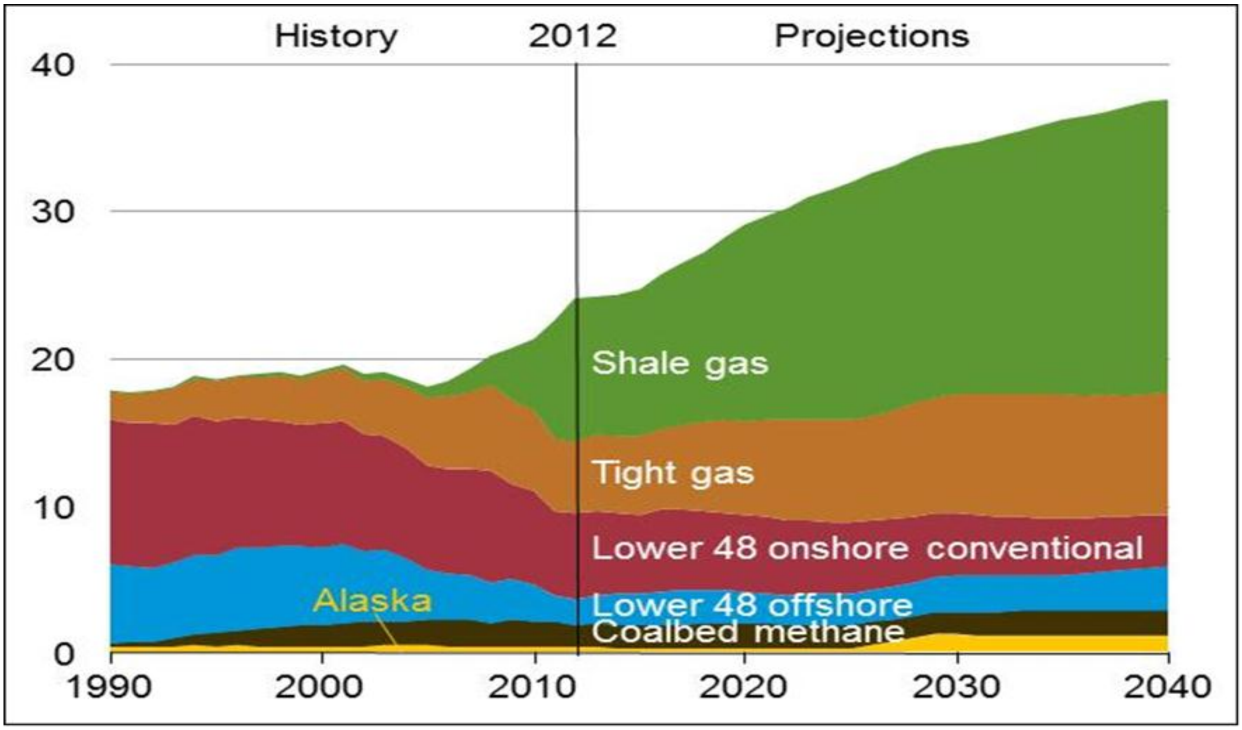
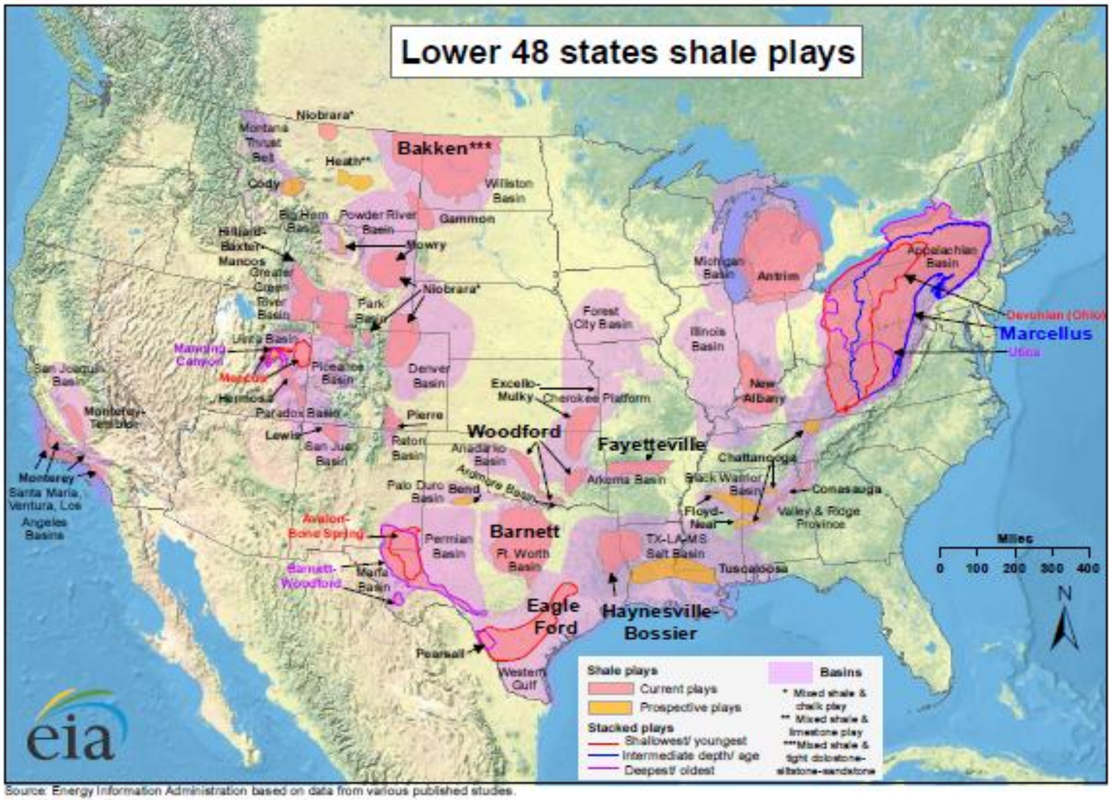
[6] Natural gas has historically flowed from the gulf coast to northern markets. Both Texas Eastern and Tennessee Gas pipelines have reversed flow segments to bring Appalachian gas south. Similarly, the Rockies Express Pipeline, built to flow west to east, added the Seneca Lateral line to bring Appalachian gas to Midwest markets.

Figure 3.2 – U.S. Dry Natural Gas Production



Source: 2014 Annual Energy Outlook, U.S. Department of Energy, Energy Information Administration

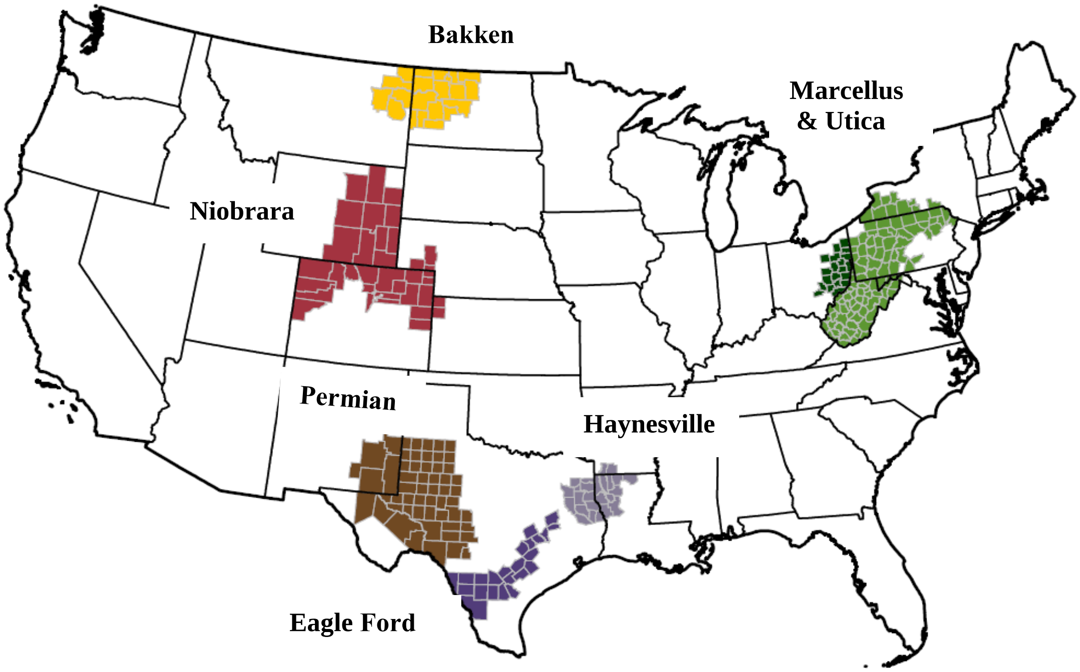
Figure 3.3 – Lower 48 States Shale Plays



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

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

Figure 3.4 – Plays Accounting for all Natural Gas Production Growth 2011 -2013



Source: *Drilling Productivity Report*, January 2015. U.S. Department of Energy, Energy Information Administration

However, even with this surfeit of gas the market is not without risks. Figure 3.5 shows Henry Hub NYMEX futures, as of January 27, 2015. While the futures are mildly in contango, price expectations offer little “signal-to-drill” in all but the lowest-cost plays. As such, producers are somewhat a victim of their own success. The fallout from reduced drilling is limited in the short term; there is no incentive to close in existing wells since the variable cost of ongoing production is small and technology efficiencies in drilling and re-fracking continue to yield productivity gains. Given the recent precipitous drop in crude prices, there will be some price support coming from decreased associated gas volumes as oil-targeted drilling is curtailed but it will be gradual. This is noteworthy since approximately 20% of supply comes from associated gas.[7] But, even with crude prices below $55/bbl there is little incentive for U.S. shale oil producers to lay down rigs right away because: 1) many U.S. shale oil producers have already hedged their 2015 production so they are covered regardless of spot price; 2) variable operating costs (not full cycle costs) are around $40/bbl for existing shale oil wells; and 3) nobody wants to be the first to cut their production – only to provide price support for competitors.

In the longer term the current lack of a “signal-to-drill” price sets the stage for asynchronous supply and demand, creating price volatility as supply chases demand – and a demand surge can be expected. While the Marcellus is prolific and breakeven costs continue to decline many other plays are higher cost with full-cycle breakeven costs greater than $4.00/MMBtu. Thus, boom and bust cycles are likely since producers respond to price signals vis-à-vis demand expectations and price signals lag demand. To make matters worse, in the past, increased power sector coal burn could displace gas and dampen volatility but, with over 60 GWs expected to retire by 2020, coal’s ability to mitigate natural gas volatility will be severely limited.[8]

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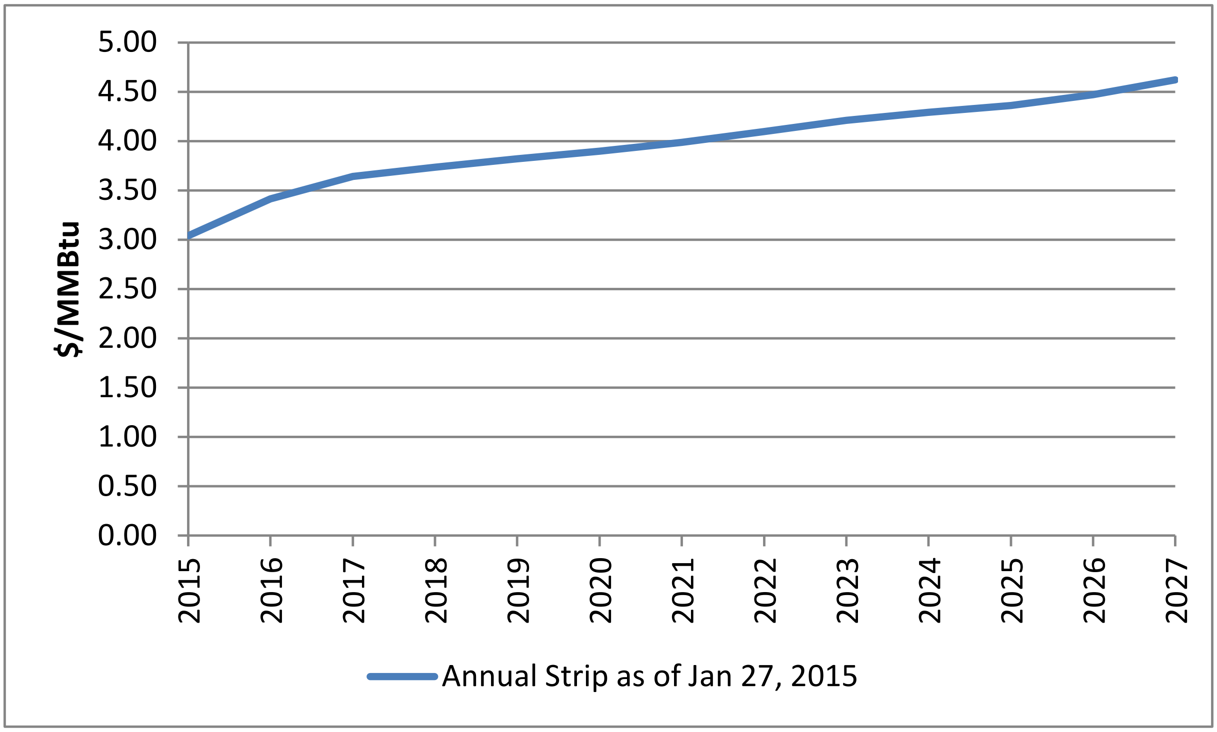
[7] Associated gas tends to be insensitive to the price of natural gas since it is produced as a byproduct to oil and/or liquids targeted drilling.

[8] *Annual Energy Outlook 2014,* Department of Energy, Energy Information Administration

Figure 3.5 – Henry Hub NYMEX Futures



The burgeoning demand for natural gas, prior to 2020, is expected to come from liquefied natural gas (LNG) exports, industry, electricity generation, and pipeline exports to Mexico.

Prior to 2009, forecasters expected that a gradual restoration of improved supply/demand balance would be achieved largely by growth in LNG imports. As such, there was tremendous growth in global liquefaction facilities located in major producing regions. This, in turn, led to significant investments in regasification capacity to accommodate future LNG imports; the U.S. has eleven existing LNG import terminals. However, the growth of domestic unconventional supplies, volumetric gains from technological efficiencies, and declining breakeven costs changed the need for LNG imports to one of LNG exports. Today, liquefaction, not regasification, facilities are being proposed with five having already been approved.[9] As such, the U.S. is anticipated to export 0.5 BCF/D starting in 2016 with volumes soaring to as much as 20 BCF/D by 2030, depending on source and scenario.[10] Several factors contribute to a wide range of price uncertainty in the mid- to long-term. Increasing well productivity, technological innovations, and large volumes of price-insensitive associated gas have flattened the supply curve. Moreover, low oil prices will dampen demand for new LNG export facilities and for oil-to-gas substitution in the transportation sector.[11] Supporting upside price risks are: 1) surging demand; 2) higher breakeven costs as producers call on higher-cost gas; 3) possible environmental restrictions on hydraulic fracturing thereby increasing recovery costs; and 4) reduced associated gas volumes as low crude prices diminish oil-targeted drilling.

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[9] Four of the five approvals were for conversion of existing regasification terminals to include liquefaction. The fifth project, in Corpus Christi, is the first approved LNG greenfield project.

[10] *Annual Energy Outlook 2014*, United States Department of Energy, Energy Information Administration.

[11] U.S. LNG export facilities, currently under construction, are safe since the export capacity is under long-term purchase agreements.

The continued build out of Appalachian take-away capacity, coupled with flow reversals on key pipelines, will keep western regional natural gas markets well-connected to North American markets as a whole. Rocky Mountain production coupled with the westward push of Marcellus volumes will maintain downward pressure on Opal vis-à-vis Henry Hub. Even West Coast prices have been pushed down 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 one of timing. Producers respond to price signals, which usually lag market demand, which then creates periods of asynchronous supply and demand.

The Future of Federal Environmental Regulation and Legislation

PacifiCorp faces a continuously changing environment with regard to electricity plant emission regulations. Although the exact nature of these changes remains uncertain, they are expected to impact the cost of future resource alternatives and the cost of existing resources in 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 successfully been passed by both the U.S. House of Representatives and the U.S. Senate for consideration by the President. The 113th Congress was challenged by the President to pursue a bipartisan, market-based solution to climate change. The President stated that if Congress did not act soon, he would direct his Cabinet to implement executive action to reduce greenhouse gas (GHG) emissions. To date, such bipartisan action has not occurred.

Accordingly, on June 25, 2013, President Obama directed the EPA to complete GHG standards for both new and existing power plants. With regard to new sources, the EPA issued a re-proposal of standards for carbon emissions from new electric generating units in September 2013. On June 2, 2014, EPA issued its Clean Power Plan proposal addressing carbon emissions from existing power plants.[12] The proposed standards are expected to be finalized by summer 2015, with implementation of regulations as proposed in state implementation plans required by summer 2016, which would require approval by the EPA. Further discussion is included below regarding how the EPA proposes to approach carbon regulation under the Clean Air Act.

Federal Renewable Portfolio Standards

Since 2010, no significant activity has occurred with respect to the development of a federal renewable portfolio standard (RPS). In addition, current political environments are shifting focus from items such as the extension of federal incentives for renewables and portfolio standards to

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[12] *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generation Units*, 79 Fed. Reg. 117 at 34836 (June 18, 2014)

the EPA's development of carbon standards. Accordingly, PacifiCorp's 2015 IRP assumes no federal RPS requirement over the course of the planning horizon.

EPA Regulatory Update – Greenhouse Gas Emissions

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

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

Guidance for Best Available Control Technology (BACT)

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

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

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

New Source Performance Standards (NSPS) are established under the CAA for certain industrial sources of emissions determined to endanger public health and welfare. NSPS must be reviewed every eight years. While NSPS were intended to focus on new and modified sources and effectively establish the floor for determining what constitutes BACT, the emission guidelines will apply to existing sources as well. In September 2013, the EPA issued a revised NSPS proposal for new fossil-fueled generating facilities. The new proposal would limit emissions of carbon dioxide to 1,000 pounds per megawatt hour (MWh) for large natural gas plants (roughly 100 MW or larger) and 1,100 pounds per MWh for smaller natural gas plants. The revised proposal continues to largely exempt simple cycle combustion turbines from meeting the standards. The standard for new coal units (1,000 to 1,100 pounds per MWh) would be set based on the application of partial carbon capture and sequestration technology. The public comment period closed in May 2014, and a final rule is expected summer 2015.

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

Consistent with the presidential directive mentioned above, the EPA issued a proposed rule, known as the Clean Power Plan, for existing sources in June 2014. At the same time, the EPA issued a proposed rule for modified or reconstructed sources. Comments on the proposed rule were due December 1, 2014, and a final rule is expected summer 2015. States will be required to submit compliance plans by summer 2016; however, a state may seek an extension to 2017 for individual plans or to 2018 for multi-state plans. The EPA has also indicated that it will propose a federal plan which states may adopt in lieu of submitting a state plan.

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). In the proposed rule, the EPA set forth emission reduction goals, expressed as a pounds of carbon dioxide per megawatt hour (lb/MWh) rate, for each state based on its formulation of BSER, which is made up of four building blocks: 1) heat rate improvements at existing coal-fueled resources; 2) increased utilization of natural gas resources; 3) increased deployment of zero-emitting resources; and 4) increased end-use energy efficiency. The EPA applied the four building blocks to the loads and resources in each state as a whole; the resulting emission reduction goal is not a requirement for individual resources but rather the goal applies on a portfolio basis to all of the resources and loads within a state. States would be required to meet the emission reduction goal by 2030, as well as an interim goal, which would be met on average over the ten-year period 2020-2029. Each state may propose how to meet its goal and is not required to achieve emission reductions in the same manner as that used by the EPA to calculate the goal.

In this IRP, the Company provides extensive analysis of potential future resource portfolios under a variety of compliance approaches to the EPA's proposed Clean Power Plan. However, significant uncertainty regarding the implementation of this program continues to exist. Once final, the rule is likely to be subject to litigation, the outcome of which may not be known for many years. In addition, the makeup of the final rule and the manner in which states choose to implement the program will have a significant impact on ultimate compliance approaches and similarly may not be known for some years. PacifiCorp will continue to monitor and engage in the EPA's rulemaking processes as well as with state agencies and a wide range of stakeholders in order to continue to assess the potential impacts of the Clean Power Plan on PacifiCorp's integrated resource planning.

EPA Regulatory Update – Non-Greenhouse Gas Emissions

Clean Air Act Criteria Pollutants – National Ambient Air Quality Standards

The CAA requires the EPA to set National Ambient Air Quality Standards (NAAQS) for certain pollutants considered harmful to public health and the environment. For a given NAAQS, the EPA and/or a state identifies various control measures that, once implemented, are meant to achieve an air quality standard for a certain pollutant, with each standard rigorously vetted by the scientific community, industry, public interest groups, and the general public.

Particulate matter (PM), sulfur dioxide (SO_2), ozone (O_3), nitrogen dioxide (NO_2), carbon monoxide (CO), and lead are often grouped together because under the CAA, each of these categories is linked to one or more NAAQS. These "criteria pollutants", while undesirable, are not toxic in typical concentrations in the ambient air. Under the CAA, they are regulated differently from other types of emissions, such as hazardous air pollutants and GHGs. Within the past few years, the EPA established new standards for particulate matter, sulfur dioxide, and nitrogen dioxide.

On November 25, 2014, the EPA issued a proposed rule to modify the standards for ground-level ozone. Comments on the proposed rule are due March 17, 2015. If revised standards are finalized, the EPA will designate areas in the country as being in "attainment" or "nonattainment" of the revised standards. Under the proposed rule, the EPA would make these designations by October 2017, and states would have until 2020 or 2037, depending on the ozone level in the area, to comply with the revised standards.

Cross-State Air Pollution Rule

In July 2011, the EPA finalized its Cross-State Air Pollution Rule (CSAPR), which required new reductions in SO_2 and nitrogen oxide (NO_X) emissions from large stationary sources, including power plants, located in 31 states and the District of Columbia. Litigation in the D.C. Circuit Court of Appeals resulted in a stay on the implementation of the CSAPR in December 2011. Ultimately, in April 2014, the U.S. Supreme Court reversed a D.C. Circuit Court of Appeals opinion that vacated the CSAPR. CSAPR Phase I implementation is now scheduled for 2015.

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

Regional Haze

The 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, the 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 impact visibility. These pollutants include fine particulate matter (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. States will be required to submit the next periodic update by July 31, 2018.

The Regional Haze Rule may drive additional SO_2 and NO_x reductions, particularly from facilities operating in the Western United States. This includes the states of Utah and Wyoming where PacifiCorp operates generating units, in 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 is nonetheless subject to the Regional Haze Rule.

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. The EPA's approval of the SO_2 SIP was appealed to federal circuit court. In addition, PacifiCorp and the state of Utah appealed the EPA's disapproval of the NO_x and PM SIP. PacifiCorp and the state's appeals were dismissed. In addition, and separate from the EPA's approval process and related litigation, the Utah Division of Air Quality undertook an additional BART analysis for each of Hunter Units 1 and 2 and Huntington Units 1 and 2, which will be provided to the EPA as a supplement to the existing Utah SIP. In October 2014, Utah proposed to amend its SIP with the updated BART analysis concluding that no incremental controls (beyond those included in the May 2011 SIP) were required at the Hunter and Huntington units. The public comment period for the amended SIP closed December 22, 2014, and the SIP is expected to be submitted for approval to the EPA in early 2015.

On January 10, 2014, the 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 - selective catalytic reduction (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 5 years

Difference aspects of the EPA's final action were appealed by a number of entities. PacifiCorp appealed the EPA's action requiring SCR at Wyodak. PacifiCorp requested, and was granted, a stay of the EPA's action as it pertains to Wyodak pending resolution of the appeals. A final decision on the appeal is expected in 2016. With respect to Naughton Unit 3, in its final action the EPA indicated support for the conversion of the unit to natural gas and that it would expedite action relative to consideration of the gas conversion once the state of Wyoming submitted the requisite SIP amendment. PacifiCorp has 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. Wyoming has not yet submitted a revised Regional Haze SIP incorporating this alternative compliance approach to the EPA.

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. The EPA approved in part, and disapproved in part, the Arizona SIP and issued a federal implementation plan (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. All appeals are pending. PacifiCorp is working with Arizona Public Service as well as state and federal agencies on an alternate compliance approach and associated approvals for Cholla Unit 4.

The state of Colorado issued a Regional Haze SIP requiring, among other things, the installation of selective non-catalytic reduction (SNCR) technology at Craig Unit 1 by 2018. Environmental groups appealed the EPA’s action, in which PacifiCorp intervened in support of the EPA. In July 2014, parties to the litigation, other than PacifiCorp, entered into a settlement agreement which requires installation of SCR equipment at Craig Unit 1 in 2021. Following settlement, the EPA filed a motion with the Tenth Circuit Court of Appeals seeking a voluntary remand to the EPA of those portions of the EPA’s approval of Colorado’s SIP relating to Craig Unit 1. This motion is pending. PacifiCorp opposed the settlement agreement between the EPA and other parties to the litigation.

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 are required to comply with the new standards by April 16, 2015. Individual sources may be granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls or for transmission system reliability reasons. On November 25, 2014, the U.S. Supreme Court announced that it will consider challenges to MATS specifically reviewing whether the EPA unreasonably refused to consider costs in making its determination to regulate hazardous pollutants from power plants. At this time, no requests for stay have been filed and the MATS rule remains in place pending a decision from the U.S. Supreme Court, expected summer 2015.

Emission reduction projects completed to date or currently permitted or planned for installation, including the scrubbers, baghouses and electrostatic precipitators required under other the EPA requirements, are consistent with achieving the MATS requirements and will support PacifiCorp’s ability to comply with the final standards for acid gases and non-mercury metallic hazardous air pollutants. PacifiCorp will be required to take additional actions to reduce mercury emissions through the installation of controls or use of reagent injection at certain of its coal-fueled generating facilities to otherwise comply with the standards.

PacifiCorp continues to plan for retirement of its Carbon facility in April 2015 as the least-cost alternative to comply with MATS and other environmental regulations for that facility. Implementation of the transmission system modifications necessary to maintain system reliability following disconnection of the Carbon facility generators from the grid is underway.

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, the EPA issued a final rule in December 2014 to regulate CCRs for the first time. Under the final rule, the EPA will regulate CCRs as nonhazardous waste under Subtitle D of RCRA and establish minimum nationwide standards for the disposal of coal combustion residuals. The final rule will be effective 180 days from publication in the federal register. Under the final rule, surface impoundments and landfills utilized for CCRs may need to close unless they can meet more stringent regulatory requirements.

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, the 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 establishes 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 U.S. and use at least 25 percent of the withdrawn water exclusively for cooling purposes. PacifiCorp's Dave Johnston generating facility withdraws more than two million gallons per day of water from waters of the U.S for once-through cooling applications. Jim Bridger, Naughton, Gadsby, Hunter, Carbon and Huntington generating facilities currently utilize closed cycle cooling towers but withdraw more than two million gallons of water per day. The 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 April 19, 2013, the EPA proposed revised effluent limit guidelines and is required, under the terms of a stipulated extension to a consent decree, to finalize the rule by September 2015. The effluent limit guidelines will also apply to gas-fired generation.

State Climate Change Regulation

While national GHG legislation has not been successfully adopted, state initiatives continue with the active development of climate change regulations that will impact PacifiCorp.

California

An executive order signed by California's governor in June 2005 would reduce GHG emissions in that state to 2000 levels by 2010, to 1990 levels by 2020 and 80 percent below 1990 levels by 2050. In 2006, the California Legislature passed, and Governor Schwarzenegger signed, Assembly Bill 32, the Global Warming Solutions Act of 2006, which set the 2020 GHG emissions reduction goal into law. It directed the California Air Resources Board (CARB) to begin developing discrete early actions to reduce GHG while also preparing a scoping plan to identify how best to reach the 2020 limit.

Pursuant to the authority of the Global Warming Solutions Act, in October 2011, CARB adopted a GHG cap-and-trade program with an effective date of January 1, 2012; compliance obligations were imposed on regulated entities beginning in 2013. The first auction of GHG 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 October 2013, CARB kicked off an Assembly Bill 32 scoping plan update designed to build upon the initial scoping plan. The scoping plan update defines climate change priorities for the next five years and sets the groundwork for post-2020 climate goals. A proposed first update issued in February 2014 indicated a post-2020 GHG reduction goal of 80 percent below 1990 levels by 2050.

Oregon and Washington

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

On July 3 2013, the Oregon Legislature passed Senate Bill 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 is to include an evaluation of how to treat imported and exported energy sources. A final report was published December 2014.

In 2008, the Washington State Legislature approved the Climate Change Framework E2SHB 2815, which establishes state GHG emissions reduction limits. Washington's emission limits are to (i) by 2020, reduce emissions to 1990 levels; (ii) by 2035, reduce emissions to 25 percent below 1990 levels; and (iii) by 2050, reduce emissions to 50 percent below 1990 levels, or 70 percent below Washington's forecasted emissions in 2050.

Greenhouse Gas Emission Performance Standards

California, Oregon and Washington have all adopted GHG emission performance standards applicable to all electricity generated within the state or delivered from outside the state that is no higher than the GHG 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 pounds of carbon dioxide equivalent per MWh, which is defined as a metric measure used to compare the emissions from various GHG based upon 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 pounds of carbon dioxide per 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 certificates (RECs) which certify renewable energy has been created, or a combination of all of these.

RPS policies are currently implemented at the state level and vary considerably in their requirements with respect to renewable targets (percentages), target dates, resource/technology eligibility, applicability of existing plants and contracts, arrangements for enforcement and penalties, and whether they allow REC trading. By the end of 2014, twenty-nine states, the District of Columbia and two territories had adopted a mandatory RPS, nine states and two territories had adopted RPS goals.[13]

Within 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

State	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 838 Oregon Renewable Energy Act (2007) • House Bill 3039 (2009)	• Initiative Measure No. 937 (2006)	• Senate Bill 202 (2008)

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[13] Database of State Incentives for Renewables & Efficiency (DSIRE) http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf

State	California	Oregon	Washington	Utah
Requirement or Goal	• 20% by 2020 • Average of 20% through 2013 • 25% by December 31, 2016 • 33% by December 31, 2020 and beyond • Based on the retail load for that compliance period	• At least 5% of load through December 31, 2014 • At least 15% of load through December 31, 2019 • At least 20% of load through December 31, 2024 • At least 25% of load for 2025 and forward. • Based on the retail load for that year • Invest in 20 MW solar by 2020 – PacifiCorp, PGE and Idaho Power combined	• At least 3% by January 1, 2012 • At least 9% by January 1, 2016 • At least 15% by January 1, 2020 • Annual targets are based on the average of the utility's load for the previous two years	• Goal of 20% by 2025 (must be cost effective • Annual targets are based on the adjusted retail sales for the calendar year 36 months prior to the target year • Adjustments for generated or purchased from qualifying zero carbon emissions and carbon capture sequestration and DSM

California

California originally established its RPS program with passage of Senate Bill 1078 in 2002. There have been several bills that have since been passed into law to amend the program. In the 2011 1st Extraordinary Special Session, the California Legislature passed Senate Bill 2[14] (SB 2 (1X)) to increase California's RPS to 33 percent by 2020. SB 2 (1X) also expanded the RPS requirements to all retail sellers of electricity and publicly owned utilities, and established the following targets for renewable procurement based on retail load:

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

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

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

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

Table 3.2 – California Compliance Period Requirements

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

SB 2 (1X) also established new “portfolio content categories” for RPS procurement, which delineated the type of renewable product that may be used for compliance and also set minimum and maximum limits on certain procurement content categories that can be used for compliance. The portfolio content categories pursuant to SB 2 (1X) are described below:

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

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

Portfolio Content Category 3 includes eligible renewable energy resource electricity products, or any fraction of the electricity, including unbundled[15] renewable energy credits that do not qualify under the criteria of Portfolio Content Category 1 or Portfolio Content Category 2.

Additionally, the California Public Utilities Commission established the balanced portfolio requirements for contracts executed after June 1, 2010. The balanced portfolio requirements set minimum and maximum levels for the Procurement Content Category products that may be used in each compliance period as shown in Table 3.3.

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[15] 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.

Table 3.3 – California Balanced Portfolio Requirements

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

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

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

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

Oregon

Oregon established the Oregon RPS with passage of Senate Bill 838 in 2007. The law, called the Oregon Renewable Energy Act[16] was adopted in June 2007 and provides a comprehensive renewable energy policy for the state. Subject to certain exemptions and cost limitations established in the Oregon Renewable Energy Act, PacifiCorp and other qualifying electric utilities must meet the following minimum targets for qualifying electricity sold to retail customers of at least five percent in 2011 through 2014, 15 percent in 2015 through 2019, 20 percent in 2020 through 2024, and 25 percent in 2025 and subsequent years. Qualifying renewable energy sources can be located anywhere in the United States portion of the Western Electricity Coordinating Council geographic area, and a limited amount of unbundled renewable energy credits can be used toward the annual compliance obligation.

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

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

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

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

PacifiCorp files an annual RPS compliance report by June 1 of every year. PacifiCorp files a renewable implementation plan on or before January 1 of even-numbered years, unless otherwise directed by the Commission. These compliance reports and implementation plans are available on PacifiCorp's website[17].

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

Utah

In March 2008, Utah's governor signed Utah Senate Bill 202[18], "Energy Resource and Carbon Emission Reduction Initiative;" legislation. Among other things, this law provides that, beginning in the year 2025, 20 percent of adjusted retail electric sales of all Utah utilities be supplied by renewable energy, if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions, and for sales avoided as a result of energy efficiency and demand-side management programs. Qualifying renewable energy sources can be located anywhere in the Western Electricity Coordinating Council areas, and unbundled renewable energy credits can be used for up to 20 percent of the annual qualifying electricity target.

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

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[17] www.pacificpower.net/ORrps

[18] http://le.utah.gov/~2008/bills/sbillenr/sb0202.pdf

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 the progress report filed on December 31, 2009 the Utah Division of Public Utilities' report to the Legislature stated that, "Given PacifiCorp's projections of its loads and qualifying electricity for 2025, PacifiCorp is well positioned to meet a target of 20 percent renewable energy by 2025."

PacifiCorp 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 an estimated target 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.

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

Washington

In November 2006, Washington voters approved Initiative 937,[19] a ballot measure establishing the Energy Independence Act, which is an RPS and energy efficiency requirement applied to qualifying electric utilities, including PacifiCorp. The law requires that qualifying utilities procure at least three percent of retail sales from eligible renewable resources or RECs by January 1, 2012 through 2015, nine percent of retail sales by January 1, 2016 through 2019 and 15 percent of retail sales by January 1, 2020 and every year thereafter.

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

PacifiCorp is required to file an annual RPS compliance report demonstrating compliance with the Energy Independence Act by June 1 of every year with the Washington Utilities and Transportation Commission. PacifiCorp's compliance reports are made available on PacifiCorp's website[20].

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.

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[19] http://www.secstate.wa.gov/elections/initiatives/text/I937.pdf

[20] www.pacificpower.net/WArps

Hydroelectric Relicensing

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

The value to relicensing hydroelectric facilities is continued availability of hydroelectric generation. Hydroelectric projects can often provide unique operational flexibility as they can be called upon to meet peak customer demands almost instantaneously and provide back-up for intermittent renewable resources such as wind. In addition to operational flexibility, hydroelectric generation does not have the emissions concerns of thermal generation. With the exception of the Klamath River, Wallowa Falls 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). The 169 MW Klamath River hydroelectric project continues to operate under its existing license while PacifiCorp works with parties to implement a 2010 settlement agreement that would result in removal of the project. The assumed date of the removal in the IRP is January 1, 2021. The 1.1 MW Wallowa Falls project and the 7.2 MW Prospect No. 3 project are currently undergoing the FERC relicensing process.

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

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

Integrated Licensing Process (ILP). The ILP involves the FERC at early stages of the relicensing and seeks to resolve stakeholder issues in a timely manner.

Potential Impact

Relicensing hydroelectric facilities involves significant process costs. The FERC relicensing process takes a minimum of five years and may take longer, depending on the characteristics of the project, the number of stakeholders, and issues that arise during the process. As of December 31, 2014, PacifiCorp had incurred approximately $10 million in costs for license implementation and ongoing hydroelectric relicensing, which are included in construction work-in-progress on PacifiCorp's Consolidated Balance Sheet. As current or upcoming relicensing and/or settlement efforts continue for the Klamath River, Wallowa Falls, Prospect No. 3, and other hydroelectric projects, additional process costs are being or will be incurred that will need to be recovered from customers. Hydro relicensing costs have and continue to have a significant impact on overall hydro generation cost. Such costs include capital investments, and related operations and maintenance costs made in fish passage facilities, recreational facilities, wildlife protection, cultural and flood management measures as well as project operational changes such as increased in-stream flow requirements to protect aquatic resources resulting in lost generation. The majority of these relicensing and settlement costs relate to PacifiCorp’s three largest hydroelectric projects: Lewis River, Klamath River and North Umpqua.

Treatment in the IRP

The known or expected operational impacts related to FERC orders and settlement commitments are incorporated in the projection of existing hydroelectric resources discussed in Chapter 5.

PacifiCorp’s Approach to Hydroelectric Relicensing

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

Utah Rate Design Information

Current rate designs in Utah have evolved over time based on orders and direction from the Public Service Commission in Utah and settlement agreements between parties during general rate cases. Most recently, current rates and rate design changes were adopted in Docket No. 13-035-184. Generally, the goals for rate design are to reflect the costs to serve customers and to provide price signals to encourage economically efficient usage. This is consistent with resource planning goals that balance consideration of costs, risk, and long-run public policy goals. The Company currently has a number of rate design elements that take into consideration these objectives, in particular, rate designs that reflect cost differences for energy or demand during different time periods and that support the goals of acquiring cost-effective energy efficiency.

Residential Rate Design

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

Changes in residential rate design that might facilitate IRP objectives include 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). Any changes in residential rate design to support energy efficiency or time-differentiated usage should be balanced with the recovery of fixed costs in order to ensure the price signals are economically efficient.

Commercial and Industrial Rate Design

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

Changes in rate design that might facilitate IRP objectives include deploying a mandatory seasonal time-of-day rate design that reflects the higher costs of on-peak usage to all commercial and industrial customers with load less than 1,000 kW rather than a self-selected few.

Irrigation Rate Design

Irrigation rates in Utah are comprised of an annual customer charge, a monthly customer charge, seasonal power charge and energy charges. The annual and monthly customer charges provide some recovery of customer-related costs incurred to serve customers regardless of usage. All other remaining costs are recovered through a seasonal power charge and energy charges. Power charge is for the irrigation season only and is designed to recover demand-related costs and to encourage irrigation customers to control and reduce their power consumption. Energy charges for irrigation customers are designed with two options. One is a time-of-day program with higher rates for on-peak consumption than for off-peak consumption. The Company is currently implementing a new irrigation time-of-use pilot in Oregon and may evaluate future changes to the Utah irrigation time-of-day program based on findings from the Oregon pilot. Irrigation customers also have an option to participate in a third party operated Irrigation Load Control Program. Customers are offered a financial incentive to participate in the program and give the Company the right to interrupt the service to the participating customers when energy costs are higher.

Energy Imbalance Market

PacifiCorp signed a memorandum of understanding with the CAISO February 12, 2013 to outline terms for the implementation of an EIM by October 2014. A benefit study was completed by Energy and Environmental Economics which shows a range of benefits to PacifiCorp and the ISO in 2017 from $21.44 million to $128.7 million per year. The Company's costs payable to CAISO are a one-time start-up fee of $2.1 million and on-going annual fees of $1.3 million. These are in addition to internal Company costs for items such as metering, software and additional staffing.

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

The EIM between PacifiCorp and CAISO launched at midnight November 1, 2014, following a 30-day test period. The new market provides automated, optimized five-minute security constrained economic dispatch across the combined balancing authority areas. The market immediately began generating benefits for customers with significant economic transfers to California occurring throughout the month of November and December with volumes exceeding 150,000 MWh. The EIM successfully modeled and integrated a variety of different energy contracts, jointly owned facilities, two balancing areas, non-power hydro constraints and wind resources into one integrated balancing area with CAISO. This degree of functionality should accommodate the varied and unique balancing areas for many of the western utilities. A regional imbalance-styled energy market has been discussed for many years in the WECC; given the relative success of the EIM in the first few months of operation, PacifiCorp is encouraged that greater efficiencies lie ahead.

As would be expected with any new market, the EIM has undergone many enhancements since the go-live date. Both CAISO and PacifiCorp have improved the EIM model, situational awareness tools for real-time operators and system integration between vendors and the ISO. PacifiCorp's Participating Resources have had their parameters modified in the resource data template to better align with the many systems within the EIM. The ability to start the EIM on schedule has provided additional time for both CAISO and PacifiCorp to further refine market systems. This ensures successive entrants into the EIM will have fewer challenges incorporating their systems into this regional energy imbalance market. PacifiCorp has fielded calls from many different western utilities who have expressed interest in joining the EIM. Part of the corporate goals for PacifiCorp in 2015 is to foster greater awareness and support of those utilities.

In regard to planning, PacifiCorp has made few changes to the normal day-to-day operation of its system. This is due to the fact that PacifiCorp is still the lone entrant in the EIM. However, with the expected increase in participation, PacifiCorp will begin to make modifications to the IRP in regard to benefits that the EIM will produce. These benefits include a reduction in reserve carrying requirements, transmission improvements to mitigate congestion and greater reliance on renewable energy.

On November 25, 2013 the Washington Utilities and Transportation Commission (WUTC) found PacifiCorp's 2013 IRP meets the requirements of Revised Code of Washington 19.280.030 and Washington Administrative Code 480-100-238. In their comments the WUTC requested the 2015 IRP "contain a detailed analysis, based on up-to-date data, of how participation in the EIM will impact the load-resource balance in the West Control Area, and potentially defer the need for new generation resources." As the go-live date was late last year there is not enough information at this point for a detailed analysis. One thing to note; the EIM is not envisioned to impact load resource balance in the West. As such, it should not impact resource additions in the future. As a participant in EIM, PacifiCorp retains responsibility for resource adequacy.

Recent Resource Procurement Activities

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

Table 3.4 – PacifiCorp's Request for Proposal Activities

RFP	RFP Objective	Status	Issued	Completed
Oregon Solar 2013S	7.0 MW_{AC}	Pending	1st Quarter 2013	December 2015
Natural Gas	Long-term physical and financial products	Complete	May 2012	May 2013
Natural Gas Transportation	Firm natural gas supply to Naughton starting 2015	Canceled	December 2013	March 2014
Renewable energy credits (Sale)	Excess system RECs	Open	Quarterly	Ongoing
Renewable energy credits (Purchase)	Oregon compliance needs	Open	Based on specific need	Ongoing
Renewable energy credits	Washington	Open	Based on	Ongoing

RFP	RFP Objective	Status	Issued	Completed
(Purchase)	compliance needs		specific need	
Renewable energy credits (Purchase)	California compliance needs	Open	Based on specific need	Ongoing
Short-term Market (Sales)	System balancing	Open	Quarterly	Ongoing

Demand-side Resources

The Company will procure and/or re-procure for several major delivery contracts in 2015 and 2016 such as the residential appliance recycling program, Home Energy Savings program, its small to mid-size business support services, energy management services, and oil and gas sector service delivery. The Company will also look to expand services to the multifamily and manufactured home sector either through the Home Energy Service program re-procurement or through a standalone request for proposals.

Oregon Solar Request for Proposal

PacifiCorp secured a 2.0 MW_{AC} solar photovoltaic project in 2012 located in Lakeview, Oregon as a result of its 2010 solar RFP to meet Oregon Statute ORS 757.370 pertaining to the solar photovoltaic generating capacity standard, which requires Oregon utilities to acquire at least 20 MW_{AC}. PacifiCorp's share of the total is a minimum of 8.7 MW_{AC} operational by 2020. A second solar RFP was issued in second quarter 2013 with a subsequent update of bids in April 2014. The RFP sought a total of 7.0 MW_{AC} to meet PacifiCorp's remaining share of the standard. PacifiCorp is in negotiation with bidders for two projects.

Natural Gas Transportation Request for Proposals

PacifiCorp issued a natural gas transportation RFP in December 2013 to secure firm natural gas supply to its Naughton Unit 3 power plant after the planned plant conversion to natural gas in April 2015. In March 2014, PacifiCorp received a permit allowing for a 2018 natural gas conversion schedule, therefore the RFP was canceled and a new request for proposals process will be initiated in early 2016.

Renewable Energy Credit (REC) Request for Proposals

PacifiCorp issued multiple REC RFPs in 2013 and 2014 for two purposes; (i) the sale of RECs in excess of compliance needs to market and, (ii) purchase of RPS-eligible RECs to fulfill specific short-term needs to PacifiCorp's RPS obligation in Oregon, Washington, and California. The REC sale RFPs are typically issued on a quarterly basis and will continue in that format for 2015. The RPS-eligible REC purchase RFPs are issued specific to address a state RPS compliance shortfalls.

Oregon

PacifiCorp issued a request for proposal to the market in December 2012, seeking offers of renewable energy credits from generation facilities that are certified by the Oregon Department of Energy as eligible for the Oregon Renewable Portfolio Standard. Procurement of unbundled

RECs were completed to partially defer qualified resource additions in the future to comply with Oregon RPS requirements.

Washington

PacifiCorp issued a request for proposal to the market in August 2013 and October 2014, seeking offers of renewable energy credits from generation facilities that are eligible for Washington's renewable portfolio program (Washington Initiative 937). Procurement of unbundled RECs were completed to comply with Washington's renewable portfolio program requirements.

California

PacifiCorp issued a request for proposal to the market in March 2014, seeking offers of renewable energy credits from generation facilities that are eligible for California's renewable portfolio standard.

Short-term Market Power Request for Proposals

PacifiCorp issued multiple short-term market power RFPs in 2013 and 2014 to sell power for system balancing purposes. These RFPs are typically issued on a quarterly basis and will continue through 2015.

CHAPTER 4 – TRANSMISSION

CHAPTER HIGHLIGHTS

- PacifiCorp is obligated to plan for and meet its customers' future needs, despite uncertainties surrounding environmental and emissions regulations and potential new renewable resource requirements. Regardless of future policy direction, the Company's planned transmission projects are well aligned to respond to changing policy direction, comply with increasing reliability requirements while providing sufficient flexibility to ensure investments cost-effectively and reliably meet its customers' future needs.
- Given the long periods of time necessary to site, permit and construct major new transmission lines, these projects need to be planned well in advance and developed in time to meet customer need.
- The Company's transmission planning and benefits evaluation efforts adhere to regulatory and compliance requirements and are responsive to commission and stakeholder requests for a robust evaluation process and criteria for evaluating transmission additions.
- 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 with continued permitting of the Walla Walla to McNary transmission line.
- While construction 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, the Company believes continued permitting of these segments is warranted to ensure it is well positioned to advance these projects as required to meet customer need.

Introduction

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

1. Reliable delivery of energy to continuously changing customer demands under a wide variety of system operating conditions.
2. Ability to supply aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled outages and the ability to maintain reliability during unscheduled outages.
3. Economic exchange of electric power among all systems and industry participants.
4. Development of economically feasible generation resources in areas where it is best suited.
5. Protection against extreme market conditions where limited transmission constrains energy supply.
6. Ability to meet obligations and requirements of PacifiCorp's Open Access Transmission Tariff (OATT).
7. Increased capability and capacity to access 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 its network customers' 10-year load and resource (L&R) forecasts. Each year, the Company solicits L&R data from each of its network customers in order to determine future load and resource requirements for all transmission network customers. These customers include PacifiCorp Energy (which serves PacifiCorp's retail customers and comprises the bulk of the Company's transmission network customer needs), Utah Associated Municipal Power Systems, Utah Municipal Power Agency, Deseret Generation & Transmission Cooperative (including Moon Lake Electric Association), Bonneville Power Administration, Basin Electric Power Cooperative, Black Hills Power and Light, Tri-State Generation & Transmission, the States Department of the Interior Bureau of Reclamation, and Western Area Power Administration.

The Company uses its customers' L&Rs and best available information to determine project need and investment timing. In the event that customer L&R forecasts change significantly, PacifiCorp may consider alternative deployment scenarios and/or schedules for its project investment as appropriate. Per FERC guidelines, the Company is able to reserve transmission network capacity based on this 10-year forecast data. PacifiCorp's experience, however, is that the lengthy planning, permitting and construction timeline required for significant transmission investments, as well as the typical useful life of these facilities, is well beyond the 10-year timeframe of load and resource forecasts.[21] A 20-year planning horizon and ability to reserve transmission capacity to meet forecasted need over that timeframe is more consistent with the time required to plan for and build large scale transmission projects, and PacifiCorp supports clear regulatory acknowledgement of this reality and corresponding policy guidance.

Reliability Standards

PacifiCorp is required to meet mandatory FERC, North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards and planning requirements.[22] 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 parts of the system are out of service. Factored into these assessments are load growth forecasts, operating history, seasonal performance, resource additions or removals, new transmission asset additions, and the largest transmission

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[21] For example, PacifiCorp's application to begin the Environmental Impact Statement process for Gateway West of its Energy Gateway Transmission Expansion Project was filed with the Bureau of Land Management in 2007 and was received in late April 2013.

[22] FERC requirements; NERC standards; WECC standards.

and generation contingencies. Based on these analyses, the Company identifies any potential system deficiencies and determines the infrastructure improvements needed to reliably meet customer loads. NERC planning standards define reliability of the interconnected bulk electric system in terms of adequacy and security. Adequacy is the electric system's ability to meet aggregate electrical demand for customers at all times. Security is the electric system's ability to withstand sudden disturbances or unanticipated loss of system elements. Increasing transmission capacity often requires redundant facilities in order to meet NERC reliability criteria.

This chapter provides:

- Justification supporting acknowledgement of the Company's plan to construct the Wallula to McNary transmission project and support for the Company's plan to continue permitting Walla Walla to McNary.
- Support for the Company's plan to continue permitting Gateway West and Gateway South;
- 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 the Company's federal regulatory obligations to its network transmission customers under its OATT. The project consists of a thirty mile 230 kilovolt (kV) transmission line between Wallula, Washington and McNary, Oregon and represents a portion of the Walla Walla, Washington to McNary, Oregon Energy Gateway transmission project (Segment A). Since 2008, the Company has worked with stakeholders to pursue permitting of the transmission project. In 2009, the Company decided to move forward with pursuing 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 Oregon Public Utility Commission. In 2014, transmission customers determined a continued need for the Wallula to McNary portion of the transmission line that has prompted the Company to restart permitting and right-of-way activities. In addition, federal, county and local public outreach activities have been reinitiated in 2015. The project is estimated to be placed into service in 2017, subject to completion of permitting. To meet its obligation to network transmission customers under the OATT, the Company requests regulatory acknowledgement of the Wallula to McNary transmission project.

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 network 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 service transmission customers under the OATT and improve reliability in the area by providing a second connection between Wallula to McNary and a future connection between Walla Walla to McNary (see below Plan to Continue Permitting – Walla Walla to McNary). The transmission line will support future resource growth, including access to renewable energy, and transmission needs.

Plan to Continue Permitting – Walla Walla to McNary

The Walla Walla to McNary transmission project will offer benefits under multiple, future resource scenarios. In addition, as part of its agreements to exchange certain assets with Idaho Power there is an option upon close of the asset exchange for Idaho Power to partner with PacifiCorp to construct the remaining Walla Walla to Wallula portion of the transmission line.[23] To ensure the Company is well positioned to advance the projects as required to meet customer need, PacifiCorp believes it is prudent to continue to permit the Walla Walla to McNary transmission project.

Gateway West – Continued Permitting

The Gateway West transmission project is comprised of two segments: 1) Windstar to Populus (Energy Gateway Segment D) and 2) Populus to Hemingway (Energy Gateway Segment E). In a future IRP, the Company will support a request for acknowledgement to construct 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 the Windstar to Populus or the Populus to Hemingway 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:

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

Figure 4.1 – Segment D

- A single-circuit 500 kV line running approximately 200 miles between the new annex substation 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

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

performance of the transmission system (i.e. reduced line losses), improve reliability, and enable access to a diverse range of new resource alternatives over the long-term.

Under the National Environmental Policy Act, the Bureau of Land Management (BLM) has completed the Environmental Impact Statement (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. The BLM is currently conducting a supplemental environmental analysis for that portion of the segment of the project which encompasses that area. A final record of decision is expected in late 2016, subject to permitting completion.

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), extending approximately 400 miles from the planned Aeolus substation in southeastern Wyoming into the Clover substation near Mona, Utah.

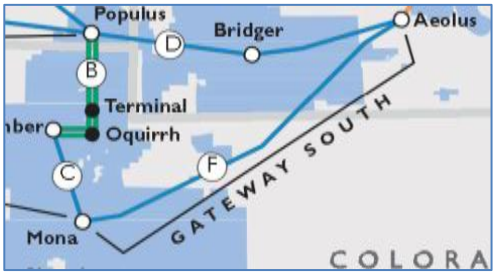

Figure 4.3 – Segment F

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. Further comments were submitted on the draft EIS and a final EIS is expected in fall of 2015 with a Record of Decision to follow in late 2015.

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 as required to meet customer need, PacifiCorp believes it is prudent to continue to permit the Gateway West and Gateway South transmission projects.

Evolution of the Energy Gateway Transmission Expansion Plan

Introduction

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

Background

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

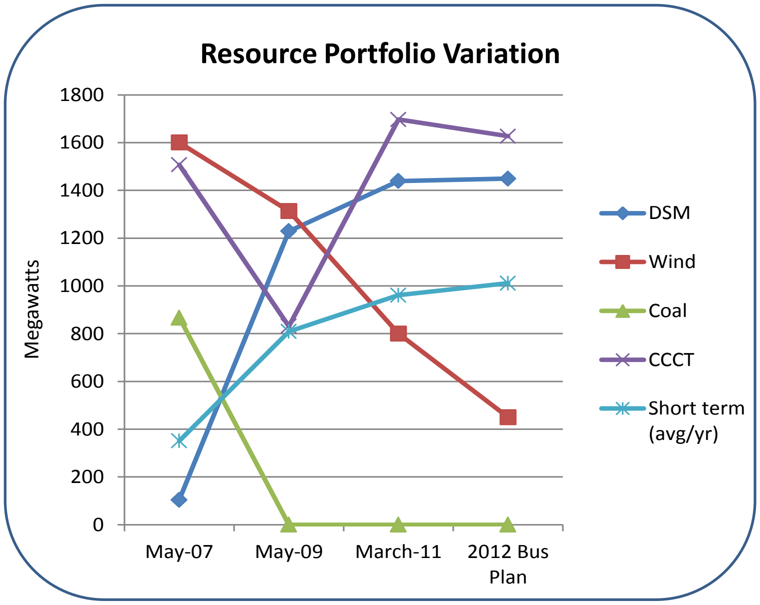

Figure 4.4 – Resource Portfolio Variation

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

Planning Initiatives

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

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

- ***Rocky Mountain Area Transmission Study***[24]
  Recommended transmission expansions overlap significantly with Energy Gateway configuration, including:
    - Bridger system expansion similar to Gateway West
    - Southeast Idaho to Southwest Utah expansion akin to Gateway Central and Sigurd-Red Butte
    - Improved East-West connectivity similar to Energy Gateway Segment H alternatives

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

- ***Western Governors' Association Transmission Task Force Report***[25]
  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.

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[24] http://psc.state.wy.us/rmats/rmats.htm

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

- ***Northern Tier Transmission Group Transmission Planning Reports***
    - 2007 Fast Track Project Process and Annual Planning Report[26]
    - 2008-2009 Transmission Plan[27]
    - 2010-2011 Transmission Plan[28]

  Each Energy Gateway segment was included in the 2007 Fast Track Project Process and has since been reevaluated as part of each Northern Tier Transmission Group biennial planning process. These are open, stakeholder processes.

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

- ***WECC/TEPPC Annual Reports* and *Western Interconnection Transmission Path Utilization Studies*** [29]

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

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

Energy Gateway Configuration

For addressing constraints identified on PacifiCorp's system, as well as meeting system reliability requirements discussed further below, the recommended bulk electric transmission additions took on a consistent footprint, which is now known as Energy Gateway. This expansion plan establishes a triangle over Utah, Idaho and Wyoming with paths extending into Oregon and Washington, and contemplates logical resource locations for the long-term based on environmental constraints, economic generation resources, and federal and state energy policies. Since Energy Gateway's announcement, this series of projects has continued to be vetted through multiple public transmission planning forums at the local, regional and interconnection-wide levels. In accordance with the local planning requirements in PacifiCorp's federal OATT, Attachment K, the Company has conducted numerous public meetings on Energy Gateway and transmission planning in general. Meeting notices and materials are posted publicly on PacifiCorp's Attachment K Open Access Same-time Information System (OASIS) site. PacifiCorp is also a member of the Northern Tier Transmission Group (NTTG) and WECC's Transmission Expansion Policy and Planning Committee (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.[30]

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

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

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

[29] http://www.wecc.biz/committees/BOD/TEPPC/External/Forms/external.aspx

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

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

Energy Gateway's Continued Evolution

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

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

As originally announced in May 2007, Energy Gateway consisted of a combination of single- and double-circuit 230 kV, 345 kV and 500 kV lines connecting Wyoming, Idaho, Utah, Oregon and Nevada. In response to regulatory and industry input regarding potential regional benefits of "upsizing" the project capacity (e.g. maximized use of energy corridors, reduced environmental impacts and improved economies of scale), the Company included in its original plan the potential for doubling the project's capacity to accommodate third-party and equity partnership interests. During late 2007 and early 2008, PacifiCorp received in excess of 6,000 MW of requests for incremental transmission service across the Energy Gateway footprint, which supported the upsized configuration. The Company identified the costs required for this upsized system and offered transmission service contracts to queue customers. These customers, however, were unable to commit due to the upfront costs and lack of firm contracts with customers to take delivery of future generation, and withdrew their requests. In parallel, PacifiCorp pursued several potential partnerships with other transmission developers and entities with transmission proposals in the Intermountain Region. Due to the significant upfront costs inherent in transmission investments, firm partnership commitments also failed to materialize, leading the Company to pursue the current configuration with the intent of only developing system capacity sufficient to meet the long-term needs of its customers.

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

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

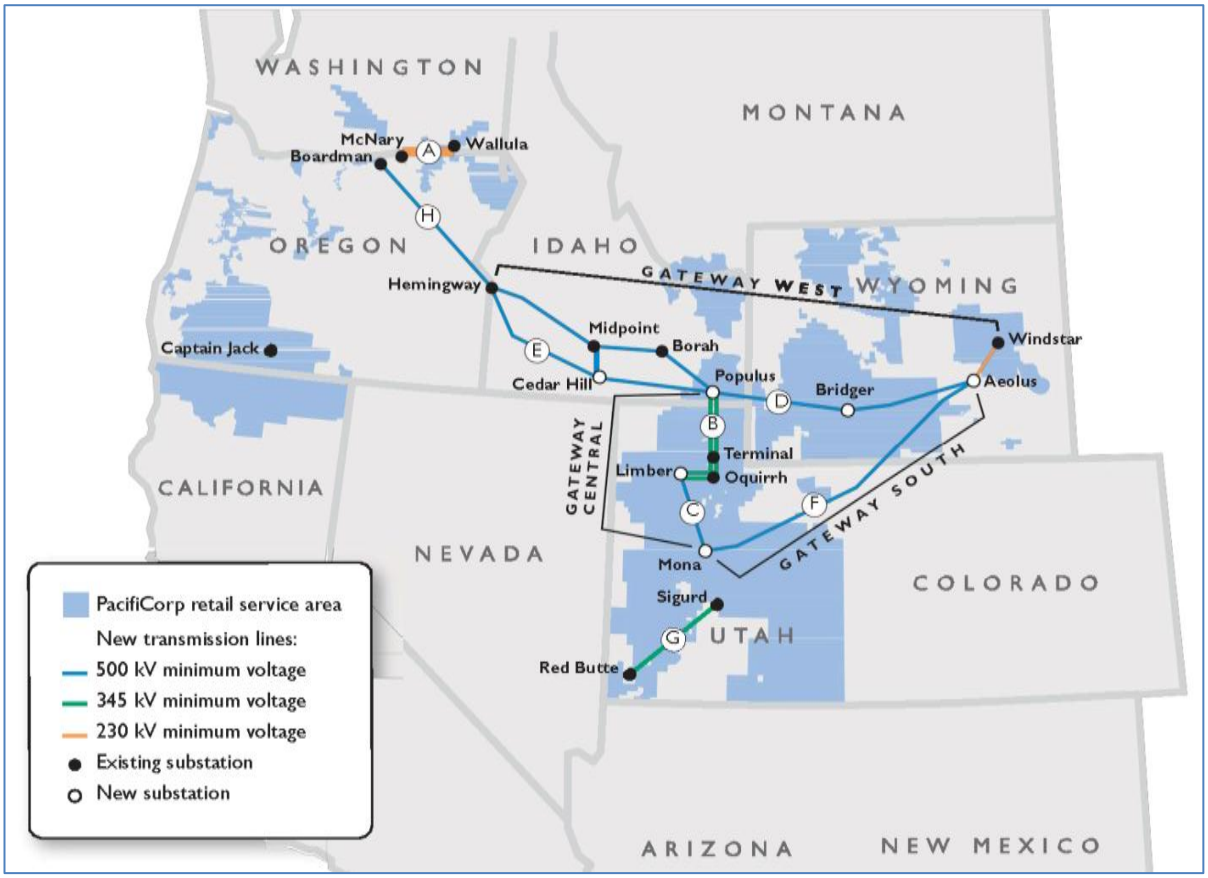
In 2012, the Company determined, due to experience with land use limitations and National Environmental Policy Act permitting requirements, that one new 230 kV line between the Windstar and Aeolus substations and a rebuild of the existing 230 kV line was feasible, and that the second new proposed 230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

In January 2013, the Company began discussions with PGE regarding changes to its Cascade Crossing transmission project and potential opportunities for joint-development and/or firm capacity rights into PacifiCorp's Oregon system. The Company further notes that it had a memorandum of understanding with PGE with respect to 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 a Cascade Crossing solution with BPA. However, because PGE decided to end discussions with BPA and instead pursue other options, PacifiCorp is not actively pursuing this development. PacifiCorp continues to look to partner with third parties on transmission development as opportunities arise such as potential partnership opportunities with Idaho Power and BPA on the Boardman to Hemingway project as an alternative to PacifiCorp's originally proposed transmission segment from eastern Idaho into southern Oregon (Hemingway to Captain Jack). 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.

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

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

Figure 4.5 – 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[31] and Scheduled In-Service
(A) Wallula-McNary	230 kV, single circuit	30 mi	• Status: local permitting completed • Scheduled in-service: 2017 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: June 2021*
(D) Windstar-Populus	230 kV single circuit 500 kV single circuit	400 mi	• Status: permitting underway • Scheduled in-service: 2019-2024*
(E) Populus-Hemingway	500 kV single circuit	500 mi	• Status: permitting underway • Scheduled in-service: 2019-2024*
(F) Aeolus-Mona	500 kV single circuit	400 mi	• Status: permitting underway • Scheduled in-service: 2020-2024*
(G) Sigurd-Red Butte	345 kV single circuit	170 mi	• Status: construction began April 2013 • Scheduled in-service: May 2015
(H) Boardman to Hemingway	500 kV single circuit	500 mi	• Status: pursuing joint-development and/or firm capacity opportunities with project sponsors • Scheduled in-service: sponsor driven

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

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[31] Status as of the filing of this IRP.

Efforts to Maximize Existing System Capability

In addition to investing in the Energy Gateway transmission projects, the Company continues to make other system improvements that have helped maximize efficient use of the existing 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 120 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 California Independent System Operator's ("ISO") Energy Imbalance Market ("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 PacifiCorp's east and west balancing authority areas and the ISO's balancing authority area for use as short-term balancing resources to ensure energy supply matches demand. By broadening the pool of lower-cost resources that can be accessed to balance systems, reliability is enhanced and system costs are reduced. In addition, the automated system is able to identify and utilize available transmission capacity to transfer the dispatched resources enabling more efficient use of the available transmission system. Other opportunities that maximize existing transmission capability include the PacifiCorp and Idaho Power asset exchange as mentioned earlier in this chapter. This arrangement, if approved by regulators, would result in an exchange of transmission assets between the parties that optimizes ownership rights and transfer capability across certain transmission lines.

In addition to the Energy Gateway transmission projects, PacifiCorp also has other planned transmission system improvements to be placed in-service over the next couple of years include:

- Construct new Standpipe substation and install a synchronous condenser located in Wyoming;
- Install an additional 230/115 kV 250 MVA transformer at Casper substation located in Wyoming;
- Install shunt capacitors at Fry substation located in Oregon;
- Install a load shedding scheme at Grass Creek substation and Thermopolis substation located in Wyoming;
- Install shunt capacitors and a static var compensator at Mathington substation located in Utah;
- Install a phase shifting transformer and series reactor at Upalco substation located in Utah;
- Install an additional 230/115 kV 250 MVA transformer and 230 kV ring bus at Union Gap substation located in Washington;
- Expand the 230 kV ring bus at Pomona Heights substation located in Washington;
- Install new relays on the Rigby to Sugarmill 161 kV line located in Idaho;
- Install new relays on the Rigby to Jefferson 161 kV line located in Idaho;
- Install a phase shifting transformer at Pinto substation located in Utah;
- Construct new Whetstone substation located in Oregon;
- Construct a 10 mile 46 kV line from the Holden substation tap to the Flowell Robison line located in Utah;
- Convert the Highland substation to 138 kV located in Utah;

- Construct a 138 kV line from Croydon substation to Silver Creek substation located in Utah;
- Convert the existing 69 kV line to 115 kV from Community Park substation to Casper substation located in Wyoming;
- 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;
- Install a 138/46kV transformer at Snyderville substation located in Utah.

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.

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CHAPTER 5 – RESOURCE NEEDS ASSESSMENT

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 peak load hour.
- For capacity expansion planning, the Company uses a 13% target planning reserve margin applied to PacifiCorp's obligation, which is calculated as projected load less distributed generation (DG), less existing Class 2 demand side management (DSM) energy efficiency savings, and less interruptible load.
- A 2014 study prepared by Navigant Consulting, Inc. produced estimates on DG 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 2015 IRP resource needs assessment treats base case DG 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 0.89% over the period 2015 through 2024. On an energy basis, PacifiCorp expects system-wide average load growth of 0.85% per year from 2015 through 2024.
- After accounting for front office transaction (FOT) availability, and prior to incorporation of future demand-side management resources, PacifiCorp's system planning reserve margin falls just short of its target planning reserve margin in 2020. With the expiration of a legacy contract, reserve margins are on target through 2022.

Introduction

This chapter presents PacifiCorp's assessment of resource needs, focusing on the first ten years of the IRP's 20-year study period, 2015 through 2024. 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. The summary level system coincident peak is presented first, followed by a profile of PacifiCorp's existing resources. Finally, load and resource balances for capacity and energy are presented. These balances are comprised of a year-by-year comparison of projected loads against the existing resource base, inclusive of available FOTs, prior to adding new resources to the portfolio.

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.

The 2015 IRP relies upon the Company's September 2014 load forecast. Table 5.1. shows the annual coincident peak load stated in megawatts as reported in the capacity load and resource balance prior to any load reductions from Class 2 DSM or DG. The system peak load grows at a compounded average annual growth rate (CAAGR) of 0.89% over the period 2015 through 2024.

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

Region	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
System	10,368	10,225	10,381	10,522	10,635	10,755	10,876	10,996	11,105	11,224

Existing Resources

On a system coincident basis, PacifiCorp is a summer-peaking utility. For the forecasted 2015 summer coincident peak, PacifiCorp owns, or has interest in, resources with an expected system peak capacity of 11,810 MW. Table 5.2 provides anticipated system peak capacity ratings by resource category as reflected in the IRP load and resource balance for 2015. 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 – 2015 Capacity Contribution at System Peak for Existing Resources

Resource Type [1/]	L&R Balance Capacity at System Peak (MW) [2/]	Percent of Total (%)
Pulverized Coal	5,938	50.3%
Gas-CCCT	2,598	22.0%
Gas-SCCT	369	3.1%
Hydroelectric	894	7.6%
DSM [3/]	433	3.7%
Renewables	356	3.0%
Purchase [4/]	818	6.9%
Qualifying Facilities	255	2.2%
Interruptible Contracts	149	1.3%
Total	**11,810**	**100%**

[1/] Sales and Non-Owned Reserves are not included.

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

[3/] DSM includes existing Class 1 (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-fired thermal plants and Table 5.4 lists existing natural gas fired plants. The assumed end of life dates are used for the 2015 IRP modeling of existing coal resources.

Table 5.3 – Coal Fired Plants

Plant	PacifiCorp Percentage Share (%)	State	Assumed End of Life Year	L&R Balance Capacity at System 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	83
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	348
Jim Bridger 4	67	WY	2037	353
Naughton 1	100	WY	2029	156
Naughton 2	100	WY	2029	201
Naughton 3*	100	WY	2029	293
Wyodak	80	WY	2039	268
TOTAL – Coal				**5,938**

* Naughton Unit 3 is planned to be converted to natural gas in 2018.

Table 5.4 – Natural Gas Plants

Natural Gas - fueled	PacifiCorp Percentage Share (%)	State	Assumed End of Life Year	L&R Balance Capacity at System Peak (MW)
Chehalis	100	WA	2043	465
Currant Creek	100	UT	2045	518
Gadsby 1	100	UT	2032	64
Gadsby 2	100	UT	2032	69
Gadsby 3	100	UT	2032	105
Gadsby 4	100	UT	2032	39
Gadsby 5	100	UT	2032	39
Gadsby 6	100	UT	2032	39
Hermiston 1 *	50	OR	2036	227
Hermiston 2 *	50	OR	2036	227
Lake Side	100	UT	2047	537
Lake Side 2	100	UT	2054	624
James Riv. (CHP)	100	WA	2015	14
TOTAL – Gas and Combined Heat & Power				**2,967**

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

Renewable Resources

Wind

PacifiCorp either owns or purchases under contract 2,373 MW of wind resources. Since the 2013 IRP Update, the Company has entered into power purchase agreements totaling 250 MW.

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

Table 5.5 – PacifiCorp-owned Wind Resources

Utility-Owned Wind Projects	State	Capacity (MW)	L&R Balance Capacity at System Peak (MW)
Foote Creek I *	WY	32	6
Leaning Juniper	OR	101	26
Goodnoe Hills Wind	WA	94	24
Marengo	WA	140	36
Marengo II	WA	70	18
Glenrock Wind I	WY	99	14
Glenrock Wind III	WY	39	6
Rolling Hills Wind	WY	99	14
Seven Mile Hill Wind	WY	99	14
Seven Mile Hill Wind II	WY	20	3
High Plains	WY	99	14
McFadden Ridge 1	WY	29	4
Dunlap 1	WY	111	16
TOTAL – Owned Wind		**1,032**	**195**

*PacifiCorp's share is 32 MW of the 40 MW project.

Table 5.6 – Non-owned Wind Resources

Power Purchase Agreements / Exchanges	PPA or QF	State	Capacity (MW)	L&R Balance Capacity at System Peak (MW)
Combine Hills	PPA	OR	41	10
Foote Creek IV	PPA**	WY	17	2
Rock River I	PPA	WY	50	7
Stateline Wind	PPA**	OR / WA	175	45
Three Buttes Wind Power	PPA	WY	99	14
Top of the World	PPA	WY	200	29
Wolverine Creek	PPA	ID	65	9
Blue Mountain*	QF	UT	80	11
Casper Wind	QF	WY	17	2
Chopin*	QF	WA	10	3
Foote Creek II	QF	WY	2	0
Foote Creek III	QF	WY	25	4
Latigo Wind*	QF	UT	60	9
Mariah Wind*	QF	OR	10	3
Meadow Creek Project – Five Pine	QF	ID	40	6
Meadow Creek Project – North Point	QF	ID	80	12
Mountain Wind Power I	QF	WY	61	9
Mountain Wind Power II	QF	WY	80	12
Oregon Wind Farms I & II	QF	OR	65	16
Orem Family Wind*	QF	OR	10	3
Pioneer Wind Park I*	QF	WY	80	12
Power County Wind Park North	QF	ID	23	3
Power County Wind Park South	QF	ID	23	3
Spanish Fork Wind Park 2	QF	UT	19	3
Three Mile Canyon	QF	WA	10	3
TOTAL – Purchased Wind			**1,341**	**229**

*New since the 2013 IRP Update. ** Storage and integration only

Solar

PacifiCorp has a total of 31 solar projects under contract representing 579 MW of nameplate capacity. Of these, fifteen projects totaling 523 MW are new since the 2013 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 Peak (MW)
Bevans Point	PPA	OR	2	1
Black Cap	PPA	OR	2	1
Utah Solar PV Program	PPA	UT	2	1
Old Mill	PPA	OR	5	2
Oregon Solar Incentive Projects (OSIP)	PPA	OR	2	1
Adams Solar Center *	QF	OR	10	4
Bear Creek Solar Center *	QF	OR	10	4
Beatty Solar*	QF	OR	5	2
Beryl Solar	QF	UT	3	1
Black Cap Solar II*	QF	OR	8	3
Bly Solar Center *	QF	OR	10	4
Buckhorn Solar	QF	UT	3	1
Cedar Valley Solar	QF	UT	3	1
Elbe Solar Center *	QF	OR	10	4
Enterprise Solar *	QF	UT	80	31
Escalante Solar I *	QF	UT	80	31
Escalante Solar II *	QF	UT	80	31
Escalante Solar III *	QF	UT	80	31
Fiddler's Canyon Solar 1-3	QF	UT	9	4
Granite Peak Solar	QF	UT	3	1
Greenville Solar	QF	UT	2	1
Ivory Pine Solar*	QF	OR	10	4
Laho Solar	QF	UT	3	1
Manderfield Solar	QF	UT	2	1
Milford Flat Solar	QF	UT	3	1
Milford Solar 2 *	QF	UT	3	1
Pavant Solar *	QF	UT	50	20
Quichapa Solar 1- 3	QF	UT	9	4
South Milford Solar	QF	UT	3	1
Sprague River Solar*	QF	OR	7	3
Utah Red Hills Renewable Park *	QF	UT	80	31
TOTAL – Purchased Solar			**579**	**223**

*New since the 2013 IRP Update.

Geothermal

PacifiCorp owns and operates the Blundell Geothermal Plant in Utah, which uses naturally created steam to generate electricity. The plant has a net generation capacity of 34 MW. Blundell is a fully renewable, zero-discharge facility. The bottoming cycle, which increased the output by 11 MW, was completed at the end of 2007. The Oregon Institute of Technology added a new small qualifying facility (QF) using geothermal technologies to produce renewable power for the campus and is rated at 0.28 MW. The Company has also entered into a QF agreement for a 10 MW Oregon geothermal plant undergoing development. The project is in default for missing commercial operating date (COD), but has not been terminated. The current scheduled commercial operation date is June 2017.

Biomass / Biogas

PacifiCorp has biomass/biogas agreements with 19 projects totaling approximately 100 MW of nameplate capacity. Each state served by PacifiCorp contains at least one project. Four of these projects totaling 6.6 MW were added since the 2013 IRP Update.

Renewables Net Metering

As of year-end 2014, PacifiCorp had 8,266 net metering customers throughout its six-state territory, generating more than 70,000 kW using solar, hydro, wind, and gas technologies. About 96% of net-metered customer generation is solar-based, followed by wind-based generation at 1.2%. Net metering has grown by more than 48% over the past year. The Company averaged 171 new net metered customers a month in 2014, compared to 115 new customers per month in 2013. Table 5.8 provides a breakdown of net metered capacity and customer counts from data collected on January 3, 2015.

Table 5.8 – Net Meter Customers and Capacities

Fuel	Solar	Wind	Gas*	Hydro	Mixed**
Nameplate (kW)	67,205	858	914	548	758
Capacity (percentage)	95.62%	1.22%	1.30%	0.78%	1.08%
Number of customers	7,993	207	5	12	49
Customer (percentage)	96.69%	2.50%	0.06%	0.15%	0.59%
*Gas includes: biofuel, waste gas, and fuel cells					
**Mixed includes projects with both wind and solar					

Hydroelectric Generation

PacifiCorp owns 1,145 MW[32] of hydroelectric generation capacity and purchases the output from 140 MW of other hydroelectric resources. 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 its watershed. Operational limitations of the hydroelectric facilities are impacted 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 reports 2015 capacity included in the load and resource balance.

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[32] 2014 PacifiCorp 10-K filing shows 1,145 MW of Net Facility Capacity.

Table 5.9 – Hydroelectric Contracts - Load and Resource Balance Capacities

Hydroelectric Contracts by Load and Resource Balance Category	L&R Balance Capacity at System Peak (MW)
Hydroelectric	99
Qualifying Facilities - Hydroelectric	42
Total Contracted Hydroelectric Resources	**141**

Table 5.10 provides the operational capacity for each of PacifiCorp's owned hydroelectric generation facilities at system peak (2015).

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

Plant	State	L&R Balance Capacity at System Peak (MW)
	West	
Big Fork	MT	4
Clearwater 1	OR	15
Clearwater 2	OR	26
Copco 1 and 2	CA	47
Fish Creek	OR	0
Iron Gate	CA	11
JC Boyle	OR	16
Lemolo 1	OR	32
Lemolo 2	OR	16
Merwin	WA	23
Rogue	OR	31
Small West Hydro [1]	CA / OR / WA	2
Soda Springs	OR	4
Swift 1	WA	240
Swift 2 [2]	WA	72
Toketee and Slide	OR	26
Yale	WA	135
	East	
Bear River	ID / UT	78
Small East Hydro [3]	ID / UT / WY	15
TOTAL – Hydroelectric before Contracts		**795**
Hydroelectric Contracts		**141**
TOTAL – Hydroelectric with Contracts		**936**

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

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

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

Hydroelectric Relicensing Impacts on Generation

Table 5.11 lists the estimated impacts to average annual hydro generation from expected FERC orders and relicensing settlement commitments. PacifiCorp assumes that the Klamath hydroelectric facilities will be decommissioned pursuant to the Klamath Hydroelectric Settlement Agreement in the year 2020 and that 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, 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)
2016-2017	1,448	1,448
2018-2019	636	2,084
2020-2034	716,820	718,904

Demand-side Management

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, the classes are:

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

- **Class 2 DSM: Resources from non-dispatchable, firm energy and capacity product offerings/programs** – Class 2 DSM programs are those for which sustainable energy and related capacity savings are achieved through facilitation of technological advancements in equipment, appliances, lighting and structures, or repeatable and predictable voluntary actions on a customer’s part to manage the energy use at their facility or home. Class 2 DSM programs generally provide financial and/or service incentives to customers to improve the efficiency of existing or new customer-owned facilities through the installation of more efficient equipment such as lighting, motors, air conditioners, or appliances or upgrading building efficiency through improved insulation levels, windows, etc. however the category has recently been expanded to include strategic energy management efforts at business facilities and home energy reports in the residential sector. The savings endure (are considered firm) over the life of the improvement or customer action. Program examples include comprehensive commercial and industrial new and retrofit energy efficiency programs, refrigerator recycling 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. Savings are measured at a customer-by-customer level (via metering and/or metering data analysis against baselines), and customers are compensated in accordance with a program's pricing parameters. As a result of their voluntary nature, participation tends to be low and savings are less predictable, making them less suitable to incorporate into resource planning exercises, at least until such time that their size and customer behavior profile provide sufficient information for a reliable diversity result (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 avoided. Program examples include large customer energy bid programs, time-of-use pricing plans, critical peak pricing plans, and inverted block tariff designs. 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.

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

PacifiCorp has been operating successful DSM programs since the late 1970s. While the Company's DSM focus has remained strong over this time, since the 2001 western energy crisis the Company's DSM pursuits have 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 2013 and 2014, the Company completed the implementation of over 30 DSM action items identified in the 2013 IRP Action Plan, all geared towards accelerating and increasing the acquisition of demand side resources. Actions such as, but not limited to, the consolidation and expansion of the Company's business programs and services under ***watt***smart business, adding direct install and direct distribution measures to residential and business programs, creating new service offerings for small business customers, expanding trade ally networks and services, and increasing the number of households receiving home energy reports across our six states from 100,000 to over 380,000 households. 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. Finally, significant changes to the Idaho and Utah Class 1 DSM portfolios were recently completed in an effort to improve program effectiveness and economics in those states and provide for a more viable delivery platform for the potential expansion of Class 1 DSM programs to the west side of the system, as the need and value for new west-side capacity resources dictate.

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

Class 1 Demand-side Management

Currently there are two Class 1 DSM programs running across PacifiCorp's six-state service area: Utah's "Cool Keeper" residential and small commercial air conditioner load control program and dispatchable irrigation load management programs in Idaho and Utah. The two programs represent over 300 MW of load reduction capability, helping the Company better manage demand during peak periods.[33]

Class 2 Demand-side Management

The Company currently manages ten distinct Class 2 DSM programs or initiatives within the Class 2 DSM category, many of which are available in multiple states.[34] In all, the combination of Class 2 DSM programs/initiatives across PacifiCorp's six states totals twenty-seven, with program services in some states combined within programs (i.e. the refrigerator recycling in California is part of the Home Energy Saving program and therefore is not counted as a standalone effort). The cumulative energy savings for the period 2003-2014 from Class 2 DSM program activity was 4.9 million MWh.

Class 3 Demand-side Management

The Company has numerous Class 3 DSM offerings currently available. They include metered time-of-day and time-of-use pricing plans (in all states, availability varies by customer class), residential seasonal inverted block rates (Idaho, Utah and Wyoming), residential year-round inverted block rates (California, Oregon and Washington) and Energy Exchange programs (all states). System-wide, approximately 19,200 customers were participating in metered time-of-day and time-of-use programs as of December 31, 2012.[35] All of the Company's residential customers not opting for a time-of-use rates are currently subject to seasonal or year-round inverted block rate plans.

Savings associated with these resources are captured within the Company's load forecast, with the exception of the more immediate call-to-action programs, and are thus captured in the integrated resource planning framework. PacifiCorp continues to evaluate Class 3 DSM programs for applicability to long-term resource planning.

As discussed in greater detail in Chapter 6, eight Class 3 DSM programs were bundled into four discrete products and provided as resource options in preliminary IRP modeling scenarios.

Class 4 Demand-side Management

Educating customers regarding energy efficiency and load management opportunities is an important component of the Company's long-term resource acquisition plan. A variety of channels are used to educate customers including television, radio, newspapers, bill inserts and messages, newsletters, school education programs, and personal contact. Load reductions due to

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

[34] PacifiCorp collaborates with the Energy Trust of Oregon and Northwest Energy Efficiency Alliance (in Washington) in delivering two of the ten programs/initiatives.

[35] Year-end 2012 participation data was used in the development of the 2015 DSM Potential Study. By the end of 2013 participation levels had declined slightly too approximately 18,900 participants.

Class 4 DSM activity will show up in Class 1 and Class 2 DSM program results and non-program reductions in the load forecast over time.

Table 5.12 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 the table below is shown as having zero MW.[36]

Table 5.12 – Existing DSM Summary, 2015-2024

Program Class	**Description**	**Energy Savings or Capacity at Generator**	**Included as Existing Resources for 2015-2024 Period**
1	Residential/small commercial air conditioner load control	115 MW summer peak	Yes
	Irrigation load management	190 MW summer peak[37]	Yes
	Interruptible contracts	2015 149 MW 2016-2024 175 MW Year around availability	Yes.
2	Company and Energy Trust of Oregon programs	0 MW	No. Class 2 DSM programs are modeled as resource options in the portfolio development process, and included in the preferred portfolio.
3	Energy Exchange	0-19[38] MW (assumes no other Class 3 DSM competing products running)	No. Program is leveraged as economic and reliability resource dependent on market prices/system loads.
	Time-based pricing	98[39] MW summer peak, 19,200 customers	No. Historical savings from customer responses to pricing signals are reflected in the load forecast.
	Inverted rate pricing	55-149 GWh[40] (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.

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[36] The historic effects of prior Class 2 DSM savings are backed out of the load forecast prior to the modeling for new Class 2 DSM.

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

[38] PacifiCorp Demand-Side Resource Potential Assessment for 2015-2034, Volume 3: Class 1 and 3 DSM Analysis, Applied Energy Group, January 30, 2015.

[39] Ibid.

[40] Ibid.

Distributed Generation

PacifiCorp's first major effort to fully assess small-scale customer-sited generation resource potential occurred in 2007 with an "Assessment of Long-Term, System Wide Potential for Demand Side and Other Supplemental Resources" (2007 Potential Study). Customer-sited distributed generation (i.e., DG) was a subset of the 2007 assessment. The technical and achievable data from the 2007 Potential Study were converted into resource quantity and cost curves (supply curves) that served as inputs to the Company's 2008 IRP models where the actionable economic potential screening was performed.

The 2007 Potential Study was updated in 2010 (included in the 2011 IRP) and again in 2012 (included in the 2013 IRP) to use the most current data and methods in developing supply curves for the 2013 IRP. As in the 2010 Potential Study, only technical and achievable technical potentials were assessed, with all economic screening conducted in the IRP model.

For the 2015 IRP, PacifiCorp contracted with Navigant Consulting Inc. (Navigant) to conduct an updated assessment of DG. Deliverables include: 1) technical potential, 2) market potential, and 3) levelized cost of energy for each DG resource in each of the six states served by the Company. Navigant examined both commercial and residential applications. Specific technologies studies include: solar photovoltaic, small scale wind, small scale hydro, and CHP for both reciprocating engines and micro-turbines. The study is included in Volume II, Appendix O.[41]

The major difference in the treatment of DG in the 2015 IRP is the application of DG as a reduction to load. The Navigant study identifies expected levels of customer-sited DG. The DG is then netted against the IRP load forecast rather than being selected as a utility resource. This methodology more accurately reflects drivers behind DG penetration, which is customer economics, not utility economics.

Initial analysis focused on the amount of technical potential of DG in PacifiCorp's service territory. The technical potential is the maximum amount that is available without consideration of costs, or adoption rates. Figure 5.1 below shows Navigant's initial estimate of technical potential.

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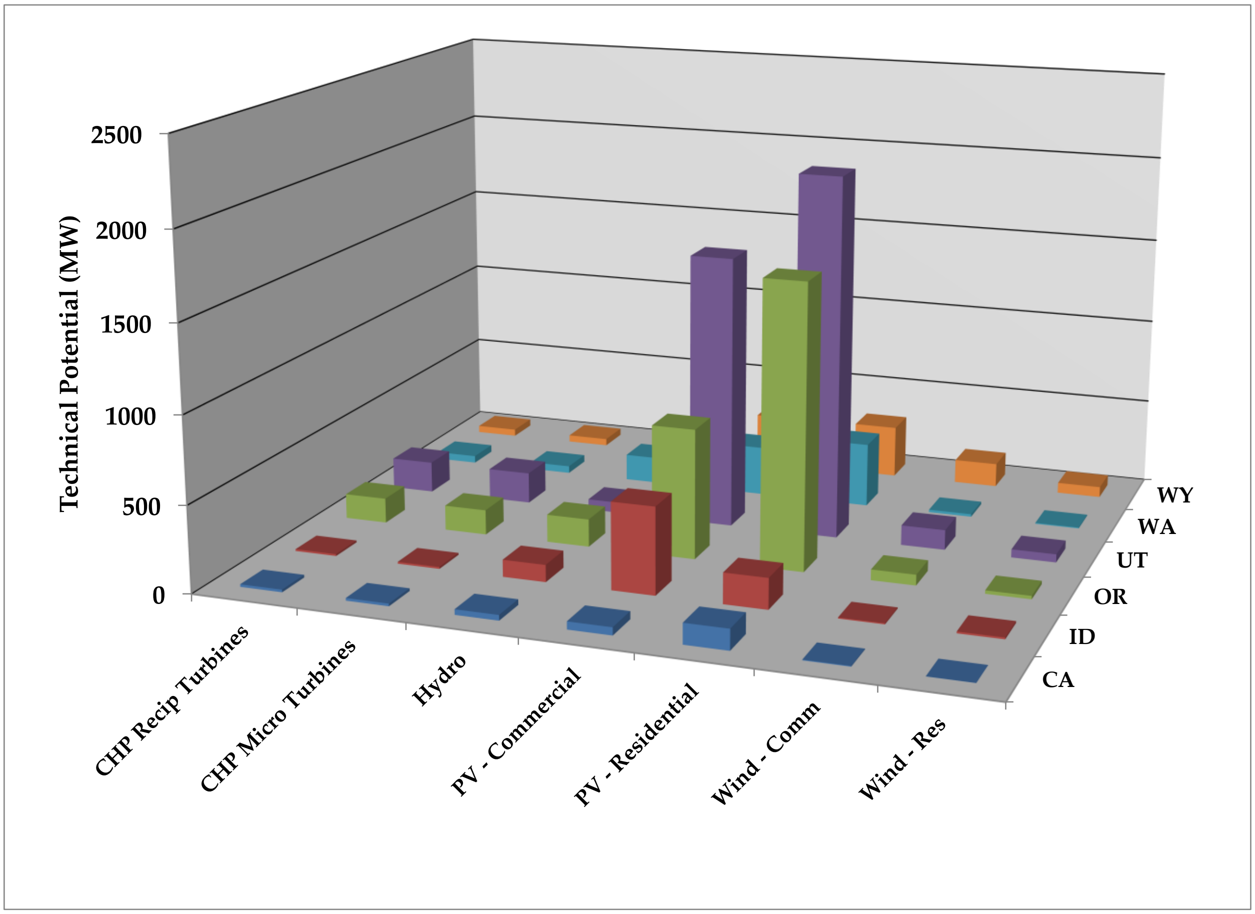
[41] The study is also online at the following location: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/2015IRPStudy/Navigant_Distributed-Generation-Resource-Study_06-09-2014.pdf

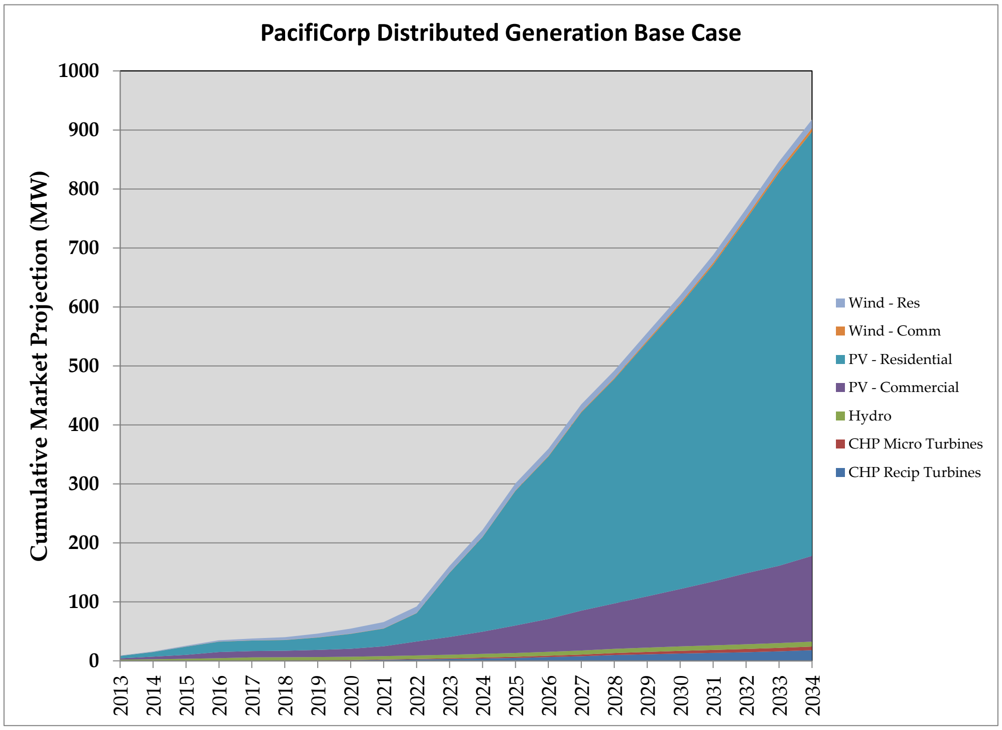
Figure 5.1 – Technical Potential Results



The technical potential was then refined by Navigant to an expected market penetration level. The market penetration for DG technologies employed Fisher-Pry payback analysis. This method looks at ‘S-curves” which describe penetration rates of products in markets. The penetration rates are dependent on the length of time needed to ‘payback’ the investment costs. This approach was applied for individual residential and commercial customers of PacifiCorp by rate class.

Figure 5.2 shows the DG base case market penetration over the 20-year study period. Note expectations for solar form the majority of new DG over time, with residential making up the overwhelming majority of installations by 2034.

Figure 5.2 – Base Case Distributed Generation



Low and high DG penetration scenarios were also examined in sensitivity cases. These are shown in Figure 5.3 and Figure 5.4 below. The Company used the base case assumptions for analysis of the core cases and in its resource needs assessment. The low and high DG penetration levels are used for sensitivity analysis.

Figure 5.3 – High Case Distributed Generation

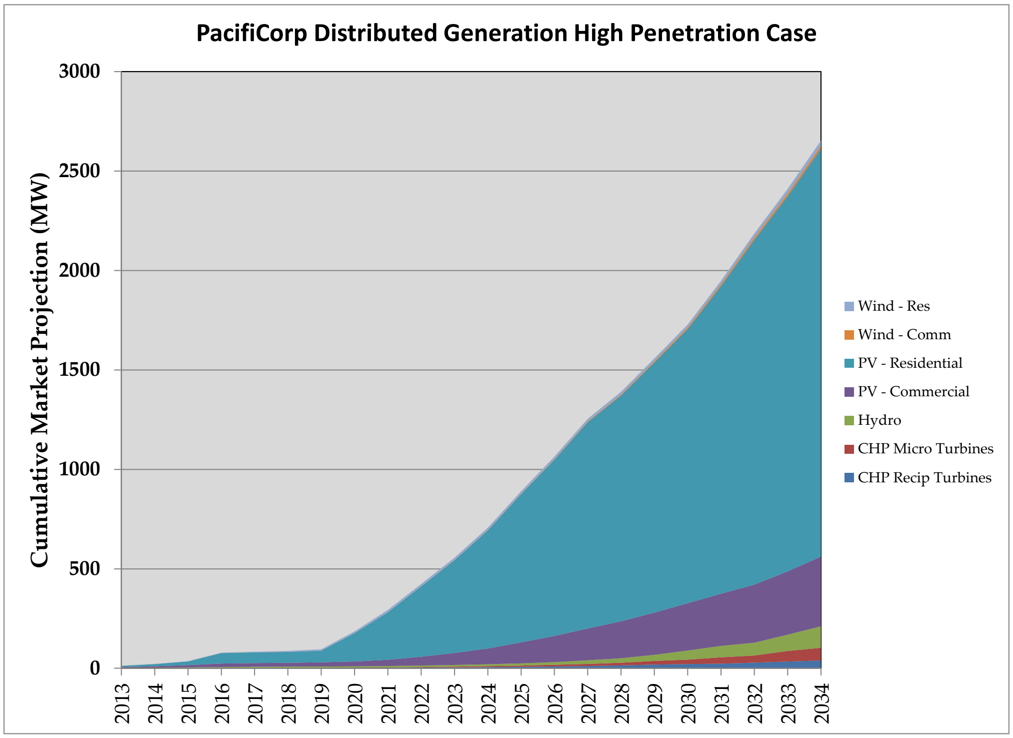
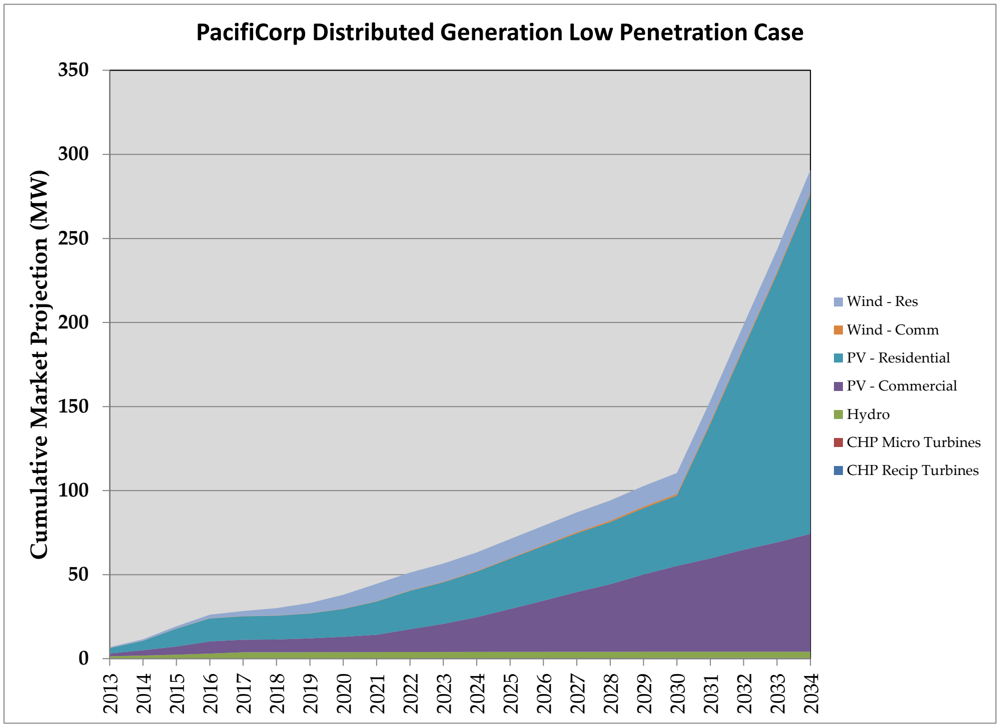


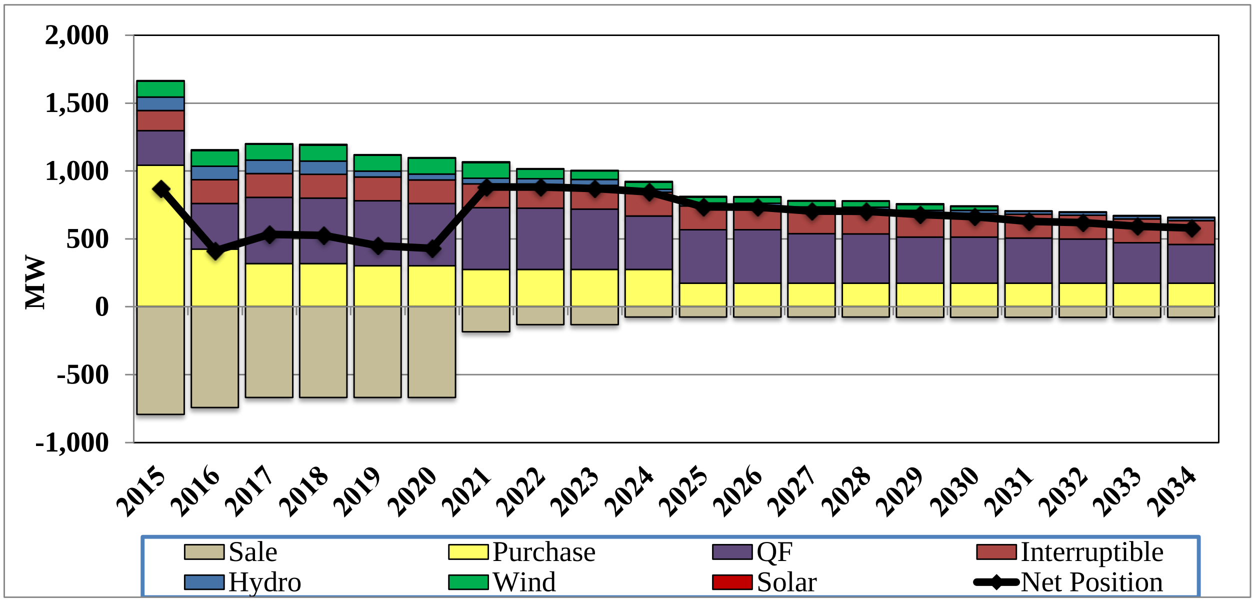
Figure 5.4 – Low Case Distributed Generation



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 5.5 presents the contract capacity in place for 2015 through 2034. 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 5.5 – Contract Capacity in the 2015 Load and Resource Balance



Listed below are the major contract expirations occurring in summer 2016:

- Expiring Bonneville Power Administration Southeast Idaho Exchange – 369 MW
- Expiring Hermiston Purchase – 227 MW

Load and Resource Balance

Capacity and Energy Balance Overview

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

The capacity balance compares generating capability to expected peak load at time of system peak load hours. It is a key part of the load and resource balance because it provides guidance as to the timing and severity of future resource deficits. It is developed by first reducing the hourly system load by hourly DG to then determining net system coincident peak load for each of the first ten years (2015-2024) of the planning horizon. Interruptible load programs and existing load reduction DSM programs 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 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 (2015-2024). The average obligation (load less existing DSM programs and DG) is computed and subtracted from the average existing resource availability for each month and time-of-day period. The energy balance complements the capacity balance in that it also indicates when resource deficits occur, but it also provides insight into what type of resource will best fill the need. The usefulness of the energy balance is limited as it does not address the cost of the available energy. The economics of adding resources to the system to meet both capacity and energy needs are addressed during the resource portfolio development process described in Chapter 8.

Load and Resource Balance Components

The capacity and energy balances make use of the same load and resource components in their calculations. The main component categories consist of the following: existing 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 DG), interruptible contracts, and existing Class 2 DSM.

Existing Resources

A description of each of the resource categories follows:

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

- **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 peak, an approach consistent with current 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 situated on the west side of the PacifiCorp system.

- **Renewable**
  This category comprises geothermal and variable (wind and solar) renewable energy capacity. The capacity balance counts the geothermal plant by the maximum dependable capability while the energy balance counts the maximum dependable capability after forced outages. 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 2015 IRP, PacifiCorp defines the peak capacity contribution of wind and solar resources as the availability among hours with the highest loss of load probability (LOLP). PacifiCorp updated its capacity contribution values for solar and wind resources, differentiated by resource type and balancing authority area (BAA), which is presented in Volume II, Appendix N. The resulting capacity contribution values are shown in Table 5.13 below.

Table 5.13 – Peak Capacity Contribution Values for Wind and Solar

	East BAA			West BAA		
	Wind	Fixed Tilt Solar PV	Single Axis Tracking Solar PV	Wind	Fixed Tilt Solar PV	Single Axis Tracking Solar PV
Capacity Contribution Percentage	14.5%	34.1%	39.1%	25.4%	32.2%	36.7%

- **Purchase**
  This includes all major purchases contracts for firm capacity and energy in the PacifiCorp system.[42] The capacity balance counts these by the maximum contract availability at time of system 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 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.

- **Sales**
  This includes all contracts for the sale of firm capacity and energy. The capacity balance counts these contracts by the maximum obligation at time of system peak and the energy balance counts them by 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 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 DG, existing Class 2 DSM, and interruptible contracts. The following are descriptions of each of these components:

- **Load** Net of Distributed Generation
  The largest component of the obligation is retail load. In the 2015 IRP, the hourly retail load at a location is first reduced by hourly distributed 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 BAAs thus reflect loads at the time of PacifiCorp's coincident system 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.

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[42] PacifiCorp has curtailment contracts for approximately 172 MW on peak capacity which 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.

- **Existing 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 2014 Class 2 DSM that is not incorporated in the forecast. The 2014 Class 2 DSM forecast (110 MW) has been accounted for by adding an existing Class 2 DSM resource in the L&R.

- **Interruptible Contracts**
  PacifiCorp has interruptible contracts for approximately 175 MW of load interruption capability beginning in 2015. These contracts allow the use of 175 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 2 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 hour for each of the first ten years of the planning horizon. Then the annual firm-capacity availability of the existing resources is determined for each of these annual system peak hours and summed as follows:

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

The peak load, interruptible contracts, and existing Class 2 DSM are netted together for each of the annual system peak hours to compute the annual peak-hour obligation:

> ***Obligation*** *= Load – Interruptible Contracts – 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% target planning reserve margin adopted for the 2015 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, inclusive of available FOTs, as shown in the following formula:

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

Capacity Balance Results

Table 5.14 shows the annual capacity balances and component line items using a target planning reserve margin of 13% to calculate the planning reserve amount. Balances for PacifiCorp's system as well as east and west BAAs are shown. It should be emphasized that while west and east balances are broken out separately, the PacifiCorp system is planned for and dispatched on a system basis. Also note that 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 –System Capacity Loads and Resources without Resource Additions

Calendar Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
East										
Thermal	6,410	6,397	6,397	6,453	6,449	6,448	6,444	6,439	6,434	6,431
Hydroelectric	117	114	114	114	114	114	114	114	114	94
Renewable	187	187	187	187	187	187	184	184	177	177
Purchase	627	406	300	300	300	300	272	272	272	272
Qualifying Facilities	139	222	348	347	346	339	337	332	331	280
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sale	(732)	(732)	(656)	(656)	(656)	(656)	(175)	(175)	(175)	(144)
Non-Owned Reserves	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)
East Existing Resources	**7,033**	**6,880**	**6,976**	**7,031**	**7,026**	**7,018**	**7,462**	**7,453**	**7,439**	**7,396**
East Total Resources	**7,033**	**6,880**	**6,976**	**7,031**	**7,026**	**7,018**	**7,462**	**7,453**	**7,439**	**7,396**
Load	7,157	6,977	7,102	7,208	7,295	7,382	7,448	7,529	7,617	7,640
Interruptible	(149)	(175)	(175)	(175)	(175)	(175)	(175)	(175)	(175)	(175)
Existing Class2 DSM	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)
East obligation	**6,935**	**6,729**	**6,854**	**6,960**	**7,047**	**7,135**	**7,200**	**7,281**	**7,370**	**7,392**
Planning Reserves (13%)	921	894	910	924	935	947	955	966	977	980
East Reserves	**921**	**894**	**910**	**924**	**935**	**947**	**955**	**966**	**977**	**980**
East Obligation + Reserves	**7,855**	**7,623**	**7,764**	**7,885**	**7,982**	**8,081**	**8,155**	**8,247**	**8,347**	**8,372**
East Position	**(823)**	**(743)**	**(789)**	**(853)**	**(957)**	**(1,064)**	**(693)**	**(794)**	**(908)**	**(976)**
Available Front Office Transactions	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**
West										
Thermal	2,495	2,251	2,248	2,248	2,248	2,248	2,245	2,241	2,239	2,239
Hydroelectric	777	770	752	775	725	728	643	620	652	646
Renewable	170	170	170	170	170	170	170	115	115	105
Purchase	191	22	22	22	5	5	5	5	5	5
Qualifying Facilities	116	114	140	135	134	120	120	120	115	115
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(210)	(160)	(160)	(160)	(160)	(160)	(156)	(105)	(105)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	**3,535**	**3,163**	**3,167**	**3,185**	**3,119**	**3,107**	**3,023**	**2,993**	**3,019**	**3,029**
West Total Resources	**3,535**	**3,163**	**3,167**	**3,185**	**3,119**	**3,107**	**3,023**	**2,993**	**3,019**	**3,029**
Load	3,206	3,237	3,271	3,301	3,323	3,354	3,406	3,429	3,455	3,476
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class2 DSM	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)
West obligation	**3,169**	**3,201**	**3,235**	**3,264**	**3,286**	**3,317**	**3,369**	**3,393**	**3,419**	**3,440**
Planning Reserves (13%)	412	416	421	424	427	431	438	441	444	447
West Reserves	**412**	**416**	**421**	**424**	**427**	**431**	**438**	**441**	**444**	**447**
West Obligation + Reserves	**3,581**	**3,617**	**3,655**	**3,689**	**3,714**	**3,748**	**3,807**	**3,834**	**3,863**	**3,887**
West Position	**(46)**	**(454)**	**(488)**	**(503)**	**(595)**	**(642)**	**(784)**	**(841)**	**(844)**	**(858)**
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	10,568	10,043	10,143	10,217	10,144	10,124	10,486	10,446	10,458	10,425
Obligation	10,104	9,930	10,089	10,225	10,333	10,452	10,569	10,674	10,788	10,832
Reserves	1,333	1,310	1,331	1,349	1,363	1,378	1,393	1,407	1,422	1,428
Obligation + Reserves	11,437	11,240	11,420	11,573	11,696	11,830	11,963	12,081	12,210	12,259
System Position	(869)	(1,197)	(1,277)	(1,357)	(1,552)	(1,706)	(1,477)	(1,635)	(1,752)	(1,834)
Available Front Office Transactions	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**

Figure 5.6 through Figure 5.8 are graphic representations of the table above for annual capacity position for the system, east balancing area, and west balancing area, respectively. 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 and Volume II, Appendix J.

Figure 5.6 – System Capacity Position Trend

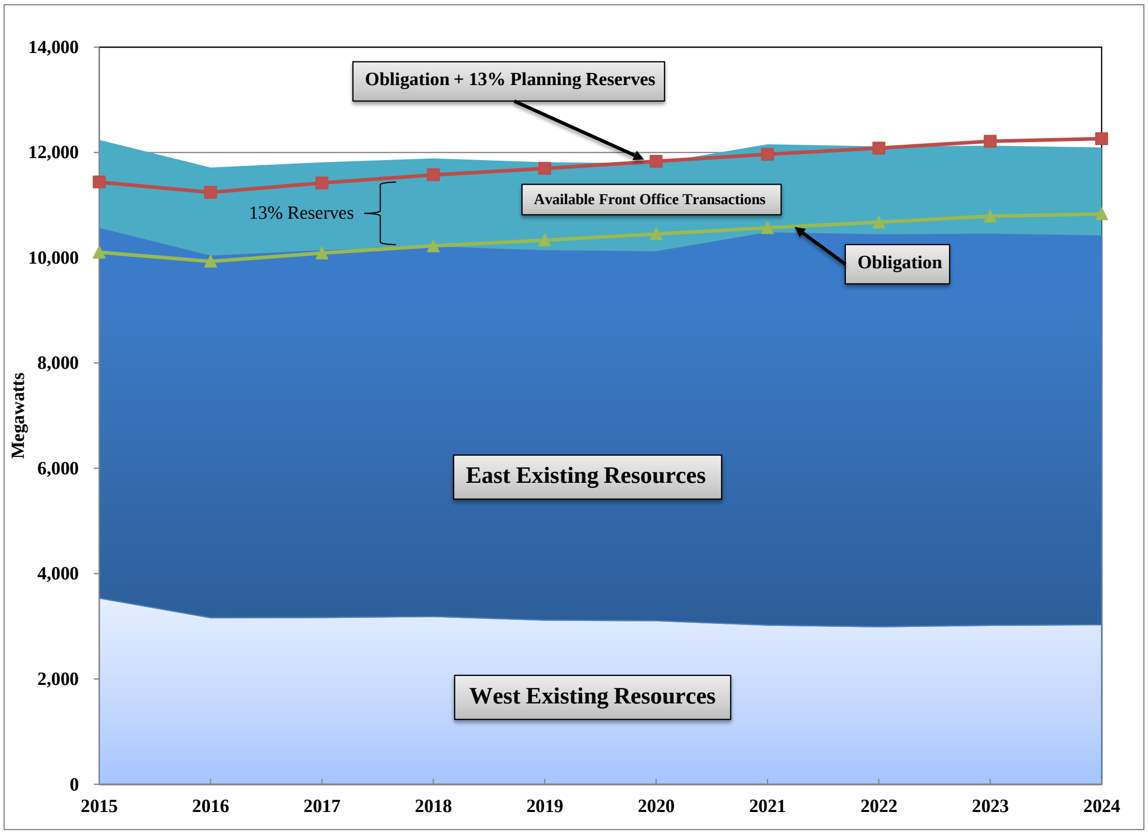


Figure 5.7 – East Capacity Position Trend

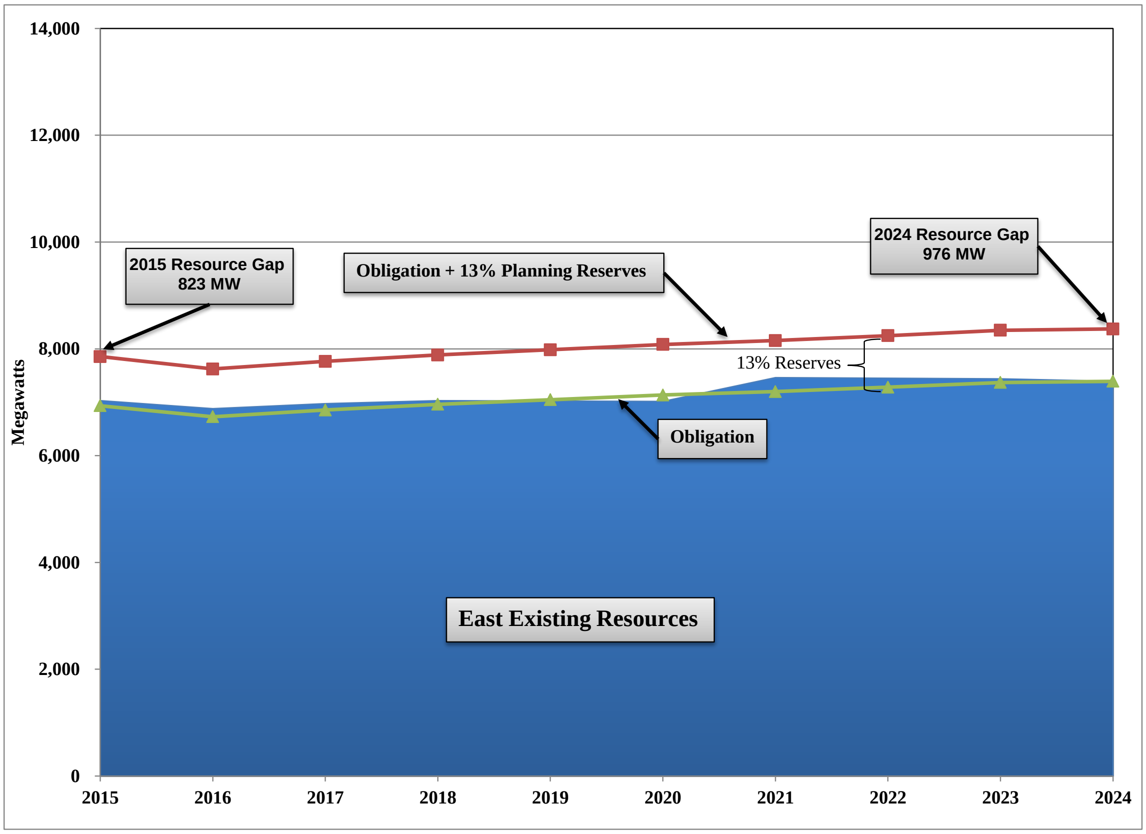
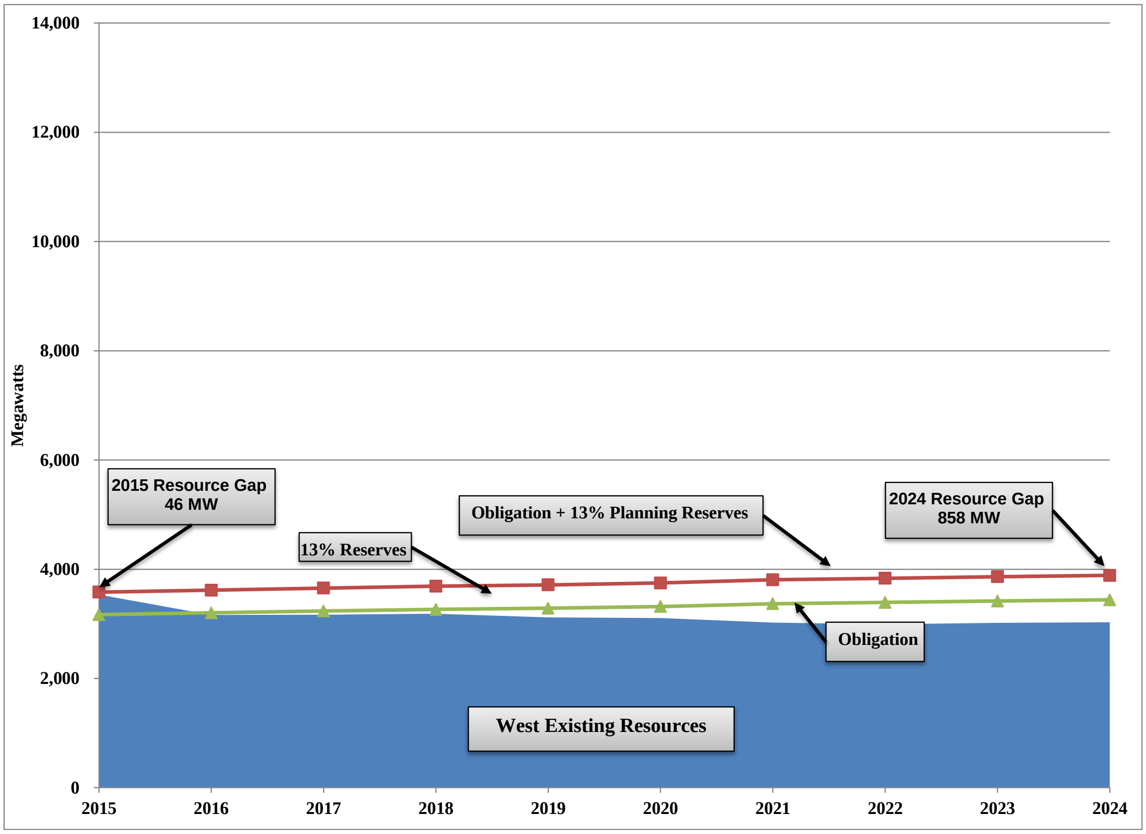


Figure 5.8 – West Capacity Position Trend



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:

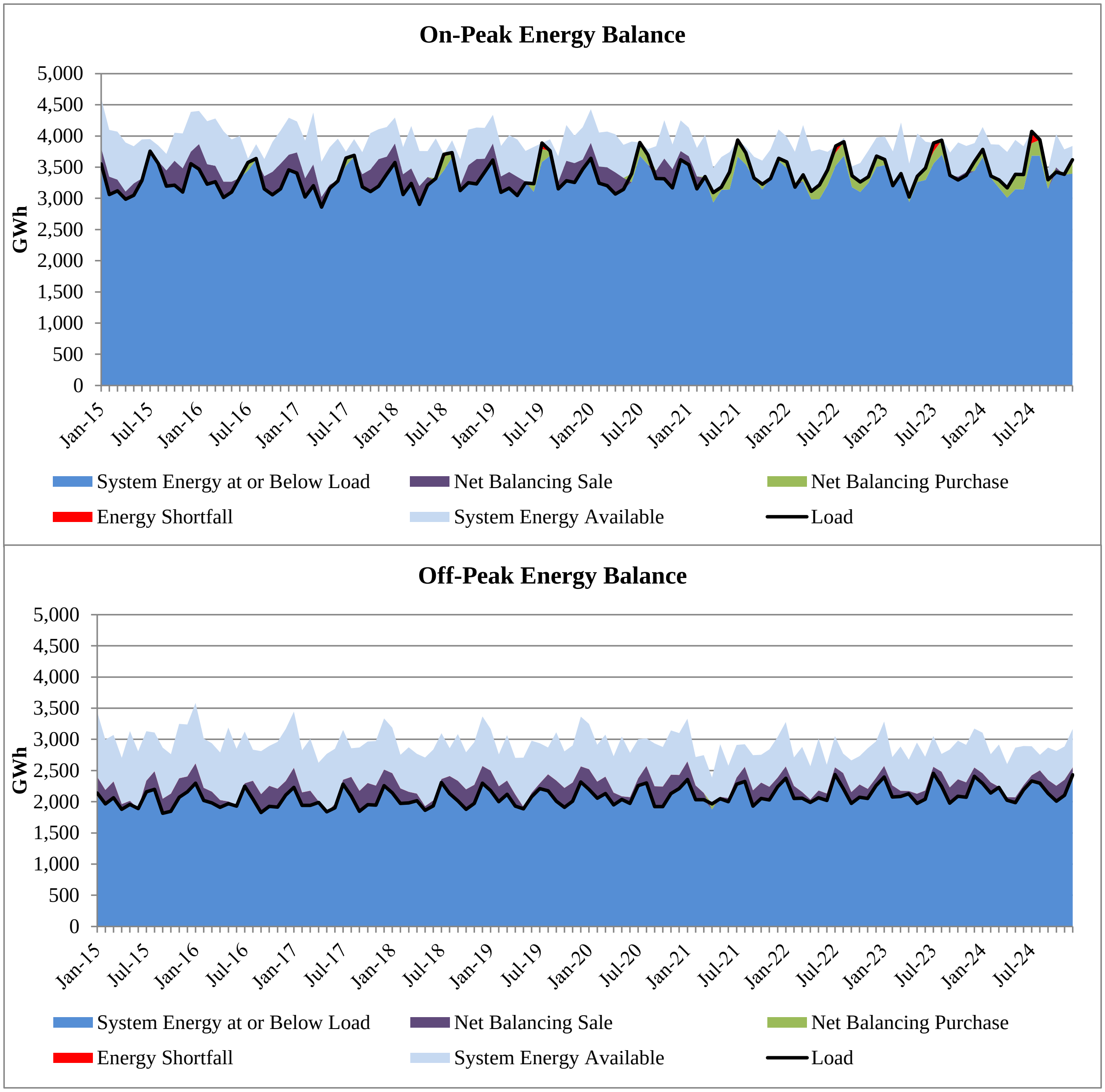
Energy Position = *Existing Resources – Obligation – Operating Reserve Requirements*

Energy Balance Results

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

Figure 5.9 provides a snapshot of how existing system resources could be used to meet forecasted load across on-peak and off-peak periods given the assumption 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 5.9 also show how much energy is available from existing resources at any given point in time. Those periods where all available resource energy falls below forecasted loads are highlighted in red, and are indicative of short energy positions absent the addition of incremental resources to the portfolio. During on-peak periods, the first energy shortfall appears in July 2018 and July in the subsequent years. During off-peak periods, there are no energy shortfalls through the 2024 timeframe.

Figure 5.9 – System Average Monthly Energy Positions



Load and Resource Balance Conclusions

Accounting for available FOTs, PacifiCorp exceeds its 13% target planning reserve margin through 2019 and falls just short of its target planning reserve margin in 2020. With the expiration of a legacy exchange contract, available system capacity is increased in the summer of 2021, and PacifiCorp's system once again exceeds its 13% target planning reserve margin through 2022.

CHAPTER 6 – RESOURCE OPTIONS

CHAPTER HIGHLIGHTS

- PacifiCorp developed resource attributes and costs for expansion resources that reflect updated information from project experience, public meeting comments and third party studies. Similar to the 2013 IRP, current economic conditions have essentially remained unchanged with reduced capital cost uncertainty. Long-term resource pricing, especially for emerging technologies, remains a challenge to predict.
- Resource costs have been generally stable since the previous IRP and any cost increases have been modest. The cost of solar photovoltaic modules stabilized in 2014 after being on a downward cost trend for several years.
- As with the 2013 IRP both large utility scale solar photovoltaic options and geothermal purchase power agreements (PPA) have been included as supply-side options in the 2015 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 IRP.
- A 2015 resource potential study, 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 measure or product 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. Capital costs, in general, have remained stable due to recessionary economic conditions in 2008-2009 and a very gradual recovery experienced in 2010-2014. As with the 2013 IRP, natural gas-fueled plants are expected to fulfill future base-load obligations for meeting customer needs therefore they have received a significant level of attention. A variety of gas-fueled generating resources were selected after consultation with major suppliers, large engineering-consulting firms, and primary stakeholders. New coal-fueled resources received minimal focus during this planning cycle due to ongoing environmental, permitting and sociopolitical obstacles for siting new coal-fueled generation. The capital and operating costs of simple and combined-cycle gas turbine plants have remained relatively flat to slightly increasing since the previous IRP. Certain alternative (i.e. non-fossil-fuel) energy resources such as wind and solar received even greater emphasis during this review cycle compared to prior reviews. Solar resource options include utility-size photovoltaic systems (PV) with both fixed and single axis tracking. Energy storage options of at least one megawatt continue to be of interest among the stakeholders, with options analyzed for large pumped-storage projects, as well as advanced battery, fly wheel and compressed air energy storage projects.

Derivation of Resource Attributes

The supply-side resource options were developed for a combination of resources. The process began with the list of major generating resources from the 2013 IRP. This resource list was reviewed and modified to reflect stakeholder input, environmental factors, cost dynamics, and anticipated permitting constraints. Once the basic list of resources was determined, the cost and performance attributes for each resource were estimated. The information sources used are listed below, followed by a brief description on how they were used in the development of the Supply Side Resource table:

- Recent (2012 and 2014) third-party, cost and performance estimates;
- Prior third-party, cost and performance studies or updated earlier estimates;
- Actual PacifiCorp or electric utility industry installations, providing current construction/maintenance costs and performance data with similar resource attributes;
- Projected PacifiCorp or electric utility industry installations, providing projected construction/maintenance costs and performance data of similar or identical resource options; and
- Recent Requests for Proposals and Requests for Information.

Recent third-party engineering information from original equipment manufacturers was used to update capital, operating and maintenance costs, performance and operating characteristics, and planned outage cycle estimates. Examples of this type of effort include the 2012 Black & Veatch estimates prepared for simple cycle and combined cycle options and the 2014 Energy Storage Screening Study performed by HDR Engineering Inc. (HDR), which was used to update various storage technologies (see Volume II, Appendix Q).

Also informative were studies prepared by others in the industry that 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. An example of this type of study is the United States Department of Energy’s 2013 Wind Technologies Market Report.

Both PacifiCorp and 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 both 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. PacifiCorp also relies on information and experience gathered through operations of its existing fleet of resources and its reviews of potential resources.

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 these uncertainties, the cost profile between the last IRP and the current IRP has not changed significantly. For example, Figure 6.1 shows the trend in North American carbon steel sheet prices over the period from August 2013 through September 2014. Similar information was presented in the 2013 IRP and has been updated 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

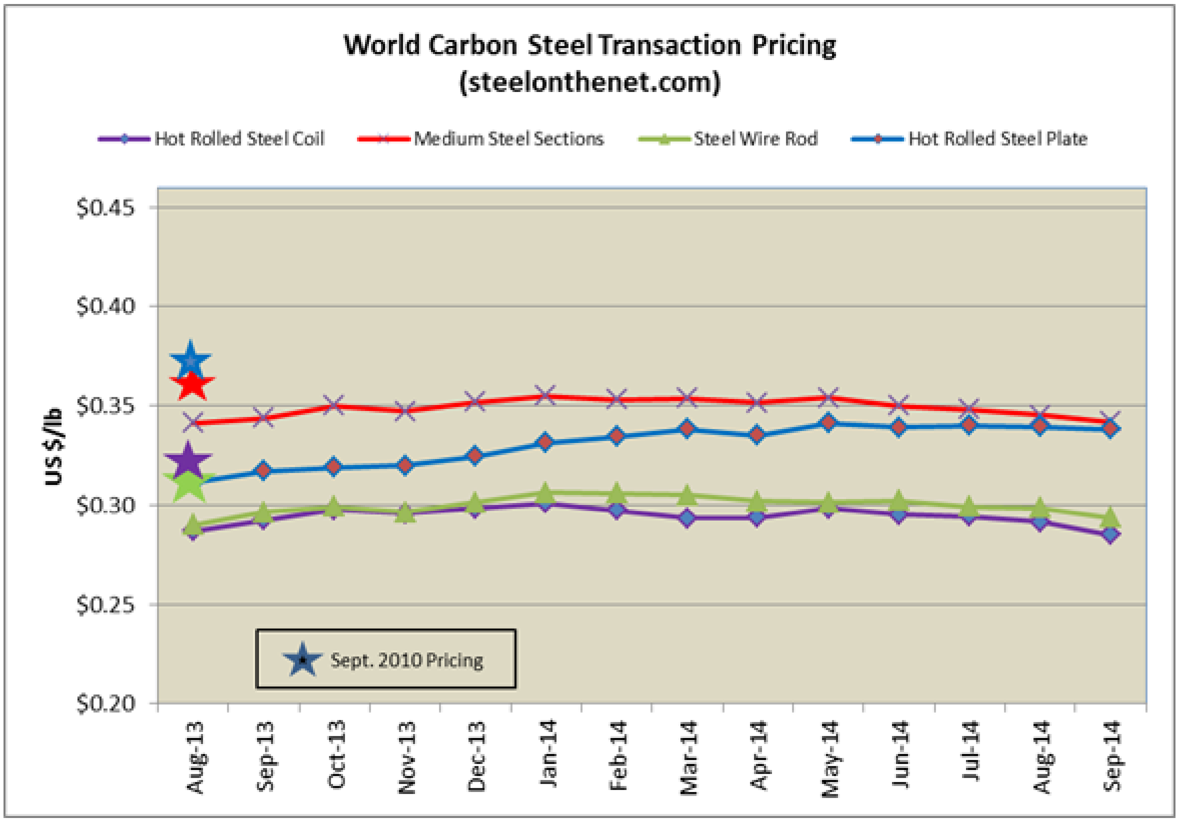
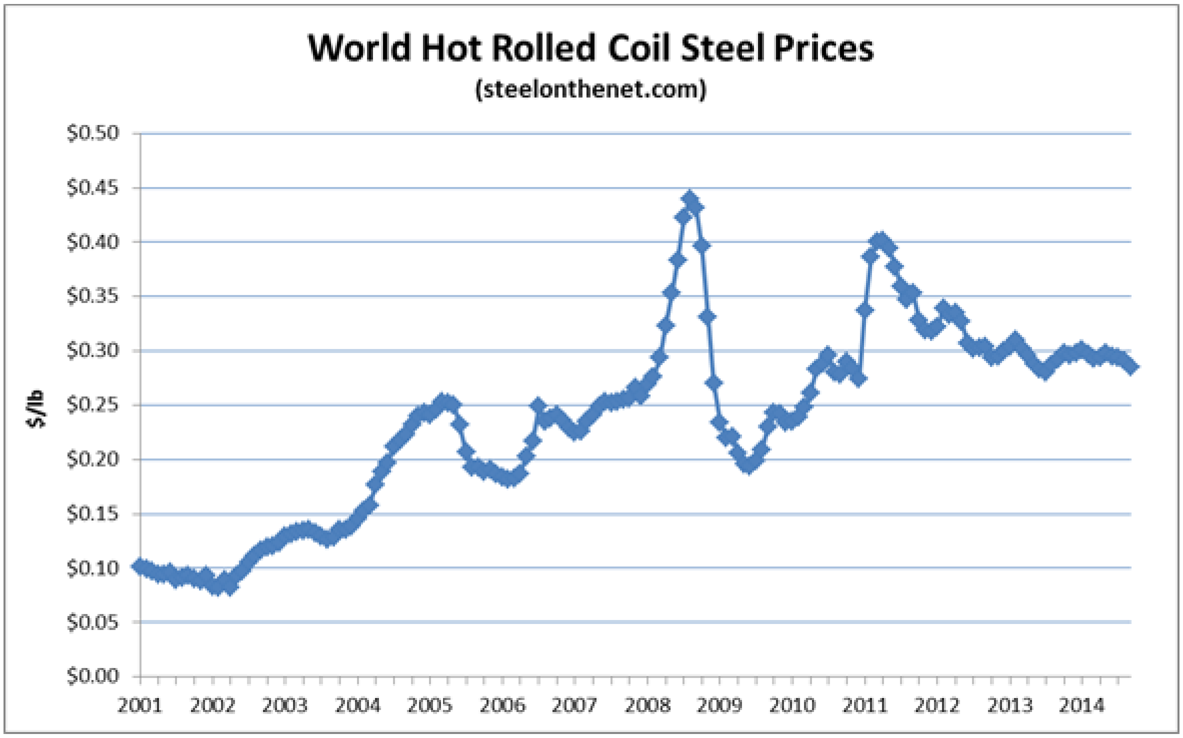


Figure 6.2 – Historic Carbon Steel Pricing



Prices for solar photovoltaic (PV) panels have fallen slightly since the 2013 IRP. The dynamic changes in the solar PV market make accurately predicting future prices difficult. Real prices are projected to flatten out for the next several years given large demand to meet the 30% federal investment tax credit deadline at the end of 2016 and recently announced panel tariffs on certain Chinese imports. Other technologies, such as gas turbines, and wind turbines have seen more stable prices since the 2013 IRP. Forecasting resource costs is increasingly more challenging for projects proposed for construction many years in the future.

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

The Supply Side Resource options tables do not include the potential for such capital cost reductions since the benefits are not expected to be realized until the next generation of new plants are built and operated. For example, construction and operating "experience curve" benefits for IGCC plants are not expected to be available until after their commercial operation dates. As such, future IRPs will be better able to incorporate the potential benefits of future cost reductions. The estimated capital costs are displayed in the Supply Side Resource tables along with expected availability of each technology.

Resource Options and Attributes

Table 6.1. lists the cost and performance attributes for supply-side resources designated by generic, elevation-specific regions where resources could potentially be located:

- ISO conditions (sea level and 59 degrees F); used as a reference only for certain modeling purposes.
- 1,500 feet elevation: eastern Oregon/Washington.
- 3,000 feet elevation: southern/central Oregon
- 5,050 feet elevation: central Utah, southern Idaho, central Wyoming.
- 6,500 feet elevation: southwestern Wyoming.

Table 6.2 presents 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 2014 dollars. In the previous IRP, there was a proxy elevation of 4,500’ reflecting potential siting of resources in northern Utah, specifically in Salt Lake/Utah/Davis/Box Elder counties; this general area has been removed from the current IRP based on recent changes in the state implementation plans for these counties regarding particulate matter 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

Table 6.1 – 2015 Supply Side Resource Table (2014$)

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	168	2019	30	1,188	2.98	9.57	9,738	2.6	3.9	58	0.0006	0.018	0.255	118
Natural Gas	Intercooled SCCT Aero x1, ISO	0	106	2019	30	1,508	2.94	15.44	8,866	2.9	3.9	80	0.0006	0.018	0.255	118
Natural Gas	SCCT Frame "F" x1, ISO	0	223	2019	35	779	3.54	10.04	9,780	2.7	3.9	20	0.0006	0.018	0.255	118
Natural Gas	IC Recips x6, ISO	0	109	2019	35	1,553	8.05	17.79	8,134	2.5	5.0	5	0.0006	0.0295	0.255	118
Natural Gas	CCCT Dry "F", 2x1, ISO	0	643	2021	40	895	1.14	4.90	6,636	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "F", DF, 2x1, ISO	0	101	2021	40	755	0.11	0.00	9,560	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", 1x1, ISO	0	393	2020	40	827	2.29	8.31	6,697	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO	0	48	2020	40	604	0.10	0.00	8,451	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", 2x1, ISO	0	790	2021	40	820	2.11	4.38	6,666	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO	0	96	2021	40	636	0.09	0.00	7,504	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", Adv 1x1, ISO	0	457	2020	40	860	2.00	7.22	6,494	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", DF, Adv 1x1, ISO	0	43	2020	40	481	0.10	0.00	8,610	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	SCCT Aero x3	1,500	159	2019	30	1,251	3.11	10.08	9,738	2.6	3.9	58	0.0006	0.018	0.255	118
Natural Gas	Intercooled SCCT Aero x1	1,500	101	2019	30	1,587	3.07	16.17	8,867	2.9	3.9	80	0.0006	0.018	0.255	118
Natural Gas	SCCT Frame "F" x1	1,500	212	2019	35	820	3.73	10.59	9,781	2.7	3.9	20	0.0006	0.018	0.255	118
Natural Gas	IC Recips x 6	1,500	109	2019	35	1,553	8.05	17.79	8,135	2.5	5.0	5	0.0006	0.030	0.255	118
Natural Gas	CCCT Dry "F", 2x1	1,500	610	2021	40	942	1.20	5.14	6,637	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "F", DF, 2x1	1,500	101	2021	40	755	0.11	0.00	9,561	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", 2x1	1,500	750	2021	40	864	2.21	4.59	6,667	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", DF, 2x1	1,500	96	2021	40	636	0.09	0.00	7,504	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", Adv 1x1	1,500	434	2020	40	906	2.00	7.22	6,495	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", DF, Adv 1x1	1,500	43	2020	40	481	0.10	0.00	8,611	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	SCCT Aero x3	3,000	151	2019	30	1,321	3.26	10.58	9,738	2.6	3.9	58	0.0006	0.018	0.255	118
Natural Gas	Intercooled SCCT Aero x1	3,000	95	2019	30	1,676	3.24	17.14	8,867	2.9	3.9	80	0.0006	0.018	0.255	118
Natural Gas	SCCT Frame "F" x1	3,000	200	2019	35	866	3.95	11.87	9,781	2.7	3.9	20	0.0006	0.018	0.255	118
Natural Gas	IC Recips x 6	3,000	109	2019	35	1,553	8.05	17.79	8,135	2.5	5.0	5	0.0006	0.030	0.255	118
Natural Gas	CCCT Dry "F", 2x1	3,000	578	2021	40	995	1.26	5.40	6,637	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "F", DF, 2x1	3,000	101	2021	40	755	0.11	0.00	9,561	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", 2x1	3,000	710	2021	40	912	2.33	4.82	6,667	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", DF, 2x1	3,000	96	2021	40	636	0.09	0.00	7,504	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", Adv 1x1	3,000	411	2020	40	956	2.11	7.57	6,495	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", DF, Adv 1x1	3,000	43	2020	40	481	0.10	0.00	8,611	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	SCCT Aero x3	5,050	140	2019	30	1,430	3.48	11.41	9,739	2.6	3.9	58	0.0006	0.018	0.255	118
Natural Gas	Intercooled SCCT Aero x1	5,050	88	2019	30	1,815	3.46	18.44	8,867	2.9	3.9	80	0.0006	0.018	0.255	118
Natural Gas	SCCT Frame "F" x1	5,050	185	2019	35	937	4.24	9.51	9,781	2.7	3.9	20	0.0006	0.018	0.255	118
Natural Gas	IC Recips x6	5,050	109	2019	35	1,553	8.05	17.79	8,135	2.5	5.0	5	0.0006	0.0295	0.255	118
Natural Gas	CCCT Dry "F", 1x1	5,050	265	2020	40	1,152	1.60	11.19	6,667	2.5	3.8	11	0.0006	0.007	0.255	118
Natural Gas	CCCT Dry "F", DF, 1x1	5,050	48	2020	40	539	0.09	0.00	7,864	0.8	3.8	11	0.0006	0.007	0.255	118
Natural Gas	CCCT Dry "F", 2x1	5,050	534	2021	40	1,077	1.36	5.80	6,637	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "F", DF, 2x1	5,050	101	2021	40	755	0.11	0.00	9,561	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", 1x1	5,050	327	2020	40	996	2.77	9.89	6,698	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", DF, 1x1	5,050	48	2020	40	604	0.10	0.00	8,452	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", 2x1	5,050	656	2021	40	987	2.51	5.18	6,667	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", DF, 2x1	5,050	96	2021	40	636	0.09	0.00	7,504	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", Adv 1x1	5,050	380	2020	40	1,035	2.34	8.58	6,495	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", DF, Adv 1x1	5,050	43	2020	40	481	0.10	0.00	8,611	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	Molten Carbonate Fuel Cell	5,050	5	2017	20	5,106	10.10	8.82	8,061	3.0	2.0	2	0	0	0	118
Natural Gas	SCCT Aero x3	6,500	131	2019	30	1,519	3.66	12.11	9,739	2.6	3.9	58	0.0006	0.018	0.255	118
Natural Gas	Intercooled SCCT Aero x1	6,500	83	2019	30	1,927	3.65	19.51	8,867	2.9	3.9	80	0.0006	0.018	0.255	118
Natural Gas	SCCT Frame "F" x1	6,500	174	2019	35	996	4.50	12.17	9,781	2.7	3.9	20	0.0006	0.018	0.255	118
Natural Gas	IC Recips x6	6,500	109	2019	35	1,553	8.05	17.79	8,135	2.5	5.0	5	0.0006	0.0295	0.255	118
Natural Gas	CCCT Dry "G/H", 2x1	6,500	618	2021	40	1,049	2.66	5.47	6,667	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "G/H", DF, 2x1	6,500	96	2021	40	636	0.09	0.00	7,504	0.8	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", Adv 1x1	6,500	358	2020	40	1,099	2.48	9.08	6,495	2.5	3.8	11	0.0006	0.008	0.255	118
Natural Gas	CCCT Dry "J", DF, Adv 1x1	6,500	43	2020	40	481	0.10	0.00	8,611	0.8	3.8	11	0.0006	0.008	0.255	118

Table 6.1 – 2015 Supply Side Resource Table (2014$) (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	5,000	526	2032	40	5,946	6.71	69.22	13,087	5.0	5.0	1,004	0.009	0.070	0.022	20.5
Coal	SCPC without CCS	5,000	600	2027	40	3,289	0.96	40.65	9,106	4.6	4.0	600	0.005	0.070	0.022	205.4
Coal	IGCC with CCS	5,000	466	2032	40	5,757	11.28	55.78	10,823	8.0	7.0	394	0.009	0.050	0.333	20.5
Coal	IGCC without CCS	5,000	560	2027	40	4,104	8.39	42.45	8,734	8.0	7.0	361	0.013	0.059	0.333	205.4
Coal	PC CCS retrofit @ 500 MW	5,000	-139	2029	20	1,305	6.20	74.52	14,372	5.0	5.0	1,004	0.005	0.070	1.200	20.5
Coal	SCPC with CCS	6,500	692	2032	40	6,734	7.26	64.29	13,242	5.0	5.0	1,004	0.009	0.070	0.022	20.5
Coal	SCPC without CCS	6,500	790	2027	40	3,724	1.27	37.71	9,214	4.6	4.0	600	0.005	0.070	0.022	205.4
Coal	IGCC with CCS	6,500	456	2032	40	6,519	13.52	60.76	11,047	8.0	7.0	394	0.009	0.050	0.333	20.5
Coal	IGCC without CCS	6,500	548	2027	40	4,647	10.06	46.24	8,915	8.0	7.0	361	0.013	0.059	0.333	205.4
Coal	PC CCS retrofit @ 500 MW	6,500	-139	2029	20	1,478	6.71	69.22	14,372	5.0	5.0	1,004	0.005	0.070	1.200	20.5
Geothermal	Blundell Dual Flash 90% CF	5,000	35	2019	40	5,748	1.30	106.79	n/a	5.0	5.0	10	n/a	n/a	n/a	n/a
Geothermal	Greenfield Binary 90% CF	5,000	43	2021	40	7,396	1.30	165.63	n/a	5.0	5.0	270	n/a	n/a	n/a	n/a
Geothermal	Generic Geothermal PPA 90% CF	5,000	30	2016	20	n/a	93.46	n/a	n/a	5.0	5.0	270	n/a	n/a	n/a	n/a
Wind	2.0 MW turbine 29% CF WA/OR	1,500	100	2020	30	2,135	0.00	34.46	n/a	Included with CF		n/a	n/a	n/a	n/a	n/a
Wind	2.0 MW turbine 31% CF UT/ID	4,500	100	2020	30	2,188	0.00	34.46	n/a	Included with CF		n/a	n/a	n/a	n/a	n/a
Wind	2.0 MW turbine 43% CF WY	6,500	100	2020	30	2,156	0.67	34.46	n/a	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar	PV Poly-Si Fixed Tilt 26.5% CF	5,000	5.4	2017	25	3,080	0.00	33.50	n/a	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar	PV Poly-Si Single Tracking 31.6% CF	5,000	5.4	2017	25	3,261	0.00	37.20	n/a	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar	PV Poly-Si Fixed Tilt 26.5% CF	5,000	50.4	2018	25	2,546	0.00	30.90	n/a	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar	PV Poly-Si Single Tracking 31.6% CF	5,000	50.4	2018	25	2,702	0.00	34.88	n/a	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar	PV Poly-Si Fixed Tilt 25.4% CF	4,000	50.4	2018	25	2,659	0.00	31.32	n/a	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar	PV Poly-Si Single Tracking 29.2% CF	4,000	50.4	2018	25	2,829	0.00	35.47	n/a	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar	CSP Trough w Natural Gas - 24% Solar	5,000	100	2019	30	5,826	0.00	66.19	11,750	Included with CF		725	n/a	n/a	n/a	n/a
Solar	CSP Tower 24% CF	5,000	100	2019	30	5,549	0.00	66.19	n/a	Included with CF		725	n/a	n/a	n/a	n/a
Solar	CSP Tower Molten Salt 30% CF	5,000	100	2019	30	6,657	0.00	66.19	n/a	Included with CF		750	n/a	n/a	n/a	n/a
Biomass	Forestry Byproduct	1,500	5	2017	30	4,291	0.96	40.65	10,017	5.06	4.4	660	0.1	0.2	0.4	205
Storage	Pumped Storage (5280 MWh)	5,000	600	2022	60	2,862	3.49	19.36	77.5%	3	1.9	0	0	0	0	0
Storage	Lithium Ion Battery (7.2 MWh/day)	5,000	1	2016	20	10,160	0.00	28.68	91.0%	3	1.9	0	0	0	0	0
Storage	Sodium-Sulfur Battery (7.2 MWh/day)	5,000	1	2016	20	4,740	0.00	28.68	72.5%	0.3	0	0	0	0	0	0
Storage	Vanadium RedOx Battery (7.2 MWh/day)	5,000	1	2016	20	5,735	0.00	36.53	70.0%	2	0	0	0	0	0	0
Storage	Advanced Fly Wheel (1667 KWh/day)	5,000	20	2019	20	2,585	0.00	1.85	85.0%	2	1	0	0	0	0	0
Storage	CAES (Mona, UT; 83.4% eff; 2,400 MWh)	4,640	300	2020	30	2,709	2.28	18.78	4,390	2.5	4.5	0	0.0006	0.018	0.255	118
Nuclear	Advanced Fission	5,000	2,234	2025	40	9,042	9.80	96.00	10,710	7.7	7.3	767	0	0	0	0
Nuclear	Small Modular Reactor x 12	5,000	518	2031	40	5,754	8.70	64.54	10,710	7.7	7.3	767	0	0	0	0

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

Supply Side Resource Options Mid-Calendar Year 2014 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	$1,188	8.247%	$97.99	9.57	1.89%	0.18	34.98	44.73	$142.72
Intercooled SCCT Aero x1, ISO	0	$1,508	8.247%	$124.34	15.44	1.89%	0.29	31.84	47.57	$171.91
SCCT Frame "F" x1, ISO	0	$779	7.767%	$60.49	10.04	1.31%	0.13	35.13	45.30	$105.79
IC Recips x6, ISO	0	$1,553	8.247%	$128.05	17.79	0.73%	0.13	29.21	47.13	$175.19
CCCT Dry "F", 2x1, ISO	0	$895	7.682%	$68.73	4.90	2.79%	0.14	23.83	28.87	$97.60
CCCT Dry "F", DF, 2x1, ISO	0	$755	7.682%	$58.00	0.00	0.00%	0.00	34.34	34.34	$92.33
CCCT Dry "G/H", 1x1, ISO	0	$827	7.682%	$63.55	8.31	3.87%	0.32	24.05	32.69	$96.24
CCCT Dry "G/H", DF, 1x1, ISO	0	$604	7.682%	$46.38	0.00	0.00%	0.00	30.35	30.35	$76.73
CCCT Dry "G/H", 2x1, ISO	0	$820	7.682%	$63.01	4.38	3.56%	0.16	23.94	28.48	$91.50
CCCT Dry "G/H", DF, 2x1, ISO	0	$636	7.682%	$48.84	0.00	0.00%	0.00	26.95	26.95	$75.79
CCCT Dry "J", Adv 1x1, ISO	0	$860	7.682%	$66.07	7.22	3.87%	0.28	23.32	30.82	$96.89
CCCT Dry "J", DF, Adv 1x1, ISO	0	$481	7.682%	$36.93	0.00	0.00%	0.00	30.92	30.92	$67.85
SCCT Aero x3	1500	$1,251	8.247%	$103.18	10.08	1.89%	0.19	34.98	45.25	$148.42
Intercooled SCCT Aero x1	1500	$1,587	8.247%	$130.92	16.17	1.89%	0.31	31.85	48.32	$179.24
SCCT Frame "F" x1	1500	$820	7.767%	$63.69	10.59	1.31%	0.14	35.13	45.86	$109.55
IC Recips x 6	1500	$1,553	8.247%	$128.05	17.79	0.73%	0.13	29.22	47.14	$175.19
CCCT Dry "F", 2x1	1500	$942	7.682%	$72.36	5.14	2.79%	0.14	23.84	29.12	$101.49
CCCT Dry "F", DF, 2x1	1500	$755	7.682%	$58.00	0.00	0.00%	0.00	34.34	34.34	$92.34
CCCT Dry "G/H", 2x1	1500	$864	7.682%	$66.35	4.59	3.56%	0.16	23.95	28.70	$95.05
CCCT Dry "G/H", DF, 2x1	1500	$636	7.682%	$48.84	0.00	0.00%	0.00	26.95	26.95	$75.79
CCCT Dry "J", Adv 1x1	1500	$906	7.682%	$69.57	7.22	3.87%	0.28	23.33	30.82	$100.39
CCCT Dry "J", DF, Adv 1x1	1500	$481	7.682%	$36.93	0.00	0.00%	0.00	30.93	30.93	$67.85
SCCT Aero x3	3000	$1,321	8.247%	$108.94	10.58	1.89%	0.20	20.48	31.26	$140.20
Intercooled SCCT Aero x1	3000	$1,676	8.247%	$138.23	17.14	1.89%	0.32	18.65	36.11	$174.34
SCCT Frame "F" x1	3000	$866	7.767%	$67.25	11.87	1.31%	0.16	20.57	32.59	$99.84
IC Recips x 6	3000	$1,553	8.247%	$128.05	17.79	0.73%	0.13	17.11	35.03	$163.08
CCCT Dry "F", 2x1	3000	$995	7.682%	$76.41	5.40	2.79%	0.15	13.96	19.51	$95.91
CCCT Dry "F", DF, 2x1	3000	$755	7.682%	$58.00	0.00	0.00%	0.00	20.11	20.11	$78.11
CCCT Dry "G/H", 2x1	3000	$912	7.682%	$70.05	4.82	3.56%	0.17	14.02	19.01	$89.07
CCCT Dry "G/H", DF, 2x1	3000	$636	7.682%	$48.84	0.00	0.00%	0.00	15.78	15.78	$64.62
CCCT Dry "J", Adv 1x1	3000	$956	7.682%	$73.45	7.57	3.87%	0.29	13.66	21.53	$94.98
CCCT Dry "J", DF, Adv 1x1	3000	$481	7.682%	$36.93	0.00	0.00%	0.00	18.11	18.11	$55.03

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

Supply Side Resource Options Mid-Calendar Year 2014 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%	49.37	na	483	47.00	2.98	11.19%	0.33	-	-	99.68	-	99.68
Intercooled SCCT Aero x1, ISO	0	33%	59.47	na	483	42.79	2.94	11.45%	0.34	-	-	105.53	-	105.53
SCCT Frame "F" x1, ISO	0	33%	36.59	na	483	47.20	3.54	14.39%	0.51	-	-	87.85	-	87.85
IC Recips x6, ISO	0	33%	60.60	na	483	39.26	8.05	8.43%	0.68	-	-	108.59	-	108.59
CCCT Dry "F", 2x1, ISO	0	78%	14.28	na	483	32.03	1.14	14.72%	0.17	-	-	47.62	-	47.62
CCCT Dry "F", DF, 2x1, ISO	0	12%	87.84	na	483	46.14	0.11	0.00%	0.00	-	-	134.08	-	134.08
CCCT Dry "G/H", 1x1, ISO	0	78%	14.08	na	483	32.32	2.29	13.33%	0.31	-	-	49.01	-	49.01
CCCT Dry "G/H", DF, 1x1, ISO	0	12%	72.99	na	483	40.79	0.10	0.00%	0.00	-	-	113.88	-	113.88
CCCT Dry "G/H", 2x1, ISO	0	78%	13.39	na	483	32.17	2.11	14.41%	0.30	-	-	47.97	-	47.97
CCCT Dry "G/H", DF, 2x1, ISO	0	12%	72.10	na	483	36.21	0.09	0.00%	0.00	-	-	108.40	-	108.40
CCCT Dry "J", Adv 1x1, ISO	0	78%	14.18	na	483	31.34	2.00	13.33%	0.27	-	-	47.79	-	47.79
CCCT Dry "J", DF, Adv 1x1, ISO	0	12%	64.54	na	483	41.56	0.10	0.00%	0.00	-	-	106.20	-	106.20
SCCT Aero x3	1500	33%	51.34	na	483	47.00	3.11	11.19%	0.35	-	-	101.80	-	101.80
Intercooled SCCT Aero x1	1500	33%	62.00	na	483	42.79	3.07	11.45%	0.35	-	-	108.22	-	108.22
SCCT Frame "F" x1	1500	33%	37.90	na	483	47.21	3.73	14.39%	0.54	-	-	89.37	-	89.37
IC Recips x 6	1500	33%	60.60	na	483	39.26	8.05	8.43%	0.68	-	-	108.59	-	108.59
CCCT Dry "F", 2x1	1500	78%	14.85	na	483	32.03	1.20	14.72%	0.18	-	-	48.26	-	48.26
CCCT Dry "F", DF, 2x1	1500	12%	87.84	na	483	46.14	0.11	0.00%	0.00	-	-	134.09	-	134.09
CCCT Dry "G/H", 2x1	1500	78%	13.91	na	483	32.17	2.21	14.41%	0.32	-	-	48.62	-	48.62
CCCT Dry "G/H", DF, 2x1	1500	12%	72.10	na	483	36.22	0.09	0.00%	0.00	-	-	108.40	-	108.40
CCCT Dry "J", Adv 1x1	1500	78%	14.69	na	483	31.34	2.00	13.33%	0.27	-	-	48.31	-	48.31
CCCT Dry "J", DF, Adv 1x1	1500	12%	64.55	na	483	41.56	0.10	0.00%	0.00	-	-	106.20	-	106.20
SCCT Aero x3	3000	33%	48.50	na	481	46.82	3.26	11.19%	0.36	-	-	98.95	-	98.95
Intercooled SCCT Aero x1	3000	33%	60.31	na	481	42.63	3.24	11.45%	0.37	-	-	106.55	-	106.55
SCCT Frame "F" x1	3000	33%	34.54	na	481	47.03	3.95	14.39%	0.57	-	-	86.09	-	86.09
IC Recips x 6	3000	33%	56.41	na	481	39.12	8.05	8.43%	0.68	-	-	104.26	-	104.26
CCCT Dry "F", 2x1	3000	78%	14.04	na	481	31.91	1.26	14.72%	0.19	-	-	47.40	-	47.40
CCCT Dry "F", DF, 2x1	3000	12%	74.30	na	481	45.97	0.11	0.00%	0.00	-	-	120.38	-	120.38
CCCT Dry "G/H", 2x1	3000	78%	13.04	na	481	32.05	2.33	14.41%	0.34	-	-	47.76	-	47.76
CCCT Dry "G/H", DF, 2x1	3000	12%	61.47	na	481	36.08	0.09	0.00%	0.00	-	-	97.64	-	97.64
CCCT Dry "J", Adv 1x1	3000	78%	13.90	na	481	31.23	2.11	13.33%	0.28	-	-	47.52	-	47.52
CCCT Dry "J", DF, Adv 1x1	3000	12%	52.35	na	481	41.40	0.10	0.00%	0.00	-	-	93.86	-	93.86

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

Supply Side Resource Options Mid-Calendar Year 2014 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	5050	$1,430	8.247%	$117.95	11.41	1.89%	0.22	14.83	26.46	$144.40
Intercooled SCCT Aero x1	5050	$1,815	8.247%	$149.66	18.44	1.89%	0.35	13.50	32.29	$181.95
SCCT Frame "F" x1	5050	$937	7.767%	$72.81	9.51	1.31%	0.12	14.90	24.53	$97.34
IC Recips x6	5050	$1,553	8.247%	$128.05	17.79	0.73%	0.13	12.39	30.31	$158.36
CCCT Dry "F", 1x1	5050	$1,152	7.682%	$88.49	11.19	2.94%	0.33	10.15	21.68	$110.16
CCCT Dry "F", DF, 1x1	5050	$539	7.682%	$41.42	0.00	0.00%	0.00	11.98	11.98	$53.39
CCCT Dry "F", 2x1	5050	$1,077	7.682%	$82.72	5.80	2.79%	0.16	10.11	16.07	$98.80
CCCT Dry "F", DF, 2x1	5050	$755	7.682%	$58.00	0.00	0.00%	0.00	14.56	14.56	$72.56
CCCT Dry "G/H", 1x1	5050	$996	7.682%	$76.49	9.89	3.87%	0.38	10.20	20.47	$96.97
CCCT Dry "G/H", DF, 1x1	5050	$604	7.682%	$46.38	0.00	0.00%	0.00	12.87	12.87	$59.25
CCCT Dry "G/H", 2x1	5050	$987	7.682%	$75.85	5.18	3.72%	0.19	10.15	15.52	$91.37
CCCT Dry "G/H", DF, 2x1	5050	$636	7.682%	$48.84	0.00	0.00%	0.00	11.43	11.43	$60.26
CCCT Dry "J", Adv 1x1	5050	$1,035	7.682%	$79.53	8.58	3.87%	0.33	9.89	18.80	$98.33
CCCT Dry "J", DF, Adv 1x1	5050	$481	7.682%	$36.93	0.00	0.00%	0.00	13.11	13.11	$50.04
Molten Carbonate Fuel Cell	5050	$5,106	6.974%	$356.09	8.82	1.33%	0.12	12.28	21.21	$377.31
SCCT Aero x3	6500	$1,519	8.247%	$125.27	12.11	1.89%	0.23	9.65	21.99	$147.26
Intercooled SCCT Aero x1	6500	$1,927	8.247%	$158.95	19.51	1.89%	0.37	8.79	28.67	$187.61
SCCT Frame "F" x1	6500	$996	7.767%	$77.33	12.17	1.31%	0.16	9.69	22.02	$99.35
IC Recips x6	6500	$1,553	8.247%	$128.05	17.79	0.73%	0.13	8.06	25.98	$154.04
CCCT Dry "G/H", 2x1	6500	$1,049	7.682%	$80.56	5.47	3.72%	0.20	6.61	12.28	$92.83
CCCT Dry "G/H", DF, 2x1	6500	$636	7.682%	$48.84	0.00	0.00%	0.00	7.44	7.44	$56.27
CCCT Dry "J", Adv 1x1	6500	$1,099	7.682%	$84.46	9.08	3.87%	0.35	6.44	15.87	$100.33
CCCT Dry "J", DF, Adv 1x1	6500	$481	7.682%	$36.93	0.00	0.00%	0.00	8.53	8.53	$45.46
SCPC with CCS	5000	$5,946	7.577%	$450.53	69.22		0.00	0.00	69.22	$519.75
SCPC without CCS	5000	$3,289	7.625%	$250.77	40.65		0.00	0.00	40.65	$291.42
IGCC with CCS	5000	$5,757	7.254%	$417.61	55.78		0.00	0.00	55.78	$473.38
IGCC without CCS	5000	$4,104	7.261%	$298.00	42.45		0.00	0.00	42.45	$340.44
PC CCS retrofit @ 500 MW	5000	$1,305	7.554%	$98.61	74.52		0.00	0.00	74.52	$173.13
SCPC with CCS	6500	$6,734	7.577%	$510.20	64.29		0.00	0.00	64.29	$574.49
SCPC without CCS	6500	$3,724	7.625%	$283.97	37.71		0.00	0.00	37.71	$321.69
IGCC with CCS	6500	$6,519	7.254%	$472.86	60.76		0.00	0.00	60.76	$533.62
IGCC without CCS	6500	$4,647	7.261%	$337.42	46.24		0.00	0.00	46.24	$383.66
PC CCS retrofit @ 500 MW	6500	$1,478	7.554%	$111.67	69.22		0.00	0.00	69.22	$180.89

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

Supply Side Resource Options Mid-Calendar Year 2014 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%	49.95	na	474	46.17	3.48	11.19%	0.39	-	-	99.99	-	99.99
Intercooled SCCT Aero x1	5050	33%	62.94	na	474	42.04	3.46	11.45%	0.40	-	-	108.83	-	108.83
SCCT Frame "F" x1	5050	33%	33.67	na	474	46.37	4.24	14.39%	0.61	-	-	84.89	-	84.89
IC Recips x6	5050	33%	54.78	na	474	38.57	8.05	8.43%	0.68	-	-	102.08	-	102.08
CCCT Dry "F", 1x1	5050	78%	16.12	na	474	31.61	1.60	13.02%	0.21	-	-	49.54	-	49.54
CCCT Dry "F", DF, 1x1	5050	12%	50.79	na	474	37.28	0.09	0.00%	0.00	-	-	88.16	-	88.16
CCCT Dry "F", 2x1	5050	78%	14.46	na	474	31.46	1.36	14.57%	0.20	-	-	47.48	-	47.48
CCCT Dry "F", DF, 2x1	5050	12%	69.02	na	474	45.33	0.11	0.00%	0.00	-	-	114.46	-	114.46
CCCT Dry "G/H", 1x1	5050	78%	14.19	na	474	31.75	2.77	13.02%	0.36	-	-	49.07	-	49.07
CCCT Dry "G/H", DF, 1x1	5050	12%	56.36	na	474	40.07	0.10	0.00%	0.00	-	-	96.53	-	96.53
CCCT Dry "G/H", 2x1	5050	78%	13.37	na	474	31.61	2.51	14.26%	0.36	-	-	47.85	-	47.85
CCCT Dry "G/H", DF, 2x1	5050	12%	57.33	na	474	35.58	0.09	0.00%	0.00	-	-	92.99	-	92.99
CCCT Dry "J", Adv 1x1	5050	78%	14.39	na	474	30.79	2.34	13.64%	0.32	-	-	47.83	-	47.83
CCCT Dry "J", DF, Adv 1x1	5050	12%	47.60	na	474	40.82	0.10	0.00%	0.00	-	-	88.52	-	88.52
Molten Carbonate Fuel Cell	5050	95%	45.31	na	474	38.21	10.10	9.86%	1.00	-	-	94.62	-	94.62
SCCT Aero x3	6500	33%	50.94	na	466	45.40	3.66	11.19%	0.41	-	-	100.41	-	100.41
Intercooled SCCT Aero x1	6500	33%	64.90	na	466	41.33	3.65	11.45%	0.42	-	-	110.30	-	110.30
SCCT Frame "F" x1	6500	33%	34.37	na	466	45.60	4.50	14.39%	0.65	-	-	85.11	-	85.11
IC Recips x6	6500	33%	53.28	na	466	37.92	8.05	8.43%	0.68	-	-	99.94	-	99.94
CCCT Dry "G/H", 2x1	6500	78%	13.59	na	466	31.08	2.66	14.26%	0.38	-	-	47.70	-	47.70
CCCT Dry "G/H", DF, 2x1	6500	12%	53.53	na	466	34.98	0.09	0.00%	0.00	-	-	88.60	-	88.60
CCCT Dry "J", Adv 1x1	6500	78%	14.68	na	466	30.27	2.48	13.64%	0.34	-	-	47.77	-	47.77
CCCT Dry "J", DF, Adv 1x1	6500	12%	43.24	na	466	40.14	0.10	0.00%	0.00	-	-	83.48	-	83.48
SCPC with CCS	5000	90%	65.74	na			6.71					NC	-	NC
SCPC without CCS	5000	92%	36.32	na			0.96					NC	-	NC
IGCC with CCS	5000	86%	63.16	na			11.28					NC	-	NC
IGCC without CCS	5000	86%	45.42	na			8.39					NC	-	NC
PC CCS retrofit @ 500 MW	5000	90%	21.90	na			6.20					NC	-	NC
SCPC with CCS	6500	90%	72.67	na			7.26					NC	-	NC
SCPC without CCS	6500	92%	40.10	na			1.27					NC	-	NC
IGCC with CCS	6500	86%	71.20	na			13.52					NC	-	NC
IGCC without CCS	6500	86%	51.19	na			10.06					NC	-	NC
PC CCS retrofit @ 500 MW	6500	90%	22.88	na			6.71					NC	-	NC

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

Supply Side Resource Options Mid-Calendar Year 2014 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)**
Blundell Dual Flash 90% CF		$5,748	6.676%	$383.72	106.79	0.00%	0.00	0.00	106.79	$490.51
Greenfield Binary 90% CF		$7,396	6.676%	$493.74	165.63	0.00%	0.00	0.00	165.63	$659.37
Generic Geothermal PPA 90% CF		$0	6.676%	$0.00	0.00	0.00%	0.00	0.00	0.00	$0.00
2.0 MW turbine 29% CF WA/OR		$2,135	7.399%	$157.96	34.46	0.00%	0.00	0.00	34.46	$192.42
2.0 MW turbine 31% CF UT/ID		$2,188	7.399%	$161.89	34.46	0.00%	0.00	0.00	34.46	$196.35
2.0 MW turbine 43% CF WY		$2,156	7.399%	$159.49	34.46	0.00%	0.00	0.00	34.46	$193.94
PV Poly-Si Fixed Tilt 26.5% CF		$3,080	8.029%	$247.32	33.50	0.00%	0.00	0.00	33.50	$280.82
PV Poly-Si Single Tracking 31.6% CF		$3,261	8.029%	$261.80	37.20	0.00%	0.00	0.00	37.20	$299.00
PV Poly-Si Fixed Tilt 26.5% CF		$2,546	8.029%	$204.43	30.90	0.00%	0.00	0.00	30.90	$235.33
PV Poly-Si Single Tracking 31.6% CF		$2,702	8.029%	$216.97	34.88	0.00%	0.00	0.00	34.88	$251.85
PV Poly-Si Fixed Tilt 25.4% CF		$2,659	8.029%	$213.47	31.32	0.00%	0.00	0.00	31.32	$244.79
PV Poly-Si Single Tracking 29.2% CF		$2,829	8.029%	$227.12	35.47	0.00%	0.00	0.00	35.47	$262.59
CSP Trough w Natural Gas - 24% Solar		$5,826	7.399%	$431.04	66.19	0.00%	0.00	17.89	84.08	$515.12
CSP Tower 24% CF		$5,549	7.399%	$410.60	66.19	0.00%	0.00	0.00	66.19	$476.79
CSP Tower Molten Salt 30% CF		$6,657	7.399%	$492.52	66.19	0.00%	0.00	0.00	66.19	$558.71
Forestry Byproduct		$4,291	7.399%	$317.49	40.65		0.00	0.00	40.65	$358.14
Pumped Storage (5280 MWh)		$2,862	7.001%	$200.38	19.36	0.00%	0.00	0.00	19.36	$219.74
Lithium Ion Battery (7.2 MWh/day)		$10,160	10.428%	$1,059.57	28.68	0.00%	0.00	0.00	28.68	$1,088.24
Sodium-Sulfur Battery (7.2 MWh/day)		$4,740	10.428%	$494.28	28.68	0.00%	0.00	0.00	28.68	$522.96
Vanadium RedOx Battery (7.2 MWh/day)		$5,735	10.428%	$598.05	36.53	0.00%	0.00	0.00	36.53	$634.58
Advanced Fly Wheel (1667 KWh/day)		$2,585	8.531%	$220.56	1.85	0.00%	0.00	0.00	1.85	$222.41
CAES (Mona, UT; 83.4% eff; 2,400 MWh)		$2,709	8.247%	$223.38	18.78	0.00%	0.00	6.69	25.47	$248.85
Advanced Fission		$9,042	7.430%	$671.78	96.00	0.00%	0.00	0.00	96.00	$767.78
Small Modular Reactor x 12		$5,754	7.430%	$427.52	64.54	0.00%	0.00	0.00	64.54	$492.06

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

Supply Side Resource Options Mid-Calendar Year 2014 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		90%	62.04	na	0	-	1.30	0.00%	0.00	-	-	63.34	(16.33)	47.02
Greenfield Binary 90% CF		90%	83.40	na	0	-	1.30	0.00%	0.00	-	-	84.70	(16.33)	68.37
Generic Geothermal PPA 90% CF		90%	-	na	0	-	93.46	0.00%	0.00	-	-	93.46	-	93.46
2.0 MW turbine 29% CF WA/OR		29%	75.74	na	0	-	0.00	0.00%	0.00	3.06	-	78.80	(18.37)	60.43
2.0 MW turbine 31% CF UT/ID		31%	72.31	na	0	-	0.00	0.00%	0.00	3.06	-	75.36	(18.37)	56.99
2.0 MW turbine 43% CF WY		43%	51.49	na	0	-	0.67	0.00%	0.00	3.06	-	55.21	(18.37)	36.85
PV Poly-Si Fixed Tilt 26.5% CF		27%	120.97	na	0	-	0.00	0.00%	0.00	0.76	-	121.74	(5.11)	116.62
PV Poly-Si Single Tracking 31.6% CF		32%	108.01	na	0	-	0.00	0.00%	0.00	0.76	-	108.78	(4.54)	104.24
PV Poly-Si Fixed Tilt 26.5% CF		27%	101.37	na	0	-	0.00	0.00%	0.00	0.76	-	102.14	(4.23)	97.91
PV Poly-Si Single Tracking 31.6% CF		32%	90.98	na	0	-	0.00	0.00%	0.00	0.76	-	91.74	(3.76)	87.98
PV Poly-Si Fixed Tilt 25.4% CF		25%	110.02	na	0	-	0.00	0.00%	0.00	0.76	-	110.78	(4.60)	106.17
PV Poly-Si Single Tracking 29.2% CF		29%	102.66	na	0	-	0.00	0.00%	0.00	0.76	-	103.42	(4.26)	99.16
CSP Trough w Natural Gas - 24% Solar		33%	178.19	na	474	12.59	0.00	0.00%	0.00	0.76	-	191.55	(8.21)	183.34
CSP Tower 24% CF		24%	226.78	na	0	-	0.00	0.00%	0.00	0.76	-	227.55	(10.75)	216.80
CSP Tower Molten Salt 30% CF		30%	212.60	na	0	-	0.00	0.00%	0.00	0.76	-	213.36	(10.32)	203.05
Forestry Byproduct		91%	45.04	na			0.96					NC	-	NC
Pumped Storage (5280 MWh)		37%	68.41	78%	481	40.29	3.49	0.00%	0.00	-	-	112.20	-	112.20
Lithium Ion Battery (7.2 MWh/day)		25%	496.91	91%	474	33.83	0.00	0.00%	0.00	-	-	530.75	-	530.75
Sodium-Sulfur Battery (7.2 MWh/day)		25%	238.79	73%	474	42.47	0.00	0.00%	0.00	-	-	281.26	-	281.26
Vanadium RedOx Battery (7.2 MWh/day)		25%	289.76	70%	474	43.99	0.00	0.00%	0.00	-	-	333.75	-	333.75
Advanced Fly Wheel (1667 KWh/day)		5%	507.79	85%	474	36.22	0.00	0.00%	0.00	-	-	544.02	-	544.02
CAES (Mona, UT; 83.4% eff; 2,400 MWh)		33%	85.22	83%	474	36.92	2.28	10.38%	0.24	-	-	124.66	-	124.66
Advanced Fission		86%	102.44	na	0	-	9.80	0.00%	0.00	-	-	112.24	-	112.24
Small Modular Reactor x 12		86%	65.65	na	0	-	8.70	0.00%	0.00	-	-	74.35	-	74.35

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

Supply Side Resource Options Mid-Calendar Year 2014 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										
Intercooled SCCT Aero x1	5050	$1,697	8.247%	$139.95	18.44	1.89%	0.35	17.08	35.86	$175.82
CCCT Dry "F", 1x1	5050	$1,064	7.682%	$81.72	11.19	2.94%	0.33	12.84	24.36	$106.09
CCCT Dry "F", DF, 1x1	5050	$498	7.682%	$38.25	0.00	0.00%	0.00	15.14	15.14	$53.39
CCCT Dry "F", 2x1	5050	$1,030	7.682%	$79.12	5.80	2.79%	0.16	12.78	18.75	$97.86
CCCT Dry "F", DF, 2x1	5050	$722	7.682%	$55.47	0.00	0.00%	0.00	18.41	18.41	$73.88
CCCT Dry "J", Adv 1x1	5050	$967	7.682%	$74.31	8.58	3.87%	0.33	12.51	21.42	$95.73
CCCT Dry "J", DF, Adv 1x1	5050	$449	7.682%	$34.50	0.00	0.00%	0.00	16.58	16.58	$51.09
Huntington										
Intercooled SCCT Aero x1	5050	$1,697	8.247%	$139.95	18.44	1.89%	0.35	13.50	32.29	$172.25
CCCT Dry "F", 1x1	5050	$1,064	7.682%	$81.72	11.19	2.94%	0.33	10.15	21.68	$103.40
CCCT Dry "F", DF, 1x1	5050	$498	7.682%	$38.25	0.00	0.00%	0.00	11.98	11.98	$50.23
CCCT Dry "F", 2x1	5050	$1,030	7.682%	$79.12	5.80	2.79%	0.16	10.11	16.07	$95.19
CCCT Dry "F", DF, 2x1	5050	$722	7.682%	$55.47	0.00	0.00%	0.00	14.56	14.56	$70.03
CCCT Dry "J", Adv 1x1	5050	$967	7.682%	$74.31	8.58	3.87%	0.33	9.89	18.80	$93.12
CCCT Dry "J", DF, Adv 1x1	5050	$449	7.682%	$34.50	0.00	0.00%	0.00	13.11	13.11	$47.62
Hunter										
Intercooled SCCT Aero x1	5050	$1,697	8.247%	$139.95	18.44	1.89%	0.35	13.50	32.29	$172.25
CCCT Dry "F", 1x1	5050	$1,064	7.682%	$81.72	11.19	2.94%	0.33	10.15	21.68	$103.40
CCCT Dry "F", DF, 1x1	5050	$498	7.682%	$38.25	0.00	0.00%	0.00	11.98	11.98	$50.23
CCCT Dry "F", 2x1	5050	$1,030	7.682%	$79.12	5.80	2.79%	0.16	10.11	16.07	$95.19
CCCT Dry "F", DF, 2x1	5050	$722	7.682%	$55.47	0.00	0.00%	0.00	14.56	14.56	$70.03
CCCT Dry "J", Adv 1x1	5050	$967	7.682%	$74.31	8.58	3.87%	0.33	9.89	18.80	$93.12
CCCT Dry "J", DF, Adv 1x1	5050	$449	7.682%	$34.50	0.00	0.00%	0.00	13.11	13.11	$47.62
Jim Bridger										
Intercooled SCCT Aero x1	6500	$1,802	8.247%	$148.64	19.51	1.89%	0.37	8.79	28.67	$177.31
CCCT Dry "G/H", 2x1	6500	$1,008	7.682%	$77.44	5.47	3.72%	0.20	6.61	12.28	$89.71
CCCT Dry "G/H", DF, 2x1	6500	$611	7.682%	$46.95	0.00	0.00%	0.00	7.44	7.44	$54.38
CCCT Dry "J", Adv 1x1	6500	$1,027	7.682%	$78.93	9.08	3.87%	0.35	6.44	15.87	$94.79
CCCT Dry "J", DF, Adv 1x1	6500	$449	7.682%	$34.50	0.00	0.00%	0.00	8.53	8.53	$43.04
Naughton										
Intercooled SCCT Aero x1	6500	$1,802	8.247%	$148.64	19.51	1.89%	0.37	13.50	33.38	$182.03
CCCT Dry "J", Adv 1x1	6500	$1,027	7.682%	$78.93	9.08	3.87%	0.35	9.89	19.32	$98.25
CCCT Dry "J", DF, Adv 1x1	6500	$449	7.682%	$34.50	0.00	0.00%	0.00	13.11	13.11	$47.62
Wyodak										
Intercooled SCCT Aero x1	6500	$1,802	8.247%	$148.64	19.51	1.89%	0.37	17.08	36.95	$185.60

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

Supply Side Resource Options Mid-Calendar Year 2014 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														
Intercooled SCCT Aero x1	5050	33%	60.82	na	459	40.68	3.46	11.45%	0.40	-	-	105.36	-	105.36
CCCT Dry "F", 1x1	5050	78%	15.53	na	459	30.59	1.60	13.02%	0.21	-	-	47.93	-	47.93
CCCT Dry "F", DF, 1x1	5050	12%	50.79	na	459	36.08	0.09	0.00%	0.00	-	-	86.97	-	86.97
CCCT Dry "F", 2x1	5050	78%	14.32	na	459	30.45	1.36	14.57%	0.20	-	-	46.33	-	46.33
CCCT Dry "F", DF, 2x1	5050	12%	70.28	na	459	43.87	0.11	0.00%	0.00	-	-	114.26	-	114.26
CCCT Dry "J", Adv 1x1	5050	78%	14.01	na	459	29.80	2.34	13.64%	0.32	-	-	46.47	-	46.47
CCCT Dry "J", DF, Adv 1x1	5050	12%	48.60	na	459	39.51	0.10	0.00%	0.00	-	-	88.21	-	88.21
Huntington														
Intercooled SCCT Aero x1	5050	33%	59.58	na	474	42.01	3.46	11.45%	0.40	-	-	105.45	-	105.45
CCCT Dry "F", 1x1	5050	78%	15.13	na	474	31.59	1.60	13.02%	0.21	-	-	48.53	-	48.53
CCCT Dry "F", DF, 1x1	5050	12%	47.78	na	474	37.26	0.09	0.00%	0.00	-	-	85.13	-	85.13
CCCT Dry "F", 2x1	5050	78%	13.93	na	474	31.44	1.36	14.57%	0.20	-	-	46.93	-	46.93
CCCT Dry "F", DF, 2x1	5050	12%	66.62	na	474	45.30	0.11	0.00%	0.00	-	-	112.03	-	112.03
CCCT Dry "J", Adv 1x1	5050	78%	13.63	na	474	30.77	2.34	13.64%	0.32	-	-	47.05	-	47.05
CCCT Dry "J", DF, Adv 1x1	5050	12%	45.30	na	474	40.80	0.10	0.00%	0.00	-	-	86.20	-	86.20
Hunter														
Intercooled SCCT Aero x1	5050	33%	59.58	na	474	42.01	3.46	11.45%	0.40	-	-	105.45	-	105.45
CCCT Dry "F", 1x1	5050	78%	15.13	na	474	31.59	1.60	13.02%	0.21	-	-	48.53	-	48.53
CCCT Dry "F", DF, 1x1	5050	12%	47.78	na	474	37.26	0.09	0.00%	0.00	-	-	85.13	-	85.13
CCCT Dry "F", 2x1	5050	78%	13.93	na	474	31.44	1.36	14.57%	0.20	-	-	46.93	-	46.93
CCCT Dry "F", DF, 2x1	5050	12%	66.62	na	474	45.30	0.11	0.00%	0.00	-	-	112.03	-	112.03
CCCT Dry "J", Adv 1x1	5050	78%	13.63	na	474	30.77	2.34	13.64%	0.32	-	-	47.05	-	47.05
CCCT Dry "J", DF, Adv 1x1	5050	12%	45.30	na	474	40.80	0.10	0.00%	0.00	-	-	86.20	-	86.20
Jim Bridger														
Intercooled SCCT Aero x1	6500	33%	61.34	na	466	41.31	3.65	11.45%	0.42	-	-	106.71	-	106.71
CCCT Dry "G/H", 2x1	6500	78%	13.13	na	466	31.06	2.66	14.26%	0.38	-	-	47.23	-	47.23
CCCT Dry "G/H", DF, 2x1	6500	12%	51.73	na	466	34.96	0.09	0.00%	0.00	-	-	86.78	-	86.78
CCCT Dry "J", Adv 1x1	6500	78%	13.87	na	466	30.26	2.48	13.64%	0.34	-	-	46.94	-	46.94
CCCT Dry "J", DF, Adv 1x1	6500	12%	40.94	na	466	40.12	0.10	0.00%	0.00	-	-	81.16	-	81.16
Naughton														
Intercooled SCCT Aero x1	6500	33%	62.97	na	474	42.01	3.65	11.45%	0.42	-	-	109.05	-	109.05
CCCT Dry "J", Adv 1x1	6500	78%	14.38	na	474	30.77	2.48	13.64%	0.34	-	-	47.97	-	47.97
CCCT Dry "J", DF, Adv 1x1	6500	12%	45.30	na	474	40.80	0.10	0.00%	0.00	-	-	86.20	-	86.20
Wyodak														
Intercooled SCCT Aero x1	6500	33%	64.20	na	462	40.93	3.65	11.45%	0.42	-	-	109.20	-	109.20

Additionally, a total resource cost sensitivity analysis was prepared for three natural gas-fired combined cycle combustion turbine resource options at an elevation of 5050 feet at varying capacity factors. Table 6.3 shows the total resource cost results for this analysis.

Table 6.3 – Total Resource Cost, for various Capacity Factors (Mills/kWh, 2014$)

Capacity Factor CCCT	40%	78%	94%
Capacity Factor Duct Fire	**10%**	**12%**	**22%**
CCCT Dry "F", 1x1	$64.86	$49.54	$46.79
CCCT Dry "F", DF, 1x1	$98.32	$88.16	$65.07
CCCT Dry "F", 2x1	$61.22	$47.48	$45.02
CCCT Dry "F", DF, 2x1	$128.26	$114.46	$83.08
CCCT Dry "G/H", 1x1	$62.55	$49.07	$46.65
CCCT Dry "G/H", DF, 1x1	$107.80	$96.53	$70.91
CCCT Dry "G/H", 2x1	$60.55	$47.85	$45.57
CCCT Dry "G/H", DF, 2x1	$104.46	$92.99	$66.93
CCCT Dry "J", Adv 1x1	$61.51	$47.83	$45.39
CCCT Dry "J", DF, Adv 1x1	$98.04	$88.52	$66.89

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 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 transmission 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 $/kW for the development and construction of a resource including: direct costs (equipment, buildings, installation/overnight construction, commissioning, contractor fees/profit and contingency), owner's costs (land acquisition, water rights, permitting, rights-of-way, design engineering, spare parts, project management, legal/financial support, grid interconnection costs, owner's contingency), and financial costs (AFUDC, capital surcharge, capitalized property taxes, escalation).
Var O&M ($/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-yr)	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

Term	Description
	for a given resource.
POR (%)	Estimated Planned Outage Rate for a given resource.
Water Consumed (gal/MWh)	Average amount of water consumed by a resource for boiler water 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.

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

Acronyms	Description
Adv	Advanced (Combined Cycle Combustion Turbine)
Aero	Aero-derivative
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
EFOR	Equivalent Forced Outage Rate
Hg	Mercury
HHV	Higher Heating Value
IC-Recip	Internal Combustion Reciprocating Engine
IGCC	Integrated Gasification Combined Cycle
ISO	International Organization for Standardization (Temp = 59^{o}F/15^{o}C, Pressure = 14.7 psia/1.013 bar)
MMBtu	Millions of British Thermal Units
PC CCS	Pulverized Coal equipped with Carbon Capture and Sequestration
POR	Planned Outage Rate
PPA	Power Purchase Agreement
PV Poly-Si	Photovoltaic modules constructed from poly-crystalline silicon semiconductor wafers
SC	Simple Cycle
SCCT	Simple Cycle Combustion Turbine
SCPC	Super-Critical Pulverized Coal
SO	Solid Oxide (Fuel Cell)

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

- Capital costs are all-inclusive and include Allowance for Funds Used during Construction (AFUDC), land, EPC (Engineer, Procure and Construct) cost premiums, owner’s costs, etc. Capital costs in Table 6.1 and Table 6.2 reflect costs in mid-2014 dollars; they do not include escalation from mid-year to the year of commercial operation.

- Capital costs include interconnection costs to the transmission system i.e. typical direct assigned costs such as switchyard and other upgrades needed to interconnect the resource to PacifiCorp's transmission network.
- For the nuclear resource, capital costs include the cost of storing spent fuel on-site during the life of the facility. Costs for ultimate off-site disposal of spent fuel are included in the variable O&M costs.
- Wind resources are representative of generic resources included in the IRP models for planning purposes. Cost and performance attributes of specific resources are identified as part of the acquisition process.
- State specific tax benefits are excluded from the IRP supply side table but would be considered in the evaluation of a specific project.

Resource Descriptions

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

Natural Gas, SCCT Aero x3 – a resource based on three General Electric LM6000PG-Sprint simple cycle aero-derivative combustion turbines fueled on natural gas. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/volatile organic compound (VOC) emissions.

Natural Gas, Intercooled SCCT Aero x1 – a resource based on a single 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 a single 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 x 6 - 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 "F", 1x1 - a combined cycle resource based on one frame-type General Electric 7FA.05 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 "F", 2x1 - a combined cycle resource based on two frame-type General Electric 7FA.05 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 "F", DF, 2x1 – 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. Duct firing is not a standalone resource and can only be added in combination with a combined cycle resource. This description also applies to the following technologies that are listed on Table 6.: CCCT Dry "F", DF, 1x1; CCCT Dry "F", DF, 2x1; CCCT Dry "G/H", DF, 1x1; CCCT Dry "G/H", DF, 2x1and CCCT Dry "J", DF, Adv 1x1.

Natural Gas, CCCT Dry "G/H", 1x1 - a combined cycle resource based on one frame-type Mitsubishi M501GAC 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 "G/H", 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.

Natural Gas, CCCT Dry "J", Adv 1x1 - a combined cycle resource based on one frame-type Mitsubishi advanced M501J combustion turbine (steam-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, Fuel Cell - a resource based on molten carbonate fuel cell. Fuel cells are highly modular; the size of the resource can be customized to a specific size.

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, SCPC without CCS - conventional coal-fired generation resource including a supercritical boiler (up to 4,000 psig) using pulverized coal with all emission controls including scrubbers, baghouses, mercury control, selective catalytic reduction (SCR) but without carbon capture and sequestration (CCS).

Coal, IGCC without CCS – advanced combustion turbine based resource using an Integrated Gasification Combined Cycle (IGCC) but without the use of carbon capture and sequestration costs. An IGCC plant produces a synthetic fuel gas from coal using an oxygen blown gasifier and burning the syn-gas in a conventional combustion turbine combined cycle power facility. IGCC would utilize the latest advanced gas turbine technology and provide fuel gas cleanup to achieve low emissions of sulfur dioxide, nitrogen oxides using SCR, mercury and particulate controls.

Coal, PC CCS retrofit @ 500 MW – a retrofit of an existing conventional coal-fired boiler/steam turbine generator 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 criteria pollutant 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 that uses an 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%.

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.

Wind, 2.0 MW turbine 29% CF WA/OR – a wind resource based on 2.0MW wind turbines located in Oregon or Washington with an estimated net annual capacity factor of 29%. The scope would include developing, permitting, engineering, procuring equipment and constructing the wind resource.

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

Wind, 2.0 MW turbine 43% CF WY – a wind resource based on 2.0MW wind turbines located in Wyoming with an estimated net capacity factor of 43%. The scope would include developing, permitting, engineering, procuring equipment and constructing a wind farm.

Solar, PV Poly-Si Fixed Tilt 26.5% CF (1.37 MWdc/MWac) – a large utility scale (50 MW) solar photovoltaic resource using poly-crystalline silica panels in a fixed tilt configuration located in south western Utah. Similar resources, with site specific capacity factors, are also included for locations in Oregon.

Solar, PV Poly-Si Single Tracking 31.5% CF (1.34 MWdc/MWac) – a large utility scale (50 MW) solar photovoltaic resource using poly-crystalline silica solar panels and single axis tracking system located in southwestern Utah. Similar resources, with site specific capacity factors, are also included for locations in Oregon.

Solar, CSP Trough with Natural Gas – a concentrated solar resource using parabolic trough technology. The system would be equipped with a backup 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, 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.

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. The estimated recharge ratio for this resource is 77.5%.

Storage, Lithium Ion Battery – a battery technology of lithium ion batteries located close to the load center. The estimated recharge ratio for this storage resource is 91%.

Storage, Sodium-Sulfur Battery – a battery technology of sodium-sulfur batteries. The estimated recharge ratio for this storage resource is 72.5%.

Storage, Vanadium RedOx Battery – a battery technology based vanadium ReDOx flow battery. The estimated recharge ratio for this storage resource is 70%.

Storage, Advanced Fly Wheel – a storage resource consisting of multiple flywheel components to deliver energy back to the grid primarily to maintain power quality. 20 MW system is included with total storage time in minutes. The estimated recharge ratio for the storage resource is 85%.

Storage, CAES – a storage system utilizing compressed air energy - 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 300 MW is assumed. The air storage reservoir is assumed to be solution mined to size. Natural gas to generate power is required. The recharge ratio for this storage resource is 83.4%; this excludes fuel required during the power generation cycle.

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. A minimum of 10 years will be required to permit and construct a nuclear plant.

Nuclear, Modular Reactor – A small modular reactor resource. Such systems hold the promise of being built off-site and transported to a location at lower cost than traditional nuclear facilities. A nominal 250 MW concept is included. It is recognized that this concept is still in the conceptual design stage which is expected to increase the time before the technology is commercially available.

Resource Option Description

Coal

Potential coal resources are shown in the Supply Side Resource options table as supercritical pulverized coal boilers (PC) and Integrated Gasification Combined Cycle (IGCC), located in both Utah and Wyoming. Current economic conditions have mitigated the concerns with material cost uncertainty that was a factor in previous IRPs. However, the uncertainty surrounding proposed carbon regulations and difficulty in obtaining environmental permits for coal based generation requires the Company to not allow the potential for the selection of coal as a resource in the 2015 IRP.

Supercritical technology is now considered the standard design technology compared to subcritical technology for pulverized coal for a number of reasons. 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 lower than 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 for a supercritical PC facility reflect the cost of adding a new unit at an existing site. PacifiCorp does not expect a significant difference in cost for a multi-unit plant at a new site versus the cost of a single unit addition at an existing site.

The requirement for CO_2 capture and sequestration (CCS) represents a significant cost for both new and existing coal resources. Recently proposed federal New Source Performance Standards for Greenhouse Gases (NSPS-GHG) regulations would require CCS for new coal resources in order to meet the proposed emissions limit of 1,100 lbs per megawatt-hour.

Two major utility-scale CCS retrofit projects have been constructed or are in process on pulverized coal plants. SaskPower's $1.24 billion, 110 MW Boundary Dam project recently entered commercial operation. Construction recently began on Petra Nova's $1.0 billion, 250 MW slip-stream WA Parrish project. These projects are expected to have CO_2 capture rates in excess of 90% capture; sequestration is accomplished through enhanced oil recovery (EOR). Both of these projects utilize amine-based technologies for carbon capture.

PacifiCorp continues to monitor 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. 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 (i.e. non-EOR) sites, and the uncertainty regarding long term liabilities for underground sequestration.

An alternative to supercritical pulverized-coal technology for coal-based generation is the application of IGCC technology. A significant advantage for IGCC when compared to pulverized coal, with amine-based carbon capture, is the reduced cost of capturing 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. Two large, utility-scale IGCC plants have recently entered service or are in construction. Duke Energy's 618 MW Edwardsport Plant (does not currently include carbon capture capability) went into service in June, 2013. Southern Company's $5.6 billion, 582 MW Kemper County project that includes carbon capture (65% capture) and sequestration (as EOR) is nearing completion. A third IGCC project, the Texas Clean Energy Project utilizing Siemens gasification technology, is planned to include CO_2 capture and is currently in an advanced stage of development. The costs presented in the Supply Side Resource option tables reflect costs based on 2007 studies of IGCC costs prepared by PacifiCorp in conjunction with the Wyoming Infrastructure Authority (WIA) to investigate the acquisition of federal grant money to demonstrate western IGCC projects.

No new cost studies were performed on new coal fueled generation options. Updated capital and O&M costs for coal-fuel generation options were based on escalating costs used in the 2013 IRP.

Natural Gas

A number of natural gas-fueled generation options are included in the Supply Side Resource options table and are intended to represent technologies that are both currently commercially available and/or will be available over the next few years. Capital costs for gas-fueled generation options are similar to capital costs reported in previous IRPs. In real terms, capital costs have shown a modest decline compared to the previous IRP, primarily driven by limited domestic orders for new gas-fired generation due to a lack of current economic growth.

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

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

Other natural gas-fired generation options include internal combustion engines and fuel cells. Internal combustion engines are represented by a large power plant consisting of six machines at 18.4 MW each at typical elevations in the West (5,000'). The underlying technology for this category is the Wartsila 18V50SG engine, although other suppliers (notably Caterpillar, General Electric, MAN and Mitsubishi) have entered the market. These machines are spark-ignited and have the advantage of a relatively high efficiency when compared to simple cycle combustion turbines, low emissions profile and a high level of availability and reliability due to the relatively high number of machines for a given target capacity. Similar to new frame and aero-derivative combustion turbines, reciprocating engines are capable of being brought on line up to full load in less than ten minutes. Reciprocating engines have distinct part-load efficiency capability on a plant basis due to having both high part-load efficiency on a standalone engine basis combined with the ability to start/stop multiple engines to meet a target capacity or reserve capability. Reciprocating engines also have the advantages of being relatively insensitive to elevation, do not require high-pressure natural gas, which is typically required for advanced combustion turbines, and have limited water requirements.

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

A number of combined cycle configurations have been provided in this version of the Supply Side Resource options table. Configuration options include 1x1 and 2x1 configurations based on "F" and "G/H" combustion turbines. The "G/H" frame combustion turbine, although they are supplied by different equipment manufacturers, are combined, since the power and performance outputs of the underlying combustion turbines are very similar. Also included in the current version of the Supply Side Resource options table is the “J” class combustion turbine, which is a large advanced combustion turbine (approximately 470 megawatts in a 1x1 combined cycle configuration under ISO conditions). The “J” class combustion turbine is now commercially available in the United States and a number of orders have been placed. General Electric has recently received orders for its new HA.02 technology, which has similar performance characteristics as the Mitsubishi “J” class combustion turbine.

The Supply Side Resource table also includes duct firing (DF), which is not a stand-alone resource option, but is an option for any combined cycle configuration to add peaking capability at relatively high efficiency and low cost. It is also a mechanism to recover lost power generation capability that occurs at high ambient temperatures. The amount of duct firing in the supply side resource options table are stated as fixed values at 50 MW for the 1x1 configuration and 100 MW for the 2x1 configuration; in reality the amount of duct firing is a design consideration and as such the incremental duct firing capacity that can be added is flexible.

The combined cycle options listed in the current supply side resource table are based on dry cooling (i.e. they use an air-cooled condenser), rather than wet cooling (i.e. using a forced draft cooling tower). It is assumed the availability of water in the western United States will continue to be limited. The assumption of dry cooling is considered to be both prudent and conservative. In certain cases and sites, sufficient water may be available for wet cooling (such as in the case of installed a CCCT at the site of an existing coal-fueled plant), in which case, performance and efficiency would be improved; the overall costs of energy would be site-specific depending on the total cost of water (commodity cost, transport/storage infrastructure cost, treatment cost, discharge cost).

For the 2015 IRP, and in comparison to the 2013 IRP, Owner’s costs were increased for new gas-fired resources. These costs include the costs to acquire and develop a greenfield site on either the west side of PacifiCorp’s system or for new resources to serve the east side load areas along the Wasatch Front. These greenfield development costs include: installation of high pressure natural gas pipeline laterals, additional power transmission interconnections, ambient air quality monitoring, permitting and purchase of property, water rights and rights of way. In the 2013 IRP, new gas-fired resource additions were assumed to be installed at brownfield additions (such as the Currant Creek or Gadsby Plants). Under new $PM_{2.5}$ state implementation plans and the limited availability of the appropriate emissions credits, these existing locations are not currently suitable for siting large resource additions. For subsequent resource additions at a developed greenfield site (or at an existing coal plant location), Owner’s costs are reduced to reflect installation at an existing (brownfield) site. For installation of new gas-fired resources at existing coal plants which do not currently have gas supplies (such as the Dave Johnston or Jim Bridger plants), there would be additional costs to install a new natural gas tap/metering point and a lateral extension from the adjacent natural gas transmission systems to plant.

Wind

Capacity Factors

The 2015 IRP reflects updated capacity factors and market prices of wind turbine generators currently available. Wind farm designers have improved capacity factors by selecting wind turbines and turbine options matched to the wind regime of specific turbine sites within wind farms. Multiple blade length options and park-based controls are two improvements that have led to net capacity improvements in some areas with wind regimes in the medium range of the wind power classifications. Net capacity factor assumptions for resources located in Wyoming and Utah increased compared to the 2013 IRP based upon analyses of wind turbine technologies currently available at representative wind sites in those states.

Capital Costs

Capital cost estimates for wind resources are based on the development and construction costs of previously built projects and recent budgetary prices for wind turbines provided by wind turbine suppliers. Wind turbine prices were updated based upon budgetary estimates provided by some major wind turbine suppliers. Wind turbine prices are expected to be stable through 2015. Overall, the costs of wind resources are expected to increase at the overall rate of inflation. A generic 2 MW wind turbine size was selected for the 2015 IRP to represent the range of wind turbine sizes currently available from major suppliers.

Wind Integration Costs

To capture the costs of integrating wind into the system, PacifiCorp applied a value of $3.06/MWh (in 2015 dollars) for resource selection. The source of this value was the Company’s 2014 wind integration study, which is included as Appendix H. Integration costs are included as a variable cost for wind resources.

Other Renewable Resources

Other renewable generation resources included in the Supply Side Resource options table include geothermal, biomass and solar.

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 several 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 Roosevelt Hot Springs geothermal resource was started in 2013; this evaluation is still ongoing.

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. 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 and injection 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 currently not compensated nor incentivized to engage in these inherently risky development efforts.

To mitigate the financial risks of geothermal development, PacifiCorp would use an RFP process to obtain market proposals for geothermal power purchase agreements or build-own-transfer project agreement structures. Geothermal developers, external to PacifiCorp, have the flexibility to structure project pricing to include development risks. Through an RFP process, PacifiCorp could choose the geothermal project with the lowest cost offered by the market and avoid considerable risk for the Company and its customers. In the event PacifiCorp identifies a geothermal asset that appears to be economically attractive but also determines that there is a significant possibility of development risk that the market will not economically absorb, PacifiCorp may approach state regulators with estimates of resource development costs and risks associated to obtain approval for a mechanism to address risks such as dry holes. Because public utility commissions typically do not allow recovery of expenditures which do not result in a direct benefit to customers, and at least one state has a statute that precludes cost recovery of any asset that is not considered to be “used and useful,” obtaining a mechanism to recover geothermal development costs may be difficult. To reflect this specific market condition, the 2015 supply side resource option for geothermal resources is based on publicly available prices for energy supplied under power purchase agreements.

Biomass

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

Solar

Three solar technologies are included in the supply side resource table: 1) fixed tilt photovoltaic (PV) systems based on poly crystalline modules, 2) single axis tracking photovoltaic (PV) systems based on poly-crystalline modules and 3) concentrated solar. Based upon current technology and market conditions, PV resources have lower capital intensity and are better suited to Utah's solar resource than concentrated solar systems. The use of lower cost fixed tilt PV systems or higher capacity factor single axis tracking PV systems is site and project specific.

Since the 2013 IRP, market prices for PV modules in the United States have started to level out after exhibiting significant declines between 2008 and 2013. During this period of PV module price declines, the component basis of PV resources shifted; the costs of PV modules, racking systems, design, and construction are now more evenly balanced. These price shifts, along with changes in inverter capabilities, national electric code changes and the adoption of higher system voltages have impacted plant designs. System designers continue to optimize designs with the objectives of maximizing resource value, decreasing the levelized cost of energy and meeting emerging safety requirements.

The market positions of PV crystalline and solar thin film have shifted in recent years. Thin film technology had typically been considered the module technology of choice for large scale PV systems which resulted in the lowest levelized cost of energy. However, crystalline module costs have shown such significant cost reductions in recent years that there is no clear module type "technology" winner. Technological improvements have increased the efficiency of some thin film designs while silicon prices and manufacturing changes have lowered the costs to manufacture crystalline panels. At this point in time, PacifiCorp considers the effective cost of energy from systems based on thin film and crystalline PV systems to be essentially comparable, for this reason a separate resource category for PV systems based on thin film modules was not explicitly included. The costs and performance included in the supply side resource table are based on the use of crystalline modules; however, this should not to be interpreted as a preference for crystalline technology over thin film technology. Any determinations on technology choice would be based on the results of a resource request for proposal process for new resources.

There has been significant solar development activity in PacifiCorp's service territory since early 2012. Solar projects in development comprise 169 of the 236 projects that filed interconnection studies with PacifiCorp from the beginning of 2012 to the end of 2014. Solar projects with nameplate capacities of 5 MW or less comprise just over half the projects that filed for interconnection. The nameplate capacity of all solar resources in the interconnection process is approximately 3,500 MW. Wind resources in development are a distant second with just under 2,000 MW in the interconnection study process.

Supply and Location of Renewable Resources

It should be noted that the primary drivers of renewable resource selection are the requirements of renewable portfolio standards, compliance with draft EPA rules under §111(d) of the Clean Air Act, and availability of tax credits. In the 2015 IRP, the availability of certain renewable resources is contingent upon transmission availability. The availability of higher capacity factor, lower cost[43] Wyoming wind begins in 2028 for the Regional Haze reference case. Table 6.6 below shows the total cumulative resource selection limits for the Regional Haze reference case. Regional Haze scenarios 1 and 2 will have different resource availability, dependent on FIP/SIP requirements for meeting Best Available Retrofit Technology (BART) requirements.

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[43] Retirement of the Dave Johnston units may allow additions of new resources in the Wyoming area without incurring significant amount of investment in transmission.

Table 6.6 – Cumulative Maximum Renewable Selection Limits by Year for the Regional Haze Reference Case

Type	Renewable Resource	Capacity Factor	Total MW Available		
			2020	2021-2022	2028-2034
Wind	Oregon Wind (Arlington)	29%	0	400	400
	Washington Wind (Walla Walla)	29%	0	600	600
	Utah Wind (South)	31%	0	400	400
	Idaho Wind (Goshen)	31%	0	800	800
	Wyoming Wind (Aeolius)	43%	0	0	762
Solar	Oregon Solar (Lakeview)	29%	405	405	405
	Washington Solar (Yakima)	22%	200	200	200
	Utah Solar (South)	32%	800	800	800
Geothermal	Utah Geothermal (Milford)	90%	30	30	30
	Oregon Geothermal (Neal Hot Springs)	90%	30	30	30

Nuclear

The supply side resource table includes two nuclear technology options. One is the larger 2,236 MW system, which reflects the traditional sized plant based on current state-of-the-art advanced licensed plants; it is modeled on the Westinghouse AP1000 technology currently being employed in Southern Company's construction of Vogtle Units 3 & 4 in Georgia. This is the technology that Blue Castle Holdings has indicated is the design basis for its proposed Blue Castle nuclear facility currently in development near Green River, Utah. Compared to other fuels, the cost of nuclear fuel is relatively low cost and exhibits limited price volatility; thus changes in nuclear fuel prices have a negligible impact on the total cost of energy. The cost of nuclear fuel used in the supply side resource table is $7.73/MWh in 2014 dollars, including the spent fuel permanent disposal levy.

In 2014, the Company commissioned Sargent & Lundy (S&L) to prepare a report to summarize costs, performance and development efforts on emerging commercially viable small modular reactor (SMR) nuclear technologies. SMR's offer simplicity, convenience, attractive economics based on transportable modular construction processes, and, most importantly, an opportunity for the producers of electric generation to reengage the nuclear option with significantly less capital risk compared to traditional large-scale reactor designs. Three emerging SMR designs were assessed (NuScale, mPower and Holtec); all are Integral Pressurized Water Reactors (iPWRs) with passive safety design features. The SMR designs use varying degrees of first-of-a-kind (FOAK) design concepts that simplify the SMR plant systems, enhancing safety, and reducing capital and operations cost. However, these FOAK design concepts create risk that SMR plants may not perform to a rated capacity and reliability or could result in design, construction, or commissioning delays. The designs of all the assessed SMRs are evolving rapidly. The Company will continue to monitor the SMR market.

At this time, other than technology monitoring, the Company is not actively involved in development efforts of either the Blue Castle project or any specific SMR technologies. Currently nuclear power is not considered a viable resource option until the 2025-2030 timeframe. Significant considerations are capital cost uncertainty (both for EPCs as well as Owner's costs), schedule risk, the high cost of development and permitting over an extended period, cost recovery uncertainty associated with unsuccessful development efforts, sociopolitical resistance and regulatory obstacles.

Energy Storage

As in previous IRPs, a number of energy storage technologies are considered; these include compressed air energy storage (CAES), pumped hydroelectric storage and advanced batteries. CAES is of significant interest because of the potential development of solution-mined storage sites associated with Magnum Energy's development activities adjacent to the Intermountain Power Project located in Delta Utah.

Energy storage continues to be of interest since the variable nature of some renewable generation alternatives could be enhanced if the energy produced during low demand or transmission constraint periods could be stored at low cost. Energy storage resources also have the ability to provide ancillary resources in the form of spinning reserves and sources of voltage control.

In 2014, PacifiCorp engaged HDR to update its 2011 Energy Storage Study[44]. Table 6.7 summarizes the costs and performance of available storage technologies from the updated HDR study. Table 6.7 does not include dry cell and Zinc-Bromide (ZnBr) battery options because these systems are similar to other options shown. Zinc-Bromide batteries are similar to the VRB batteries, while dry cells are similar to the Lithium-Ion (Li-Ion) batteries.

Table 6.7 – HDR Energy Storage Study Summary Cost and Capacity Results (2014$)

	Flywheel	Li-Ion	NaS	VRB	Pumped Storage	CAES
System Cost ($/kW and/or $/kWh)	$2,862 per kW	$800 - $1,200/kWh (High Energy)	$4,000/kW	$675/kWh	$1,700-$2,500/kW	$2,000-$2,300/kW
Rated System Size (MW)	20	1 - 32	1	1	600	300+
Rated Capacity (hours)	0.25	1 (High Energy)	7.2	1	8 to 10	8+
Roundtrip, AC to AC efficiency (%)	85	91	70 – 75	65 – 75	75 – 82	64

Three examples of pumped storage hydro projects are described in the HDR study. The three example projects detailed in the 2014 Energy Storage Screening Study are Swan Lake North in Oregon, JD Pool in Washington and Black Canyon in Wyoming. These proxy projects were selected based on technical and commercial development progress. A composite case is presented in the resource table representing both the size of this technology (over 600 MW)[45] and costs at the high end range to reflect the permitting, design and construction cost uncertainty. CAES is represented in the 2015 IRP at the size case described in the HDR study. A 300 net MW capacity case is shown in the resource table at the 4,640 foot elevation reflecting prospective CAES resources under development by Magnum Energy near Delta, Utah. Capital costs include the solution mining component of the technology.

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[44] See Volume II, Appendix Q for the 2014 Energy Storage Study (except associated appendices) the full version is available on accompanying data disk and PacifiCorp's IRP web page at: http://www.pacificorp.com/es/irp.html.

[45] EDF, the developer of the Swan Lake pumped storage project, has recently indicated that they are currently exploring a project size of 300-400 MW instead of the originally contemplated 600 MW, reflecting the results of their internal valuation modeling work.

Battery energy storage is unique in that capital costs are defined in terms of energy storage capability and not necessarily in terms of the amount of energy that can be delivered instantaneously. In order to properly compare different battery systems it is necessary to compare the battery systems on a common operating basis. The common operating basis is defined by the sodium-sulfur (NaS) battery and all systems were compared on storing 7.2 hours of energy. The results shown in the "$/kW–Capacity" and the "$/kWh Energy Storage" columns are based on the high end cost estimates provided in the HDR study. The replacement cost is the average of the initial cost range. All other columns are calculated from the first three columns of data and other data contained in the HDR study. All O&M costs are assumed to be fixed. The "Adjusted $/kWh" is an estimated cost on a $/kWh basis for those battery technologies where only $/kW values were provided in the HDR report; an estimated replacement cost after 10 years for all three battery technologies is assumed.

For the battery technologies listed in the supply side resource tables, normalized capital costs were determined based on specific reference cases and operating assumptions. Since these only reflect one operating scenario, there may be battery technology applications and operating conditions which may be more cost effective under different design and operating conditions. The information provided also does not represent normalized lifecycle costs which are influenced by many factors. Life-cycle costs for battery technologies depend on many variables, which include individual battery technology degradation rates and depth of discharge (DoD) sensitivities, which also depend on site specific conditions and operating conditions. For example, the capacity of Li-Ion batteries falls to below 75% after 100,000 cycles at 100% DoD, or falls to 75% after 1,000,000 cycles at 2.5% DoD. NaS batteries, on the other hand, last for 2,500 cycles at 100% DoD, or 5,000 cycles at 80% DoD; however, their life is unknown if operated at 2.5% DoD. Although VRB batteries do not degrade based on number of cycles, they have additional parasitic loads that impact available energy based on operating history. Performance is also sensitive to temperature which is not considered in this summary effort. The HDR report provides more details on the effects of these variables on the different battery technologies. PacifiCorp is working to provide more details on the costs and trade-offs of the various battery technologies especially for applications other than for traditional load/resource uses such as load shifting.

Anaerobic Digesters – Washington State Service Territory

Study Description

In response to the Company's 2013 IRP, the Washington Utility and Transportation Commission ordered the Company to perform an analysis of the potential for baseload generation resources based on anaerobic digestion in the Company's service territory in the state of Washington. In 2014, the Company commissioned Harris Group Incorporated to perform an extensive assessment on power generation potential from anaerobic digestion. The study effort focused on electric power generation from dairies since it is expected that the bulk of the biogas fuel feedstock derived from anaerobic digestion would be supplied by dairy waste.

Methodology

An assessment was made of the distribution of dairies in the Company's service territory; this included a breakdown on the size and number of dairies. The bulk of the dairies in the Company's service territory are located in Yakima County. From the dairy distribution estimates of the biogas potential, both in terms of fuel quality and quantity, were prepared. The power generation potential was determined based on the estimated biogas potential by dairy size and the assumption that the predominant form of power generation would use reciprocating engines. Cost estimates were prepared on the basis of dairy size inasmuch as the cost of generation resources is lower cost for larger sized dairies due to economies of scale.

Results

Based on the study effort, the estimated power generation potential based on biogas from anaerobic digestion in the Company's Washington state service territory is 16-27 megawatts. Capital costs were estimated to be in the range of $3,200 to $3,700 per kilowatt installed for systems of 500 kilowatts and larger. The final report has been published and is available in Volume II, Appendix P and on the Company's website.[46] A public presentation on the report findings was prepared and made at the 2015 IRP Public Input Meeting 4 on September 25; a copy of that presentation is also available on the Company's website.[47]

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 2015 IRP were derived from the 2015 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.[48] 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. Supply curves provide a representative look at how much of a particular resource can be acquired at a particular price point. Resource modeling utilizing supply curves allows utilities to select least-cost resources (products and quantities) based on each resource's competitiveness against alternative resource options.

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

- Resource quantities available in each year—either 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;
- Persistence of resource savings; for example, Class 2 DSM (energy-focused) resource measure lives;
- Seasonal availability and hours available (Class 1 and 3 DSM capacity resources);

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[46] http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/2015IRPStudy/Anaerobic_Digesters_Resource_Assessment_06-24-2014.pdf.

[47] http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP_PIM04_9-25-26-2014.pdf

[48] The 2015 DSM potential study is included on the data disk provided and available on PacifiCorp's demand-side management web page. http://www.pacificorp.com/es/dsm.html

- 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 and 3 DSM capacity resources, or dollars per megawatt-hour over the resource's life for Class 2 DSM energy resources).

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

Class 1 DSM Capacity Supply Curves

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

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

The potentials and costs for each product were provided at the state level resulting in three products across six states or the development of 18 Class 1 DSM supply curves for the 2015 IRP modeling process.

Class 1 DSM resource price differences between states for similar resources were driven by resource differences in each market, such as irrigation pump size and hours of operation as well as product performance differences. For instance, residential air conditioning load control in 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.

The assessment of potential for distributed standby generation[49] was combined with an assessment of commercial/industrial energy management system controls in the development of the resource opportunity and costs of the Class 1 DSM commercial/industrial curtailment product. The costs for this product are generally constant across all jurisdictions assuming a pay-for-performance delivery model.

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

- Participation in the Class 1 DSM DLC air conditioning and water heating programs or DLC irrigation programs would take precedence over participation in Class 3 DSM Time-of-Use (TOU) rates/programs, assuming customers already enrolled in the DLC air conditioning and water heating and DLC irrigation programs would not opt out to participate in the TOU programs.

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

- Participation in the Class 1 DSM commercial/industrial curtailment programs would take precedent over Class 3 DSM Demand Buyback, Time-of-Use, Real-Time Pricing and/or Critical Peak Pricing programs where load curtailment is offered.

Table 6.8 and Table 6.9 show the summary level Class 1 DSM resource information, by control area, used in the development of the Class 1 DSM resource supply curves. Potential shown is incremental to the existing Class 1 DSM resources identified in Table 5.12. For existing program offerings, it is assumed that the Company could begin acquiring incremental potential in 2016. For resources representing new product offerings, it is assumed the Company could begin acquiring potential in 2017, accounting for the time required for program design, regulatory approval, vendor selection, etc.

Table 6.8 – Class 1 DSM Program Attributes West Control Area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Levelized Cost ($/kW-yr)	First Year(s) Available
Residential and Small Commercial Air Conditioning and Water Heating	Residential and commercial time-of-use and critical peak pricing	50 hours, average of 4 hours per event	Summer	47	$116 - $152	2017
Irrigation Direct Load Control	Irrigation time-of-use and critical peak pricing	52 hours, average of 4 hours per event	Summer	18	$69 - $71	2017
Commercial/Industrial Curtailment (includes distributed standby generation)	Demand buyback, commercial time-of-use, real time pricing and critical peak pricing	30 hours, average of 4 hours per event	Summer	43	$74-$76	2017

Table 6.9 – Class 1 DSM Program Attributes East Control Area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Levelized Cost ($/kW-yr)	First Year(s) Available
Residential and Small Commercial Air Conditioning and Water Heating	Residential and commercial time-of-use and critical peak pricing	50 hours, average of 4 hours per event	Summer	77	$62 - $156	2016-2017
Irrigation Direct Load Control	Irrigation time-of-use and critical peak pricing	52 hours, average of 4 hours per event	Summer	47	$51 - $71	2016-2017
Commercial/Industrial Curtailment (includes distributed standby generation)	Demand buyback, commercial time-of-use, real time pricing and critical peak pricing	30 hours, average of 4 hours per event	Summer	142	$76-$78	2017

Class 3 DSM Capacity Supply Curves

The Company analyzed the potentials for eight discrete opt-in Class 3 DSM products:

1) Residential time-of-use rates;
2) Residential critical peak pricing;
3) Commercial time-of-use rates;
4) Commercial critical peak pricing;
5) Commercial real-time pricing;
6) Commercial and industrial demand buyback;
7) Voluntary irrigation time-of-use rates; and
8) Voluntary irrigation critical peak pricing.

After accounting for product interactions through the participation hierarchy described in PacifiCorp's DSM Potential Study,[50] supply curves were created for four bundled Class 3 DSM product categories, which are capacity-focused resources like Class 1 DSM products:

1) Residential pricing;
2) Commercial and industrial pricing;
3) Commercial and industrial demand buyback; and
4) Irrigation pricing.

The potentials and costs for each product category were provided at the state level, resulting in four products across six states or the development of 24 Class 3 DSM supply curves for the 2015 IRP modeling process.

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

Modest product price differences between states for most Class 3 DSM resources were driven by resource opportunity differences. The DSM potential study assumed the same fixed costs in each state in which it is offered regardless of quantity available. Therefore, states with lower resource availability for a particular product have a higher cost per kilowatt-year. In the case of demand buyback, costs are assumed to scale with the MWs and MWhs enrolled, and are thus nearly constant across states.

Table 6.10 and Table 6.11 show the summary level Class 3 DSM resource information, by control area, used in the development of the Class 3 DSM resource supply curves. Potential shown is incremental to the existing Class 3 DSM resources identified in Table 5.12. In 2015 and 2016, it's assumed the only impacts realized are from existing time-of-use rates. The impacts from new time-of-use rates are available beginning in 2017, accounting for the time required for program design, regulatory approval, vendor selection, etc. Dynamic pricing products (critical peak pricing and real-time pricing) are assumed to be available for acquisition beginning in 2020, following the assumed installation of advance metering infrastructure (AMI) by the end of 2019, whose costs are not captured in the levelized costs for those products.

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[50] PacifiCorp Demand-side Resource Potential Assessment for 2015-2034, Volume 5: Class 1 and 3 DSM Analysis Appendix G, Table G-1.

Table 6.10 – Class 3 DSM Program Attributes, West Control Area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Levelized Cost ($/kW-yr)	First Year(s) Available
Residential Pricing	Residential A/C and Water Heating DLC	148 - 150 hours	Summer	40	$16 - $29	2017
Commercial/Industrial Pricing	C&I Curtailment and Demand Buyback	165 - 230 hours	Summer	22	$5 - $11	2017
Commercial/Industrial Demand Buyback	C&I Curtailment, Time-of-Use, Critical Peak Pricing, and Real-Time Pricing	50 hours	Summer	3	$24	2017
Irrigation Pricing	Irrigation DLC	60 - 61 hours	Summer	3	$5 - $6	2017

Table 6.11 – Class 3 DSM Program Attributes, East Control Area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Levelized Cost ($/kW-yr)	First Year(s) Available
Residential Pricing	Residential A/C and Water Heating DLC	60-150 hours	Summer	82	$18 - $28	2017
Commercial/Industrial Pricing	C&I Curtailment and Demand Buyback	98 - 252 hours	Summer	51	$4 - $11	2017
Commercial/Industrial Demand Buyback	C&I Curtailment, Time-of-Use, Critical Peak Pricing, and Real Time Pricing	50 hours	Summer	10	$24-$25	2017
Irrigation Pricing	Irrigation DLC	49 - 61 hours	Summer	3	$5 - $6	2017

Class 2 DSM, Energy Supply Curves

The 2015 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[51]
- **Measure:**
  - 109 residential measures

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[51] Oregon's Class 2 DSM potential was assessed in a separate study commissioned by the Energy Trust of Oregon.

  - 171 commercial measures
  - 150 industrial measures
  - 19 irrigation measures
  - Nine street lighting measures

- **Facility type[52]:**
  - Six residential facility types
  - 28 commercial facility types
  - 30 industrial facility types
  - Two irrigation facility type
  - Four street lighting types

The 2015 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 13.4 million MWh.[53] 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 10.9 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 50,000 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 the 27 bundles used in the development of the Class 2 DSM supply curves for the 2015 IRP are the same as those developed for the 2013 IRP.

Bundle development began with the Class 2 DSM technical potential identified by the 2015 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

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[52] 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.

[53] 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.

Northwest Power and Conservation Council's aggressive[54] regional planning assumptions, it was assumed that 85 percent of the technical potential for discretionary (retrofit) resources and 77 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 81 percent of the technical potential.

The 2013 DSM potential assessment 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. These market ramp rates were applied in California, Idaho and Wyoming in the development of the supply curves provided for the 2013 IRP modeling effort. Since that time, PacifiCorp's programs have continued to gain traction and market ramp rates were removed in California and Idaho in the development of the 2015 IRP supply curves. However, as momentum in the Wyoming industrial sector is still building, the 2015 DSM potential study applied the "Emerging" market ramp rate used in the 2013 DSM potential study to industrial measures in Wyoming. [55]

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 2015 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 2015 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.[56] Table 6.12 shows the 20-year MWh potential for Class 2 DSM cost bundles, designated by ranges of $/MWh.

Table 6.13 shows the associated bundle price after applying cost credits afforded to Class 2 DSM resources within the model. These cost credits include the following:

- A transmission and distribution investment deferral credit of $54/kW-year;
- Stochastic risk reduction credit of $4.02/MWh[57];
- Northwest Power Act 10-percent credit (Oregon and Washington resources only)[58]

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[54] 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.

[55] The Wyoming industrial market ramp rate is provided in Table E-1 of Volume 4 of the 2015 DSM potential study report.

[56] Note for Washington state Yakima and Walla Walla are modeled as separate resources making seven total sets of curves of 27 bundles, totaling 189 Class 2 DSM supply curves.

[57] 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.

[58] 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.

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 6.12 – Class 2 DSM MWh Potential by Cost Bundle

Bundle Cost ($/MWh)	California	Idaho	Oregon	Utah	Washington	Wyoming
<=10	30,331	92,569	825,665	844,577	240,894	361,822
10-20	21,989	85,081	132,013	2,015,723	121,227	196,956
20-30	26,202	27,983	558,510	1,395,248	70,320	294,359
30-40	20,471	36,945	138,175	844,350	57,730	244,710
40-50	6,943	18,176	166,858	455,228	43,377	217,083
50-60	6,264	21,938	74,488	232,260	56,447	99,352
60-70	11,906	22,615	31,192	199,908	46,483	52,133
70-80	4,217	12,098	111,248	121,324	20,012	25,305
80-90	5,721	10,428	95,838	187,073	49,849	94,715
90-100	3,304	25,935	115,241	99,577	14,151	51,928
100-110	3,254	3,893	52,537	111,496	21,588	7,898
110-120	4,636	14,905	-	133,370	36,821	16,366
120-130	1,361	3,173	33,791	68,446	11,022	14,095
130-140	1,894	5,291	46,292	40,182	7,121	20,567
140-150	12,752	9,047	65,726	67,985	6,314	6,556
150-160	3,001	5,285	1,118	68,483	13,729	9,501
160-170	1,261	1,245	211,761	57,846	5,186	6,847
170-180	2,373	5,011	5,808	26,946	10,439	9,173
180-190	1,119	4,692	-	93,370	2,358	10,029
190-200	2,734	8,424	15,596	19,218	5,105	3,328
200-250	5,027	9,149	20,896	67,965	14,108	28,550
250-300	5,927	8,380	3,760	119,276	37,312	38,205
300-400	15,182	22,589	21,409	384,577	56,865	39,492
400-500	4,707	8,443	38,715	57,957	39,828	20,383
500-750	9,218	17,778	24,179	104,247	21,148	38,720
750-1,000	1,156	3,626	2,692	10,629	6,345	14,257
> 1,000	1,843	4,069	92,882	22,500	6,294	9,381

Table 6.13 – Class 2 DSM Adjusted Prices by Cost Bundle

Bundle Cost ($/MWh)	Levelized Bundle Price After Adjustments ($/MWh)					
	California	Idaho	Oregon	Utah	Washington	Wyoming
<= 10	-	-	-	-	-	-
10 - 20	0.24	-	-	-	-	3.61
20 - 30	11.11	7.37	6.87	9.32	4.85	12.69
30 – 40	14.54	5.33	12.14	18.06	8.92	18.99

Bundle Cost ($/MWh)	**Levelized Bundle Price After Adjustments ($/MWh)**					
	California	**Idaho**	**Oregon**	**Utah**	**Washington**	**Wyoming**
40 – 50	29.30	25.14	15.20	22.43	23.43	32.59
50 - 60	38.81	31.82	5.89	20.17	26.38	40.11
60 – 70	52.67	46.84	33.76	40.00	41.60	50.07
70 – 80	52.78	52.88	45.39	45.67	39.94	54.93
80 – 90	68.40	64.34	37.29	68.20	47.58	69.16
90 – 100	67.77	66.21	73.27	67.28	58.78	77.40
100 – 110	80.27	73.16	84.99	84.36	63.51	73.56
110 – 120	90.79	86.26	N/A	81.35	75.15	100.14
120 – 130	102.48	99.59	71.97	100.48	90.38	99.89
130 – 140	108.19	108.11	111.63	118.04	96.34	112.57
140 – 150	115.68	110.92	97.29	90.17	110.12	120.11
150 - 160	133.15	133.46	129.55	124.19	122.30	135.55
160 – 170	134.04	124.02	115.74	105.28	143.79	141.75
170 – 180	154.62	148.17	155.16	151.65	147.29	157.69
180 – 190	157.50	160.42	N/A	157.42	134.23	160.48
190 – 200	171.24	159.31	174.83	180.06	165.11	173.95
200 – 250	200.35	186.91	205.84	174.60	184.57	192.15
250 – 300	245.54	244.78	258.28	222.07	241.94	242.93
300 – 400	341.43	333.83	292.73	308.05	322.95	325.60
400 – 500	424.84	417.84	432.05	386.82	380.32	414.85
500 – 750	545.50	575.15	521.73	527.35	568.91	566.21
750 – 1,000	837.82	873.66	898.39	820.57	838.14	764.83
> 1,000	2,297.73	9,999.00	1,353.39	4,921.77	2,987.36	3,183.83

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.

An accelerated Class 2 DSM acquisition scenario was created for inclusion in one of the IRP core cases. Unlike the proxy accelerated scenario created by the Company and used in the 2013 IRP, the 2015 IRP accelerated scenario was informed by work completed by AEG as part of the 2015 DSM potential study. The analysis sought to assess a realistic level of acceleration, recognizing that there may be barriers to accelerating certain measures, including timing of new construction and equipment replacement, product availability, delivery infrastructure, and other factors. To identify measures that would be candidates for accelerated acquisition, AEG reviewed aggressive program structures that have proven successful in real markets; programs with direct installation, early replacements, or neighborhood blitzes. While this accelerated case is speculative and hypothetical in nature, this research allowed the analysis to be grounded in real-world delivery examples with evidence of evaluated traction and market success.[59] Under

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[59] The data sources, methodology, and results of this analysis are detailed in Chapter 6 of Volume 2 of the 2015 DSM potential study report.

the accelerated scenario, the total available potential over the 20-year planning period did not change, however the assumed delivery costs for accelerated measures were adjusted to acknowledge that such a scenario would likely require higher incentive and non-incentive program expenditures to expand participation and delivery infrastructure[60].

Distribution Energy Efficiency

The Company continues to evaluate distribution energy efficiency, including conservation voltage reduction, options for feasibility and cost-effectiveness. To date, the largest effort in this category has been in the area of voltage optimization. Details of our 2010-2013 analysis and pilot project work are documented in Appendix E of the 2013 IRP.

The Company's efforts in the past two years have further corroborated its earlier conclusions. These four points are specifically of concern with regard to energy savings from distribution system voltage optimization:

1) Potential energy savings are small for PacifiCorp's distribution system given the Company's standard operating practices;

2) System changes such as load transfers, new feeders and the voltage control changes that can be necessary when distributed energy resources are brought online always introduce difficulty in estimating the net voltage changes over the long term;

3) The dynamic and unpredictable nature of customer loads, and their interaction with voltage control devices on complex distribution circuits, makes the accurate determination of energy savings statistically dubious; and

4) Recent and ongoing work at the National Electric Energy Testing, Research & Applications Center (NEETRAC) has identified that the ratio between energy reduction and voltage reduction can fall substantially over time, greatly affecting the business case for any voltage reduction project.

In addition to voltage optimization, the Company investigated the possible applications and cost-effectiveness of solid state "edge of grid" technologies now available, and has evaluated potential efficiency savings from changes to specifications in streetlights and service transformers. None of these opportunities were found to be cost effective for the Company.

Distribution energy efficiency measures were not modeled as potential resources in this IRP, since savings from such measures are unreliable and generally not cost-effective.

Transmission Resources

For the 2015 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

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

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 6.14 provides an example how the transmission integration costs at a location may be structured based on the size of the resource additions.

Table 6.14 – 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
2,5000 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 need to 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.

Two FOT types were included for portfolio analysis: an annual flat product, and a HLH third quarter product. An annual flat product reflects energy provided to PacifiCorp at a constant delivery rate over all the hours of a year. Third-quarter HLH transactions represent purchases received 16 hours per day, six days per week from July through September. Table 6.15 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.

Table 6.15 – Maximum Available Front Office Transaction Quantity by Market Hub

Market Hub/Proxy FOT Product Type	Megawatt Limit and Availability
Mid-Columbia Flat Annual (“7x24”) and 3rd Quarter Heavy Load Hour (“6x16”)	400 MW + 375 MW with 10% price premium, 2015-2034
California Oregon Border (COB) Flat Annual (“7x24”) and 3rd Quarter Heavy Load Hour (“6x16”)	400 MW, 2015-2034
Southern Oregon / Northern California (NOB) 3rd Quarter Heavy Load Hour (“6x16”)	100 MW, 2015-2034
Mona 3rd Quarter, Heavy Load Hour (6x16)	300 MW, 2015-2034

CHAPTER 7 – MODELING AND PORTFOLIO EVALUATION APPROACH

CHAPTER HIGHLIGHTS

- The IRP modeling approach seeks to determine the comparative cost, risk, and reliability attributes of resource portfolios. The 2015 IRP modeling and evaluation approach consists of three basic steps within the broader IRP process, including resource portfolio development, cost and risk analysis, and the preferred portfolio selection process.
- PacifiCorp uses System Optimizer to produce unique resource portfolios across a range of different planning assumptions. During the public input process, PacifiCorp proposed combinations of planning assumptions to define core cases, each designed to produce a unique resource portfolio defined by the type, timing and location of new resources as well as assumed retirement dates for existing resources. Based input from stakeholders participating in this process, PacifiCorp refined its core case definitions resulting in 34 unique core case resource portfolios.
- Taking into consideration stakeholder comments received during the public input process, PacifiCorp also developed 15 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.
- PacifiCorp developed a new spreadsheet-based modeling tool, the 111(d) Scenario Maker, to facilitate modeling of EPA's proposed rule to regulate CO_2 emissions from existing generating units under §111(d) of the Clean Air Act.
- PacifiCorp uses Planning and Risk (PaR) to perform stochastic risk analysis of core case and sensitivity case resource portfolios. PaR studies are performed for three natural gas price scenarios (low, base, and high), which inform selection of the preferred portfolio, and a high CO_2 price scenario, which informs PacifiCorp's 2015 IRP acquisition path analysis. Additional cost and risk considerations include results from deterministic risk analysis.
- Informed by comprehensive modeling, PacifiCorp's preferred portfolio selection process involves pre-screening and initial screening steps using both cost and risk metrics reported from PaR and final screening analysis that compares resource portfolios on the basis of expected costs, low-probability high cost outcomes, reliability, deterministic risk, and other criteria.

Introduction

The IRP modeling approach seeks to determine 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. This chapter describes the modeling and risk analysis process that supports this portfolio performance evaluation, documents key modeling assumptions, and describes how this information is used to identify PacifiCorp's preferred portfolio. The results of PacifiCorp's modeling and portfolio evaluation approach are summarized in Chapter 8.

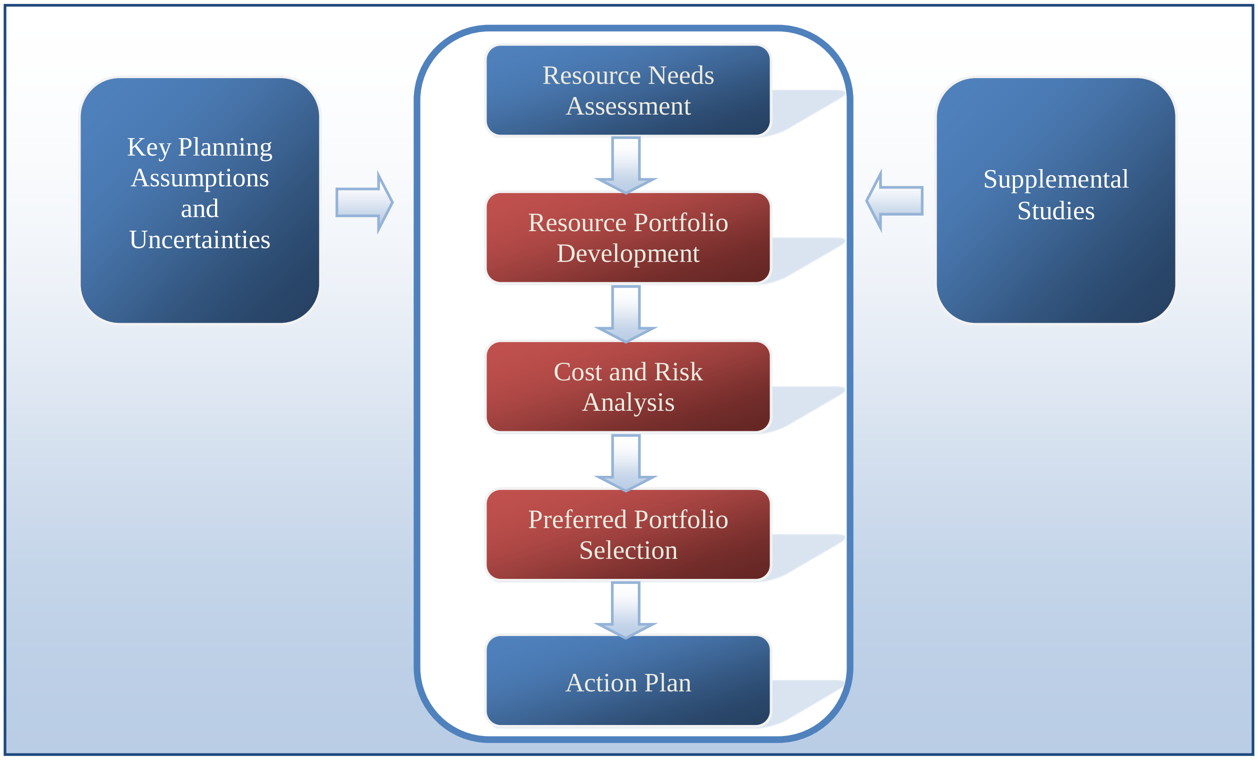
The modeling and portfolio evaluation steps within the broader IRP process consist of three basic steps, highlighted in red in Figure 7.1. The three basic modeling and portfolio evaluation steps, discussed in detail in this chapter, include:

- Resource Portfolio Development
  Resource expansion plan modeling is used to identify resource portfolios that meet projected resource needs. Each resource portfolio is uniquely characterized by the type, timing, and location of new resources in PacifiCorp's system over time. These resource portfolios are produced using a specific combination of planning assumptions, referred to as case definitions, related to environmental and tax policies, wholesale power and natural gas prices, load growth net of assumed distributed generation penetration levels, and new resource cost and performance data.

- Cost and Risk Analysis
  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 using Monte Carlo random sampling of stochastic variables, which include load, natural gas and wholesale electricity prices, hydro generation, and unplanned thermal outages. Deterministic risk modeling is performed on top performing resource portfolios to assess the impact of applying planning assumptions that differ from those used in the resource portfolio development process.

- Preferred Portfolio Selection
  The preferred portfolio selection process is based upon modeling results from the resource portfolio development and cost and risk analysis steps. Preliminary and initial screening of resource portfolios is based upon the present value revenue requirement (PVRR) of system costs, assessed on a deterministic and expected value basis and on an upper tail stochastic risk basis. Resource portfolios that remain after preliminary and initial screening are ranked using a risk-adjusted PVRR metric, a metric that combines the expected value PVRR with upper tail stochastic risk PVRR. Additional selection criteria consider relative portfolio differences in supply reliability and carbon dioxide (CO_2) emissions. The final selection process considers results of deterministic risk analysis modeling, resource diversity, and other supplemental modeling results.

Figure 7.1 – Modeling and Portfolio Evaluation Steps within the IRP Process



Resource Portfolio Development

Resource expansion plan modeling, performed using System Optimizer, is used to identify resource portfolios that meet projected resource needs. Each resource portfolio is uniquely characterized by the type, timing, and location of new resources in PacifiCorp's system over time. These resource portfolios are produced using a specific combination of planning assumptions related to environmental and tax policies, wholesale power and natural gas prices, load growth net of assumed distributed generation penetration levels, and new resource cost and performance data.

System Optimizer

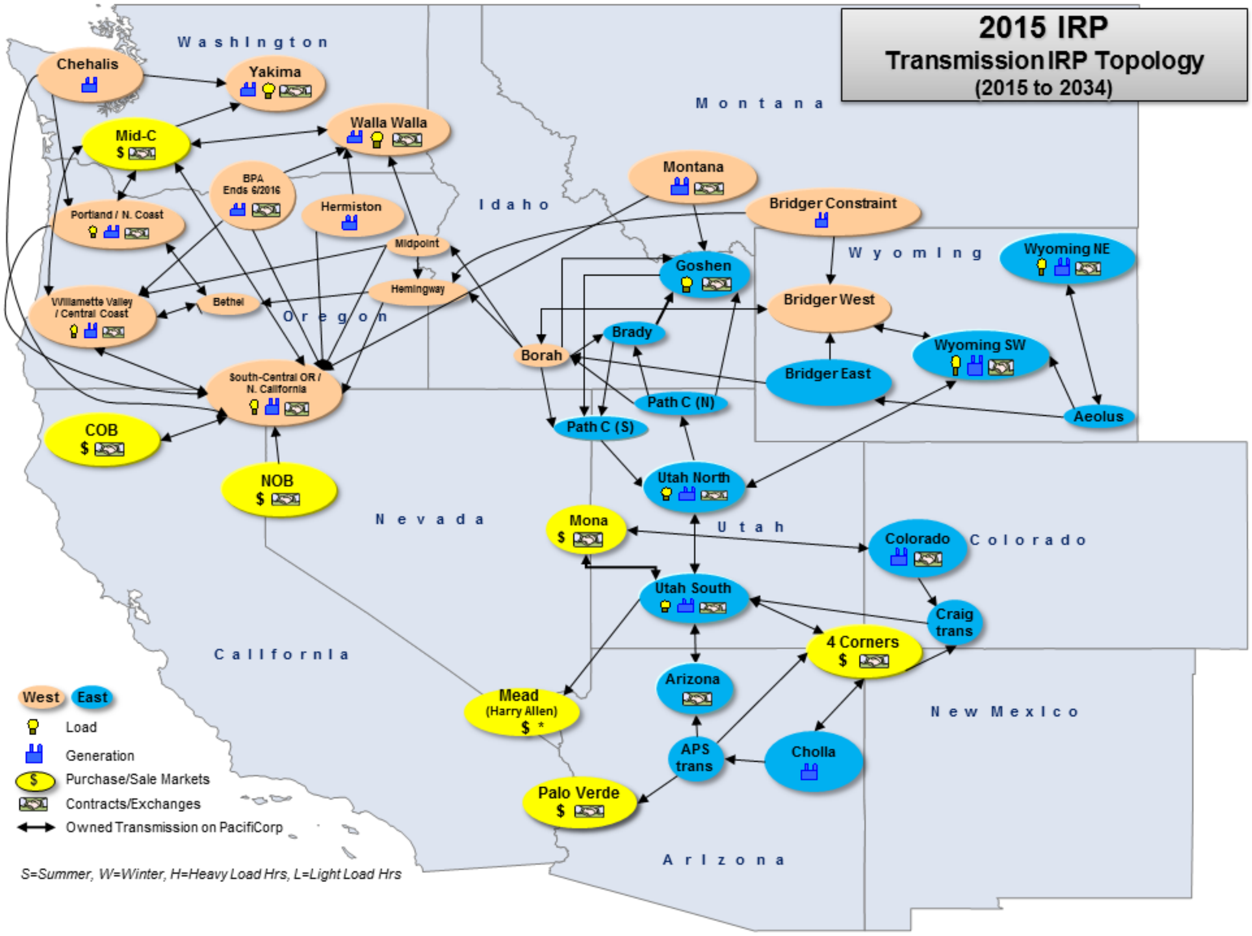
The System Optimizer model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability and other constraints. Over the 20-year planning horizon, it optimizes resource additions subject to resource costs and capacity constraints (summer peak loads plus a 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, System Optimizer will select additional resources as required to meet summer peak loads inclusive of a target planning reserve margin.

To accomplish these optimization objectives, System Optimizer 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 demand side management 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 2015 IRP transmission system model topology.

Figure 7.2 – Transmission System Model Topology



Transmission Costs

In developing resource portfolios for the 2015 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.

Resource Adequacy

Resource adequacy is modeled in the portfolio development process by ensuring each portfolio meets a target planning reserve margin. In its 2015 IRP, PacifiCorp continues to apply a 13% planning reserve margin target. The planning reserve margin, which influences the need for new resources, is applied to PacifiCorp’s forecast coincident system peak load net of offsetting “load resources” such as dispatchable load control or energy efficiency capacity. Planning to achieve a 13% 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% target planning reserve margin in the 2015 IRP.

New Resource Options

Dispatchable Thermal Resources

System Optimizer 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 in least cost merit. 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 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 as 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 System Optimizer with either an annual flat or third quarter on-peak delivery pattern in every year of the twenty-year planning horizon. As configured in System Optimizer, FOTs contribute capacity toward meeting the 2015 IRP's 13% 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% 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 2015 IRP is included in Chapter 6. PacifiCorp's evaluation of resource adequacy in the western power markets is summarized in Volume II, Appendix J.

Demand Side Management

System Optimizer can select incremental DSM resources during the resource portfolio development process. 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 an assumed capacity contribution based on aggregate energy savings during on-peak hours in July, 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). System Optimizer evaluates Class 1 DSM resources by considering capacity contribution, cost, and operating characteristics. Operating characteristics include variables such as maximum energy that the Class 1 DSM resource may dispatch in a day and in a given year.

Class 3 DSM resources, much like Class 1 DSM, are capacity-based resources with savings assumed to be achieved with rate design (i.e., time-of-use rates or critical peak pricing). PacifiCorp performed Class 3 DSM sensitivity analysis in its 2015 IRP, but did not include Class 3 DSM resources in its resource portfolio development process. Additional discussion of DSM resources modeled in the 2015 IRP is included in Chapter 6 and in Volume II, Appendix D.

Wind and Solar Resources

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

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 14.5% and 25.4%, respectively. The capacity contribution of new and existing fixed tilt solar photovoltaic resources in PacifiCorp's east and west BAAs is set to 34.1% and 32.2%, respectively. New single axis tracking solar photovoltaic capacity contribution values in PacifiCorp's east and west BAAs are set to 39.1% and 36.7%, respectively. Volume II, Appendix N of this report summarizes PacifiCorp's updated wind and solar capacity contribution study used to derive these values.

Energy Storage Resources

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. System Optimizer dispatches a storage resource to optimize energy used by the resource subject to constraints such as storage cycle efficiency, the daily balance of take and return energy, and fuel costs (for example, the cost of natural gas for expanding air with gas turbine expanders). To determine the least-cost resource expansion plan, System Optimizer 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

System Optimizer 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 2015 IRP, the PVRR is calculated inclusive of real levelized capital revenue requirement through the end of the 2034 planning period.

Environmental Policy

Regional Haze and Other Environmental Coal Costs

All case definitions developed for the 2015 IRP consider one of four potential Regional Haze compliance scenarios developed for planning purposes. 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 scenario 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 scenario assumes an early retirement for a given coal unit as part of a potential inter-temporal or fleet trade-off 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 twenty year planning horizon and avoidance of future costs related to known or assumed MATS, CCR, ELG or CWA compliance requirements, as applicable.

EPA's Proposed 111(d) Rule

PacifiCorp developed a three step process, which includes the use of a spreadsheet-based modeling tool, to incorporate the U.S. Environmental Protection Agency's (EPA) draft rule establishing state emission rate targets for existing generating units under §111(d) of the Clean Air Act (111(d) or 111(d) rule) into the 2015 IRP resource portfolio development process.[61] Figure 7.3 summarizes the three-step process used to model EPA's draft 111(d) rule for any case that assumes state emission targets must be met at any point during the twenty year planning horizon.[62]

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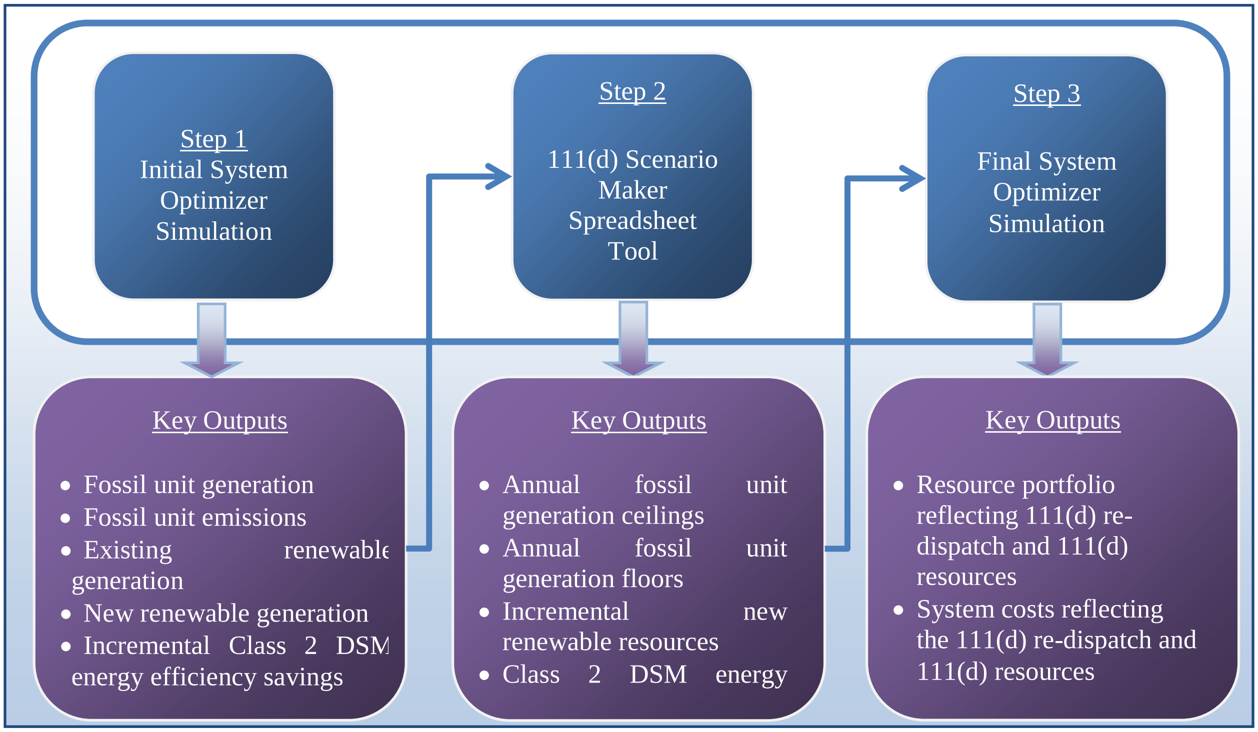
[61] Please refer to Chapter 3 of PacifiCorp's 2015 IRP for a more detailed description of EPA's draft 111(d) rule.

[62] Some of the 2015 IRP case definitions do not implement EPA's draft 111(d) rule or otherwise assume the rule will be implemented on a mass cap basis. The three step 111(d) modeling process does not apply to these cases. Cases that assume a mass cap utilize hard emission cap constraint logic available in System Optimizer.

Figure 7.3 – Three Step Modeling Process Implemented for 111(d) Emission Rate Cases



First, an initial System Optimizer simulation is completed assuming that new combined cycle plants will be regulated under the 111(d) rule. Given the low emission rate targets established by EPA for Idaho, Oregon, and Washington, new combined cycle plants added in these states exceed state emission rate targets, making it more difficult to meet EPA's state emission rate standard. As such, PacifiCorp assumes that no new combined cycle plants can be built in these states. Any new combined cycle plants selected in this initial System Optimizer simulation sited in Utah or Wyoming have emission rates that fall below the Utah and Wyoming state emission rate targets, making it easier to meet EPA's emission rate standard in these states. CO_2 emissions and generation from fossil units regulated under 111(d), new and existing renewable generation, and incremental Class 2 DSM energy efficiency savings are reported from this initial System Optimizer simulation, which served as inputs to the next modeling step.

In the second modeling step, annual CO_2 emissions, generation, and Class 2 DSM energy efficiency savings reported from the initial System Optimizer simulation are loaded into PacifiCorp's 111(d) Scenario Maker spreadsheet-based modeling tool. The 111(d) Scenario Maker calculates an annual 111(d) emission rate for each state in which PacifiCorp owns fossil-fired generation.[63] The 111(d) emission rate is calculated by summing all 111(d)-affected CO_2 emissions and dividing those emissions by the sum of 111(d)-affected generation, allocated renewable energy, and accumulated incremental Class 2 DSM energy efficiency savings from each state by year.[64] If the average 111(d) emission rate over the period 2020 through 2029 shows that PacifiCorp would not meet its share of a state's average 111(d) emission rate target over the same period based on the initial System Optimizer results, the 111(d) Scenario Maker is

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[63] This includes Arizona, Colorado, Montana, Oregon, Utah, Washington, and Wyoming.

[64] Allocated system renewable energy is based on system generation allocation factor assumptions under the 2010 revised multistate protocol, unless a resource is situs assigned to a specific state. PacifiCorp assumes that renewable energy can only be credited to the compliance solution under 111(d) if PacifiCorp has rights to renewable energy credits from a given renewable resource. Class 2 DSM energy savings are accumulated beginning 2017.

then used to determine compliance actions that need to be implemented in order to meet the emission rate standard for each state.

The 111(d) Scenario Maker is configured to accommodate a broad range of compliance actions by applying a best system of emission reduction (BSER) as contemplated in EPA's draft rule. All 2015 IRP cases defined as having a 111(d) emission rate target assume, for compliance purposes, that PacifiCorp can allocate system renewable energy toward meeting emission rate targets in any given state. This flexible allocation of "111(d) attributes" from renewable resources is also applied to cumulative Class 2 DSM energy efficiency savings from Idaho and California, where PacifiCorp does not have a 111(d) compliance obligation. Use of this flexible allocation of renewable energy and select Class 2 DSM energy efficiency savings is the lowest cost compliance action as it does not lead to any incremental system costs from adding resources for purpose of meeting 111(d) requirements.

Recognizing flexible allocation of system renewable energy and selecting Class 2 DSM energy efficiency savings may not be enough to meet EPA's draft emission rate targets in all states for all cases, the 111(d) Scenario Maker can be used to implement other BSER compliance actions. These include re-dispatch of existing fossil-fired generating units, adding new renewable resources to the system, and acquiring additional Class 2 DSM resources. The 111(d) Scenario Maker allows for flexibility in prioritizing which compliance action to implement in any given case, providing the opportunity to study different compliance strategies built around varying combinations of potential BSER compliance actions.

In the third and final modeling step, annual generation minimums and maximums from fossil-fired generation affected by 111(d) regulations, incremental renewable resources as identified in the 111(d) Scenario Maker, and Class 2 DSM energy efficiency savings used to meet emission rate targets are reported and used as inputs to a final System Optimizer simulation. Consequently, the final System Optimizer simulation produces a resource portfolio and system cost data reflecting the impacts of meeting 111(d) emission rates consistent with 111(d) compliance strategies and emission rate targets defined for a given case definition.

State Renewable Portfolio Standards (RPS)

For case definitions targeting new renewable resources as a state RPS compliance strategy, a spreadsheet-based modeling tool, called the RPS Scenario Maker, is used to derive the size, type, timing, and location of new renewable resources needed to meet increment state RPS compliance requirements. The RPS Scenario Maker is also used to report state RPS compliance profiles for case definitions targeting RPS compliance strategies that rely on unbundled renewable energy credits (RECs).

The RPS Scenario Maker uses retail sales forecast net of incremental Class 2 DSM and distributed generation penetration data, state-specific RPS targets, state-specific REC balances, forecasted generation from existing RPS-eligible renewable resources, and cost and performance assumptions for potential new resources. The RPS Scenario Maker considers compliance flexibility mechanisms specific to any given state RPS program including unbundled REC rules and banking rules that cannot be configured in System Optimizer. There are three steps to derive state RPS-driven renewable resource additions.

First, an initial System Optimizer simulation is completed to determine if there are any cost-effective system renewable resources selected for a given case. Annual renewable generation from cost-effective system renewable resources added to the portfolio in this initial System Optimizer simulation are reported, which serve as inputs to the next modeling step. This initial System Optimizer simulation is the same initial simulation as used for the first step of the 111(d) modeling process discussed above.

In the second modeling step, annual system renewable energy from the initial System Optimizer simulation, allocated among states consistent with the 2010 revised multistate protocol, are loaded into the RPS Scenario Maker. The RPS Scenario Maker, configured with constraints to meet RPS targets and to accommodate state-specific RPS banking provisions, is used to select incremental new renewable resources based on levelized cost net of the market value of energy for the assumed hourly energy profile of each renewable alternative. RECs from incremental renewable resources added in the RPS Scenario Maker for a specific state RPS program are situs assigned to the state needing the resource to meet its RPS requirement.[65] For cases that also include a 111(d) state emission rate target, RPS-driven generation from renewable resources is also loaded into the 111(d) Scenario Maker, described above.[66]

In the third and final modeling step, a final System Optimizer simulation is completed with the addition of new RPS-drive renewable resources derived from the RPS Scenario Maker. The final System Optimizer Simulation produces a resource portfolio and system cost data reflecting the impacts of meeting state RPS requirements for cases targeting compliance with new renewable resources, and as applicable, the final simulation captures the influence of RPS-driven renewable resources in meeting any assumed 111(d) emission rate targets.

General Assumptions

Study Period and Date Conventions

PacifiCorp executes its 2015 IRP models for a 20-year period beginning January 1, 2015 and ending December 31, 2034. 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.

Inflation Rates

The 2015 IRP model simulations and cost data reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. A single annual escalation rate value of 1.9% is assumed. The annual escalation rate reflects the average of the annual corporate inflation rates for the period 2015 through 2034, using PacifiCorp's September 2014 inflation curve. PacifiCorp's inflation curve is a straight average of forecasts for Gross Domestic Product (GDP) inflator and Consumer Price Index (CPI).

Discount Factor

The 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 2015 IRP is 6.66%. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which

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[65] Of the three states with RPS requirements, it is assumed that California and Washington requirements are met with unbundled REC purchases, consistent with findings in the 2013 IRP. Case definitions in the 2015 IRP were used to assess similar strategies for meeting forecasted Oregon RPS requirements.

[66] PacifiCorp assumes that "111(d) attributes" from situs assigned renewable energy driven by state RPS compliance needs are not reallocated to any other state.

requires that the after-tax WACC be used to discount all future resource costs.[67] PVRR figures reported in the 2015 IRP are reported in 2015 dollars.

Case Definitions

Case definitions specify a combination of planning assumptions used to develop each unique resource portfolio during the resource development process. Core cases include combinations of alternative assumptions for key planning uncertainties informed by the current planning environment. Sensitivity cases isolate the impact to the resource portfolio and system costs when modifying a single assumption. The resource portfolio and system cost data from sensitivity cases are compared to one of the core case portfolios.

During the public input process, PacifiCorp proposed combinations of planning assumptions to define core cases and sensitivity cases. Through this process, PacifiCorp refined its case definitions, taking into consideration comments and recommendations from its stakeholder group. The final core case definitions reflect multiple combinations of planning assumptions related to:

- Requirements under EPA's proposed 111(d) rule;
- Compliance strategies for state 111(d) emission rate targets;
- Class 2 DSM (energy efficiency);
- CO_2 price assumptions;
- Availability of FOTs;
- State RPS compliance strategies;
- Regional Haze compliance requirements; and
- Wholesale electricity and natural gas forward prices.

The final sensitivity case definitions isolate the impact of the following variables on the resource portfolio and system costs:

- Load forecast;
- Distributed generation penetration levels;
- Addition of energy storage resources;
- Addition of Energy Gateway transmission segments;
- Extension of production tax credits;
- Separate east/west balancing authority area resource portfolios;
- High CO_2 price assumptions;
- Alternative, stakeholder proposed, solar resource cost assumptions;
- Addition of Class 3 DSM resources; and
- Restricted 111(d) attributes.

Core Case Assumptions

Planning assumptions used in defining core cases for the 2015 IRP are summarized in turn below.

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

Requirements under EPA's Proposed 111(d) Rule

Five alternative assumptions defining compliance requirements related to EPA's draft 111(d) rule are used. These assumptions include:

- *No Requirement*: Assumes there are no emission rate targets or mass cap requirements associated with the 111(d) rule.

- *Emission Rate Target (All States)*: Assumes application of EPA's proposed state 111(d) emission rate targets are applied to PacifiCorp's affected fossil-fired resources in all states, including those states in which PacifiCorp does not serve retail customers. This includes Arizona, Colorado, Montana, Oregon, Utah, Washington, and Wyoming.

- *Emission Rate Target (Retail States)*: Assumes application of EPA's proposed state 111(d) emission rat targets are applied to PacifiCorp's affected fossil-fired resources in those states where PacifiCorp serves retail customers. This includes Oregon, Utah, Washington, and Wyoming.

- *Mass Cap (New & Existing)*: Assumes EPA's proposed 111(d) targets are applied to PacifiCorp's system as a mass cap. The mass cap is calculated off of state emissions data from new and existing fossil-fired resources from EPA's modeling over the 2020 through 2030 timeframe, allocated to PacifiCorp's system based on its pro-rata share of state emissions in the 2012 benchmark year. Because the mass cap is calculated based on new and existing fossil-fired resources, the cap is applied to both new and existing fossil-fired generation in PacifiCorp's system beginning 2020.

- *Mass Cap (Existing)*: Assumes EPA's proposed 111(d) targets are applied to PacifiCorp's system as a mass cap. The mass cap is calculated off of state emissions data from existing fossil-fired resources used to calculate state emission rate targets. The emissions are taken from EPA's modeling over the 2020 through 2030 timeframe, allocated to PacifiCorp's system based on its pro-rata share of state emissions in the 2012 benchmark year. Because the mass cap is calculated off of existing fossil-fired resources, the cap is applied to existing fossil-fired generation in PacifiCorp's system beginning 2020.

Table 7.1 shows interim 111(d) emission rate goals and the final emission rate targets by state, which are assumed to apply to PacifiCorp's system. PacifiCorp does not have existing generation affected by EPA's draft 111(d) in Idaho or California.

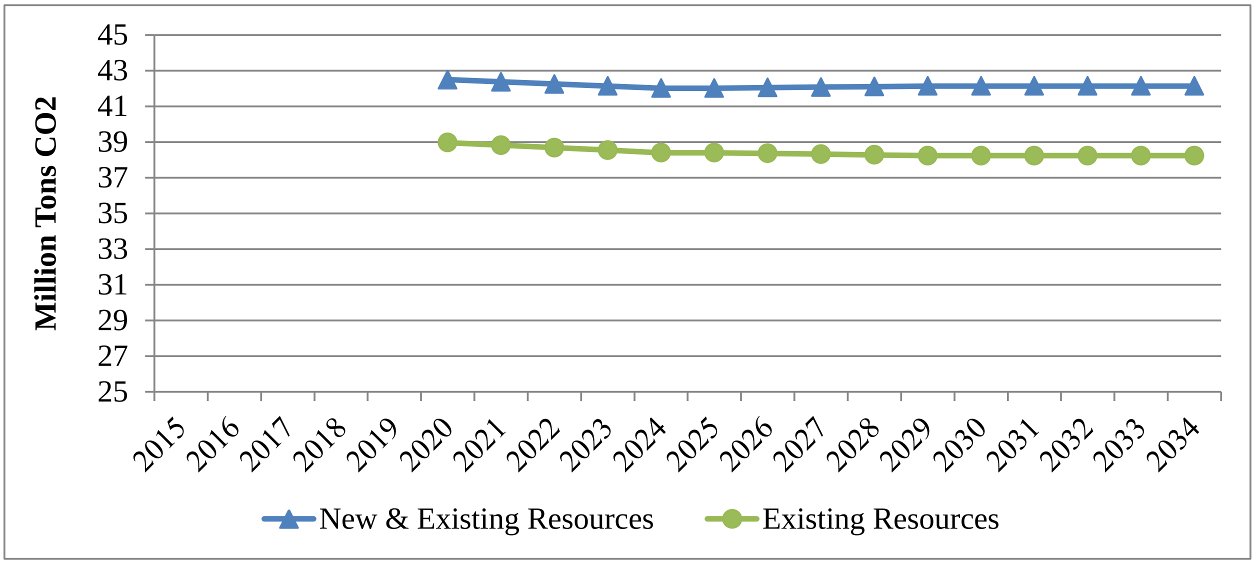
Table 7.1 – State 111(d) Emission Rate Assumptions

State	Interim Goal (Average 2020 – 2029) (lb CO_2/MWh)	Final Target (2030 and Beyond) (lb CO_2/MWh)
Wyoming	1,808	1,714
Utah*	1,378	1,322
Oregon	407	372
Washington	264	215
Montana	1,882	1,771
Colorado	1,159	1,108
Arizona	753	702

*EPA's calculation of the Utah target treated PacifiCorp's Lake Side 2 combined cycle plant as an existing resource. The Company used an emission rate for Utah that assumes Lake Side 2 is correctly classified as under construction based on its status in the 2012 benchmark year.

Figure 7.4 shows assumed mass caps for cases in which EPA's proposed 111(d) rule is applied via a hard emissions cap on fossil-fired generation within PacifiCorp's system. The new and existing resources mass cap is applied to all new and existing fossil-fired generation in PacifiCorp's system. The existing resources mass cap is applied only to the fossil-fired generation in PacifiCorp's system used by EPA to calculate its state emission rate targets.

Figure 7.4 – PacifiCorp System 111(d) Mass Cap Assumptions



Compliance Strategies for 111(d) Emission Rate Cases

For those case definitions that include a 111(d) emission rate target, PacifiCorp developed three different compliance strategies. Each of the three compliance strategies assume that, for compliance purposes, PacifiCorp can allocate system renewable energy toward meeting emission rate targets in any given state. The three compliance strategies include:

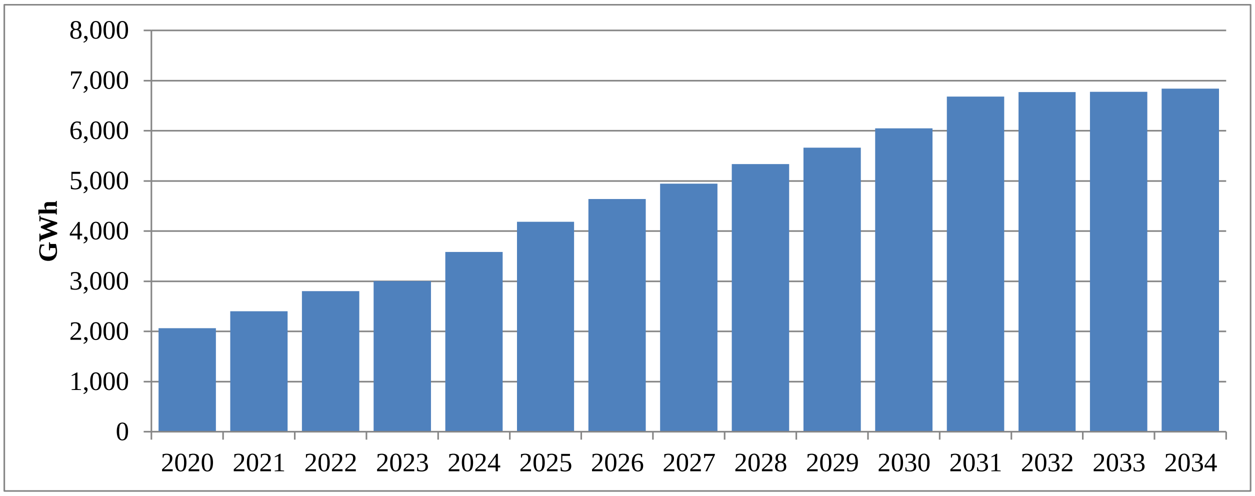
- *Prioritize Re-dispatch with Base Energy Efficiency*: Prioritizes BSER 111(d) compliance actions in the following order. First, for compliance purposes, system renewable energy and cumulative Class 2 DSM energy efficiency savings from California and Idaho are allocated among the states. Cumulative cost-effective Class 2 DSM energy efficiency savings from an initial System Optimizer simulation are applied to state targets in Oregon, Utah, Washington, and Wyoming. Second, existing fossil-fired generation is re-dispatched, as needed. PacifiCorp assumes that existing combined cycle plants in its west BAA, where plant emission rates exceed state emission rate targets, cannot be dispatched below annual generation levels equivalent to annual operation at plant minimums. For coal resources, PacifiCorp assumes that annual generation levels cannot fall below an equivalent 70% annual average capacity factor. PacifiCorp also assumes that 111(d) re-dispatch will not cause coal consumption to fall below coal contract minimums, as applicable. Selection of fossil-fired generating units that are subject to re-dispatch is informed by the rank order of variable operating costs (highest to lowest). Lastly, new renewable resources are added to the system, as required.

- *Prioritize Re-dispatch with Incremental Energy Efficiency*: Prioritizes BSER 111(d) compliance actions in the following order. First, for compliance purposes, system renewable energy and cumulative Class 2 DSM energy efficiency savings from California and Idaho are allocated among the states. Cumulative selection of Class 2 DSM energy efficiency savings set at levels no lower than 1.5% of retail sales beginning 2017 from an initial System Optimizer simulation are applied to state targets in Oregon, Utah, Washington, and Wyoming. Second, existing fossil-fired generation is re-dispatched, as needed. PacifiCorp assumes that existing combined cycle plants in its west BAA, where plant emission rates exceed state emission rate targets, cannot be dispatched below annual generation levels equivalent to annual operation at plant minimums. For coal resources, PacifiCorp assumes that annual generation levels cannot fall below an equivalent 70% annual average capacity factor. PacifiCorp also assumes that 111(d) re-dispatch will not cause coal consumption to fall below coal contract minimums, as applicable. Selection of fossil-fired generating units that are subject to re-dispatch is informed by the rank order of variable operating costs (highest to lowest). Lastly, new renewable resources are added to the system, as required.

- *Prioritize New Renewable Resources with Incremental Energy Efficiency*: Prioritizes BSER 111(d) compliance actions in the following order. First, for compliance purposes, system renewable energy and cumulative Class 2 DSM energy efficiency savings from California and Idaho are allocated among the states. Cumulative selection of Class 2 DSM energy efficiency savings set at no lower than 1.5% of retail sales beginning 2017 from an initial System Optimizer simulation are applied to state targets in Oregon, Utah, Washington, and Wyoming. Second, new renewable resources are added to the system. New renewable resources additions are based on levelized cost net of the market value of energy for the assumed hourly energy profile of each renewable alternative with consideration of transmission limits. Energy from new renewable resources is limited to expected energy levels assumed in EPA's calculation of state emission rate targets, pro-rata allocated to PacifiCorp's system based on retail sales. Lastly, existing fossil-fired generation is re-dispatched, as needed. PacifiCorp assumes that existing combined cycle plants in its west BAA, where plant emission rates exceed state emission rate targets, cannot be dispatched below annual generation levels equivalent to annual operation at plant minimums. For coal resources, PacifiCorp assumes that annual generation levels cannot fall below an equivalent 70% annual average capacity factor. PacifiCorp also assumes that 111(d) re-dispatch will not cause coal consumption to fall below coal contract minimums, as applicable. Selection of fossil-fired generating units that are subject to re-dispatch is informed by the rank order of variable operating costs (highest to lowest).

Figure 7.5 shows the ceiling applied to annual new renewable resources tied to EPA's calculation of state emission rate targets. The renewable energy included in EPA's calculation of state emission rate targets is pro-rata allocated to PacifiCorp's system based on retail sales.

Figure 7.5 – New Renewable Resource Energy Ceiling for 111(d) Compliance Strategies



Class 2 DSM (Energy Efficiency)

In addition to PacifiCorp's base case Class 2 DSM supply curve assumptions, an additional set of Class 2 DSM supply curves is evaluated in PacifiCorp's 2015 IRP core case definitions assuming accelerated acquisition of energy efficiency savings. Assumptions for the accelerated Class 2 DSM case are informed by the updated conservation potential assessment, prepared by Applied Energy Group (AEG) in support of the 2015 IRP. In preparing these assumptions, AEG reviewed aggressive program structures proven successful in real markets. Under this accelerated case, total resource potential over the 20-year planning horizon is unchanged relative to the base case. However, the technical potential of the measures is assumed to be achieved sooner at higher delivery costs acknowledging that such a scenario would likely require higher incentive and non-incentive program expenditures to expand participation and delivery infrastructure.

CO_2 Price Assumptions

With the introduction of EPA's proposed 111(d) rule, PacifiCorp has reflected how future regulations targeting CO_2 emission reductions in the electric sector might influence its resource plan. PacifiCorp has also developed core cases that include, incremental to EPA's proposed 111(d) rule, CO_2 price assumptions that were recommended by members of its stakeholder group. Consideration of these core cases recognize that there could be future CO_2 emission policies applicable to the electric sector that go beyond requirements proposed by EPA in its 111(d) rule.[68] Figure 7.6 shows CO_2 price assumptions applied to these core cases during the 2015 IRP portfolio development process.[69] Prices are applied to each ton of CO_2 emissions from new and existing resources, beginning in 2020 at $22.39/ton and rising at 1.9% per year, reaching $75.77/ton by 2034.

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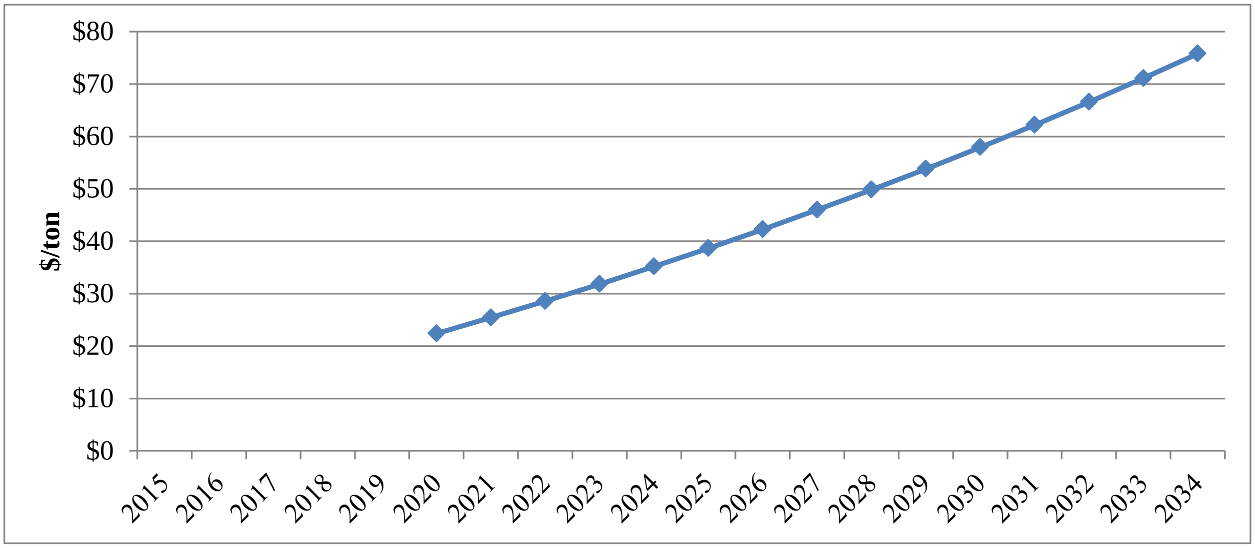
[68] The Oregon Public Utility Commission (OPUC), in their IRP guidelines, directs utilities to construct a base-case scenario that reflects what it considers to be the most likely regulatory compliance future for CO_2, as well as alternative scenarios "ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities."

[69] A second set of CO_2 price assumptions, also recommended by members of PacifiCorp's stakeholder group, are used to evaluate cost and risk of resource portfolios modeled using PaR.

Figure 7.6 – Nominal CO2 Price Assumptions for the Portfolio Development Process



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 beginning 2019.

State RPS Compliance Strategies

State RPS programs in California and Washington provide opportunities to use unbundled RECs to meet forecasted compliance requirements. Based on current unbundled REC market prices, PacifiCorp continues to pursue an unbundled REC strategy to meet future RPS compliance requirements in these states. The Oregon RPS program allows unbundled RECs to be used for up to 20% of annual compliance requirements; however, unbundled RECs can be banked indefinitely. Core case definitions reflect three different Oregon RPS compliance strategies. These three compliance strategies include:

- *Early Renewable Resource Acquisition*: Assumes new renewable resources needed for future Oregon RPS compliance requirements are added prior to projected expiration of the existing REC bank in 2028, with consideration of timelines required for permitting, procurement, and construction (2020 to 2021 timeframe, depending upon renewable resource technology).

- *Deferred Renewable Resource Acquisition*: Assumes new renewable resources needed for future Oregon RPS compliance requirements are added concurrent with the projected expiration of the existing REC bank in 2028.

- *Unbundled RECs*: Assumes future Oregon RPS compliance requirements are met with acquisition of unbundled RECs.

Regional Haze Compliance Requirements

Core case definitions reflect one of four Regional Haze compliance scenarios, a reference scenario and three alternatives, developed for planning purposes. These scenarios are built around both known and prospective Regional Haze compliance requirements for specific coal generating units in PacifiCorp's fleet.[70] Assumed inter-temporal and fleet trade-off compliance alternatives, whether built around known or prospective Regional Haze compliance requirements, represent potential scenarios that might, pending agency support, achieve an appropriate balance of economic justification for PacifiCorp's customers and emissions reductions contributing to long-term visibility improvements in affected Class I areas. Table 7.2 summarizes Regional Haze compliance requirements for each of the four scenarios used during the 2015 IRP portfolio development process.

Table 7.2 – State 111(d) Emission Rate Assumptions

Coal Unit*	Reference	Scenario 1	Scenario 2	Scenario 3
Dave Johnston 1	Shut Down Dec 2027	Shut Down Mar 2019	Shut Down Mar 2019	Shut Down Dec 2027
Dave Johnston 2	Shut Down Dec 2027	Shut Down Dec 2027	Shut Down Dec 2023	Shut Down Dec 2027
Dave Johnston 3	SCR Mar 2019	Shut Down Dec 2027	Shut Down Dec 2027	Shut Down Dec 2027
Dave Johnston 4	Shut Down Dec 2027	Shut Down Dec 2032	Shut Down Dec 2032	Shut Down Dec 2027
Hunter 2	SCR Dec 2021	Shut Down Dec 2032	Shut Down Dec 2024	Shut Down Dec 2032
Huntington 1	SCR Dec 2022	Shut Down Dec 2036	Shut Down Dec 2024	SCR Dec 2022
Huntington 2	SCR Dec 2022	Shut Down Dec 2021	Shut Down Dec 2021	Shut Down Dec 2029
Jim Bridger 1	SCR Dec 2022	Shut Down Dec 2023	Shut Down Dec 2023	SCR Dec 2022
Jim Bridger 2	SCR Dec 2021	Shut Down Dec 2032	Shut Down Dec 2028	SCR Dec 2021
Wyodak	SCR Mar 2019	Shut Down Dec 2039	Shut Down Dec 2032	Shut Down Dec 2039

*Common to all scenarios: Carbon 1&2 shut down 2015; Colstrip 3&4 SCR 2023/2022, respectively; Craig 1&2 SCR 2021/2018, respectively; Hayden 1&2 SCR 2015/2016, respectively; Naughton 1&2 shut down 2029; Naughton 3 gas conversion 2018, shutdown 2029; Hunter 1&3 SCR 2021/2024, respectively; and Bridger 3&4 SCR 2015/2016, respectively.

Wholesale Electricity and Natural Gas Forward Prices

Three different wholesale electricity and natural gas forward price curve assumptions are used in core case definitions, a base case and two scenarios.[71] The base case forward price curve is PacifiCorp's September 2014 official forward price curve (OFPC), the most current official forward price curve available at the time 2015 IRP modeling was initiated. PacifiCorp's OFPC is derived using a combination of forward market observations, a transition period between market and fundamentals, and a fundamentals-based forecast.

The front 72 months of the OFPC represents where the forward market was trading at market close for a given trading day. For the September 2014 OFPC, prices over the front 72-months are based on market forwards as of September 30, 2014. The blending period of the FPC (months 73 through 84) is calculated by averaging the month-on-month market-based price from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC is based upon recent third-party price forecasts. PacifiCorp reviews third party natural gas price forecasts each time it updates the OFPC, which occurs at least quarterly. PacifiCorp uses the third party natural gas price forecast in Aurora, an

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[70] Detailed financial analysis of coal units with known Regional Haze compliance deadlines and implementation timelines for compliance alternatives that would require emission control retrofit decisions be made in the next two to four years, thereby falling within the 2015 IRP action plan window, is presented in Volume III of the 2015 IRP.

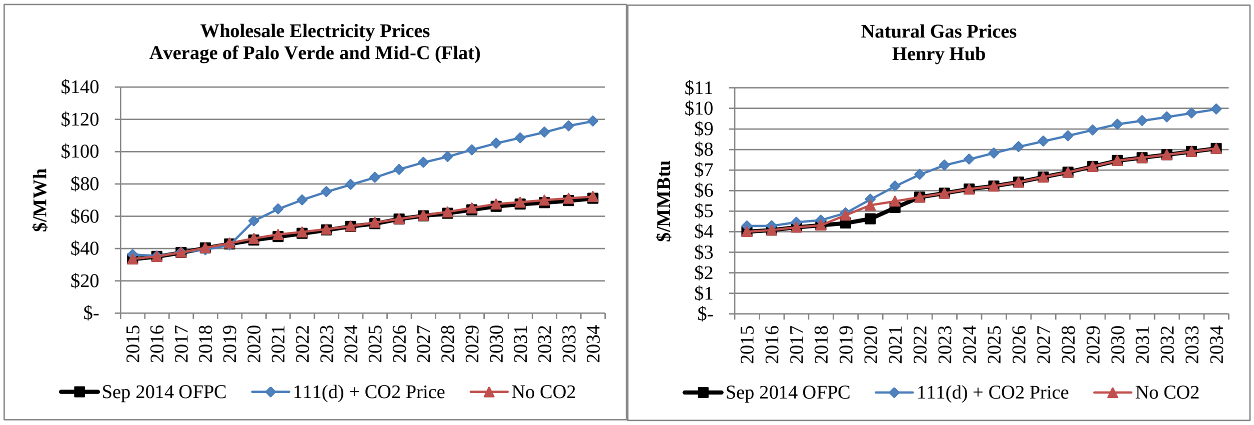
[71] Additional price curve scenarios, described later in Chapter 7, are used to evaluate stochastic risk of each portfolio with Planning and Risk.

electric market model, to produce an accompanying wholesale electricity price forecast for market hubs in which PacifiCorp is active. As with forecasted natural gas prices, the electricity price forecast developed with Aurora is updated with each OFPC update.

The fundamentals portion of PacifiCorp's September OFPC incorporates EPA's proposed 111(d) rule. To account for 111(d) in Aurora, PacifiCorp applied state 111(d) emission rate constraints in the model, assuming energy efficiency goals assumed by EPA in its calculation of state emission rate targets is achievable. PacifiCorp further assumes no coal unit efficiency improvements are implemented and that regionally, the use of renewable energy for 111(d) compliance purposes is based upon ownership, not by physical location of renewable resources in any given state. Moreover, PacifiCorp's Aurora-based forecast assumes that new combined cycle units will be regulated under 111(d).

In addition to the base case, PacifiCorp developed two additional scenarios that align with CO_2 policy assumptions used during the resource portfolio development process, discussed above. One of these scenarios reflects a forward price curve absent any compliance requirements under EPA's proposed 111(d) rule. The second scenario reflects wholesale and market price impacts of including CO_2 price assumptions, incremental to 111(d) requirements, across the electric sector. In both of these scenarios, changes in CO_2 policy assumptions can influence demand for natural gas from the electric sector, which in turn, influences forecasted natural gas prices. PacifiCorp uses the Integrated Planning Model (IPM®), a linear program optimization model that simulates the North American power system, to estimate changes in natural gas prices associated with changes in CO_2 policy assumptions. As is done for the base case OFPC, the resulting natural gas price forecasts are used in Aurora to develop a corresponding wholesale electricity price forecast. Figure 7.7 summarizes the three wholesale electricity and natural gas price assumptions used in core case definitions for the 2015 IRP.[72]

Figure 7.7 – Wholesale Electricity and Natural Gas Prices in Core Case Definitions



Core Case Definitions

Table 7.3 summarizes the combination of core case assumptions used to specify core case definitions for the portfolio development process in the 2015 IRP. In addition, PacifiCorp has produced core case fact sheets, summarizing key assumptions and System Optimizer model results for each core case. These fact sheets are provided in Volume II, Appendix M.

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[72] Additional electricity and natural gas price assumptions, based on low and high natural gas price scenarios and high CO_2 price assumptions, are used to evaluate cost and risk of resource portfolios with Planning and Risk (PaR).

Table 7.3 – Core Case Definitions

Case ID	111(d) Requirement	111(d) Strategy	CO_2 Price	FOTs	Regional Haze	OR RPS	Price Curve
C01	None	None	No	Base	R, 1, 2	Early	No CO_2
C02	Emission Rate (All States)	Re-disp./Base EE	No	Base	1, 2	Early	Base
C03	Emission Rate (All States)	Re-disp./Inc. EE	No	Base	1, 2	Early	Base
C04	Emission Rate (All States)	Renew./Inc. EE	No	Base	1, 2	Early	Base
C05	Emission Rate (Retail States)	Re-disp./Base EE	No	Base	1, 2	Early	Base
C05a	Emission Rate (Retail States)	Re-disp./Base EE	No	Base	1, 2, 3	Late	Base
C05b	Emission Rate (Retail States)	Re-disp./Base EE	No	Base	1, 3	RECs	Base
C06	Emission Rate (Retail States)	Re-disp./Inc. EE	No	Base	1, 2	Early	Base
C07	Emission Rate (Retail States)	Renew./Inc. EE	No	Base	1, 2	Early	Base
C09	Emission Rate (Retail States)	Re-disp./Base EE	No	Limited	1, 2	Early	Base
C11	Emission Rate (Retail States)	Re-disp./Acc. EE	No	Base	1, 2	Early	Base
C12	Mass Cap (New & Existing)	None	No	Base	1, 2	Early	Base
C13	Mass Cap (Existing)	None	No	Base	1, 2	Early	Base
C14	Emission Rate (Retail States)	Re-disp./Base EE	Yes	Base	1, 2	Early	111(d) + CO_2
C14a	Emission Rate (Retail States)	Re-disp./Base EE	Yes	Base	1, 2	Early	111(d) + CO_2

*Note, core case IDs throughout the 2015 IRP are often reported using the case ID followed by a hyphen and a numerical value ranging from 1 through 3 (i.e., C05a-3). The numerical value following the hyphen identifies the Regional Haze scenario applied to the case. The Reference Regional Haze scenario is identified with the letter "R". Case C14a is a variant of case C14 that allows endogenous coal unit retirements among not assumed to retire under the applicable Regional Haze scenario.

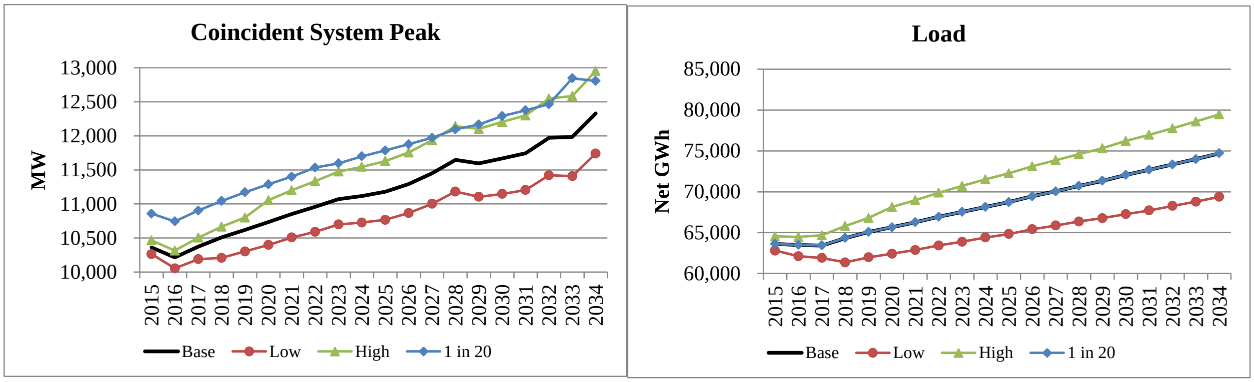
Sensitivity Case Assumptions

Planning assumptions used in defining sensitivity cases for the 2015 IRP are summarized in turn below.

Load Forecast

PacifiCorp includes three different load forecast sensitivities. The low load forecast sensitivity reflects low economic growth assumptions from IHS Global Insight and low Utah and Wyoming industrial loads. The high load forecast sensitivity reflects high 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 5th and 95th percentile. The third load forecast sensitivity is a 1-in-20 (5% probability) extreme weather scenario. The 1-in-20 year peak weather 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 7.8 compares the low, high, and 1-in-20 load sensitivities, net of base case distributed generation penetration levels, alongside the base case load forecast.

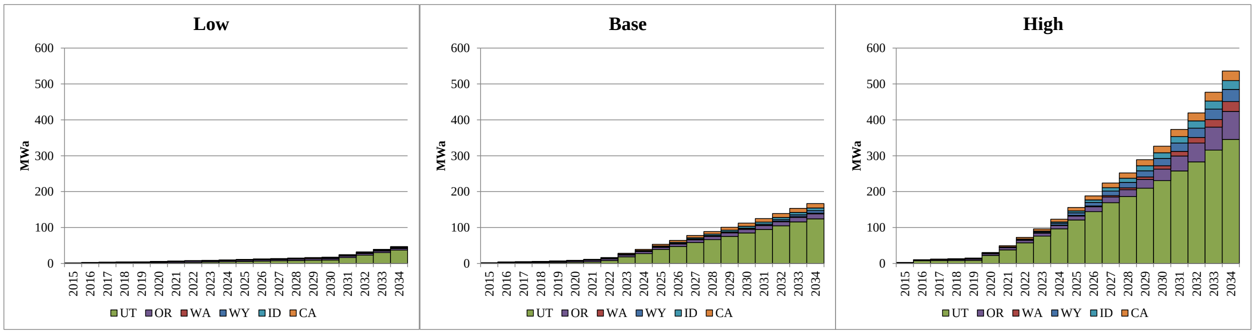
Figure 7.8 – Load Sensitivity Assumptions



Distributed Generation

Two distributed penetration sensitivities are analyzed. As compared to base penetration levels that incorporated annual reductions in technology costs, the low distributed generation sensitivity reflects reduced reductions in technology costs, reduced technology performance levels, and lower retail electricity rates. In contrast, the high distributed generation sensitivity reflects more aggressive technology cost reduction assumptions, higher technology performance levels, and higher retail electricity rates. Figure 7.9 summarizes distributed generation penetration levels for the low and high sensitivities alongside the base case.

Figure 7.9 – Distributed Generation Sensitivity Assumptions



Energy Storage

PacifiCorp includes two energy storage sensitivities. Both force large scale energy storage resources into the resource portfolio. The first storage sensitivity forces a 400 MW pumped storage plant sited in PacifiCorp's west BAA. The second storage forces a 300 MW compressed air energy storage (CAES) plant in PacifiCorp's east BAA.

Energy Gateway

PacifiCorp has studied two Energy Gateway transmission sensitivities, patterned after scenarios defined in the 2013 IRP (Energy Gateway scenarios 2 and 5). PacifiCorp base case includes Energy Gateway Segments C and G. Incremental to the base case, the first sensitivity includes Energy Gateway Segments D, with assumed in-service date in 2022. The second sensitivity includes Energy Gateway Segments D, E, and F with assumed in-service dates of 2022, 2023, and 2024, respectively.

Production Tax Credits

PacifiCorp's base case assumes that production tax credits (PTCs) and investment tax credits (ITCs) applicable to eligible renewable resources expire consistent with current federal tax policies. The PTC sensitivity assumes the PTC is available through the 20-year planning horizon, beginning at 23¢/kWh in 2015 escalating at 1.9% per year.

Separate East/West BAAs

As required by the Washington Utilities and Transportation Commission, PacifiCorp's 2015 IRP includes a sensitivity that produces standalone resource portfolios for the east and west BAAs. The sensitivity is generated both with and without 111(d) emission rate targets. This sensitivity required different assumptions for the east and west BAAs, summarized in turn below.

West BAA Assumptions

- Maintains 13% target planning reserve margin, applicable to a winter peak;
- Allow January on-peak FOTs, maintaining limits at Mid-C (775 MW), COB (300 MW), and NOB (100 MW);
- Class 2 DSM capacity contribution values are updated to align with a winter peak;
- All of Jim Bridger is included in the west BAA;
- With 111(d) emission rate targets, assume the Chehalis combined cycle plant is retired at the end of 2019, assume new combined cycle plants are not allowed, and assume Oregon can use a west BAA allocation of renewable energy to meet PacifiCorp's share of state 111(d) emission rate targets; and
- Without 111(d), assume new combined cycle plants can be built in the west BAA.

East BAA Assumptions

- Maintains a 13% target planning reserve margin, applicable to a summer peak;
- Maintain summer on-peak FOTs, maintaining the Mona limit at 300 MW;
- Maintain Class 2 DSM capacity contribution values, aligned with a summer peak;
- None of Jim Bridger is included in the east BAA; and
- With 111(d), assume flexible allocation of east BAA renewable energy can be used to meet PacifiCorp's share of Utah and Wyoming emission rate targets.

High CO_2 Price

One sensitivity case includes CO_2 price assumptions, recommended by members of PacifiCorp's stakeholder group, that are higher than those used in PacifiCorp's core case definitions. The high CO_2 prices are assumed to be incremental to EPA's proposed 111(d) emission rate targets. Figure 7.10 shows the high CO_2 prices for this sensitivity along with the incremental CO_2 price assumption used in core case definitions. Figure 7.11 shows forward price curve assumptions developed for the high CO_2 price sensitivity.

Figure 7.10 – High CO2 Price Sensitivity Assumptions

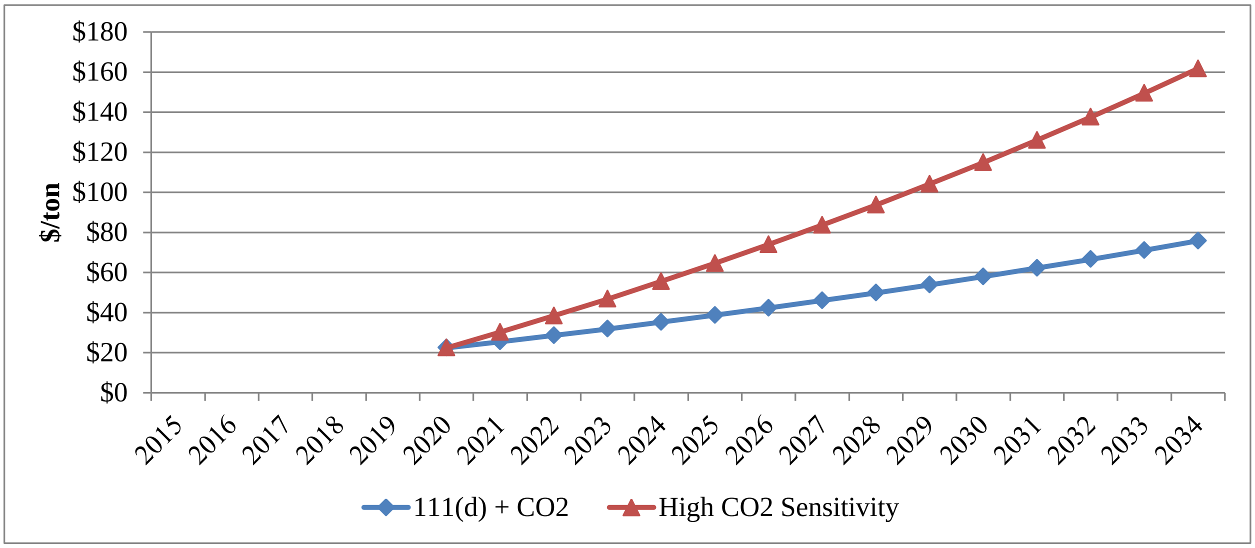
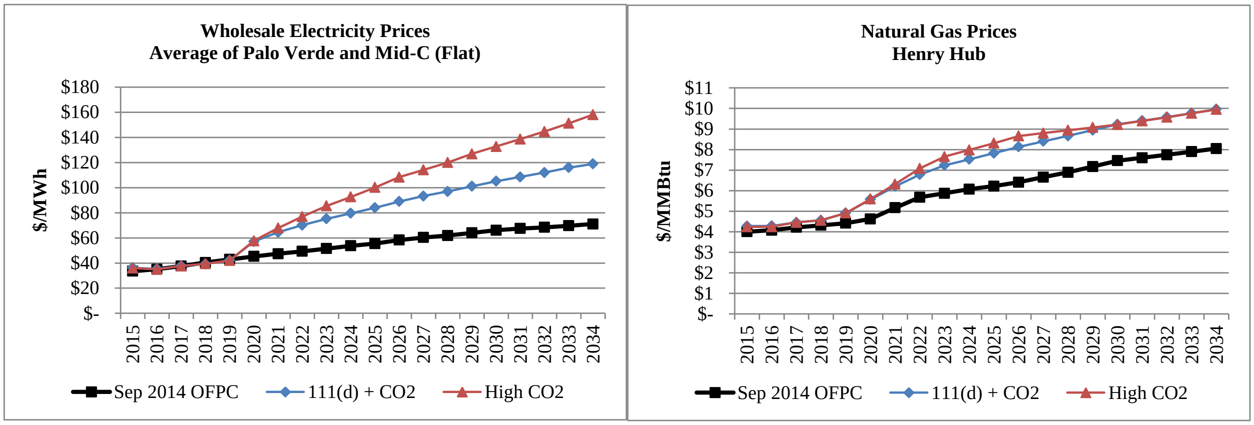


Figure 7.11 – Wholesale Electricity and Natural Gas Prices in the High CO2 Sensitivity



Solar Resource Costs

One sensitivity case reflects alternative solar resource cost assumptions as recommended by members of PacifiCorp's stakeholder group. This sensitivity case also includes high distributed generation penetration assumptions, summarized above. Figure 7.12 shows utility scale cost assumptions, represented in real 2014 dollars, for this sensitivity case alongside PacifiCorp's base case assumptions.[73]

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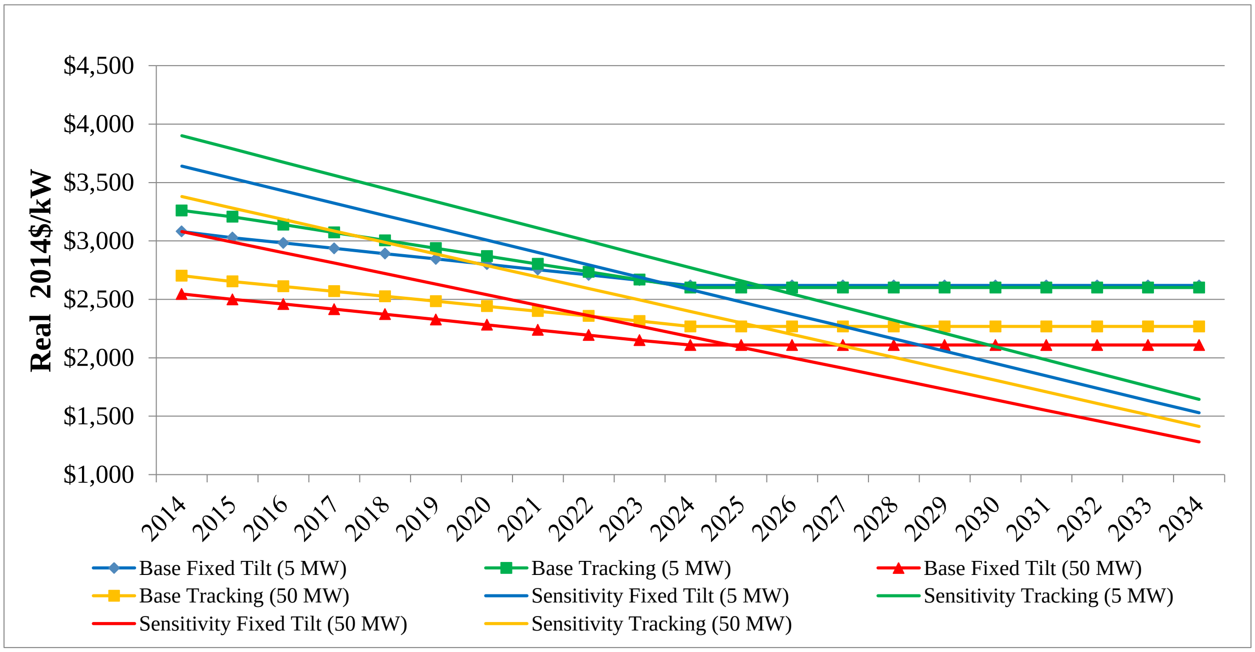
[73] PacifiCorp's base case solar resource costs assume real de-escalation through the first ten years of the planning period due to such factors as technology and manufacturing improvements, government subsidization, over supply compared to demand and improvement in implementation process.

Figure 7.12 – Solar Cost Sensitivity Assumptions



Class 3 DSM

Class 3 DSM includes non-firm price responsive capacity resources. The Class 3 DSM sensitivity case utilizes Class 3 DSM supply curves developed as part of the conservation potential study updated for the 2015 IRP. Class 3 DSM supply curves are comprised of four products across six states. The four products include residential pricing programs, commercial and industrial pricing programs, commercial and industrial demand buyback programs, and irrigation pricing programs. Dynamic pricing products (critical peak pricing and real-time pricing) are assumed to be available beginning 2020, following an assumed installation of advanced metering infrastructure (AMI) by the end of 2019, costs of which are not included in the levelized cost of these Class 3 DSM products.

Restricted 111(d) Attributes

PacifiCorp's base case 111(d) emission rate modeling assumptions allows for allocation of renewable energy among states for both RPS and 111(d) compliance purposes. This approach assumes that the renewable attributes of a REC used for RPS compliance are separate and distinct from 111(d) attributes used for 111(d) compliance. Moreover, this compliance approach assumes that the two distinct attributes (RECs and 111(d) attributes) can be used for compliance independent of one another. This sensitivity case assumes that state RPS-eligible RECs and 111(d) attributes are distinct; however, it is assumed that RECs and 111(d) attributes must be surrendered at the same time. Consequently, if a state RPS programs requires more RECs to meet its RPS requirements than 111(d) attributes required to meet its 111(d) targets, then 111(d) attributes that could otherwise be used to mitigate 111(d) compliance costs in another state are lost. Conversely, if a state requires more 111(d) attributes to meet its 111(d) emission rate targets than RECs needed to meet its RPS requirements, then the state will more than meet its RPS requirements, effective eliminating the need for the RPS program as a policy tool to drive renewable resource acquisition.

Sensitivity Case Definitions

Table 7.4 summarizes the combination of planning assumptions used to specify sensitivity case definitions and the core case to which the sensitivity study is benchmarked. The benchmark case ID reflects the applicable Regional Haze scenario assumption In addition, PacifiCorp has produced sensitivity case fact sheets, summarizing key assumptions and System Optimizer model results for each sensitivity case. These fact sheets are provided in Volume II, Appendix M.

Table 7.4 – Sensitivity Case Definitions

Case ID	111(d) Attributes	DSM	Resource Specific	Price Curve	Load	Distributed Gen.	System
S-01	Flexible Allocation	Class 1 & 2	Base	Base	Low	Base	Base
S-02	Flexible Allocation	Class 1 & 2	Base	Base	High	Base	Base
S-03	Flexible Allocation	Class 1 & 2	Base	Base	1-in-20	Base	Base
S-04	Flexible Allocation	Class 1 & 2	Base	Base	Base	Low	Base
S-05	Flexible Allocation	Class 1 & 2	Base	Base	Base	High	Base
S-06	Flexible Allocation	Class 1 & 2	Forced Pump Storage	Base	Base	Base	Base
S-07	Flexible Allocation	Class 1 & 2	Base	Base	Base	Base	Energy Gateway 2
S-08	Flexible Allocation	Class 1 & 2	Base	Base	Base	Base	Energy Gateway 5
S-09	Flexible Allocation	Class 1 & 2	Extended PTC	Base	Base	Base	Base
S-10	Flexible Allocation	Class 1 & 2	Base	Base	Base	Base	East/West BAA
S-11	Flexible Allocation	Class 1 & 2	Base	High CO2	Base	Base	Base
S-12	Flexible Allocation	Class 1 & 2	Alternative Solar Cost	Base	Base	High	Base
S-13	Flexible Allocation	Class 1 & 2	Forced CAES	Base	Base	Base	Base
S-14	Flexible Allocation	Class 1, 2 & 3	Base	Base	Base	Base	Base
S-15	Restricted	Class 1 & 2	Base	Base	Base	Base	Base

*All sensitivity cases except S-07, S-08, S-10, and S-11 are benchmarked to the core case C05-1 with Regional Haze scenario 1 assumptions. Sensitivity cases S-07 and S-08 are benchmarked to core case C07-1. Sensitivity case S-10 is benchmarked to a variant of case C05a under Regional Haze scenario 3. Sensitivity case S-11 is benchmarked to core case C14-1.

Cost and Risk Analysis

Once unique resource portfolios are developed using System Optimizer, 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 Planning and Risk (PaR). Deterministic risk modeling is performed on top performing resource portfolios to assess the impact of applying planning assumptions that differ from those used in the resource portfolio development process.

Planning and Risk (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 Monte Carlo random sampling of stochastic variables, which include: load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages.[74] 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 wind integration study, are captured in the stochastic simulations. PacifiCorp's updated wind integration study is provided in Volume II, Appendix H.

The stochastic parameters used in PaR for the 2015 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 lognormal 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 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 R of this report discusses the methodology on how the stochastic parameters for the 2015 IRP were developed.

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

Table 7.5 through7.7 summarize 2015 IRP short-term volatility and mean reversion parameters by season for load, natural gas prices, and electricity prices, respectively. Table 7.8 through Table 7.11 summarize natural gas and electricity price correlation by delivery point and season.Table 7.12 lists short term volatility and mean reversion parameters for hydro generation by season.

Table 7.5 – Short Term Load Stochastic Parameters

Short-term Volatility	**CA/OR without Portland**	**Portland**	**ID**	**UT**	**WA**	**WY**
Winter 2015 IRP	0.044	0.030	0.029	0.020	0.043	0.016
Spring 2015 IRP	0.036	0.029	0.045	0.025	0.036	0.016
Summer 2015 IRP	0.036	0.035	0.051	0.045	0.046	0.015
Fall 2015 IRP	0.040	0.031	0.048	0.029	0.042	0.018
Short-term Mean Reversion	**CA/OR without Portland**	**Portland**	**ID**	**UT**	**WA**	**WY**
Winter 2015 IRP	0.226	0.224	0.268	0.333	0.215	0.279
Spring 2015 IRP	0.278	0.164	0.093	0.295	0.220	0.318
Summer 2015 IRP	0.238	0.336	0.102	0.260	0.243	0.179
Fall 2015 IRP	0.207	0.324	0.176	0.339	0.182	0.230

Table 7.6 – Short Term Gas Price Parameters

Short-Term Volatility	**East Natural Gas**	**West Natural Gas**
Winter 2015 IRP	0.048	0.063
Spring 2015 IRP	0.029	0.026
Summer 2015 IRP	0.029	0.029
Fall 2015 IRP	0.036	0.043
Short-term Mean Reversion	**East Natural Gas**	**West Natural Gas**
Winter 2015 IRP	0.058	0.091
Spring 2015 IRP	0.110	0.083
Summer 2015 IRP	0.060	0.070
Fall 2015 IRP	0.110	0.109

Table 7.7 – Short Term Electricity Price Parameters

Short-Term Volatility	**Four Corners**	**COB**	**Mid-Columbia**	**Palo Verde**
Winter 2015 IRP	0.076	0.118	0.178	0.062
Spring 2015 IRP	0.092	0.318	0.317	0.072
Summer 2015 IRP	0.111	0.257	0.477	0.091
Fall 2015 IRP	0.060	0.063	0.069	0.047
Short-term Mean Reversion	**Four Corners**	**COB**	**Mid-Columbia**	**Palo Verde**
Winter 2015 IRP	0.095	0.193	0.282	0.093
Spring 2015 IRP	0.277	0.682	0.488	0.198
Summer 2015 IRP	0.380	0.534	0.943	0.289
Fall 2015 IRP	0.240	0.168	0.152	0.217

Table 7.8 – Winter Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.305	1.000				
COB	0.176	0.629	1.000			
Mid - Columbia	0.129	0.574	0.948	1.000		
Palo Verde	0.318	0.804	0.621	0.524	1.000	
Natural Gas West	0.708	0.212	0.183	0.152	0.139	1.000

Table 7.9 – Spring Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.100	1.000				
COB	0.065	0.620	1.000			
Mid - Columbia	0.115	0.404	0.848	1.000		
Palo Verde	0.110	0.821	0.597	0.294	1.000	
Natural Gas West	0.762	0.109	0.073	0.107	0.122	1.000

Table 7.10 – Summer Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.070	1.000				
COB	0.053	0.489	1.000			
Mid - Columbia	0.016	0.443	0.741	1.000		
Palo Verde	0.083	0.856	0.522	0.439	1.000	
Natural Gas West	0.885	0.078	0.084	0.002	0.099	1.000

Table 7.11 – Fall Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.223	1.000				
COB	0.243	0.333	1.000			
Mid - Columbia	0.224	0.325	0.901	1.000		
Palo Verde	0.289	0.765	0.384	0.345	1.000	
Natural Gas West	0.631	0.132	0.254	0.260	0.185	1.000

Table 7.12 – Hydro Short Term Stochastic Parameters

	Short-term Volatility	Short-term Mean Reversion
Winter 2015 IRP	0.170	0.836
Spring 2015 IRP	0.105	0.813
Summer 2015 IRP	0.139	1.093
Fall 2015 IRP	0.195	1.193

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 2013. For new resources, the unplanned outage rates are as specified for those resources as listed in the supply side resource table in Chapter 6.

Figure 7.13 and Figure 7.14 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 $4.11/MWh to $11.23/MWh during the 20-year study period. For Palo Verde electricity prices, the difference between the first and 99th percentiles range from $2.34/MWh to $6.07/MWh.

Figure 7.13 – Simulated Annual Mid-C Electricity Market Prices

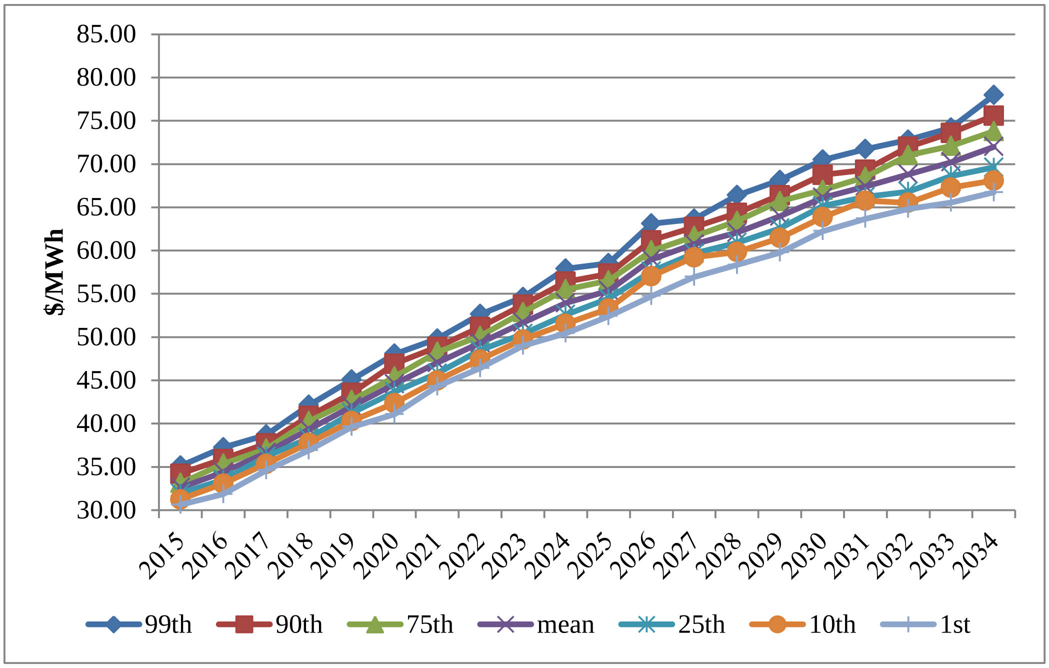


Figure 7.14 – Simulated Annual Palo Verde Electricity Market Prices

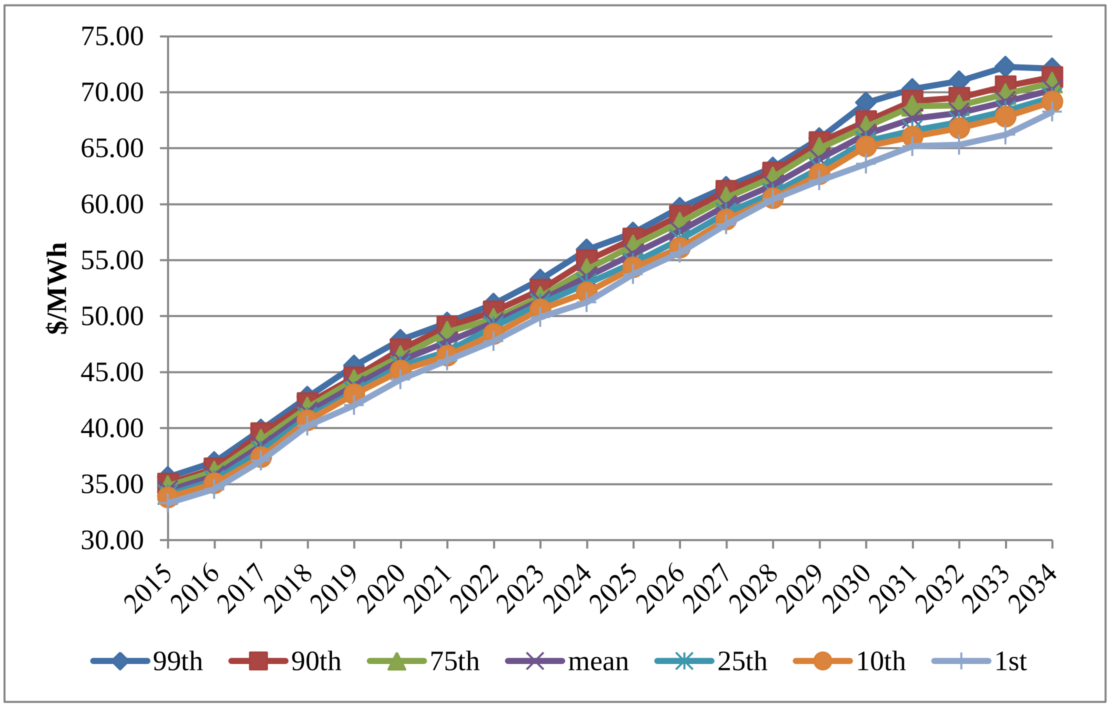


Figure 7.15 and Figure 7.16 show annual electricity prices at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles for west and east natural gas prices. For west natural gas prices, differences between the first and 99th percentiles range from $0.27/MMBtu to $0.81/MMBtu during the 20-year study period. For east natural gas prices, differences between the first and 99th percentiles range from $0.34/MMBtu to $0.90/MMBtu.

Figure 7.15 – Simulated Annual Western Natural Gas Market Prices

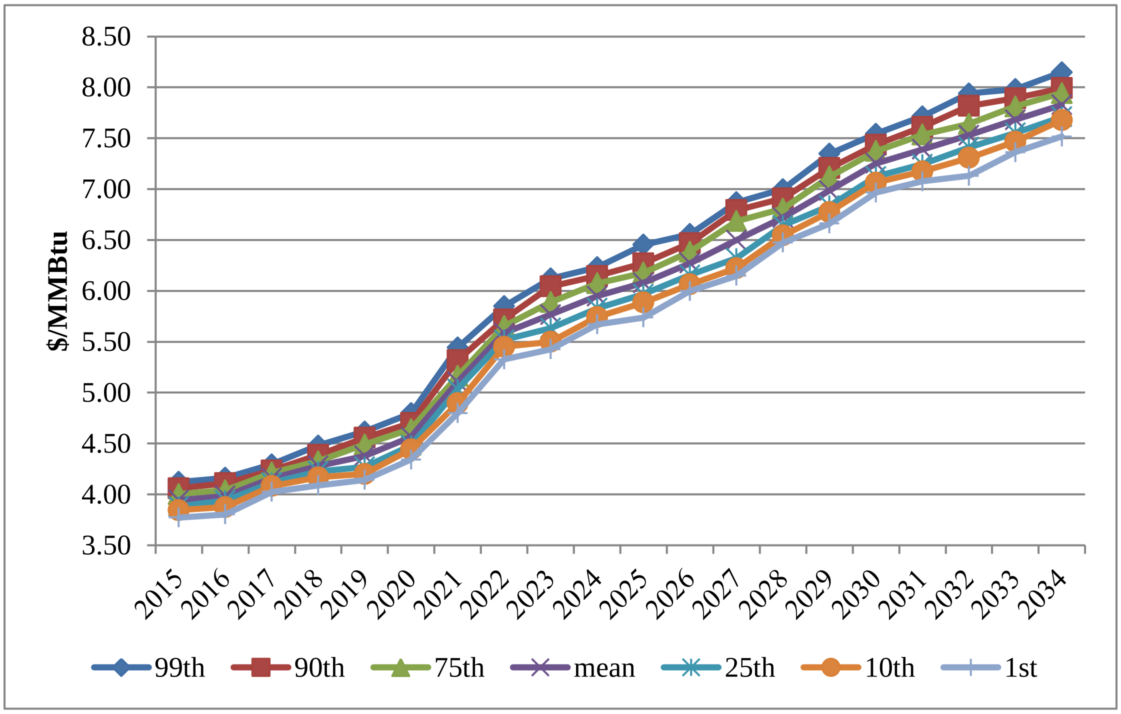


Figure 7.16 – Simulated Annual Eastern Natural Gas Market Prices

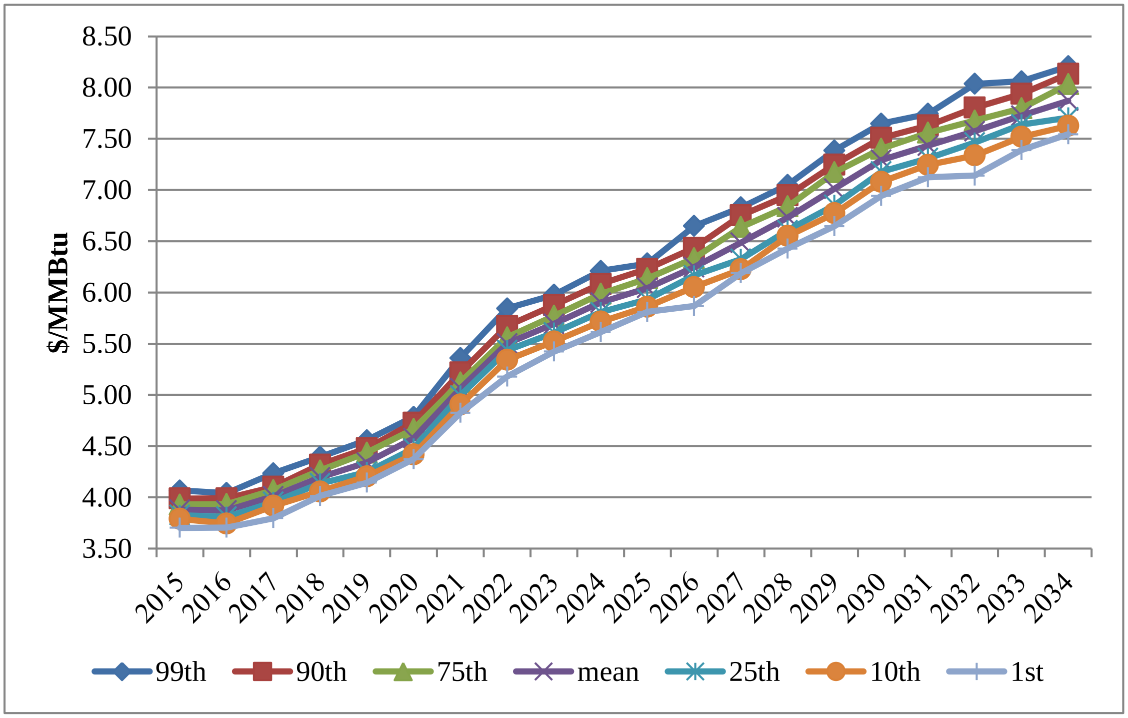


Figure 7.17 through Figure 7.22 show annual loads by load area and for PacifiCorp’s system at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. For Idaho (Goshen) load, the annual differences between the first and 99th percentiles range from 184 GWh to 382 GWh. The drop in Idaho (Goshen) load from 2015 to 2017 is due to the expiration of a wholesale contract, under which PacifiCorp serves third party retail load. For Utah load, the annual difference between the first and 99th percentiles ranges from 1,408 GWh to 2,683 GWh. For Wyoming load, the annual difference between the first and 99th percentiles range from 139 GWh to 279 GWh. For Oregon/California load, annual differences between the first and 99th percentiles range from 895 GWh to 1,551 GWh. For Washington load, the annual difference between the first and 99th percentile ranges from 233 GWh to 473 GWh. For PacifiCorp’s system load, the annual difference between the first and 99th percentiles ranges from 2,110 GWh to 4,643 GWh.

Figure 7.17 – Simulated Annual Idaho (Goshen) Load

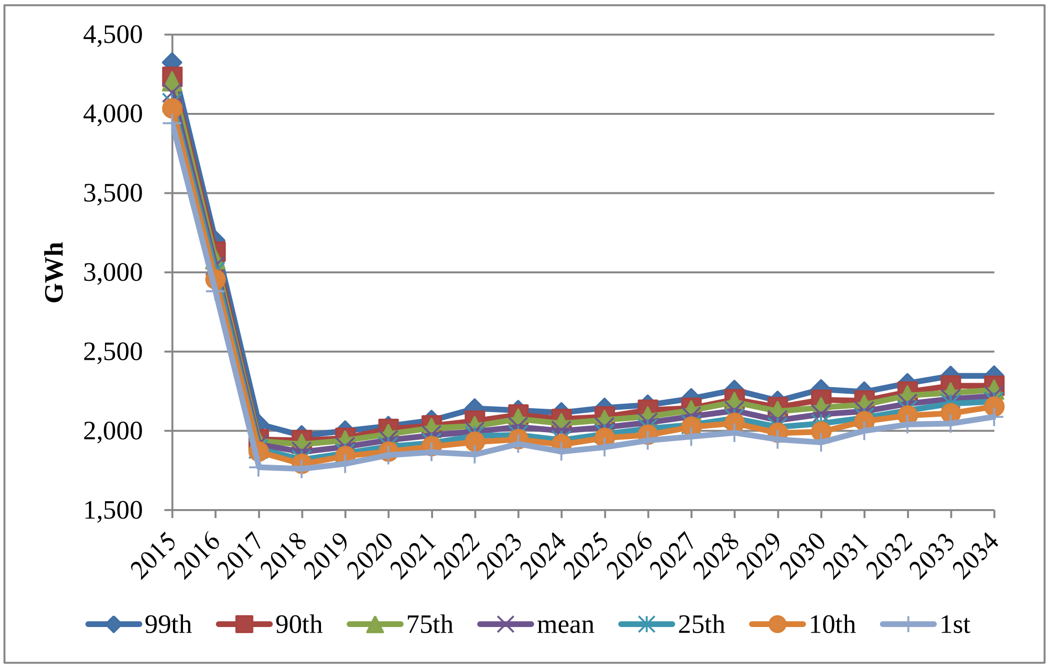


Figure 7.18 – Simulated Annual Utah Load

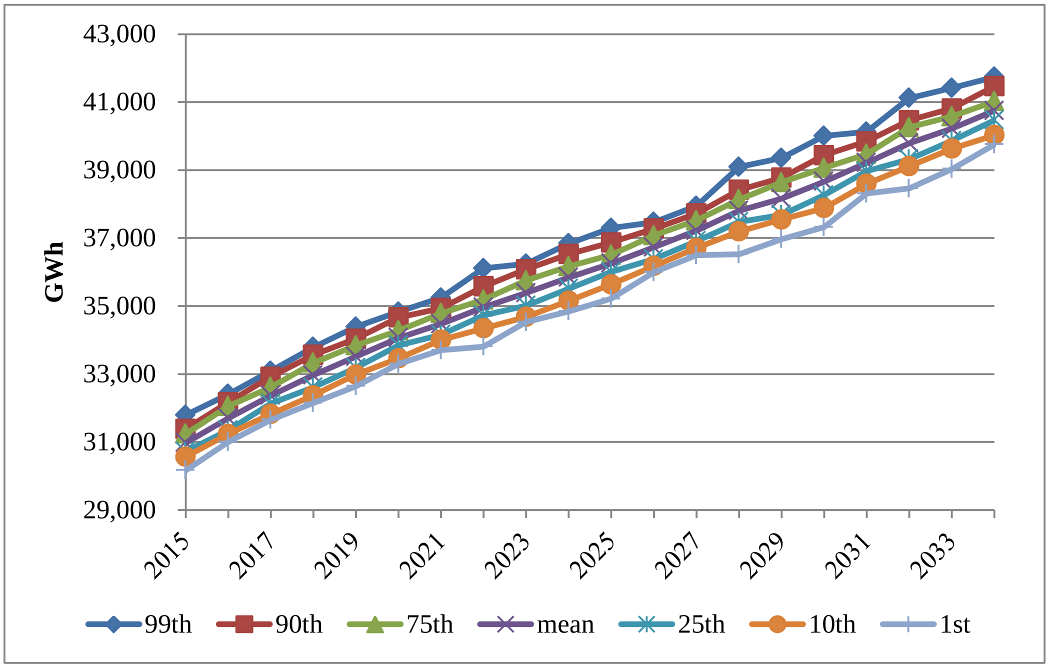


Figure 7.19 – Simulated Annual Wyoming Load

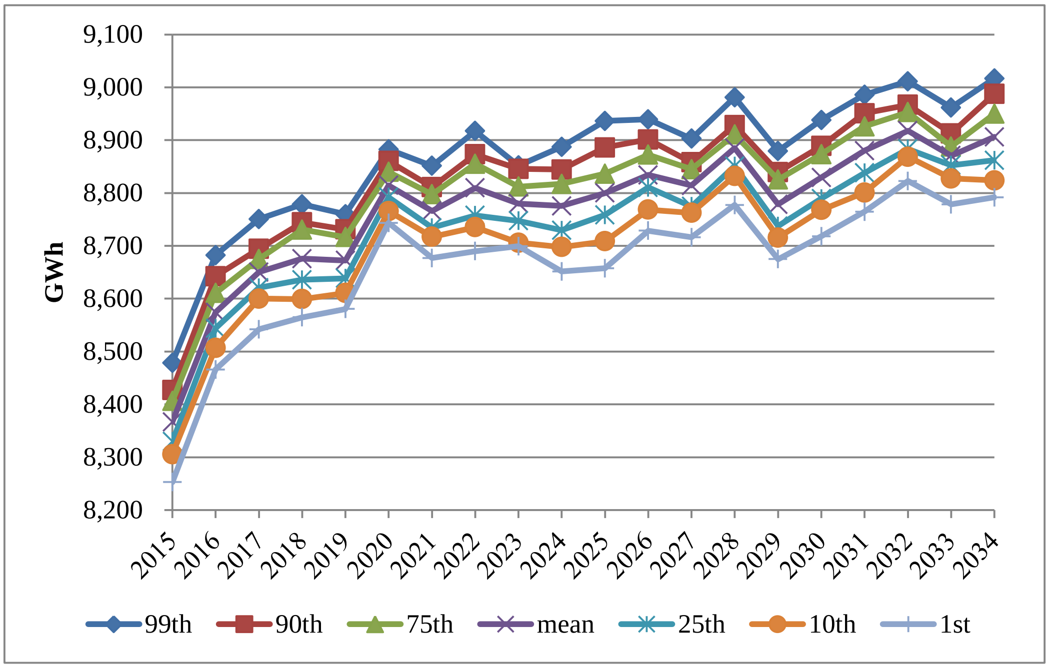


Figure 7.20 – Simulated Annual Oregon/California Load

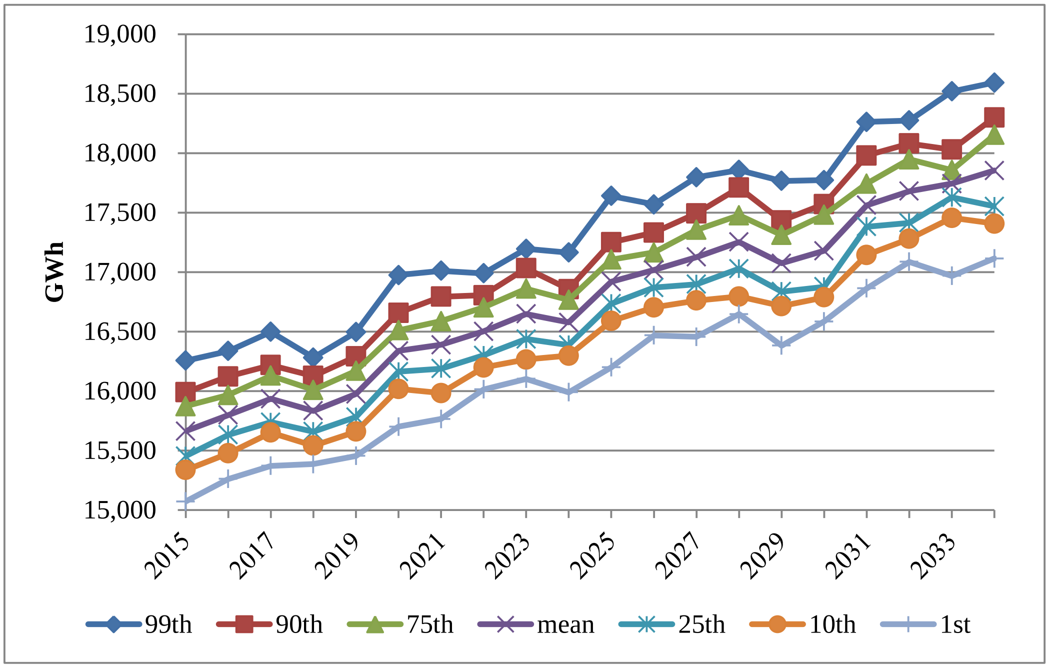


Figure 7.21 – Simulated Annual Washington Load

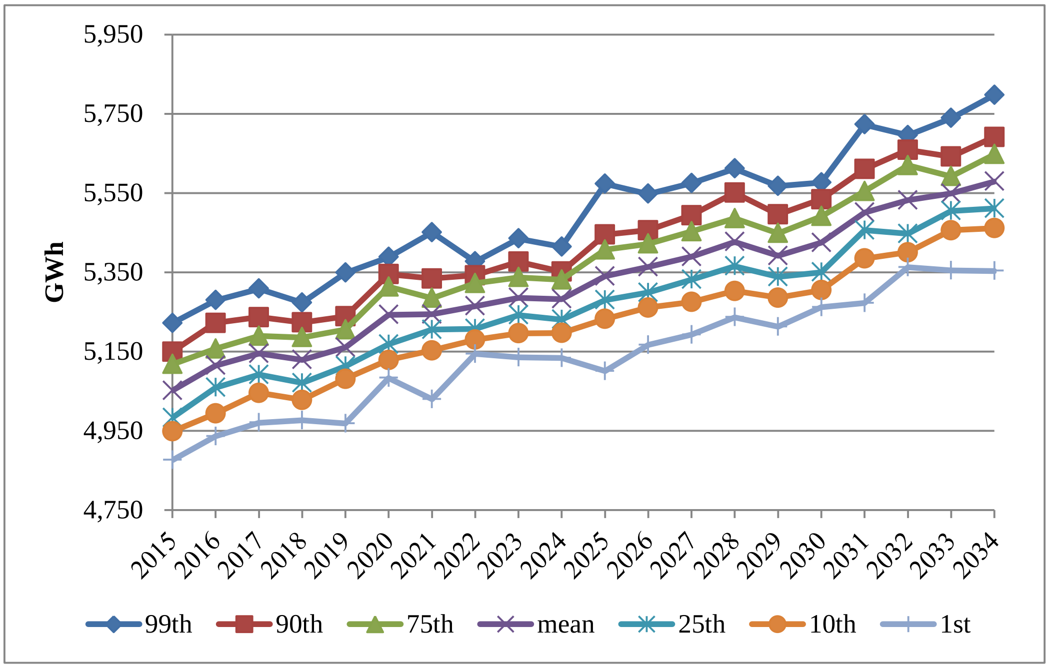


Figure 7.22 – Simulated Annual System Load

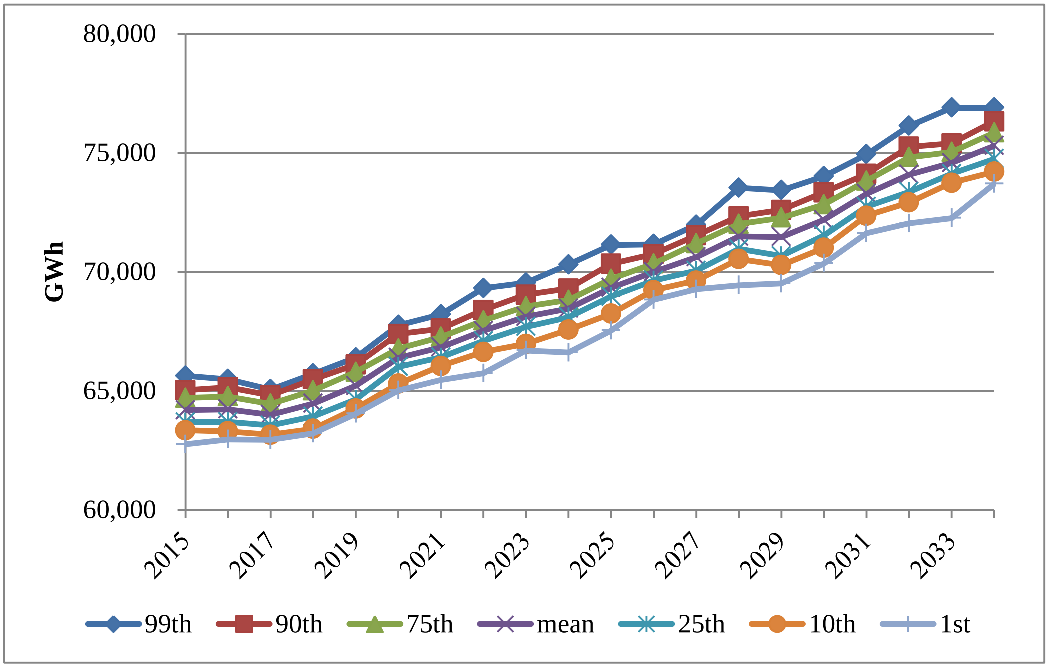
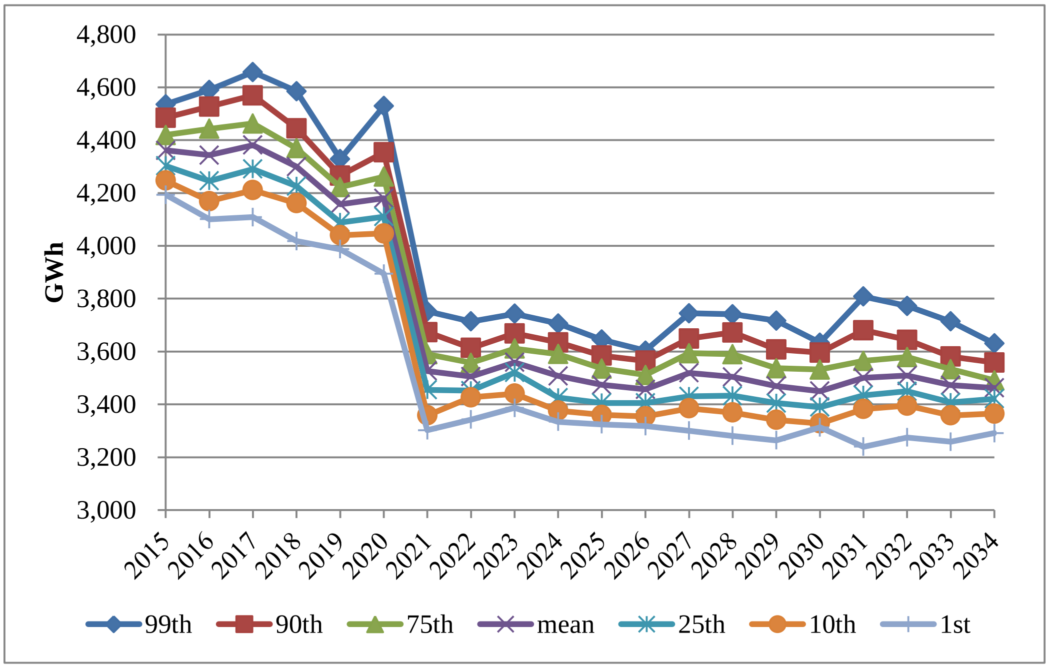


Figure 7.23 shows hydro generation at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. PacifiCorp can dispatch its hydro generation on a limited basis to meet load and reserve obligations. The parameters 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 7.23 – 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 2015 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 results 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, and 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;
- 5th and 95th 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 System Optimizer for any given resource portfolio.[75] 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 System Optimizer, are calculated on an escalated real-levelized basis. Other components in the stochastic mean PVRR include fixed costs for new DSM resources in the portfolio, also taken from System Optimizer, and CO_2 emission costs for any scenarios that include a CO_2 price assumption.

Risk-Adjusted Mean 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 System Optimizer, 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 System Optimizer, 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 stochastic 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

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

present value of annual costs over the period 2015 through 2034. This measure meets Oregon IRP guidelines to report 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 load obligation that is higher than 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 2015 through 2034 planning horizon, reported in gigawatt-hours, as well as the upper-tail ENS (average of the three iterations with the highest ENS). In the 2015 IRP, ENS is priced at $1,000/MWh consistent with a FERC imposed price cap.

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

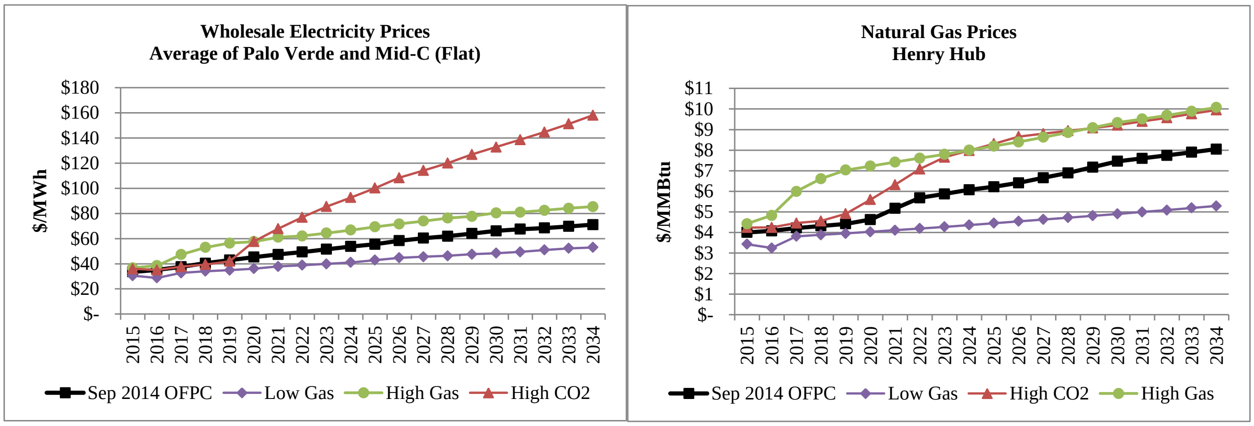
Cumulative CO_2 Emissions
Annual CO_2 emissions from each portfolio are reported from PaR and summed for the twenty year planning period. Comparison of total CO_2 emissions is used to identify potential outliers among resource portfolios that might otherwise be comparable with regard to expected cost,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

Forward Price Curve Scenarios

Each of the unique resource portfolios developed with System Optimizer during the resource portfolio development process are analyzed in PaR among four price curve scenarios. The price curve scenarios include PacifiCorp's September 2014 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. A fourth price curve scenario includes a high CO_2 price assumption, as recommended by members of PacifiCorp's IRP stakeholder group, is primarily used to inform PacifiCorp's 2015 IRP acquisition path analysis.

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. Figure 7.24 summarizes the four forward price curve scenarios used to analyze unique portfolios in PaR. The CO_2 price assumptions used in the high CO_2 price forward curve scenario are identical to those used for sensitivity case S-11, shown in Figure 7.10.

Figure 7.24 – Wholesale Electricity and Natural Gas Prices in PaR Simulations



Wholesale Electricity Prices
Average of Palo Verde and Mid-C (Flat)

Natural Gas Prices
Henry Hub

Environmental Policy

Regional Haze and Other Environmental Coal Costs

All portfolio fixed costs and timing of planned maintenance outages unique to each coal unit for each Regional Haze scenario, inclusive of prospective costs related to MATS, CCR, ELG, and CWA, used in System Optimizer are captured in all PVRR results from PaR.

EPA's Proposed 111(d) Rule

PacifiCorp's 111(d) modeling approach applied during the portfolio development process for case definitions that include 111(d) state emission rate targets is not conducive to stochastic modeling performed using PaR, which relies on chronological unit commitment and dispatch. With chronological dispatch, PaR does not have foresight to account for how current dispatch decisions might influence future dispatch restrictions needed to meet assumed emission rate targets in a given year. Consequently, it is not possible to establish annual dispatch limits for a given fossil-fired generating unit in PaR. Further, it is not feasible to impose manual dispatch limits for a stochastic PaR simulation, considering each simulation produces 50 iterations with varying combinations of load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages. Each of these iterations produces different emission rates for each year. Considering PaR simulations are performed for nearly 50 unique resource portfolios (inclusive of sensitivity cases) among four different price curve scenarios, many thousands of 111(d) Scenario Maker models would need to be created to develop thermal dispatch limits by unit and time period for input back into PaR.

Considering these challenges, the PVRR of system costs reported by PaR in the 2015 IRP reflect resource portfolio impacts of 111(d), but do not reflect re-dispatch of fossil-fired generation resources that might be required to meet assumed state 111(d) emission rate targets. PaR results are, nonetheless, used to screen relative cost and risk differences among candidate portfolios. Compliance with state 111(d) emission rate targets, with consideration of fossil-fired generation re-dispatch, is factored into the preferred portfolio selection process by comparing portfolio costs from System Optimizer and by performing deterministic risk analysis using System Optimizer.

State Renewable Portfolio Standards (RPS)

Any renewable resources included in resource portfolios developed using System Optimizer, including state RPS renewable resource selections from the RPS Scenario Maker, are included in

PaR. These renewable resources are modeled as non-dispatchable, must-run resources using the same fixed energy profiles, which vary by month and time of day, as applied in System Optimizer.

Other PaR Modeling Methods and Assumptions

Transmission System

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

Resource Adequacy

The resource portfolio developed using System Optimizer, which meets an assumed 13% target planning reserve margin, is fixed in all PaR simulations. With fixed resources, the unit commitment and dispatch logic in PaR accounts operating reserve requirements. These reserve requirements include contingency reserves, which are calculated as 3% of load and 3% of generation. In addition, PaR reserve requirements account for regulation reserves, which include ramp, regulating, and following reserves. PacifiCorp's regulation reserve assumptions are included in PacifiCorp's updated wind integration study, provided in Volume II, Appendix H.

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 CAES plants, a heat rate is included as a parameter to capture fuel conversion efficiency.

General Assumptions

The same general assumptions for study period (20-years beginning 2015), annual inflation rates (1.9%), and discount rates (6.66%) applied in System Optimizer 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 deterministic risk analysis, fuel source diversity, and customer rate impacts.

Deterministic Risk Analysis

Deterministic risk analysis is performed to quantify changes in system costs when a resource portfolio, developed under a given set of planning assumptions, is locked down and simulated under an alternative set of planning assumptions. For its 2015 IRP, PacifiCorp performed deterministic risk analysis using System Optimizer to evaluate resource portfolio costs for core cases C05a-3 and C05b-3, developed assuming state 111(d) emission rate target, and for case C13-1, developed assuming EPA's proposed 111(d) rule is implemented as a PacifiCorp system mass cap applicable to PacifiCorp's system.[76] The deterministic risk analysis was performed by

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[76] These three cases ranked highest using the risk adjusted mean PVRR metric among portfolios analyzed with PaR.

imposing the mass cap assumed when developing core case C13-1 to the resource portfolios developed under core cases C05a-3 and C05b-3. Similarly, the resource portfolio developed under core case C13-1, was evaluating in System Optimizer assuming it must meet state emission rate targets applicable to those states in which PacifiCorp serves retail customers.

Fuel Source Diversity

PacifiCorp considers relative differences in resource mix among portfolios by comparing the capacity of new resources in to performing portfolios by resource type, differentiated by fuel source. PacifiCorp also reports summary 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 System Optimizer 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.

Preferred Portfolio Selection

The preferred portfolio selection process is based upon modeling results from the resource portfolio development and cost and risk analysis steps. Preliminary and initial screening of resource portfolios is based upon the PVRR of system costs, assessed on a deterministic and expected value basis and on an upper tail stochastic risk basis. Resource portfolios that remain after preliminary and initial screening are ranked using a risk-adjusted mean PVRR metric, a metric that combines the expected value PVRR with upper tail stochastic risk PVRR. Additional selection criteria consider relative portfolio differences in supply reliability and CO_2 emissions. The final selection process considers results of deterministic risk analysis modeling, resource diversity, and other supplemental modeling results.

Pre-Screening

The pre-screening process is the initial step in the preferred portfolio selection process. The pre-screening process plots the mean PVRR and upper-tail mean PVRR (net of fixed costs) for each unique resource portfolio using base, low, and high forward price curve assumptions. The pre-screening step eliminates outlier portfolios that have substantially higher cost and risk metrics relative to others. Pre-screening also eliminates portfolios, produced for comparison purposes, that may not meet future environmental compliance requirements.

Initial Screening

Initial screening also relies upon plots of the mean PVRR and the upper-tail mean PVRR (net of fixed costs) for each unique resource portfolio remaining after removal of portfolios during the pre-screening step. Based on the data used to produce these plots, PacifiCorp applied the following selection criteria when identifying portfolios with the best combination of cost and risk for the base, low, and high forward price curve scenarios:

- Identify the portfolio with the lowest mean PVRR to establish a cost and risk threshold calculated as 2% of the least-cost portfolio;
- Identify portfolios that fall within the threshold amount as compared to the least cost portfolio;
- Identify portfolios that fall within the threshold amount as compared to the least risk portfolio, using the upper tail mean PVRR net of fixed costs the risk metric; then
- Select portfolios that fall within the least cost *and* least risk thresholds among *any* price curve scenario.

Final Screening

During the final screening process, resource portfolios remaining after the initial screening step are ranked by risk-adjusted mean PVRR, the primary metric used to identify top performing portfolios. Portfolio rankings are reported for the base, low, and high price curve 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 System Optimizer, which captures the impact of re-dispatch for those case developed assuming application of state 111(d) emission rate targets. The final screening process also includes review of deterministic risk analysis 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. Comparative analysis of fuel source diversity and customer rate impacts is also performed.

Preliminary Selection

Selection of a preliminary preferred portfolio is based upon the Company’s assessment of the criteria and measures used to summarize and rank candidate portfolios in the final screening analysis. In this phase, PacifiCorp considers comparative analysis of fuel source diversity and customer rate impacts.

Final Preferred Portfolio Selection

Final selection is made after performing additional analysis, as required, on the preliminary preferred portfolio taking into consideration conclusions drawn from analyses performed throughout the modeling process or new resource information that might affect resource needs received since modeling assumptions were locked down. For the 2015 IRP, PacifiCorp includes in its preferred portfolio an updated list of executed qualifying facility contracts for projects expected to come on-line in 2015 and 2016 that were not included when assumptions for the portfolio development process were lock down in September 2014.

CHAPTER 8 – MODELING AND PORTFOLIO SELECTION RESULTS

CHAPTER HIGHLIGHTS

- Core case portfolios are primarily influenced by Regional Haze assumptions, assumptions related to EPA's proposed rule to regulate CO_2 emissions under §111(d) of the Clean Air Act, and state RPS compliance assumptions. Portfolios developed with CO_2 price assumptions, incremental to EPA's proposed 111(d) rule, tend to include more renewable resources and modular nuclear resources in the out years of the planning horizon.
- PacifiCorp's proposed 111(d) emission rate targets for states in which PacifiCorp owns fossil generation and serves retail customers can be met with re-allocation of existing system renewable resources, acquisition of cost-effective energy efficiency resources, and re-dispatch of existing fossil units.
- Using a range of cost and risk metrics to evaluate a wide range of resource portfolios, PacifiCorp selected a preferred portfolio meeting its energy and capacity needs with cost effective energy efficiency resources and short-term firm market purchases through the front ten years of the 20-year planning horizon.
- Over the front ten years of the planning horizon, accumulated acquisition of incremental energy efficiency resources meets 86% of forecast load growth from 2015 through 2024.
- The first deferrable thermal resource in the 2015 IRP preferred portfolio is added in 2028, four years later relative to the 2013 IRP preferred portfolio.
- By the end of the twenty-year planning horizon, PacifiCorp's 2015 IRP preferred portfolio reflects an assumed reduction in existing owned capacity totaling 2,775MW. By 2034, it is assumed that approximately 2,800 MW of existing coal generation will either be retired or converted to operate as natural gas-fired generation.
- The 2015 IRP preferred portfolio reflects 816 MW of executed qualifying facility power purchase agreements from new wind and solar projects expected to come on-line in 2015 and 2016.
- PacifiCorp's forecasted CO_2 emissions from the preferred portfolio fall below 1990 levels by 2025. By the end of the 20-year planning period, PacifiCorp's CO_2 emissions from the preferred portfolio are projected to drop 14% below 1990 emission levels.

Introduction

This chapter reports modeling and performance evaluation results for the resource portfolios developed with a broad range of input assumptions using System Optimizer and simulated with Planning and Risk (PaR). Using model data from the portfolio development process and subsequent cost and risk analysis of unique preferred portfolio alternatives, PacifiCorp steps through its preferred portfolio selection process and presents the 2015 IRP preferred portfolio. This chapter also presents modeling results for 2015 IRP sensitivity cases.

Resource Portfolio Development

Core Case Resource Portfolios

Figure 8.1summarizes the cumulative capacity of new resources selected by System Optimizer, along with cumulative reduction in existing resources, through 2034, for resource portfolios developed under the reference Regional Haze scenario and under Regional Haze scenarios 1 and 3. Figure 8.2 presents the same summary for resource portfolios developed under the reference Regional Haze scenario and under Regional Haze scenarios 2 and 3. Resource portfolios developed under the same Regional Haze scenarios share the same assumptions for the timing of unit retirements. Those cases developed under Regional Haze Scenario 2 assume more early retirements, and therefore, generally have more new natural gas-fired capacity. New renewable resources vary among portfolios due to assumed state renewable portfolio standard (RPS) compliance or 111(d) compliance strategies. Portfolios developed assuming EPA's proposed 111(d) rule is supplemented with a future policy that applies an incremental cost on CO_2 emissions (cases C14 and C14a) include new modular nuclear resources. 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. Summary portfolio results are also shown in the case fact sheets presented in Volume II, Appendix M.

Figure 8.1 – Total Cumulative Capacity through 2034, Regional Haze Scenarios 1 and 3

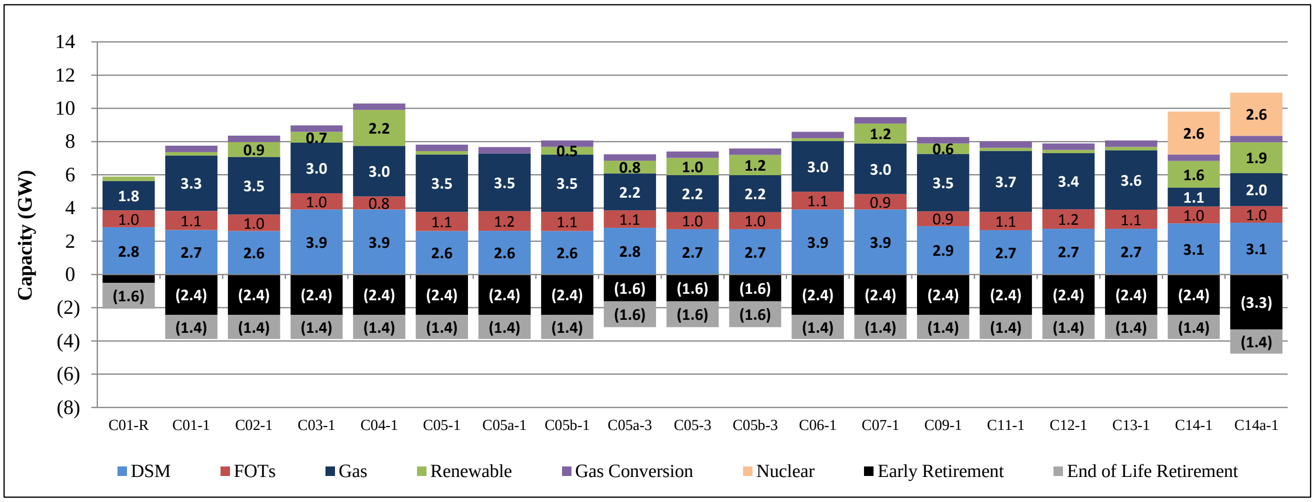
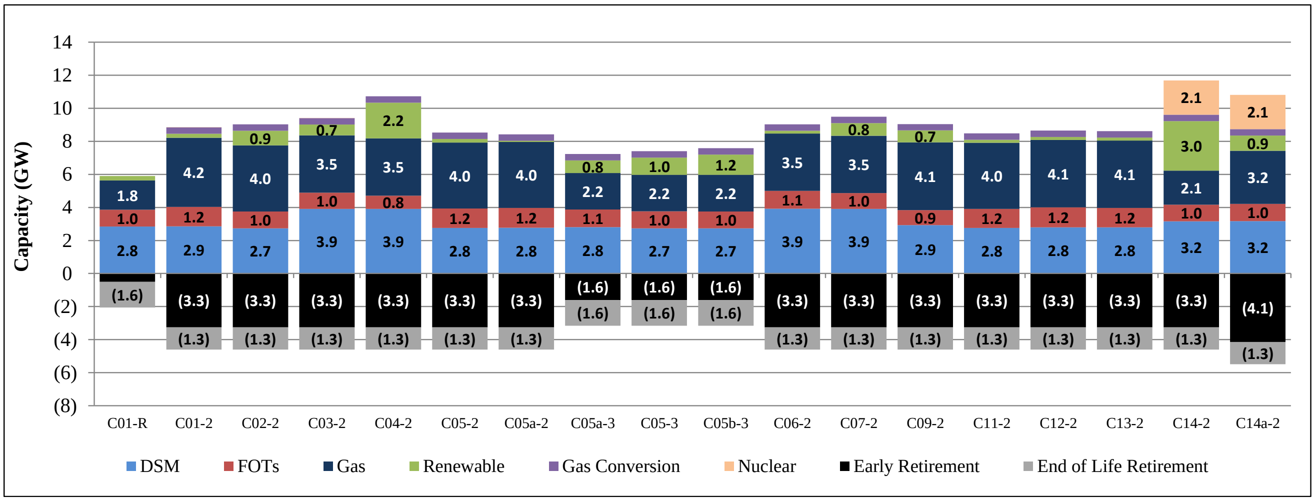


Figure 8.2 – Total Cumulative Capacity through 2034, Regional Haze Scenarios 2 and 3



System Costs

Figure 8.3 shows the present value revenue requirement (PVRR) of system costs among resource portfolios developed under reference Regional Haze assumptions and under Regional Haze scenarios 1 and 3. Figure 8.4 shows the same data for resource portfolios developed under the reference Regional Haze scenario and under Regional Haze scenarios 2 and 3. With incremental CO_2 emission costs, cases C14 and C14a have system costs significantly higher than all other cases. Cases with 111(d) compliance strategies that prioritize adding incremental Class 2 DSM energy efficiency savings (cases C03 and C06) and prioritizing additional new renewable resources (cases C04 and C07) are higher cost than cases developed with a 111(d) compliance strategy that prioritizes re-dispatch of existing fossil-fired generating units. Figure 8.5 shows the differential in system PVRR costs between cases developed under Regional Haze scenarios 1 and 2. Among cases developed without a CO_2 price assumption incremental to EPA's proposed 111(d) rule, Regional Haze scenario 2 portfolio costs are between $458 million and $649 million higher than Regional Haze scenario 1 portfolio costs. The CO_2 price assumptions in cases C14 and C14a largely overshadow the relative cost differential between Regional Haze scenarios. Detailed portfolio cost results, showing system cost line items by year, are included in Volume II, Appendix K. Summary portfolio costs are also shown in the case fact sheets presented in Volume II, Appendix M.

Figure 8.3 – System Optimizer PVRR Costs for Regional Haze Scenarios 1 and 3

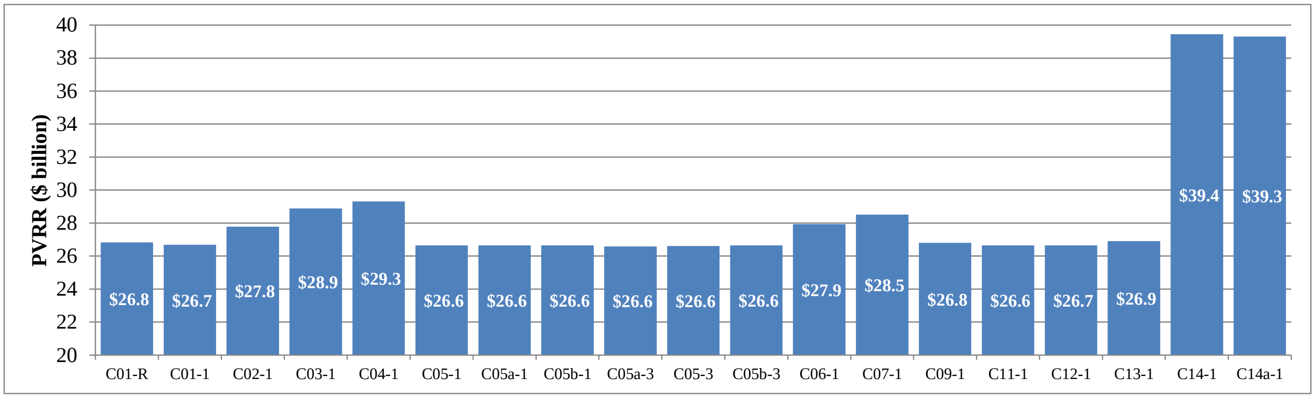


Figure 8.4 – System Optimizer PVRR Costs for Regional Haze Scenarios 2 and 3

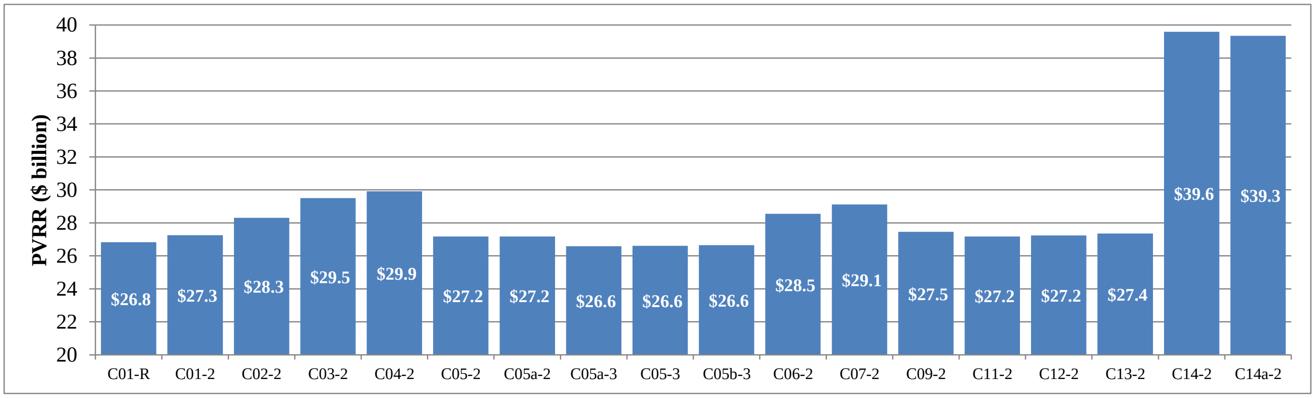
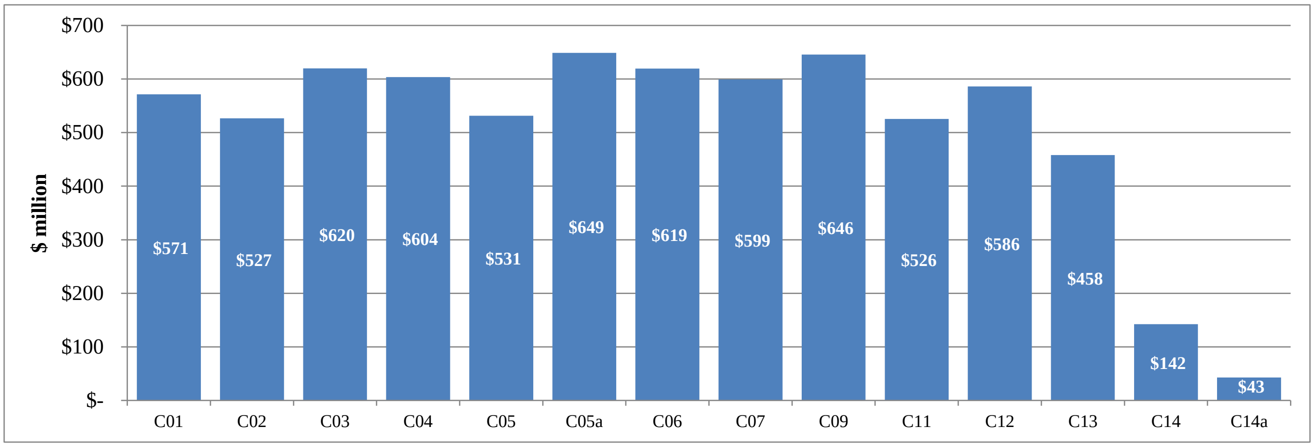


Figure 8.5 – Increase in System Optimizer PVRR Costs under Regional Haze Scenario 2 Relative to Regional Haze Scenario 1



Carbon Dioxide Emissions

Figure 8.6 shows annual CO_2 emissions among resource portfolios developed under reference Regional Haze assumptions and under Regional Haze scenarios 1 and 3. Figure 8.7 shows the same data for resource portfolios developed under the reference Regional Haze scenario and under Regional Haze scenarios 2 and 3. All cases show CO_2 emission reductions over the 20-year planning horizon with the assumed end-of-life retirement of existing fossil-fired generating units. EPA's proposed 111(d) rule drives CO_2 emission reductions beginning 2020. The resource portfolio developed under reference Regional Haze assumptions and without 111(d) compliance requirements has the highest CO_2 emissions when compared to other portfolios. Portfolios showing the most dramatic CO_2 emission reductions include those cases that have additional CO_2 costs imposed on fossil-fired generation (cases C14 and C14a). Cumulative CO_2 emissions over the 20-year planning horizon for each resource portfolio is included in Volume II, Appendix K. Annual CO_2 emission profiles are also shown in the case fact sheets presented in Volume II, Appendix M.

Figure 8.6 – System Optimizer Annual CO2 Emissions for Regional Haze Scenarios 1 and 3

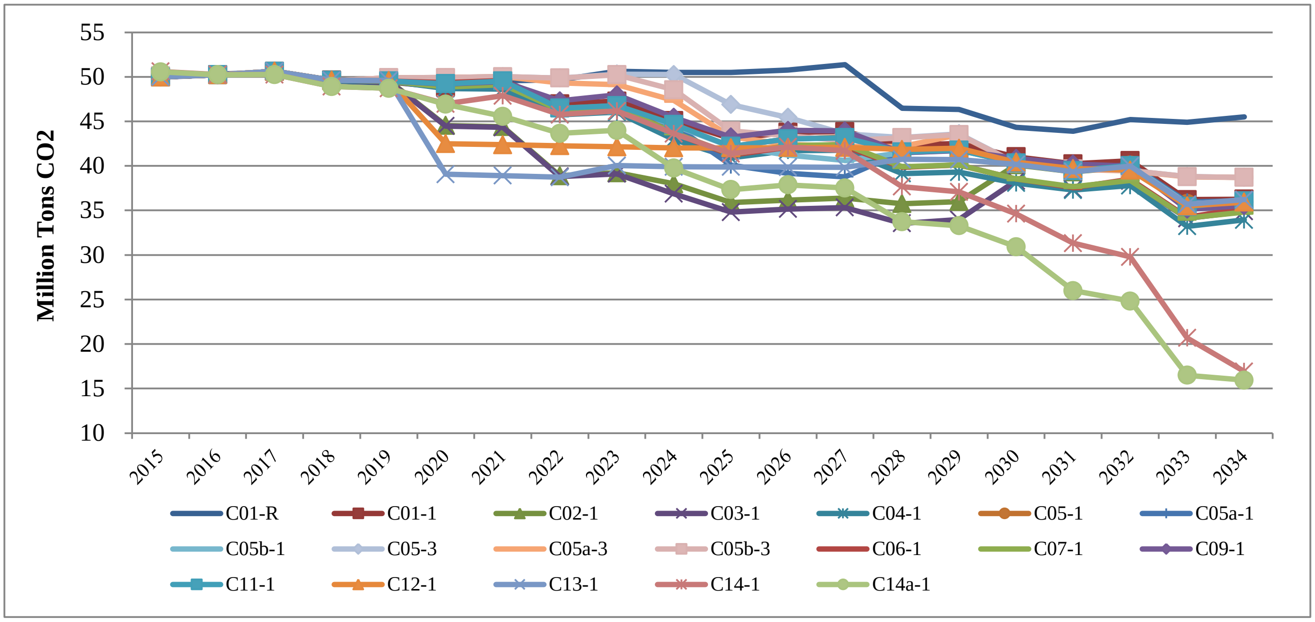
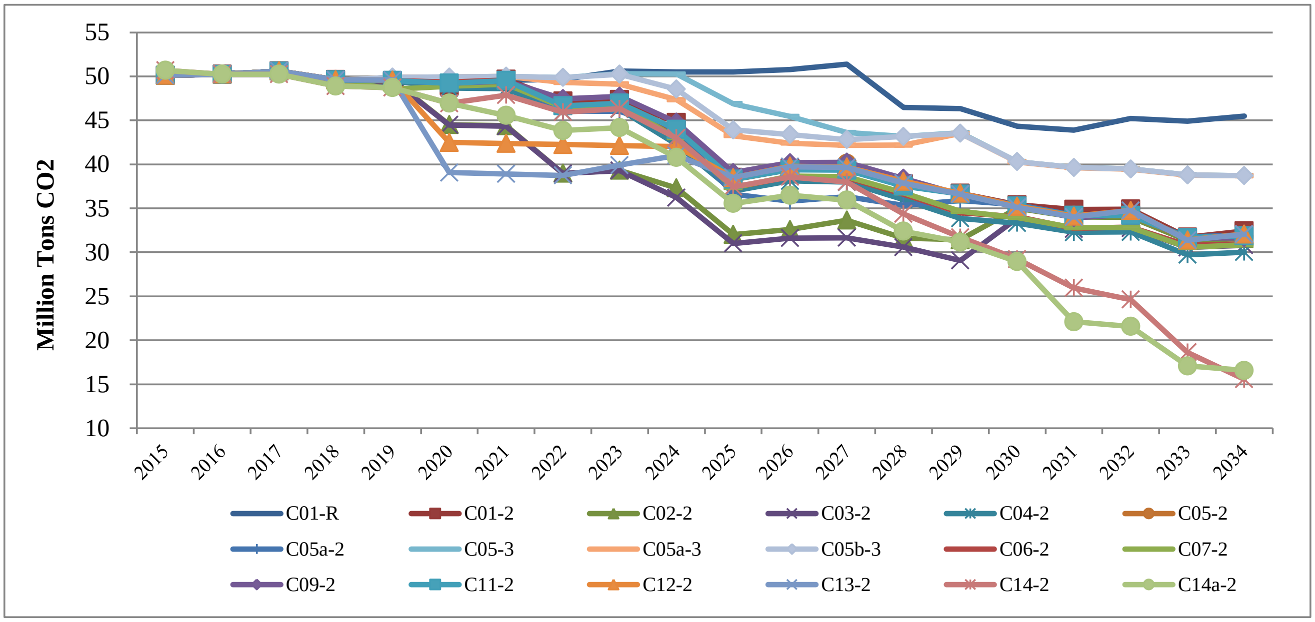


Figure 8.7 – System Optimizer Annual CO2 Emissions for Reference Haze Scenarios 2 and 3



Cost and Risk Analysis

Results of resource portfolio cost and risk analysis are presented as PacifiCorp steps through its preferred portfolio selection process in the section that follows. Stochastic modeling results from PaR are also summarized in Volume II, Appendix L.

Preferred Portfolio Selection

Pre-Screening

As described in Chapter 7, PacifiCorp simulates each unique resource portfolio in PaR. For the 2015 IRP, PaR simulations used to inform selection of the preferred portfolio are done for three price curve scenarios developed around base, low, and high natural gas price assumptions. A fourth price curve scenario, reflecting high CO_2 price assumptions recommended by members of PacifiCorp's stakeholder group, is largely used to inform PacifiCorp's 2015 IRP acquisition path analysis. Pre-screening scatter plots, shown in Figure 8.8 through Figure 8.10 for the low, base, and high price scenarios, show the mean PVRR of each unique core case portfolio on the horizontal axis and the upper-tail mean PVRR less fixed costs on the vertical axis.[77] The red dashed line depicted on each of the following figures demarcates the threshold used to identify outlier portfolios. Portfolios to the left and below the dashed red line are lower cost and lower risk and are deemed superior relative to those portfolios to the right and above the red dashed line.

Figure 8.8 – Pre-Screen Scatter Plots, Low Price Curve Scenario

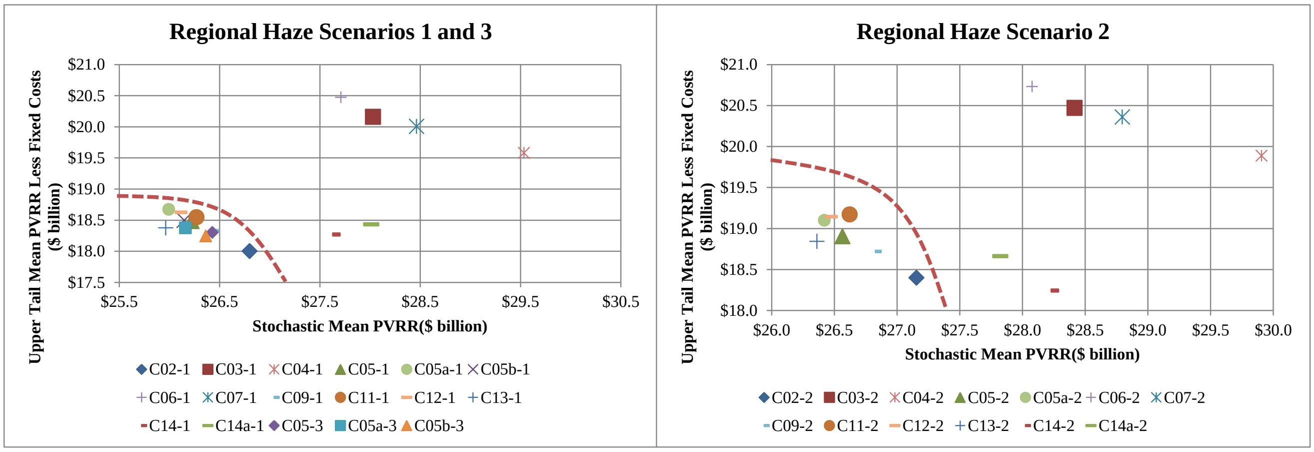
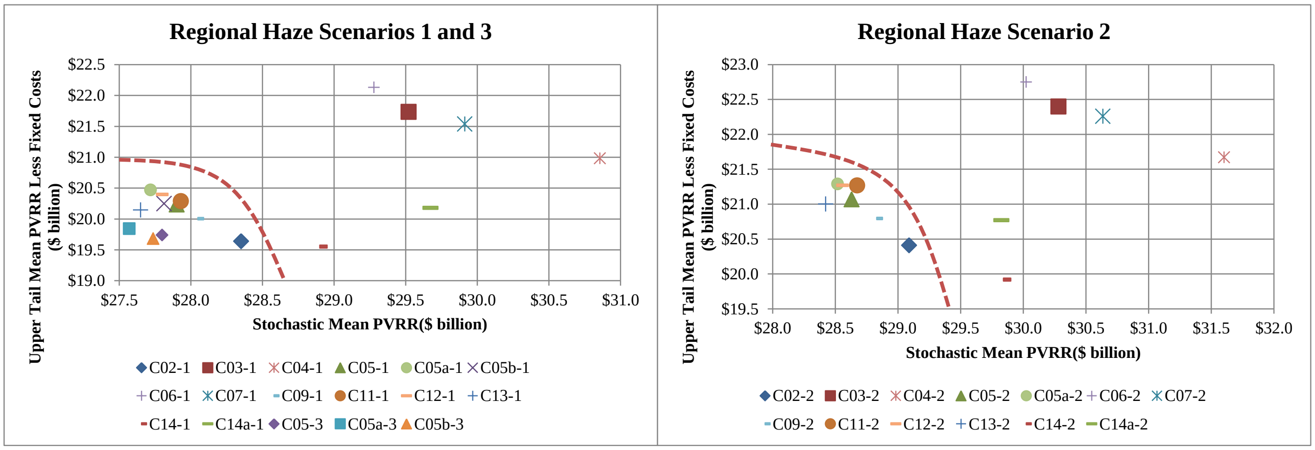


Figure 8.9 – Pre-Screen Scatter Plots, Base Price Curve Scenario



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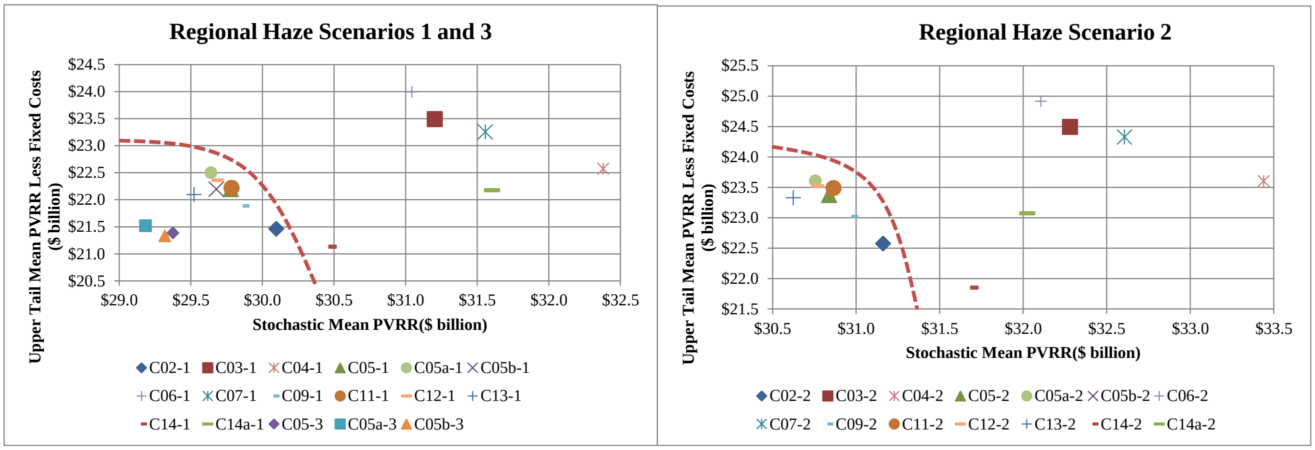
[77] Case C01 is not considered as a candidate for the preferred portfolio as it was developed without EPA's proposed 111(d) rule or any other future CO_2 policy assumption. Stochastic model results from Case C01 are reported in Volume II, Appendix L.

Figure 8.10 – Pre-Screen Scatter Plots, High Price Curve Scenario



A consistent set of resource portfolios among Regional Haze and price curve scenarios are outliers in relation to other portfolios included on the above plots. These portfolios, developed under core cases C03, C04, C06, C07, C14, and C14a, are removed from consideration as candidates for the preferred portfolio.

Initial Screening

With the removal of pre-screened portfolios, scatter plots of the stochastic mean PVRR and upper tail mean PVRR less fixed costs for the remaining portfolios are viewed with finer resolution. Figure 8.11 through Figure 8.13 show these scatter plots for the low, base, and high price curve scenarios. The red line demarcates the group of portfolios designated as superior with respect to the combination of the cost and risk metrics. The red demarcation line is established by calculating a cost/risk variance threshold using 2% of the stochastic mean PVRR of the least cost portfolio under each price curve scenario and applying this threshold to the least cost and least risk portfolios on each scatter plot. For example, under base price curve scenario, the least cost portfolio has a stochastic mean PVRR of $27.6 billion. Two percent of this figure is $550 million, which sets the threshold used for the base price curve scenario. Any portfolio that is within $550 million of the lowest cost portfolio and within $550 million of the least risk portfolio in the base price curve scenario is to the left and blow the red dashed line. The cost/risk threshold used in the low and high price curve scenarios is $520 million and $580 million, respectively.

Figure 8.11 – Initial Screen Scatter Plot, Low Price Curve Scenario

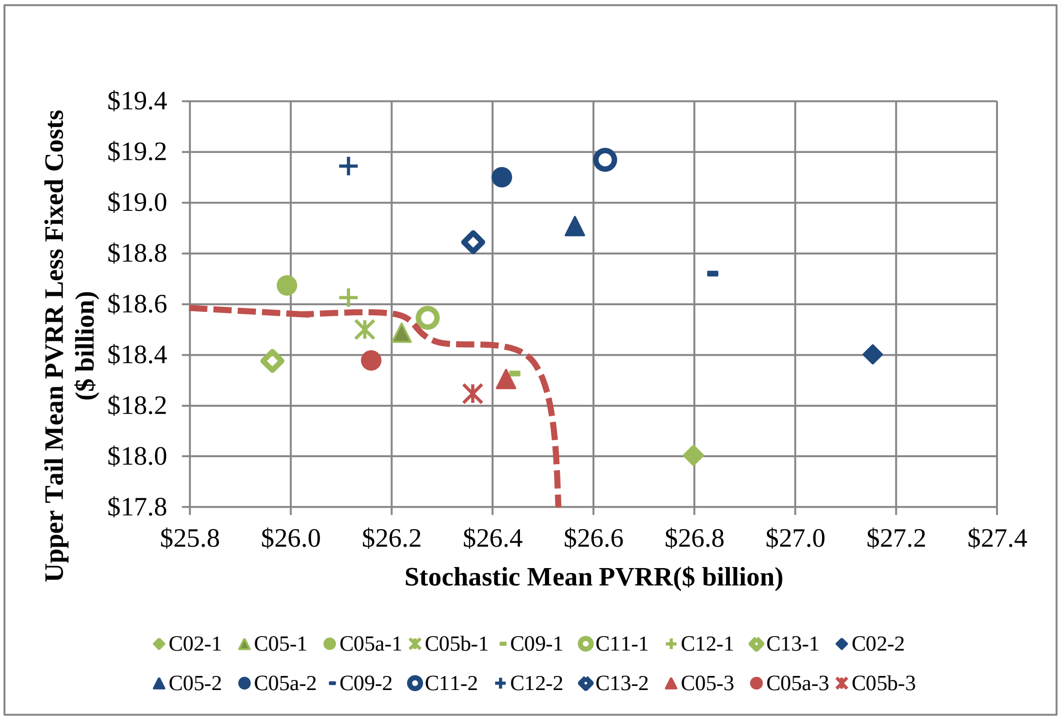


Figure 8.12 – Initial Screen Scatter Plot, Base Price Curve Scenario

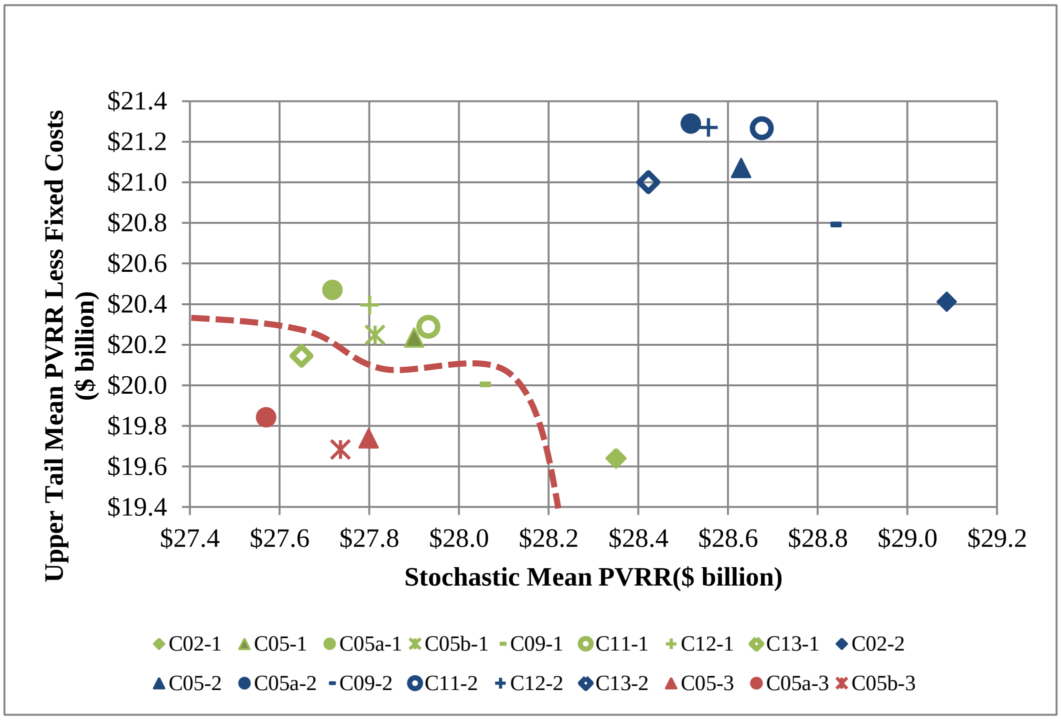
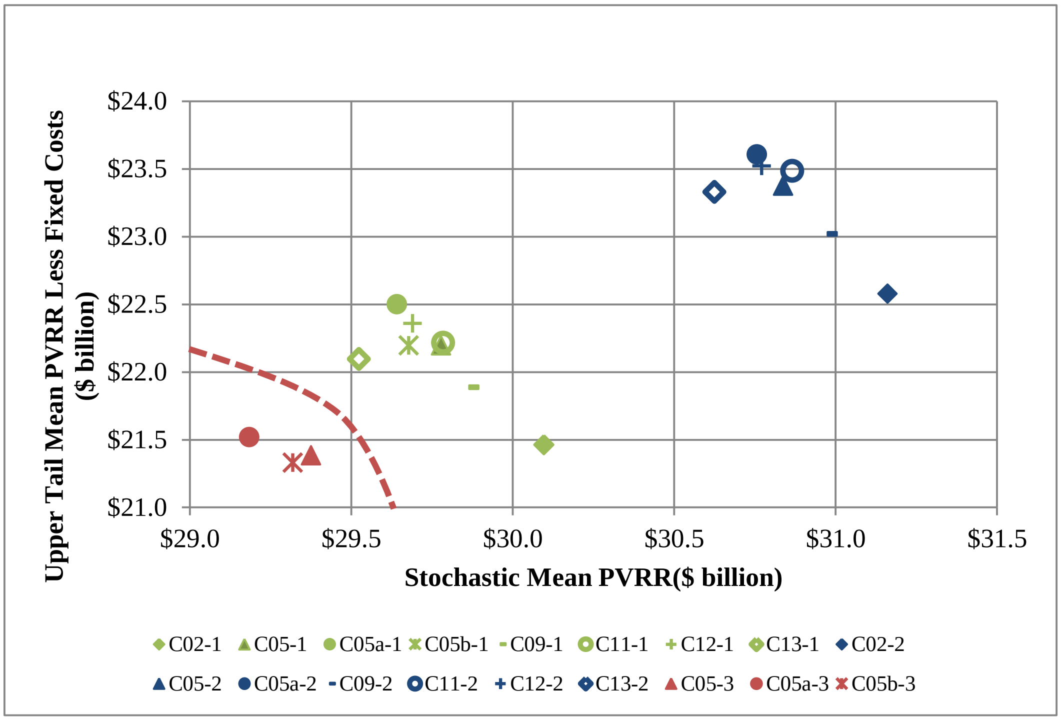


Figure 8.13 – Initial Screen Scatter Plot, High Price Curve Scenario



Portfolios that fall within the threshold identified by the red dashed line in the figures above under any price curve scenario are considered as candidates for the preferred portfolio and passed along for final screening. Based upon the initial screening scatter plot analysis, the top performing portfolios using least cost/least risk metrics include portfolios from cases C05-1, C05b-1, C05-3, C05a-3, C05b-3, C09-1 and C13-1 (seven portfolios).

Final Screening

Risk-adjusted PVRR

The risk adjusted PVRR is the primary metric used to identify top performing resource portfolios during the final screening step. Table 8.1. reports the risk-adjusted PVRR values and relative ranking among the seven portfolios identified in the initial screening step. Portfolios developed under Regional Haze scenario 3 rank high on a risk adjusted PVRR basis. Case C13-1, developed assuming a 111(d) mass cap on existing PacifiCorp units under Regional Haze scenario 1 also ranks high. Case C05a-3 has the highest risk-adjusted PVRR rank under base price curve assumptions and also scores the highest rank when the risk-adjusted PVRR is averaged among low, base, and high price curve scenarios. The top three portfolios ranked by average risk-adjusted PVRR among the low, base, and high price curve scenarios include cases C05a-3, C13-1, and C05b-3.

Table 8.1 – Risk-adjusted PVRR among Top Performing Portfolios

	Base Price Curve Scenario			Low Price Curve Scenario			High Price Curve Scenario			Average		
	Risk Adjusted PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Risk Adjusted PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Risk Adjusted PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Risk Adjusted PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank
C05-1	$29,319	$351	6	$27,547	$267	4	$31,295	$629	6	$29,387	$349	6
C05b-1	$29,226	$259	5	$27,471	$190	2	$31,189	$522	5	$29,295	$257	5
C05-3	$29,211	$244	4	$27,767	$487	6	$30,870	$203	3	$29,283	$244	4
C05a-3	$28,967	$0	1	$27,481	$201	3	$30,667	$0	1	$29,038	$0	1
C05b-3	$29,140	$173	3	$27,692	$412	5	$30,808	$141	2	$29,214	$175	3
C09-1	$29,469	$502	7	$27,769	$489	7	$31,381	$714	7	$29,540	$501	7
C13-1	$29,053	$86	2	$27,281	$0	1	$31,023	$357	4	$29,119	$81	2

Oregon RPS Compliance

As compared to case C05b-3, case C05a-3 costs are reduced when 448 MW of Oregon situs RPS wind resources (coming online in 2028) are removed from the resource portfolio. Without the 448 MW of Oregon situs RPS wind resources, approximately 467,000 annual unbundled renewable energy credit (REC) purchases would be required over the 2018 through 2034 timeframe to achieve the same level of Oregon RPS compliance as achieved in case C05b-3. Table 8.2 summarizes the unbundled REC price that would cause the PVRR from case C05a-3 to equal the PVRR from case C05b-3. Based on the risk-adjusted mean PVRR from PaR, which does not reflect fossil-fired re-dispatch associated with EPA's proposed 111(d) rule, nominal levelized unbundled REC prices of between $37/REC (high price curve assumptions) and $55/REC (low price curve assumptions) yield a break-even PVRR. Based on PVRR costs from System Optimizer, which reflects 111(d) re-dispatch costs, nominal levelized unbundled REC prices of $18/REC yield break-even economics with base price curve assumptions. There is sufficient unbundled REC volume available at prices well below these break-even unbundled REC price levels that can be used to satisfy near-term state RPS compliance. Moreover, an unbundled REC strategy does not eliminate the option to pursue longer-term compliance with bundled RECs for new renewable resources, which are not needed for Oregon RPS compliance until 2028. These results indicate that case C05a-3 is lower cost and lower risk than case C05b-3.

Table 8.2 – System Cost Impact of Oregon Situs RPS Renewable Resources

	PaR		System Optimizer	
	Reduction in Risk-adjusted PVRR with Removal of OR Situs RPS Renewables ($m)	Nominal Levelized Reduction in Risk-adjusted PVRR per MWh of OR Unbundled RECs	Reduction in System PVRR with Removal of OR Situs RPS Renewables ($m)	Nominal Levelized Reduction in System PVRR per MWh of OR Unbundled RECs
Low Price Curve	$211	$55/REC	n/a	
Base Price Curve	$173	$45/REC	$71	$18/REC
High Price Curve	$141	$37/REC	n/a	

Deterministic Risk Analysis

PacifiCorp performed a deterministic risk analysis for the three portfolios with the highest rank based on average risk-adjusted mean PVRR (cases C05a-3, C05b-3, and C13-1). Resource portfolios from cases C05a-3 and C05b-3, developed assuming state emission rate targets under EPA's proposed 111(d) rule, were locked down and simulated assuming 111(d) is implemented as a mass cap applied to PacifiCorp's existing fossil-fired resources. Conversely, the resource portfolio from case C13-1, developed assuming 111(d) is implemented as a mass cap applied to PacifiCorp's existing fossil-fired resources, was locked down and simulated assuming 111(d) is implemented via state emission rate targets. Table 8.3 summarizes the deterministic risk analysis results, showing that the portfolio from case C05a-3 is lower cost under either of the 111(d) scenarios. The portfolio from case C13-1 includes new combined cycle plants sited in Oregon. When faced with 111(d) assumptions implemented as a state emission rate target, these new combined cycle plants make it more difficult to meet PacifiCorp's share of the Oregon state emission rate target, increasing costs when compared to cases C05a-3 and C05b-3.

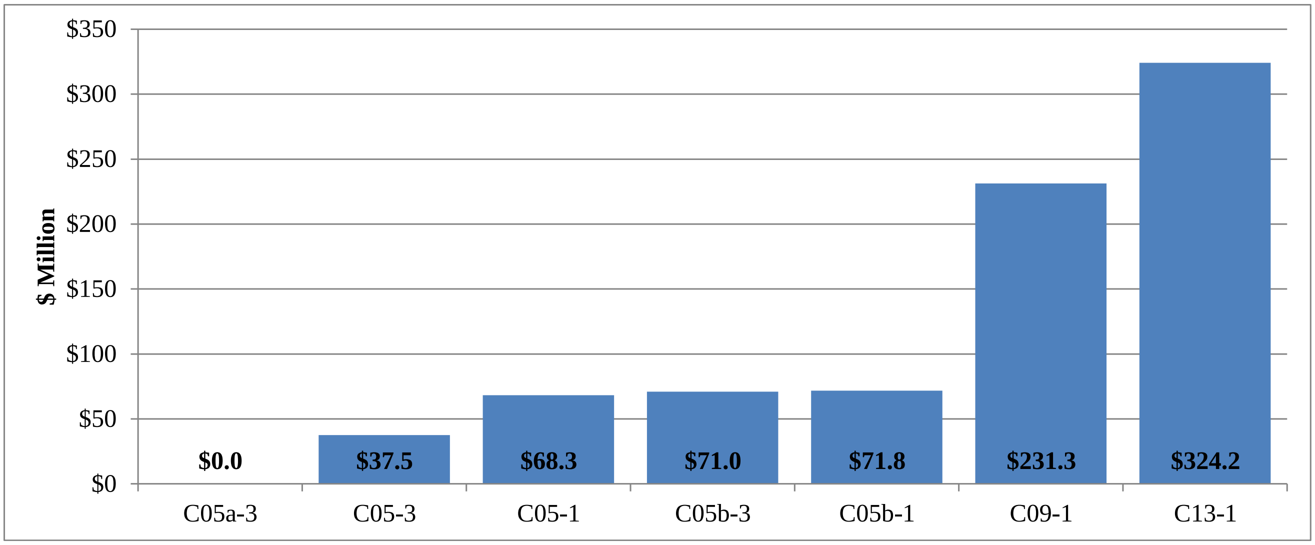
Table 8.3 – Deterministic Risk Analysis Results

	111(d) State Emission Rate Targets with Flexible Allocation of Renewables		**111(d) Mass Cap Applicable to PacifiCorp's Existing Fossil Units**	
Case	**System Optimizer PVRR ($m)**	**Increase from Lowest Cost Portfolio ($m)**	**System Optimizer PVRR ($m)**	**Increase from Lowest Cost Portfolio ($m)**
C05a-3	$26,578	n/a	$26,879	n/a
C05b-3	$26,649	$71	$27,023	$144
C13-1	$27,042	$465	$26,902	$23

System Optimizer PVRR

As discussed in Chapter 7, PaR results do not incorporate the cost associated with 111(d) re-dispatch of fossil-fired generating units. To ensure that these re-dispatch costs do not distort the relative rank of portfolio costs among the top performing portfolios identified using the risk-adjusted mean PVRR metric from PaR, PacifiCorp also reviewed the relative differences in PVRR among these portfolios as reported by System Optimizer, which does incorporate 111(d) fossil-fired re-dispatch costs. Figure 8.14 shows the change in System Optimizer PVRR among the top performing portfolio relative to the lowest cost portfolio (case C05a-3). As discussed above, with nominal levelized unbundled REC purchases below approximately $18/REC, case C05a-3 is lower cost relative to case C05b-3. Case C05a-3 is the lowest cost portfolio when considering costs associated with re-dispatch of fossil-fired generation resources under EPA's proposed 111(d) rule.

Figure 8.14 – Change in System Optimizer PVRR among Top Performing Portfolios



Energy Not Served

Table 8.4 and Table 8.5 report average annual energy not served (ENS) and upper-tail mean ENS, for each of the seven portfolios identified in the initial screening analysis. The difference among the top and bottom ranked resource portfolios based on annual average ENS is approximately 0.03% (mean ENS) and 0.04% (upper-tail mean) of the average annual forecasted load over the twenty year planning horizon. Each of the portfolios, built to a 13% planning reserve margin, provide a reliable supply of system energy and capacity. Differences in ENS metrics among portfolios are not material for any of the price curve scenarios.

Table 8.4 – Average Annual Stochastic Mean ENS among Top Performing Portfolios

	Base Price Curve Scenario			Low Price Curve Scenario			High Price Curve Scenario			Average		
	Average Annual ENS, 2015-2034 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2015-2034 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2015-2034 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2015-2034 (GWh)	Change from Lowest ENS Portfolio	Rank
C05-1	61	18	4	60	18	4	62	18	3	61	18	4
C05b-1	60	17	3	60	18	3	62	18	4	61	18	3
C05-3	65	22	7	64	22	7	67	22	7	65	22	7
C05a-3	62	19	5	61	19	5	64	19	5	62	19	5
C05b-3	64	21	6	63	21	6	65	21	6	64	21	6
C09-1	56	13	2	55	13	2	57	13	2	56	13	2
C13-1	43	0	1	42	0	1	44	0	1	43	0	1

Table 8.5 – Average Annual Upper-tail Mean ENS among Top Performing Portfolios

	Base Price Curve Scenario			Low Price Curve Scenario			High Price Curve Scenario			Average		
	Average Annual ENS, 2015-2034 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2015-2034 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2015-2034 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2015-2034 (GWh)	Change from Lowest ENS Portfolio	Rank
C05-1	85	31	7	85	31	7	86	32	7	85	31	7
C05b-1	81	28	5	81	28	5	82	28	5	82	28	5
C05-3	84	31	6	84	30	6	85	31	6	84	31	6
C05a-3	80	26	3	79	26	3	81	26	3	80	26	3
C05b-3	81	27	4	80	27	4	82	27	4	81	27	4
C09-1	79	25	2	78	25	2	79	25	2	79	25	2
C13-1	53	0	1	53	0	1	54	0	1	54	0	1

Carbon Dioxide Emissions

Figure 8.15 shows mean CO_2 emission levels (average of the 50 Monte Carlo iterations) from PaR, which does not reflect re-dispatch of fossil fired generation associated with EPA's proposed 111(d) rule, for the seven portfolios identified in the initial screening analysis when simulated using base price curve assumptions. Variation in mean CO_2 emissions is driven by differences in assumed coal unit retirements between Regional Haze scenarios 1 and 3. All portfolios show a drop in emissions in 2018 when Naughton Unit 3 is converted to natural gas-fired unit. Regional Haze scenario 1 portfolios show a further drop in emissions in 2022 and 2024 after assumed retirements of Huntington Unit 2 and Jim Bridger Unit 1, respectively. Emission reductions in 2025 coincide with the assumed natural gas conversion of Cholla Unit 4, an assumption common to all portfolios. By the end of the 20-year planning horizon, emission reductions are similar among the top performing portfolios.

Figure 8.15 – PaR Mean CO_2 Emissions among Top Performing Portfolios

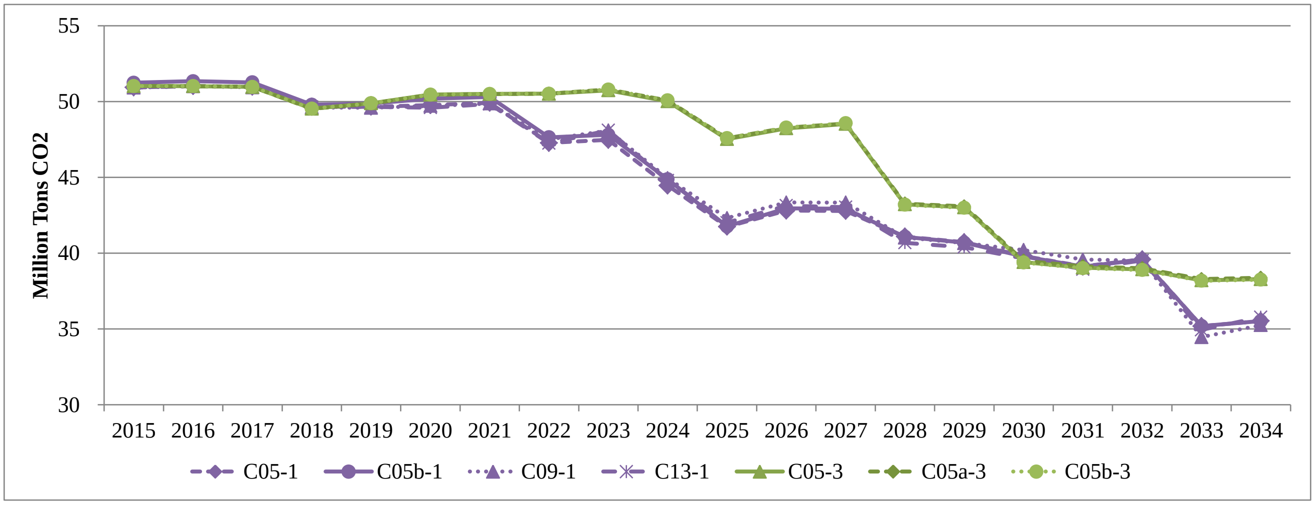
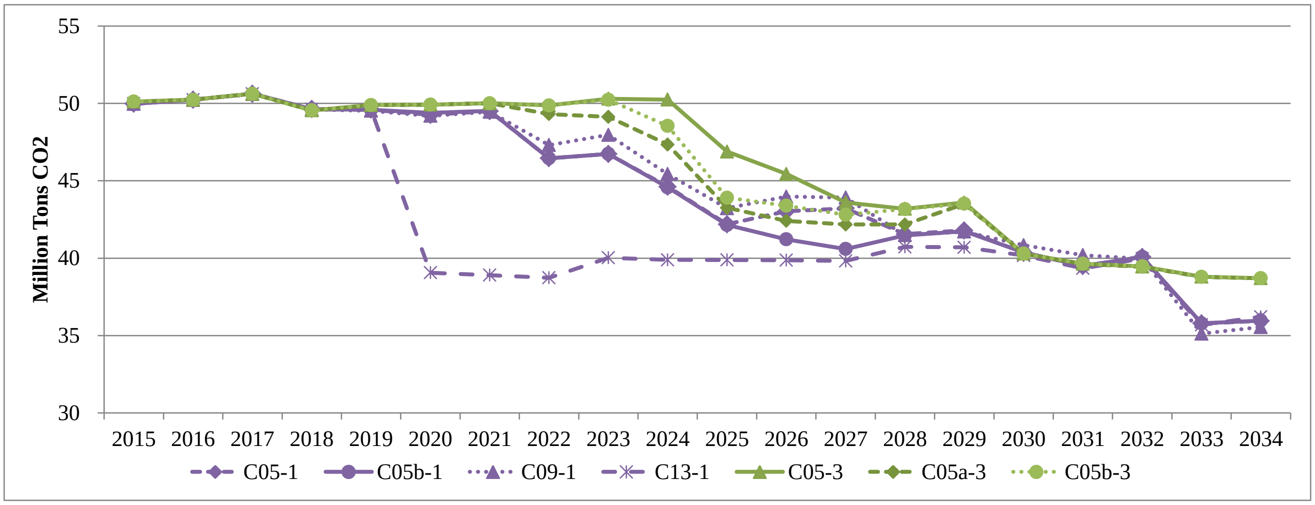


Figure 8.16 shows the same data from System Optimizer, which captures re-dispatch of fossil fired generation associated with EPA's proposed 111(d) rule. When re-dispatch of fossil fired generation is factored into the emissions profile for the top performing resource portfolios, the differential in emissions between resource portfolios developed under Regional Haze scenarios 1 and 3 narrows

over the 2022 to 2030 timeframe. When the mass cap applied to existing fossil-fired resources in case C13-1 is enforced in System Optimizer, emissions are reduced in 2020.

Figure 8.16 – System Optimizer CO_2 Emissions among Top Performing Portfolios



Fuel Source Diversity

Figure 8.17 summarizes the nameplate capacity of cumulative resource selections through 2024 among the seven portfolios remaining after initial screening. This figure illustrates the similarity among the top performing portfolios, identified using cost and risk metrics, through the first 10 years of the planning period when differences in resources among portfolios is most likely to influence the 2015 IRP action plan. All of these resource portfolios are dominated by Class 2 DSM resources and FOT resources. Portfolios developed under Regional Haze scenario 1, which assumes incremental early coal unit retirements relative to Regional Haze scenario 3, show new combined cycle plants (denoted as CCCT in the chart) in the 2022 to 2024 timeframe. Differences in renewable resources are driven by Oregon RPS assumptions. Cases that assume early acquisition of Oregon RPS resources (cases C05-3, C05-1, C09-1, and C13-1) have new renewable plants showing up in the 2020 to 2023 timeframe. As discussed above, use of unbundled RECs for Oregon RPS compliance is a lower cost lower risk alternative.

Figure 8.17 – Resource Types among Top Performing Portfolios

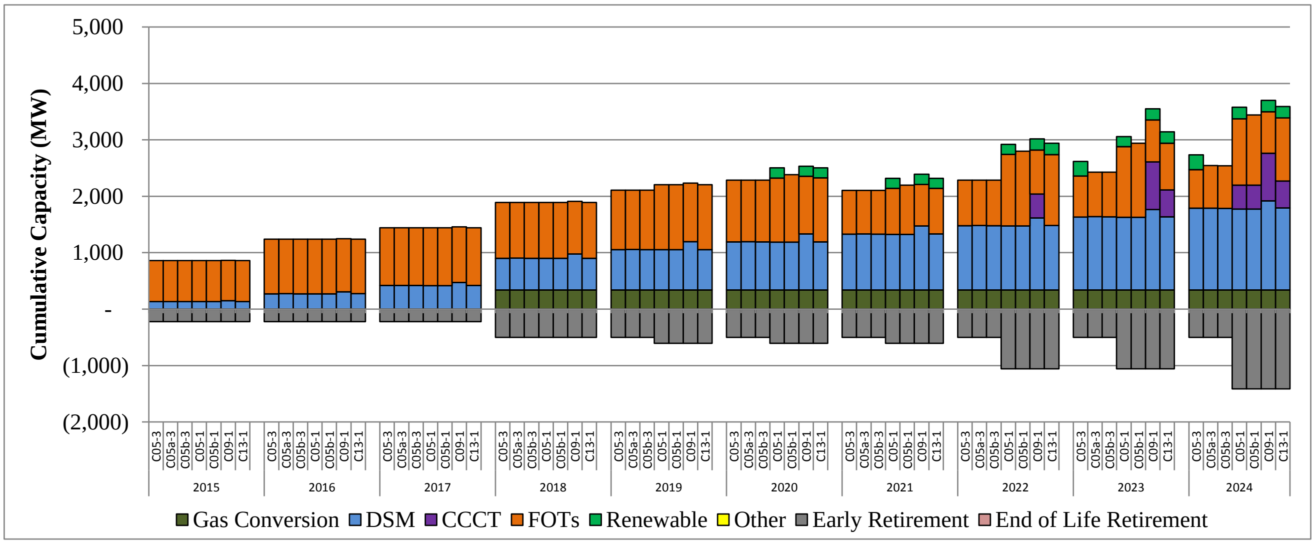


Table 8.6 reports the generation share in each portfolio among new resources by resource category in 2024 and 2034 for the seven portfolios selected during the initial screening process. Through 2024, DSM resources contribute significant levels of energy among all top performing portfolios. New combined cycle resources also provide energy in portfolios developed under Regional Haze scenario 1. By 2034, DSM and new combined cycle resources provide the largest share of new system energy among top performing resource portfolios.

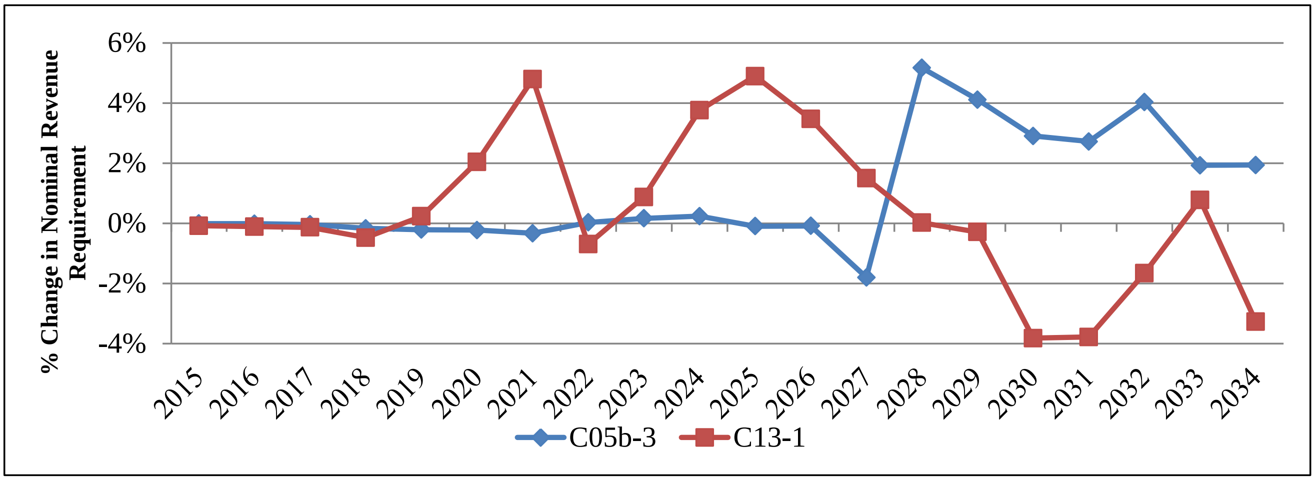
Table 8.6 – Percentage Share of Energy from New Resources by Category

2024					
Case ID	**Thermal Natural Gas**	**FOTs**	**Renewable**	**DSM**	**Combined Renewables/ DSM**
C05-1	28%	13%	5%	54%	59%
C05b-1	29%	14%	0%	56%	56%
C05-3	0%	11%	9%	80%	89%
C05a-3	0%	13%	0%	87%	87%
C05b-3	0%	13%	0%	87%	87%
C09-1	45%	7%	4%	45%	49%
C13-1	31%	12%	5%	52%	57%
2034					
Case ID	**Thermal Natural Gas**	**FOTs**	**Renewable**	**DSM**	**Combined Renewables/ DSM**
C05-1	66%	4%	2%	28%	30%
C05b-1	65%	4%	3%	28%	31%
C05-3	51%	6%	8%	35%	43%
C05a-3	52%	6%	6%	36%	42%
C05b-3	50%	5%	9%	35%	44%
C09-1	64%	3%	4%	29%	33%
C13-1	66%	4%	1%	29%	30%

Customer Rate Impacts

Figure 8.18 shows the difference in nominal revenue requirement as a percentage change in nominal revenue requirement from cases C05b-3 and C13-1 (among the highest ranking portfolios on a risk-adjusted mean PVRR basis) relative to case C05a-3 (the highest ranking portfolio on a risk-adjusted mean PVRR basis). The nominal revenue requirement from case C05b-3 is between 1.9% and 5.2% higher relative to case C05a-3 over the 2028 to 2034 timeframe. This coincides with the timing of new Oregon RPS renewable resources added in case C05b-3 that can be avoided with lower cost unbundled REC purchases. The nominal revenue requirement from case C13-1 rises relative to case C05a-3 in 2020 and 2021, coinciding with the timing of new renewable resources, and again in the 2023 to 2024 timeframe, coinciding with the timing of new combined cycle resources. In the long-term, nominal revenue requirement is lower in case C13-1 relative to case C05a-3, largely driven by differences in the timing of new resources between the two portfolios.

Figure 8.18 – Customer Rate Impacts Benchmarked to Case C05a-3



Preliminary Selection

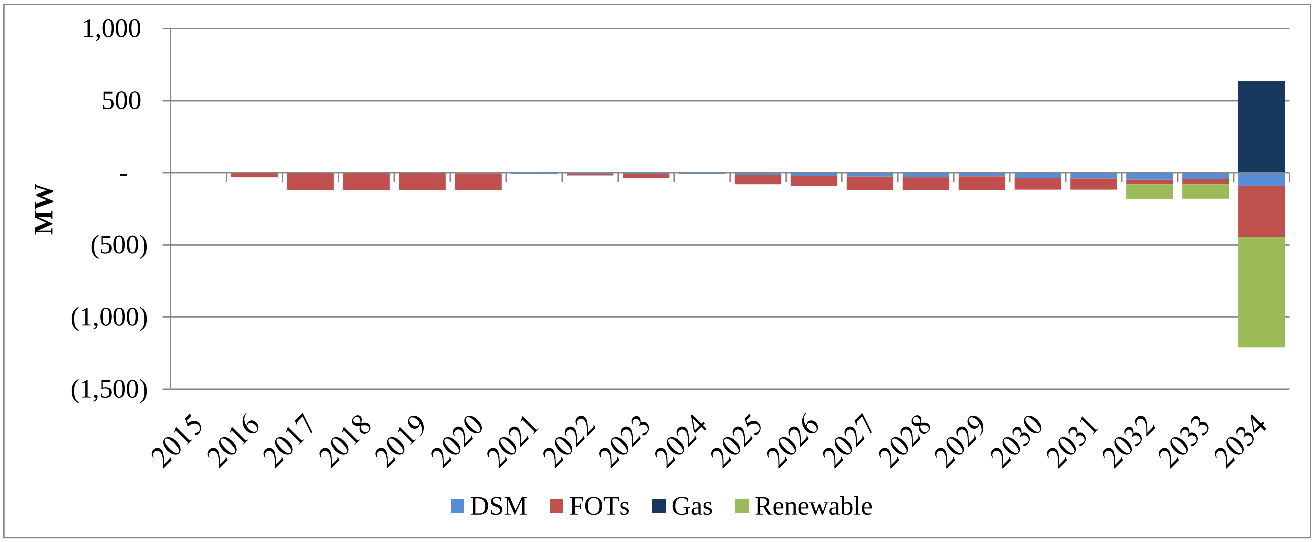
Based upon the criteria and analysis used to summarize and rank candidate portfolios in the final screening analysis, PacifiCorp has selected case C05a-3 as its preliminary preferred portfolio for the 2015 IRP. Final selection criteria supporting case C05a-3 as the preliminary preferred portfolio includes:

- Case C05a-3 ranks highest on a risk-adjusted PVRR basis and has the lowest PVRR based on System Optimizer results;
- The portfolio developed under case C05a-3 accommodates a least cost, least risk state RPS compliance strategy using unbundled RECs;
- Deterministic risk analysis shows case C05a-3 is least cost based on System Optimizer PVRR results;
- The portfolio from case C05a-3 provides a reliable supply of energy based on ENS data reported from PaR;
- Forecasted CO_2 emissions from case C05a-3 decline over the 20-year planning horizon; and
- Relative to other top performing portfolios, case C05a-3 mitigates near-term customer rate impacts.

Final Preferred Portfolio Selection

PacifiCorp's 2015 IRP preferred portfolio is a variant of case C05a-3, that incorporates an updated list of executed qualifying facility contracts that were not included when modeling assumptions were locked down in September 2014. This resource portfolio variant of case C05a-3 (referred to as C05a-3Q) was developed using System Optimizer with the addition of 3 MW of Utah solar coming online in 2015, 320 MW of Utah solar coming online in 2016, and acceleration of 80 MW of Utah solar from December 2016 to December 2015. With these updates, PacifiCorp's 2015 IRP preferred portfolio reflects 816 MW of new wind and solar qualifying facility power purchase agreements for projects coming online in 2015 (327 MW) and 2016 (489 MW). Figure 8.19 summarizes the cumulative change in resource portfolio capacity in the preferred portfolio as compared to case C05a-3. With qualifying facility power purchase agreement updates, FOTs are reduced through the planning horizon, DSM resources are slightly reduced, primarily beyond the first ten years of the planning period, renewable resources in 2032 are displaced, and incremental renewable resources in 2034 are replaced with a combined cycle plant.

Figure 8.19 – Cumulative Increase/(Decrease) in Preferred Portfolio Capacity Relative to Case C05a-3



The 2015 IRP Preferred Portfolio

Figure 8.20 presents a summary of cumulative resource capacity in PacifiCorp's 2015 IRP preferred portfolio, including the 816 MW of executed qualifying facility power purchase agreements from new wind and solar projects expected to come on-line in 2015 and 2016. Through the front ten years of the planning horizon, PacifiCorp's incremental resource needs can be met with DSM and FOTs. The first deferrable thermal resource in the 2015 IRP preferred portfolio is added in 2028, four years later relative to the 2013 IRP preferred portfolio. By the end of the twenty-year planning horizon, PacifiCorp's 2015 IRP preferred portfolio reflects an assumed reduction in existing owned capacity totaling 2,775 MW. By 2034, it is assumed that approximately 2,800 MW of existing coal generation will either be retired or converted to operate as natural gas-fired generation.

Figure 8.20 – Summary of PacifiCorp's 2015 IRP Preferred Portfolio

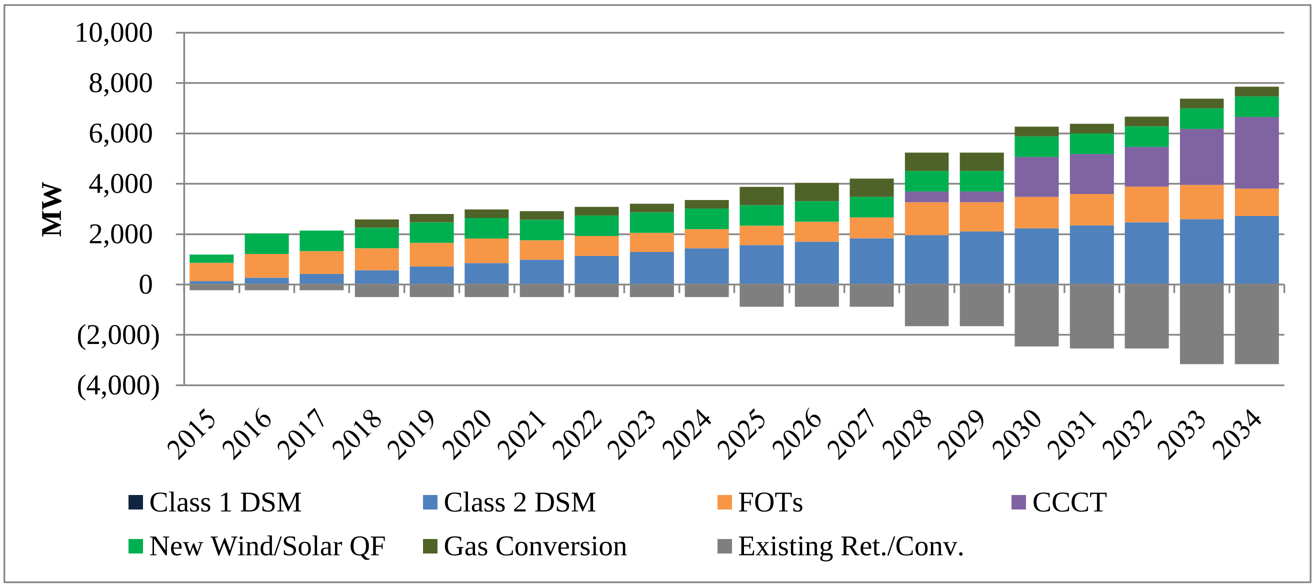


Figure 8.21 compares total Class 2 DSM energy efficiency savings by state in the 2015 IRP preferred portfolio relative to the 2013 IRP preferred portfolio. Driven by increased cost-effective lighting opportunities followed by cost-effective opportunities in heating, cooling, water heating, appliances and industrial process end-uses, Class 2 DSM energy efficiency savings in the 2015 IRP preferred portfolio exceed energy efficiency savings from the 2013 IRP preferred portfolio by 59 percent by 2024.

Figure 8.21 – Comparison of Total Energy Efficiency Savings in the 2015 IRP Preferred Portfolio and the 2013 IRP Preferred Portfolio

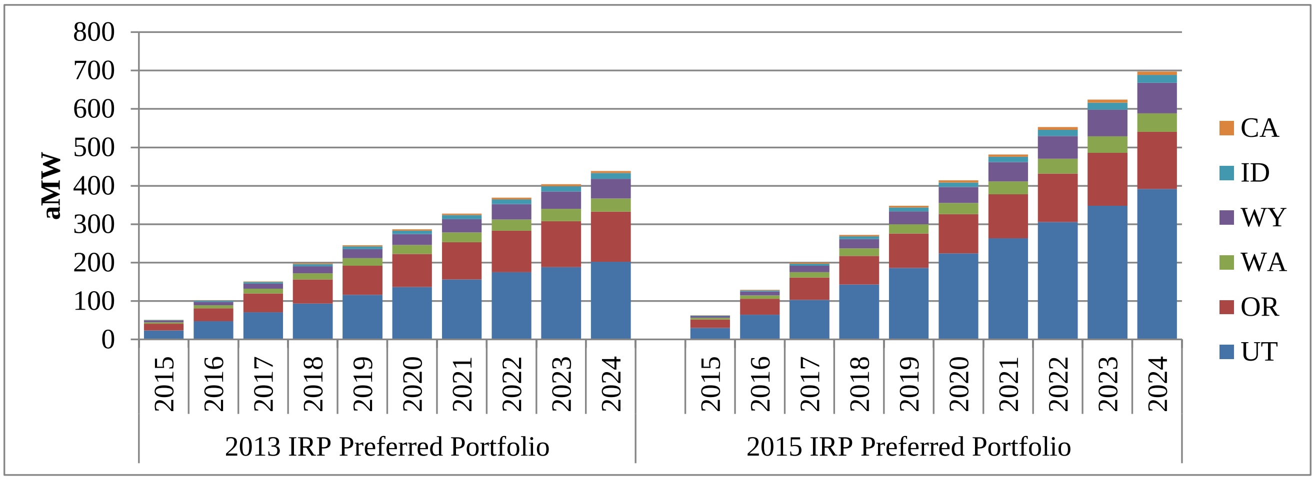


Figure 8.22 compares FOTs from the 2015 IRP preferred portfolio to FOTs in the 2013 IRP preferred portfolio. On average 2015 IRP preferred portfolio FOTs through 2024 are down 29% when compared to the 2013 IRP preferred portfolio.

Figure 8.22 – Comparison of FOTs in the 2015 IRP Preferred Portfolio with the 2013 IRP Preferred Portfolio

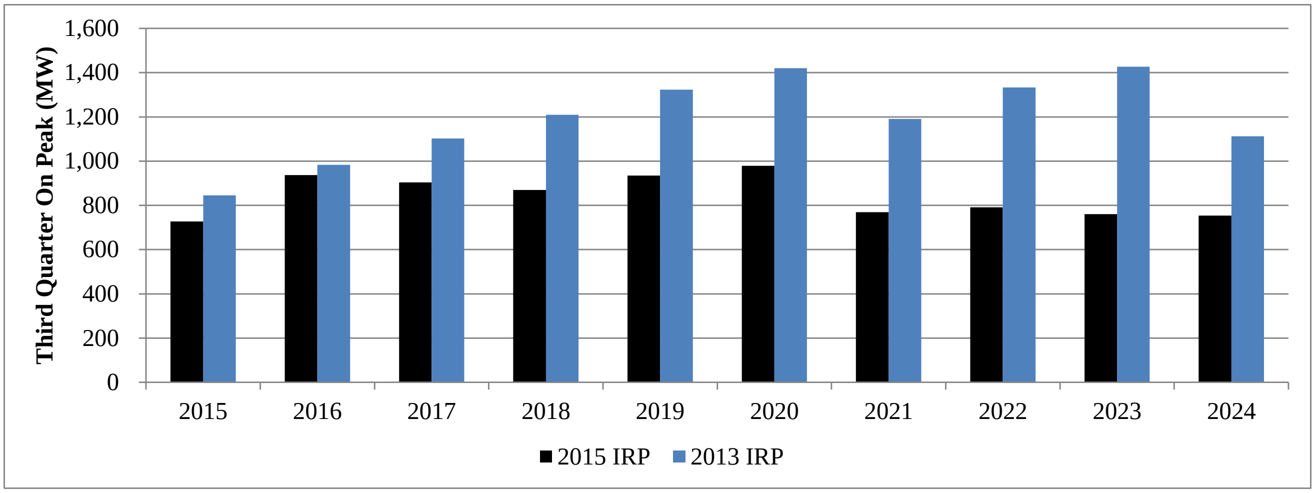


Figure 8.23 shows the contribution of energy from preferred portfolio resources to load growth projections from 2015 levels. Over the front ten years of the planning horizon, accumulated acquisition of incremental energy efficiency resources meets 86% of forecast load growth from 2015 through 2024. Energy represented as “Other” is primarily from distributed generation.

Figure 8.23 – Energy Contribution of Preferred Portfolio Resources to Load Growth

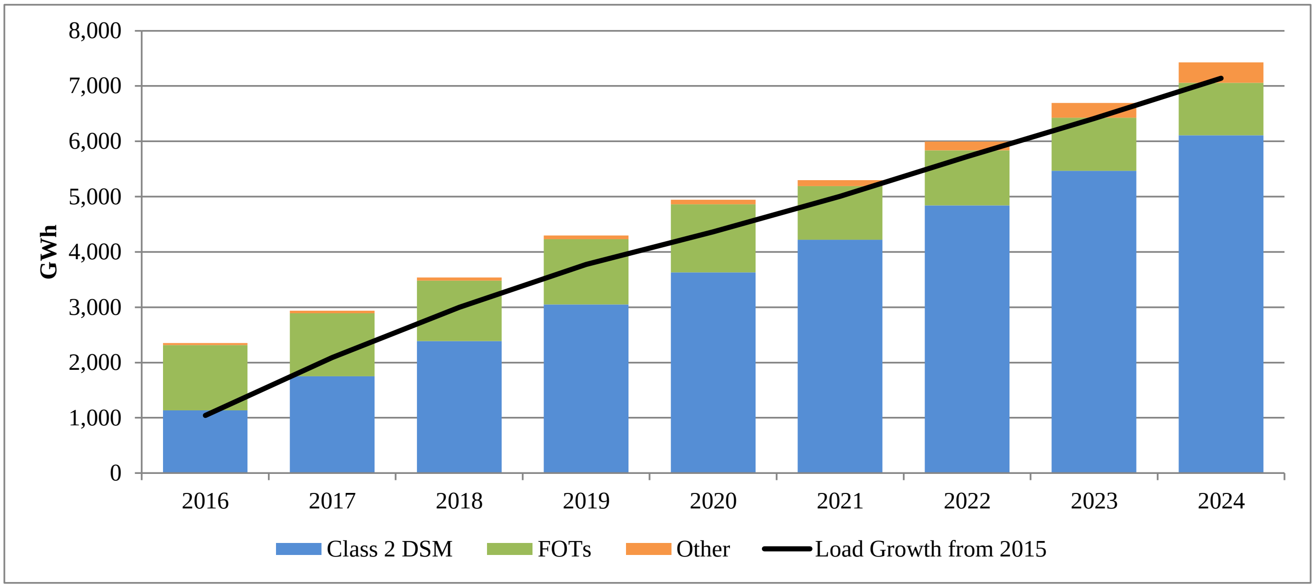
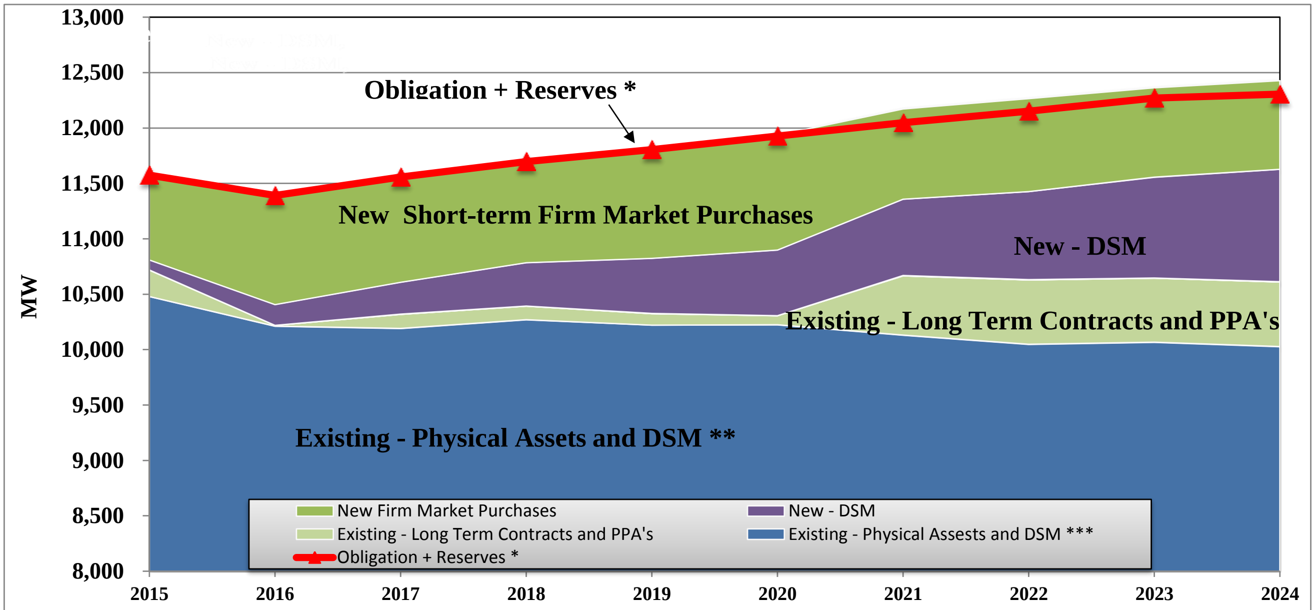


Figure 8.24 graphically displays how preferred portfolio resources meet PacifiCorp’s capacity needs over time. Through 2024, PacifiCorp meets its capacity needs, inclusive of a 13% target planning reserve margin, through incremental acquisition of new DSM resources and through short-term firm forward market purchases.

Figure 8.24 – 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 8.25 and Figure 8.26 show how PacifiCorp's system energy and 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.[78] On an energy basis, coal generation drops below 50% by 2025, falls to 36% by 2030, and declines to 31% by the end of the planning period. On a capacity basis, coal resources drop to 41% by 2025, fall to 28% by 2030, and decline to 24% by the end of the planning period. Reduced energy and capacity from coal is offset primarily by increased energy and capacity from new natural gas and DSM resources.

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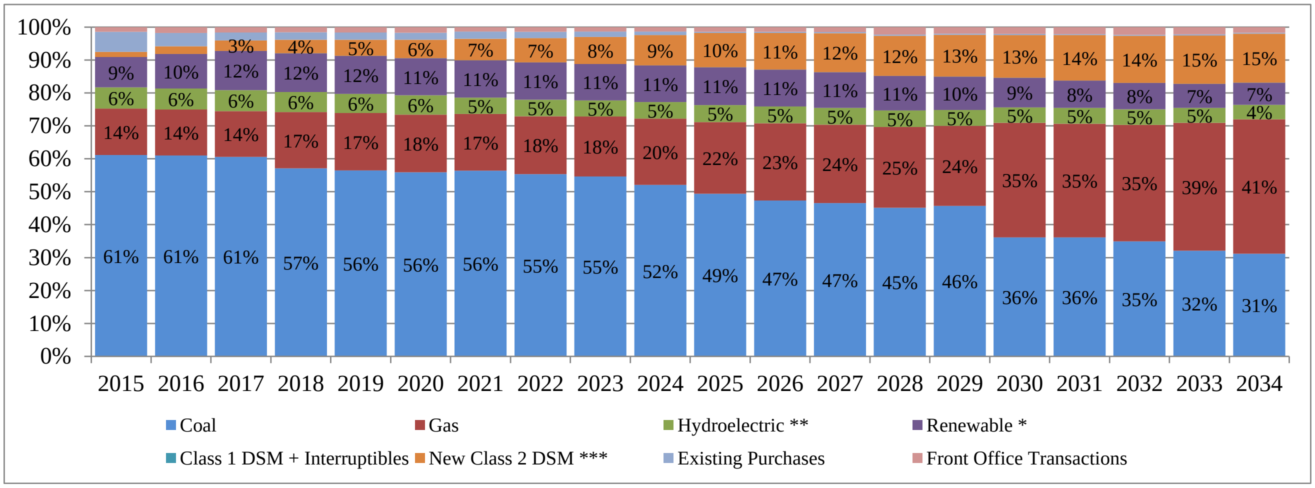
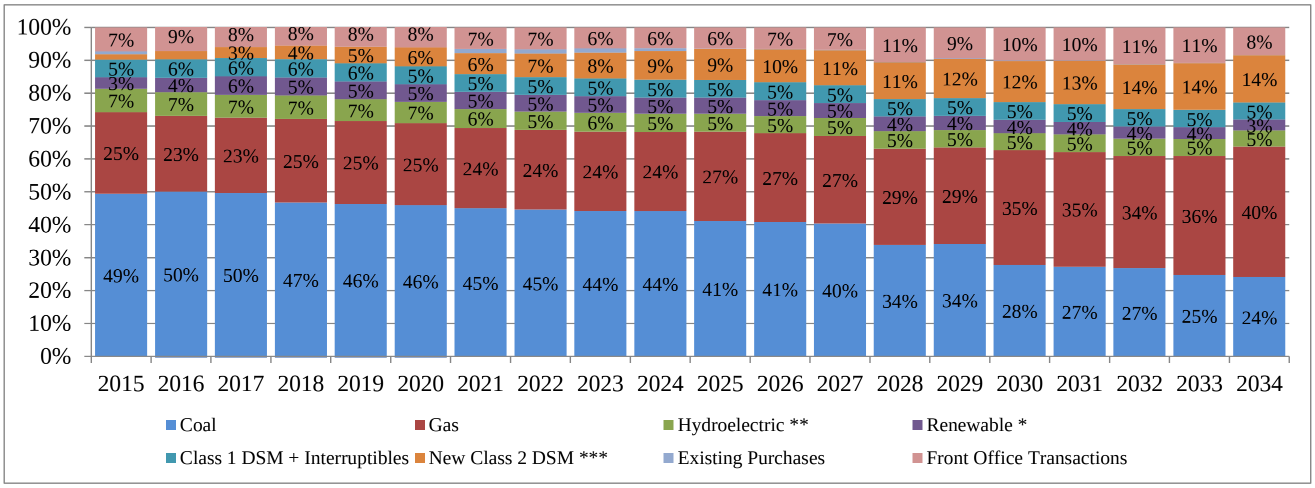
[78] The projected PacifiCorp 2015 IRP preferred portfolio "energy mix" is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with wind, biomass, geothermal and qualifying hydro facilities in PacifiCorp's energy 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 and/or other environmental commodities or (c) excluded from energy purchased. PacifiCorp's 2015 IRP preferred portfolio energy mix includes owned resources and purchases from third parties.

Figure 8.25 – Projected Energy Mix with Preferred Portfolio Resources



*Renewable resources include wind, solar, and geothermal.
**Hydroelectric resources included owned and contracted.
***Class 2 DSM resources represent cumulative acquisition of new DSM resources over time.

Figure 8.26 – Projected Capacity Mix with Preferred Portfolio Resources



*Renewable resources include wind, solar, and geothermal.
**Hydroelectric resources included owned and contracted.
***Class 2 DSM resources represent cumulative acquisition of new DSM resources over time.

Figure 8.27 shows PacifiCorp's RPS compliance forecast for California, Oregon, and Washington covering the period 2015 through 2024. Utah's RPS goal is tied to a 2025 compliance date, so the 2015 through 2024 position is not shown. However, PacifiCorp meets the Utah 2025 state target of 20%, and has a significant bank to sustain continued future compliance in Utah.

Figure 8.27 – Annual State RPS Position Forecasts

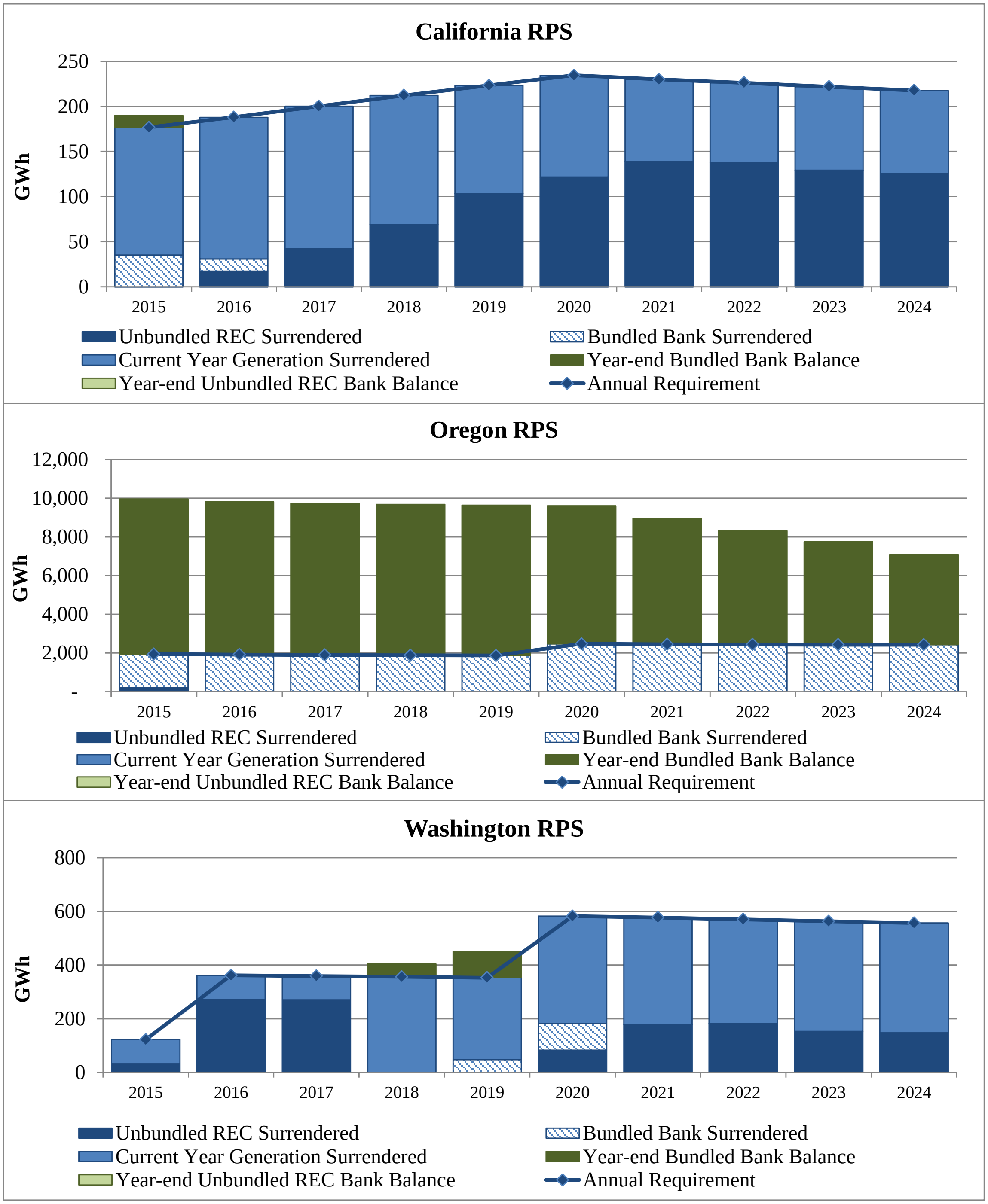


Figure 8.28 shows CO_2 emissions from the preferred portfolio through 2034 under base price curve assumptions. Relative to 1990 CO_2 emissions of approximately 46 million tons, PacifiCorp's forecasted CO_2 emissions from the preferred portfolio fall below 1990 levels by 2025. By the end of the 20-year planning period, PacifiCorp's CO_2 emissions from the preferred portfolio are projected to drop 14% below 1990 emission levels.

Figure 8.28 – Preferred Portfolio CO_2 Emissions

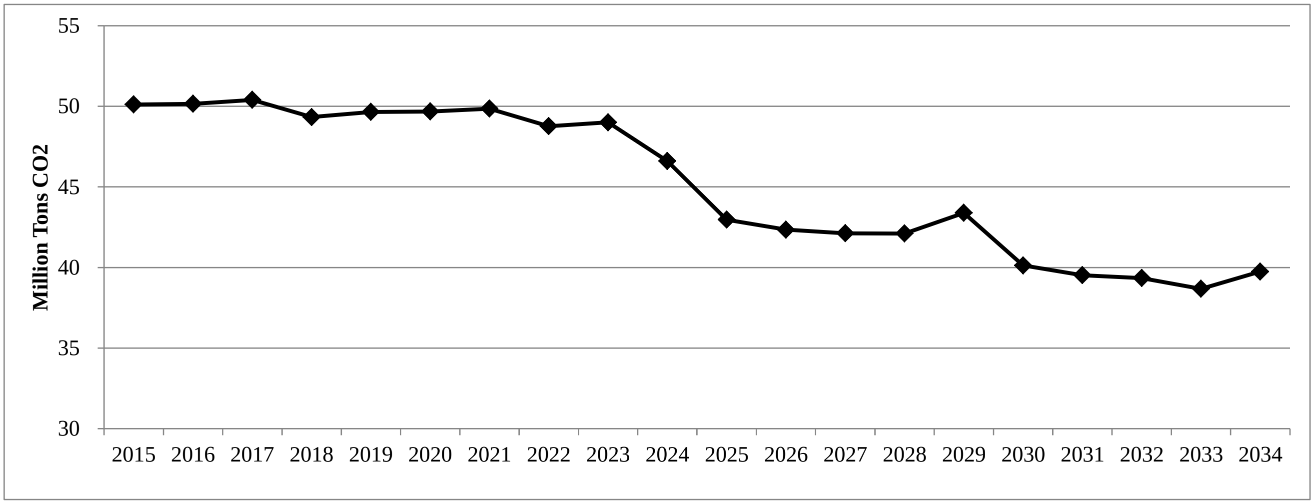


Table 8.7 provides line-item detail of PacifiCorp’s 2015 IRP preferred portfolio showing new resource capacity along with changes in existing resource capacity through the 20-year planning horizon. Table 8.8 shows line-item detail of PacifiCorp’s peak load and resource capacity balance, inclusive of preferred portfolio resources, through the first ten years of the planning horizon.

Table 8.7 – PacifiCorp's 2015 IRP Preferred Portfolio

Preferred Portfolio (Case C05a-3Q)		Nameplate Capacity (MW)																				**Resource Totals 1/**	
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	**10-year**	**20-year**
East	**Existing Plant Retirements/Conversions**																						
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	(33)
	Hunter 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	-	-	(269)
	Huntington 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	(450)
	Carbon 1 (Coal Early Retirement/Conversions)	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon 2 (Coal Early Retirement/Conversions)	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(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)	(50)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	(358)
	Coal Ret_AZ - Gas RePower	-	-	-	-	-	-	-	-	-	-	387	-	-	-	-	-	-	-	-	-	-	387
	Coal Ret_WY - Gas RePower	-	-	-	337	-	-	-	-	-	-	-	-	-	-	-	(337)	-	-	-	-	337	-
	Expansion Resources																						
	CCCT - DJohns - F 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	313	-	-	-	-	-	313
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	-	-	-	-	-	423
	CCCT - Utah-N - F 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	635	635	-	1,270
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	846	-	-	-	-	-	846
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	1,159	-	-	635	635	-	2,852
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.9	-	-	4.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.9	-	-	4.9
	DSM, Class 2, ID	4	4	5	5	5	4	4	4	5	5	5	5	5	5	5	4	4	4	5	4	45	90
	DSM, Class 2, UT	69	78	84	86	92	81	84	90	91	93	75	76	80	80	77	75	72	72	73	70	847	1,596
	DSM, Class 2, WY	6	8	10	12	14	12	13	14	15	16	13	13	14	15	15	15	16	16	17	17	121	271
	DSM, Class 2 Total	79	90	99	102	111	97	101	108	110	114	92	94	99	99	97	94	93	92	94	92	1,012	1,958
	FOT Mona Q3	-	-	-	-	-	-	-	-	-	-	-	-	-	161	44	110	104	268	300	74	-	53
West	**Expansion Resources**																						
	Oregon Solar Capacity Standard	-	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	10.6	-	-	10.6	-	-	10.6	-	-	-	-	-	10.6	31.8
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	5.0	-	-	-	-	-	-	-	-	-	-	-	-	5.0	5.0
	DSM, Class 1 Total	-	-	-	-	-	-	-	5.0	10.6	-	-	10.6	-	-	10.6	-	-	-	-	-	15.6	36.8
	DSM, Class 2, CA	1	2	2	2	2	1	1	2	2	2	1	1	1	1	1	1	1	1	1	1	16	29
	DSM, Class 2, OR	44	39	36	33	29	27	25	25	23	23	21	22	22	22	21	21	20	21	20	20	303	511
	DSM, Class 2, WA	8	9	10	10	11	9	10	10	11	11	9	9	9	9	9	8	8	8	8	7	98	181
	DSM, Class 2 Total	54	49	47	44	42	38	36	36	36	35	31	32	32	32	31	30	29	30	28	28	417	721
	FOT COB Q3	-	62	29	-	60	104	-	-	-	-	-	-	-	268	248	268	268	268	185	138	26	95
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	227	375	375	370	375	375	269	291	261	254	271	292	335	375	375	375	375	375	375	375	317	335
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	Existing Plant Retirements/Conversions	(222)	-	-	57	-	-	-	-	-	-	-	-	-	(762)	-	(1,144)	(77)	-	(627)	-		
	Annual Additions, Long Term Resources	133	146	146	146	153	135	137	149	157	149	123	137	130	555	139	1,284	122	122	762	755		
	Annual Additions, Short Term Resources	727	937	904	870	935	979	769	791	761	754	771	792	835	1,304	1,167	1,253	1,247	1,411	1,360	1,087		
	Total Annual Additions	860	1,084	1,050	1,016	1,088	1,113	906	941	917	903	893	928	965	1,859	1,305	2,537	1,369	1,533	2,123	1,841		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Table 8.8 – Preferred Portfolio Capacity Load and Resource Balance

Calendar Year	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
East										
Thermal	6,410	6,397	6,397	6,453	6,453	6,453	6,450	6,447	6,445	6,442
Hydroelectric	117	114	114	114	114	114	114	114	114	94
Renewable	187	187	187	187	187	187	184	184	177	177
Purchase	627	406	300	300	300	300	272	272	272	272
Qualifying Facilities	139	222	348	347	346	339	337	332	331	280
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sale	(732)	(732)	(656)	(656)	(656)	(656)	(175)	(175)	(175)	(144)
Non-Owned Reserves	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)
Transfers	760	607	570	548	553	577	235	230	229	230
East Existing Resources	**7,792**	**7,488**	**7,545**	**7,579**	**7,582**	**7,599**	**7,703**	**7,691**	**7,679**	**7,637**
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	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
East Planned Resources	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
East Total Resources	**7,792**	**7,488**	**7,545**	**7,579**	**7,582**	**7,599**	**7,703**	**7,691**	**7,679**	**7,637**
Load	7,157	6,977	7,102	7,208	7,295	7,382	7,448	7,529	7,617	7,640
Existing Resources:										
Interruptible	(149)	(175)	(175)	(175)	(175)	(175)	(175)	(175)	(175)	(175)
Class 2 DSM	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)
New Resources:										
Class 2 DSM	(59)	(126)	(200)	(277)	(360)	(433)	(509)	(590)	(673)	(758)
East obligation	**6,876**	**6,603**	**6,654**	**6,684**	**6,687**	**6,702**	**6,691**	**6,691**	**6,697**	**6,634**
Planning Reserves (13%)	913	878	884	888	889	891	889	889	890	882
East Reserves	**913**	**878**	**884**	**888**	**889**	**891**	**889**	**889**	**890**	**882**
East Obligation + Reserves	**7,789**	**7,481**	**7,539**	**7,572**	**7,576**	**7,592**	**7,580**	**7,580**	**7,587**	**7,516**
East Position	**4**	**7**	**7**	**7**	**7**	**7**	**122**	**111**	**92**	**121**
East Reserve Margin	13.3%	13.4%	13.4%	13.4%	13.4%	13.4%	15.1%	14.9%	14.7%	15.1%
West										
Thermal	2,495	2,251	2,248	2,248	2,248	2,248	2,245	2,241	2,239	2,239
Hydroelectric	777	770	752	775	725	728	643	620	652	646
Renewable	170	170	170	170	170	170	170	115	115	105
Purchase	191	22	22	22	5	5	5	5	5	5
Qualifying Facilities	116	114	140	135	134	120	120	120	115	115
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(210)	(160)	(160)	(160)	(160)	(160)	(156)	(105)	(105)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	(761)	(608)	(571)	(549)	(554)	(578)	(236)	(232)	(230)	(232)
West Existing Resources	**2,775**	**2,554**	**2,596**	**2,637**	**2,565**	**2,529**	**2,788**	**2,761**	**2,789**	**2,797**
Front Office Transactions	770	993	959	922	991	1,037	815	839	806	800
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	5	17	17
Other	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**770**	**993**	**959**	**922**	**991**	**1,037**	**815**	**844**	**823**	**816**
West Total Resources	**3,545**	**3,548**	**3,555**	**3,559**	**3,556**	**3,566**	**3,602**	**3,605**	**3,612**	**3,613**
Load	3,206	3,237	3,271	3,301	3,323	3,354	3,406	3,429	3,455	3,476
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
Class 2 DSM	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)
New Resources:										
Class 2 DSM	(32)	(61)	(88)	(115)	(139)	(161)	(181)	(202)	(222)	(242)
West obligation	**3,138**	**3,140**	**3,146**	**3,150**	**3,147**	**3,157**	**3,188**	**3,191**	**3,197**	**3,198**
Planning Reserves (13%)	408	408	409	409	409	410	414	415	417	417
West Reserves	**408**	**408**	**409**	**409**	**409**	**410**	**414**	**415**	**417**	**417**
West Obligation + Reserves	**3,546**	**3,548**	**3,555**	**3,559**	**3,556**	**3,567**	**3,603**	**3,606**	**3,613**	**3,615**
West Position	**(1)**	**(1)**	**(1)**	**(1)**	**(0)**	**(1)**	**(0)**	**(1)**	**(2)**	**(2)**
West Reserve Margin	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%
System										
Total Resources	11,338	11,036	11,100	11,137	11,138	11,165	11,305	11,297	11,291	11,250
Obligation	10,013	9,743	9,800	9,833	9,834	9,858	9,880	9,882	9,894	9,832
Reserves	1,321	1,286	1,293	1,298	1,298	1,301	1,304	1,304	1,307	1,299
Obligation + Reserves	11,335	11,029	11,094	11,131	11,132	11,159	11,183	11,187	11,200	11,131
System Position	3	6	6	6	6	6	122	110	91	120
Reserve Margin	13.2%	13.3%	13.3%	13.3%	13.3%	13.3%	14.4%	14.3%	14.1%	14.4%

Sensitivity Analyses

PacifiCorp completed sensitivity analysis for 15 cases. Assumptions for the sensitivity cases are presented in Chapter 7 and summarized in case fact sheets located in Volume II, Appendix M. In addition to the summary of results presented below, System Optimizer results are provided in Volume II, Appendix K and PaR results are provided in Volume II, Appendix L.

Load Sensitivities (S-01, S-02, and S-03)

PacifiCorp conducted three System Optimizer runs for three alternative load growth scenarios: low load growth (case S-01), high load growth (case S-02), and a 1-in-20 extreme system peak scenario (case S-03). Each of these sensitivities is benchmarked to core case C05-1. Table 8.9 summarizes PVRR cost impacts for each load sensitivity case. Nominal levelized cost results are calculated as the change in system PVRR divided by the present value change in coincident system peak ($/kW-mo) or the present value change in load ($/MWh).

Table 8.9 – Load Sensitivity System Optimizer PVRR Cost Results

	Base Load (C05-1)	Low Load (S-01)	High Load (S-02)	1-in-20 Peak (S-03)
PVRR ($m)	$26,646	$24,715	$28,334	$27,709
Increase/(Decrease) from Base ($m)	n/a	($1,931)	$1,688	$1,063
Nominal Levelized Increase/(Decrease) from Base ($/kW-mo)	n/a	($43)	$39	$15
Nominal Levelized Increase/(Decrease) from Base ($/MWh)	n/a	($55)	$58	$13,057

Under the low load forecast sensitivity, the first deferrable combined cycle resource is deferred by four years when compared to the benchmark case. By 2034, new thermal resources are reduced by 423 MW. Under the high load forecast sensitivity, the first deferrable combined cycle plant is accelerated by four years when compared to the benchmark case. Total new thermal resource additions are increased by 635 MW by the end of the planning horizon. Under the 1-in-20 peak load forecast scenario, the timing of the first deferrable combined cycle plant is accelerated by five years when compared to the benchmark portfolio. Total new thermal resource capacity is increased by 203 MW by the end of the study period.

Distributed Generation Sensitivities (S-04 and S-05)

Low and high distributed generation (DG) penetration sensitivities were analyzed. Both sensitivities are benchmarked to core case C05-1. Table 8.10 summarizes PVRR cost impacts of the low and high DG penetration sensitivities.

Table 8.10 – DG Sensitivity System Optimizer PVRR Cost Results

	Base DG (C05-1)	Low DG (S-04)	High DG (S-05)
PVRR ($m)	$26,646	$26,885	$26,016
Increase/(Decrease) from Base ($m)	n/a	$239	($630)
Nominal Levelized Increase/(Decrease) from Base ($/kW-mo)	n/a	$26	($31)
Nominal Levelized Increase/(Decrease) from Base ($/MWh)	n/a	$74	($74)

In the low DG sensitivity case, the timing of the first deferrable thermal resource was unchanged relative to the benchmark case. By the end of the study period, total new thermal resource capacity was increased by 212 MW. In the high DG sensitivity case, the timing of the first deferral thermal resource is delayed by three years, and the total thermal capacity added by the end of the planning horizon is decreased by 423 MW.

Energy Gateway Sensitivity (S-07 and S-08)

Incremental to the base case, Energy Gateway sensitivity case S-07 includes Segment D, with an assumed 2022 in-service year. Energy Gateway sensitivity case S-08 includes Segments D, E, and F, with assumed in-service years of 2022, 2024, and 2023, respectively. Both Energy Gateway sensitivity cases are benchmarked to core case C07-1, which has a resource portfolio with higher penetration of renewable resources. Figure 8.29 shows cumulative new renewable resources in the benchmark portfolio and in each Energy Gateway sensitivity portfolio. Incremental Energy Gateway transmission provides access to high capacity factor, low cost wind resources in Wyoming, and with the addition of Segment F, access to Wyoming wind is higher in sensitivity case S-08 than in sensitivity case S-07. The C07-1 benchmark case includes 25 MW of Wyoming wind. Sensitivity cases S-07 and S-08 include 525 MW and 959 MW of Wyoming wind, respectively.

Figure 8.29 – Cumulative New Renewable Resource Capacity in Energy Gateway Sensitivity Cases

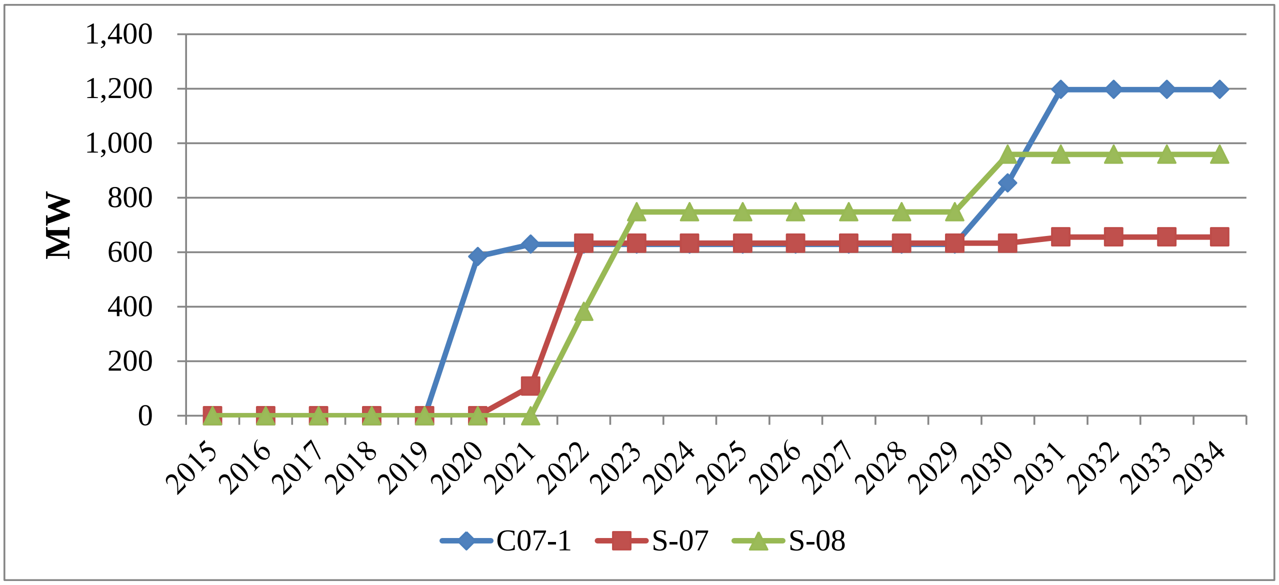


Table 8.11 summarizes PVRR impacts of both sensitivities from System Optimizer. Increased access to low cost Wyoming wind resources reduces the cost of meeting PacifiCorp's share of state 111(d) emission rate targets under a compliance strategy that prioritizes increased energy efficiency and adding incremental renewable resources. This reduces system costs; however, this benefit is not enough to fully offset the assumed incremental cost of the Energy Gateway segments modeled in sensitivity cases S-07 and S-08.

Table 8.11 – Increase/(Decrease) of Energy Gateway Sensitivity System Optimizer PVRR Relative to the Benchmark

	S-07	S-08
PVRR without Incremental Energy Gateway Transmission Costs ($m)	($234)	($583)
PVRR of Incremental Energy Gateway Transmission Costs ($m)	$945	$2,044
Total PVRR ($m)	$711	$1,461

Table 8.12 summarizes the stochastic mean PVRR costs impacts of both sensitivities from PaR for the low, base, and high price curve scenarios. Relative to System Optimizer, under stochastic conditions, PaR results show increased benefits of Energy Gateway Segments that are relatively stable across price curve scenarios. However, these benefits do not fully offset assumed incremental Energy Gateway costs.

Table 8.12 – Increase/(Decrease) of Energy Gateway Sensitivity PaR Stochastic Mean PVRR Relative to the Benchmark

	Sensitivity Case S-07		
	Low Price Curve Scenario	Base Price Curve Scenario	High Price Curve Scenario
PVRR without Incremental Energy Gateway Transmission Costs ($m)	($247)	($264)	($265)
PVRR of Incremental Energy Gateway Transmission Costs ($m)	$945	$945	$945
Total PVRR ($m)	$698	$681	$680
	Sensitivity Case S-08		
	Low Price Curve Scenario	Base Price Curve Scenario	High Price Curve Scenario
PVRR without Incremental Energy Gateway Transmission Costs ($m)	($560)	($624)	($665)
PVRR of Incremental Energy Gateway Transmission Costs ($m)	$2,044	$2,044	$2,044
Total PVRR ($m)	$1,484	$1,421	$1,379

The Energy Gateway project originated under different conditions than exist today. The type, timing, and location of future resource needs will drive future analysis of Energy Gateway projects. Based upon the PaR results, benefits are approximately 30% of levelized Energy Gateway costs on a PVRR basis through the 2034 planning horizon. Finding one or more partners to share in Energy Gateway project costs may provide opportunities to size PacifiCorp customer costs with benefits and provide regional benefits. PacifiCorp plans to continue its

Energy Gateway permitting efforts as outlined in the 2015 IRP action plan, presented in Chapter 9.

Production Tax Credit Extension Sensitivity (S-09)

Sensitivity case S-09 assumed the production tax credit (PTC) is available through the planning horizon. This sensitivity case is benchmarked to core case C05-1. Figure 8.30 shows cumulative new renewable resources in the benchmark portfolio and in the S-09 sensitivity portfolio. With the PTC extension, 449 MW of economic Wyoming wind is selected in sensitivity case S-09 (106 MW in 2020, 326 MW in 2028, and 17 MW in 2030). Following the addition of this system wind, an additional 143 MW of Utah wind is added in 2022 to meet Oregon's RPS requirements through 2034.

Figure 8.30 – Cumulative New Renewable Resource Capacity in the PTC Sensitivity Case

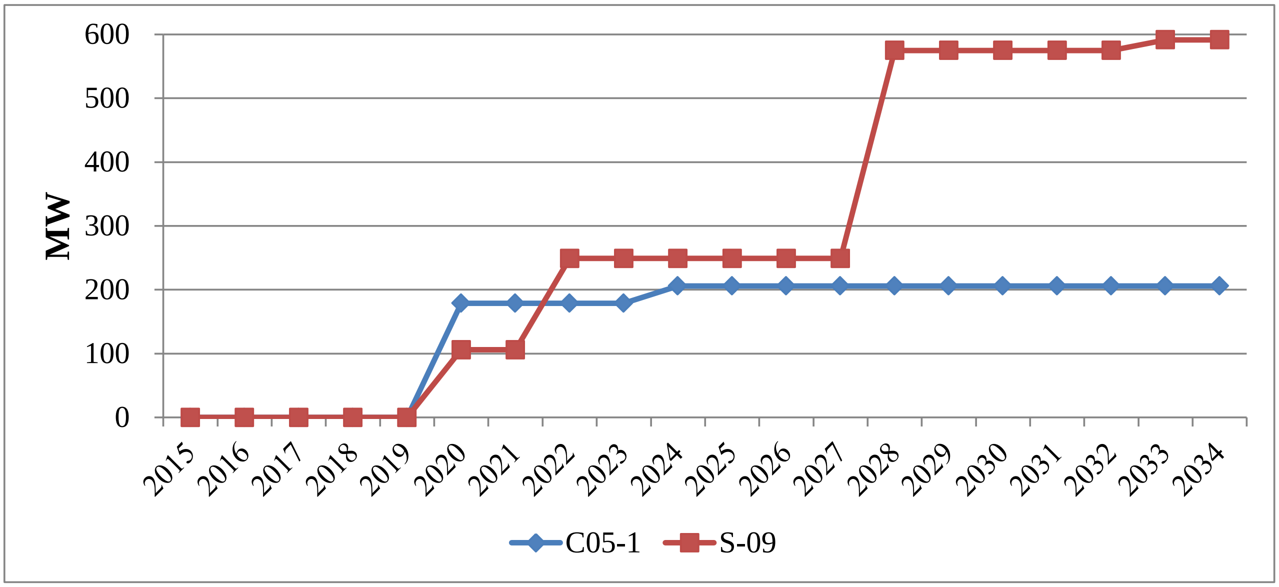


Table 8.13 shows system cost impacts of sensitivity case S-09 relative to the C05-1 benchmark case. Results are shown for base price curve assumptions using System Optimizer and three price curve scenarios applied in PaR. System Optimizer results reflect incremental 111(d) compliance benefits from the additional renewable resources, added at lower cost with assumed PTC benefits that are included in the S-09 portfolio. PaR results reflect portfolio cost and stochastic risk impacts of S-09, but do not reflect 111(d) re-dispatch benefits. With medium to high price curve assumptions, S-09 shows stochastic risk benefits. The PaR stochastic mean results under low price curve assumptions are marginally higher cost than the benchmark case.

Table 8.13 – System Optimizer and PaR PVRR Costs Results for the PTC Sensitivity

	System Optimizer	PaR Stochastic Mean		
	Base Price Curve	Low Price Curve	Base Price Curve	High Price Curve
Increase/(Decrease) in PVRR from Benchmark ($m)	($203)	$9	($29)	($53)

East and West Balancing Authority Area Sensitivity (S-10)

Sensitivity case S-10 produces standalone resource portfolios for the east (summer peaking) and west (winter peaking) balancing authority areas (BAAs). This sensitivity is benchmarked to a variant of case C05a-3, which is developed under Regional Haze scenario 3 and assumes an unbundled REC strategy for state RPS programs, consistent with the preferred portfolio. System Optimizer simulations for sensitivity case S-10 was performed both with and without state 111(d) emission rate targets. PaR results incorporate resource portfolio impacts of 111(d), but do not account for re-dispatch costs under 111(d). Table 8.14 shows system cost impacts of sensitivity case S-10, reflecting the sum of system costs from both east and west standalone portfolios, relative to the benchmark case. Results are shown for base price curve assumptions using System Optimizer (with and without 111(d)) and three price curve scenarios applied in PaR (reflecting portfolio impacts of 111(d)). Results show that standalone east and west resource portfolios, when combined, are higher cost than a single system resource portfolio. Results also show that the incremental cost of two standalone resource portfolios increases under 111(d).

Table 8.14 – System Optimizer and PaR PVRR Results for the East and West Balancing Authority Area Sensitivity

Increase/(Decrease) in PVRR from Benchmark ($m)	System Optimizer	PaR Stochastic Mean		
	Base Price Curve	Low Price Curve	Base Price Curve	High Price Curve
Without 111(d) Emission Rate Targets	$1,149	n/a		
With 111(d) Emission Rate Targets	$1,326	$2,031	$2,109	$2,158

Figure 8.31 summarizes the cumulative change in resource portfolio capacity when two standalone east and west portfolios are combined relative to a single system resource portfolio without imputation of 111(d) state emission rate targets. Positive values show cumulative resource additions relative to the system portfolio benchmark, and negative values show the cumulative reduction in capacity relative to the system portfolio benchmark. In the standalone east and west portfolios, each individual BAA cannot rely on resource selections in the other BAA to meet the target planning reserve margin. January FOTs are needed in the west to meet its winter peak, and a natural gas peaking unit is added in 2023, five years earlier than the first deferrable thermal resource in the benchmark system portfolio. Without access to summer west side markets, incremental DSM resources are needed in the east.[79]

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[79] For the east standalone portfolio, FOT limits for the Mona market had to be increased from 300 MW to 711 MW, 459 MW, and 359 MW in 2015, 2016, and 2017, respectively, for the east to meet a 13% target planning reserve margin.

Figure 8.31 – Cumulative Increase/(Decrease) in Portfolio Capacity for the East and West Balancing Authority Area Sensitivity without 111(d)

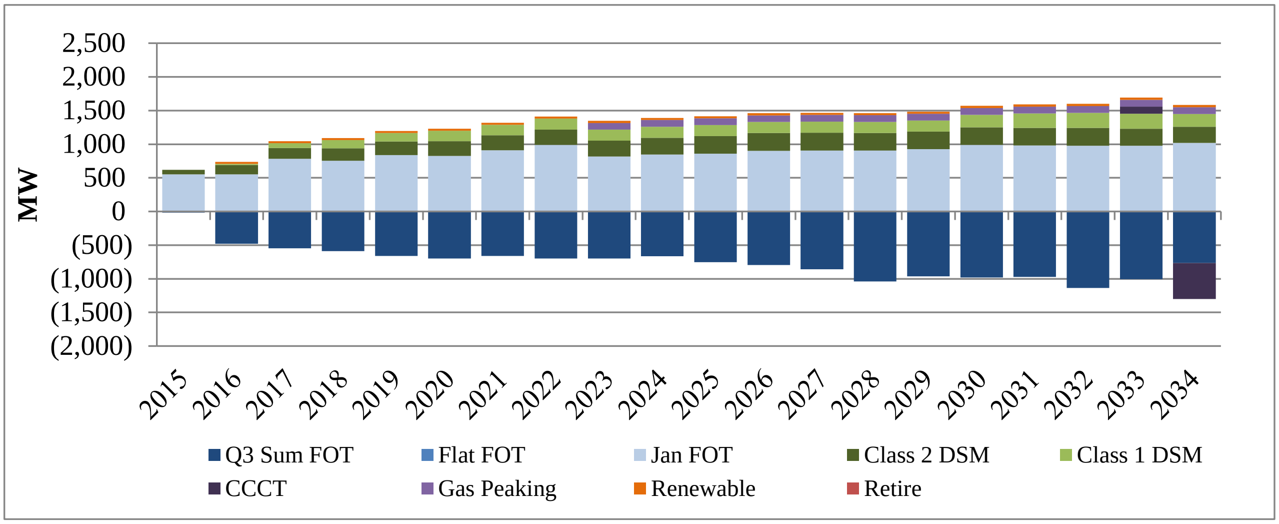
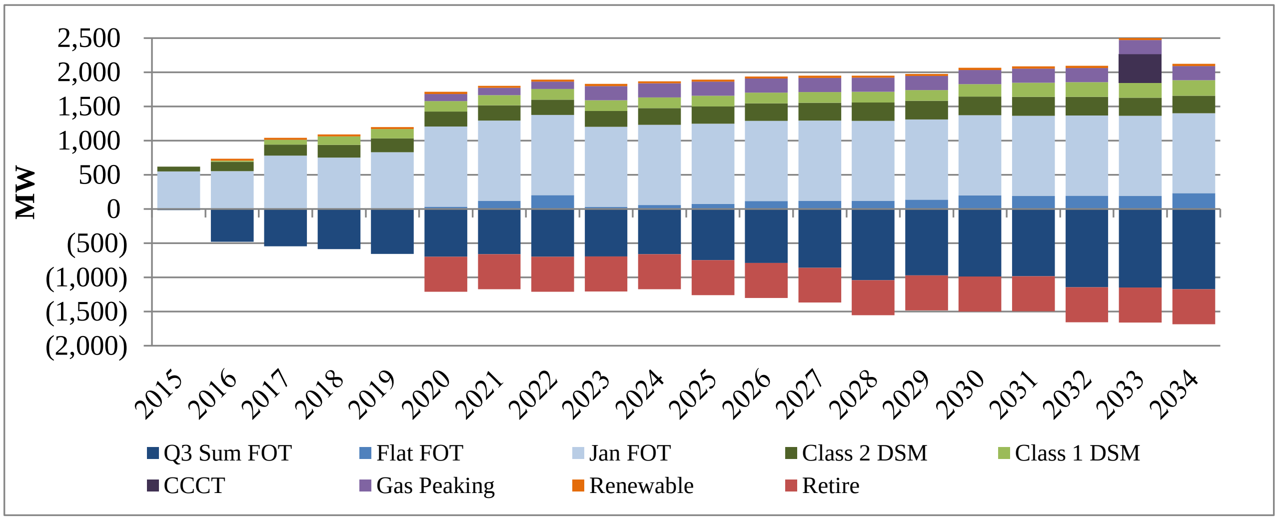


Figure 8.32 summarizes the cumulative change in resource portfolio capacity when two standalone east and west portfolios are combined relative to a single system resource portfolio with imputation of 111(d) state emission rate targets. Positive values show cumulative resource additions relative to the system portfolio benchmark, and negative values show the cumulative reduction in capacity relative to the system portfolio benchmark. With 111(d) state emission rate targets, the standalone west BAA cannot rely on flexible allocation of system 111(d) attributes from renewable resources in the east. To minimize 111(d) compliance costs, Chehalis is retired at the end of 2019, eliminating PacifiCorp's 111(d) compliance requirements in Washington. This accelerates the timing of the west side natural gas peaking resource to 2020, eight years before the first deferrable thermal resource is added in the benchmark case.

Figure 8.32 – Cumulative Increase/(Decrease) in Portfolio Capacity for the East and West Balancing Authority Area Sensitivity with 111(d)



High CO_2 Price Sensitivity (S-11)

Sensitivity case S-11 produces a resource portfolio with high CO_2 price assumptions. The S-11 sensitivity case is benchmarked to case C14-1. Figure 8.33 shows the change in annual costs from a base price curve System Optimizer simulation for sensitivity case S-11 relative to the benchmark case C14-1. On an annual basis, costs increase beginning 2021 when the higher CO_2 price assumption is applied. By 2034, the cumulative PVRR cost of sensitivity case S-11 is $5.6 billion higher than the benchmark case.

Figure 8.33 – Increase/(Decrease) in System Optimizer Costs for the High CO_2 Price Sensitivity Relative to the Benchmark

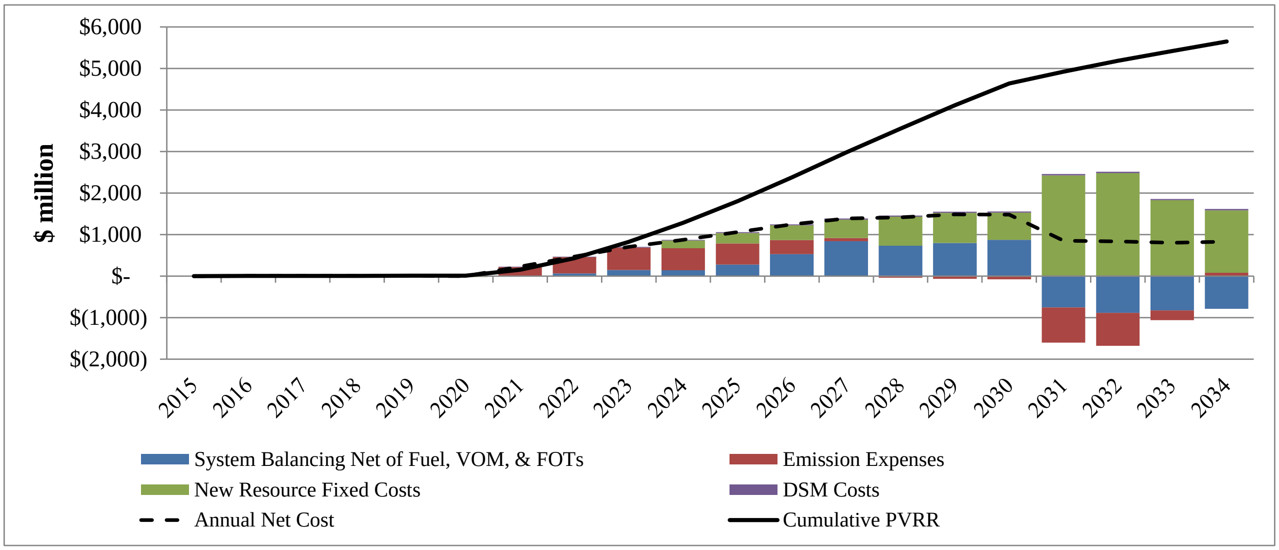


Table 8.15 summarizes system cost impacts of sensitivity case S-11 based on simulations from both System Optimizer and PaR. The PaR results, which do not reflect 111(d) fossil re-dispatch costs or CO_2 costs, show lower cost impacts than reported from System Optimizer. PaR results show the cost impact of sensitivity case S-11 is reduced with higher price curve assumptions, reflecting the gross margin benefits of a portfolio with significant nuclear and renewable resources.

Table 8.15 – System Optimizer and PaR PVRR Results for the High CO_2 Price Sensitivity

	System Optimizer	PaR Stochastic Mean		
	Base Price Curve	Low Price Curve	Base Price Curve	High Price Curve
Increase/(Decrease) in PVRR from Benchmark ($m)	$5,650	$3,027	$2,640	$2,310

Stakeholder Solar Cost Sensitivity (S-12)

Sensitivity case S-12 produces a resource portfolio using alternative solar resource costs, recommended by members of PacifiCorp's IRP stakeholder group, and high DG penetration levels. The S-12 sensitivity case is benchmarked to case C05-1 and to sensitivity case S-05 (the high DG sensitivity discussed above).

The portfolio from sensitivity case S-12 adds 759 MW (154 MW in the east and 605 MW in the west) of cost-effective utility-scale system solar resources in 2034, consuming available transmission capacity in the east. Without transmission, this displaces 154 MW of Oregon RPS solar that is included in case C05-1 and sensitivity case S-05 starting 2020. Consequently, maintaining the same Oregon RPS compliance strategy as the benchmark case, Oregon RPS renewables needed in sensitivity case S-12 (259 MW of west side wind in 2023) are higher cost. Moreover, with the high DG penetration assumption applied to sensitivity case S-12, over 1,000 MW of new combined cycle capacity is eliminated from the portfolio by 2034.

Table 8.16 summarizes system cost impacts of sensitivity case S-12 relative to case C05-1 and sensitivity case S-05 based on simulations from both System Optimizer and PaR. When compared to case C05-1, costs are reduced in both System Optimizer and PaR, largely due to the higher DG penetration level assumptions applied in S-11. When compared to S-05, which includes high DG penetration assumptions, the cost from sensitivity case S-11 are higher in both System Optimizer and PaR, reflecting the increased cost associated with meeting Oregon RPS requirements.

Table 8.16 – System Optimizer and PaR PVRR Results for the Solar Cost Sensitivity

	System Optimizer	PaR Stochastic Mean		
	Base Price Curve	Low Price Curve	Base Price Curve	High Price Curve
Increase/(Decrease) in PVRR from C05-1 ($m)	($617)	($558)	($691)	($803)
Increase/(Decrease) in PVRR from S-05 ($m)	$14	$34	$15	$3

Energy Storage Sensitivities (S-06 and S-13)

Sensitivity case S-06 forces a west side 400 MW pumped storage plant in 2024, coincident with the timing of the first combined cycle plant in the C05-1 benchmark case.[80] Sensitivity case S-13 forces a 300 MW compressed air energy storage (CAES) plant in 2024, sited in PacifiCorp's east BAA.[81] Sensitivity cases S-06 and S-13 are also benchmarked to case C05-1. Table 8.17 summarizes PVRR impacts of both sensitivities from System Optimizer, where storage resources provide firm capacity applied toward meeting a 13% target planning reserve margin. System Optimizer does not explicitly capture operating reserve benefits of storage projects. Both storage plants provide system benefits relative to the benchmark case; however, these benefits do not fully offset the assumed incremental fixed costs of the pumped storage and CAES plants modeled in sensitivity cases S-06 and S-13.

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[80] The pumped storage plant has an assumed nominal capital cost of $3,455/kW, assumed first year nominal fixed operations & maintenance costs of $23.37/kW-yr, and nominal first year variable operations & maintenance costs of $4.21/MWh.

[81] The CAES plant has an assumed nominal capital cost of $3,270/kW, assumed first year nominal fixed operations & maintenance costs of $22.67/kW-yr, and nominal first year variable operations & maintenance costs of $2.75/MWh.

Table 8.17 – Increase/(Decrease) of Energy Storage Sensitivity System Optimizer PVRR Relative to the Benchmark

	S-06 (Pumped Storage)	S-13 (CAES)
PVRR without Storage Resource Fixed Costs ($m)	($63)	($53)
PVRR of Storage Resource Fixed Costs ($m)	$511	$453
Total PVRR ($m)	$448	$400

Table 8.18 summarizes the stochastic mean PVRR costs impacts of both energy storage sensitivities from PaR for the low, base, and high price curve scenarios. Relative to System Optimizer, PaR captures incremental operating reserve benefits of storage projects. Other grid benefits, such as frequency regulation are not captured in System Optimizer or PaR. With these additional operating reserve and stochastic benefits, PaR results show more system benefits of the two storage projects when compared to System Optimizer results. However, these benefits do not fully offset assumed incremental fixed costs of the pumped storage and CAES plants.

Table 8.18 – Increase/(Decrease) of Energy Storage Sensitivity PaR Stochastic Mean PVRR Relative to the Benchmark

	Sensitivity Case S-06 (Pumped Storage)		
	Low Price Curve Scenario	Base Price Curve Scenario	High Price Curve Scenario
PVRR without Storage Resource Fixed Costs ($m)	($76)	($74)	($72)
PVRR of Storage Resource Fixed Costs ($m)	$511	$511	$511
Total PVRR ($m)	$435	$437	$439
	Sensitivity Case S-08 (CAES)		
	Low Price Curve Scenario	**Base Price Curve Scenario**	**High Price Curve Scenario**
PVRR without Storage Resource Fixed Costs ($m)	($87)	($80)	($76)
PVRR of Storage Resource Fixed Costs ($m)	$453	$453	$453
Total PVRR ($m)	$366	$373	$378

Class 3 DSM (S-14)

Sensitivity case S-14 produces a portfolio using non-firm price responsive Class 3 DSM supply curves. The S-14 sensitivity case is benchmarked to case C05-1. Table 8.19 summarizes system cost impacts of sensitivity case S-14 relative to case C05-1. The portfolio from sensitivity case S-14 includes approximately 47 MW of Class 3 DSM by 2022, increasing to 213 MW by 2034. These Class 3 DSM resources, supplemented with additional Class 2 DSM resources, displace 5 MW of Class 1 DSM resources in 2022 and 33 MW by 2034. The incremental Class 3 and Class 2 DSM resources also displace FOTs from 2022 through 2027 and from 2030 through 2031 and defer or displace combined cycle resources beginning 2028. While PVRR costs are reduced relative to the benchmark case, the Class 3 DSM supply curves assume installation of advanced metering infrastructure (AMI) by the end of 2019, costs of which are not included in the levelized costs of these Class 3 DSM products.

Table 8.19 – System Optimizer and PaR PVRR Results for the Class 3 DSM Sensitivity

	System Optimizer	PaR Stochastic Mean		
	Base Price Curve	Low Price Curve	Base Price Curve	High Price Curve
Increase/(Decrease) in PVRR from C05-1 ($m)	($44)	($48)	($57)	($63)

Restricted 111(d) Attribute Sensitivity (S-15)

Sensitivity case S-15 produces a portfolio assuming state RPS-eligible RECs and 111(d) attributes must be surrendered at the same time. Sensitivity case S-15 is benchmarked to case C05-1. Linking the Washington RPS program to 111(d) would force PacifiCorp to meet its share of the state 111(d) emission rate target with situs assigned renewable resources, or alternatively, PacifiCorp could eliminate its Washington 111(d) compliance obligation by retiring Chehalis at the end of 2019. Considering the low emission rate targets proposed by EPA in its 111(d) rule for Washington, a significant amount of situs assigned renewables would be required to offset emissions from Chehalis. For this sensitivity, PacifiCorp assumes a lower cost alternative would be to retire Chehalis at the end of 2019. With this early retirement, sensitivity case S-15 includes incremental FOTs and DSM resources, along with a 2020 west side natural gas peaking resource. Table 8.20 summarizes system cost impacts of sensitivity case S-15 relative to case C05-1.

Table 8.20 – System Optimizer and PaR PVRR Results for the Restricted 111(d) Attribute Sensitivity

	System Optimizer	PaR Stochastic Mean		
	Base Price Curve	Low Price Curve	Base Price Curve	High Price Curve
Increase/(Decrease) in PVRR from C05-1 ($m)	$411	$434	$406	$360

Additional Analysis

Trigger Point Analysis

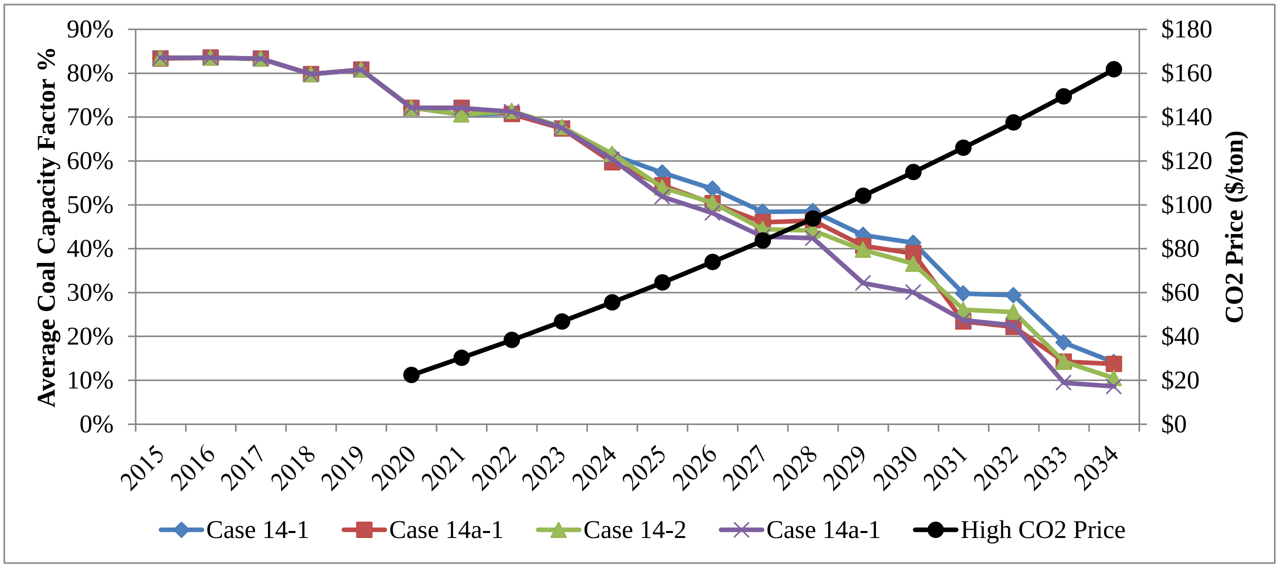
Oregon Public Utility Commission (OPUC) IRP guideline 8(c) requires the utility to identify at least one portfolio of resources that is substantially different from the preferred portfolio that can be compared on a risk and cost basis among a range of CO_2 compliance scenarios. Included in PacifiCorp's 2015 IRP core cases, there are four portfolios developed with CO_2 price assumptions incremental to emission rate targets in EPA's proposed 111(d) (cases C14-1, C14-2, C14a-1, and C14a-2). Each of these portfolios is substantially different from the preferred portfolio. Table 8.21 compares the stochastic mean and risk-adjusted PVRR of these portfolios relative to the preferred portfolio among different price curve assumptions, including a scenario assuming high CO_2 prices. The four C-14 cases are lower cost than the preferred portfolio when high CO_2 prices are assumed.

Table 8.21 – Comparison of Trigger Point Portfolios to the Preferred Portfolio

	Base Price Curve		Low Price Curve		High Price Curve		High CO_2 Price Curve	
Case	Increase in Stochastic Mean PVRR Relative to the Preferred Portfolio ($b)	Increase in Risk-adjusted PVRR Relative to the Preferred Portfolio ($b)	Increase in Stochastic Mean PVRR Relative to the Preferred Portfolio ($b)	Increase in Risk-adjusted PVRR Relative to the Preferred Portfolio ($b)	Increase in Stochastic Mean PVRR Relative to the Preferred Portfolio ($b)	Increase in Risk-adjusted PVRR Relative to the Preferred Portfolio ($b)	Decrease in Stochastic Mean PVRR Relative to the Preferred Portfolio ($b)	Decrease in Risk-adjusted PVRR Relative to the Preferred Portfolio ($b)
C14-1	1.40	1.48	1.54	1.62	1.38	1.45	(1.12)	(1.17)
C14-2	2.34	2.47	2.14	2.25	2.60	2.73	(1.52)	(1.59)
C14a-1	2.17	2.29	1.92	2.03	2.52	2.65	(1.87)	(1.96)
C14a-2	2.33	2.45	1.73	1.83	2.94	3.09	(2.08)	(2.19)

Figure 8.34 shows fleet average coal capacity factors from the C14 cases taken from PaR under the high CO_2 price assumptions (primary vertical axis) and the assumed nominal annual CO_2 prices (secondary vertical axis). As CO_2 prices rise, fleet average coal capacity factors drop. The introduction of a CO_2 price in 2020 causes a decline in coal generation. As the CO_2 price rises over the 2020 to 2023 timeframe, coal generation levels remain relatively stable. As assumed CO_2 prices begin to approach $60/ton in the 2024 timeframe, coal generation begins to fall again, with continued declines as CO_2 prices are assumed to rise. A step change reduction in coal capacity factors occurs in the 2029 to 2031 timeframe when CO_2 price assumptions exceed $100/ton.

Figure 8.34 – Stochastic Mean Coal Capacity Factors from C14 Portfolios and High CO_2 Price Assumptions



Greenhouse Gas Goals

Washington

In its order in Docket UE-120416 the Washington Utilities and Transportation Commission (WUTC) found PacifiCorp met all statutory requirements for the 2013 IRP. The WUTC also stated that:

> "The Company's 2015 IRP should also examine ways in which PacifiCorp can contribute to Washington's goal of reducing carbon emissions to 1990 levels by 2020 and evaluate the rate impacts of any such measure."

For PacifiCorp's system, the 1990 emission level was approximately 46 million tons. Table 8.22 shows portfolios with 2020 emissions falling below 1990 levels along with the cost of these portfolios relative to the preferred portfolio. Detailed portfolios for these cases are included in Volume II, Appendix K.

Table 8.22 – Cost/Risk Comparison of Portfolios that Meet Washington's Goal of Reducing Carbon Emissions to 1990 Levels by 2020

	Portfolio Cost and Emissions			Increase/(Decrease) from the Preferred Portfolio		
Case	**Stochastic Mean PVRR ($ millions)**	**Risk Adjusted PVRR on Scenario ($ millions)**	**CO_2 Emissions in 2020 (million tons)**	**Stochastic Mean PVRR ($ millions)**	**Risk Adjusted PVRR on Scenario ($ millions)**	**CO_2 Emissions in 2020 (million tons)**
C05a-3Q	$27,500	$28,890	49.7	$0	$0	0.0
C02-1	$28,350	$29,790	44.5	$850	$900	(5.1)
C02-2	$29,088	$30,564	44.5	$1,588	$1,674	(5.2)
C03-1	$29,521	$31,019	44.5	$2,021	$2,129	(5.2)
C03-2	$30,282	$31,820	44.5	$2,782	$2,930	(5.2)
C12-1	$27,801	$29,215	42.5	$301	$325	(7.2)
C12-2	$28,557	$30,013	42.5	$1,057	$1,123	(7.2)
C13-1	$27,649	$29,053	39.1	$149	$163	(10.6)
C13-2	$28,422	$29,865	39.1	$922	$975	(10.6)

Oregon

OPUC IRP guideline 8(d) requires that a portfolio be constructed that meets Oregon energy policies, including state goals for reducing greenhouse emissions. Several of the portfolios developed in this IRP fall below the Oregon goal stated in House Bill 3543 (10 percent below 1990 emission levels by 2020). For PacifiCorp's system, the 1990 emission level was approximately 46 million tons. Ten percent below this level equates to approximately 41.4 million tons. Table 8.23 compares preferred portfolio costs, both on a stochastic mean and risk-adjusted PVRR basis, with portfolios that meets the Oregon goal in House Bill 3543. Detailed portfolios for these cases are included in Volume II, Appendix K.

Table 8.23 – Cost/Risk Comparison of Portfolios that Meet Oregon House Bill 3543 Emission Goals with the Preferred Portfolio

	Portfolio Cost and Emissions			**Increase/(Decrease) from the Preferred Portfolio**		
Case	**Stochastic Mean PVRR ($ millions)**	**Risk Adjusted PVRR on Scenario ($ millions)**	**CO_2 Emissions in 2020 (million tons)**	**Stochastic Mean PVRR ($ millions)**	**Risk Adjusted PVRR on Scenario ($ millions)**	**CO_2 Emissions in 2020 (million tons)**
C05a-3Q	$27,500	$28,890	49.7	$0	$0	0.0
C13-1	$27,649	$29,053	39.1	$149	$163	(10.6)
C13-2	$28,422	$29,865	39.1	$922	$975	(10.6)

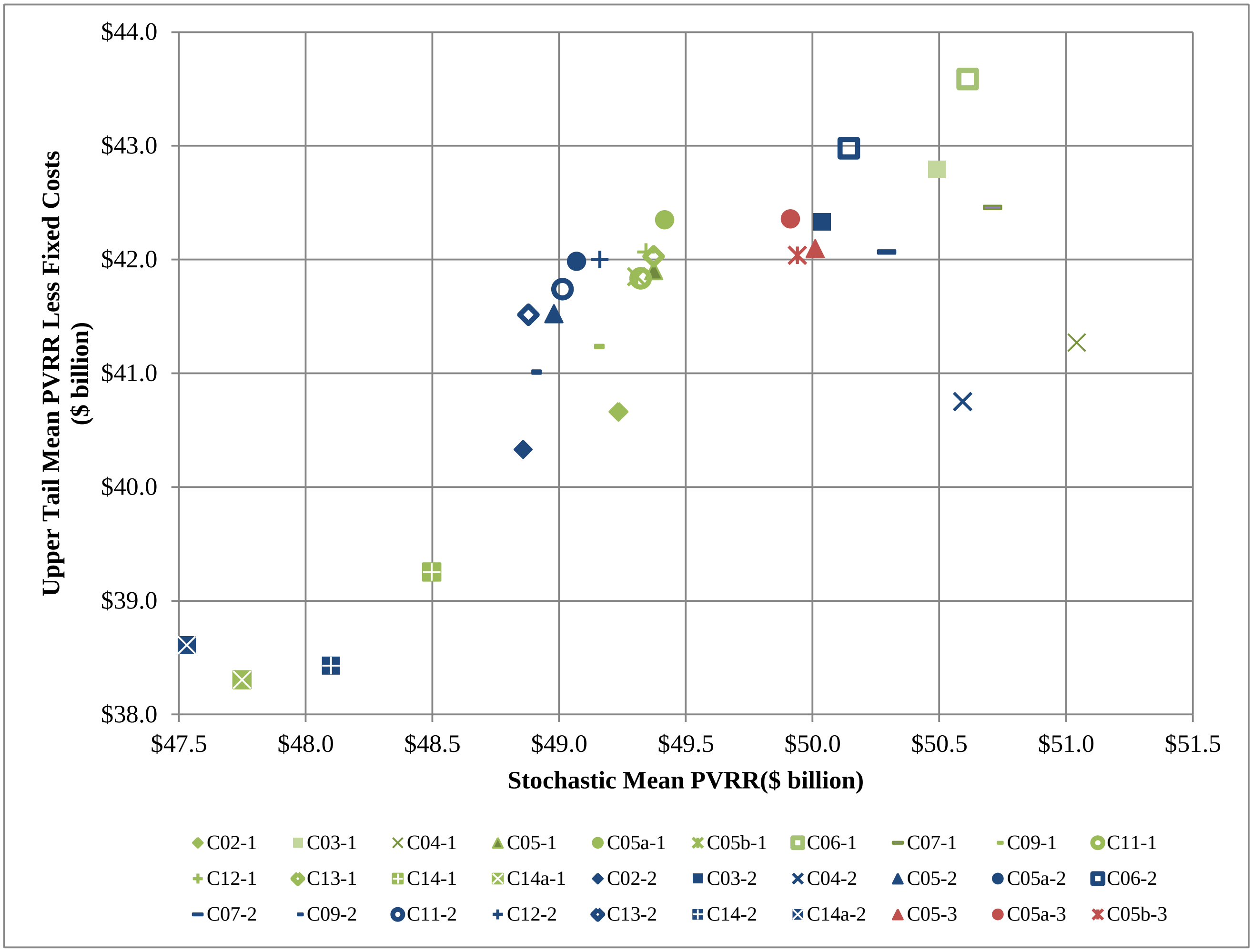
High CO_2 Price Scenario PaR Results

In its cost and risk analysis, PacifiCorp completed PaR simulations under low, base, and high price curve scenarios. Results from these PaR simulations informed selection of the 2015 IRP preferred portfolio. PacifiCorp also completed PaR simulations assuming high CO_2 price curve assumptions, which inform the 2015 IRP acquisition path analysis summarized in Chapter 9. To this end, assumptions used in the high CO_2 price scenario help identify how PacifiCorp's resource portfolio might be impacted if future CO_2 policies are expanded beyond what might be required under the current policy environment (i.e., EPA's proposed 111(d) rule).

Figure 8.35 presents the scatter plot, formatted consistent with the scatter plots used in the pre-screening and initial screening steps of the preferred portfolio selection process, for core cases simulated under the high CO_2 price scenario in PaR. As expected, resource portfolios developed with CO_2 price assumptions incremental to 111(d) requirements (core cases C14 and C14a) are lower cost and lower risk relative to portfolios that were developed with 111(d) considerations but without incremental CO_2 price assumptions. When allowing endogenous coal unit retirements beyond those assumed for Regional Haze scenarios (core case C14a), costs are lower than the C14 portfolios developed with specific timing for assumed coal unit retirements.

The stochastic mean PVRR differential between case C05a-3 (pre-cursor to the 2015 IRP preferred portfolio) and case C14a-2 is $2.26 billion favorable to C05a-3 under base price curve assumptions without an assumed CO_2 price, while the stochastic mean PVRR differential between case C05a-3 and C14a-2 is $2.38 billion favorable to C14a-2 under the high CO_2 price scenario. These PVRR differentials do not account for the reality that resource plans change with changes in the planning environment (i.e., with the introduction policies resulting in a high CO_2 price).

Figure 8.35 – High CO2 Price Scenario Core Case Portfolio Scatter Plot



CHAPTER 9 – ACTION PLAN AND RESOURCE PROCUREMENT

CHAPTER HIGHLIGHTS

- The 2015 IRP action plan identifies steps to be taken during the next two to four years to deliver resources in the preferred portfolio.
- PacifiCorp's 2015 IRP action plan includes action items for renewable resources, short-term firm market purchases of front office transactions (FOTs), demand side management resources, coal resources, and transmission.
- The 2015 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 2015 IRP preferred portfolio and the 2013 IRP Update and fall ten-year plan business plan portfolios are primarily driven by changes in load forecasts and model assumptions. The 2015 IRP preferred portfolio will serve as the starting point for resource assumptions in the fall 2015 ten-year business plan.
- PacifiCorp further discusses how it can mitigate procurement delay risk, summarizes planned procurement activities tied to the action plan, assesses trade-offs between owning and 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 2015 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 2015 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 2015 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 2015 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 the 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 2015 IRP action plan, reporting on progress in delivering the prior action plan, and presenting the 2015 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 2015 IRP Action Plan

The 2015 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 2015 IRP process. Table 9. details specific 2015 IRP action items by category.

Table 9.1 – 2015 IRP Action Plan

Action Item	**6. Renewable Resource Actions**
1a	**Renewable Portfolio Standard Compliance** • 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.
1b	**Renewable Energy Credit Optimization** • 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.
1c	**Oregon Solar Capacity Standard** • Conclude negotiations with shortlisted bids from the 2013S Request for Proposals (RFP), seeking up to 7 MW_{AC} of competitively priced capacity from qualifying solar systems that will be used to satisfy PacifiCorp's obligation under Oregon's 2020 solar capacity standard.
Action Item	**7. Firm Market Purchase Actions**
2a	**Front Office Transactions** • 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:

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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>
<tr><th>Action Item</th><th>8. Demand Side Management (DSM) Actions</th></tr>
<tr><td>3a</td><td>
<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.

</td></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></tr>
<tr><th>Action Item</th><th>9. Coal Resource Actions</th></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.

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<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 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.

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	- 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.
4c	**Wyodak** - 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.
4d	**Cholla Unit 4** - 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.
Action Item	**10. Transmission Actions**
5a	**Energy Gateway Permitting** - Continue permitting for the Energy Gateway transmission plan, with near term targets as follows: – 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.
5b	**Wallula to McNary 230 kilovolt Transmission Line** - 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.

Progress on Previous Action Plan Items

This section describes progress that has been made on previous active action plan items documented in the 2013 Integrated Resource Plan and 2013 Integrated Resource Plan Update reports filed with the state commissions on April 30, 2013 and March 31, 2014, 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 – 2013 IRP Action Plan Status Update

Action Item	Activity	Status
1a. Renewable Resource Actions -Wind Integration	Update the wind integration study for the 2015 IRP. The updated wind integration study will consider the implications of an energy imbalance market along with comments and feedback from the technical review committee and IRP stakeholders provided during the 2012 Wind Integration Study.	The 2014 Wind Integration Study (WIS) estimates the regulation reserve requirements from historical load and wind generation production data. The updated WIS, provided in Volume II, Appendix H, also estimates the incremental cost associated with integrating wind resources specific to PacifiCorp's system. Study results incorporate estimated impacts of the energy imbalance market. The 2014 WIS was developed with participation of a technical review committee (TRC). The 2014 WIS addresses recommendations the TRC included in its review of the 2012 WIS.
1b. Renewable Resource Actions - Renewable Portfolio Standard Compliance	With renewable portfolio standard (RPS) compliance achieved with unbundled renewable energy credit (REC) purchases, the preferred portfolio does not include incremental renewable resources prior to 2024. Given that the REC market lacks liquidity and depth beyond one year forward, the Company will pursue unbundled REC requests for proposal (RFP) to meet its state RPS compliance requirements. 1. Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in	1. PacifiCorp issued a REC RFP on August 14, 2013 for RECs that qualify for the Washington RPS. While there were a number of offers received, none were compelling from a price/structure perspective. Furthermore, when issued, PacifiCorp did not see a need for RECs until 2016. PacifiCorp issued a REC RFP on October 22, 2014 for Washington RPS-eligible RECs. Bids were due November 6, 2014; five offers were selected that matched needs and specific pricing criteria. 2. PacifiCorp issued a REC RFP on December 31, 2012 with bids due January 15, 2013 for unbundled RECs that will qualify for the Oregon RPS. A numbers of offers were selected that met matched needs and specific pricing criteria.

Action Item	Activity	Status
	meeting Washington renewable portfolio standard obligations. 2. Issue at least annually, RFPs seeking historical, then current-year, or forward-year vintage unbundled RECs that will qualify for Oregon renewable portfolio standard obligations. As part of the solicitation and bid evaluation process, evaluate the tradeoffs between acquiring bankable RECs early as a means to mitigate potentially higher cost long-term compliance alternatives. 3. Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify for California renewable portfolio standard obligations.	3. PacifiCorp issued a REC RFP on March, 14, 2014 for California-eligible RECs. Bids were due March 28, 2014; no bids were selected. PacifiCorp plans to issue a new REC RFP prior to year end 2015.
1c. Renewable Resource Actions - Renewable Energy Credit Optimization	On a quarterly basis, issue reverse RFPs to sell RECs not required to meet state RPS compliance obligations.	PacifiCorp issued a total of five reverse RFPs to sell RECs in calendar year 2013. For 2014, PacifiCorp issued three reverse REC RFPs, with the most recent issued December 2, 2014. A total of nine transactions were completed.
1d. Renewable Resource Actions – Solar	1. Issue an RFP in the second quarter of 2013 soliciting Oregon solar photovoltaic resources to meet the Oregon small solar compliance obligation (Oregon House Bill 3039). Coordinate the selection process with the Energy Trust of Oregon to seek 2014 project funding. Complete evaluation of proposals and select potential winning bids in the fourth quarter of 2013. 2. Issue a request for information 180 days	1. PacifiCorp issued a solar RFP on April 30, 2013. A power purchase agreement (PPA) with Stone House Solar LLC (5 MW_{AC}) was executed in November 2013; however the project was unable to meet credit requirements. The PPA was subsequently terminated on March 3, 2014. Based on final project ranking from RFP bids, PacifiCorp initiated negotiation with Obsidian Renewables LLC for its 5 MW_{AC} Old Mill Solar LLC project. PacifiCorp anticipates finalizing the Old Mill Solar PPA in the first half of 2015. PacifiCorp continues to negotiate a second PPA with Bevans Point Solar LLC

Action Item	Activity	Status
	after filing the 2013 IRP to solicit updated market information on utility scale solar costs and capacity factors.	(2 MW_{AC}). The two PPAs would satisfy PacifiCorp's remaining solar capacity requirement. The selection process was coordinated with the Energy Trust of Oregon (ETO), and the project(s) benefit from ETO funding. 2. PacifiCorp hired Black & Veatch in October 2013 to provide a report with updated market information on current EPC costs for both 5 MW_{AC} and 50 MW_{AC} single axis tracking and fixed tilt solar photovoltaic systems at selected locations. The study included Lakeview, OR and three Utah locations, Salt Lake City, Milford, and Veyo. Capital and O&M costs, as well as performance parameters were updated.
1e. Renewable Resource Actions - Capacity Contribution	Track and report the statistics used to calculate capacity contribution from wind resources and available solar information as a means of testing the validity of the peak load carrying capability (PLCC) method.	Following stakeholder input, and analysis of different capacity factor contribution methodologies, PacifiCorp produced a wind and solar capacity contribution study using the capacity factor approximation method. The wind and solar capacity contribution study is included in Volume II, Appendix N.
2a. Distributed Generation Actions - Distributed Solar	Manage the expanded Utah Solar Incentive Program to encourage the installation of the entire approved capacity. Beginning in June 2014, as stipulated in the Order in Docket No. 11-035-104, the Company will file an Annual Report with program results, system costs, and production data. These reports will also provide an opportunity to evaluate and improve the program as the Company will use this opportunity to recommend changes. Interested parties will have an opportunity to comment on the report and any associated recommendations.	In 2012, the Utah Solar Incentive Program (Docket No. 11-035-104) was extended and expanded to encourage the installation of 60 MW of customer sited solar. The program is scheduled to run for five years through 2017. The Utah Commission, in its approval of the program, ordered evaluation reports, including such information as number of applications, the number and size of completed installations, total installed costs of all completed installations, generation data for large systems, and the number, if any, of surrendered deposit. The initial report was filed June 5, 2014, with an update filed October 30, 2014. The next annual report will be filed in June 2015. Overall, the report showed there was significant interest in the program, however many participants failed either to pay initial deposits, or complete

Action Item	Activity	Status
		projects. As of January 30, 2015, 7.3 MW out of the 60 MW target have been installed.
2b. Distributed Generation Actions - Combined Heat & Power (CHP)	Pursue opportunities for acquiring CHP resources, primarily through the Public Utilities Regulatory Policies Act (PURPA) Qualifying Facility contracting process. For the 2013 IRP Update, complete a market analysis of CHP opportunities that will: (1) assess the existing, proposed, and potential generation sites on PacifiCorp's system; (2) assess availability of fuel based on market information; (3) review renewable resource site information (i.e. permits, water availability, and incentives) using available public information; and (4) analyze indicative project economics based on avoided cost pricing to assist in ranking probability of development.	Appendix B of PacifiCorp's 2013 IRP Update contains an executive summary of the requisite study. The study covers opportunities across PacifiCorp's jurisdictions focusing on PacifiCorp's western balancing authority area, including the states of Oregon, California and Washington, due to available woody biomass fuel supply across those states. Several factors including (but not limited too) recession, mill closures, declining avoided cost prices, and uncertainty with tax credits have contributed to a pull-back by independent developers of biomass facilities. Overall results of the evaluation suggest that the Company should continue being responsive to independent and customer-developed new generation opportunities through PURPA projects and assist those developments on their decisions as they determine the use of the generation for off-setting on-site load or selling to the utility.
3a. Firm Market Purchase Actions - Front Office Transactions	Acquire economic front office transactions or power purchase agreements as needed through the summer of 2017. 1. Resources will be procured through multiple means, such as periodic market RFPs that seek resources less than five years in term, and bilateral negotiations. 2. Include in the 2013 IRP Update a summary of the progress the Company has made to acquire front office transactions over the 2014 to 2017 forward period.	As discussed in the 2013 IRP Update, the Company executed a purchase transaction for 25 MW of firm, heavy-load-hour energy for July-September, 2014. This resulted following an RFP in accordance with Washington regulatory requirements. PacifiCorp has and will continue to pursue its routine acquisition of firm market purchases as outlined in its 2015 IRP action plan.

Action Item	Activity	Status
4a. Flexible Resource Actions - Energy Imbalance Market (EIM)	Continue to pursue the EIM activities with the California Independent System Operator (CAISO) and the Northwest Power Pool to further optimize existing resources resulting in reduced costs for customers.	The Energy Imbalance Market between PacifiCorp and the CAISO launched at midnight November 1, 2014, following a 30-day test period. The new market provides automated, optimized five-minute security constrained economic dispatch across the combined balancing authority areas. The market immediately began generating benefits for customers with significant economic transfers to California occurring throughout the month of November. Although the market is fully functional, some data and software issues resulted in excessive price volatility. Some of the pricing issues have been and will be corrected through ongoing settlement processes. In addition, PacifiCorp and the CAISO are implementing additional operator tools and procedures, incorporating model refinements and enabling additional resources to participate in the market. On December 1, 2014, the Federal Energy Regulatory Commission (FERC) issued an order granting the CAISO's request for a 90-day limited waiver tariff to remove the $1,000 per megawatt-hour price constraint and replace it with the marginal economic bid price while market startup improvements are being made. FERC also requested that the CAISO file a monthly progress report during the 90-day waiver period with the first report due December 15, 2014.
5a. Hedging Actions Natural Gas Request for Proposal	Convene a workshop for stakeholders by October 2013 to discuss potential changes to the Company's process in evaluating bids for future natural gas RFPs, if any, to secure additional long-term natural gas hedging products.	An initial workshop with stakeholders on process improvements and need for future requests for proposals was held on October 29, 2013. Parties also provided comments in early December 2013. Additional meetings were held with the Utah Office of Consumer Services and the Utah Department of Public Utilities in January 2014. PacifiCorp met with Public Utilities Commission of Oregon staff in April 2014. Discussions were also held with the Wyoming Office of Consumer Advocate in September 2014. Through these stakeholder discussions, PacifiCorp received comments

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		on streamlining the procurement process, bid evaluation methods, and hedge products. While stakeholders were generally open to pursuing additional long-term natural gas hedges, none of the stakeholders indicated a strong desire to immediately procure additional long-term natural gas hedges. Based on these stakeholder discussions, and based on PacifiCorp's review of long-term market fundamental forecasts continuing to show potential for downside price pressure with prolific domestic supply, PacifiCorp does not intend to pursue a new long-term natural gas RFP at this time.
6a. Plant Efficiency Improvement Actions	Production efficiency studies have been conducted to satisfy requirements of the Washington I-937 Production Efficiency Measure that have identified categories of cost effective production efficiency opportunity. 1. By the end of the first quarter of 2014, complete an assessment of the plant efficiency opportunities identified in the Washington I-937 studies that might be applicable to other wholly owned generation facilities. 2. Prior to initiating modeling efforts for the 2015 IRP, determine a multi-state "total resource cost test" evaluation methodology to address regulatory recovery among states with identified capital expenditures. 3. Prior to initiating modeling efforts for the 2015 IRP, present to IRP stakeholders in a public input meeting the Company's recommended approach to analyzing cost	1. PacifiCorp completed a multi-plant analysis of potential energy conservation opportunities at wholly owned generation facilities. The "Energy Analysis Report" was included as Appendix C in the 2013 IRP Update. This assessment was done with consideration of the results from studies completed for Washington Initiative 937 (I-937). PacifiCorp completed inspections at a total of eight plants. The report outlines methods used to identify potential systems and equipment providing cost-effective energy efficiency improvements, summarizes the outcomes of inspections, and ranks identified systems and equipment according to cost-effective analysis. The systems identified are separated into three categories by plant: (1) high potential to be cost-effective, (2) needing further study to determine cost-effectiveness, or (3) unlikely to be cost-effective. 2. A total resource cost test methodology was presented and explained to the Washington I-937 Advisory Group and accepted with no objections noted in the WUTC's order approving the Company's 10-year conservation potential

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	effective production efficiency resources in the 2015 IRP.	and 2014-2015 biennial conservation target, effective January 1, 2014. 3. At the August 7-8, 2014 public input meeting, PacifiCorp presented the analysis methodology used for Washington I-937 requirements to IRP stakeholders for potential use as the 2015 IRP. The methodology evaluates production energy efficiency (EE) improvement projects through the thermal project evaluation model. Unlike retail DSM projects, production EE projects are capitalized and placed in rate base with costs allocated among states. Production EE projects will compete for capital the same as other production capital projects and prioritized based on financial analysis performed using the thermal project evaluation model. Based on upon the overall size of these projects, PacifiCorp chose not to evaluate production EE opportunities as specific resource options in its 2015 IRP portfolio development modeling. Nonetheless, produce EE opportunities identified as potentially cost effective will be inserted into PacifiCorp's budget cycle in spring 2015 for the 2016 budget year. Additional projects identified for implementation may be dependent on planned maintenance outages when affected systems and/or equipment are not needed for unit operation. Projects that require more research will receive a thorough study to determine cost-effectiveness. The work of investigating these projects in more detail began in late 2014 and will continue in 2015.
7a. Demand Side Management (DSM) Actions - Class 2 DSM	Acquire 1,425 – 1,876 gigawatt hours (GWh) of cost-effective Class 2 energy efficiency resources by the end of 2015 and 2,034 – 3,180 GWh by the end of 2017.	The combined 2013 and 2014 actual results of 1,163 GWh represent 82 and 62 percent respectively of the 1,425 – 1,876 GWh three year (by 2015) target savings range and 119 percent of the 2013-2014 preferred portfolio resource selections.

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	1. Collaborate with the Energy Trust of Oregon on a pilot residential home comparison report program to be offered to Pacific Power customers in 2013 and 2014. At the conclusion of the pilot program and the associated impact evaluation, assess further expansion of the program.	1. The 24 month pilot program was implemented in August 2013. Results through December 2014 were not meeting expectations; work is underway with the Energy Trust of Oregon and program vendor to identify the root cause prior to further expansion.
	2. Implement an enhanced consolidated business program to increase DSM acquisition from business customers in all states excluding Oregon. a) Utah base case schedule is 1st quarter 2014 with an accelerated target of 3rd quarter 2013. b) Washington base case schedule is 4th quarter 2014, with an accelerated target of 1st quarter 2014. c) Wyoming, California, and Idaho base case schedule is 4th quarter 2014, with an accelerated target of 2nd quarter 2014.	2(a) The company filed an enhanced consolidated program for business customers in May 2013. The Utah Commission approved the changes effective July 1, 2013. 2(b) The Company filed an enhanced consolidated program for business customers in November 2013. The Washington Commission approved the changes effective January 1, 2014. 2(c) The Company filed an enhanced consolidated program for business customers in Wyoming in April 2014 and in Idaho in August 2014. The filings were approved by the Wyoming and Idaho Commissions effective December 1, 2014 and November 13, 2014, respectively. The Company filed an enhanced consolidated program for business customers in California in February 2015 requesting an effective date of May 1, 2015.
	3. Accelerate to the 2nd quarter of 2014, an evaluation of waste heat to power where generation is used to offset customer requirements – investigate how to integrate opportunities into the DSM portfolio.	3. The analysis was completed by 2nd quarter of 2014 and the evaluation report published in August, 2014. Opportunities are modest however will be integrated into next round of ***watt***smart business program updates no later than 2016.

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	4. Increase acquisitions from business customers through prescriptive measures by expanding the "Trade Ally Network". a) Base case target in all states is 3rd quarter 2014, with an accelerated target of 4th quarter 2013.	4. A contract amendment with the Company's trade ally coordinator to expand the Trade Ally Network was executed August 2, 2013. The change (1) increased Trade Ally activities in training and recruitment, (2) extended work related to Utah's evaporative cooling initiative, and (3) emphasized collection of actionable market data.
	5. Accelerate small-mid market business DSM acquisitions by contracting with third party administrators to facilitate greater acquisitions by increasing marketing, outreach, and management of comprehensive custom projects by 1st quarter 2014.	5. Contracts were finalized with two small to mid-market third-party administrators specializing in business customer project facilitation February 25, 2014.
	6. Increase the reach and effectiveness of "express" or "typical" measure offerings by increasing qualifying measures, reviewing and realigning incentives, implementing a direct install feature for small commercial customers, and expanding the residential refrigerator and freezer recycling program to include commercial units. a) Utah base case schedule is 1st quarter 2014 with an accelerated target of 3rd quarter 2013. b) Washington base case schedule is 4th quarter 2014, with an accelerated target of 1st quarter 2014. c) Wyoming, California, and Idaho base case schedule is 4th quarter 2014, with an accelerated target of 2nd quarter 2014.	6(a) Revisions to the existing ***watt*smart** Business program were previewed with Utah's DSM Advisory Committee in December 2013. The revisions added program measures including evaporative pre-cooler retrofit, demand-controlled commercial kitchen ventilation and others. Updates were also made to existing typical upgrade measures and a small business lighting offering was added. An amendment to the refrigerator/freezer recycling program vendor agreement was made in October, 2014, allowing for qualifying residential equipment at business facilities to be recycled through the residential recycling program. 6(b) In Washington the proposed additions and updates, except for the direct install offering (small business lighting offering) were part of the ***watt*smart** Business filing that became effective January 1, 2014. A final review by the Company's Washington's demand side advisory group of the direct install offer (small business lighting offer) was completed in July, 2014, and the

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		offering added to the ***watt**smart* business program effective October 1, 2014 (no explicit Commission approval is required in Washington for these types of changes). The Company filed in February, 2014, for authorization to allow qualifying residential equipment at business facilities to be recycled through the residential recycling program, which was approved by the Washington Commission effective April 1, 2014. 6(c) In Wyoming the proposed additions and updates, except for the direct install offer (small business lighting offer) were part of the business program consolidation filing approved by the Wyoming Commission effective December 1, 2014. A filing to allow residential equipment at business facilities to be recycled through the residential recycling program was made in June, 2014, and was approved by the Wyoming Commission effective September 1, 2014. The Wyoming direct install offering (small business lighting offering) was filed December 11, 2014 and was approved by the Wyoming Commission effective March 1, 2015. The California additions and updates, including the direct install offer (small business lighting offer), were included in the California business program consolidation filing made in February, 2015. The Company has requested an effective date of May 1, 2015. The authorization to recycle residential equipment at business facilities through the residential recycling program in California was implemented effective May 12, 2014. The Idaho updates, including the addition of the direct install offer (small business lighting offer), were

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		included in the business program consolidation filing approved by the Idaho Commission effective November 13, 2014. The authorization to recycle residential equipment at business facilities through the residential recycling program in Idaho was implemented effective July 1, 2014.
	7. Increase the reach of behavioral DSM programs: ▪ Evaluate and expand the residential behavioral pilot. Utah base case schedule is 2nd quarter, 2014, with an accelerated target of 4th quarter 2013. ▪ Accelerate commercial behavioral pilot to the end of the first quarter 2014. ▪ Expand residential programs system-wide pending evaluation results System-wide target is 3rd quarter 2015, with an accelerated target of 3rd quarter 2014.	7(a) A filing to extend the current residential behavior pilot program through 2017 and expand participation to a total of 279,000 households was approved by the Utah Commission effective September 15, 2014. 7(b) Due to the lack of demonstrated performance of commercial behavioral programs, the Company has yet to find a state that both qualifies and is receptive to running the commercial pilot. Work continues however to design a "low risk" or "no risk" pilot for consideration and filing first quarter of 2015. 7(c) A filing to extend the current residential behavior pilot program through 2017 and expand participation to a total of 46,500 households was approved by the Washington Commission effective September 12, 2014. Program discussions were held with the Idaho Commission staff in August, 2014, at which time a 15,000 household residential program was proposed. Staff supported the company's proposal. Reports are scheduled to begin being distributed in January 2015, and continue through 2017. A filing to offer a 15,000 household residential behavioral program in Wyoming was approved by the Commission effective January 8, 2015 and is scheduled to run through 2017.

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		A review of program capability continues in California where the program vendor's initial assessment suggests that there are too few residential customers to form representative control and treatment groups capable of effectively evaluating program savings.
	8. Increase acquisition of residential DSM resources: a) Implement cost effective direct install options by the end of 2013. b) Expand offering of "bundled" measure incentives by the end of 2013. c) Increase qualifying measures by the end of 2013. d) Review and realign incentives: Utah schedule is 1st quarter 2014 e) Review and realign incentives: Washington base case schedule is 2nd quarter 2014, with accelerated target of 1st quarter 2014 f) Review and realign incentives: Wyoming, California, and Idaho base case schedule is 3rd quarter 2014, with an accelerated target of 2nd quarter 2014	8(a) A residential direct install (direct distribution of energy savings kits) RFP was issued with responses received January 2014. Kits were added to the Home Energy Savings Program in Washington effective January 1, 2014, Idaho effective April 14, 2014, California effective May 12, 2014, Utah effective September 9, 2014, implemented October 24, 2014, and Wyoming effective February 12, 2015. 8(b) Incentives encouraging customers to install bundles of weatherization (i.e. insulation, windows) and heating and cooling equipment (i.e. central air conditioners, heat pumps) were added in Idaho in September 2012, Utah in November 2012, Washington in January 2014, California in May 2014, and Wyoming in February 2015. 8(c) Measure updates were made in Washington effective with the January 2014 program changes, Idaho in with the changes effective in April 2014, California in May 2014, Utah in October, 2014, and Wyoming in February 2015. 8(d) Utah updates were filed July, 2014, and approved by the Utah Commission effective September 9, 2014, implemented October 24, 2014. 8(e) Work is complete with realigned incentives available in Washington January 1, 2014. 8(f) Work was completed in Idaho effective April 2014, Utah

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		in October 2014, and Wyoming in February 2015.
	9. Accelerate acquisitions by expanding refrigerator and freezer recycling to incorporate retail appliance distributors and commercial units – 3rd quarter 2013.	9. Provisions were added to the Company's recycling program in California effective May 12, 2014, Idaho effective July 1, 2014, Utah effective August 17, 2014, Wyoming effective September 1, 2014 and in Washington effective January 1, 2015.
	10. By the end of 2013, complete review of the impact of accelerated DSM on Oregon and the Energy Trust of Oregon, and re-contract in 2014 for appropriate funding as required.	10. The review was completed in October, 2013, and it was determined the ETO had sufficient funding available for 2014 activities. The OPUC was notified in November 2013, of the funding position. A revised funding agreement between the Company and the ETO was executed in February 2014.
	11. Include in the 2013 IRP Update Class 2 DSM decrement values based upon accelerated acquisition of DSM resources.	11. The Class 2 DSM decrement study based on accelerated acquisition of DSM resources was completed and included as Appendix D to the Company's 2013 IRP Update filed March 31, 2014.
	12. Include in the 2014 conservation potential study an analysis testing assumptions in support of accelerating acquisition of cost-effective Class 2 DSM resources, and apply findings from this analysis into the development of candidate portfolios in the 2015 IRP.	12. The 2014 conservation potential study analytical work was completed in July, 2014, and two sets of Class 2 DSM supply curves (base case and accelerated case) were developed for consideration in the 2015 IRP. Core case C11 in the 2015 IRP was developed to examine impact of accelerated Class 2 DSM. See Chapters 7 and 8 for further discussion.
7b. Demand Side Management (DSM) Actions - Class 3 DSM	Develop a pilot program in Oregon for a Class 3 irrigation time-of-use program as an alternative approach to a Class 1 irrigation load control program for managing irrigation loads in the west. The pilot program will be developed for the 2014 irrigation season and	A two year pilot program was put in place beginning with the 2014 irrigation season which implemented on-peak energy surcharges and off-peak energy credits. A report on the pilot was filed with the OPUC on December 1, 2014 and may also be found at the following location: http://www.pacificorp.com/es/irp/irpsupport.html

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	findings will be reported in the 2015 IRP.	PacifiCorp has proposed modifications in the program to increase participation levels. This was in line with the results of surveys conducted at the conclusion of the 2014 irrigation season. The proposed changes may be found at the following location: http://apps.puc.state.or.us/edockets/docket.asp?DocketID=19404
8a. Coal Resource Actions - Naughton Unit 3	1. Continue permitting and development efforts in support of the Naughton Unit 3 natural gas conversion project. The permit application requesting operation on coal through year-end 2017 is currently under review by the Wyoming Department of Environmental Quality, Air Quality Division. 2. Issue a request for proposal to procure gas transportation for the Naughton plant as required to support compliance with the conversion date that will be established during the permitting process. 3. Issue an RFP for engineering, procurement, and construction (EPC) of the Naughton Unit 3 natural gas retrofit as required supporting compliance with the conversion date that will be established during the permitting process.	1. In its action on January 10, 2014, the EPA was in favor of the natural gas conversion on Naughton Unit 3, but could not take action because this alternative was not included in the Wyoming Regional Haze state implementation plan (SIP) and related documents. In support of the natural gas conversion, PacifiCorp received the Wyoming Department of Environmental Quality (WDEQ) BART permit MD-15946 on June 20, 2014. Note that the WDEQ construction permit MD-14506 was received prior to the EPA's referenced action and has an effective date of July 5, 2013. PacifiCorp is continuing its activities to support the WDEQ in its efforts to re-submit the Wyoming Regional Haze SIP that will recommend the conversion to natural gas for Naughton Unit 3. This activity remains on target for full environmental approval completion by January 1, 2017. In mid-2015 the Company will resume its technical project development activities specifically targeted to establish NFPA 85 compliance obligations. 2. An Initial natural gas RFP was issued on December 23, 2013. PacifiCorp Energy suspended the RFP in March 2014 pending resolution of the BART permit amendment process for Naughton Unit 3. In June 2014, the Company received a permit authorizing the natural gas conversion of Naughton Unit 3 by June 30, 2018, and will therefore issue a new gas transportation request for proposals in

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		2016. 3. A tentative technical evaluation of the EPC RFP proposals was completed. Work to continue the RFP evaluation has been suspended until early 2016.
8b. Coal Resource Actions - Hunter Unit 1	Complete installation of the baghouse conversion and low NO_X burner compliance projects at Hunter Unit 1 as required by the end of 2014.	The baghouse and low NO_X burner projects came online May 27, 2014. All work and testing were complete before November 1, 2014. The projects are now closed out.
8c. Coal Resource Actions - Jim Bridger Units 3 and 4	Complete installation of selective catalytic reduction (SCR) compliance projects at Jim Bridger Unit 3 and Jim Bridger Unit 4 as required by the end of 2015 and 2016, respectively.	Construction of the Unit 3 SCR is progressing on target for a November 2015 in-service date. The structural steel is erected, and the reactor modules are assembled. The majority of the ammonia receiving area is complete; and electrical work is moving forward. Construction of the Unit 4 SCR is progressing with the erection of structural steel beginning in January 2015. The Unit 4 construction remains on-target for a November 2016 in-service date.
8d. Coal Resource Actions - Cholla Unit 4	Continue to evaluate alternative compliance strategies that will meet Regional Haze compliance obligations, related to the U.S. Environmental Protection Agency's Federal Implementation Plan requirements to install SCR equipment at Cholla Unit 4. Provide an update of the Cholla Unit 4 analysis regarding compliance alternatives in the 2013 IRP Update.	Evaluation is included in Volume III. PacifiCorp will 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 asset by the end of April 2025.
9a. Transmission Actions - System Operational and Reliability Benefits Tool (SBT)	60 days after filing the 2013 IRP, establish a stakeholder group and schedule workshops to further review the System Benefit Tool (SBT). 1. For the 2013 IRP Update, complete additional analysis of the Energy Gateway West Segment D that evaluates staging	On June 28, 2013, an email was sent from the IRP Mailbox to the IRP participant distribution list soliciting stakeholder participation on the SBT workgroup. The first SBT workgroup kick-off workshop was held on July 29, 2013. PacifiCorp transmission established an email mailbox for SBT correspondence and a webpage. Notices of workshops and presentation materials were posted on the "Transmission

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	implementation of Segment D by sub-segment. 2. In preparation for the 2015 IRP, continue to refine the SBT for Energy Gateway West Segment D and develop SBT analyses for additional Energy Gateway segments.	SBT" webpage. Workshops were held with interested Stakeholders on July 29, 2013, August 26, 2013, September 17, 2013, (with an optional make-up webinar on September 30), and November 20, 2013. 1. Given the delay in the in-service dates, PacifiCorp did not include a sub-segment SBT analysis for Segment D in the 2013 IRP Update. 2. PacifiCorp will develop cost and benefit support for transmission projects for which it is seeking Commission acknowledgement.
9b. Transmission Actions - Energy Gateway Permitting	Continue permitting for the Energy Gateway transmission plan, with near term targets as follows: 1. Segment D, E, and F, continue funding of the required federal agency permitting environmental consultant as actions to achieve final federal permits. 2. Segment D, E, and F, continue to support the federal permitting process by providing information and participating in public outreach projected through the next 2 to 4 years. 3. Segment H Cascade Crossing, complete benefits analysis in 2013. 4. Segment H Boardman to Hemingway, continue to support the project under the conditions of the Boardman to Hemingway Transmission. Project Joint Permit Funding Agreement, projected through 2015.	1. PacifiCorp continues to fund the required federal agency permitting environmental consultant as actions to achieve final federal permits. 2. A record of decision was received for eight of ten sub-segments of Segments D and E with the record of decision on the remaining two sub-segments anticipated in late 2016. A draft EIS for Segment F for the Gateway South project was received in February 2014. A final EIS is anticipated in fall of 2015 with a record of decision by the end of 2015. 3. As noted in the November 26, 2013, Oregon IRP Reply Comments, PacifiCorp had a memorandum of understanding with Portland General Electric (PGE) with respect to the development of Cascade Crossing that terminated by its own terms and further discussions with PGE on Cascade Crossing as an option have been ended. Thus, no benefits analysis will be completed. 4. PacifiCorp continues to support the Boardman to Hemingway project consistent with the project Joint Permit Funding Agreement. PacifiCorp has participated in the permitting process by providing review and comment of cost, scope and schedule of the project. As a participant in the project PacifiCorp continues to

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		collaborate with Idaho Power in the permitting process providing guidance of activities and plans associated with the permitting phase of the project.
9b. Transmission Actions - Energy Gateway Permitting (as edited by Order NO. 14-252)	Continue permitting Segments D, E, F, and H until PacifiCorp files its 2015 IRP, at which time a SBT analysis for these segments may be performed.	PacifiCorp has continued to permit the Segments as discussed above. The Company is not proposing an acknowledgement Action Item for the Segments in the 2015 IRP – thus there is not an SBT analysis provided.
9c. Transmission Actions - Sigurd to Red Butte 345 kilovolt Transmission Line	Complete project construction per plan.	As of March 1, 2015, construction of the transmission line is primarily complete with remaining items being addressed and reclamation being conducted. Installation of communications equipment is complete and is undergoing testing. Construction work is complete at Sigurd Substation and awaiting final testing. Construction is primarily complete at Red Butte Substation with minor grading occurring and remaining items being addressed. The project is on schedule for final testing by PacifiCorp to occur starting May 1, 2015, with the line to be energized on May 28, 2015.
10a. Planning Reserve Margin Actions	Continue to evaluate in the 2015 IRP the results of a System Optimizer portfolio sensitivity analysis comparing a range of planning reserve margins considering both cost and reliability impacts of different levels of planning reserve margin assumptions. Complete for the 2015 IRP an updated planning reserve margin analysis that is shared with stakeholders during the public process.	An updated analysis planning reserve margins (PRM) study is included in Volume II, Appendix I. PacifiCorp continues to target a 13% PRM. PacifiCorp reviewed its PRM study results with IRP stakeholders at the September 25-26, 2014 public input meeting.
11a. Planning and Modeling Process Improvement Actions - Modeling and Process	Within 90 days of filing the 2013 IRP, schedule an IRP workshop with stakeholders to discuss potential process improvements that can more efficiently achieve meaningful cost and risk analysis of resource plans in the context of the IRP and implement process	PacifiCorp sent an email to stakeholders on July 23, 2013 to determine stakeholder availability. Thereafter, a public stakeholder meeting was held on September 23, 2013 to discuss potential improvements. Additionally, stakeholders were provided the opportunity submit written comments to the Company. The first public input meeting on June 5, 2014

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	improvements in the 2015 IRP.	went through the stakeholder comments and suggestions. These resulted in several changes to the 2015 IRP. Examples include PacifiCorp's introduction of a Feedback Form for stakeholders to provide comments throughout the public input process. Comments received through this process directly influenced assumptions and core case definitions adopted for the 2015 IRP. PacifiCorp is also increasing transparency by including data disks with its 2015 IRP filing, and held technical workshops on new models introduced to the 2015 IRP (the 111(d) Scenario Maker model). PacifiCorp further improved its modeling approach by including estimates of transmission integration and reinforcement costs specific to each unique resource portfolio.
11b. Planning and Modeling Process Improvement Actions - Cost/Benefit Analysis of DSM Resource Alternatives	Complete a cost/benefit analysis on the level of detail used to evaluate prospective DSM resources in the IRP. The analysis will consider the tradeoffs between model run-time and resulting resource selections, will be shared with stakeholders early in the 2015 IRP public process, and will inform how prospective DSM resources will be aggregated in developing resource portfolios for the 2015 IRP.	PacifiCorp has not seen an increase in amount of time for model runs using the latest version of System Optimizer as opposed to the 2013 IRP. As such there is no need to run a cost/benefit analysis of limiting the 27 DSM cost bundles. All DSM resource options were thoroughly studied in the 2015 IRP.

Acquisition Path Analysis

Resource and Compliance Strategies

PacifiCorp worked with stakeholders to define core case definitions for the 2015 IRP. Core case definitions contain a combination of specific planning assumptions related to CO_2 emission policies, compliance strategies under EPA's proposed 111(d) rule, potential Regional Haze compliance requirements, state RPS compliance strategies, and DSM acquisition strategies. PacifiCorp further analyzed sensitivity cases on planning assumptions related to load forecasts, distributed generation penetration levels, Energy Gateway transmission projects, CO_2 emission policies, and compliance strategies under EPA's proposed 111(d) rule. The array of planning assumptions that define core case and sensitivity case resource portfolios provides the framework for a resource acquisition path analysis by evaluating how resource selections are impacted by shifts planning assumptions.

Given current load expectations, portfolio modeling performed for the 2015 IRP shows the resource acquisition path in the preferred portfolio is robust among a wide range of policy and market conditions, particularly in the near-term, when FOTs and energy efficiency resources are consistently selected. With regard to renewable resource acquisition, the portfolio development modeling performed in the 2015 IRP shows that new renewable resource needs are driven by RPS compliance obligations and potential 111(d) policy outcomes and associated compliance strategies. Beyond load, the most significant driver affecting resource selection in the 2015 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 EPA's proposed 111(d) rule or some other future policy targeting electric sector emission reductions, also influences resource selections in the 2015 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 (2015-2024) and long-term (2025-2034) resource strategies.

Acquisition Path Decision Mechanism

The Utah Commission requires that PacifiCorp provide "[a] plan of different resource acquisition paths with a decision mechanism to select among and modify as the future unfolds."[82] PacifiCorp's decision mechanism is centered on the business planning and IRP processes, which together constitute the decision framework for making resource investment decisions. The IRP models are used on a macro-level to evaluate alternative portfolios and futures as part of the IRP process, and then on a micro-level to evaluate the economics and system benefits of individual resources as part of the supply-side resource procurement and DSM target-setting/valuation processes. 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 2015 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

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[82] Public Service Commission of Utah, In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp, Report and Order, Docket No. 90-2035-01, June 1992, p. 28.

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 (2015-2024)	Long Term Resource Acquisition Strategy (2025-2034)
Higher sustained load growth	High economic drivers and increased demand from industrial customers	• Increase acquisition of FOTs • Increase acquisition of Class 2 DSM resources in the 2020– 2024 timeframe • Accelerate and increase acquisition of a gas-fired thermal resources by approximately 4 years (2024) • Increase acquisition of RECs to maintain compliance with RPS requirements consistent with load growth expectations by state	• Increase acquisition of gas-fired thermal resources. • Balance timing of thermal resource acquisition with FOTs and cost-effective Class 2 DSM energy efficiency resources • Evaluate cost effective RPS compliance strategies, including tradeoffs between resource acquisition and use of compliance flexibility mechanisms like banking and use of unbundled RECs
Lower sustained load growth	Low economic drivers suppress load requirements with reduced demand from industrial customers	• Reduce acquisition of FOTs • Continue to pursue Class 2 DSM energy efficiency resources	• Reduce acquisition of gas-fired thermal resources • Balance timing of thermal resource acquisition with FOTs and cost-effective Class 2 DSM energy efficiency resources
Higher sustained distributed generation penetration levels	More aggressive technology cost reductions, improved technology performance, and higher electricity retail rates	• Reduce acquisition of FOTs • Continue to pursue Class 2 DSM energy efficiency resources	• Reduce acquisition of gas-fired thermal resources • Balance timing of thermal resource acquisition with FOTs and cost-effective Class 2 DSM energy efficiency resources
Lower sustained distributed generation penetration levels	Less aggressive technology cost reductions, reduced technology performance, and lower electricity retail rates	• Increase acquisition of FOTs (primarily beginning 2024) • Continue to pursue Class 2 DSM energy efficiency resources	• Increase acquisition of gas-fired thermal resources. • Balance timing of thermal resource acquisition with FOTs and cost-effective Class 2 DSM energy efficiency resources
State implementation of 111(d) emission rate targets	EPA's proposed state emission rate targets applied to PacifiCorp's share of fossil generation in AZ, CO, and MT without relief on 2020 to 2029 compliance timeline	• Initiate new renewable resource procurement activities for resources coming on-line as early as 2020 • Reduce acquisition of FOTs concurrent with addition of system renewable resources.	• Maintain long-term acquisition of new gas-fired thermal resources, DSM and FOTs.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2015-2024)	Long Term Resource Acquisition Strategy (2025-2034)
State implementation of 111(d) via a mass cap	Mass cap applied to PacifiCorp's system covering CO_2 emissions from existing fossil-fired generation beginning 2020	• Potentially accelerate acquisition of gas-fired thermal resources, dependent upon derivation of mass cap limits. • Increase acquisition of Class 2 DSM resources • Balance timing of thermal resource acquisition and Class 2 DSM acquisition with FOTs	• Increase acquisition of Class 2 DSM resources • Balance timing of thermal resource acquisition and Class 2 DSM resource acquisition with FOTs
Restricted use of "111(d) attributes"	State RPS RECs and 111(d) attributes must be surrendered together in OR and WA	• Evaluate early retirement of Chehalis to eliminate WA 111(d) compliance obligation • Procure natural gas peaking resource • Increase acquisition of Class 2 DSM resources • Increase acquisition of FOTs	• Increase acquisition of Class 2 DSM resources • Increase acquisition of FOTs
New CO_2 policy incremental to EPA's proposed 111(d) rule	Incremental to EPA's proposed 111(d) rule, fossil-fired generation is faced with a CO_2 emissions cost at approximately $22/ton in 2020 rising to approximately $76/ton by 2034	• Increase acquisition of gas-fired thermal resources to offset potential early retirement of coal units • Increase acquisition of Class 2 DSM resources	• Begin adding new renewable resources, up to 1,600 MW to replace generation from fossil-fired assets • Procure low emission base load modular nuclear resources (over 2,000 MW) thermal resources to replace generation from fossil-fired assets • Increase acquisition of Class 2 DSM resources
Regional Haze outcome with early coal unit retirements	Potential Regional Haze inter-temporal and fleet trade-off compliance scenario with coal unit assumptions as defined in Regional Haze Scenario 1 and Scenario 2 (see Chapter 7)	• Increase acquisition of FOTs concurrent with assumed coal unit retirements • Accelerate acquisition of gas-fired thermal generation to 2024	• Increase procurement of new gas-fired thermal resources • Balance timing of FOTs and DSM resource acquisition with timing of new gas-fired generation
Limited availability of FOTs	Eliminates availability of FOTs at NOB (100 MW) and Mona (300 MW) beginning 2019	• Increase acquisition of Class 2 DSM resources	• Accelerate timing and new gas-fired thermal resource by two years • 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 need. There are various reasons why a particular proxy resource cannot be procured in the timeframe identified in the 2015 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 Company'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% 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 2015 IRP and the 2013 IRP Update include decreased load forecasts and lower power prices. The 2013 IRP Update also assumed conversion of Naughton Unit 3 in 2015, whereas the 2015 IRP preferred portfolio assumes Naughton Unit 3 will be converted to natural gas in 2018.[83] With the delay in the Naughton Unit 3 conversion, there is an assumed 50 MW reduction in its capacity beginning 2015 until the conversion is completed in 2018.[84] Finally, the 2015 IRP includes an updated DSM conservation potential assessment, which supports increased acquisition of DSM resources the 2013 IRP and 2013 IRP Update.

Resource portfolio differences relative to the 2013 IRP Update also show reductions in distributed solar and combined heat and power (CHP). These perceived declines are actually driven by modeling changes. For the 2015 IRP, distributed generation (DG), informed by a study producing DG penetration forecasts, included in Volume II, Appendix O, is applied as a reduction in load, not as a resource for selection in portfolio modeling. Other changes in the

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[83] Financial analysis of the 2018 Naughton Unit 3 natural gas conversion is presented in Volume III.

[84] The state of Wyoming's permits governing natural gas conversion of Naughton Unit 3 set forth specific environmental compliance requirements for the unit in the interim period between the April 2015 MATS compliance deadline through the end of 2017, when the unit ceases coal-fueled operation. The Company's IRP modelling assumptions include a 50 MW reduction in Unit 3 capacity during the interim period. For modeling purposes, it was assumed that this level of capacity reduction would be required to allow the unit's existing emissions control equipment to meet the more restrictive interim period permit limits. During the interim period, actual unit performance and certified emissions data will be utilized to demonstrate compliance, which will likely result in actual available capacity being different than that assumed for IRP modeling.

portfolio reflect a reduction in RPS-driven renewable resources. As outlined in Chapter 8, the least cost least risk state RPS compliance strategy relies on unbundled RECs. PacifiCorp continues to plan on using unbundled RECs to meet its forecasted needs under the California and Washington RPS programs.

Table 9.4 compares the 2015 IRP preferred portfolio with the 2013 IRP Update portfolio for the front ten years of the 2015 IRP planning period (2015-2024). The table shows year by year capacity differences by major resource categories (yellow highlighted table).

Table 9.4 – Comparison of the 2015 IRP Preferred Portfolio with the 2013 IRP Update Portfolio

2015 IRP vs 2013 IRP Update

2015 IRP Preferred Portfolio

	Capacity (MW)											Resource Totals
Resource	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2015-2024**
Expansion Options												
Gas - CCCT		-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking		-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency		133	139	146	146	153	135	137	144	146	149	**1,429**
DSM - Load Control		-	-	-	-	-	-	-	5	11	-	**16**
Renewable - Wind		-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar		-	7	-	-	-	-	-	-	-	-	**7**
Renewable - Distributed Solar		-	-	-	-	-	-	-	-	-	-	-
Combined Heat & Power		-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions *		727	937	904	870	935	979	769	791	761	754	**843**
Existing Unit Changes												
Coal Early Retirement/Conversions		(222)	-	-	(280)	-	-	-	-	-	-	**(502)**
Thermal Plant End-of-life Retirements		-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions		-	-	-	337	-	-	-	-	-	-	**337**
Turbine Upgrades		-	-	-	-	-	-	-	-	-	-	-
Total		**638**	**1,084**	**1,050**	**1,073**	**1,088**	**1,113**	**906**	**941**	**917**	**903**	

Study includes Naughton 3 gas conversion in 2018

FOT in resource total are 10-year averages

2015 IRP Preferred Portfolio less 2013 IRP Update

	Capacity (MW)											Resource Totals
Resource	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2015-2024**
Expansion Options												
Gas - CCCT		-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking		-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency		35	44	51	58	71	61	63	70	82	83	**618**
DSM - Load Control		-	-	-	-	-	-	-	5	11	-	**16**
Renewable - Wind		-	-	-	-	-	-	-	-	-	(184)	**(184)**
Renewable - Utility Solar		(2)	7	-	-	-	-	-	-	-	-	**5**
Renewable - Distributed Solar		(14)	(16)	(17)	(13)	(14)	(15)	(15)	(15)	(15)	(15)	**(151)**
Combined Heat & Power		(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	**(11)**
Front Office Transactions *		144	236	73	(61)	(92)	(282)	(273)	(307)	(449)	(548)	**(156)**
Existing Unit Changes												
Coal Early Retirement/Conversions		280	-	-	(280)	-	-	-	-	-	-	-
Thermal Plant End-of-life Retirements		-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions		(338)	-	-	337	-	-	-	-	-	-	**(1)**
Turbine Upgrades		-	-	-	-	-	-	-	-	-	-	-
Total		**103**	**270**	**107**	**40**	**(35)**	**(237)**	**(227)**	**(248)**	**(373)**	**(666)**	

FOT in resource total are 10-year averages

2013 IRP Update

	Capacity (MW)											Resource Totals
Resource	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2015-2024**
Expansion Options												
Gas - CCCT	645	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	110	98	96	95	88	82	74	74	74	64	66	**810**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	184	**184**
Renewable - Utility Solar	6	2	-	-	-	-	-	-	-	-	-	**2**
Renewable - Distributed Solar	11	14	16	17	13	14	15	15	15	15	15	151
Combined Heat & Power	1	1	1	1	1	1	1	1	1	1	1	11
Front Office Transactions *	445	583	701	831	931	1,027	1,261	1,042	1,098	1,210	1,302	**999**
Existing Unit Changes												
Coal Early Retirement/Conversions	-	(502)	-	-	-	-	-	-	-	-	-	**(502)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	338	-	-	-	-	-	-	-	-	-	**338**
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-
Total	1,218	**534**	**814**	**944**	**1,034**	**1,123**	**1,351**	**1,132**	**1,189**	**1,290**	**1,569**	

Study includes Naughton 3 gas conversion in 2015

FOT in resource total are 10-year averages

Table 9.5 compares the fall 2014 ten-year business plan portfolio with the 2015 IRP preferred portfolio. Differences between the two portfolios are driven by reduced loads and updated DSM supply curve assumptions. The 2015 IRP preferred portfolio shows increased energy efficiency and reduced FOTs relative to the fall 2014 ten-year business plan portfolio. Changes in distributed solar and CHP are driven by changes in modeling approach, as discussed above.

Table 9.5 – Comparison of the 2015 IRP Preferred Portfolio with the Fall 2014 Business Plan Portfolio

2015 IRP vs Fall 2014 Ten-Year Business Plan

2015 IRP Preferred Portfolio

	Capacity (MW)											Resource Totals
Resource	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2015-2024**
Expansion Options												
Gas - CCCT		-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking		-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency		133	139	146	146	153	135	137	144	146	149	**1,429**
DSM - Load Control		-	-	-	-	-	-	-	5	11	-	**16**
Renewable - Wind		-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar		-	7	-	-	-	-	-	-	-	-	**7**
Renewable - Distributed Solar		-	-	-	-	-	-	-	-	-	-	-
Combined Heat & Power		-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions *		727	937	904	870	935	979	769	791	761	754	**843**
Existing Unit Changes												
Coal Early Retirement/Conversions		(222)	-	-	(280)	-	-	-	-	-	-	**(502)**
Thermal Plant End-of-life Retirements		-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions		-	-	-	337	-	-	-	-	-	-	**337**
Turbine Upgrades		-	-	-	-	-	-	-	-	-	-	-
Total		**638**	**1,084**	**1,050**	**1,073**	**1,088**	**1,113**	**906**	**941**	**917**	**903**	

Study includes Naughton 3 gas conversion in 2018

FOT in resource total are 10-year averages

2015 IRP Preferred Portfolio less Fall 2014 Ten-Year Business Plan

	Capacity (MW)											Resource Totals
Resource	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2015-2024**
Expansion Options												
Gas - CCCT		-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking		-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency		34	43	54	57	70	60	63	70	81	81	**613**
DSM - Load Control		-	-	-	-	-	-	-	5	9	(22)	**(8)**
Renewable - Wind		-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar		(7)	5	-	-	-	-	-	-	-	-	**(2)**
Renewable - Distributed Solar		(14)	(16)	(17)	(13)	(14)	(15)	(15)	(15)	(15)	(15)	**(151)**
Combined Heat & Power		(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	**(11)**
Front Office Transactions *		(204)	(250)	(405)	(388)	(400)	(414)	(374)	(386)	(483)	(544)	**(385)**
Existing Unit Changes												
Coal Early Retirement/Conversions		(5)	-	-	5	-	-	-	-	-	-	-
Thermal Plant End-of-life Retirements		-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions		-	-	-	(1)	-	-	-	-	-	-	**(1)**
Turbine Upgrades		-	-	-	-	-	-	-	-	-	-	-
Total		**(197)**	**(220)**	**(369)**	**(341)**	**(345)**	**(370)**	**(327)**	**(328)**	**(409)**	**(501)**	

FOT in resource total are 10-year averages

Fall 2014 Ten-Year Business Plan

	Capacity (MW)											Resource Totals
Resource	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2015-2024**
Expansion Options												
Gas - CCCT	645	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	111	99	96	92	89	83	75	74	74	65	67	**815**
DSM - Load Control	-	-	-	-	-	-	-	-	-	1	22	**24**
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	1	7	2	-	-	-	-	-	-	-	-	**9**
Renewable - Distributed Solar	11	14	16	17	13	14	15	15	15	15	15	151
Combined Heat & Power	1	1	1	1	1	1	1	1	1	1	1	11
Front Office Transactions *	760	931	1,188	1,309	1,258	1,335	1,393	1,142	1,178	1,243	1,298	**1,227**
Existing Unit Changes												
Coal Early Retirement/Conversions	-	(217)	-	-	(285)	-	-	-	-	-	-	**(502)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	-	-	338	-	-	-	-	-	-	**338**
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-
Total	1,529	**835**	**1,304**	**1,419**	**1,414**	**1,433**	**1,483**	**1,233**	**1,269**	**1,326**	**1,404**	

Study includes Naughton 3 gas conversion in 2018

FOT in resource total are 10-year averages

PacifiCorp's 2015 IRP preferred portfolio will serve as the starting point for resource assumptions in the fall 2015 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 2015 IRP action plan, PacifiCorp intends to continue using competitive solicitation processes in accordance with the then-current law, rules, and/or guidelines in each of the states in which PacifiCorp operates, as applicable. 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 account 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 2015 IRP action plan.

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

The Company will procure and/or re-procure for several major delivery contracts in 2015 and 2016 such as the residential appliance recycling program, Home Energy Savings program, its small to mid-size business support services, energy management services, and oil and gas sector service delivery. The Company will also look to expand services to the multifamily and manufactured home sector either through the Home Energy Service program re-procurement or through a standalone request for proposals. See Volume II, Appendix D for further information.

Naughton Unit 3

The 2015 IRP action plan includes an action item to 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. Both RFPs will be used to ensure competitive market bids are evaluated to fuel the unit as a gas-fired facility and to complete the conversion project. PacifiCorp may update its economic analysis of the Naughton Unit 3 natural gas conversion in conjunction with the RFP processes to align gas transportation and EPC cost assumptions with market bids.

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, use the site for additional resources in the future, change fueling strategies or sources, efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and utilize the plant at cost as long as it remains economic. In addition, by owning a plant, 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 2015 IRP, known and prospective environmental regulations can impact coal plant utilization and investment decisions.

Under EPA's proposed 111(d) rule, compliance strategies will be affected by changes to the rule (i.e., targets, timelines, etc.) once finalized and how states choose to develop implementation plans for EPA review and approval. 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 is currently being pursued for the Naughton Unit 3 generating unit. 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 CO_2 emissions, renewable resources to meet compliance requirements, and changes in load and transmission infrastructure. These scenario risks relate to the uncertainty in predicting the scope, timing, and cost impact of CO_2 emission 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 2015 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.