PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

April 4, 2017

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-3398

Attn: Filing Center

RE: LC 67–PacifiCorp's 2017 Integrated Resource Plan

Enclosed please find twenty copies of PacifiCorp's 2017 Integrated Resource Plan (2017 IRP). The 2017 IRP is also available electronically on PacifiCorp's IRP website, at http://www.pacificorp.com/es/irp.html.

As with the 2015 IRP, PacifiCorp will provide data discs for the 2017 IRP. These discs provide support and additional details for the analyses included in the 2017 IRP. The Company plans to supplement this filing on April 11, 2017, to distribute the data discs, which will contain both non-confidential and confidential work papers.

PacifiCorp submits the 2017 IRP to the Public Utility Commission of Oregon (Commission) under OAR 860-027-0400. Information outlining how PacifiCorp has addressed the procedural and substantive elements of the Commission's rules is provided in Appendix B – IRP Regulatory Compliance, Tables B.2 and B.3.

Formal correspondence for this proceeding should be addressed as follows:

Oregon Dockets
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
oregondockets@pacificorp.com

Erin Apperson
Attorney
Pacific Power
825 NE Multnomah Street, Suite 1800
Portland, OR 97232
erin.apperson@pacificorp.com

It is respectfully requested that all data requests regarding this filing be addressed as follows:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, Oregon, 97232

PacifiCorp appreciates the time and effort Oregon participants have dedicated to helping the Company develop its 2017 IRP.

Informal inquiries may be directed to Natasha Siores at (503) 813-6583.

Sincerely,



R. Bryce Dalley
Vice President, Regulation

Enclosures

cc: Service List LC 62
Service List LC 67

CERTIFICATE OF SERVICE

I certify that I electronically filed a true and correct copy of PacifiCorp's 2017 Integrated Resource Plan on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

Service List
LC 62

Jess Kincaid
Oregon Department of Energy
625 Marion St. NE
Salem, OR 97301-3737
jess.kincaid@state.or.us

Philip H. Carver (C)
Oregon Department of Energy
625 Marion St. NE Ste 1
Salem, OR 97301
phil.carver@state.or.us

Renee M. France (C)
Oregon Department of Justice
1162 Court St NE
Salem, OR 97301-4096
Renee.m.france@doj.state.or.us

OPUC Dockets
Citizens' Utility Board of Oregon
610 SW Broadway, Ste 400
Portland, OR 97205
dockets@oregoncub.org

Bob Jenks (C)
Citizens' Utility Board of Oregon
610 SW Broadway, Ste 400
Portland, OR 97205
bob@oregoncub.org

Michael Goetz
Citizens' Utility Board of Oregon
610 SW Broadway, Ste 400
Portland, OR 97205
mike@oregoncub.org

Wendy Gerlitz (C)
NW Energy Coalition
1205 SE Flavel
Portland, OR 97202
wendy@nwenergy.org

Fred Heutte (C)
NW Energy Coalition
1205 SE Flavel
Portland, OR 97202-0308
fred@nwenergy.org

Ralph Cavanagh
Natural Resources Defense Council
111 Sutter St. Floor 20
San Francisco, CA 94104
rcavanagh@nrdc.org

Angus Duncan (C)
Natural Resources Defense Council
2373 NW Johnson St
Portland, OR 97210
angusduncan@b-e-f.org

Dustin Till (C)
Pacific Power
825 NE Multnomah St, Suite 1800
Portland, OR 97232-2149
dustin.till@pacificorp.com

Patrick G Hager
121 SW Salmon Street 1WTC0702
Portland, OR 97204
Pge.opuc.filings@pgn.com;
Patrick.hager@pgn.com

Oregon Dockets
PacifiCorp dba Pacific Power
825 NE Multnomah St, Suite 2000
Portland, OR 97232-2149
oregondockets@pacificorp.com

John Crider (C)
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088
john.crider@state.or.us

Paul Garrahan (C)
Department of Justice
1162 Court St NE
Salem OR, 97301-4096
paul.garrahan@doj.state.or.us

Michael O'Brien (C)
Renewable Northwest
421 SW 6th Avenue, #1125
Portland, OR 97204
michael@renewablenw.org

Bradley Mullins (C)
Mountain West Analytics
333 SW Taylor, Suite 400
Portland, OR 97204
brmullins@mwanalytics.com

Stewart Merrick
Northwest Pipeline GP
295 Chipeta Way
Salt Lake City, UT 84108
Stewart.merrick@williams.com

Gloria Smith (C)
Sierra Club Environmental Law
85 Second Street, 2nd Floor
San Francisco, CA 94105
gloria.smith@sierraclub.org

Renewable NW Dockets
Renewable Northwest
421 SW 6th Avenue, #1125
Portland, OR 97204-1629
dockets@renewablenw.org

V. Denise Saunders (C)
Portland General Electric
121 SW Salmon Street 1WTC1301
Portland, OR 97204
Denise.Saunders@pgn.com

Franco Albi (C)
Portland General Electric
121 SW Salmon Street 1WTC0702
Portland, OR 97204
franco.albi@pgn.com

Colin McConnaha (C)
Dept of Environmental Quality
811 SW Sixth Ave
Portland, OR 97204
Colin.mcconnaha@state.or.us

Michael T. Weirich (C)
Department of Justice
1162 Court St NE
Salem OR, 97301-4096
michael.wierich@state.or.us

Jesse E. Cowell (C)
Davison Van Cleve
333 SW Taylor St, Suite 400
Portland, OR 97204
jec@dvclaw.com

IRP Mailbox
PacifiCorp
825 NE Multnomah St, Suite 800
Portland, OR 97232
irp@pacificorp.com

Travis Ritchie (C)
Sierra Club Environmental Law
85 Second Street, 2nd Floor
San Francisco, CA 94105
Travis.ritchie@sierraclub.org

Irion Sanger (C)
Sanger Law PC
1117 SE 53rd Ave
Portland OR 97215
irion@sanger-law.com

Alexa Zimbalist (C)
Sierra Club
85 Second Street, 2nd Floor
San Francisco, CA 94105
alexa.zimbalist@sierraclub.org

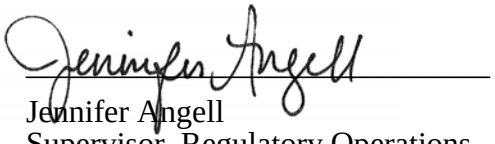
Justin Wilson (C)
Western Clean Energy Campaign
1536 Wynkoop St. Ste 420
Denver, CO 80202
justin@westerncec.org

Nancy Esteb, PhD
PO Box 490
Carlsborg, WA, 98324
Esteb44@centurylink.net

John Lowe
Renewable Energy Coalition
12050 SW Tremont St.
Portland, OR 97225-5430
jravenesanmarcos@yahoo.com

Teresa Hagins
Northwest Pipeline GP
8907 NE 219th Street
Battle Ground, WA 98604
Teresa.l.hagins@williams.com

Dated April 4, 2017.



Jennifer Angell
Supervisor, Regulatory Operations

CERTIFICATE OF SERVICE

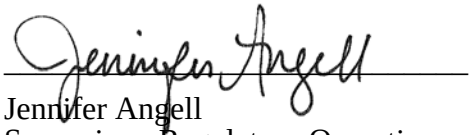
I certify that I electronically filed a true and correct copy of PacifiCorp's **2017 Integrated Resource Plan** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

Service List
LC 67

ICNU LC 67	
JESSE E COWELL **(C)** DAVISON VAN CLEVE 333 SW TAYLOR ST., SUITE 400 PORTLAND, OR 97204 jec@dvclaw.com	BRADLEY MULLINS **(C)** MOUNTAIN WEST ANALYTICS 333 SW TAYLOR STE 400 PORTLAND, OR 97204 brmullins@mwanalytics.com
ODOE LC 67	
DIANE BROAD **(C)** OREGON DEPARTMENT OF ENERGY 625 MARION ST NE SALEM, OR 97301-3737 diane.broad@state.or.us	JESSE D. RATCLIFFE **(C)** OREGON DEPARTMENT OF ENERGY 1162 COURT ST NE SALEM, OR 97301-4096 jesse.d.ratcliffe@doj.state.or.us jesse.d.ratcliffe@doj.state.or.us
WENDY SIMONS **(C)** OREGON DEPARTMENT OF ENERGY 625 MARION ST NE SALEM, OR 97301 wendy.simons@oregon.gov	
OREGON CITIZENS UTILITY BOARD	
OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 dockets@oregoncub.org	MICHAEL GOETZ **(C)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY STE 400 PORTLAND, OR 97205 mike@oregoncub.org
ROBERT JENKS **(C)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY STE 400 PORTLAND, OR 97205 bob@oregoncub.org	
PGE LC 67	
FRANCO ALBI PORTLAND GENERAL ELECTRIC 121 SW SALMON ST, 1WTC0702 PORTLAND, OR 97204 franco.albi@pgn.com	PATRICK G HAGER PORTLAND GENERAL ELECTRIC 121 SW SALMON ST 1WTC0702 PORTLAND, OR 97204 pge.opuc.filings@pgn.com patrick.hager@pgn.com

V. DENISE SAUNDERS PORTLAND GENERAL ELECTRIC 121 SW SALMON ST 1WTC1301 PORTLAND, OR 97204 denise.saunders@pgn.com	
RENEWABLE NW LC 67	
RENEWABLE NORTHWEST 421 SW 6TH AVE., STE. 1125 PORTLAND, OR 97204 dockets@renewablenw.org	MICHAEL O'BRIEN **(C)** RENEWABLE NORTHWEST 421 SW 6TH AVENUE #1125 PORTLAND, OR 97204 michael@renewablenw.org
SILVIA TANNER RENEWABLE NORTHWEST 421 SW 6TH AVE, STE 1125 PORTLAND, OR 97204 silvia@renewablenw.org	
STAFF LC 67	
BENJAMIN FITCH-FLEISCHMANN **(C)** PUBLIC UTILITY COMMISSION OF OREGON PO BOX 1088 SALEM, OR 97308 ben.fitch@state.or.us	SOMMER MOSER **(C)** PUC STAFF - DEPARTMENT OF JUSTICE 1162 COURT ST NE SALEM, OR 97301 sommer.moser@doj.state.or.us
MICHAEL T WEIRICH **(C)** PUC STAFF--DEPARTMENT OF JUSTICE BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM, OR 97301-4096 michael.weirich@state.or.us	
PACIFICORP LC 67	
PACIFICORP, DBA PACIFIC POWER 825 NE MULTNOMAH ST, STE 2000 PORTLAND, OR 97232 oregondockets@pacificorp.com	ERIN APPERSON PACIFIC POWER 825 NE MULTNOMAH STE 800 PORTLAND, OR 97232 erin.apperson@pacificorp.com
R. BRYCE DALLEY PACIFIC POWER 825 NE MULTNOMAH ST., STE 2000 PORTLAND, OR 97232 bryce.dalley@pacificorp.com	

Dated April 4, 2017.



Jennifer Angell
Supervisor, Regulatory Operations

2017 INTEGRATED RESOURCE PLAN

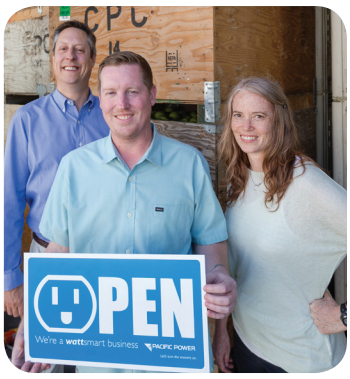
Volume I

April 4, 2017











PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

This 2017 Integrated Resource Plan Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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

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Solar: *Pavant Solar Plant*
Transmission: *Sigurd to Red Butte Transmission Line*
Demand-Side Management: *Smart thermostat*
Pacific Power wattsmart Business Customer Meeting
Thermal-Gas: *Blundell Geothermal Plant*

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CHAPTER 1 – EXECUTIVE SUMMARY

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

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

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

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

Figure 1.1 – Key Elements of PacifiCorp's IRP Process



Preferred Portfolio Highlights

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

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

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

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

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

New Renewable Resources and Transmission

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

Beyond 2020, the preferred portfolio includes an additional 859 MW of new wind—85 MW of Wyoming wind coming online in 2031, and 774 MW of Idaho wind in 2036. New solar resource

additions totaling 1,040 MW come on-line over the 2028 to 2036 timeframe. Approximately 77 percent of the new solar is located in Utah (beginning 2031), and the remaining 23 percent is located on the west side of PacifiCorp's system (beginning 2028).

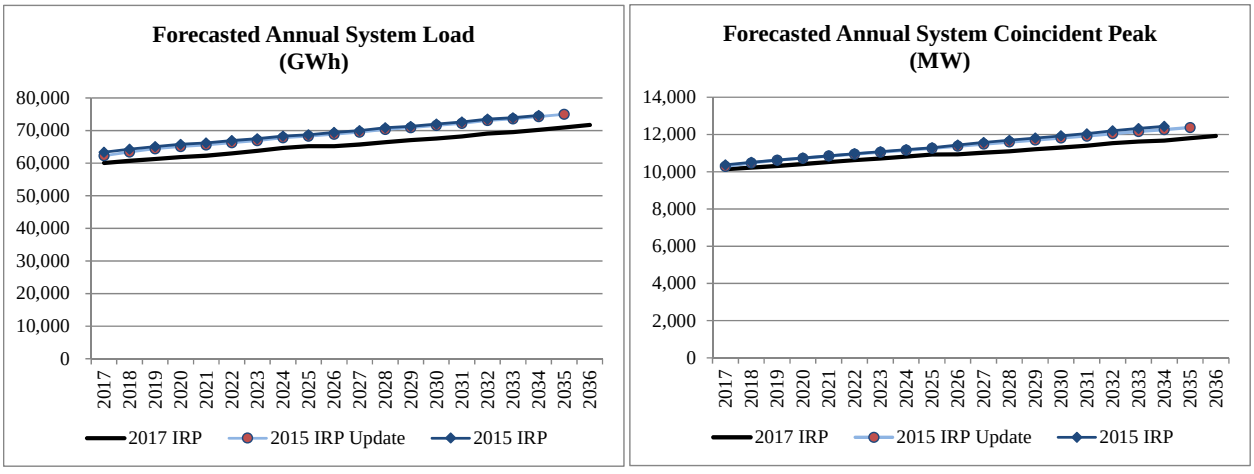
Wind Repowering

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

Demand Side Management

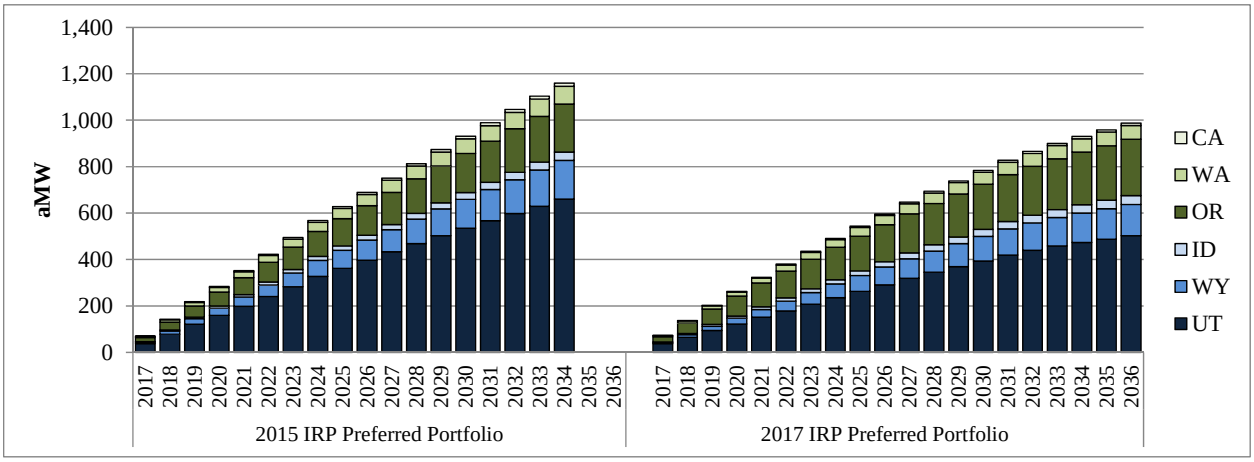
PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and direct load control programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. Consequently, the load forecast used as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

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



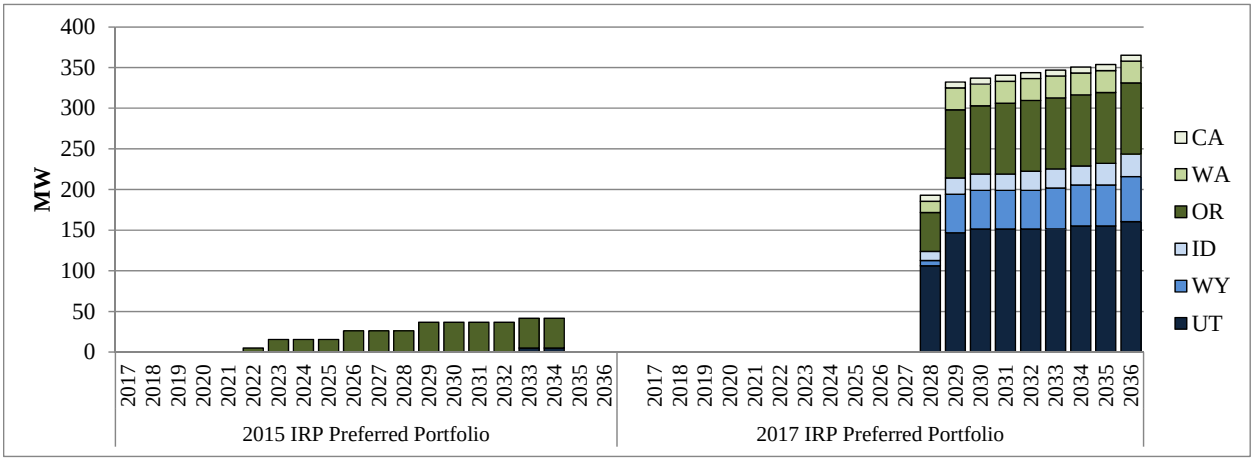
DSM resources continue to play a key role in PacifiCorp's resource mix. Over the first ten years of the planning horizon, accumulated acquisition of new incremental energy efficiency resources meets 88 percent of forecasted load growth from 2017 through 2026 (up from 86 percent in the 2015 IRP). Figure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

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



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

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



Wholesale Power Market Purchases

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

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

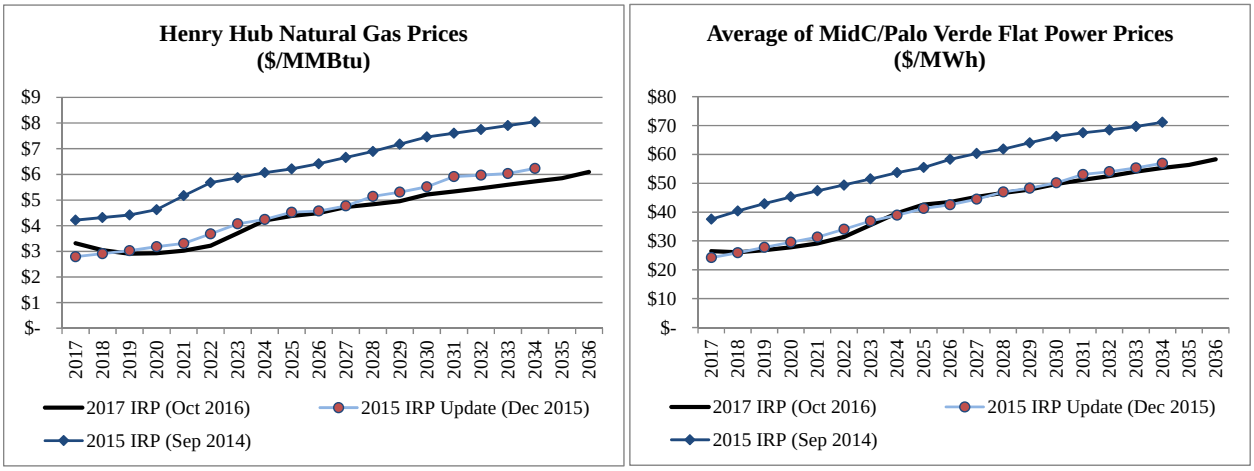
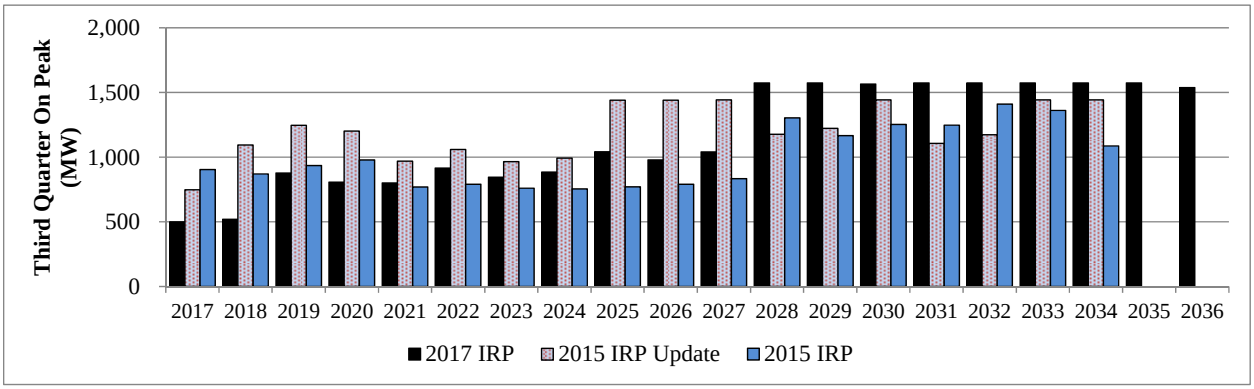


Figure 1.6 compares wholesale market firm purchases from the 2017 IRP preferred portfolio to the market purchases included in the preferred portfolio of recent IRPs. While market conditions for firm wholesale power purchases are favorable, reduced loads and continued investment in energy efficiency programs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

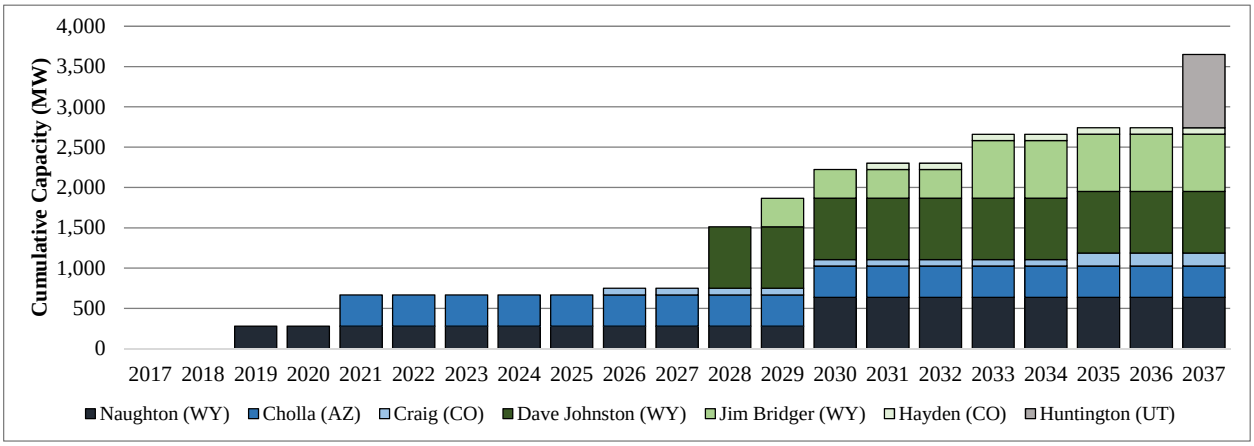
Figure 1.6 – Comparison of Summer Market Purchases in Recent IRPs



Existing Coal Resources

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

Figure 1.7 – 2017 IRP Preferred Portfolio Coal Unit Retirements



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

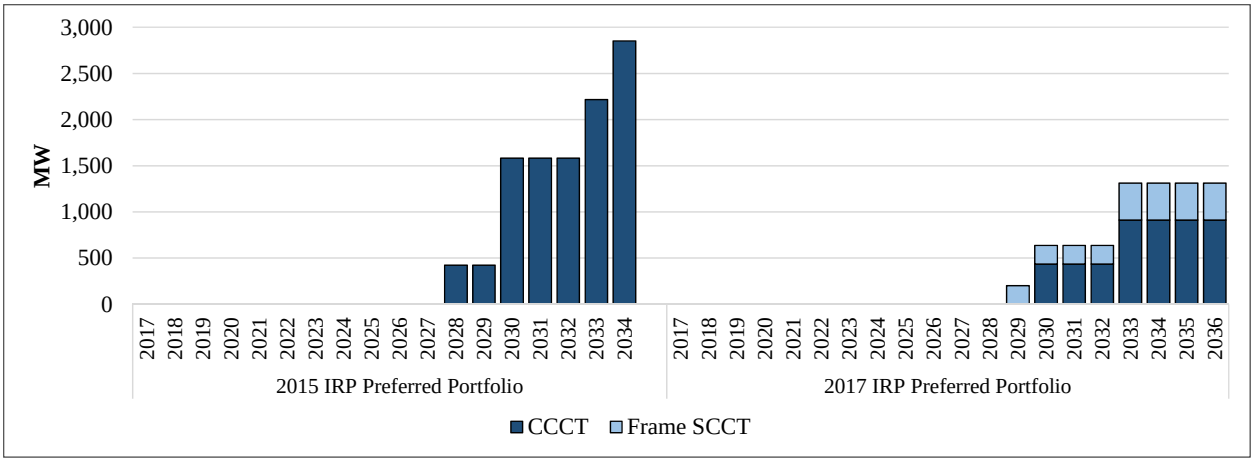
Reflecting an updated operating permit from the state of Wyoming, PacifiCorp assumes Naughton Unit 3 retires at the end of 2018—one year later than in the 2015 IRP Update.

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

Natural Gas Resources

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

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



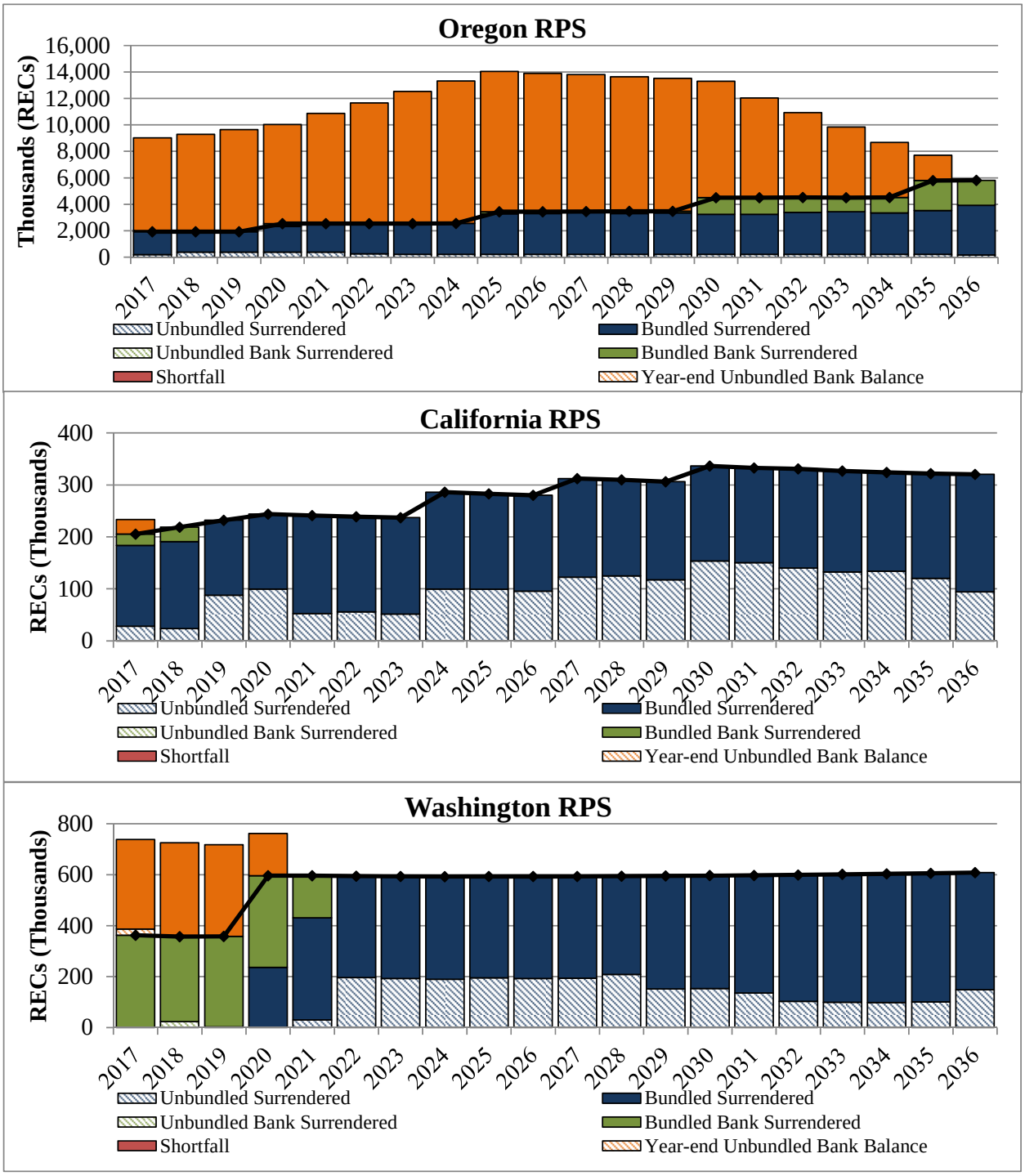
Renewable Portfolio Standards

Figure 1.9 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for the wind repowering project and new

renewable resources in the preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources, they also contribute to meeting RPS targets in PacifiCorp's western states.

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

Figure 1.9 – Annual State RPS Compliance Forecast

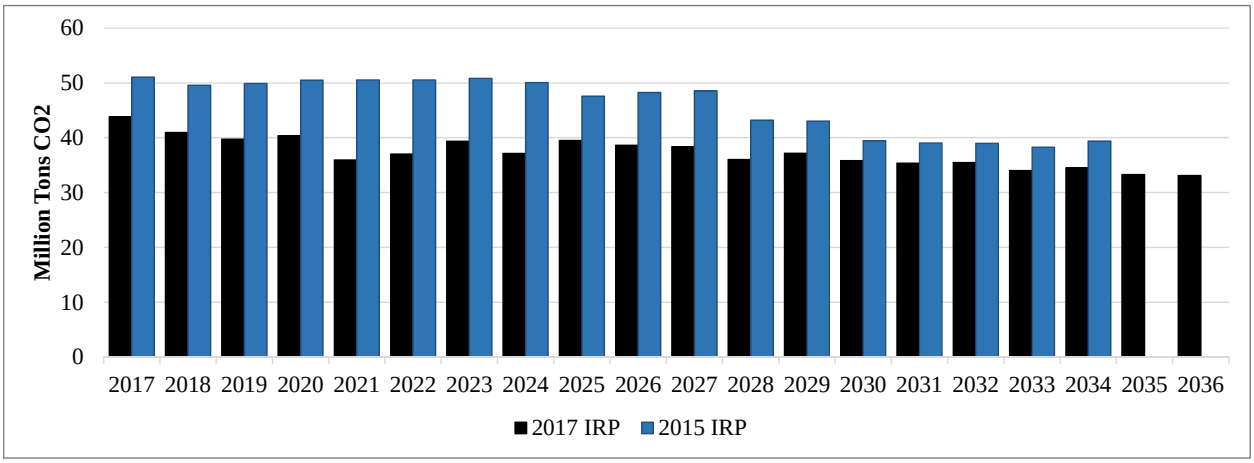


Carbon Dioxide Emissions

The 2017 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects a continued trajectory of declining carbon dioxide (CO_2) emissions. PacifiCorp's emissions have been declining and continue to decline as a result of a number of factors, including PacifiCorp's participation in the Energy Imbalance Market (EIM), which reduces customer costs and maximizes use of clean

energy; PacifiCorp's on-going expansion of renewable resources and transmission; and Regional Haze compliance that capitalizes on flexibility. Figure 1.10 compares projected annual CO_2 emissions between the 2017 IRP and 2015 IRP preferred portfolios. Over the first 10 years of the planning horizon, average annual CO_2 emissions are down by over 10.5 million tons (21 percent) relative to the 2015 IRP. By the end of the planning horizon, system CO_2 emissions are projected to fall from 43.8 million tons in 2017 to 33.1 million tons in 2036—a 24.5 percent reduction.

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



Load and Resource Balance

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

Capacity Balance

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

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

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

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

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

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

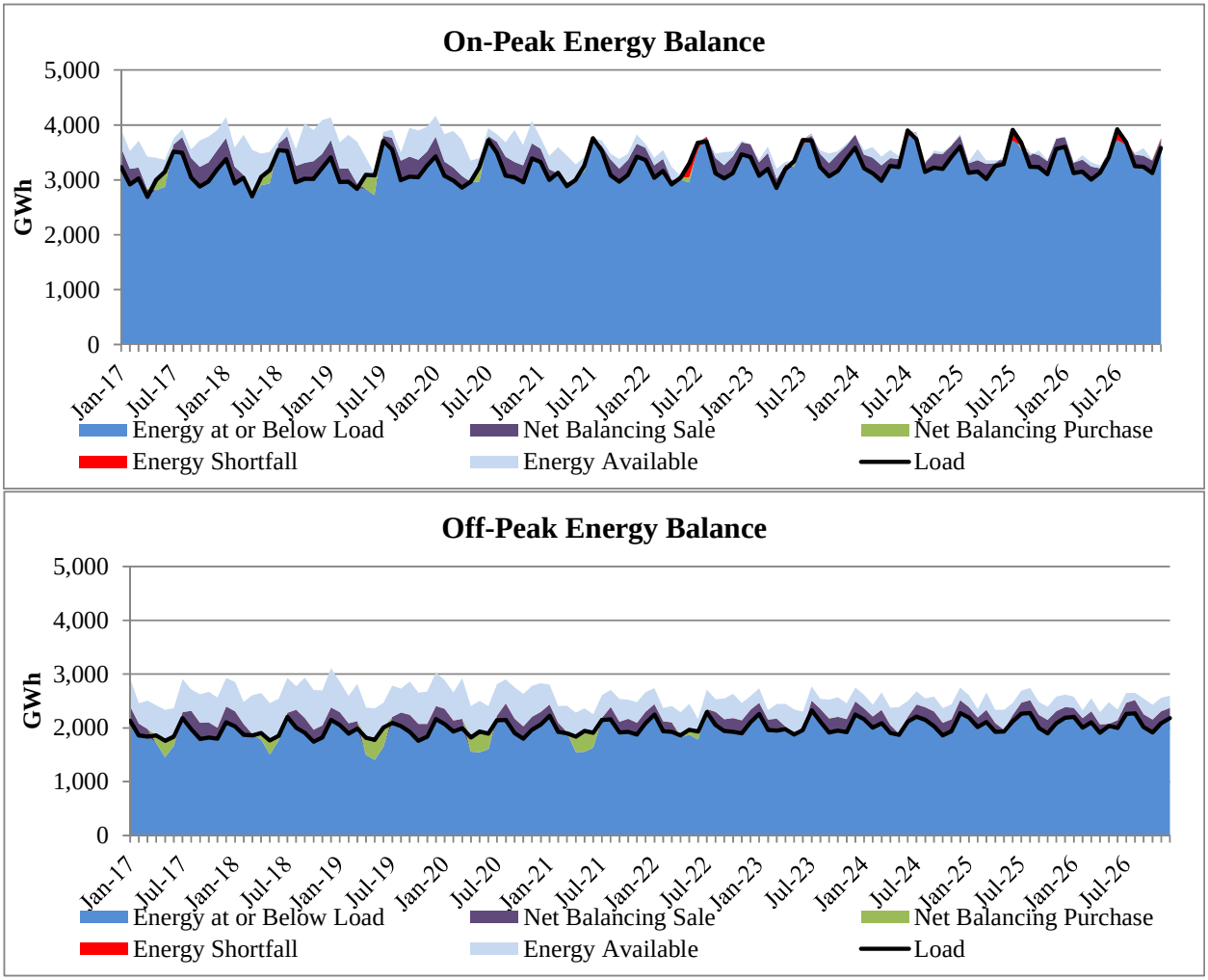
Energy Balance

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

Figure 1.11 provides a snapshot of how existing system resources could be used to meet forecasted load across on-peak and off-peak periods given current planning assumptions and

recent wholesale power and natural gas prices.[1] The figure shows expected monthly energy production from system resources during on-peak and off-peak periods in relation to load, reflecting coal unit retirement assumptions and incremental energy efficiency savings from the 2017 IRP preferred portfolio before adding any new generating resources. At times, system resources are economically dispatched above load levels facilitating net system balancing sales. This occurs more often in off-peak periods than in on-peak periods. At other times, economic conditions result in net system balancing purchases, which occur more often during on-peak periods. Figure 1.11 also shows how much system energy is available from existing resources at any given point in time. Those periods where all available resource energy falls below forecasted loads are highlighted in red, and indicate short energy positions without addition of any new generating resources to the portfolio. During on-peak periods, the first energy shortfall appears in summer 2022. There are no energy shortfalls during off-peak periods over this timeframe.

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



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

2017 IRP Advancements and Supplemental Studies

IRP Advancements

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

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

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

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

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

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

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

Supplemental Studies

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

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

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

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

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

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

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

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

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

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

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

Action Plan

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

Table 1.4 - 2017 IRP Action Plan

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

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

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

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

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

CHAPTER 2 – INTRODUCTION

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

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

Other significant studies conducted to support the 2017 IRP include:

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

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

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

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

2017 Integrated Resource Plan Components

The basic components of PacifiCorp's 2017 IRP include:

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

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

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

In an effort to improve transparency PacifiCorp is also providing data discs for the 2017 IRP. These discs support and provide additional details for the analysis described within the

document. Discs containing confidential information are provided separately under non-disclosure agreements, or specific protective orders in docketed proceedings.

The Role of PacifiCorp's Integrated Resource Planning

PacifiCorp's IRP mandate is to assure, on a long-term basis, an adequate and reliable electricity supply at a reasonable cost and in a manner "consistent with the long-run public interest."[1] The main role of the IRP is to serve as a roadmap for determining and implementing the Company's long-term resource strategy according to this IRP mandate. In doing so, it accounts for state commission IRP requirements, the current view of the planning environment, corporate business goals, and uncertainty. As a business planning tool, it supports informed decision-making on resource procurement by providing an analytical framework for assessing resource investment tradeoffs, including supporting RFP bid evaluation efforts. As an external communications tool, the IRP engages numerous stakeholders in the planning process and guides them through the key decision points leading to PacifiCorp's preferred portfolio of generation, demand-side, and transmission resources.

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

Public Input Process

The IRP standards and guidelines for certain states require PacifiCorp to have a public input process allowing stakeholder involvement in all phases of plan development. The Company organized five state meetings and held seven public meetings, some of which spanning two days to facilitate information sharing, collaboration, and expectations for the 2017 IRP. The topics covered all facets of the IRP process, ranging from specific input assumptions to the portfolio modeling and risk analysis strategies employed. Table 2.1 lists the public input meetings/conferences and highlights major agenda items covered. Volume II, Appendix C (Public Input Process) provides more details concerning the public input process.

Table 2.1 – 2017 IRP Public Input Meetings

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

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

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

In addition to the public input meetings, PacifiCorp used other channels to facilitate resource planning-related information sharing and consultation throughout the IRP process. The Company maintains a public website (https://www.pacificorp.com/es/irp.html), an e-mail "mailbox" (irp@pacificorp.com), and a dedicated IRP phone line (503-813-5245) to support stakeholder communications and address inquiries by public participants. Additionally, a stakeholder Feedback Form was used to provide opportunities for stakeholders to submit additional input and ask questions throughout the 2017 IRP public input process. The submitted forms are located on the PacifiCorp's IRP website: https://www.pacificorp.com/es/irp/irpcomments.html in the comments section.

CHAPTER 3 – THE PLANNING ENVIRONMENT

CHAPTER HIGHLIGHTS

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

Introduction

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

Major issues in the power industry market include capacity resource adequacy and associated standards for the Western Electricity Coordinating Council (WECC). As discussed elsewhere in this IRP, future natural gas prices, the role of gas-fired generation and the falling costs and increasing efficiencies of renewables are some of the critical factors affecting the selection of the portfolio that best achieves least-cost, least-risk planning objectives.

On the government policy and regulatory front, a significant issue facing PacifiCorp continues to be planning for an eventual, but highly uncertain, climate change regulatory regime. This chapter focuses on climate change regulatory initiatives. A high-level summary of the Company's greenhouse gas emissions mitigation strategy is included as well as a review of significant policy developments for currently regulated pollutants.

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

Wholesale Electricity Markets

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

PacifiCorp actively participates in the wholesale market by making purchases and sales to keep its supply portfolio in balance with customers' constantly varying needs. This interaction with the market takes place on time scales ranging from sub-hourly to years in advance. Without the wholesale market, PacifiCorp or any other load serving-entity would need to construct or own an unnecessarily large margin of supply that would go unused in all but the most unusual circumstances and would substantially diminish the ability to cost-effectively match delivery patterns to the profile of customer demand.

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

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

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

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

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

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

As with all markets, electricity markets are faced with a wide range of uncertainties, although some uncertainties are easier to evaluate than others. Market participants are routinely studying demand uncertainties driven by weather and overall economic conditions. Similarly, there is a reasonable amount of data available to gauge resource supply developments. For example, WECC publishes an annual assessment of power supply and numerous data services track the status of new resource additions. A review of the WECC power supply assessment is provided in Volume II, Appendix J (Western Resource Adequacy Evaluation). The latest assessment, published December 2016, indicates that even when including only existing and under-construction units, WECC as a whole has ample resources through 2026. WECC's Californian and Mexican sub-regions, however, fall short starting 2024. The WECC sub-regions in which PacifiCorp operates (Northwest Power Pool and Rocky Mountain Reserve Group) are both capacity sufficient through 2026.

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

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

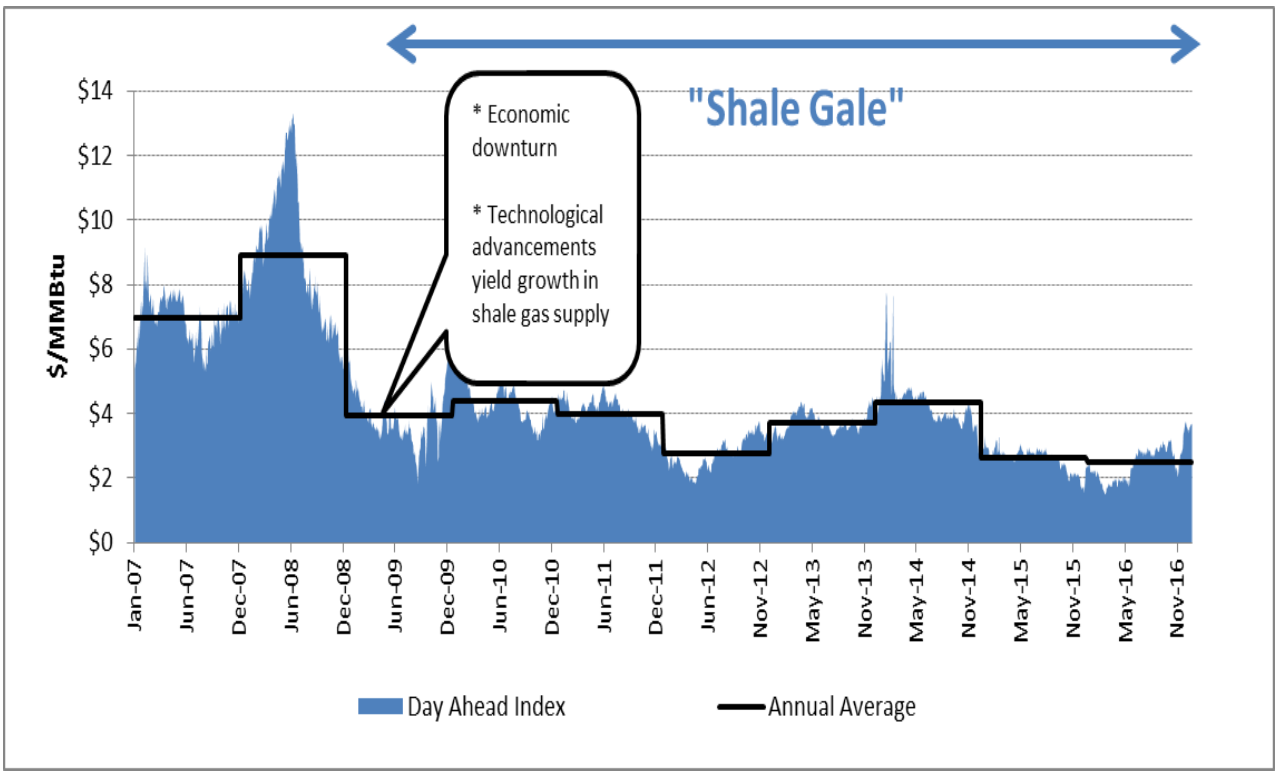
Natural Gas Uncertainty

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

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

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

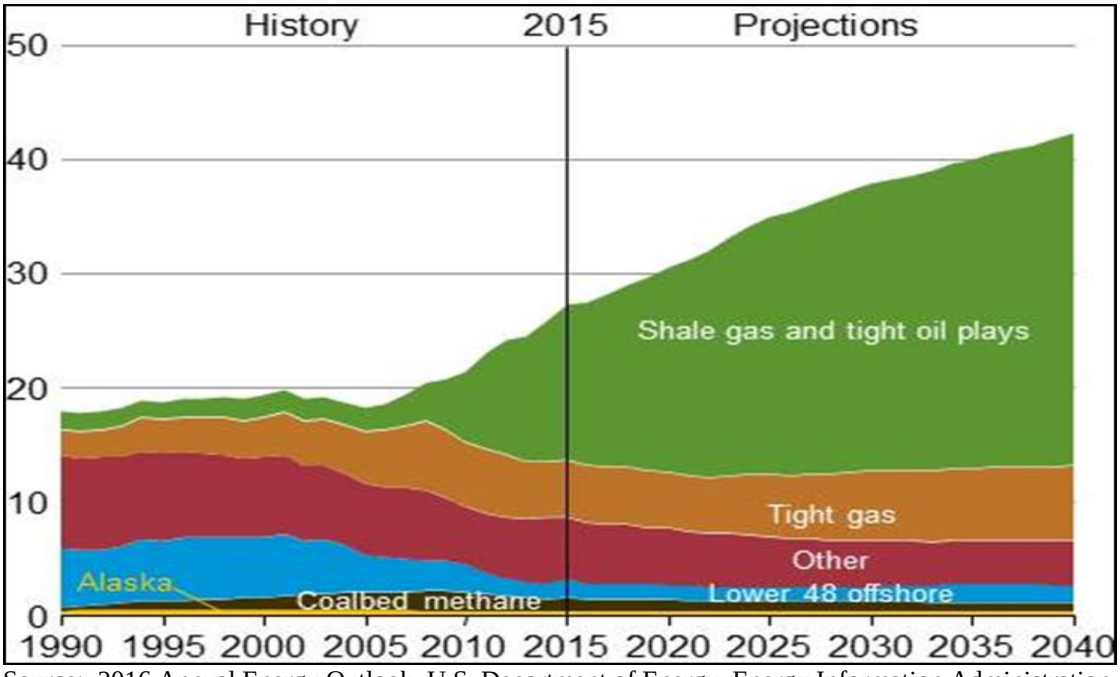
Figure 3.1 – Henry Hub Day-Head Gas Price History



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

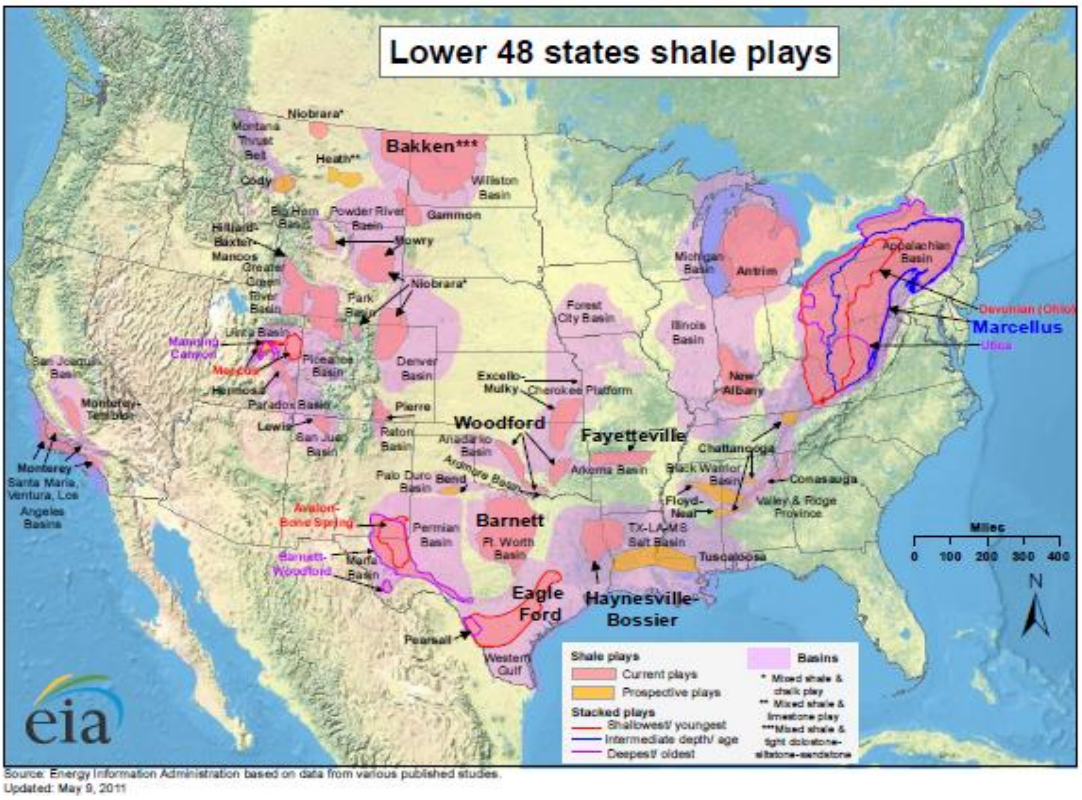
Historically, depletion of conventional mature resources largely offset unconventional resource growth. But as shale gas "came into its own," production gains outpaced depletion. Figure 3.2 through Figure 3.4 show United States natural gas production by source and location.

Figure 3.2 – U.S. Dry Natural Gas Production



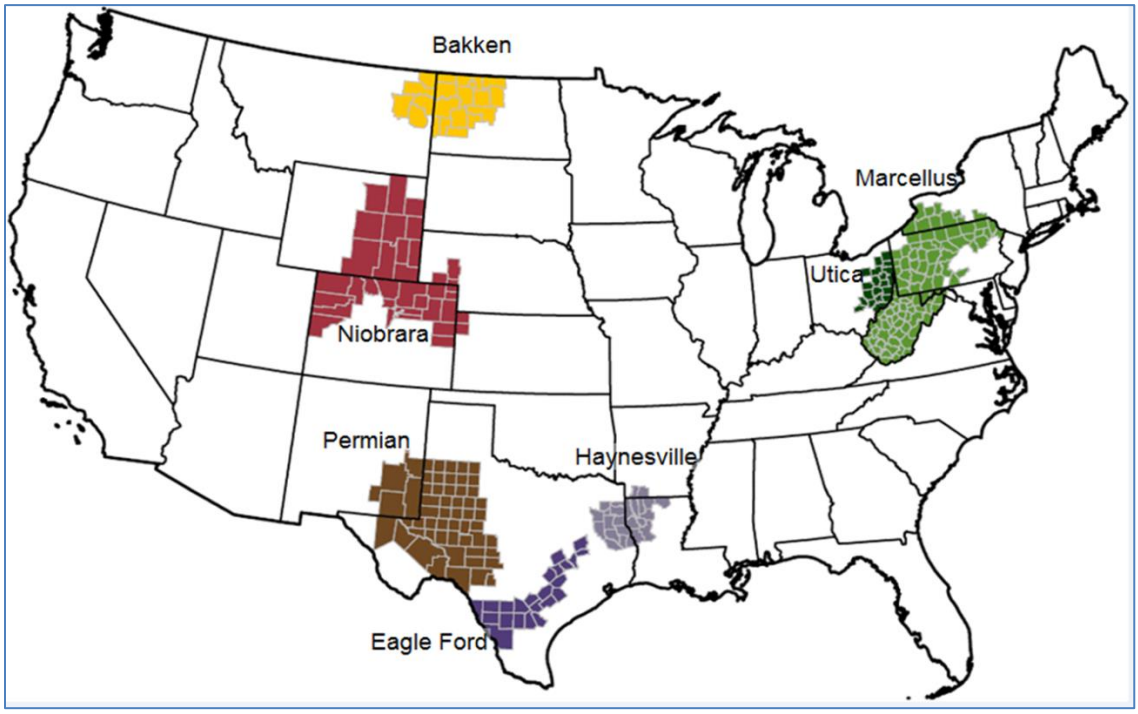
Source: 2016 Annual Energy Outlook, U.S. Department of Energy, Energy Information Administration

Figure 3.3 – Lower 48 States Shale Plays



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

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



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

Figure 3.5 shows Henry Hub NYMEX futures as of January 20, 2017. While futures are mildly in contango, it would appear that price expectations offer little "signal-to-drill." But as producers

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

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

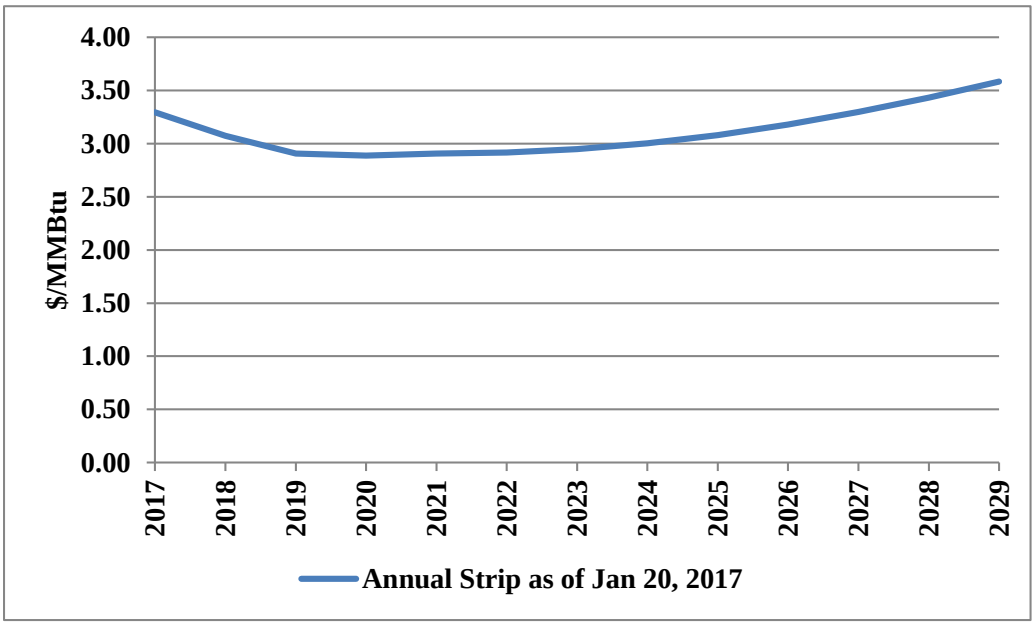
This resiliency of supply coupled with the flexibility to quickly ramp up production will shorten the length of asynchronous supply and demand cycles. Unexpected weather-induced demand spikes or cuts, as well as supply disruptions, will still whipsaw prices for short periods of time. But LNG startups,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

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

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

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

Figure 3.5 – Henry Hub NYMEX Futures



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

The Future of Federal Environmental Regulation and Legislation

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

Federal Climate Change Legislation

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

Federal Renewable Portfolio Standards

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

Federal Policy Update

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

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

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

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

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

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

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

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

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

Clean Air Act Criteria Pollutants – National Ambient Air Quality Standards

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

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

Regional Haze

EPA's regional haze rule, finalized in 1999, requires states to develop and implement plans to improve visibility in certain national park and wilderness areas. On June 15, 2005, EPA issued final amendments to its regional haze rule. These amendments apply to the provisions of the regional haze rule that require emission controls known as the Best Available Retrofit Technology (BART) for industrial facilities meeting certain regulatory criteria with emissions that have the potential to affect visibility. These pollutants include fine PM, NO_X, SO_2, certain volatile organic compounds, and ammonia. The 2005 amendments included final guidelines, known as BART guidelines, for states to use in determining which facilities must install controls and the type of controls the facilities must use. States were given until December 2007 to develop their implementation plans, in which states were responsible for identifying the facilities that would have to reduce emissions under BART guidelines, as well as establishing BART emissions limits for those facilities. States are also required to periodically update or revise their implementation plans to reflect current visibility data and the effectiveness of the state's long-term strategy for achieving reasonable progress toward visibility goals. On December 14, 2016, EPA issued a final rule setting forth revised and clarifying requirements for periodic updates in state implementation plans. States are currently required to submit the next periodic update by July 31, 2021.

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

Utah Regional Haze

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

Wyoming Regional Haze

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

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

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

Arizona Regional Haze

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

Colorado Regional Haze

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

Mercury and Hazardous Air Pollutants

The Mercury and Air Toxics Standards (MATS) became effective April 16, 2012. The MATS rule requires that new and existing coal-fueled facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources were required to comply with the new standards by April 16, 2015. However, individual sources may have been granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls or for transmission system reliability reasons. In June 2015, the U.S. Supreme Court found that EPA did not properly consider costs in making its determination to regulate hazardous pollutants from power plants. In December 2015, the D.C. Circuit Court of Appeals ruled that MATS may be enforced as EPA modifies the rule to comply with the Supreme Court decision. By April 2015, PacifiCorp had taken the required actions to comply with MATS across its generation facilities.

Coal Combustion Residuals

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

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

The legislation:

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

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

Water Quality Standards

Cooling Water Intake Structures

The federal Water Pollution Control Act ("Clean Water Act") establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among other things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact" to aquatic organisms. In May 2014, EPA issued a final rule, effective October 2014, under § 316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The final rule established requirements for electric generating facilities that withdraw more than two million gallons per day, based on total design intake capacity, of water from waters of the United States and use at least 25 percent of the withdrawn water exclusively for cooling purposes. PacifiCorp's Dave Johnston generating facility withdraws more than two million gallons per day of water from waters of the U.S. for once-through cooling applications. Jim Bridger, Naughton, Gadsby, Hunter, and Huntington generating facilities currently use closed-cycle cooling towers but withdraw more than two million gallons of water per day. The rule includes impingement (i.e., when fish and other aquatic organisms are trapped against screens when water is drawn into a facility's cooling system) mortality standards and entrainment (i.e., when organisms are drawn into the facility) standards. The standards will be set on a case-by-case basis to be determined through site-specific studies and will be incorporated into each facility's discharge permit.

Effluent Limit Guidelines

EPA first issued effluent guidelines for the Steam Electric Power Generating Point Source Category (i.e., the Steam Electric effluent guidelines) in 1974, with subsequent revisions in 1977 and 1982. On November 3, 2015, EPA finalized revised effluent limit guidelines. The rule does not allow the discharge of bottom ash or fly ash transport water and directly impacts the Wyodak, Dave Johnston, and Naughton facilities.

2015 Tax Extender Legislation

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

Bonus Depreciation

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

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

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

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

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

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

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

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

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

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

State Policy Update

California

Under the authority of the Global Warming Solutions Act, the California Air Resources Board (CARB) adopted a greenhouse gas cap-and-trade program in October 2011, with an effective date of January 1, 2012; compliance obligations were imposed on regulated entities beginning in

2013. The first auction of greenhouse gas allowances was held in California in November 2012, and the second auction in February 2013. PacifiCorp is required to sell, through the auction process, its directly allocated allowances and purchase the required amount of allowances necessary to meet its compliance obligations.

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

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

Oregon

In 2007, the Oregon Legislature passed House Bill (HB) 3543 – Global Warming Actions, which establishes greenhouse gas reduction goals for the state that: (1) end the growth of Oregon greenhouse gas emissions by 2010; (2) reduce greenhouse gas levels to 10 percent below 1990 levels by 2020; and (3) reduce greenhouse gas levels to at least 75 percent below 1990 levels by 2050. In 2009, the legislature passed SB 101, which requires the Public Utility Commission of Oregon (OPUC) to submit a report to the legislature before November 1 of each even-numbered year regarding the estimated rate impacts for Oregon's regulated electric and natural gas companies of meeting the greenhouse gas reduction goals of 10 percent below 1990 levels by 2020 and 15 percent below 2005 levels by 2020. The OPUC submitted its most recent report November 1, 2014.

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

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

bill also includes provisions to create a community solar program in Oregon and encourage greater reliance on electricity for transportation.

Washington

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

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

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

Utah

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

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

Greenhouse Gas Emission Performance Standards

California, Oregon and Washington have all adopted greenhouse gas emission performance standards applicable to all electricity generated in the state or delivered from outside the state

that is no higher than the greenhouse gas emission levels of a state-of-the-art combined cycle natural gas generation facility. The standards for Oregon and California are currently set at 1,100 lb CO_2/MWh, which is defined as a metric measure used to compare the emissions from various greenhouse gases based on their global warming potential. In March 2013, the Washington Department of Commerce issued a new rule, effective April 6, 2013, lowering the emissions performance standard to 970 lb CO_2/MWh.

Renewable Portfolio Standards

An RPS requires a retail seller of electricity to include in its resource portfolio a certain amount of electricity from renewable energy resources, such as wind, geothermal and solar energy. The retailer can satisfy this obligation by using renewable energy from its own facilities, purchasing renewable energy from another supplier's facilities, using Renewable Energy Credits (RECs) that certify renewable energy has been created, or a combination of all of these.

RPS policies are currently implemented at the state level and vary considerably in their renewable targets (percentages), target dates, resource/technology eligibility, applicability of existing plants and contracts, arrangements for enforcement and penalties, and use of REC trading. By the end of 2016, twenty-nine states, the District of Columbia, and three territories had adopted a mandatory RPS, and eight states and one territory had adopted RPS goals.[12]

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

Table 3.1– State RPS Requirements

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

California

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

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

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

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

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

Table 3.2 – California Compliance Period Requirements

Compliance Period	Procurement Quantity Requirement Calculation
Compliance Period 1 (2011-2013)	(20% * 2011 Retail Sales) + (20% * 2012 Retail Sales) + (20% * 2013 Retail Sales)
Compliance Period 2 (2014-2016)	(21.7% * 2014 Retail Sales) + (23.3% * 2015 Retail Sales) + (25% * 2016 Retail Sales)
Compliance Period 3 (2017-2020)	(27% * 2017 Retail Sales) + (29% * 2018 Retail Sales) + (31% * 2019 Retail Sales) + (33% * 2020 Retail Sales)
Compliance Period 4 (2021-2024)	(34.8% * 2021 Retail Sales) + (36.5% * 2022 Retail Sales) + (38.3% * 2023 Retail Sales) + (40% * 2024 Retail Sales)
Compliance Period 5 (2025-2027)	(41.7% * 2025 Retail Sales) + (43.3% * 2026 Retail Sales) + (45% * 2027 Retail Sales)
Compliance Period 6 (2028-2030)	(46.7% * 2028 Retail Sales) + (48.3% * 2029 Retail Sales) + (50% * 2030 Retail Sales)

SB 2 (1X) established new "portfolio content categories" for RPS procurement, which delineated the type of renewable product that may be used for compliance and also set minimum and maximum limits on certain procurement content categories that can be used for compliance.

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

- Have a first point of interconnection with a California balancing authority, have a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area, or are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source;[16] or
- Have an agreement to dynamically transfer electricity to a California balancing authority.

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

[14] http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf
[15] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350
[16] The use of another source to provide real-time ancillary services required to maintain an hourly or sub-hourly import schedule into a California balancing authority is permitted, but only the fraction of the schedule actually generated by the eligible renewable energy resource will count toward this portfolio content category

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

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

Table 3.3 – California Balanced Portfolio Requirements

California RPS Compliance Period	Balanced Portfolio Requirement
Compliance Period 1 (2011-2013)	Category 1 – Minimum of 50% of Requirement Category 3 – Maximum of 25% of Requirement
Compliance Period 2 (2014-2016)	Category 1 – Minimum of 65% of Requirement Category 3 – Maximum of 15% of Requirement
Compliance Period 3 (2017-2020) Compliance Period 4 (2021-2024) Compliance Period 5 (2025-2027) Compliance Period 6 (2028-2030)	Category 1 – Minimum of 75% of Requirement Category 3 – Maximum of 10% of Requirement

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

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

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

Oregon

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

[17] A REC can be sold either "bundled" with the underlying energy or "unbundled" as a separate commodity from the energy itself into a separate REC trading market.
[18] http://www.leg.state.or.us/07reg/measpdf/sb0800.dir/sb0838.en.pdf

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

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

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

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

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

Qualifying renewable energy sources can be located anywhere in the United States portion of the Western Electricity Coordinating Council geographic area, and a limited amount of unbundled renewable energy credits can be used toward the annual compliance obligation. Eligible renewable resources include electricity generated from wind, solar photovoltaic, solar thermal, wave, tidal, ocean thermal, geothermal, certain types of biomass and biogas, municipal solid waste, and hydrogen power stations using anhydrous ammonia.

Electricity generated by a hydroelectric facility is eligible if the facility is not located in any federally protected areas designated by the Pacific Northwest Electric Power and Conservation

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

[20] In 2009, Oregon passed House Bill 3039, also called the Oregon Solar Initiative, requiring that on or before January 1, 2020, the total solar photovoltaic generating nameplate capacity must be at least 20 megawatts from all electric companies in the state. The Public Utility Commission of Oregon determined that PacifiCorp's share of the Oregon Solar Initiative was 8.7 megawatts.

Planning Council as of July 23, 1999, or any area protected under the federal Wild and Scenic Rivers Act, P.L. 90-542, or the Oregon Scenic Waterways Act, ORS 390.805 to 390.925; or if the electricity is attributable to efficiency upgrades made to the facility on or after January 1, 1995, and up to 50 average megawatts of electricity per year generated by a certified low-impact hydroelectric facility owned by an electric utility and up to 40 average megawatts of electricity per year generated by certified low-impact hydroelectric facilities not owned by electric utilities.

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

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

Utah

In March 2008, Utah's governor signed Utah SB 202, the Energy Resource and Carbon Emission Reduction Initiative.[22] The Energy Resource and Carbon Emission Reduction Initiative is codified in Utah Code Title 54 Chapter 17. Among other things, this law provides that, beginning in the year 2025, 20 percent of adjusted retail electric sales of all Utah utilities be supplied by renewable energy if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions and for sales avoided as a result of energy efficiency and demand side management programs. Qualifying renewable energy sources can be located anywhere in the Western Electricity Coordinating Council areas, and unbundled renewable energy credits can be used for up to 20 percent of the annual qualifying electricity target.

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

Under the Carbon Reduction Initiative, PacifiCorp is required to file a progress report by January 1 of each of the years 2010, 2015, 2020 and 2024. Following PacifiCorp's December 31, 2009 progress report, the Utah Division of Public Utilities' report to the Legislature stated: "Given PacifiCorp's projections of its loads and qualifying electricity for 2025, PacifiCorp is well positioned to meet a target of 20 percent renewable energy by 2025."

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

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

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

Washington

In November 2006, Washington voters approved I-937, a ballot measure establishing the Energy Independence Act, which is an RPS and energy efficiency requirement applied to qualifying electric utilities, including PacifiCorp.[23] The law requires that qualifying utilities procure at least three percent of retail sales from eligible renewable resources or RECs by January 1, 2012 through 2015; nine percent of retail sales by January 1, 2016 through 2019; and 15 percent of retail sales by January 1, 2020, and every year thereafter.

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

PacifiCorp is required to file an annual RPS compliance report by June 1 of every year with the Washington Utilities and Transportation Commission demonstrating compliance with the Energy Independence Act. PacifiCorp's compliance reports are available on PacifiCorp's website.[24]

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

Transportation Electrification

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

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

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

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

Hydroelectric Relicensing

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

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

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

FERC has sole jurisdiction under the Federal Power Act to issue new operating licenses for non-federal hydroelectric projects on navigable waterways, federal lands, and under other criteria. FERC must find that the project is in the broad public interest. This requires weighing, with "equal consideration," the impacts of the project on fish and wildlife, cultural resources, recreation, land use, and aesthetics against the project's energy production benefits. Because some of the responsible state and federal agencies have the ability to place mandatory conditions in the license, FERC is not always in a position to balance the energy and environmental equation. For example, the National Oceanic and Atmospheric Administration Fisheries agency

and the U.S. Fish and Wildlife Service have the authority in the relicensing process to require installation of fish passage facilities (fish ladders and screens) and to specify their design. This is often the largest single capital investment that will be considered in relicensing and can significantly impact project economics. Also, because a myriad of other state and federal laws come into play in relicensing, most notably the Endangered Species Act and the Clean Water Act, agencies' interests may compete or conflict with each other, leading to potentially contrary or additive licensing requirements. PacifiCorp has generally taken a proactive approach towards achieving the best possible relicensing outcome for its customers by engaging in negotiations with stakeholders to resolve complex relicensing issues through settlement agreements that are submitted to FERC for incorporation into a new license. FERC welcomes license applications that reflect broad stakeholder involvement or that incorporate measures agreed upon through multi-party settlement agreements. History demonstrates that with such support, FERC generally accepts proposed new license terms and conditions reflected in settlement agreements.

Potential Impact

Relicensing hydroelectric facilities involves significant process costs. The FERC relicensing process takes a minimum of five years and may take longer, depending on the characteristics of the project, the number of stakeholders, and issues that arise during the process. As of December 31, 2016, PacifiCorp had incurred approximately $16 million in costs for license implementation and ongoing hydroelectric relicensing, which are included in construction work-in-progress on PacifiCorp's Consolidated Balance Sheet. As current or upcoming relicensing and settlement efforts continue for the Weber, Prospect No. 3, and other hydroelectric projects, additional process costs are being or will be incurred that will need to be recovered from customers. Hydroelectric relicensing costs have and will continue to have a significant impact on overall hydroelectric generation cost. Such costs include capital investments and related operations and maintenance costs associated with fish passage facilities, recreational facilities, wildlife protection, cultural and flood management measures. Project operational and flow-related changes, such as increased in-stream flow requirements to protect aquatic resources, can also directly result in lost generation. The majority of these relicensing and settlement costs relate to PacifiCorp's three largest hydroelectric projects: Lewis River, Klamath River, and North Umpqua.

Treatment in the IRP

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

PacifiCorp's Approach to Hydroelectric Relicensing

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

Utah Rate Design Information

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

Residential Rate Design

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

Changes in residential rate design that might facilitate IRP objectives include a critical peak pricing program or an expansion of time-of-use rates. These types of rate designs are discussed in more detail in Volume I, Chapter 6 (Resource Options). As part of the Sustainable Transportation and Energy Plan (STEP) legislation enacted in SB 115, the company developed a pilot time-of-use program to encourage off-peak charging of electric vehicles for residential customers. The results of this pilot may inform future rate design offerings. Any changes in standard residential rate design or institution of optional rate options to support energy efficiency or time-differentiated usage should be balanced with the recovery of fixed costs to ensure price signals are economically efficient and do not unduly shift costs to other customers.

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

Commercial and Industrial Rate Design

Commercial and industrial rates in Utah include customer charges, facilities charges, power charges (for usage over 15 kW) and energy charges. As with residential rates, customer charges and facilities charges are generally intended to recover costs that do not vary with energy usage. Power charges are applied to a customer's monthly demand on a kW basis and are intended to recover the costs associated with demand or capacity needs. Energy charges are applied to the customer's metered usage on a kWh basis. All commercial and industrial rates employ seasonal variations in power and/or energy charges with higher rates in the summer months to reflect the higher costs to serve during the summer peak period. Additionally, for customers with load 1,000 kW or more, rates are further differentiated by on-peak and off-peak periods for both power and energy charges. For commercial and industrial customers with load less than 1,000 kW, the company offers two optional time-of-day rates—one that differentiates energy rates for on- and off-peak usage, and one that differentiates power charges by on- and off-peak usage. Currently, about 16 percent of the eligible customers are on the energy time-of-day option and less than one percent are on the power time-of-day option.

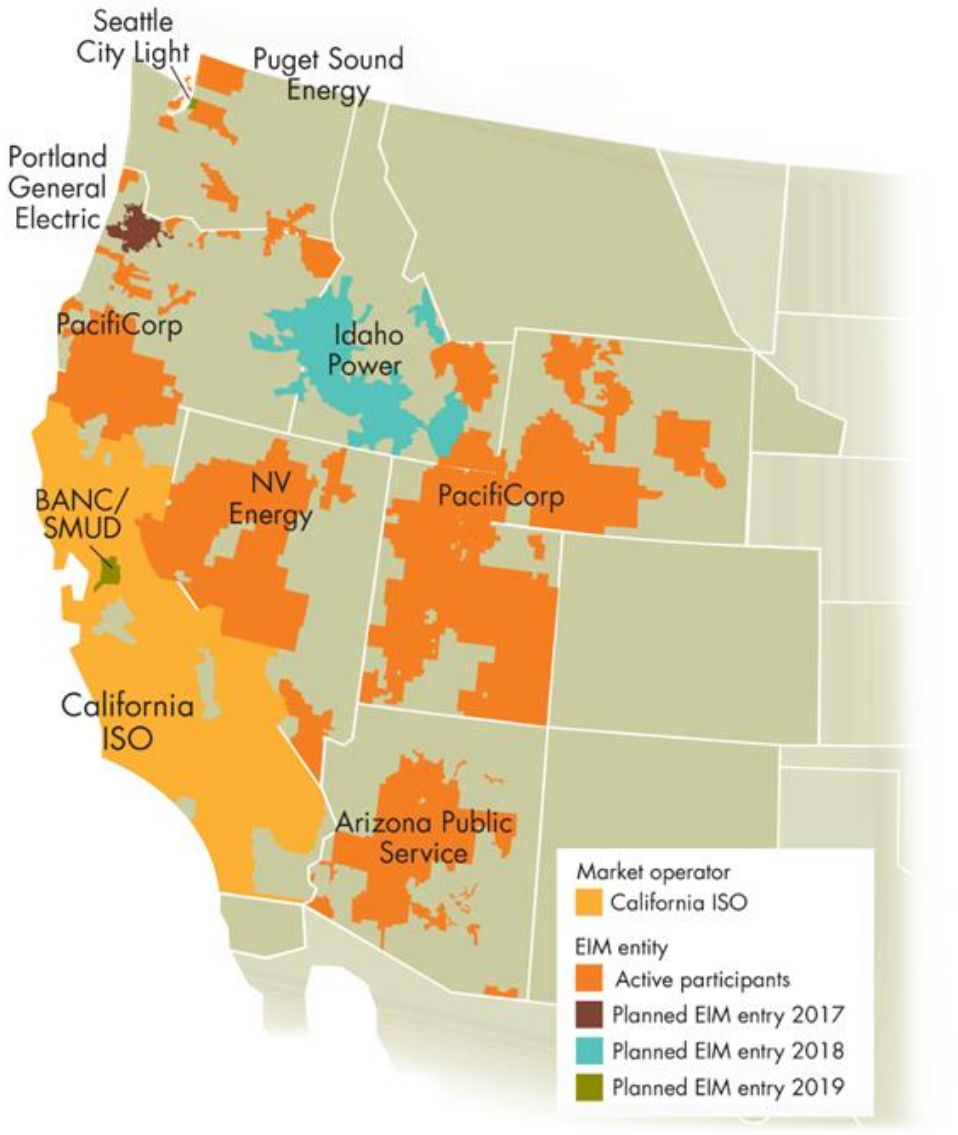
Irrigation Rate Design

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

Energy Imbalance Market

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

Figure 3.6 – Energy Imbalance Market Expansion



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

A significant contributor to EIM benefits are transfers across balancing authority areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations when energy is transferred into the CAISO balancing authority area to serve California load. The transfer volumes are therefore a good indicator of a portion of the

benefits attributed to the EIM. Transfers can take place in both the five and 15-minute market dispatch intervals.

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

Recent Resource Procurement Activities

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

Table 3.4 – PacifiCorp's Request for Proposal Activities

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

Demand Side Management (DSM) Resources

In 2016, through competitive procurement processes, the company selected vendors to continue and adaptively manage the successful, cost-effective delivery of its two largest Class 2 DSM programs: Home Energy Savings and wattsmart Business. Home Energy Savings vendor services include the management of incentives for lighting, appliances, new homes, and other energy efficiency measures and the delivery of wattsmart starter kits containing efficient light bulbs and

water-saving measures. Wattsmart Business vendor services include management of trade ally networks to deliver energy efficiency options to commercial, industrial, and irrigation customers; targeted offerings for small business customers; point-of-purchase incentives for efficient lighting; efficiency options for oil and gas customers; and engineering services for large custom projects. In 2017, PacifiCorp will evaluate and re-procure, as appropriate, the delivery contract(s) for residential behavior program(s).

2017 Transfer Frequency Response Request for Proposals

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

Natural Gas Asset Management and Supply Request for Proposals

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

Renewable Resource and REC Request for Proposals

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

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

2015 Market Resource Request for Proposals

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

Renewable Energy Credits (Sale) Request for Proposals

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

Short-Term Market Power Request for Proposals

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

CHAPTER 4 – TRANSMISSION

CHAPTER HIGHLIGHTS

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

Introduction

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

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

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

Regulatory Requirements

Open Access Transmission Tariff

Consistent with the requirements of its OATT, approved by the Federal Energy Regulatory Commission (FERC), PacifiCorp plans and builds its transmission system based on two customer-type agreements—network customer or point-to-point transmission service. For the network customers, PacifiCorp uses customer ten-year load and resource (L&R) forecasts, as well as network transmission service requests. Each year, the Company solicits L&R data from each of its network customers to determine future load and resource requirements for all transmission network customers. These customers include PacifiCorp Energy Supply Management (ESM) (which serves PacifiCorp's retail customers and comprises the bulk of the Company's transmission network customer needs), Utah Associated Municipal Power Systems, Utah Municipal Power Agency, Deseret Power Electric Cooperative (including Moon Lake Electric Association), Bonneville Power Administration, Basin Electric Power Cooperative, Black Hills Power, Tri-State Generation & Transmission, the United States Department of the Interior Bureau of Reclamation, and the Western Area Power Administration.

The Company uses its customers' L&R forecasts and best available information, including transmission service requests, to determine project need and investment timing. If customer L&R forecasts change significantly, PacifiCorp may consider alternative deployment scenarios or schedules for its project investment, as appropriate. In accordance with FERC guidelines, the Company is able to reserve transmission network capacity based on these data. PacifiCorp's experience, however, is that the lengthy planning, permitting and construction timeline required for significant transmission investments, as well as the typical useful life of these facilities, is well beyond the 10-year timeframe of L&R forecasts.[1] A 20-year planning horizon and ability to reserve transmission capacity to meet existing and forecasted need over that timeframe is more consistent with the time required to plan for and build large-scale transmission projects, and PacifiCorp supports clear regulatory acknowledgement of this reality and corresponding policy guidance.

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

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

Reliability Standards

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

This chapter provides:

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

Request for Acknowledgement of Wallula to McNary

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

Factors Supporting Acknowledgement

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

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

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

Reliability benefits correspond to the fact that with only a single line between Wallula and McNary, line outages, either planned or unplanned, cause disruption of service to customers. This disruption can result in loss of service under existing contracts or reduced reliability for customers served from the Wallula substation. The second line provides service reliability in a single line outage condition. Additionally, the new line will provide lightning protection, allowing continued operation of the line if there is a lightning strike, whereas the existing line is not protected. In the past, customer service has been disrupted due to line outages caused by lightning strikes on the existing line. Constructing a second 230 kV line between the Wallula and McNary substations will provide additional flexibility and added reliability to customers served in the area and is required to comply with PacifiCorp's OATT and Federal Power Act obligations. With the new line in place, outages on either the new or existing line can occur

without interruption of customer service, thus providing added reliability of service. The Walla Walla to McNary transmission project alleviates a constrained transmission path used to move resources into and out of the Walla Walla and Wallula areas. At this time, only the Wallula to McNary transmission line segment is being constructed to meet a customer request for point-to-point service under PacifiCorp's OATT. The segment between Walla Walla and Wallula will be completed when there is a transmission customer need.

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

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

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

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

Plan to Continue – Wallula to McNary

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

Request for Acknowledgement of Aeolus to Bridger/Anticline

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

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

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

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

Factors Supporting Acknowledgement

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

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

Completion of the new transmission segment will allow the addition of up to 1,270 MWs of additional wind resources (depending on re-dispatch) added to the system east of the TOT 4A cut plane. PacifiCorp's preferred portfolio includes 1,100 MW of new wind resources, which reflects a least-cost, least risk mix when the anticipated economic re-dispatch of resources in the area is considered. Importantly, the transmission project includes critical voltage support, which is the

system limitation in the area. The new transmission capacity, voltage support, generation re-dispatch, and a generator tripping scheme will allow for a disproportionate amount of wind generation to be integrated into the system. The 230 kV transmission system today east of the TOT 4A cut plane is operating at the limits of the system and has fully exhausted the ability to interconnect additional resources behind the cut plane. The addition of this new transmission segment has the potential to provide a path for projects sited east of the TOT 4A interconnected at or near Aeolus Substation.

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

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

Gateway West – Continued Permitting

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

Windstar to Populus (Segment D)

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

- D1—A single-circuit 230 kV line that will run approximately 75 miles between the existing Windstar substation in eastern Wyoming and the planned Aeolus substation near Medicine Bow, Wyoming;
- D2—A single-circuit 500 kV line running approximately 140 miles from the planned

Figure 4.1 - Segment D



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

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

Populus to Hemingway (Segment E)

Figure 4.2 - Segment E



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

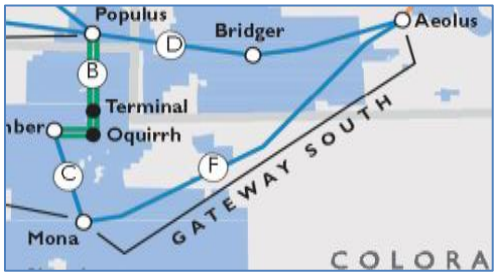
The Gateway West project would enable the Company to more efficiently dispatch system resources, improve performance of the transmission system (i.e., reduce line losses), improve reliability, and enable access to a diverse range of new resource alternatives over the long term.

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

Gateway South – Continued Permitting

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

Figure 4.3 - Segment F



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

Plan to Continue Permitting – Gateway West and Gateway South

The Gateway West and Gateway South transmission projects continue to offer benefits under multiple, future resource scenarios. To ensure the Company is well positioned to advance the

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

Energy Gateway Transmission Expansion Plan

Introduction

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

Background

Until PacifiCorp's announcement of Energy Gateway in 2007, its transmission planning efforts traditionally centered on the generation additions identified in the IRP. With timelines of seven to ten years or more required to site, permit, and build transmission, this traditional planning approach was proven problematic, leading to a perpetual state of transmission planning and new transmission capacity not being available in time to be viable transmission resource options for meeting customer need. The existing transmission system has been at capacity for several years, and new capability is necessary to enable new resource development.

The Energy Gateway Transmission Expansion Plan, formally announced in May 2007, has origins in numerous local and regional transmission planning efforts discussed further below. Energy Gateway was designed to ensure a reliable, adequate system capable of meeting current and future customer needs. Importantly, given the changing resource picture, its design supports multiple future resource scenarios by connecting resource-rich areas and major load centers across PacifiCorp's multi-state service area. In addition, the ability to use these resource-rich areas helps position PacifiCorp to meet current state renewable portfolio requirements. Please refer to the regional maps of wind, solar, biomass, and geothermal potential available on PacifiCorp's Energy Gateway project website to see an overlay of the Energy Gateway project and renewable resource potential.[3] Energy Gateway has since been included in all relevant local, regional and interconnection-wide transmission studies.

Planning Initiatives

Energy Gateway is the result of robust local and regional transmission planning efforts. PacifiCorp has participated in numerous transmission planning initiatives, both leading up to and since Energy Gateway's announcement. Stakeholder involvement has played an important role in each of these initiatives, including participation from state and federal regulators, government

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

agencies, private and public energy providers, independent developers, consumer advocates, renewable energy groups, policy think tanks, environmental groups, and elected officials. These studies have shown a critical need to alleviate transmission congestion and move constrained energy resources to regional load centers throughout the west, and include:

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

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

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

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

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

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

- ***Northern Tier Transmission Group (NTTG) Transmission Planning Reports***

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

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

- ***WECC/Transmission Expansion Policy and Planning Committee (TEPPC) Annual Reports* and *Western Interconnection Transmission Path Utilization Studies***
  These analyses measure the historical use of transmission paths in the west to provide insight into where congestion is occurring and assess the cost of that congestion. The Energy Gateway segments have been included in the analyses that support these studies, alleviating several points of significant congestion on the system, including Path 19 (Bridger West) and Path 20 (Path C).

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

Energy Gateway Configuration

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

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

These groups continually evaluate PacifiCorp's transmission plan in their efforts to develop and refine the optimal regional and interconnection-wide plans. Please refer to PacifiCorp's OASIS site for information and materials related to these public processes.[4]

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

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

Energy Gateway's Continued Evolution

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

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

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

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

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

In 2012, the Company determined that one new 230 kV line between the Windstar and Aeolus substations and a rebuild of the existing 230 kV line were feasible, and that the second new proposed 230 kV line and proposed 500 kV line planned between Windstar and Aeolus would be eliminated. This decision resulted from the Company's ongoing focus on meeting customer needs, taking stakeholder feedback and land-use limitations into consideration, and finding the best balance between cost and risk for customers. In January 2012, the Company signed the Boardman to Hemingway Permitting Agreement with Idaho Power Company and the Bonneville Power Administration (BPA) that provides for the Company's participation through the permitting phase of the project. The Boardman to Hemingway project was pursued as an alternative to PacifiCorp's originally proposed transmission segment from eastern Idaho into southern Oregon (Hemingway to Captain Jack). Idaho Power leads the permitting efforts on the Boardman to Hemingway project, and PacifiCorp continues to support these activities under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement. The proposed line provides additional connectivity between PacifiCorp's west and east balancing authority areas and supports the full projected line rating for the Gateway projects at full build out. PacifiCorp plans to continue forward in support of the project under the Permit Funding agreement and will assess next steps post-permitting based on customer need and possible benefits.

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

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

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

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

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

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

PacifiCorp evaluated four Energy Gateway scenarios in this 2017 IRP:

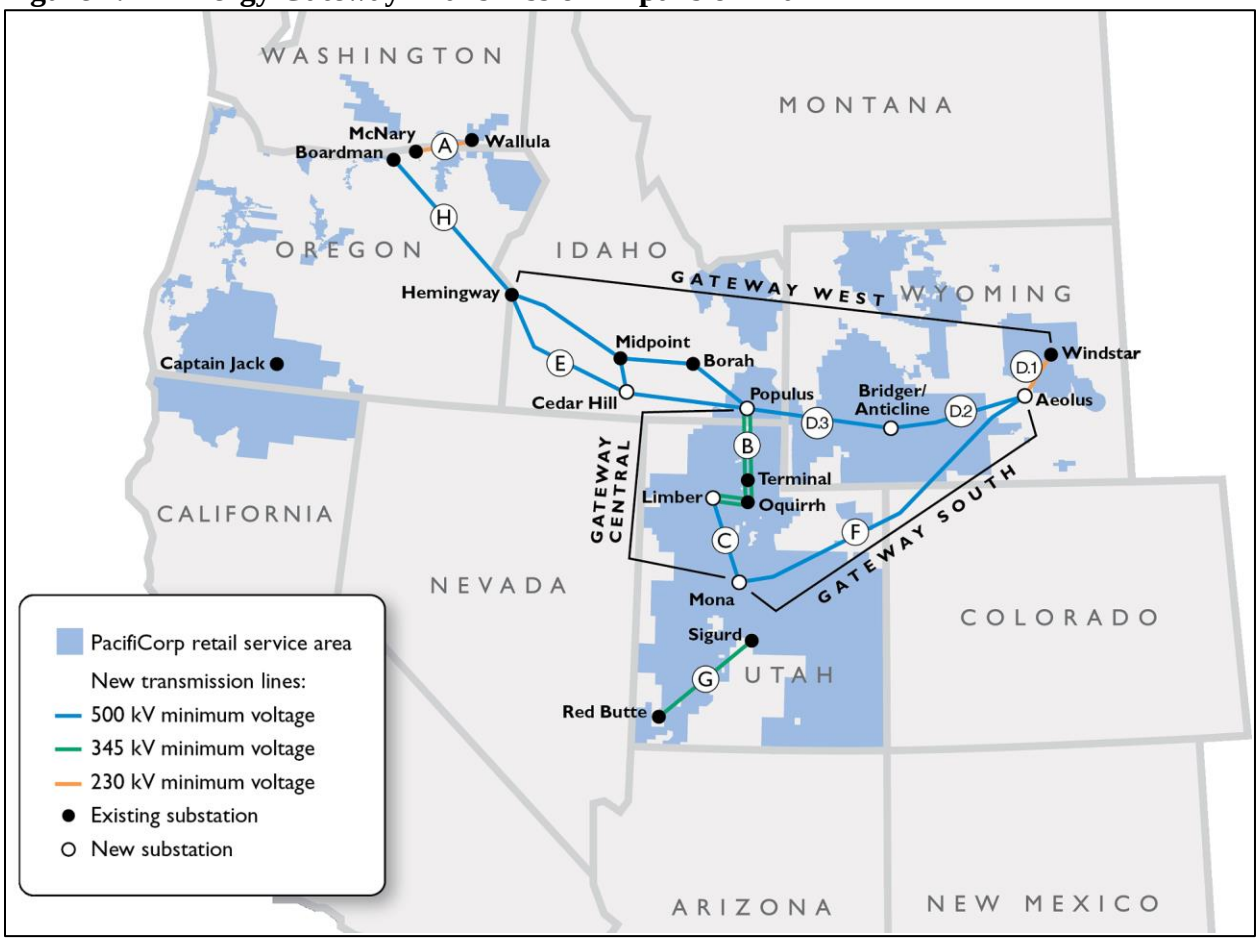
- Energy Gateway 1: Segment D Windstar to Aeolus 230 kV (one new line and one re-built line) and Aeolus to Bridger/Anticline 500 kV line;
- Energy Gateway 2: Segment F Windstar to Aeolus 230 kV (one new line and one re-built line) and Aeolus to Mona/Clover 500 kV line;
- Energy Gateway 3: Segments D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

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

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

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

Figure 4.4 – Energy Gateway Transmission Expansion Plan



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

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

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

Efforts to Maximize Existing System Capability

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

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

Transmission System Improvements Placed In-Service Since the 2015 IRP

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

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

Planned Transmission System Improvements

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

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

CHAPTER 5 – LOAD AND RESOURCE BALANCE

CHAPTER HIGHLIGHTS

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

Introduction

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

System Coincident Peak Load Forecast

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

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

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

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

Existing Resources

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

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

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

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

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

[3/] DSM includes existing Class 1 (direct load control) and Class 2 (energy efficiency) programs.

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

Thermal Plants

Table 5.3 lists PacifiCorp's existing coal-fueled thermal plants and Table 5.4 lists existing natural-gas-fueled plants. The assumed end-of-life dates are used for the 2017 IRP modeling of existing coal resources.

Table 5.3 – Coal-Fueled Plants

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

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

Table 5.4 – Natural-Gas-Fueled Plants

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

Renewable Resources

Wind

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

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

Table 5.5 – Owned Wind Resources

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

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

Table 5.6 – Non-Owned Wind Resources

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

[1/] New since 2015 IRP Update

Solar

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

Table 5.7 – Non-Owned Solar Resources

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

[1/] New since 2015 IRP Update

Geothermal

PacifiCorp owns and operates the Blundell geothermal plant in Utah, which uses naturally created steam to generate electricity. The plant has a net generation capacity of 34 MW. Blundell is a fully renewable, zero-discharge facility. The bottoming cycle, which increased the output by 11 MW, was completed at the end of 2007. The Oregon Institute of Technology added a new small qualifying facility (QF) using geothermal technologies to produce renewable power for the campus that is rated at 0.28 MW. PacifiCorp has a six-year power purchase agreement with a 3.65 MW QF geothermal project near Lakeview, Oregon, which became operational September 2016.

Biomass/Biogas

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

Renewables Net Metering

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

Table 5.8 – Net Metering Customers and Capacities

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

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

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

Hydroelectric Generation

PacifiCorp owns 1,135 MW of hydroelectric generation capacity and purchases the output from 127 MW of other hydroelectric resources.[1] These resources provide operational benefits such as flexible generation, spinning reserves and voltage control. PacifiCorp-owned hydroelectric plants are located in California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah.

The amount of electricity PacifiCorp is able to generate or purchase from hydroelectric plants is dependent upon a number of factors, including the water content of snow pack accumulations in the mountains upstream of its hydroelectric facilities and the amount of precipitation that falls in

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

its watershed. Operational limitations of the hydroelectric facilities are affected by varying water levels, licensing requirements for fish and aquatic habitat, and flood control, which lead to load and resource balance capacity values that are different from net facility capacity ratings.

Hydroelectric purchases are categorized into two groups, as shown in Table 5.9, which shows 2017 capacity included in the load and resource balance.

Table 5.9 – Hydroelectric Contracts - Load and Resource Balance Capacities

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

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

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

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

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

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

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

Hydroelectric Relicensing Impacts on Generation

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

operating restrictions will be imposed in new licenses, such as higher bypass flow requirements, that will reduce generation available from these facilities.

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

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

Demand Side Management (DSM)

DSM resources/products vary in their dispatchability, reliability, term of load reduction and persistence over time. Each has its value and place in effectively managing utility investments, resource costs and system operations. Those that have greater persistence and firmness can be reasonably relied upon as a base resource for planning purposes; those that do not are more suited as system reliability resource options. The reliability resource options are used to avoid outages or high resource costs as a result of weather conditions, plant outages, market prices, and unanticipated system failures. PacifiCorp categorizes DSM resources into four general classes based on their relative characteristics:

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

- **Class 2 DSM—Resources from non-dispatchable, firm energy and capacity product offerings/programs**—Class 2 DSM programs are those for which sustainable energy and related capacity savings are achieved through facilitation of technological advancements in equipment, appliances, lighting and structures, or repeatable and predictable voluntary actions on a customer's part to manage the energy use at their facility or home. Class 2 DSM programs generally provide financial or service incentives to customers to improve the efficiency of existing or new customer-owned facilities through: (1) the installation of more efficient equipment, such as lighting, motors, air conditioners, or appliances; (2) upgrading building efficiency through improved insulation levels, windows, etc.; or (3) behavioral modifications, such as strategic energy management efforts at business facilities and home energy reports for residential customers. The savings endure (are considered firm) over the life of the improvement or customer action. Program examples include comprehensive commercial and industrial new and retrofit energy efficiency programs, comprehensive home improvement retrofit programs, strategic energy management and home energy reports.

- **Class 3 DSM—Resources from price responsive energy and capacity product offerings/programs—**Class 3 DSM programs seek to achieve short-duration (hour by hour) energy and capacity savings from actions taken by customers voluntarily, based on a financial incentive or signal. As a result of their voluntary nature, participation tends to be low and savings are less predictable, making Class 3 DSM resources less suitable to incorporate into resource planning, at least until their size and customer behavior profile provide sufficient information for a reliable diversity result (predictable impact) for modeling and planning purposes. Savings typically only endure for the duration of the incentive offering and, in many cases, loads tend to be shifted rather than being avoided. The impacts of Class 3 DSM resources may not be explicitly considered in the resource planning process; however, they are captured naturally in long-term load growth patterns and forecasts. Program examples include time-of-use pricing plans, critical peak pricing plans, and inverted block tariff designs.

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

PacifiCorp has been operating successful DSM programs since the late 1970s. While the Company's DSM focus has remained strong over this time, since the 2001 western energy crisis, the Company's DSM pursuits have expanded to new heights in terms of investment level, state presence, breadth of DSM resources pursued (Classes 1 through 4) and resource planning considerations. Work continues on the expansion of cost-effective program portfolios and savings opportunities in all states while at the same time adapting programs and measure baselines to reflect the impacts of advancing state and federal energy codes and standards. In Oregon, the Company continues to work closely with the Energy Trust of Oregon to help identify additional resource opportunities, improve delivery and communication coordination, and ensure adequate funding and Company support in pursuit of DSM resource targets.

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

Table 5.12 below summarizes the Company's existing DSM programs, their assumed impact, and how they are treated for purposes of incremental resource planning. Note that since incremental Class 2 DSM is determined as an outcome of resource portfolio modeling and is

characterized as a new resource in the preferred portfolio, existing Class 2 DSM in Table 5.12 is shown as having zero MW.[2]

Table 5.12 – Existing DSM Resource Summary

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

[1/] Assumes six percent for planning reserves in addition to realized irrigation load curtailment in Idaho and Utah of 170 MW and 20 MW, respectively, with an additional 3 MW from the Oregon pilot through 2020.

[2/] Due to the timing of the 2017 IRP load forecast, there is a small amount (100 MW) of existing Class 2 DSM in Table 5.14 (System Capacity Loads and Resources without Resource Additions).

Private Generation

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

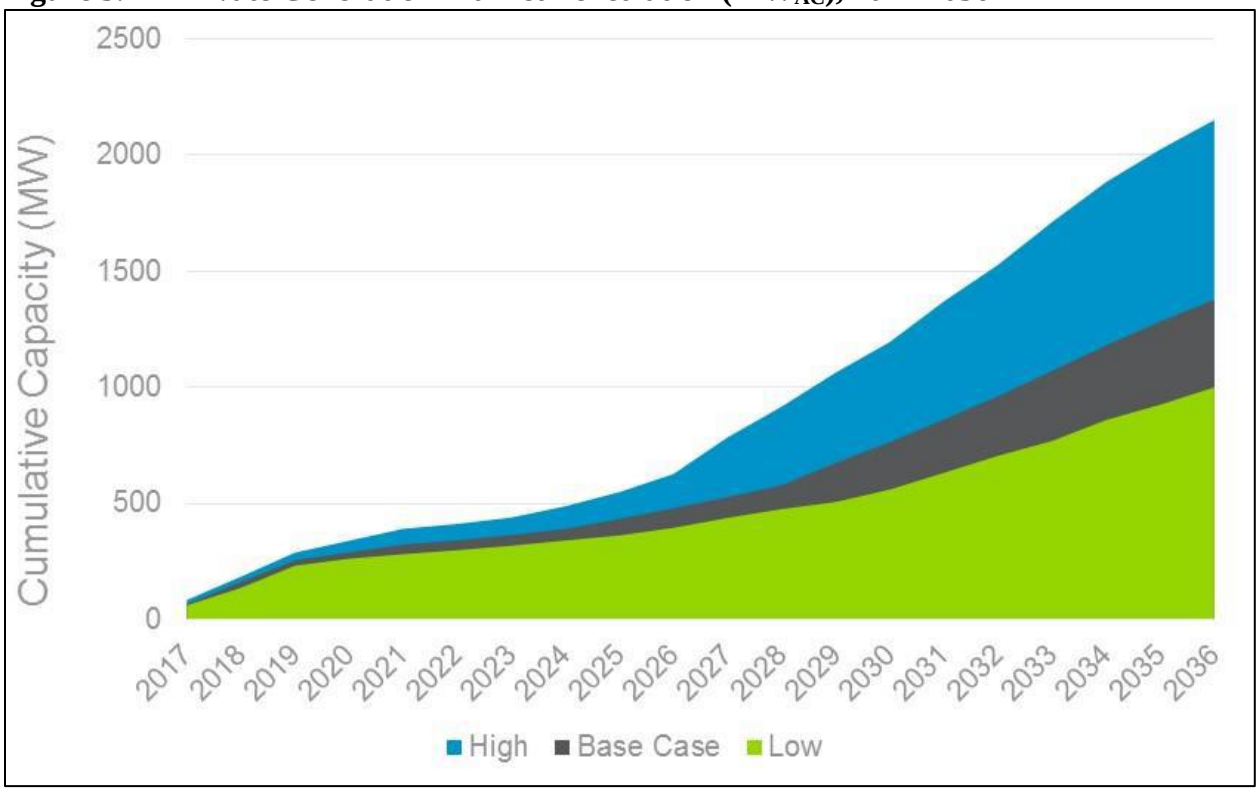
Navigant estimates approximately 1.4 GW of cumulative private generation capacity will be installed in PacifiCorp's territory from 2017-2036 in the base case scenario.[3] As shown in Figure 5.1, the low and high scenarios project a cumulative installed capacity of 1.00 GW and 2.10 GW by 2036, respectively.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

[2] The historical effects of previous Class 2 DSM savings are backed out of the load forecast before the modeling for new Class 2 DSM.

[3] The complete Navigant Study is available in Volume II, Appendix O (Private Generation Study).

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

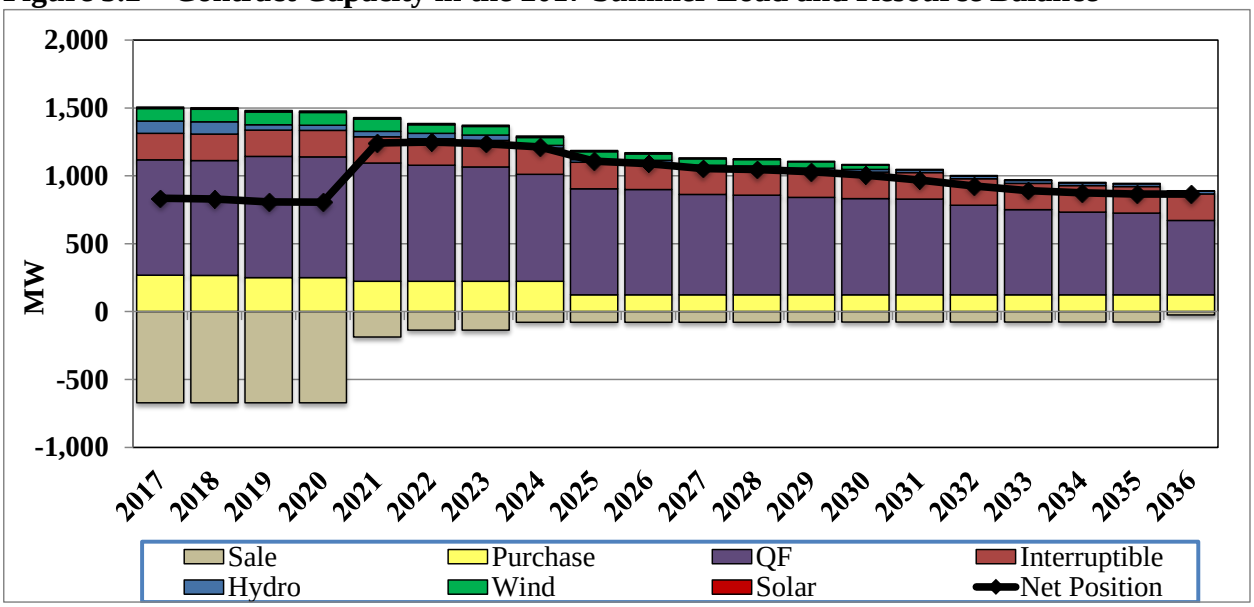
Figure 5.1 – Private Generation Market Penetration (MW_{AC}), 2017-2036



Power Purchase Contracts

PacifiCorp obtains the remainder of its capacity and energy requirements through long-term firm contracts, short-term firm contracts, and spot market purchases. Figure 5.2 presents the contract capacity in place for 2017 through 2036. As shown, major capacity reductions in purchases and hydro contracts occur. For planning purposes, PacifiCorp assumes that current purchases from small qualifying facility and interruptible load contracts are extended through the end of the IRP study period. Note that renewable wind contracts are shown at their capacity contribution levels.

Figure 5.2 – Contract Capacity in the 2017 Summer Load and Resource Balance



Load and Resource Balance

Capacity and Energy Balance Overview

The purpose of the load and resource balance is to compare annual obligations with the annual capability of PacifiCorp's existing resources, without new generating resource additions. This is done with two views of the system, the capacity balance and energy balance.

The capacity balance compares generating capability to expected peak load at time of system summer peak load hours. It is a key part of the load and resource balance because it helps guide the timing and severity of potential future resource need. It is developed by first reducing the hourly system load by hourly private generation projections to determine the net system coincident peak load for each of the first ten years (2017-2026) of the planning horizon. Interruptible load programs, existing load reduction DSM programs, and new load reduction DSM programs from the preferred portfolio at the time of the net system coincident peak are further netted from the peak load forecast to compute the annual peak-hour obligation. Then the annual firm capacity availability of the existing resources, reflecting assumed coal unit retirements from the preferred portfolio, is determined. The annual resource deficit or surplus is then computed by multiplying the obligation by the target planning reserve margin (PRM) and then subtracting the result from existing resources, accounting for available FOTs.

The energy balance shows the average monthly on-peak and off-peak surplus or deficit of energy over the first ten years of the planning horizon (2017-2026). The average obligation (load less existing DSM programs, new DSM programs from the preferred portfolio, and projected private generation) is computed and subtracted from the average existing resource availability for each month and time-of-day period. The usefulness of the energy balance is limited because it does not address the cost of the available energy. The economics of adding resources to the system to meet both capacity and energy needs are addressed during the resource portfolio development process described in Chapter 8 (Modeling and Portfolio Selection Results).

Load and Resource Balance Components

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

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

Existing Resources
A description of each of the resource categories follows:

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

Hydroelectric
This category includes all hydroelectric generation resources operated in the PacifiCorp system, as well as a number of contracts providing capacity and energy from various counterparties. The capacity balance counts these resources by the maximum capability that is sustainable for one hour at the time of system summer peak, an approach consistent with current Western Electric Coordinating Council (WECC) capacity reporting practices. The energy associated with stream flow is estimated and shaped by the hydroelectric dispatch from the Vista Decision Support System model. Also accounted for are energy impacts of hydro relicensing requirements, such as higher bypass flows that reduce generation. Over 90 percent of the hydroelectric capacity is on the west side of the PacifiCorp system.

Renewable
This category comprises geothermal and variable (wind and solar) renewable energy capacity. The capacity balance counts the geothermal plant by the maximum dependable capability while the energy balance counts the maximum dependable capability after forced outages. The capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand. For purposes of the 2017 IRP, PacifiCorp defines the peak capacity contribution of wind and solar resources as the availability among hours with the highest loss of load probability. PacifiCorp updated its capacity contribution values for solar and wind resources, differentiated by resource type and balancing authority area, which is presented in Volume II, Appendix N (Wind and Solar Capacity Contribution Study). The resulting capacity contribution values are shown in Table 5.13 below.

Table 5.13 Summer Peak Capacity Contribution Values for Wind and Solar

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

Purchase

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

Qualifying Facilities (QF)

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

Dispatchable Load Control (Class 1 DSM)

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

Sales

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

Non-owned Reserves

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

Obligation

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

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

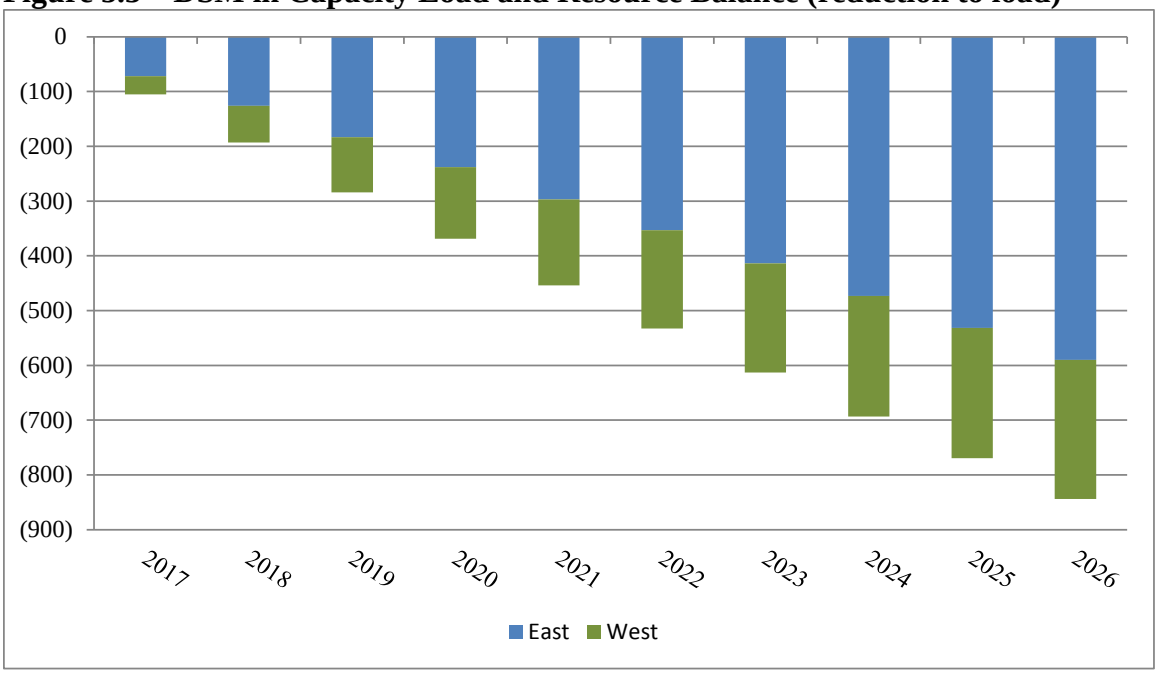
Load Net of Private Generation

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

Class 2 DSM

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

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



Interruptible Contracts

PacifiCorp has interruptible contracts for approximately 195 MW of load interruption capability beginning in 2017. These contracts allow the use of 195 MW of capacity for meeting reserve requirements. Both the capacity balance and energy balance count these resources at the level of full load interruption on the executed hours. Interruptible resources directly curtail load and thus full planning reserves are not held for the load that may be curtailed. As with Class 1 DSM, this resource is categorized as a decrease to the peak load.

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

Position
The position is the resource surplus or deficit after subtracting obligation plus required reserves from total resources. While similar, the position calculation is slightly different for the capacity and energy views of the load and resource balance. Thus, the position calculation for each of the views will be presented in their respective sections.

Capacity Balance Determination

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

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

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

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

The amount of reserves to be added to the obligation is then calculated. This is accomplished by the net system obligation calculated above multiplied by the 13 percent target planning reserve margin (PRM) adopted for the 2017 IRP. The formula for this calculation is:

> **Planning Reserves** = Obligation x PRM

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

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

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

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

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

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

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

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

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

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

Figure 5.4 – Summer System Capacity Position Trend

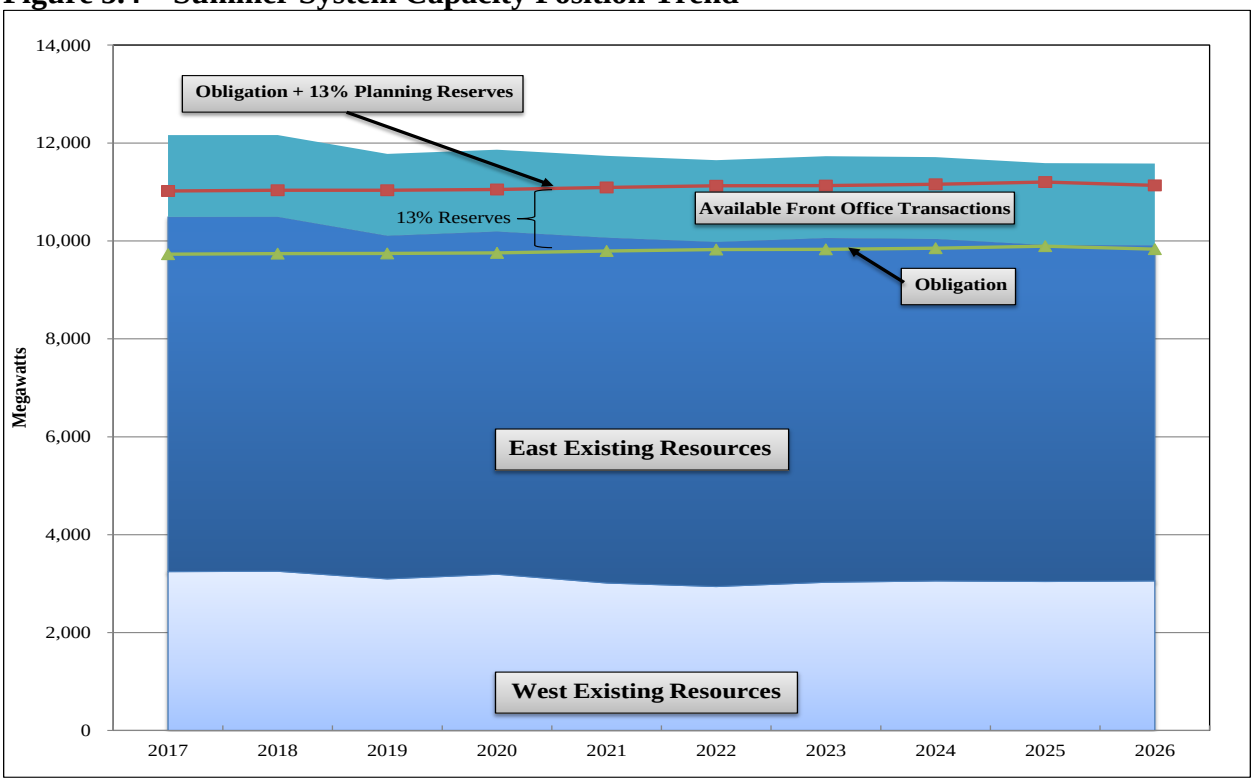


Figure 5.5 – Winter System Capacity Position Trend

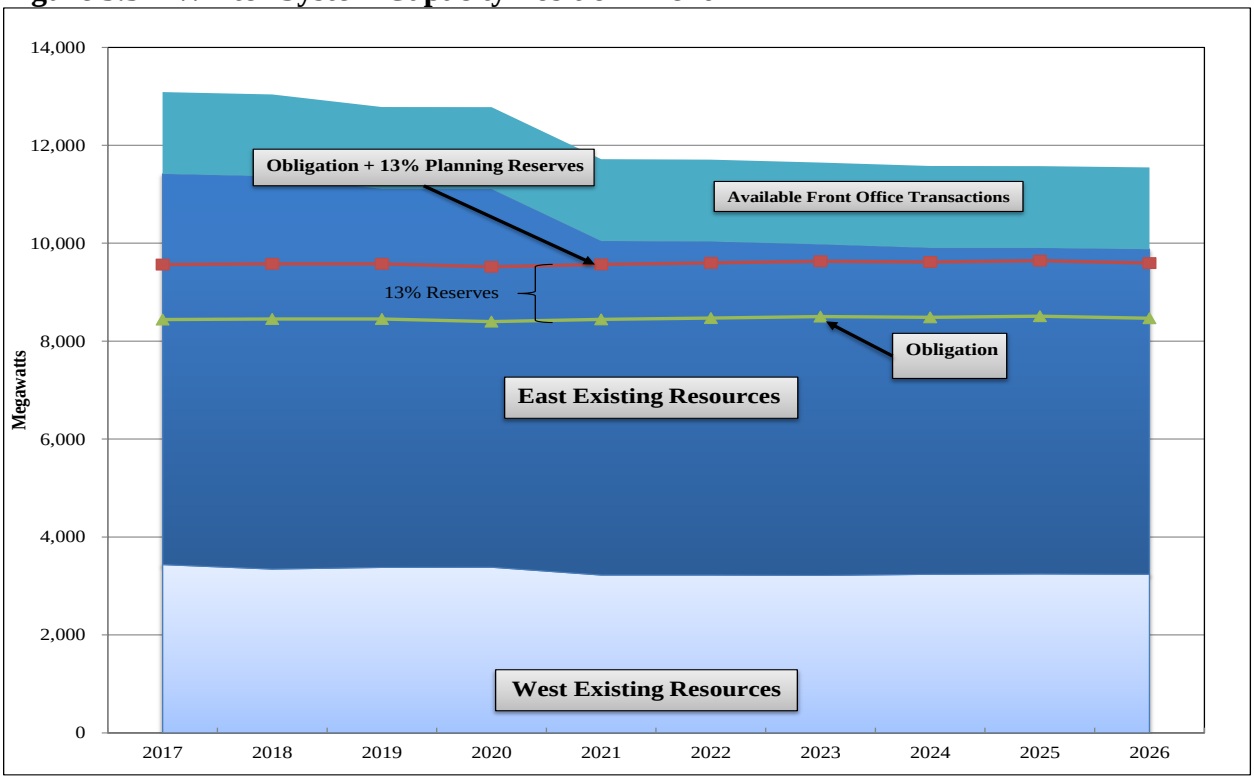


Figure 5.6 – East Summer Capacity Position Trend

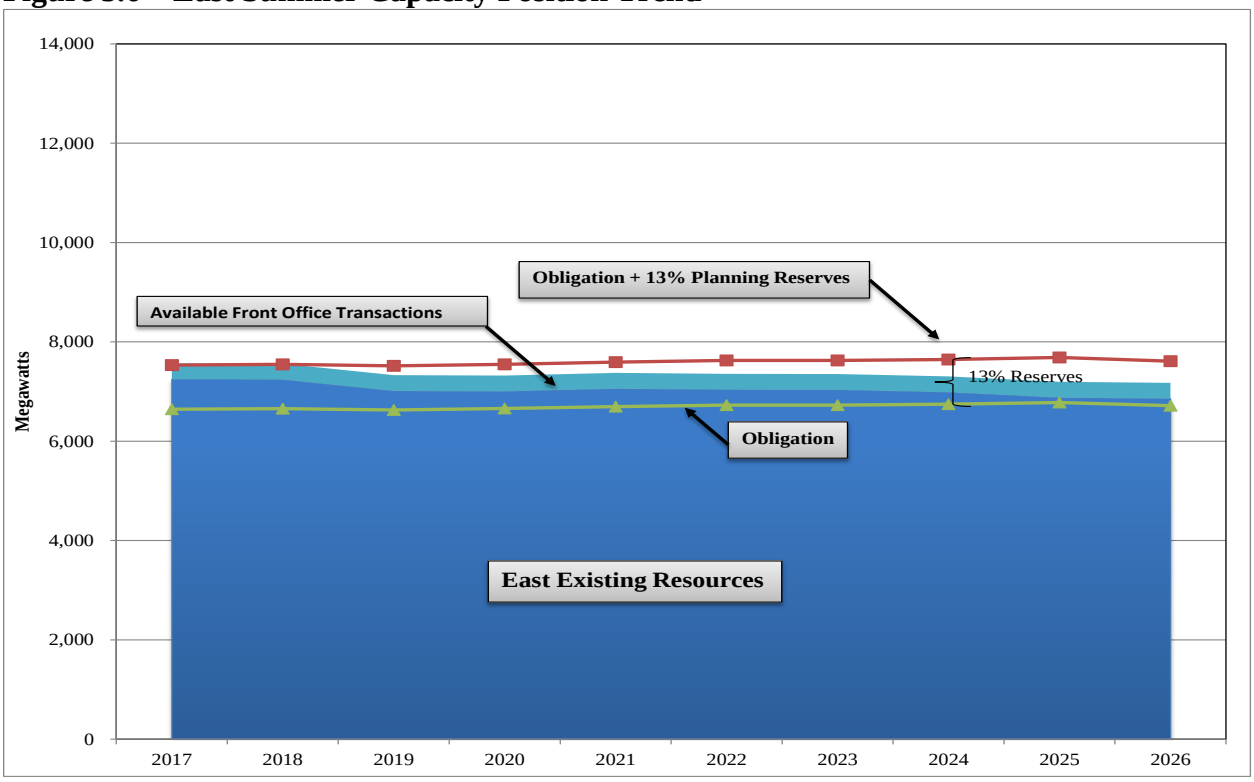
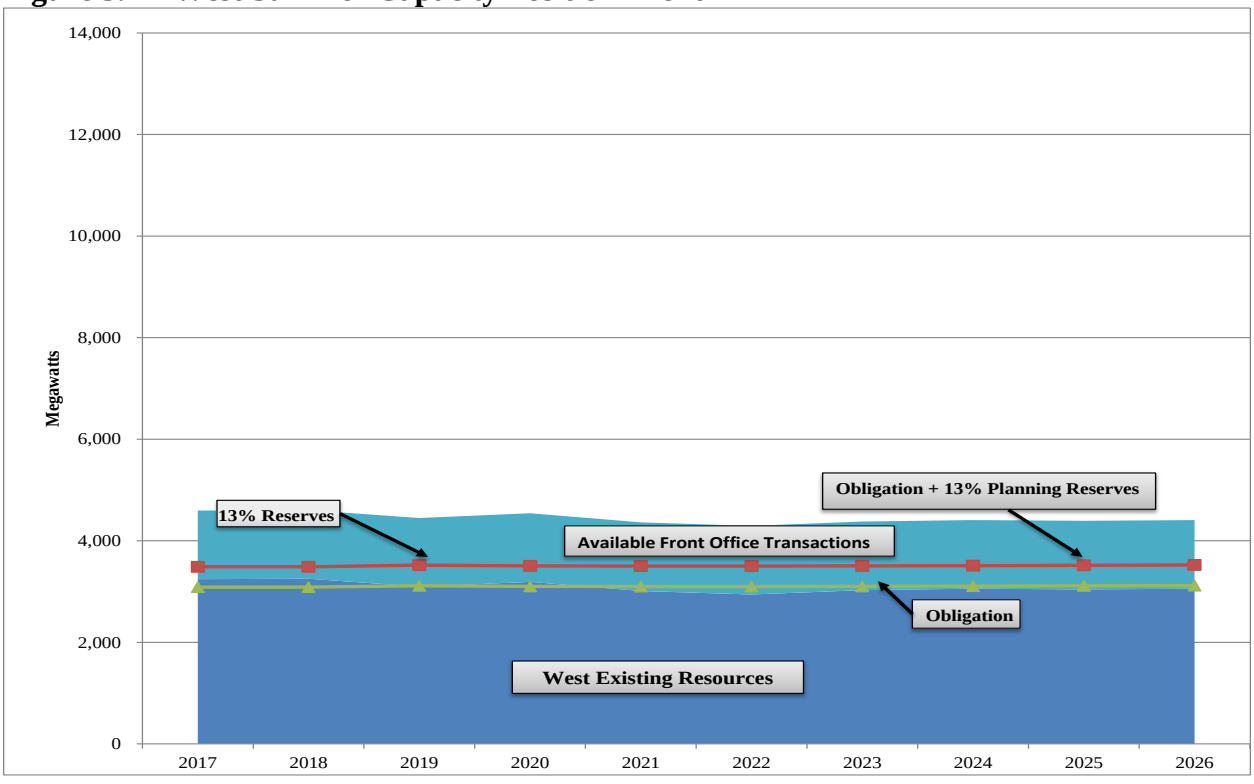


Figure 5.7 – West Summer Capacity Position Trend



Energy Balance Determination

Methodology
The energy balance shows the monthly on-peak and off-peak surplus (deficit) of energy. The on-peak hours are weekdays and Saturdays from hour-ending 7:00 am to 10:00 pm; off-peak hours are all other hours. This is calculated using the formulas that follow. Please refer to the section on load and resource balance components for details on how energy for each component is counted.

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

The average obligation is computed using the following formula:

> **Obligation** = Load + Firm Sales

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

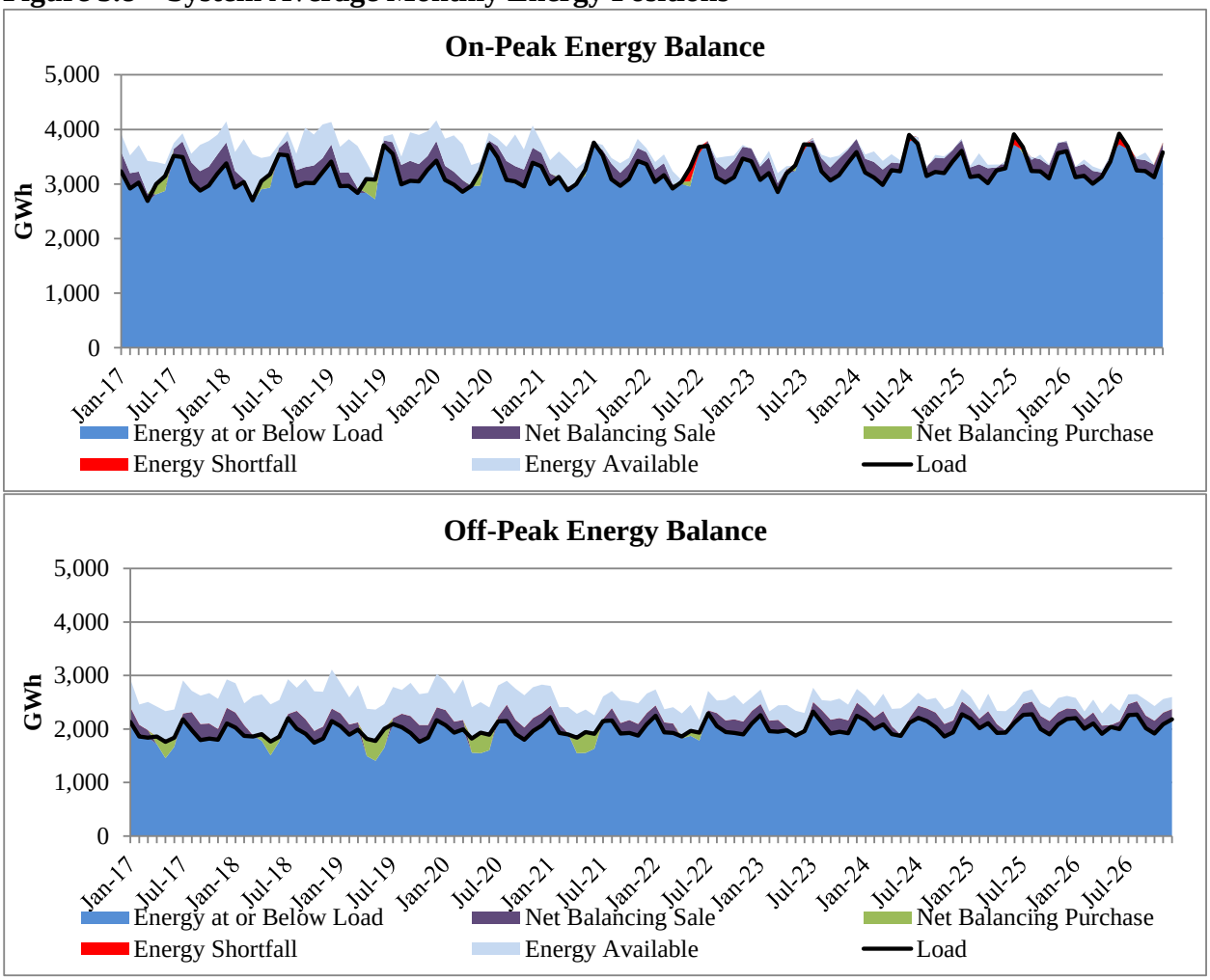
> **Energy Position** = Existing Resources – Obligation – Operating Reserve Requirements

Energy Balance Results

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

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

Figure 5.8 – System Average Monthly Energy Positions



CHAPTER 6 – RESOURCE OPTIONS

CHAPTER HIGHLIGHTS

- PacifiCorp developed resource attributes and costs for expansion resources that reflect updated information from project experience, public input meeting comments and third party studies.
- Generally, resource costs have remained stable since the 2015 IRP and any cost increases have been modest. Renewable resource costs in particular, have continued to fall.
- As with the 2015 IRP both large utility scale solar photovoltaic options and geothermal purchase power agreements (PPAs) have been included as supply-side options in the 2017 IRP and updated to reflect current conditions.
- The number of combustion turbine types and configurations has been slightly modified to reflect different siting locations and are identified in the Supply Side Resource options table.
- Energy storage systems continue to be of interest to PacifiCorp stakeholders. Options for advanced large batteries (one megawatt), pumped hydro and compressed air energy storage are included in the 2017 IRP.
- A Demand-Side Resource Potential Assessment for 2017-2036, conducted by Applied Energy Group, served as the basis for updated resource characterizations covering demand-side management (DSM) resources. The demand-side resource information was converted into supply curves by resource type and competes against other resource alternatives in IRP modeling.
- PacifiCorp applied cost reduction credits for energy efficiency, reflecting risk mitigation benefits, transmission & distribution investment deferral benefits, and a 10 percent market price credit for Washington and Oregon as allowed by the Northwest Power Act.
- Transmission integration costs and transmission reinforcement costs are based on the timing and location of resource selection.

Introduction

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

Supply-side Resources

The list of supply-side resource options has been updated to reflect the realities evidenced through permitting, internally-generated studies and externally-commissioned studies undertaken to better understand the details of available generation resources. Renewable resources, particularly solar and wind resource options, have been reviewed and updated to capture recent trends in cost and performance. Solar resource options include utility-size photovoltaic systems (PV) with both fixed and single axis tracking. A variety of gas-fueled generating resources were

selected after consultation with major suppliers and large engineering-consulting firms. Stakeholder feedback and industry journals also influenced the selection of resources. The capital and operating costs of simple and combined-cycle gas turbine plants have remained relatively low in recent years, with a flat to slightly decreasing cost trend. Energy storage options of at least one megawatt continue to be of interest among the stakeholders, with options analyzed for large pumped hydro projects, as well as advanced battery and compressed air energy storage projects. Additionally, in response to stakeholder requests, multiple different battery energy storage configurations were also evaluated. New coal-fueled resources received minimal focus during this cycle due to ongoing environmental, economic, permitting and sociopolitical obstacles for siting new coal-fueled generation.

Derivation of Resource Attributes

The supply-side resource options were developed from a combination of resources. The process began with the list of major generating resources from the 2015 IRP. This resource list was reviewed and modified to reflect stakeholder input, new technology developments, environmental factors, cost dynamics and anticipated permitting requirements. Once the basic list of resources was determined, the cost and performance attributes for each resource were estimated. The information sources used are listed below, followed by a brief description on how they were used in the development of the Supply Side Resource table:

- Recent (2016) third-party, cost and performance estimates;
- Prior third-party, cost and performance studies or updated earlier estimates;
- Publicly available cost and performance estimates;
- Actual PacifiCorp or electric utility industry installations, providing current construction/maintenance costs and performance data with similar resource attributes;
- Projected PacifiCorp or electric utility industry installations, providing projected construction/maintenance costs and performance data of similar or identical resource options; and
- Recent Requests for Proposals and Requests for Information.

Recent third-party engineering information from original equipment manufacturers were used to develop capital, operating and maintenance costs, performance and operating characteristics and planned outage cycle estimates. Engineering-consultants or government agencies have access to this data based on prior research studies, academia, actual installations, and direct information exchanges with original equipment manufacturers. Examples of this type of effort include the 2016 Black & Veatch estimates prepared for simple cycle and combined cycle options. For this IRP cycle, the energy storage effort was performed by two different consultants. The bulk energy storage portion of the 2014 HDR Engineering (HDR) that focused on pumped storage and compressed air energy storage was updated by Black & Veatch. The battery energy storage part of the 2014 HDR study was updated by DNV-GL.

Prior studies include studies prepared by others but not specifically for the Integrated Resource Plan process, and include similar types of cost and performance data provided in the Supply-Side Resource table. This information includes publicly available engineering and government agency reports. Examples of this type of study include the United States Department of Energy's 2015 Wind Technologies Market Report.

PacifiCorp or industry installations provide a solid basis for capital/maintenance costs and operating histories. Performance characteristics were adjusted to site-specific conditions identified in the Supply Side Resource Table. For instance, the capacity of combustion turbine based resources varies with elevation and ambient temperature and, to a lesser extent, relative humidity. Adjustments were made for site-specific elevations of actual plants to more generic, regional elevations for future resources. Examples of actual PacifiCorp installations used to develop the cost and performance information provided in the Supply Side Resource table include O&M costs for the Company's Gadsby GE LM6000PC peaking units and the Lake Side 2 combined cycle plant.

Requests for Information (RFI) and Requests for Proposals (RFP) also provide a useful source of cost and performance data. In these cases, original equipment manufacturers provided technology specific information. Examples of RFIs informing the Supply Side Resource Table include obtaining updated equipment pricing for wind turbine equipment from original equipment suppliers and reviews of capital costs prepared by engineering firms by engineer-procure-construct firms.

Handling of Technology Improvement Trends and Cost Uncertainties

The capital cost uncertainty for some generation technologies is relatively high. Various factors contribute to this uncertainty, including the relatively small number of facilities that have been built, especially for new and emerging technologies, as well as prolonged economic uncertainty. Despite this uncertainty, the cost profile between the 2015 IRP and the 2017 IRP has not changed significantly. For example, Figure 6.1 shows the trend in North American carbon steel sheet prices over the period from October 2015 through September 2016. Similar information was presented in the 2015 IRP and is shown in Figure 6.2. These figures illustrate near term changes in capital costs of generation resources.

Figure 6.1 - World Carbon Steel Pricing by Type

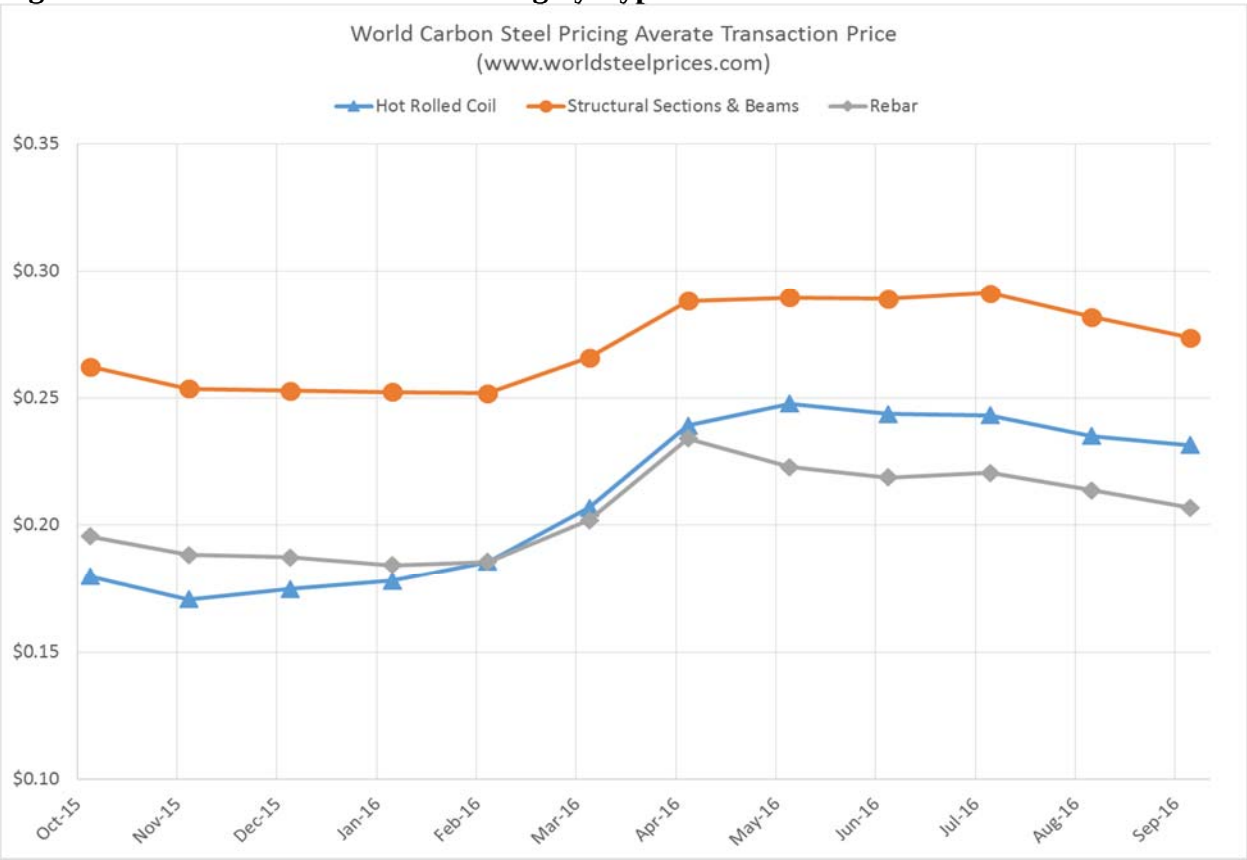
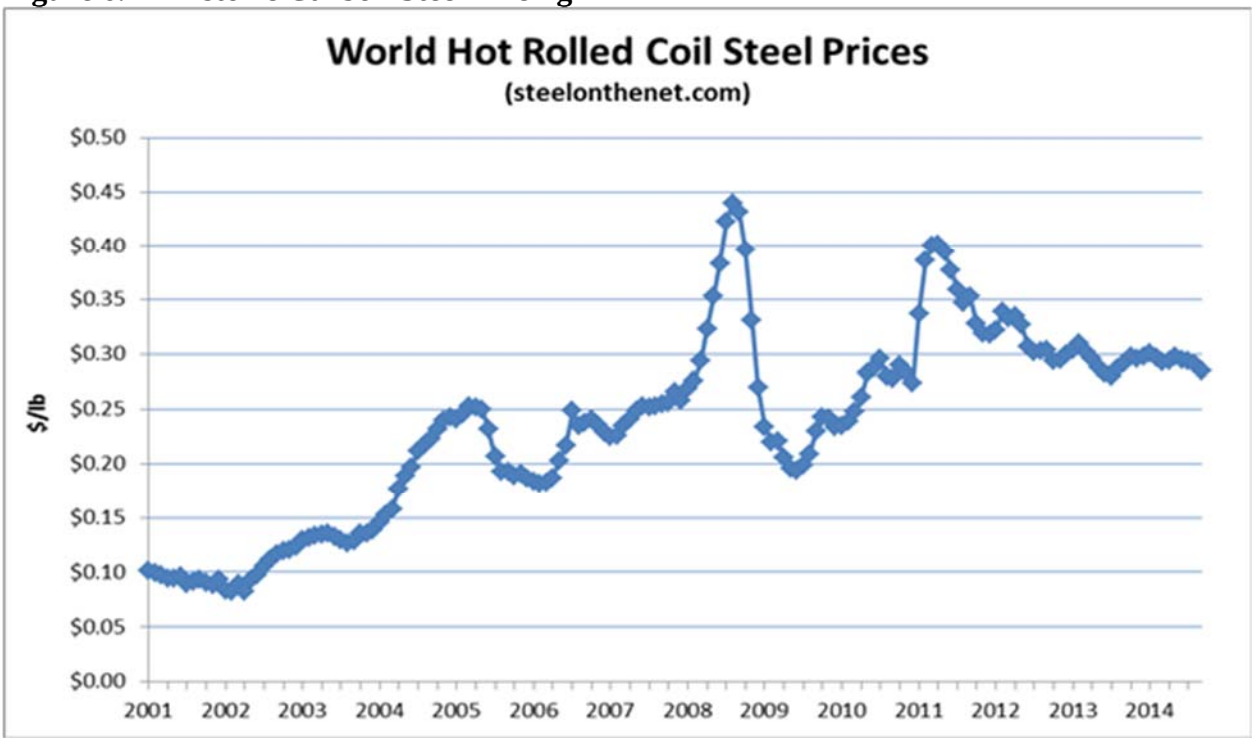


Figure 6.2 - Historic Carbon Steel Pricing



Prices for solar photovoltaic (PV) panels as well as balance of plant costs have fallen since the 2015 IRP. Real prices are projected to flatten out for the next several years given large demand

to meet the 30 percent federal ITC deadline at the end of 2016 and recently announced panel tariffs on certain Chinese imports, but uncertainty in the solar market makes it difficult to accurately predict future prices. Other technologies, such as gas turbines and wind turbines have seen more stable prices since the 2015 IRP. Long-term (10+ years) pricing for this equipment remains challenging to forecast.

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

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

Resource Options and Attributes

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

- ISO conditions (sea level and 59 degrees F); this is used as a reference for certain modeling purposes.
- 1,500 feet elevation: eastern Oregon/Washington.
- 3,000 feet elevation: southern/central Oregon
- 4,500 feet elevation: northern Utah, specifically Salt Lake/Utah/Tooele/Box Elder counties
- 5,050 feet elevation: central Utah, southern Idaho, central Wyoming.
- 6,500 feet elevation: southwestern Wyoming

Tables 6.2 and 6.3 present the total resource cost attributes for supply-side resource options, and are based on estimates of the first-year, real-levelized costs for resources, stated in June 2016 dollars. Similar to the approach taken for the 2015 IRP, it is not currently envisioned that new combined cycle resources could be economically permitted in northern Utah, specifically Salt Lake/Utah/Davis/Box Elder counties due to state implementation plans for these counties regarding particulate matter of 2.5 microns and less ($PM_{2.5}$).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Table 6.4 - Glossary of Terms from Supply Side Resource Table

Term	Description
Fuel	Primary fuel used for electricity generation or storage.
Resource	Primary technology used for electricity generation or storage.
Elevation (afsl)	Average feet above sea level for the proxy site for the given resource.
Net Capacity (MW)	For natural gas-fired generation resources, the Net Capacity is the net dependable capacity (net electrical output) for a given technology, at the given elevation, at the annual average ambient temperature in a "new and clean" condition.
Commercial Operation Year	The resource availability year is the earliest year the technology associated with the given generating resource is commercially available for procurement and installation. The total implementation time is the number of years necessary to implement all phases of resource development and construction: site selection, permitting, maintenance contracts, IRP approval, RFP process, owner's engineering, construction, commissioning and grid interconnection.
Design Life (years)	Average number of years the resource is expected to be "used and useful," based on various factors such as manufacturer's guarantees, fuel availability and environmental regulations.
Base Capital ($/kW)	Total capital expenditure in $/kW for the development and construction of a resource including: direct costs (equipment, buildings, installation/overnight construction, commissioning, contractor fees/profit and contingency), owner's costs (land, water rights, permitting, rights-of-way, design engineering, spare parts, project management, legal/financial support, grid interconnection costs, owner's contingency), and financial costs (AFUDC, capital surcharge, property taxes and escalation during construction, if applicable).

Term	Description
Var O&M ($/MWh)	Includes real levelized variable operating costs such as combustion turbine maintenance, water costs, boiler water/circulating water treatment chemicals, pollution control reagents, equipment maintenance and fired hour fees.
Fixed O&M ($/kW-year)	Includes labor costs, combustion turbine fixed maintenance fees, contracted services fees, office equipment and training.
Full Load Heat Rate HHV (Btu/kWh)	Net efficiency of the resource to generate electricity for a given heat input in a "new and clean" condition on a higher heating value basis.
EFOR (%)	Estimated Equivalent Forced Outage Rate, which includes forced outages and derates for a given resource at the given site.
POR (%)	Estimated Planned Outage Rate for a given resource at the given site.
Water Consumed (gal/MWh)	Average amount of water consumed by a resource for make-up, cooling water make-up, inlet conditioning and pollution control.
SO_2 (lbs/MMBtu)	Expected permitted level of sulfur dioxide emissions in pounds of sulfur dioxide per million Btu of heat input.
NOx (lbs/MMBtu)	Expected permitted level of nitrogen oxides (expressed as NO_2) in pounds of NOx per million Btu of heat input.
Hg (lbs/TBtu)	Expected permitted level of mercury emissions in pounds per trillion Btu of heat input.
CO_2 (lbs/MMBtu)	Pounds of carbon dioxide emitted per million Btu of heat input.

Table 6.5 - Glossary of Acronyms Used in the Supply Side Resources

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

Resource Descriptions

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

Wind

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

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

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

Solar

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

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

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

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

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

Biomass

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

Geothermal

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

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

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

Natural Gas

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

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

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

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

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

Natural Gas, CCCT Dry "G/H", DF, 1x1 – an option that can be added to a combined cycle plant to increase its capacity by the addition of duct burners in the heat recovery steam generator. This increases the amount of steam generated in the heat recovery steam generator. The amount of

duct firing is up to the owner. Depending on the amount of duct firing added, the size of the steam turbine, steam turbine generator and associated feedwater, steam condensing and cooling systems may need to be increased. This description also applies to the following technologies that are listed on Table 6.1: CCCT Dry "G/H", DF, 2x1; CCCT Dry "J/HA.02", DF, 1x1; CCCT Dry "J/HA.02", DF, 2x1.

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

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

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

Storage

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

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

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

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

Storage, CAES – A compressed air energy storage (CAES) system consists of air storage reservoir replacing the compressor on a conventional gas turbine. The gas turbine exhaust powers a power turbine providing a simple cycle gas turbine energy at lower costs than a conventional gas turbine. Off-peak energy is used to compress air into the storage reservoir. A

system size of 320 MW is assumed. The air storage reservoir is assumed to be solution mined to size. Natural gas is required to generate power.

Nuclear

Nuclear, Advanced Fission – a large 2,234 MW nuclear resource reflects the current state-of-the-art advanced nuclear plant and is modeled after the Westinghouse AP1000 technology currently being installed by Southern Company at the Vogtle Generating Station in Georgia. The assumed location for this resource is the proposed Blue Castle site near Green River, Utah which is in development. It is expected that the resource would be available no earlier than 2025.

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

Coal

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

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

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

Resource Options Descriptions

Wind

PacifiCorp commissioned a study of utility scale wind generation by Black & Veatch in 2016 to get market based estimates of the capital cost to build new wind projects, the ongoing operation and maintenance costs, and energy production for projects of a nominal 100 MW size. PacifiCorp reviewed operation and maintenance costs for existing Company owned projects and communicated with wind equipment manufacturers and construction companies for supplemental cost information that was used to inform the 2017 IRP. The wind turbine generator (WTG) selection and net capacity factors are based upon the analysis performed by Black & Veatch to design projects that delivered the lowest cost of energy to customers. Black & Veatch

chose Vestas 2.0 MW WTGs for their sample layouts in Washington, Oregon, Idaho and Utah, and chose Vestas 3.3 MW WTGs for their sample layouts in Wyoming. While Vestas WTGs are sited in the IRP, WTGs from all manufacturers that meet PacifiCorp's quality standards would be acceptable for new wind farm construction.

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

Wind Capital Costs

Capital cost estimates for wind resources in the IRP are based upon a combination of the Black & Veatch study and communications with wind equipment and construction companies. All wind resources are specified in 100 MW blocks, but the model can choose a fractional amount of a block.

Wind Resource Capacity Factors and Energy Shapes

Resource options in the topology bubbles are assigned capacity factors based upon historic or expected project performance. Assigned capacity factor values for wind resources are 43 percent in Wyoming, 38% in Washington, Oregon and Idaho, and 31 percent in Utah. Capacity factor is a separate modeled parameter from the capital cost, and is used to scale wind energy shapes used by both the System Optimizer and Planning and Risk models. The hourly generation shape reflects average hourly wind variability. The hourly generation shape is repeated for each year of the simulation.

Wind Integration Costs

To capture the costs of integrating wind into the system, PacifiCorp applied a value of $0.573/MWh (in 2016 dollars) for resource selection. To capture the costs of integrating solar into the system, PacifiCorp applied a value of $0.603/MWh (in 2016 dollars). Additional detailed information can be found in the Company's 2017 flexible reserve study (Volume II, Appendix F). Integration costs were incorporated into wind capital costs based on a 30-year project life expectancy and generation performance.

Solar

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

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

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

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

Biomass

Cost and performance data for biomass based resources were obtained from third-party studies. The Pacific Northwest and Atlantic Southeast are generally considered good regions for siting biomass generation plants because the climate supports the abundant growth of fuel resources. In general, large-scale (greater than 50 MW) plants are rare, which is why the resource is represented as a 5 MW plant in the supply side resource table. Many biomass products have multiple potential uses including industrial manufacturing, agriculture and energy generation. Because these other uses increase the demand and cost of the source material, biomass electric generation facilities often operate in areas that pay high prices for electricity production or have significant regulatory or incentive structures in place to support biomass based electric generation. Select coal plants in the United States and other parts of the world have been converted from burning coal to burning various types of biomass, including wood chips, cellulosic switch grass, municipal solid waste, or, in rare cases, an engineered fuel which adds processing and sorbents to the aforementioned base fuels. The greatest challenge to building large biomass generation plants or retrofitting existing coal units is the cost and the availability, reliability, and homogeneity of a long-term fuel supply. The cost and logistical challenges of acquiring, transporting, processing and handling large quantities of biomass fuel pose significant

challenges. While PacifiCorp currently does not own any biomass plants, the Company does purchase power from a number of biomass resources in Oregon through power purchase agreements.

Geothermal

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

The cost recovery mechanisms currently available to PacifiCorp as a regulated electric utility are not compatible with the inherent risks associated with the development of geothermal resources for power generation. The primary risks of geothermal development are dry holes, well integrity and insufficient resource adequacy (flow, temperature and pressure). These risks cannot be fully quantified until wells are drilled and completed. The cost to validate total production capability of a geothermal resource can be as high as 35 percent of total project costs. Exploration test wells typically cost between $500,000 and $1.5 million per well. Full production and injection wells cost between $4-5 million per well. Variations in the permeability of subsurface materials can determine whether wells in close proximity are commercially viable, lacking in pressure or temperature, or completely dry with no interconnectivity to a geothermal resource. As a regulated utility subject to the public utility commissions of six states, PacifiCorp is not compensated nor incentivized to engage in these inherently risky development efforts.

To mitigate the financial risks of geothermal development, PacifiCorp would use a Request for Proposals (RFP) process to obtain market proposals for geothermal power purchase agreements or build-own-transfer project agreement structures. Geothermal developers, external to PacifiCorp, have the flexibility to structure project pricing to include all development risks. Through an RFP process, PacifiCorp could choose the geothermal project with the lowest cost offered by the market and avoid considerable risk for the Company and its customers. Several geothermal projects submitted proposals in response to the 2016 Oregon Renewables RFP, but none of the geothermal projects were selected as a new PacifiCorp generation source. In the event PacifiCorp identifies a geothermal asset that appears to be economically attractive but also determines that there is a significant possibility of development risk that the market will not economically absorb, PacifiCorp may approach state regulators with estimates of resource development costs and risks associated to obtain approval for a mechanism to address risks such as dry holes. Because public utility commissions typically do not allow recovery of expenditures

which do not result in a direct benefit to customers, and at least one state has a statute that precludes cost recovery of any asset that is not considered to be "used and useful," obtaining a mechanism to recover geothermal development costs may be difficult.

Supply and Location of Renewable Resources

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

Table 6.6 - Cumulative Maximum Renewable Selection Limits

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

Solar = Fixed Tilt / Single Tracking

Table 6.7 - Cumulative Maximum Renewable Selection Limits

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

Natural Gas

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

A variety of natural gas-fueled generating resources that are and will continue to be available for a several years are included in the Supply Side Resource Table (Table 6.1). The variety of natural gas resources were selected to provide for generating performance and services essential to safe and reliable operation of the energy grid. Natural gas resources generate cost competitive power while producing low air emissions. Natural gas-fueled resources have proven to be highly

reliable and safe. Performance, cost and operating characteristics for each resource were provided at elevations of 1,500, 3,000, 5,050 and 6,500 feet above mean sea level, representative of geographic areas in which the resource could be located. Performance, cost and operating characteristics were also provided at ISO conditions (zero feet above mean sea level and 59 °F) as a reference. The essential services provided by the resource are peaking, intermediate and base generation.

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

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

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

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

Duct Firing (DF) of the combined cycle is shown in the Supply Side Resource table. Duct firing is not a stand-alone resource option, but is considered to be an available option for any combined cycle configuration and represents a low cost option to add peaking capability at relatively high efficiency and also a mechanism to recover lost power generation capability at high ambient

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

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

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

Energy Storage

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

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

Battery Energy Storage Study

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

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

Table 6.8 - Updated Battery Technologies and Data

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

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

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

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

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

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

Table 6.10 - Battery Energy Storage Special Escalation Rates

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

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

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

Bulk Energy Storage Study

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

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

- Pumped Hydro (PH)
- Swan Lake North

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

Case-by-Case Analysis of Energy Storage Solutions

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

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

Nuclear

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

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

NuScale is developed an advanced reactor design in the small modular reactor (SMR) category. Although it is an FOAK technology, the design has inherent safety features which support reduced capital costs and operating cost estimates. PacifiCorp has a seat on the NuScale advisory board, however PacifiCorp has no monetary interest in NuScale or the SMR project being developed for the Idaho National Lab site. PacifiCorp added 5% contingency and 10% delay

costs due to the project being FOAK. Details of NuScale's SMR can be found at http://www.nuscalepower.com/.

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

Coal

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

Supercritical technology is considered the standard design technology compared to subcritical technology for pulverized coal. Increasing coal costs make the added efficiency of the supercritical technology more cost-effective. Additionally, there is a greater competitive marketplace for large supercritical boilers than for large subcritical boilers. Increasingly, large boiler manufacturers only offer supercritical boilers in the 500-plus MW sizes. Due to the increased efficiency of supercritical boilers, overall emission intensity rates are smaller than for similarly sized subcritical units. Compared to subcritical boilers, supercritical boilers also have better load following capability, faster ramp rates, use less water and require less steel for construction. The costs shown in Table 6.1 for a supercritical PC facility reflect the cost of adding a new unit at an existing site.

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

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

The Petra Nova project is especially meaningful in that the project entailed a retrofit of an existing coal-fueled plant using an amine based system and captures approximately 5,000 tons per day from the 240 MWe equivalent flue gas slipstream from NRG's W.A. Parish unit 8. Captured CO_2 is transported through an 81-mile pipeline and used for EOR at the West Ranch Oilfield, located on the Gulf Coast of Texas. It is the largest retrofit of a carbon capture technology of a pulverized coal plant in the world. The project was constructed and

commissioned on schedule. No major cost increases have been reported; material cost increases and schedule delays have been the prevailing characteristic of a number of recent clean coal projects. Petra Nova is a 50-50 joint venture by NRG and JX Nippon. The United States Department of Energy (DOE) is providing up to $190 million in grants as part of the Clean Coal Power Initiative program (CCPI), a cost-shared collaboration between the federal government and private industry. Managed and executed in the U.S., the capture system is based on Mitsubishi's proprietary KM CDR Process® and uses its KS-1™ amine solvent.

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

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

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

An alternative to supercritical pulverized-coal technology for coal-based generation is the application of IGCC technology. A significant advantage for IGCC when compared to pulverized coal with amine-based carbon capture, is the reduced cost of capturing CO_2 from the process. Only a limited number of IGCC plants have been built and operated around the world. In the United States, these facilities have been demonstration projects, resulting in capital and operating costs that are significantly greater than those costs for conventional coal plants. These projects have been constructed with significant federal funding. One large, utility-scale IGCC plant with carbon capture capability recently went into service. Southern Company’s 582 MWnet $6.8 billion Kemper County project includes carbon capture (65% capture) and sequestration (for EOR). The plant is expected to enter commercial operation on coal-fuel based syn-gas in the first quarter of 2017.

The Texas Clean Energy Project is a second IGCC project which also includes carbon dioxide capture and is currently in an advanced stage of development. This project anticipates using Siemens gasification technology with CO_2 capture being used for both EOR purposes and urea

production. However, it is uncertain at this stage if this project will progress to construction given recent de-funding announcements by the US DOE.

The costs presented in the supply-side resource option tables for new IGCC resources are based on 2007 studies of IGCC costs associated with efforts to partner PacifiCorp with the Wyoming Infrastructure Authority (WIA) to investigate the acquisition of federal grant money to demonstrate western IGCC projects.

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

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

Coal Plant Efficiency Improvements

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

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

When economically justified, efficiency improvements are obtained through major component upgrades of the electricity generating equipment. The most notable examples of upgrades resulting in greater generating capacity are steam turbine upgrades. Turbine upgrades can consist of adding additional rows of blades to the rearward section of the turbine shaft (generically known as a "dense pack" configuration), but can also include replacing existing blades, replacing end seals, and enhancing seal packing media. Currently the Company has no plans to make any major steam turbine or generator upgrades over the next 10 years.

Demand-side Resources

Resource Options and Attributes

Source of Demand-side Management Resource Data

Demand-side management (DSM) resource opportunity estimates used in the development of the 2017 IRP were derived from the Demand-side Resource Potential Assessment for 2017-2036 (DSM Potential Study) conducted by Applied Energy Group (AEG). This study provided a broad estimate of the size, type, location and cost of demand-side resources.[1] For the purpose of integrated resource planning, the demand-side resource information from the DSM Potential Study was converted into supply curves by type of DSM (i.e. capacity-focused Classes 1 and 3 DSM and energy-based Class 2 DSM) for modeling against competing supply-side alternatives.

Demand-side Management Supply Curves

Resource supply curves are a compilation of point estimates showing the relationship between the cumulative quantity and cost of resources, providing a representative look at how much of a particular resource can be acquired at a particular price point. Resource modeling utilizing supply curves allows the selection of least-cost resources (products and quantities) based on each resource's competitiveness against alternative resource options. At the time of preparation for the 2017 IRP, the Company had established DSM acquisition targets and funding levels and had begun acquiring savings for calendar year 2017. To ensure that the 2017 IRP analysis is consistent with those planned Class 2 DSM acquisition levels, expected DSM savings in each state were fixed for calendar year 2017. Beyond 2017, the model optimized DSM selections.

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

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

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

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

Class 1 DSM Capacity Supply Curves

The potentials and costs for Class 1 DSM products were provided at the state level, with impacts specified separately for summer and winter peak periods. Resource price differences between states for similar resources reflect differences in each market, such as irrigation pump size and hours of operation, as well as product performance differences. For instance, residential air conditioning load control in Oregon is more expensive than Utah on a unitized or dollar-per-kilowatt-year basis due to climatic differences that result in a lower load impact per installed switch

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

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

Table 6.11 - Class 1 DSM Program Attributes West Control Area

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

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

Table 6.12 - Class 1 DSM Program Attributes East Control Area

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

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

Class 2 DSM, Energy Supply Curves

The 2017 DSM potential study provided the information to fully assess the potential contribution from Class 2 DSM resources over the IRP planning horizon accounting for known changes in building codes, advancing equipment efficiency standards, market transformation, resource cost changes, changes in building characteristics and state-specific resource evaluation considerations (e.g., cost-effectiveness criteria).

Class 2 DSM resource potential was assessed by state down to the individual measure and facility levels; e.g., specific appliances, motors, lighting configurations for residential buildings, small offices, etc. The DSM potential study provided Class 2 DSM resource information at the following granularity:

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

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

The 2017 DSM potential study levelized total resource costs (including measure costs and a 20 percent adder for program administrative costs) over the study period at PacifiCorp's cost of capital, consistent with the treatment of supply-side resources. Consistent with regulatory mandates, Utah Class 2 DSM resource costs were levelized using utility costs (incentive and non-incentive program costs) instead of total resource costs.

The technical potential for all Class 2 DSM resources across five states over the twenty-year DSM potential study horizon totaled 11.2 million MWh.[5] The technical potential represents the total universe of possible savings before adjustments for what is likely to be realized (achievable). When the achievable assumptions described below are considered the technical potential is reduced to an achievable technical potential for modeling consideration of 9.5 million MWh. The achievable technical potential, representing available potential at all costs, is provided to the IRP model for economic screening relative to supply-side alternatives.

Despite the granularity of Class 2 DSM resource information available, it was impractical to model the Class 2 DSM resource supply curves at this level of detail. The combination of measures by facility type and state generated over 33,000 separate permutations or distinct measures that could be modeled using the supply curve methodology. To reduce the resource options for consideration without losing the overall resource quantity available or its relative cost, resources were consolidated into bundles, using ranges of levelized costs to reduce the number of combinations to a more manageable number. The range of measure costs in each of

[3] Oregon's Class 2 DSM potential was assessed in a separate study commissioned by the Energy Trust of Oregon.
[4] Facility type includes such attributes as existing or new construction, single or multi-family, etc. Facility types are more fully described in Chapter 4 of Volume 2 of the 2015 DSM potential study; pages 4-3 for residential, pages 4-5 for commercial, and pages 4-8 for industrial.
[5] The identified technical potential represents the cumulative impact of Class 2 DSM measure installations in the 20th year of the study period. This may differ from the sum of individual years' incremental impacts due to the introduction of improved codes and standards over the study period.

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

Bundle development began with the Class 2 DSM technical potential identified by the 2017 DSM potential study. To account for the practical limits associated with acquiring all available resources in any given year, the technical potential by measure was adjusted to reflect the amount that is realistically achievable over the 20-year planning horizon. Consistent with the Northwest Power and Conservation Council's aggressive[6] regional planning assumptions, it was assumed that 85 percent of the technical potential for discretionary (retrofit) resources and 73 percent of lost-opportunity (new construction or equipment upgrade on failure) could be achievable over the 20-year planning period. Over the planning period, the aggregate (both discretionary and lost opportunity) achievable technical potential is 79 percent of the technical potential.

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

The Energy Trust of Oregon (ETO) applies achievability assumptions and ramp rates in a similar manner in its resource assessment. For a more detailed description of the methods used in PacifiCorp's 2017 DSM Potential study and the ETO's resource assessment, see Appendix E in Volume 4 of the 2015 DSM potential study report. Neither PacifiCorp nor the ETO performed an economic screening of measures in the development of the Class 2 DSM supply curves used in the development of the 2017 IRP, allowing resource opportunities to be economically screened against supply-side alternatives in a consistent manner across PacifiCorp's six states.

Twenty-seven cost bundles were available across six states (including Oregon), which equates to 189 Class 2 DSM supply curves. Table 6.13 shows the 20-year MWh potential for Class 2 DSM cost bundles, designated by ranges of $/MWh. Table 6.14 shows the associated bundle price after applying cost credits afforded to Class 2 DSM resources within the model. These cost credits include the following:

- A transmission and distribution investment deferral credit of $13.56/kW-year
- Stochastic risk reduction credit of $5.03/MWh[8]
- Northwest Power Act 10-percent credit (Oregon and Washington resources only)[9]

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

[7] The Wyoming industrial market ramp rate is provided in Table E-1 of Volume 4 of the 2017 DSM potential study report.

[8] PacifiCorp developed this credit from two sets of production dispatch simulations of a given resource portfolio, and each set has two runs with and without DSM. One simulation is on deterministic basis and another on stochastic basis. Differences in production costs between the two sets of simulations determine the dollar per MWh stochastic risk reduction credit.

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

Table 6.13 - Class 2 DSM MWh Potential by Cost Bundle

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

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

Table 6.14 - Class 2 DSM Adjusted Prices by Cost Bundle

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

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

Distribution Efficiency

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

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

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

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

Transmission Resources

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

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

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

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

For any initial resource additions up to 500 MW there would not be incremental transmission costs as there is capacity currently available. However, if a resource added is in any size between 500 MW and 1,500 MW, the transmission integration costs would be $350 million. If a second

resource added subsequently at the same location and total capacity between the two resources does not exceed 1,500 MW, there would not be transmission integration costs for this second resource.

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

Market Purchases

PacifiCorp and other utilities engage in purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations. In addition to reflecting spot market purchase activity and existing long-term purchase contracts in the IRP portfolio analysis, PacifiCorp modeled front office transactions (FOT). FOTs are proxy resources, assumed to be firm, that represent procurement activity made on an on-going forward basis to help the Company cover short positions.

As proxy resources, FOTs represent a range of purchase transaction types. They are usually standard products, such as heavy load hour (HLH), light load hour (LLH), and super peak (hours ending 13 through 20) and typically rely on standard enabling agreements as a contracting vehicle. FOT prices are determined at the time of the transaction, usually via an exchange or third party broker, and are based on the then-current forward market price for power. An optimal mix of these purchases would include a range of volumes and terms for these transactions.

Solicitations for FOTs can be made years, quarters or months in advance, however, most transactions made to balance PacifiCorp's system are made on a balance of month, day-ahead, hour-ahead, or intra-hour basis. Annual transactions can be available three or more years in advance. Seasonal transactions are typically delivered during quarters and can be available from one to three years or more in advance. The terms, points of delivery, and products will all vary by individual market point.

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

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

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

CHAPTER 7 – MODELING AND PORTFOLIO EVALUATION APPROACH

CHAPTER HIGHLIGHTS

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

Introduction

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

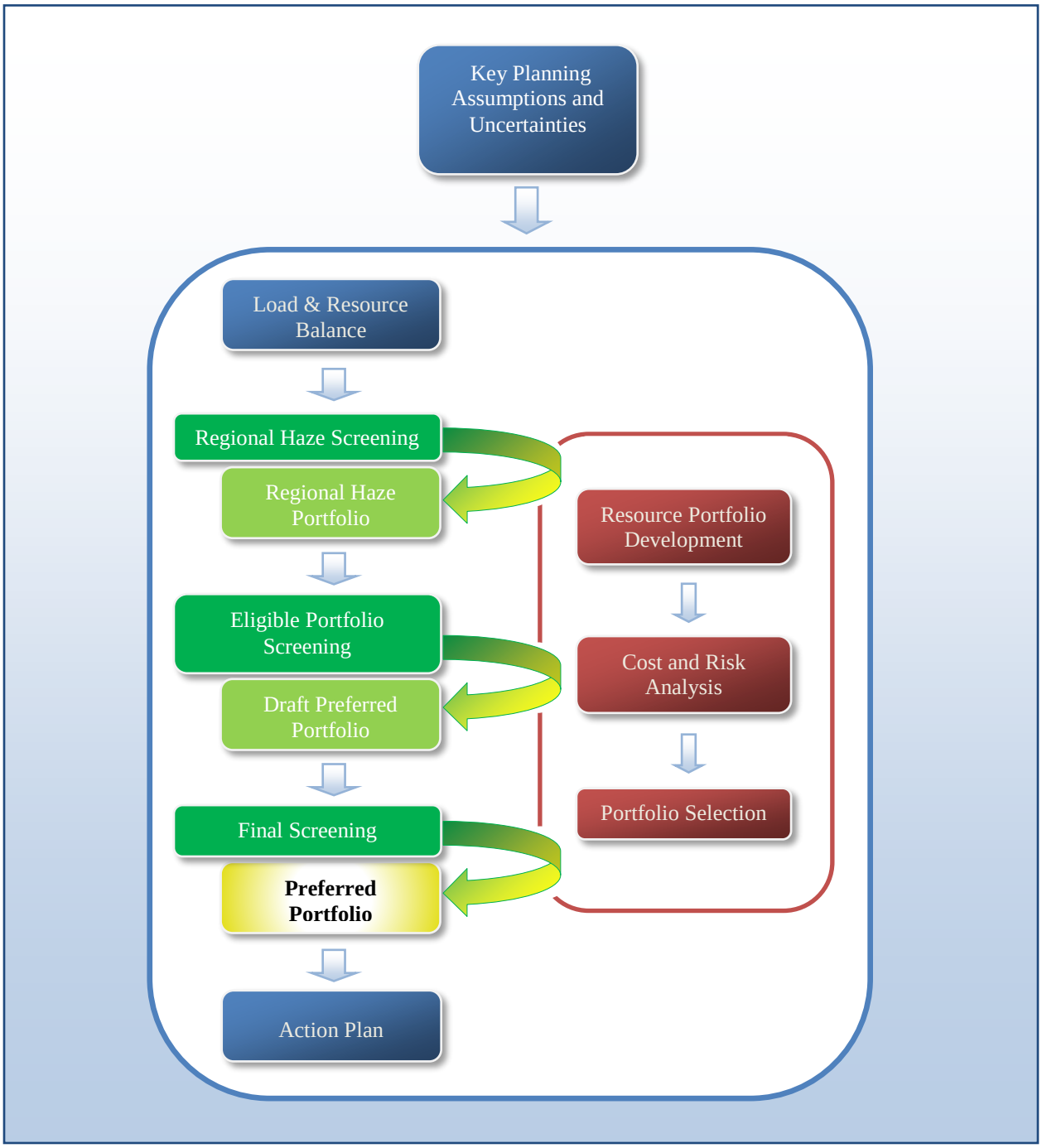
The first section of this chapter describes the screening and evaluation processes for portfolio selection. Following sections summarize portfolio risk analyses, document key modeling assumptions, and describe how this information is used to select the preferred portfolio. The last section of this chapter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

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

Modeling and Evaluation Steps

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

Figure 7.1 – Portfolio Evaluation Steps within the IRP Process



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

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

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

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

Resource Portfolio Development

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

System Optimizer (SO)

The SO model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability and other constraints. Over the 20-year planning horizon, it optimizes resource additions subject to resource costs and capacity constraints (summer peak

loads, winter peak loads, plus a target planning reserve margin for each load area represented in the model). In the event that an early retirement of an existing generating resource is assumed for a given planning scenario, SO will select additional resources as required to meet summer and winter peak loads inclusive of the target planning reserve margin.

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

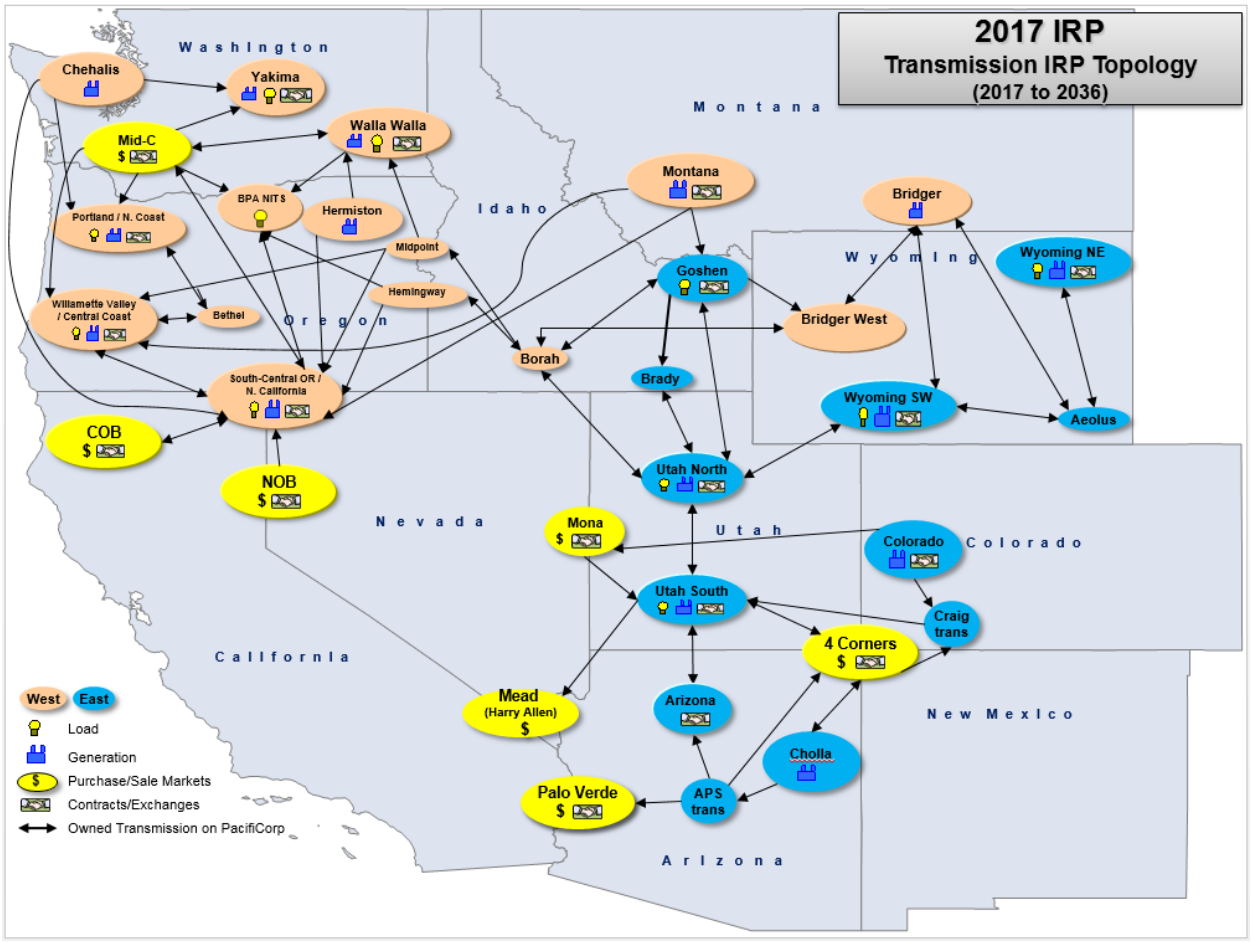
Transmission System

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

Transmission Costs

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

Figure 7.2 – Transmission System Model Topology



Resource Adequacy

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

New Resource Options

Dispatchable Thermal Resources

SO performs time-of-day least cost dispatch of existing and potential new thermal resources to meet load while minimizing costs. Dispatch costs applicable to thermal resources include fuel costs, non-fuel variable operations & maintenance (VOM) costs, and the cost of emissions, as applicable. For existing and potential new dispatchable thermal resources, System Optimizer uses

generator specific inputs for fuel costs, VOM, heat rates, emission rates, and any applicable price for emissions to establish the dispatch cost of each generating unit for each dispatch interval. Thermal resources are dispatched by least cost merit order. The power produced by these resources can be used to meet load or to make off-system sales at times when resource dispatch costs fall below market prices. Conversely, at times when dispatch costs exceed market prices, off-system purchases can displace dispatchable thermal generation to minimize system energy costs. Dispatch of thermal resources reflects any applicable transmission constraints connecting generating resources with both load and market bubbles as defined in the transmission topology for the model.

Front Office Transactions

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

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

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

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

Demand Side Management

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

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

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

Wind and Solar Resources

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

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

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

cost, size of the storage and time to fill the storage, heat rate (if fuel is used), operating and maintenance cost, minimum capacity, and maximum capacity.

Capital Costs and End-Effects

SO uses annual capital recovery factors to convert capital dollars into real levelized revenue requirement costs to address end-effects that arise with capital-intensive projects that have different lives and in-service dates. All capital costs evaluated in the IRP are converted to real levelized revenue requirement costs. Use of real levelized revenue requirement costs is an established and preferred methodology for analyzing capital-intensive resource decisions among resource alternatives that have unequal lives and/or when it is not feasible to capture operating costs and benefits over the entire life of any given resource. To achieve this, the real levelized revenue requirement method spreads the return of investment (book depreciation), return on investment (equity and debt), property taxes and income taxes over the life of the investment. The result is an annuity or annual payment that grows at inflation such that the PVRR is identical to the PVRR of the nominal annual requirement when using the same nominal discount rate. For the 2017 IRP, the PVRR is calculated inclusive of real levelized capital revenue requirement through the end of the 2036 planning period.

General Assumptions

Study Period and Date Conventions

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

Inflation Rates

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

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 2017 IRP is 6.57 percent. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.[2] PVRR figures reported in the 2017 IRP are reported in January 1, 2017 dollars.

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

Environmental Policy and Price Scenarios

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

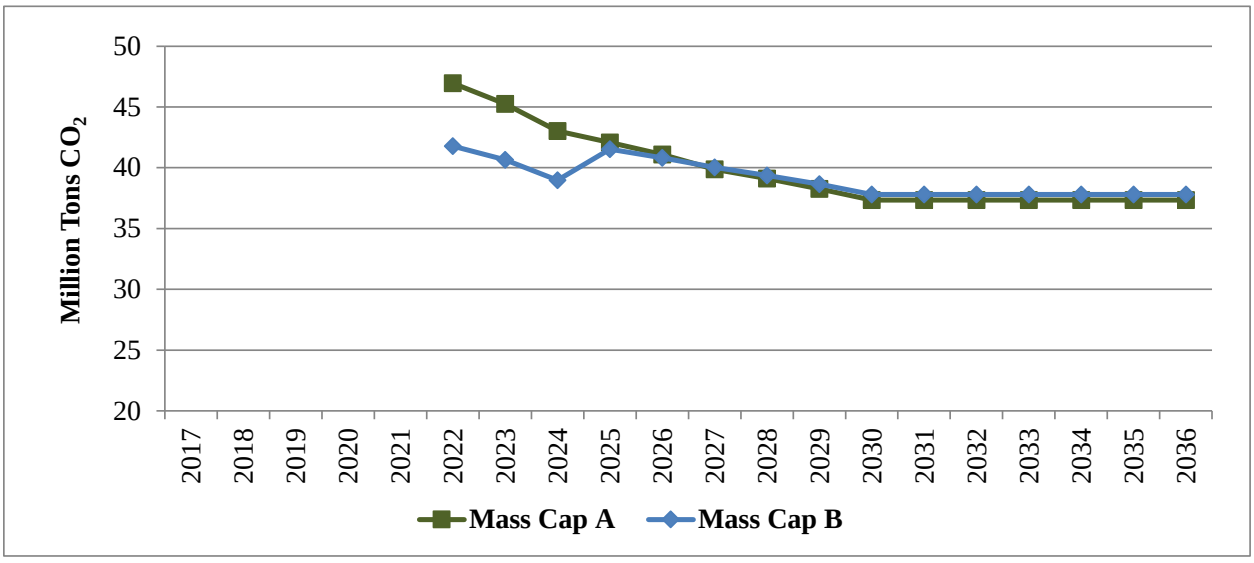
Emissions Policy Scenarios

The two CO_2 emissions policy scenarios are defined by two differing interpretations of the Environmental Protection Agency's (EPA) Clean Power Plan (CPP).

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

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

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



Price Scenario Development

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

Table 7.1 – Price-Emissions Scenarios

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

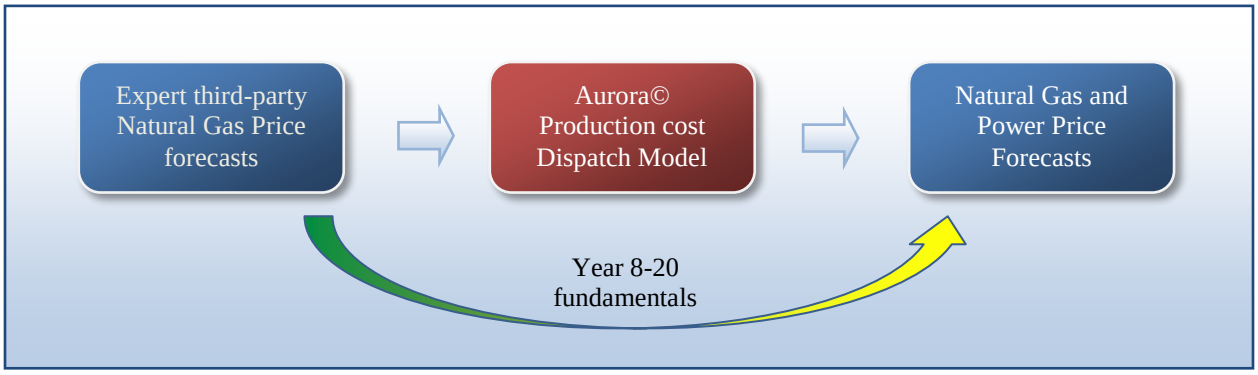
Table 7.1 Notes

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

Wholesale Electricity and Natural Gas Forward Prices

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

Figure 7.4 - Price Scenario Modeling



At the time PacifiCorp's 2017 IRP modeling was initiated, the most current OFPC was produced in October 2016. For both gas and electricity, the front 72 months of the OFPC reflects market forwards at the close of the markets on a given trading day. For the October 2016 OFPC, prices over the front 72-months are based on market forwards as of October 12, 2016. The blending period (months 73 through 84) is calculated by averaging the month-on-month market forward from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects an expert third-party price forecast. The fundamentals portion of the electricity OFPC reflects prices as forecast by AURORAXMP (Aurora),

a WECC-wide market model.[3] Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. PacifiCorp reviews third party natural gas price forecasts each quarter for the OFPC, and as a corollary, the electricity OFPC is also updated. Scenarios, unlike the OFPC, do not incorporate market forwards since scenarios are designed to reflect an alternative view to that of the market. As such, both electricity and natural gas price scenarios are fundamentals-based forecasts.

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

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

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

[3] AURORAXMP is a production cost simulation model, developed by EPIS, LLC.
[4] Plausible allocation designs are based on EPA's Clean Power Plan, as finalized August 3, 2016 and authorized by §111(d) of the Clean Air Act.

Figure 7.5 – Nominal Wholesale Electricity and Natural Gas Price Scenarios

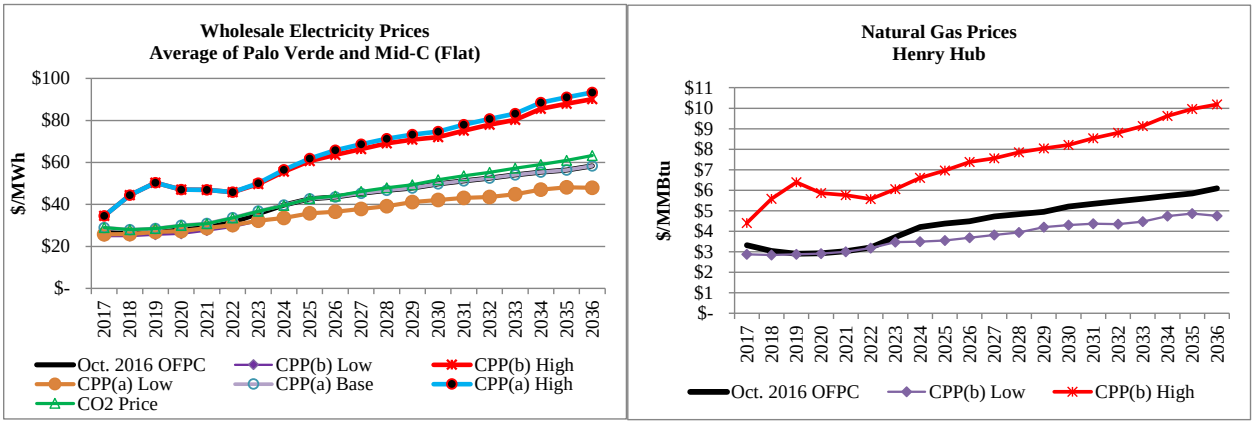


Figure 7.6 through Figure 7.8 illustrate the CPP constraints in relation to regional emissions from the price curve development process discussed above. The CPP does not constrain emissions except in the high as price scenarios, indicating that under base natural gas and low natural gas futures, regional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

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

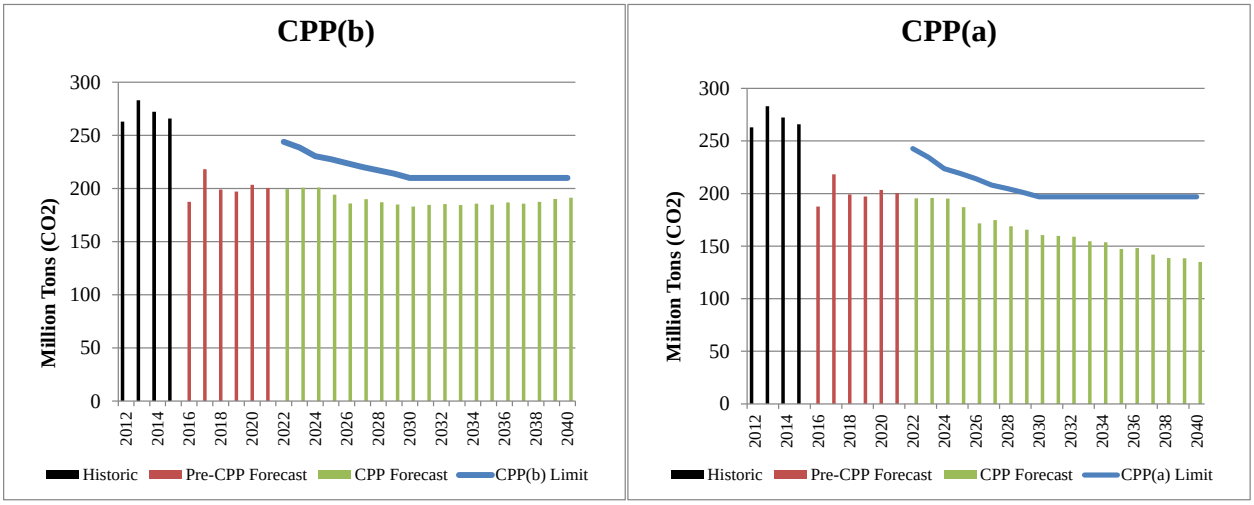


Figure 7.7 – U.S.WECC CO_2 Emissions, Low Natural Gas Prices

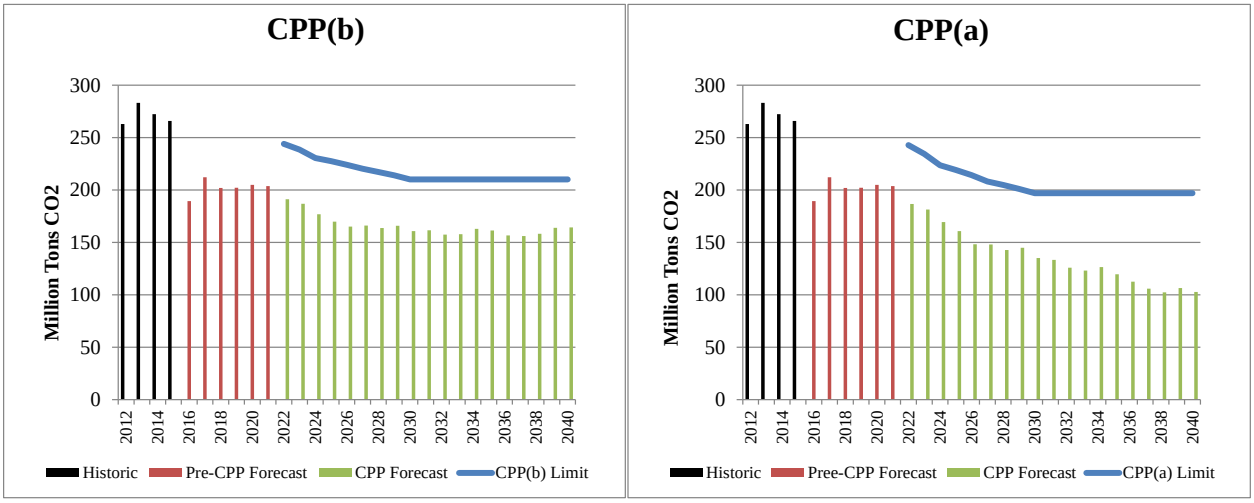
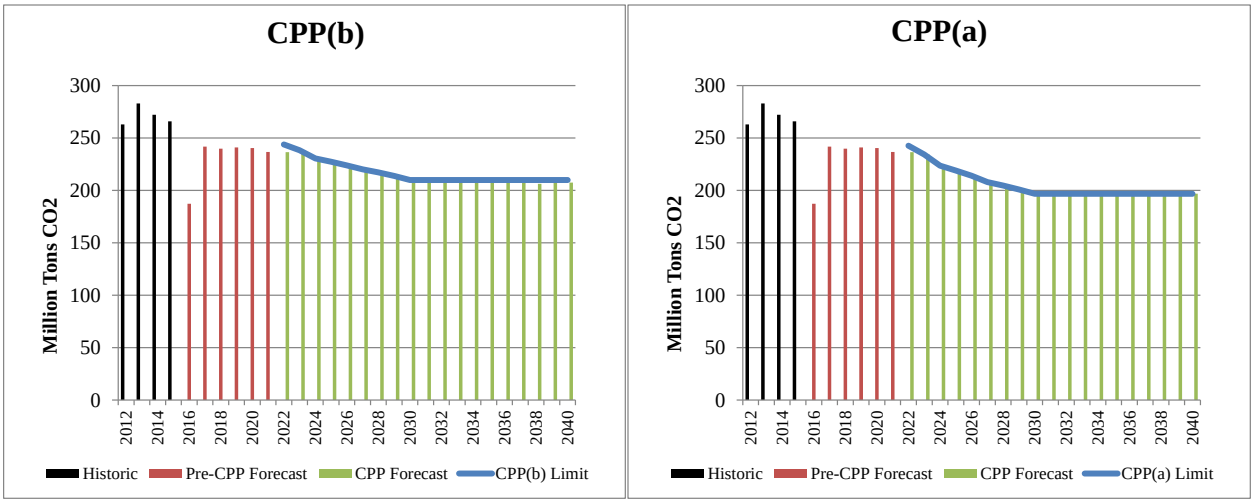


Figure 7.8 - U.S. WECC CO_2 Emissions, High Natural Gas Prices



PacifiCorp System CPP Shadow Prices

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

Particulate Matter Emissions

The Washington Utilities and Transportation Commission (WUTC) requested that investor-owned utilities in Washington start incorporating the non-energy benefits of fine particular matter ($PM_{2.5}$) emissions in conservation and energy planning calculations going forward, including incorporating these benefits into the IRP. In further discussion with WUTC staff to clarify this

request, it became clear that staff was requesting a broad health impacts analysis (and potentially other societal impacts) of PacifiCorp's generating resources. Following further clarification and conversation with WUTC staff, both staff and PacifiCorp agreed that it would not be feasible to conduct such an analysis for this IRP (either focused on $PM_{2.5}$ or other emissions), but that this issue may be raised in future IRPs. Generally, PacifiCorp considers health assessments and other societal externalities to be outside the scope of the IRP, which focuses on the economic costs of various resource decisions including direct costs to serve our customers.

Cost and Risk Analysis

Planning and Risk (PaR)

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

Cost and Risk Analysis

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

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

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

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

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

Stochastic Model Parameter Estimation

Stochastic parameters are developed with econometric modeling techniques. The short-run seasonal stochastic parameters are developed using a single period auto-regressive regression equation (commonly called an AR(1) process). The standard error of the seasonal regression defines the short run volatility, while the regression coefficient for the AR(1) variable defines the mean reversion parameter. Loads and commodity prices are mean-reverting in the short term. For instance, natural gas prices are expected to hover around a moving average within a given month and loads are expected to hover near seasonal norms. These built-in responses are the essence of mean reversion. The mean reversion rate tells how fast a forecast will revert to its expected mean following a shock. The short-run regression errors are correlated seasonally to capture inter-variable effects from informational exchanges between markets, inter-regional impacts from shocks to electricity demand and deviations from expected hydroelectric generation performance. The stochastic parameters are used to drive the stochastic processes of the following variables:

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

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

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

Table 7.2 – Short Term Load Stochastic Parameters

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

Table 7.3 - Short Term Gas Price Parameters

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

Table 7.4 - Short Term Electricity Price Parameters

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

Table 7.5 - Winter Season Price Correlation

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

Table 7.6 - Spring Season Price Correlation

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

Table 7.7 - Summer Season Price Correlation

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

Table 7.8 - Fall Season Price Correlation

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

Table 7.9 - Hydro Short Term Stochastic

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

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

Figure 7.9 - Simulated Annual Mid-C Electricity Market Prices

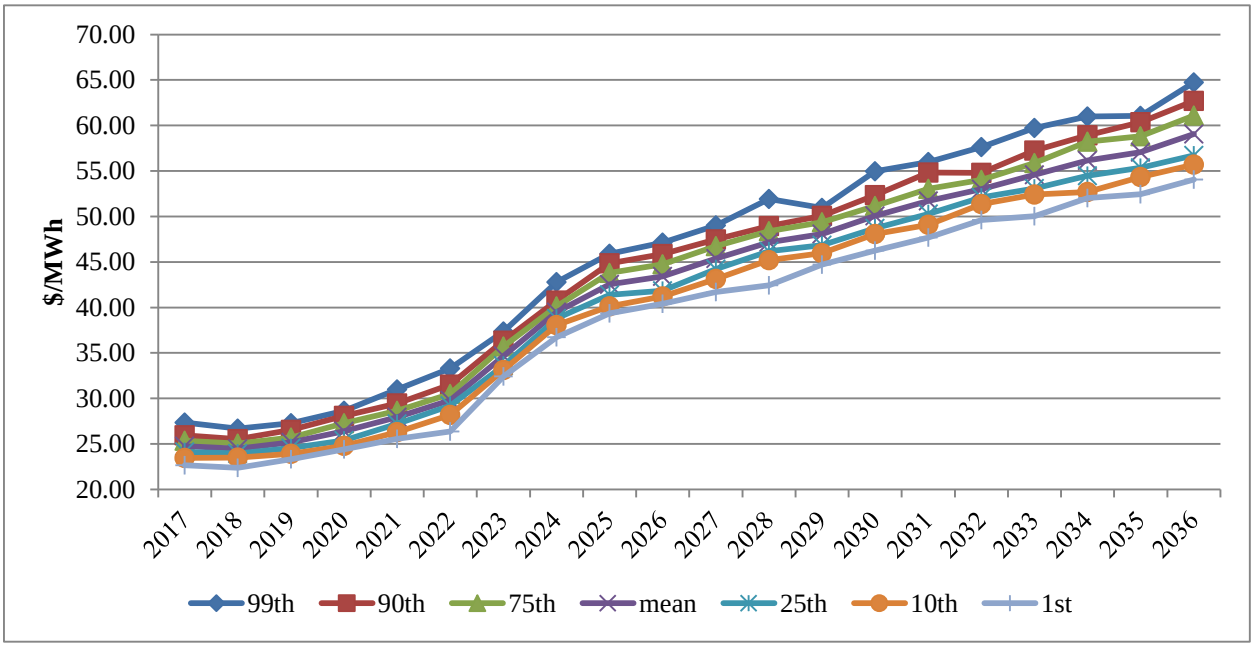


Figure 7.10 - Simulated Annual Palo Verde Electricity Market Prices

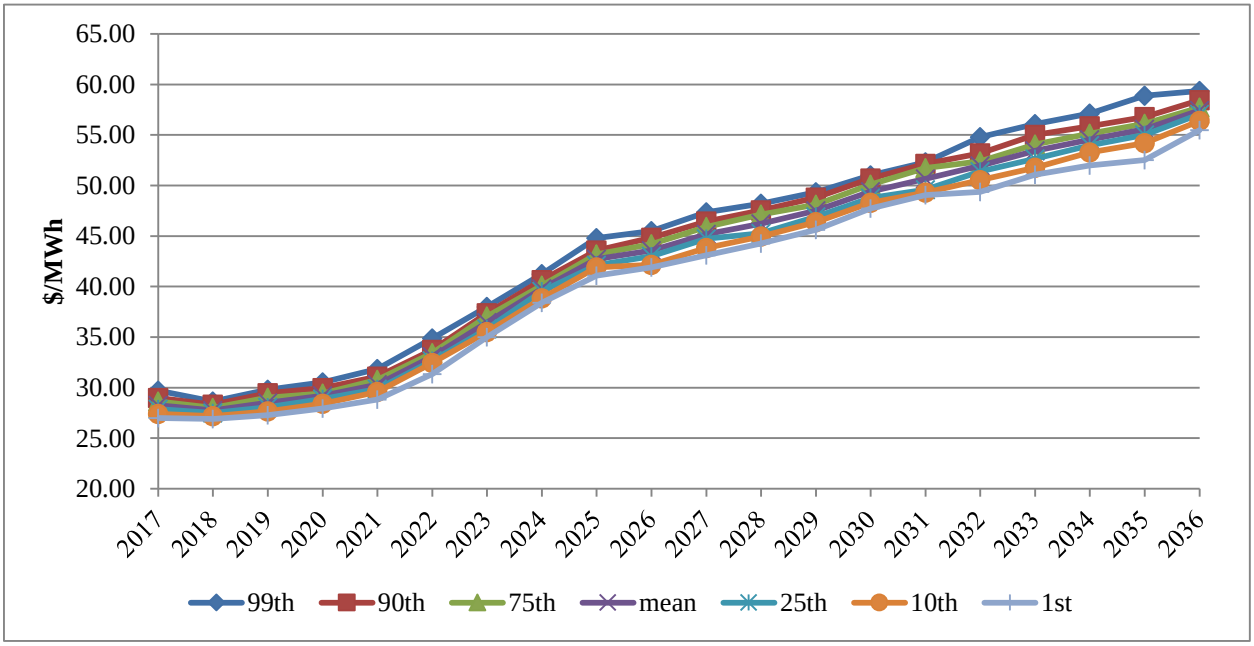


Figure 7.11 and Figure 7.12 show annual electricity prices at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles for west and east natural gas prices. For west natural gas prices, differences between the first and 99th percentiles range from $0.22/MMBtu to $0.48/MMBtu during the 20-year study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

Figure 7.11 - Simulated Annual Western Natural Gas Market Prices

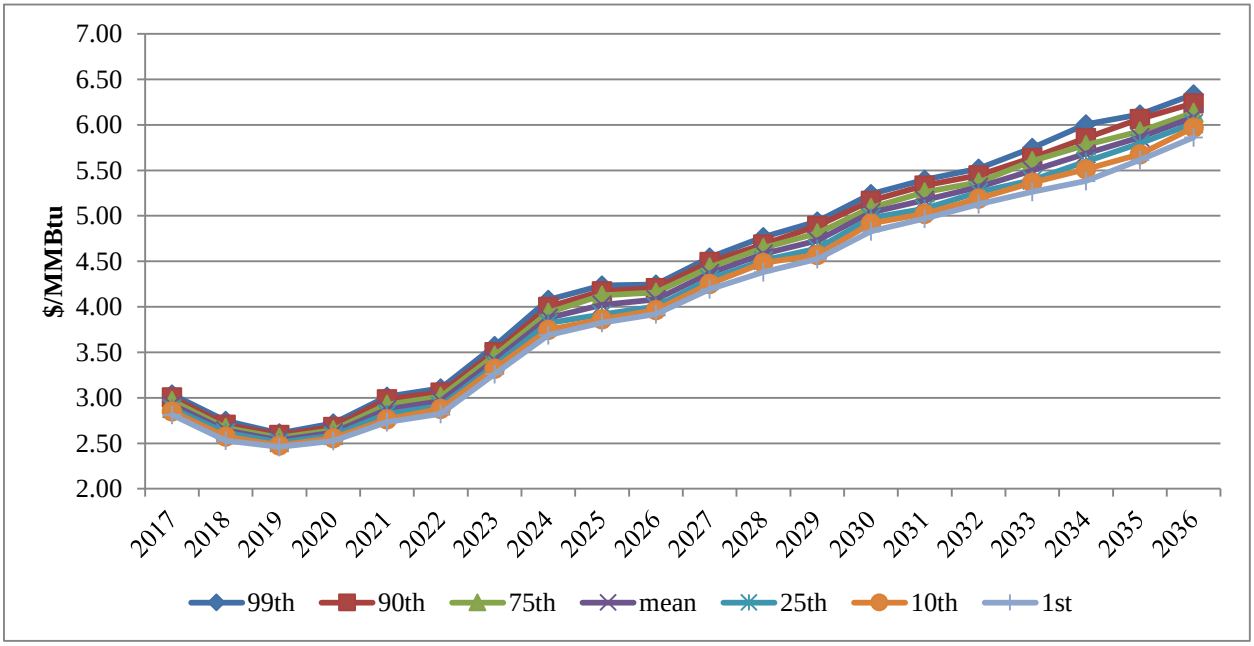


Figure 7.12 - Simulated Annual Eastern Natural Gas Market Prices

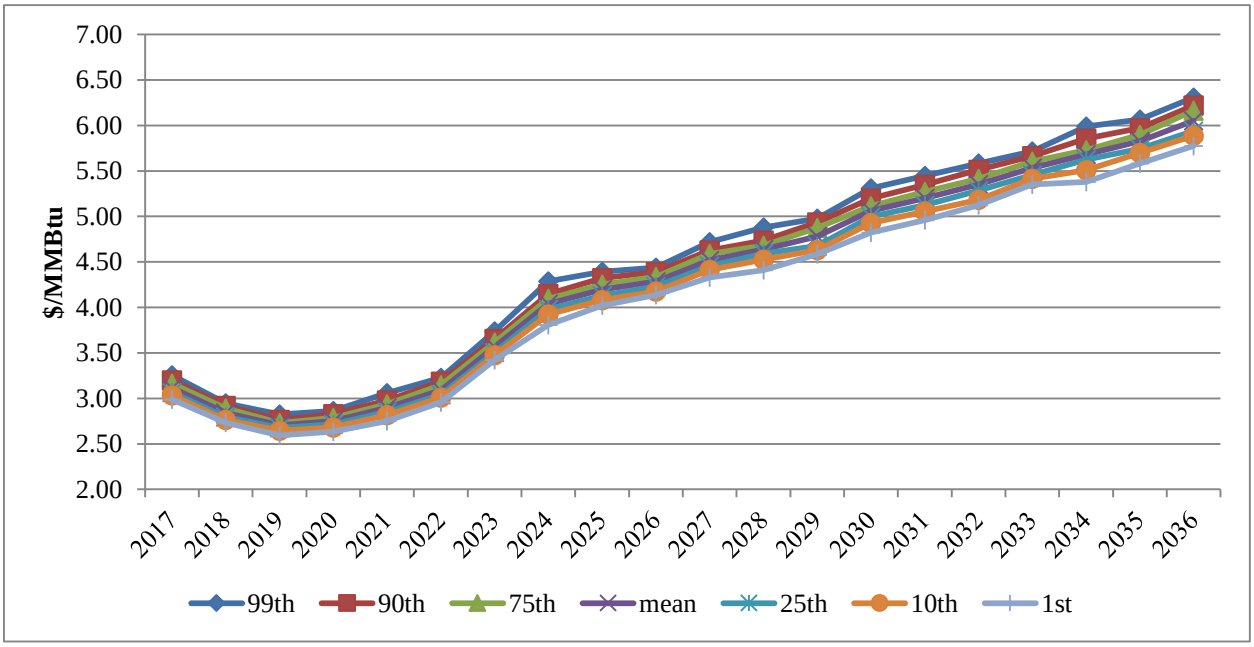


Figure 7.13 through Figure 7.18 show annual loads by load area and for PacifiCorp's system at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. For Idaho (Goshen) load, the annual differences between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

Figure 7.13 - Simulated Annual Idaho (Goshen) Load

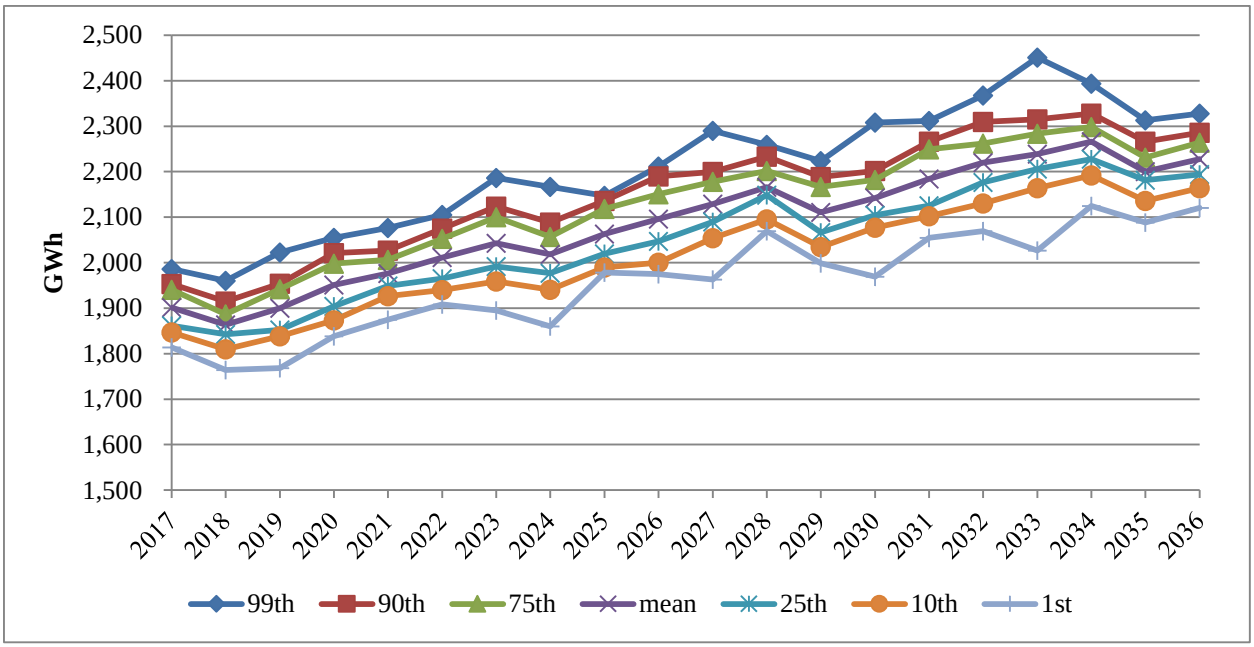


Figure 7.14 - Simulated Annual Utah Load

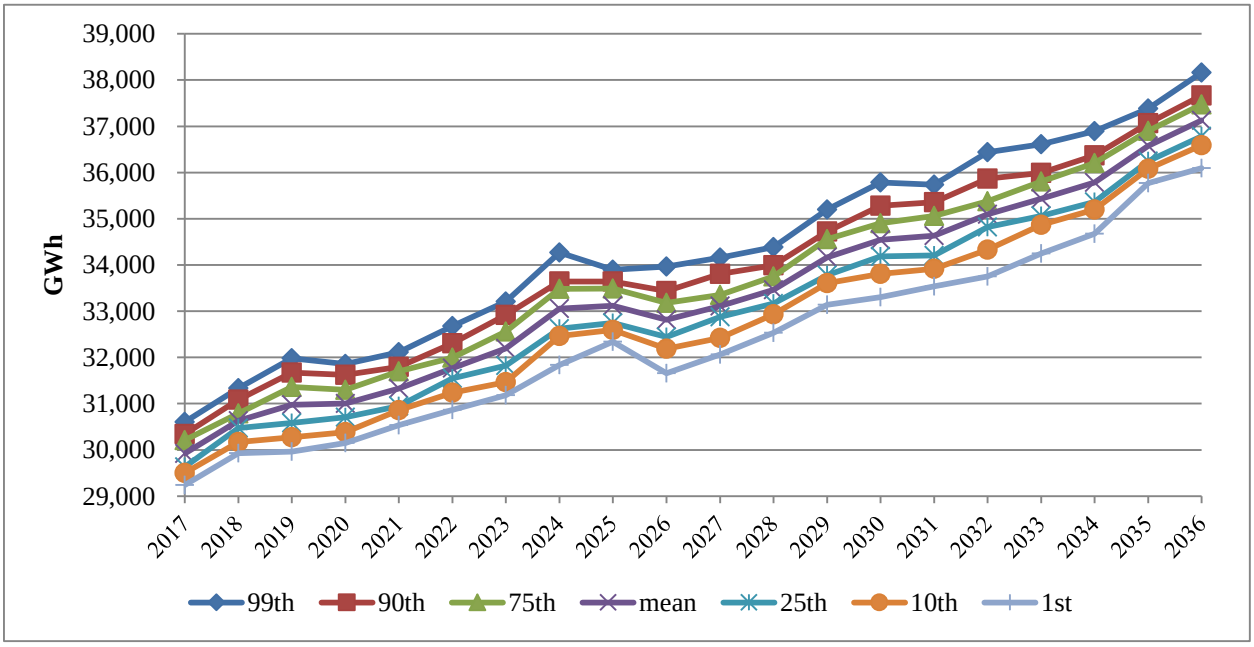


Figure 7.15 - Simulated Annual Wyoming Load

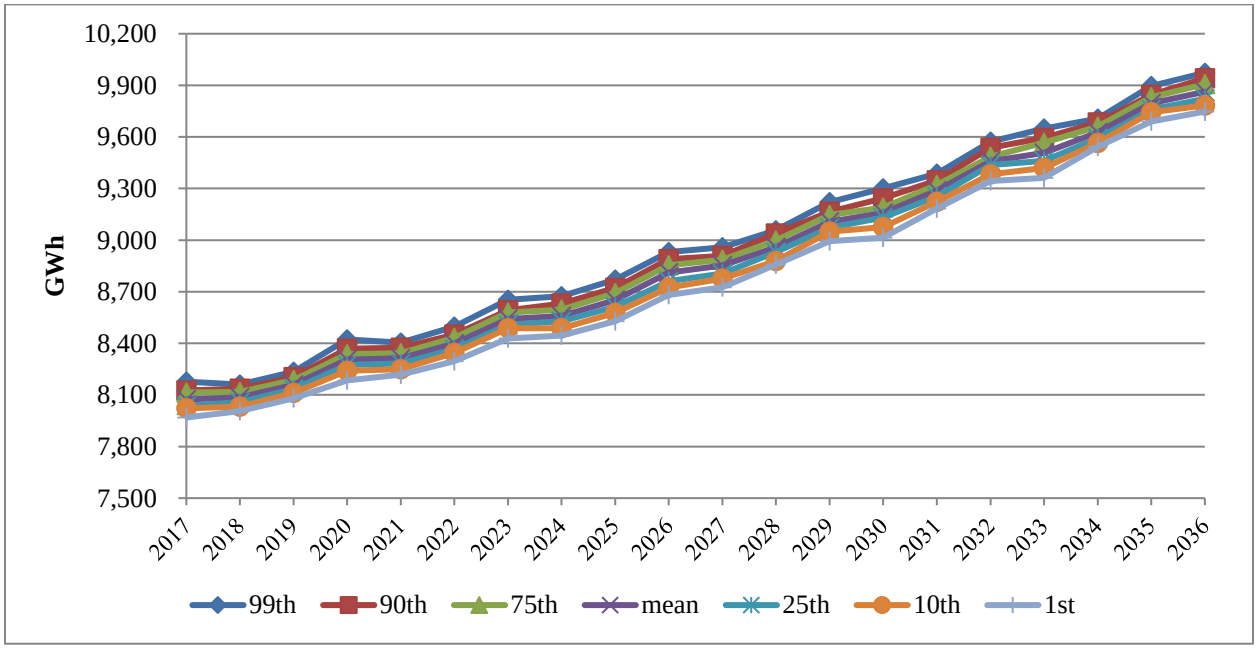


Figure 7.16 - Simulated Annual Oregon/California Load

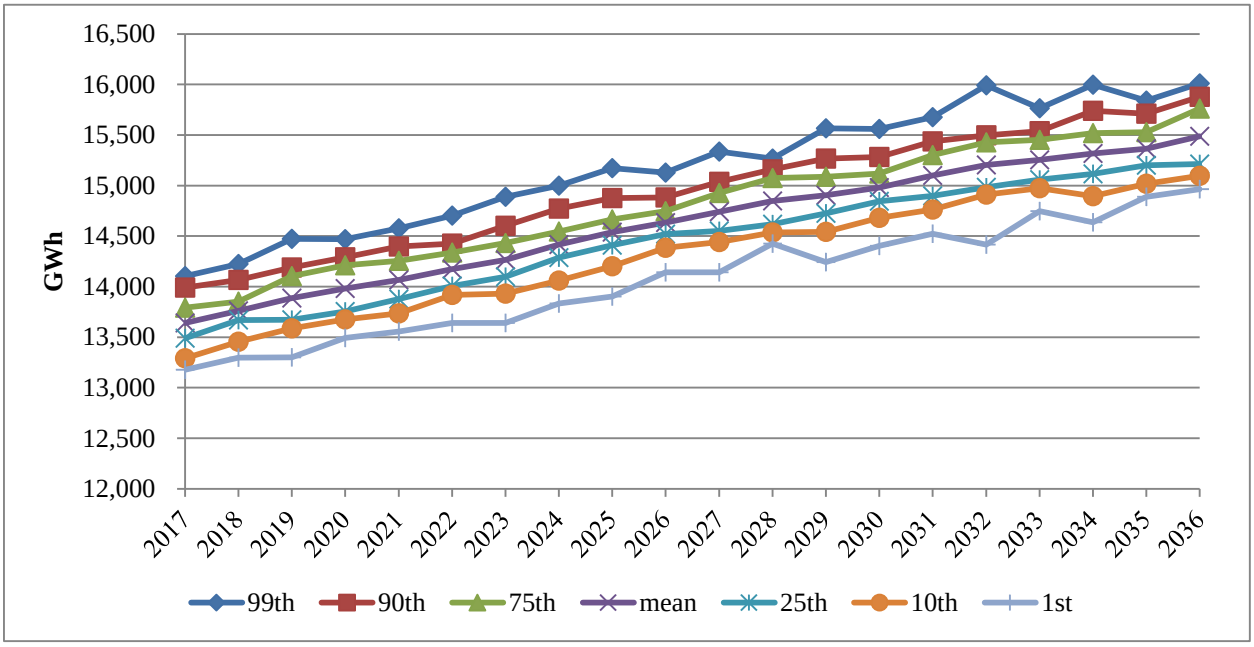


Figure 7.17 - Simulated Annual Washington Load

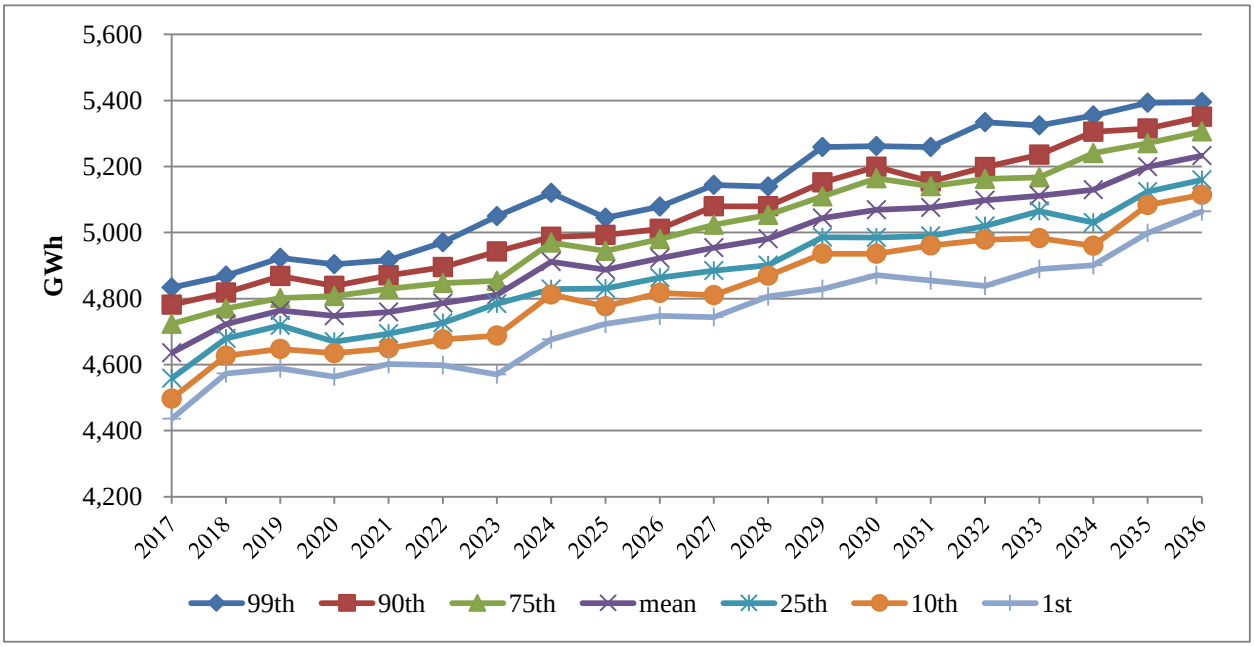


Figure 7.18 - Simulated Annual System Load

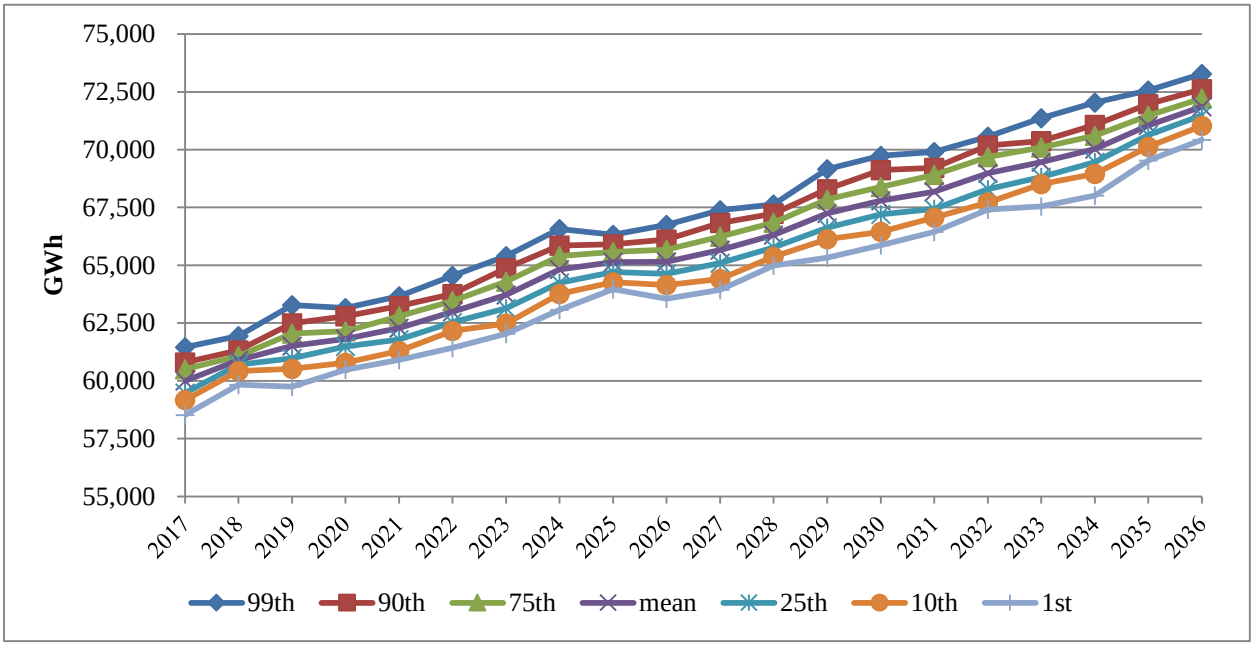
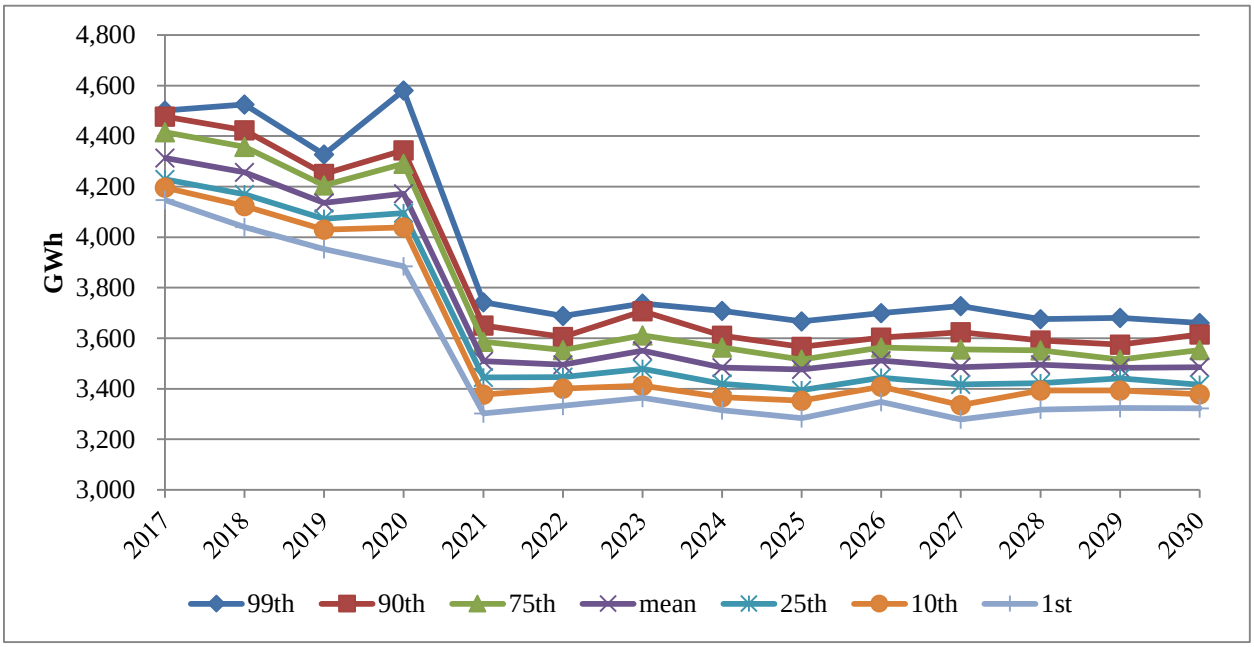


Figure 7.19 shows hydro generation at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. PacifiCorp can dispatch its hydro generation on a limited basis to meet load and reserve obligations. The parameters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

Figure 7.19 - Simulated Annual Hydro Generation



Monte Carlo Simulation

During model execution, the PaR model makes time-path-dependent Monte Carlo draws for each stochastic variable based on input parameters. The Monte Carlo draws are percentage deviations from the expected forward value of each variable. The Monte Carlo draws of the stochastic variables among all resource portfolios modeled are the same, which allows for a direct comparison of stochastic results among all of the resource portfolios being analyzed. In the case of natural gas prices, electricity prices, and regional loads, the PaR model applies Monte Carlo draws on a daily basis. In the case of hydroelectric generation, Monte Carlo draws are applied on a weekly basis.

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

The expected values of the Monte Carlo simulation are the average result of all 50 iterations. Results from subsets of the 50 iterations are also summarized to signify particularly adverse cost conditions, and to derive associated cost measures as indicators of high-end portfolio risk. These cost measures, and others are used to assess portfolio performance, which are described below.

Stochastic Portfolio Performance Measures

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

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

Stochastic Mean PVRR

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

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

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

Risk-Adjusted PVRR

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

Upper-Tail Mean PVRR

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

95th and 5th Percentile PVRR

The 5th and 95th percentile PVRRs are also reported from the 50 Monte Carlo iterations. These measures capture the extent of upper-tail (high cost) and lower-tail (low cost) stochastic outcomes. As described above, the 95th percentile PVRR is used to derive the high-end cost risk premium for the risk-adjusted mean PVRR measure. The 5th percentile PVRR is reported for informational purposes.

Production Cost Standard Deviation

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

Average and Upper-Tail Energy Not Served

Certain iterations of a stochastic simulation will have ENS, a condition where there are insufficient resources, inclusive of system balancing purchases, available to meet load or operating reserve requirements because of physical constraints. This occurs when Monte Carlo draws of stochastic variables result in a load obligation that is higher than the capability of the available resources in the portfolio. For example, this might occur in Monte Carlo draws with large load shocks concurrent with a random unplanned plant outage event. Consequently, ENS, when averaged across all 50 iterations, serves as a measure of reliability that can be compared among resource portfolios. PacifiCorp calculates an average annual value over the 2017 through 2036 planning horizon, reported in gigawatt-hours, as well as the upper-tail ENS (average of the three iterations with the highest ENS). In the 2017 IRP, ENS is priced at $1,000/MWh.

Loss of Load Probability

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

Cumulative CO_2 Emissions

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

Forward Price Curve Scenarios

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

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

Other PaR Modeling Methods and Assumptions

Transmission System

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

Resource Adequacy

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

Energy Storage Resources

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

General Assumptions

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

Other Cost and Risk Considerations

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

Fuel Source Diversity

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

Customer Rate Impacts

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

Portfolio Selection

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

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

Final Screening Stage and Preferred Portfolio Selection

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

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

Case Definitions

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

Regional Haze Case Definitions

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

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

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

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

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

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

Table 7.10 - Regional Haze Case Assumptions

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

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

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

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

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

Core Case Definitions

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

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

Table 7.11 - Core Case Definitions

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

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

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

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

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

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

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

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

Sensitivity Case Definitions

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

Table 7.12 - Sensitivity Definitions

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

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

Regional Haze Sensitivities

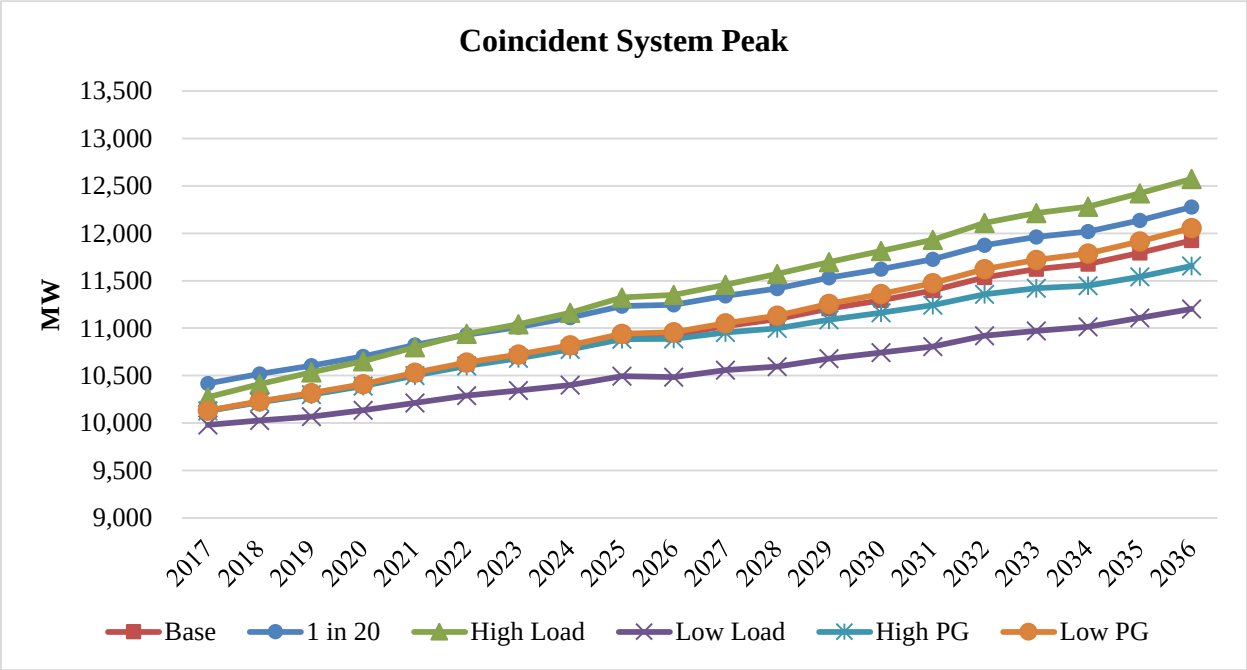
An additional sensitivity (RH-2a) was performed relevant to Region Haze case 2 (RH-2) in response to stakeholder feedback at the PacifiCorp IRP January 26-27, 2017 public input meeting. As a result, the selected Regional Haze case (RH-5) was modified and re-optimized, becoming RH-5a. Both additional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

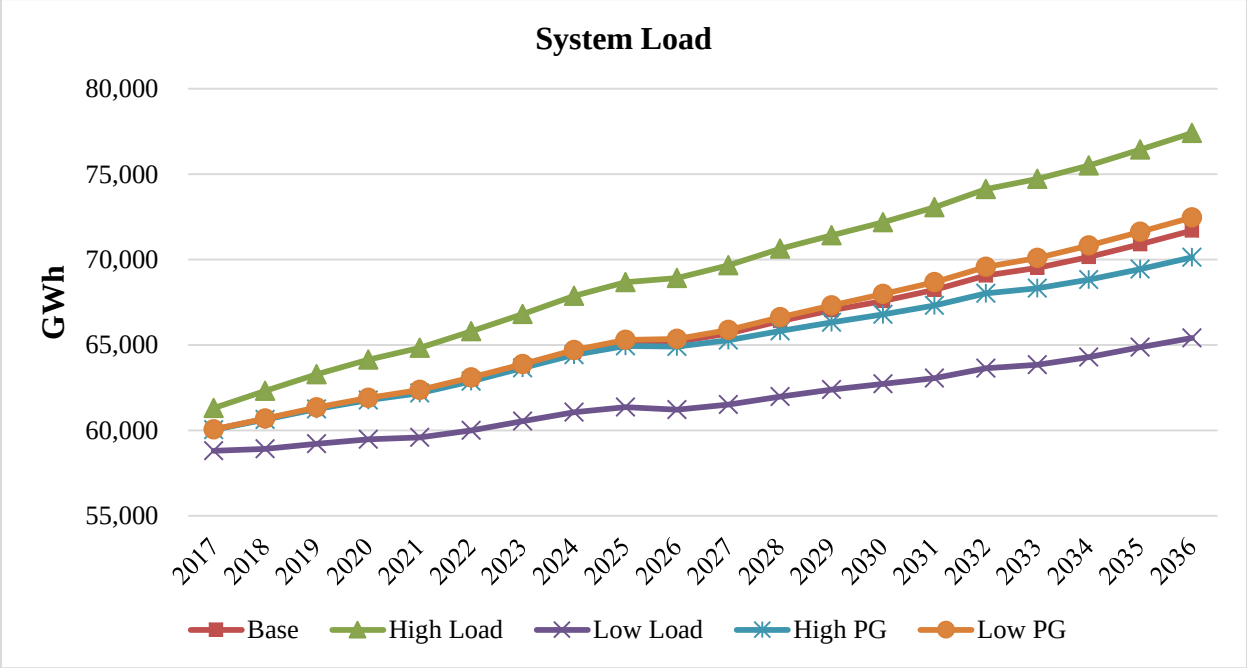
Load Sensitivities

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

sensitivities, net of base case distributed generation penetration levels, alongside the base case load forecast.

Figure 7.20 - Load Sensitivity Assumptions



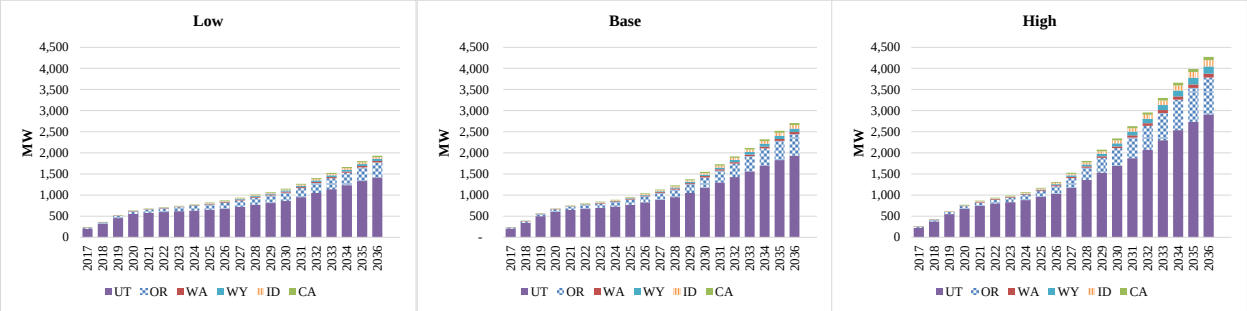


Private Generation Sensitivities

Two private generation sensitivities are analyzed. As compared to base private generation penetration levels that incorporated annual reductions in technology costs, the low private generation sensitivity reflects reduced reductions in technology costs, reduced technology

performance levels, and lower retail electricity rates. In contrast, the high private generation sensitivity reflects more aggressive technology cost reduction assumptions, higher technology performance levels, and higher retail electricity rates. Figure 7.21 summarizes private generation penetration levels for the low and high sensitivities alongside the base case.

Figure 7.21 - Private Generation Sensitivity Assumptions



CPP Mass Cap C

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

CPP Mass Cap D

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

Limited Availability of FOTs

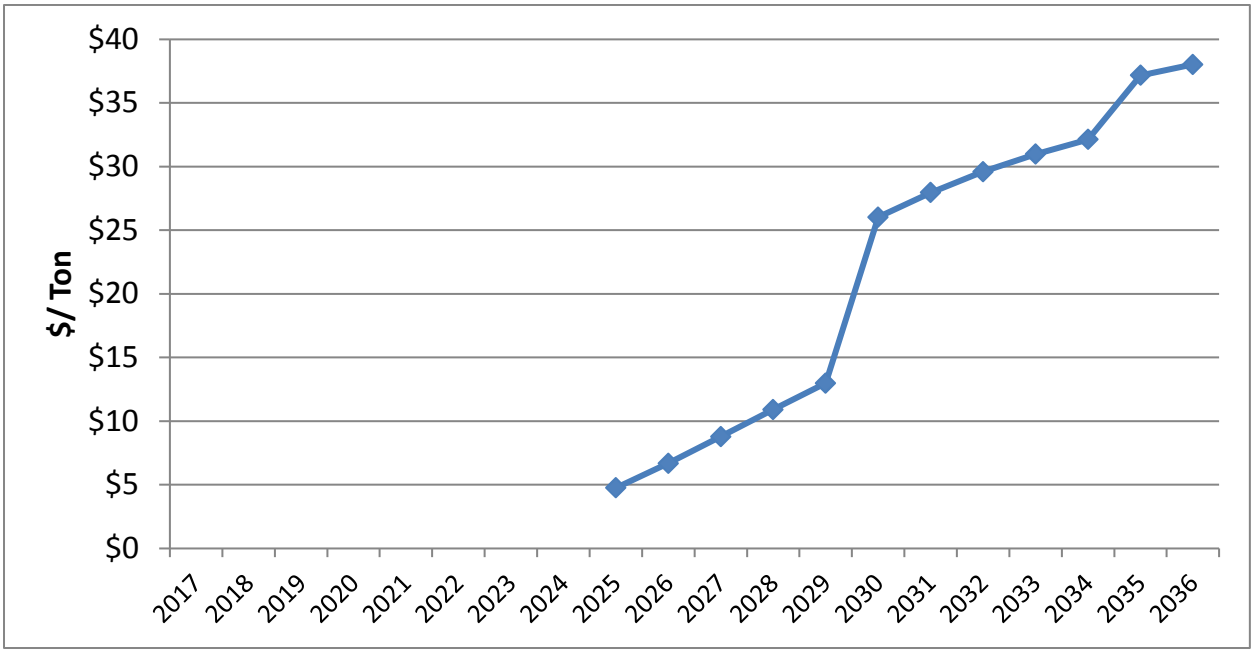
As noted in Chapter 6, PacifiCorp develops FOT limits based on its active participation in wholesale power markets; its view of physical delivery constraints, market liquidity, and market depth; and with consideration of regional resource supply. Alternative FOT limit assumptions applied during the portfolio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

CO_2 Price

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

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

Figure 7.22 – Nominal CO2 Price Assumptions for the CO2 Sensitivity



No CO_2 Policy

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

Business Plan Sensitivity

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

Energy Gateway Sensitivities

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

Table 7.13 - Energy Gateway Sensitivities

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

Energy Storage

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

East/West Split

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

WCA Assumptions

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

CHAPTER 8 – MODELING AND PORTFOLIO SELECTION RESULTS

CHAPTER HIGHLIGHTS

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

Introduction

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

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

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

Regional Haze Portfolio Screening

Resource Portfolio Development

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

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

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

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

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

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

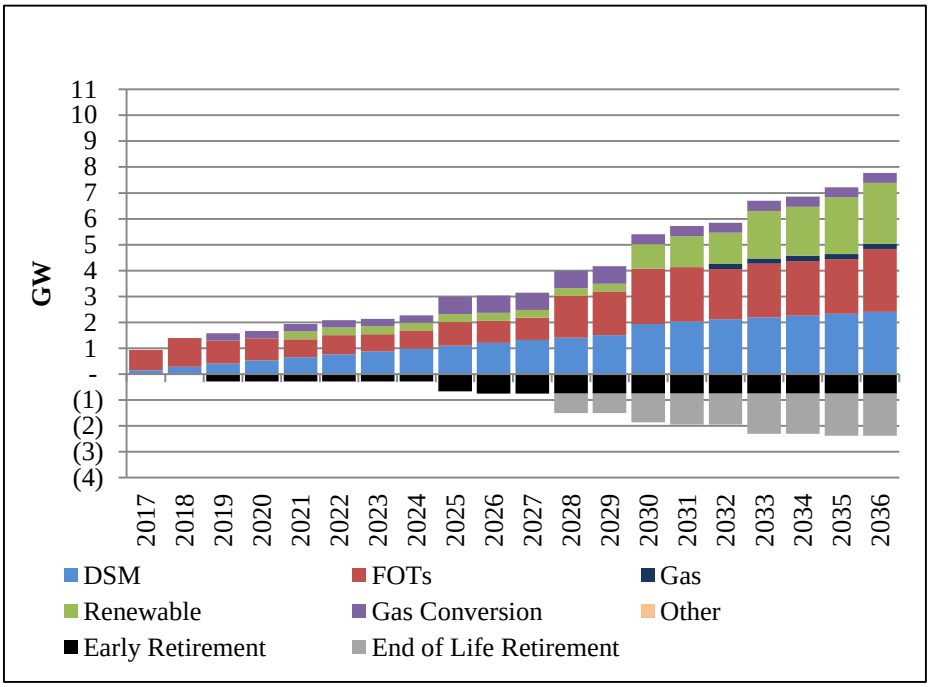


Figure 8.2 – Cumulative Capacity through 2036, Regional Haze Case 1

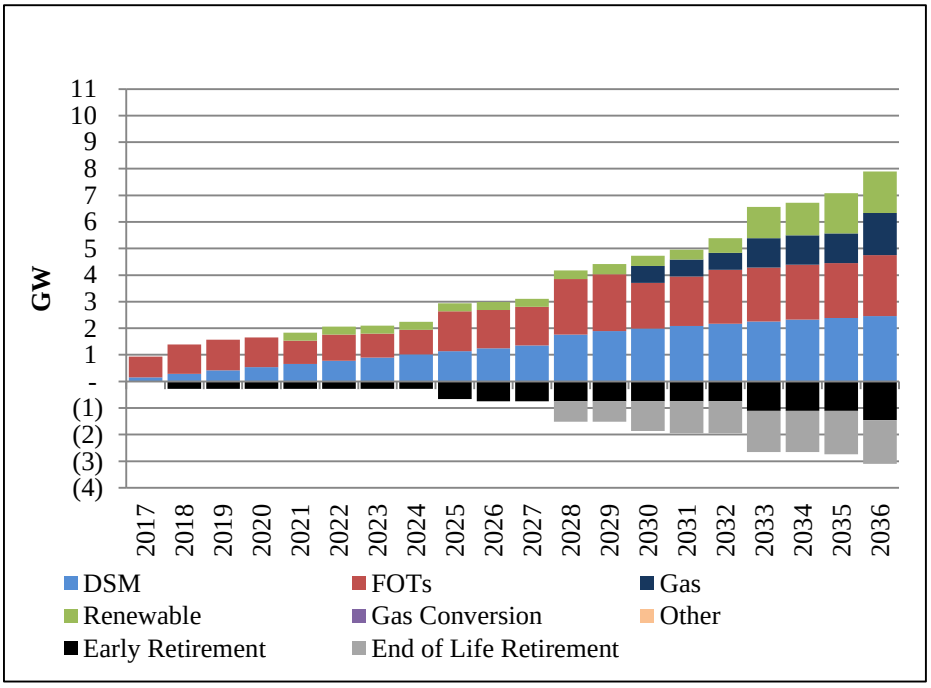


Figure 8.3 – Cumulative Capacity through 2036, Regional Haze Case 2

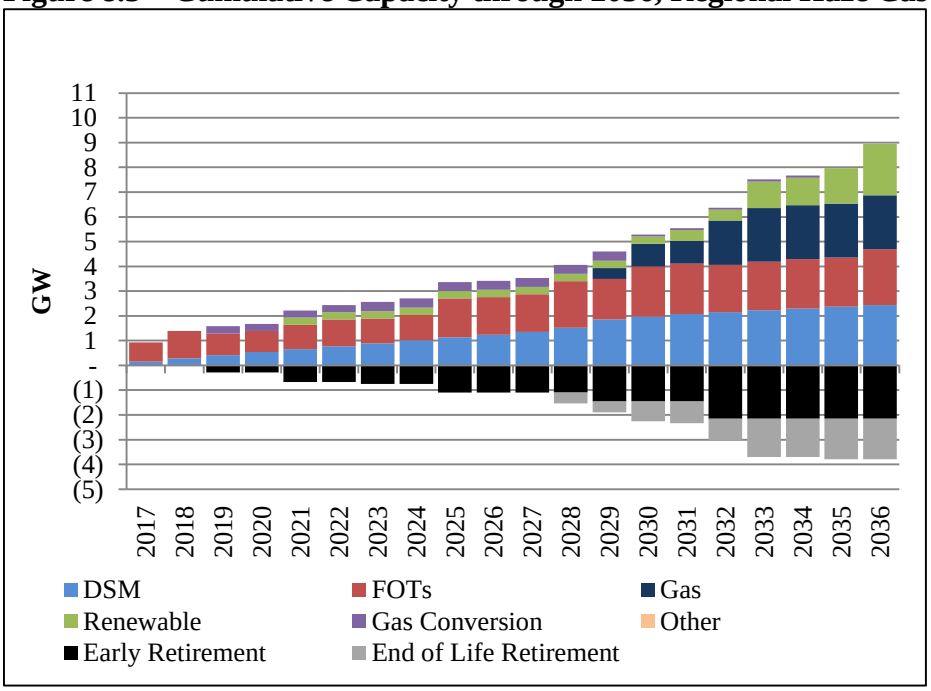


Figure 8.4 – Cumulative Capacity through 2036, Regional Haze Case 3

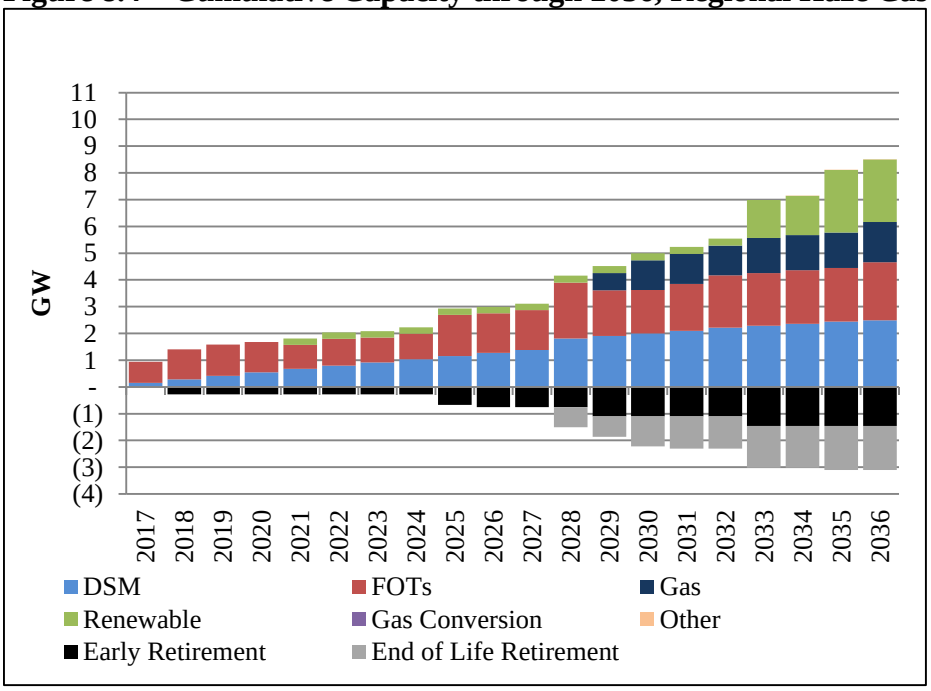


Figure 8.5 – Cumulative Capacity through 2036, Regional Haze Case 4

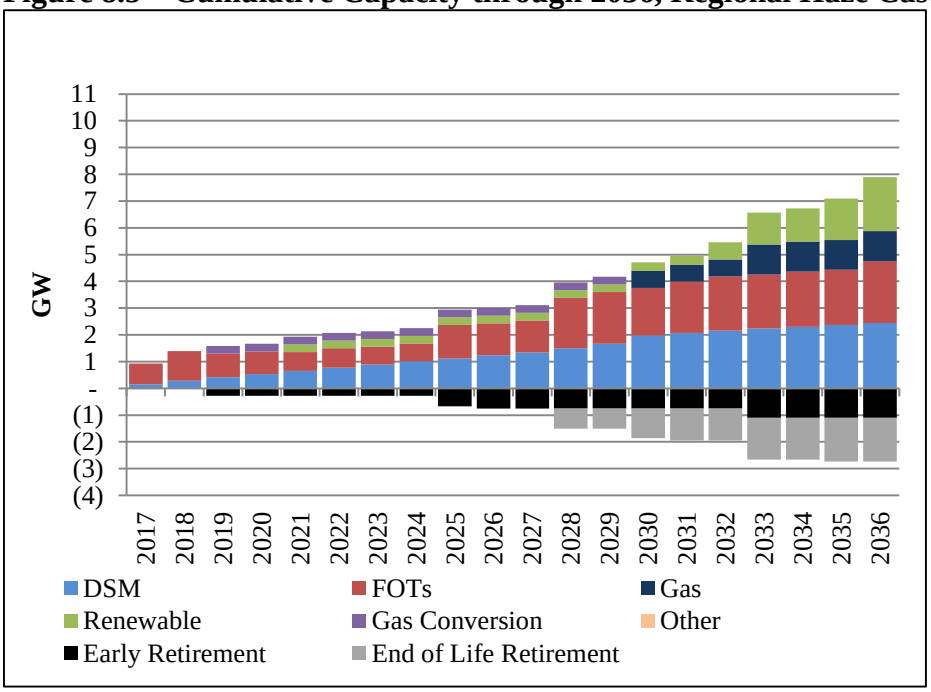


Figure 8.6 – Cumulative Capacity through 2036, Regional Haze Case 5

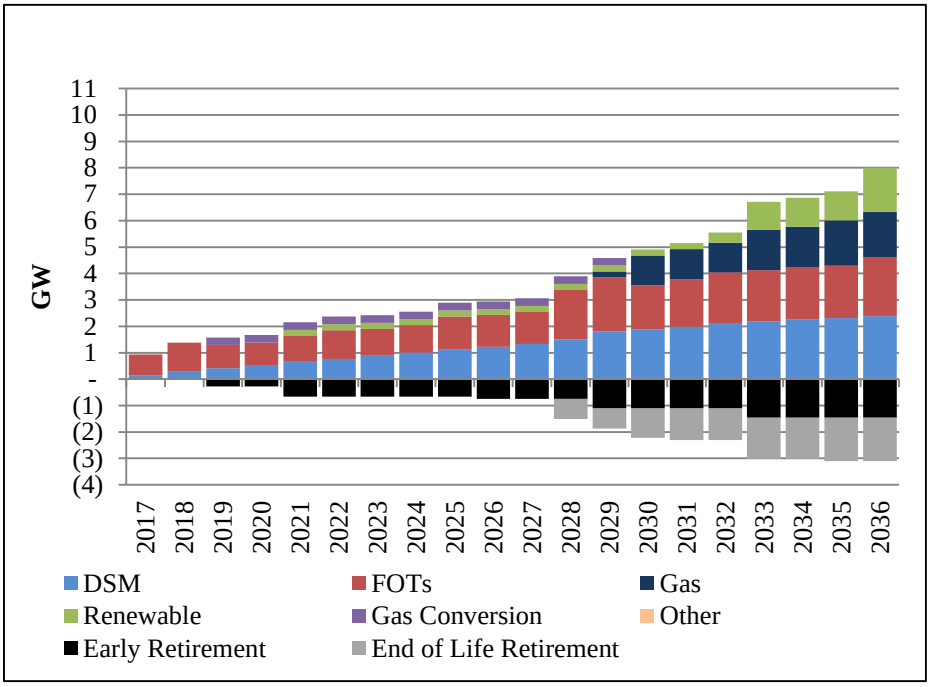
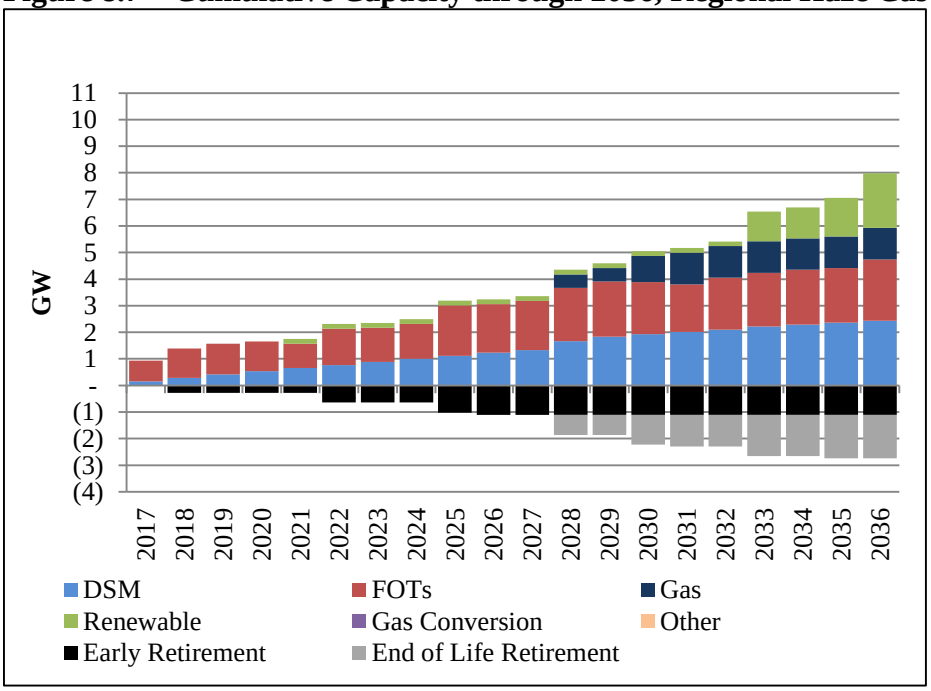


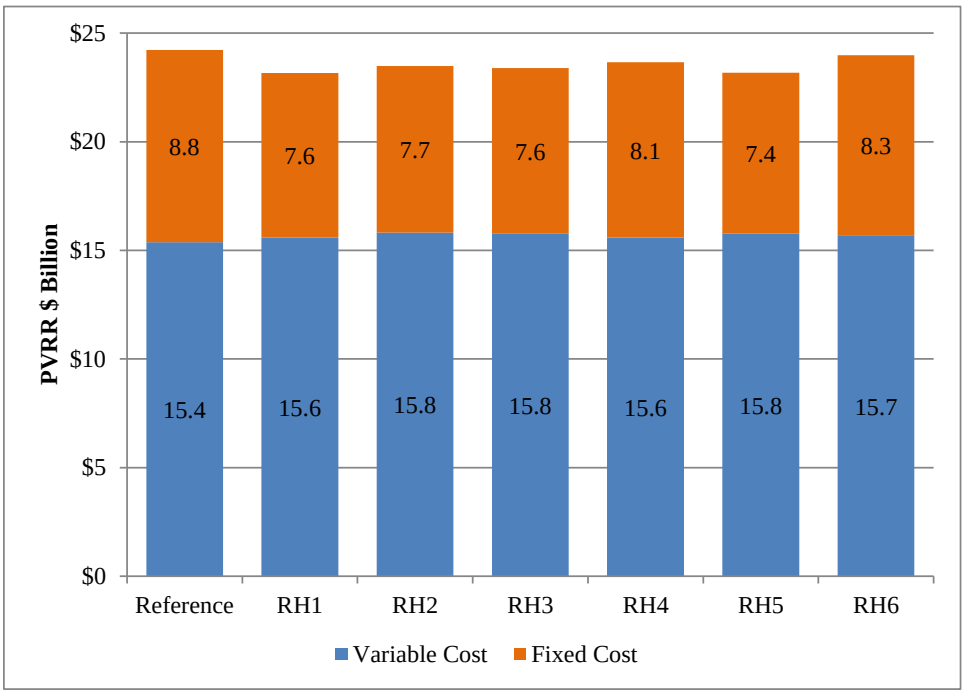
Figure 8.7 – Cumulative Capacity through 2036, Regional Haze Case 6



System Costs

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

Figure 8.8 – System Optimizer PVRR Costs for Regional Haze Cases



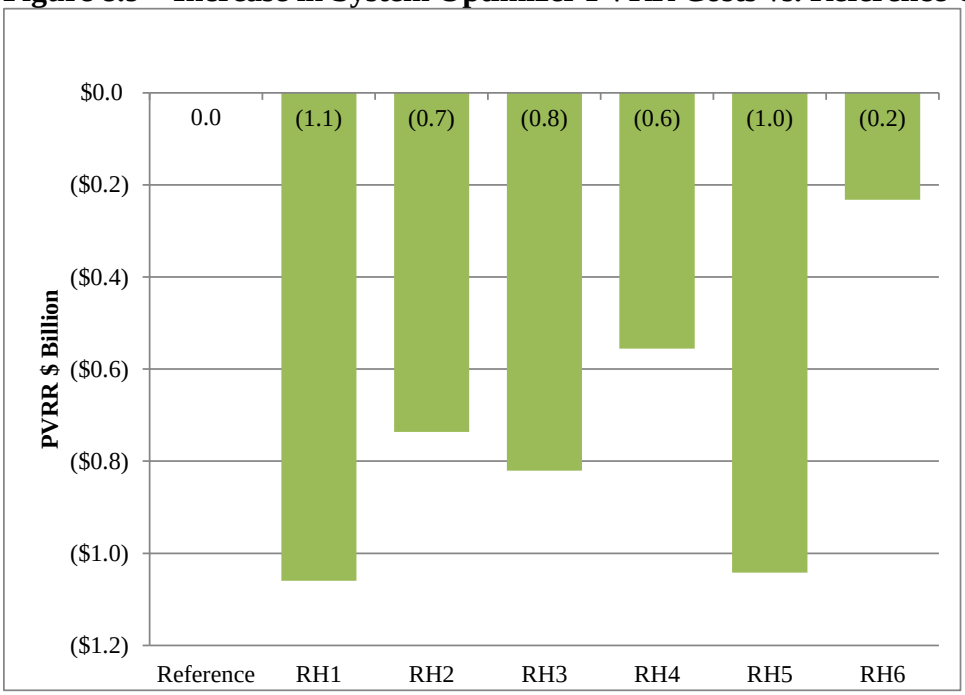
Based upon the System Optimizer PVRR, Regional Haze cases 1 and 5 provide the lowest net system costs, which are notably lower than the system costs from all other cases developed assuming medium natural gas prices and Clean Power Plan (CPP) CO_2 emission limits as defined under the Mass Cap B scenario.

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

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

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

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



Regional Haze Cost and Risk Analysis

PaR Configuration and Metrics

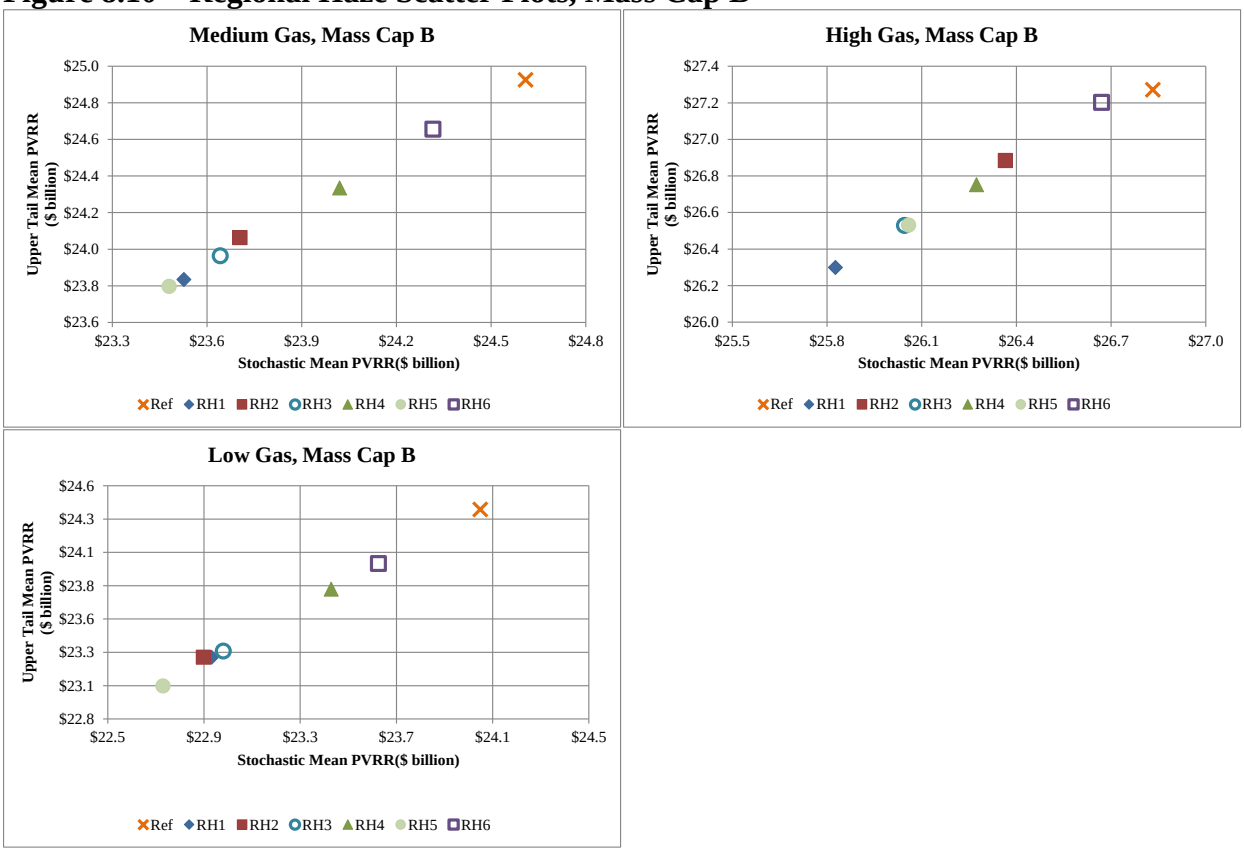
PaR model results are used to develop portfolio ranking metrics, which include the mean PVRR, upper-tail PVRR, risk-adjusted PVRR, mean Energy Not Served (ENS), upper-tail ENS, and CO_2 emissions. PaR is configured to calculate 50-iterations of 12 sample weeks representing the months of each study year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

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

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

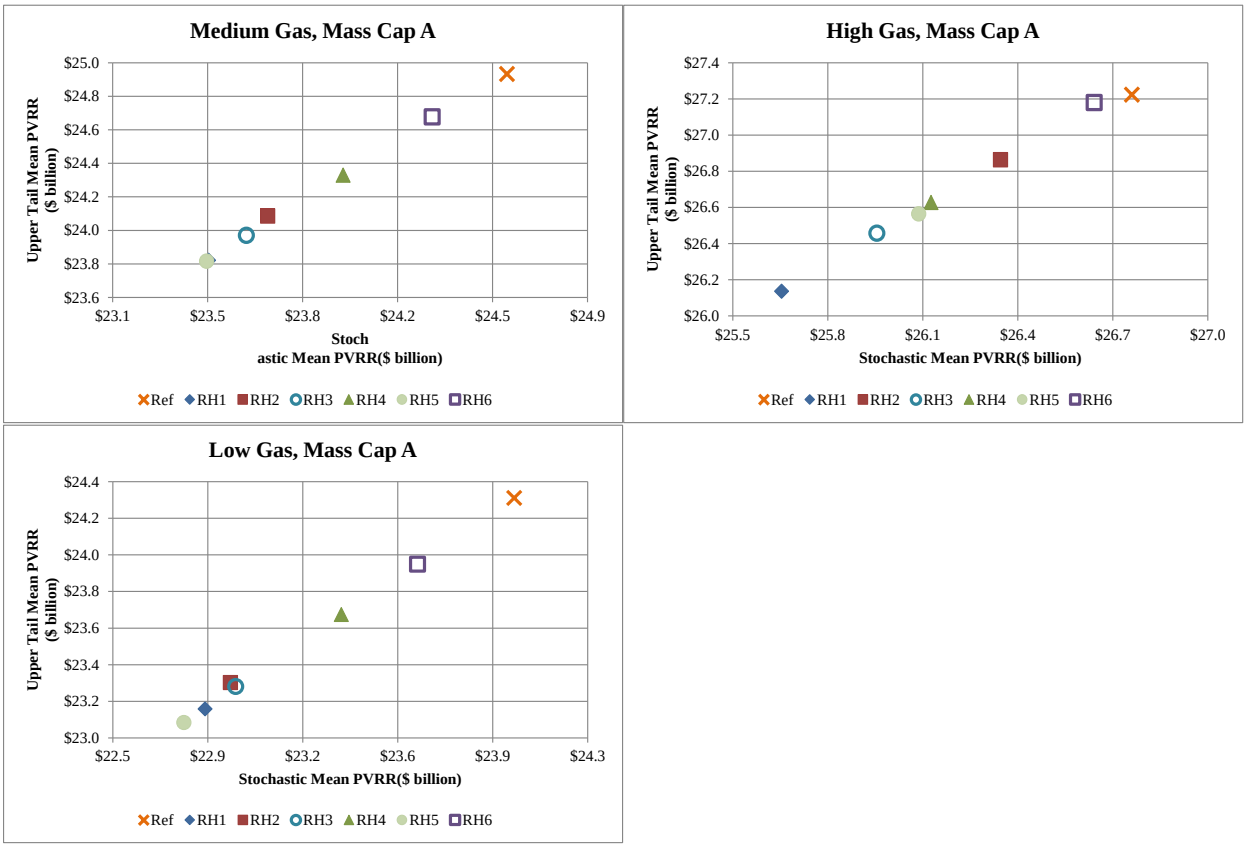
Scatter plots, shown in Figure 8.10 and Figure 8.11, present the mean PVRR of each unique Regional Haze case portfolio on the horizontal axis and the upper-tail mean PVRR on the vertical axis. Portfolios toward the left-bottom corner of each scatter plot contain the least-cost, least-risk mix of resources,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

Figure 8.10 – Regional Haze Scatter Plots, Mass Cap B



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

Figure 8.11 – Regional Haze Scatter Plots, Mass Cap A

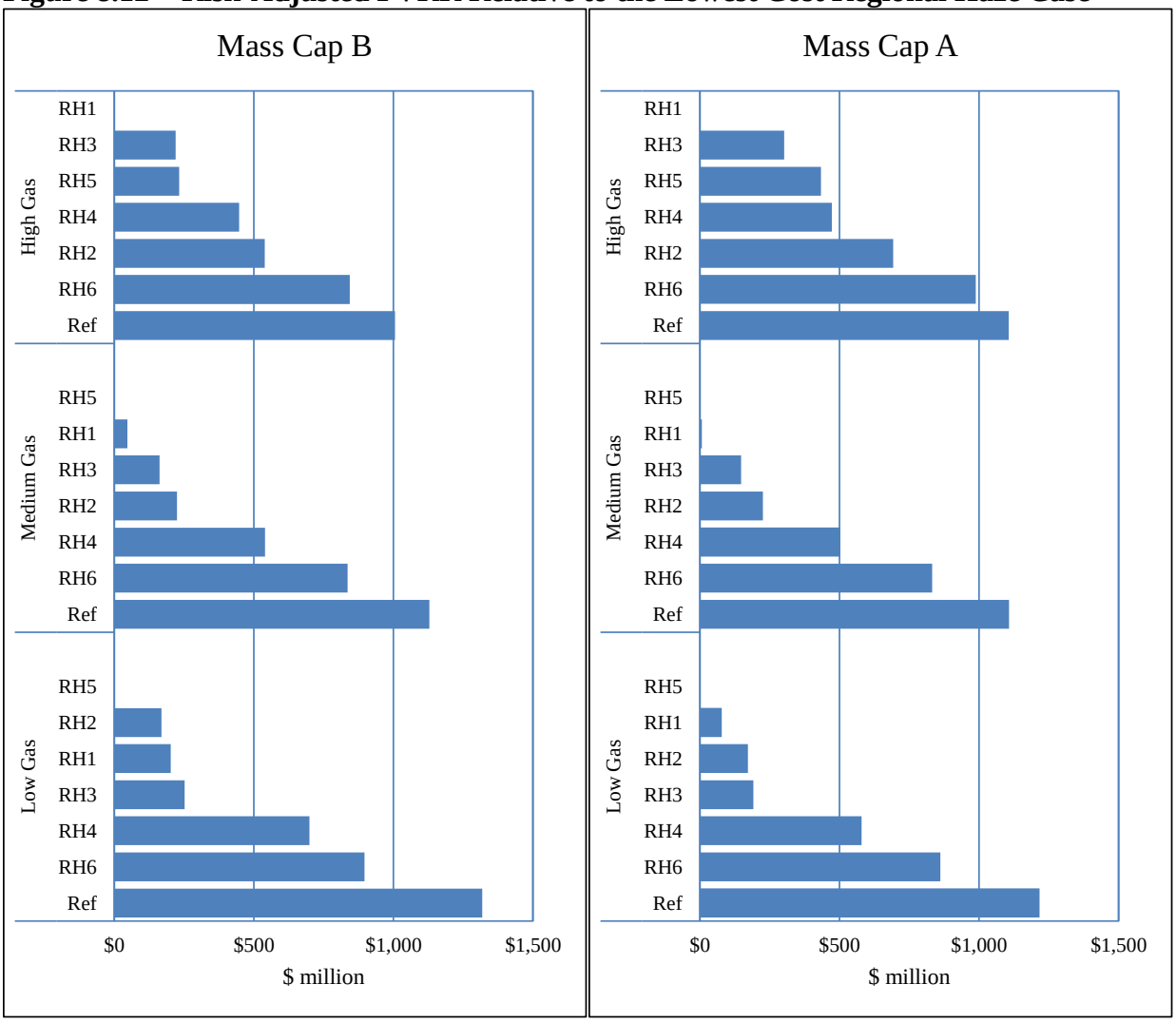


With fixed costs included in the upper-tail mean, which does not change among stochastic iterations, cost and risk are highly correlated. RH-5 is least-cost, least-risk under both medium and low natural gas price scenarios. RH-1 is least-cost, least-risk when high natural gas prices are assumed. The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

Risk-Adjusted PVRR

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

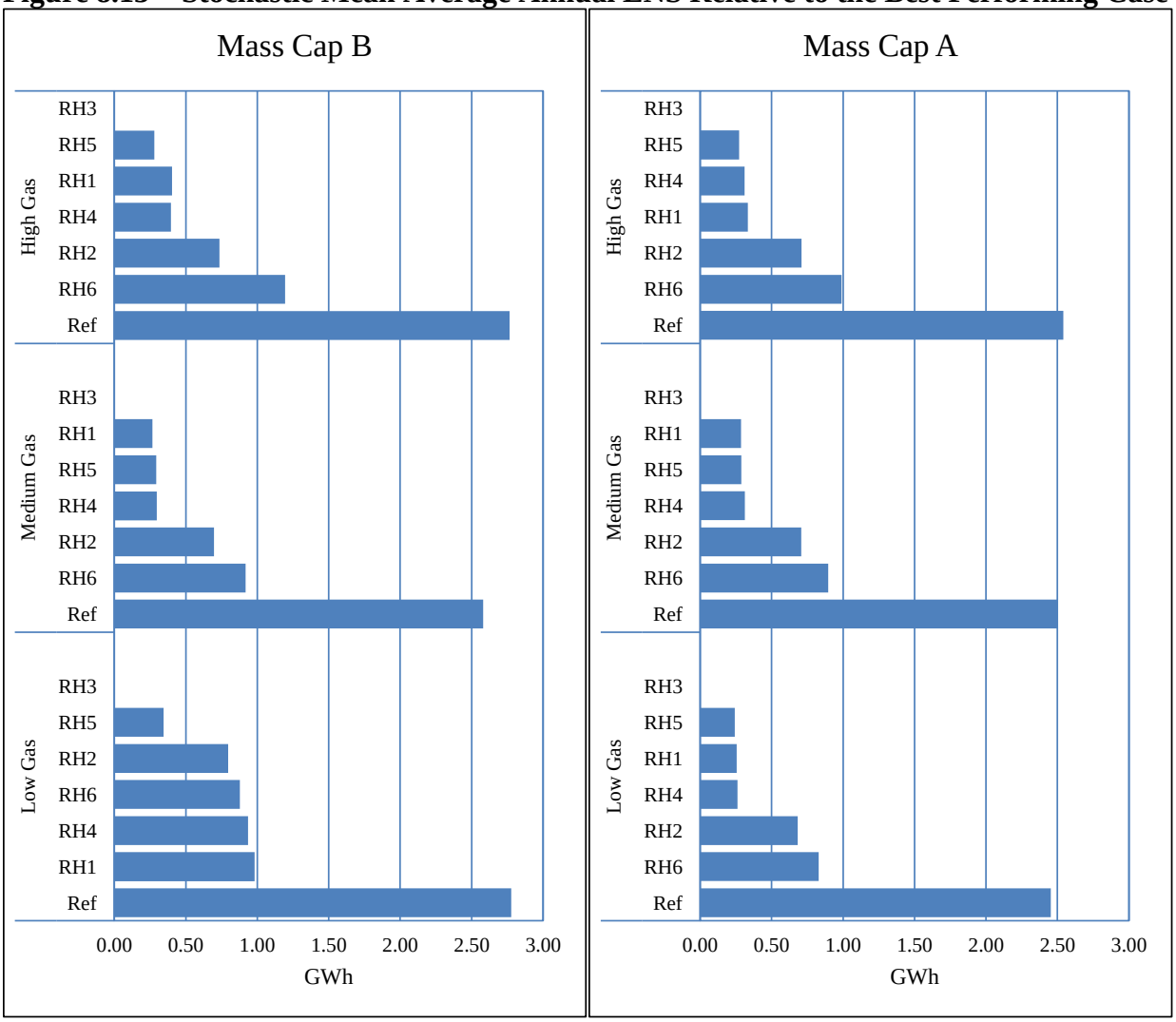
Figure 8.12 – Risk-Adjusted PVRR Relative to the Lowest Cost Regional Haze Case



Average Energy Not Served (ENS)

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

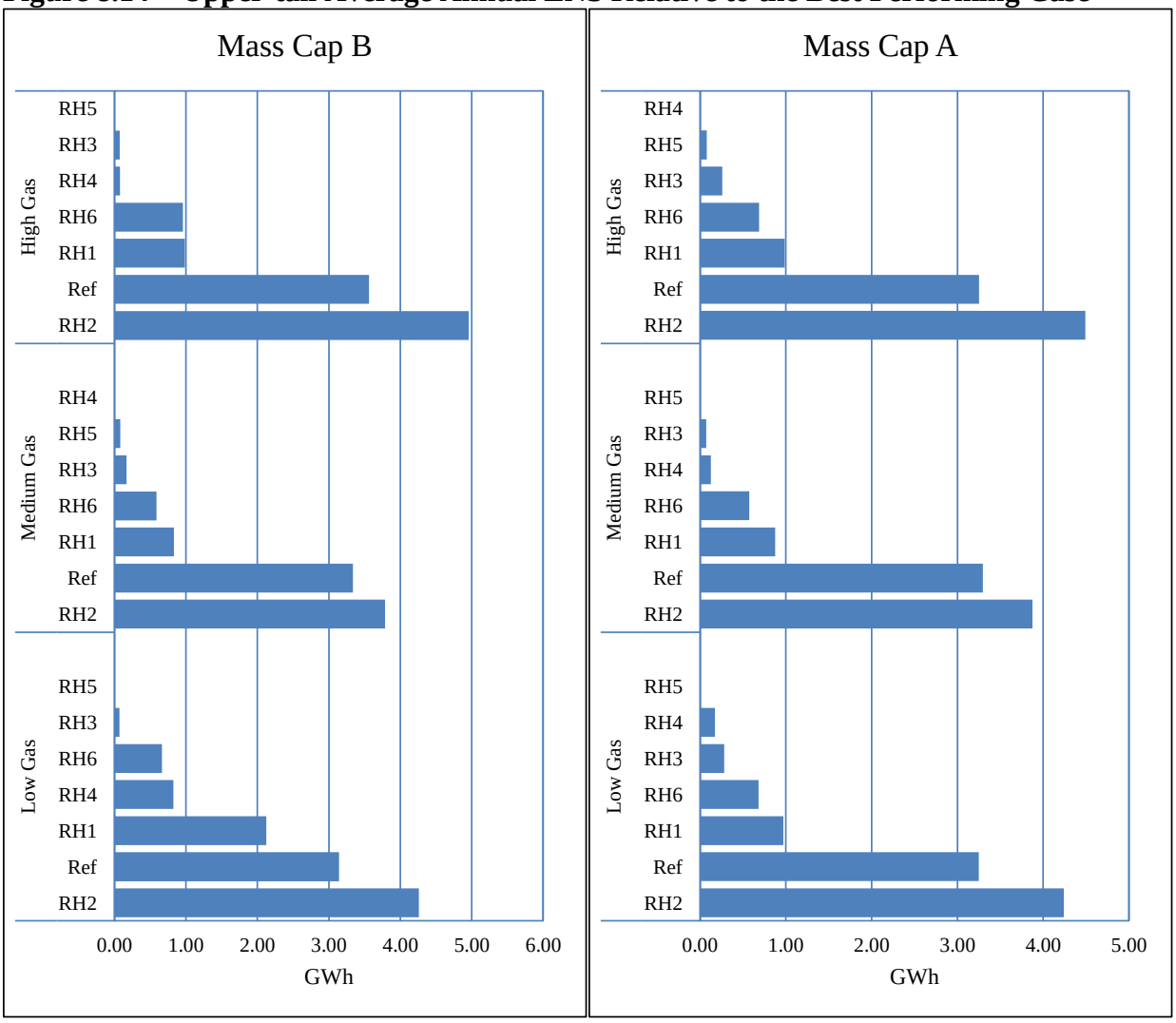
Figure 8.13 – Stochastic Mean Average Annual ENS Relative to the Best Performing Case



Upper-tail Average ENS

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

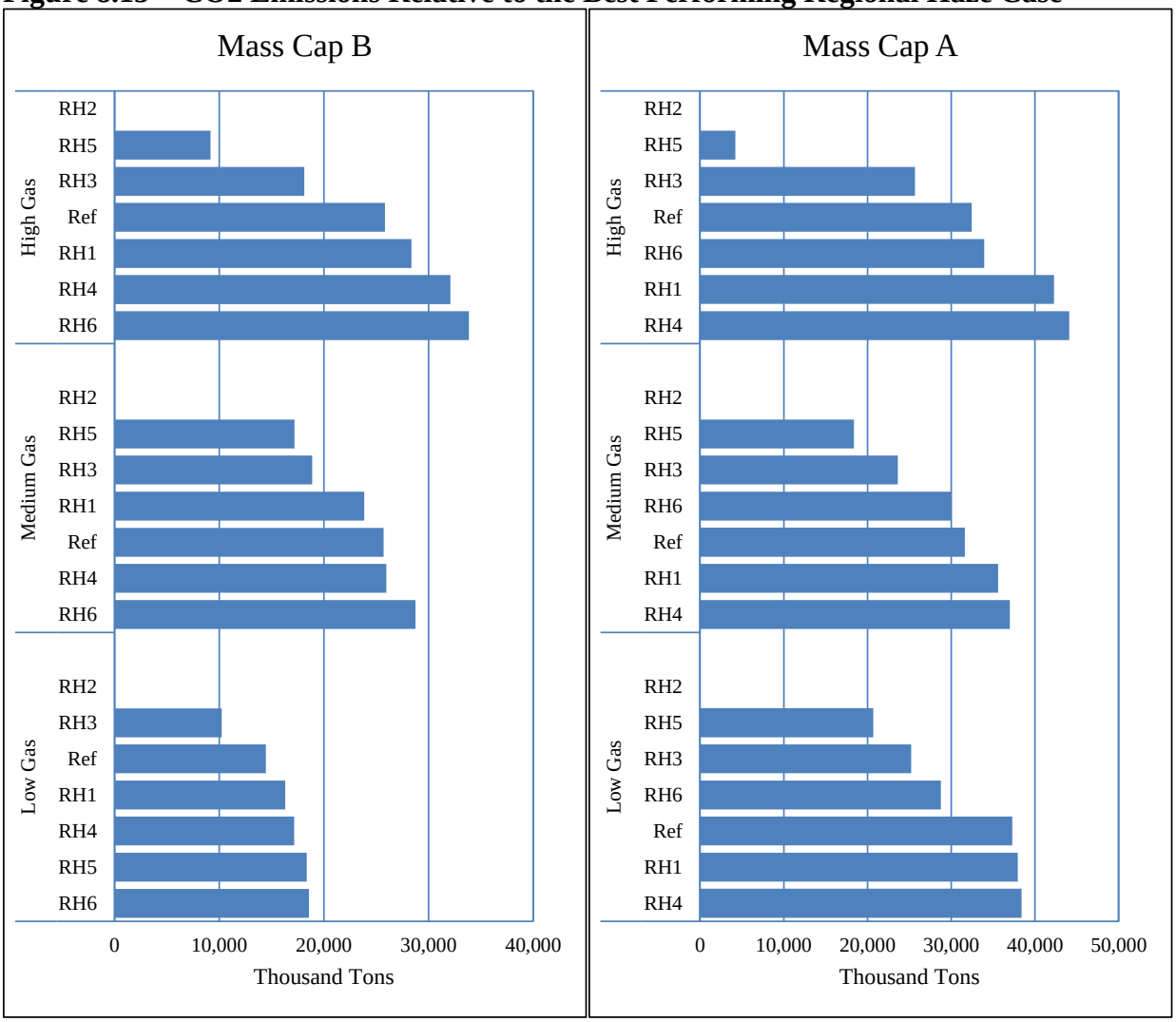
Figure 8.14 – Upper-tail Average Annual ENS Relative to the Best Performing Case



CO_2 Emissions

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

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



Shadow Prices

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

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

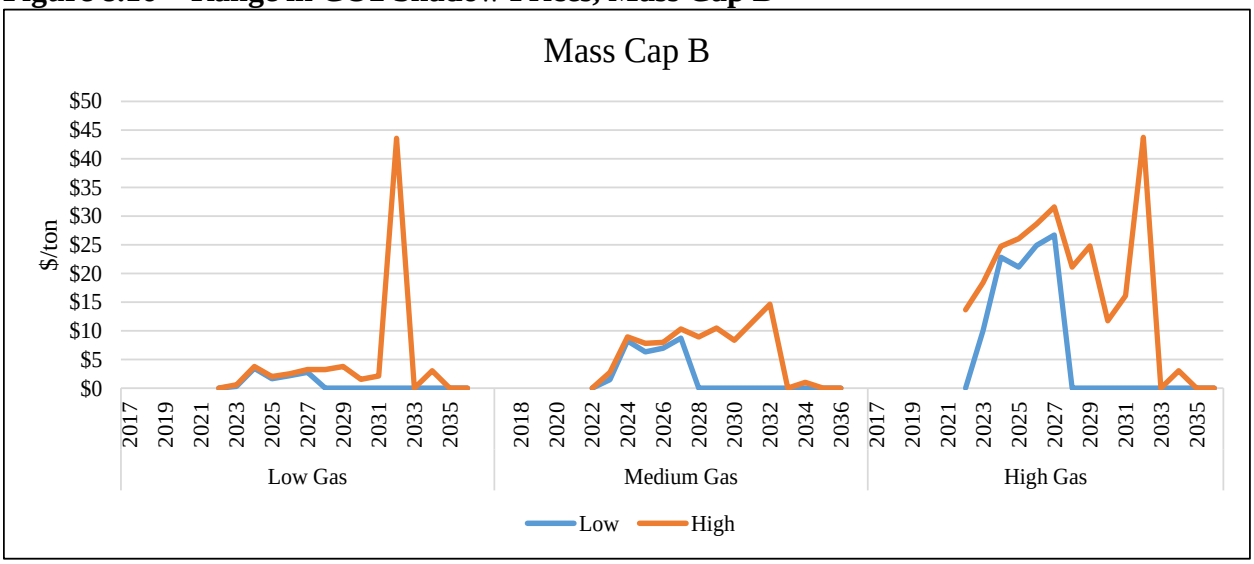
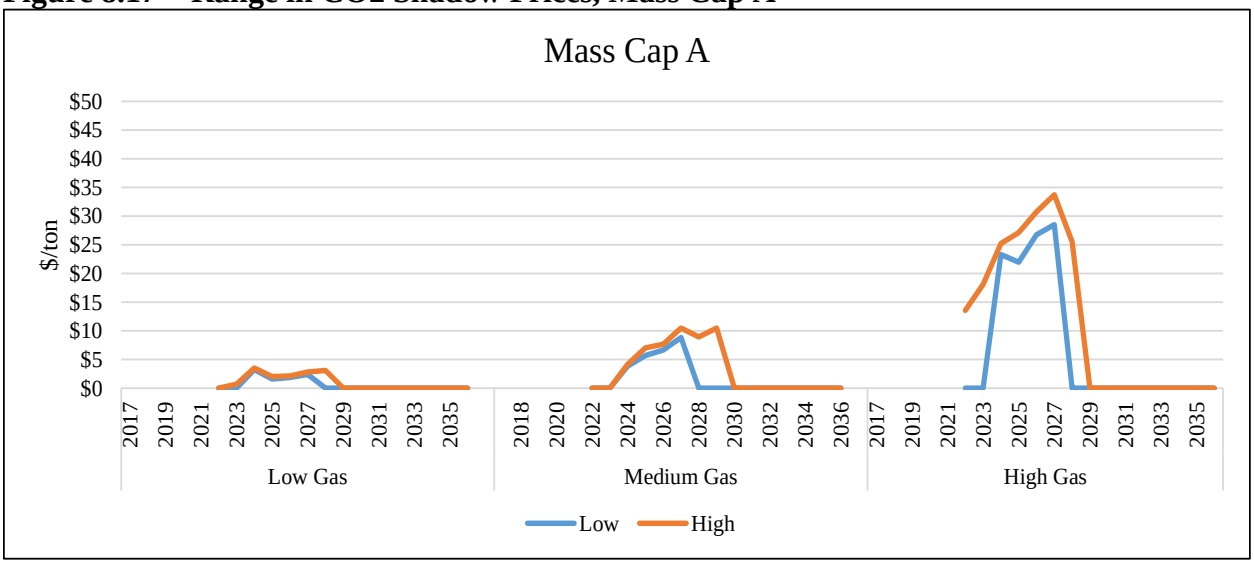


Figure 8.17 – Range in CO2 Shadow Prices, Mass Cap A



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

Regional Haze Case Portfolio Selection

On the basis of cost-risk metrics, PacifiCorp selected Regional Haze case 5 (RH-5) as the top performing portfolio in this phase of the portfolio selection process. However, stakeholder input received by PacifiCorp during the public input process influenced a change to the configuration of RH-5. To present a complete picture of the Regional Haze case final selection, this section begins

with a review of the initial outcomes, followed by a full assessment of the enhancement to RH-5 and the impact this enhancement had on cost-risk metrics.

Initial Results and Conclusions

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

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

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

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

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

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

Regional Haze Case 5 Enhancement

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

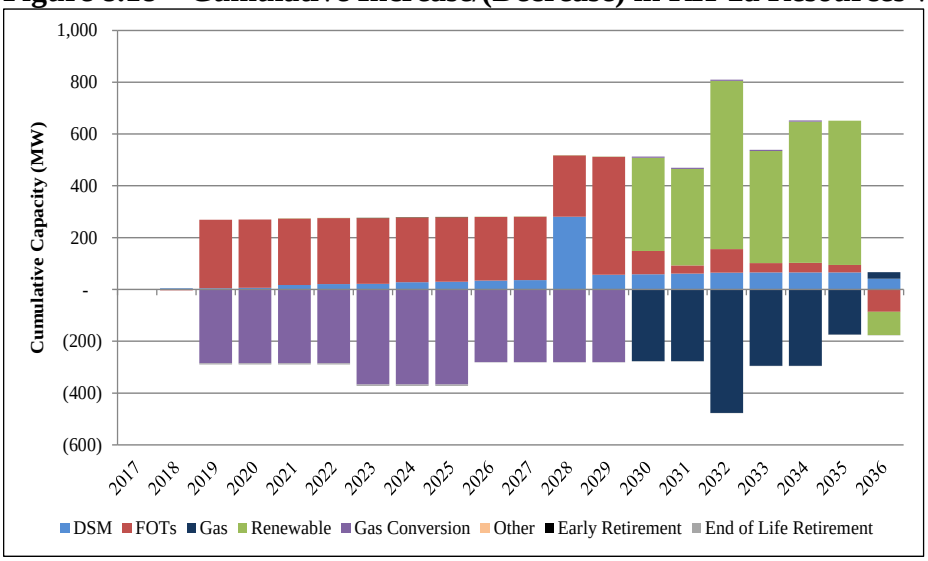
Sensitivity RH-2a

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

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

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

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



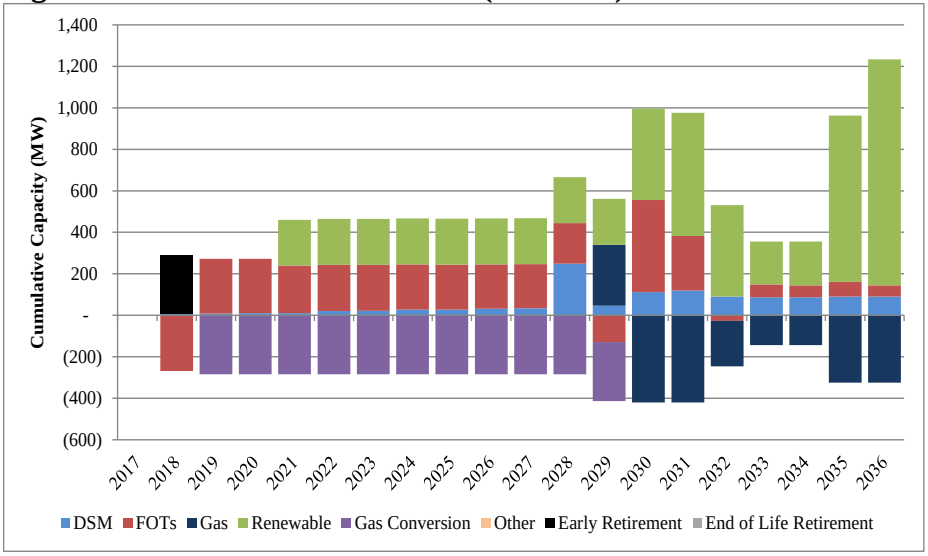
Sensitivity RH-5a

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

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

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

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



Final Regional Haze Portfolio Selection

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

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

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

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

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

Eligible Portfolio Screening

Eligible Portfolio Development

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

Core Case Portfolio Development

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

Table 8.4 – Core Cases

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

The following tables and figures present portfolio additions and system costs for the core cases. Additional information is provided specific to the merits of each case, including situs-assigned renewable additions for the renewables core cases, RE-1 through RE-1c and RE-2. Detailed

resource portfolio results for each core case, showing new resource capacity and changes to existing resource capacity by year, are contained in Volume II, Appendix K (Capacity Expansion Results Detail). Summary portfolio results are also shown in the case fact sheets presented in Volume II, Appendix M (Case Study Fact Sheets).

Cumulative Additional Resource Capacity

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

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

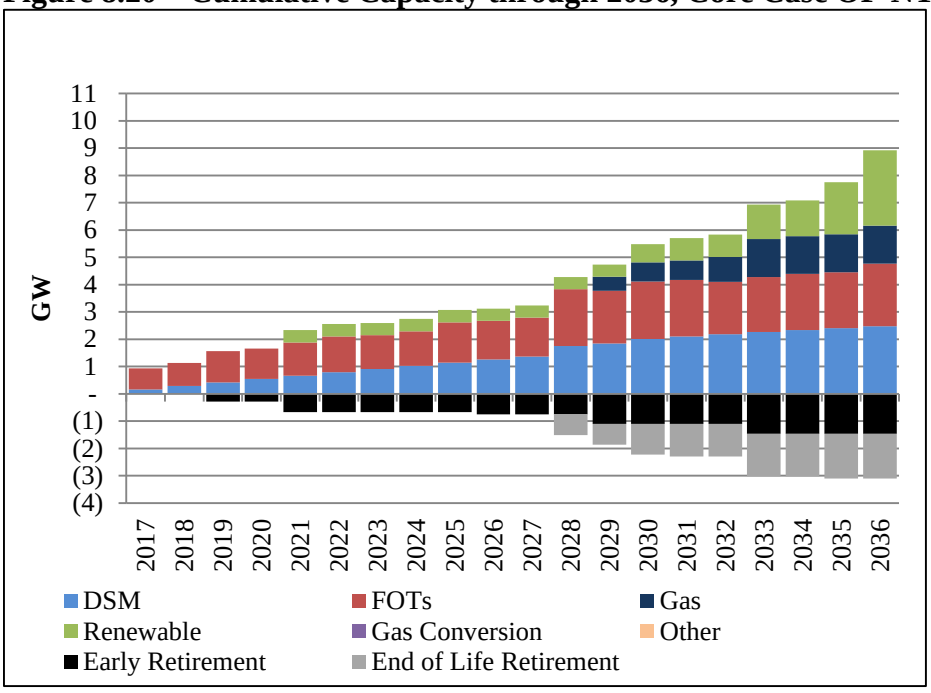


Figure 8.21 – Cumulative Capacity through 2036, Core Case FR-1

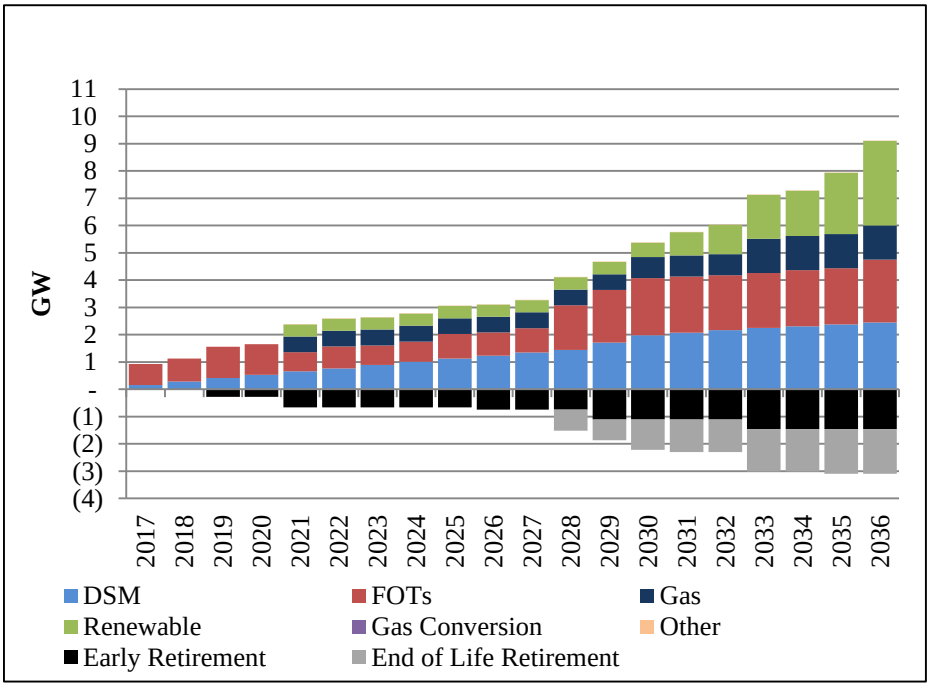


Figure 8.22 – Cumulative Capacity through 2036, Core Case FR-2

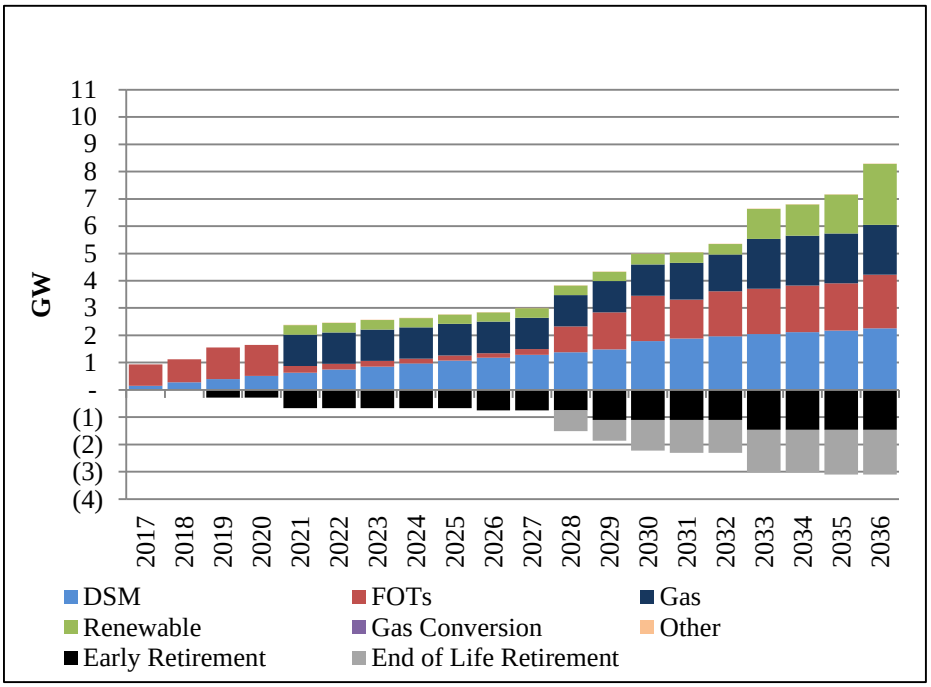


Figure 8.23 – Cumulative Capacity through 2036, Core Case RE-1a

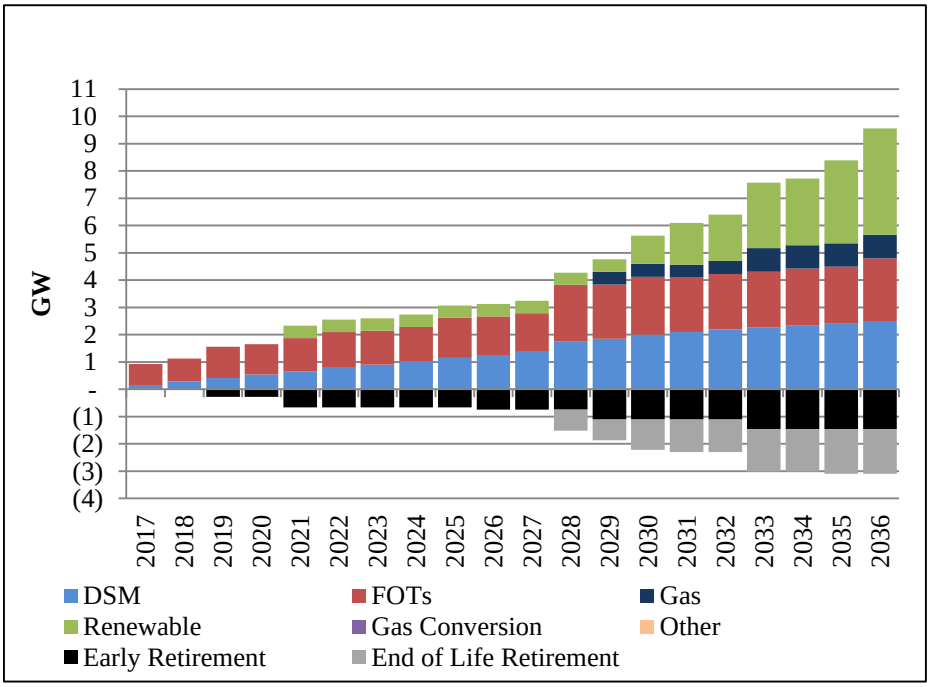


Figure 8.24 – Cumulative Capacity through 2036, Core Case RE-1b

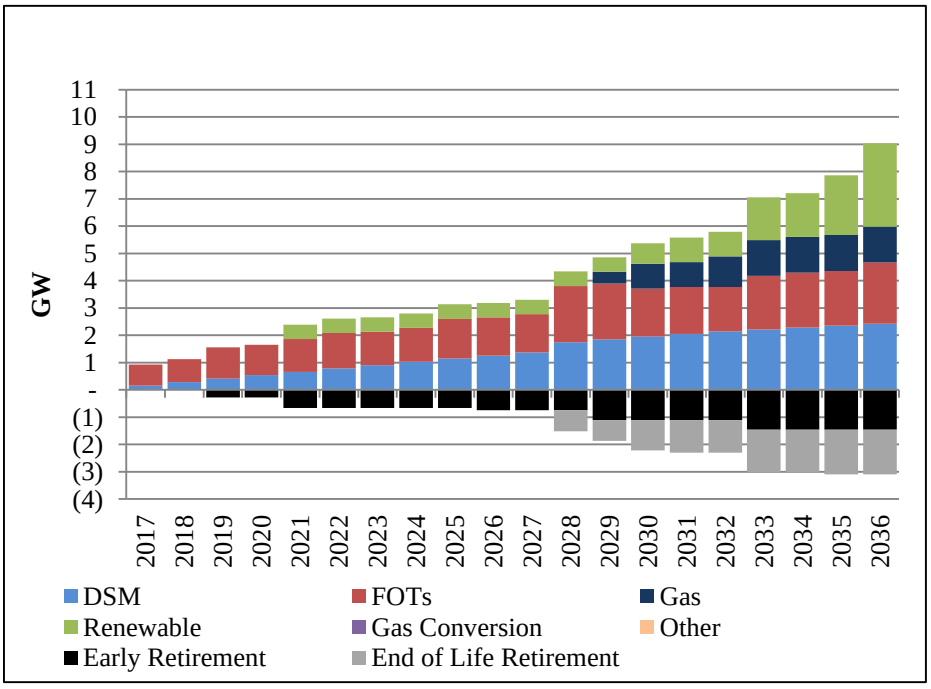


Figure 8.25 – Cumulative Capacity through 2036, Core Case RE-1c

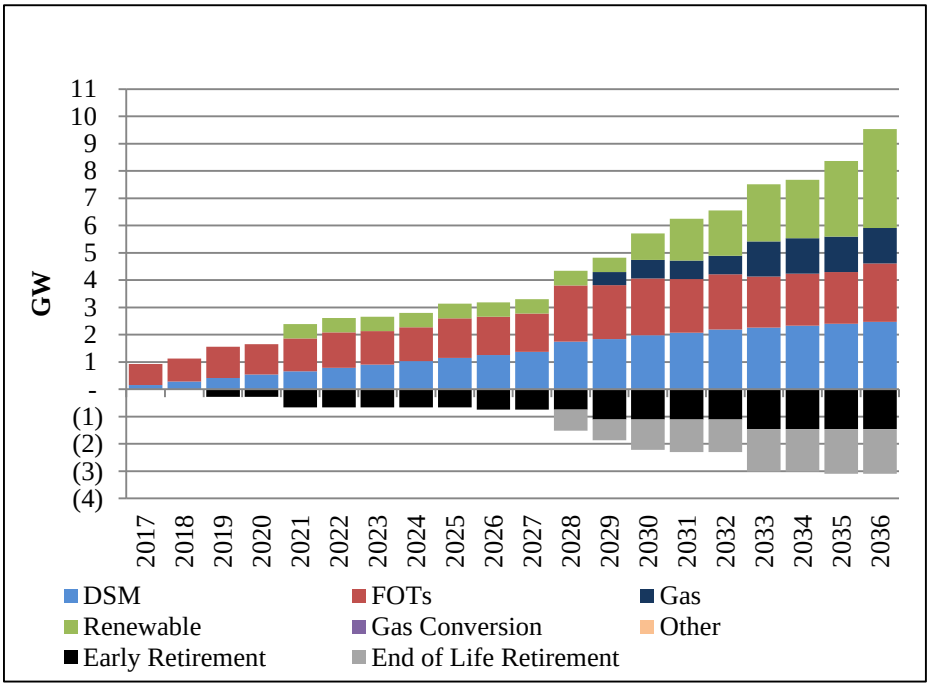


Figure 8.26 – Cumulative Capacity through 2036, Core Case RE-2

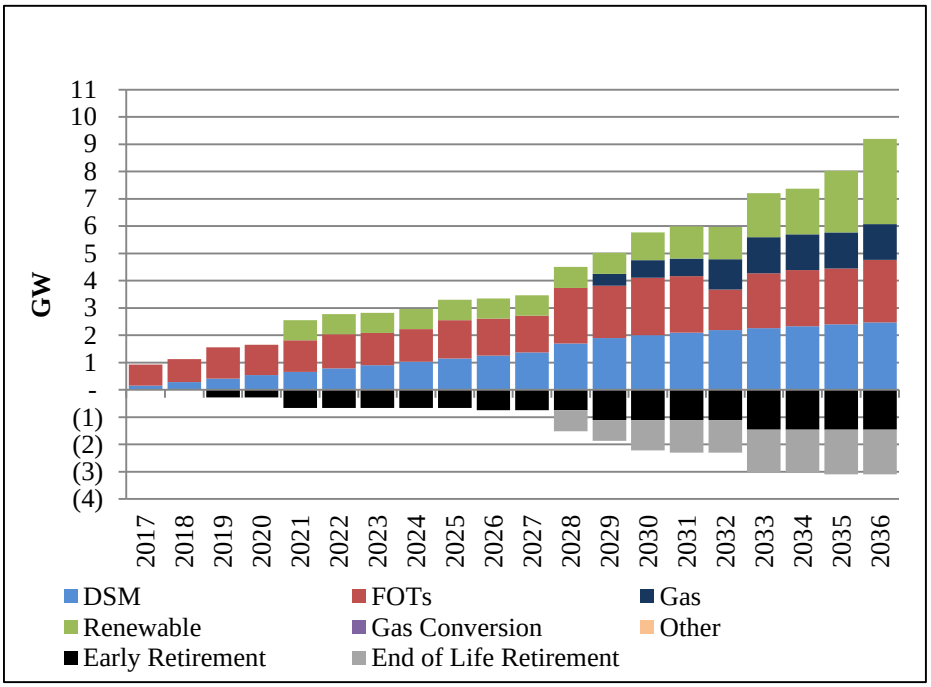
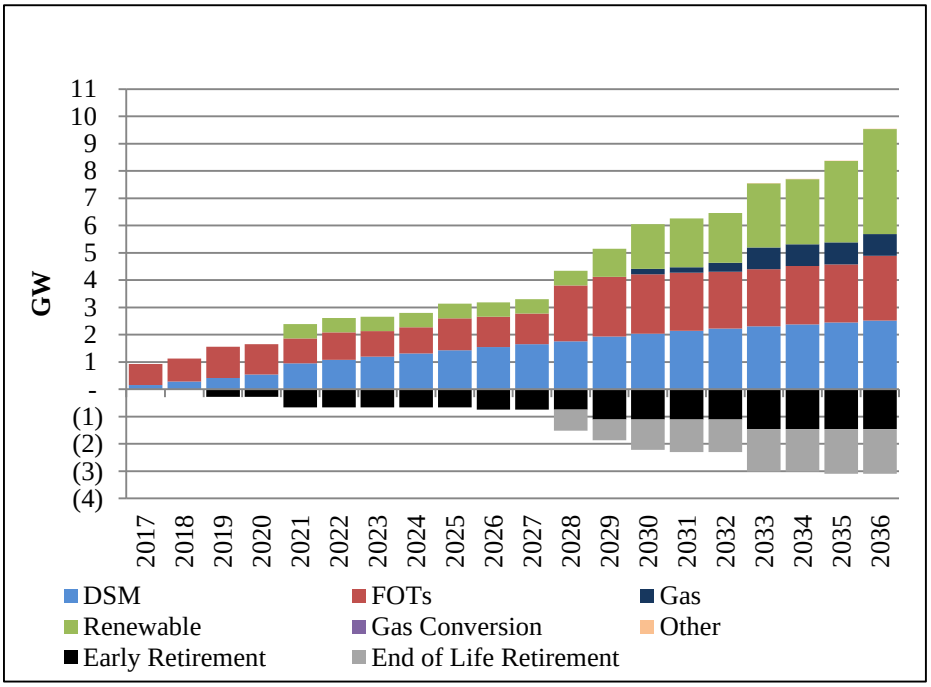


Figure 8.27 – Cumulative Capacity through 2036, Core Case DLC-1



Situs-Assigned Renewable Resources

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

Just-in-Time Compliance

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

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

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

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

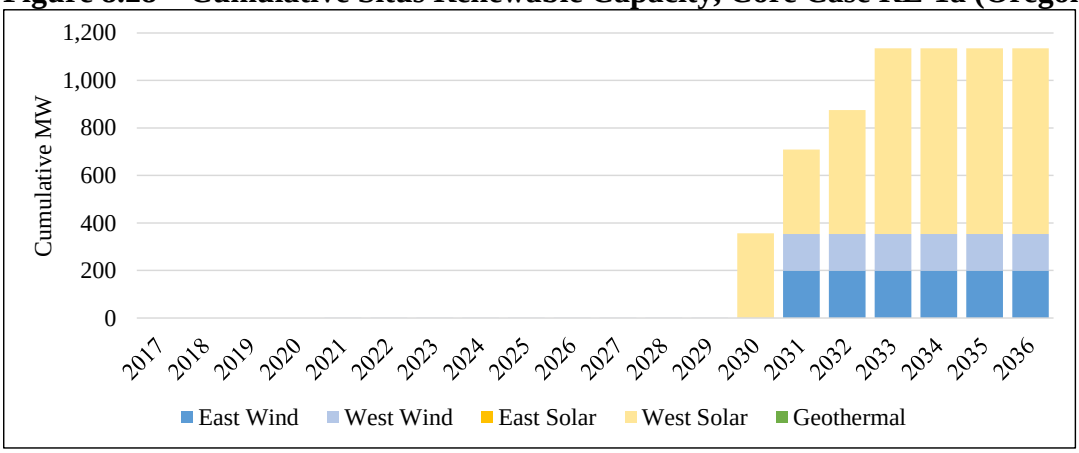


Figure 8.29 – Cumulative Situs Renewable Capacity, Core Case RE-1b (Washington RPS)

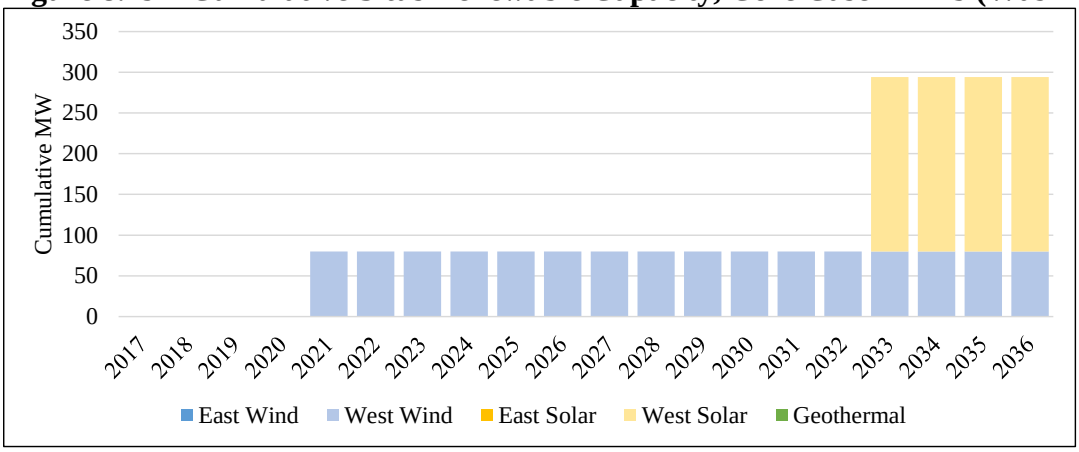
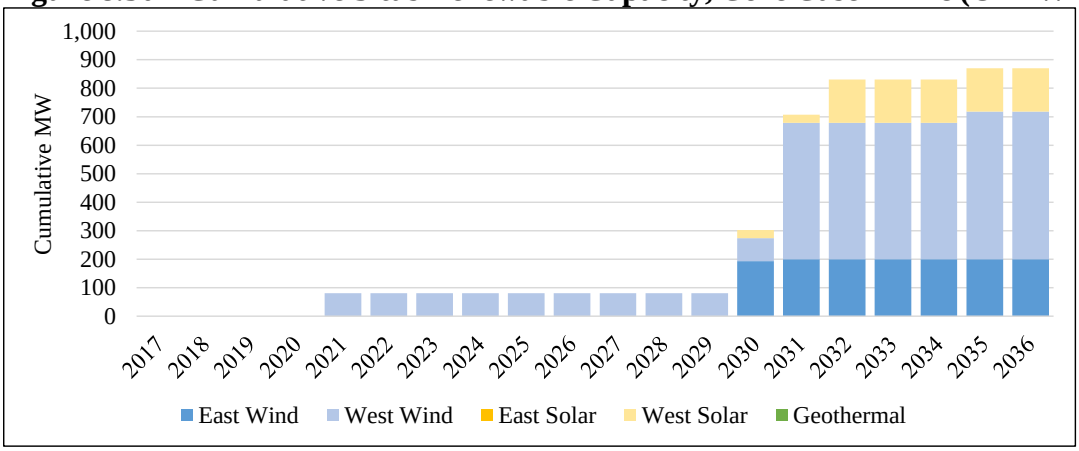


Figure 8.30 – Cumulative Situs Renewable Capacity, Core Case RE-1c (OR+WA Combined)

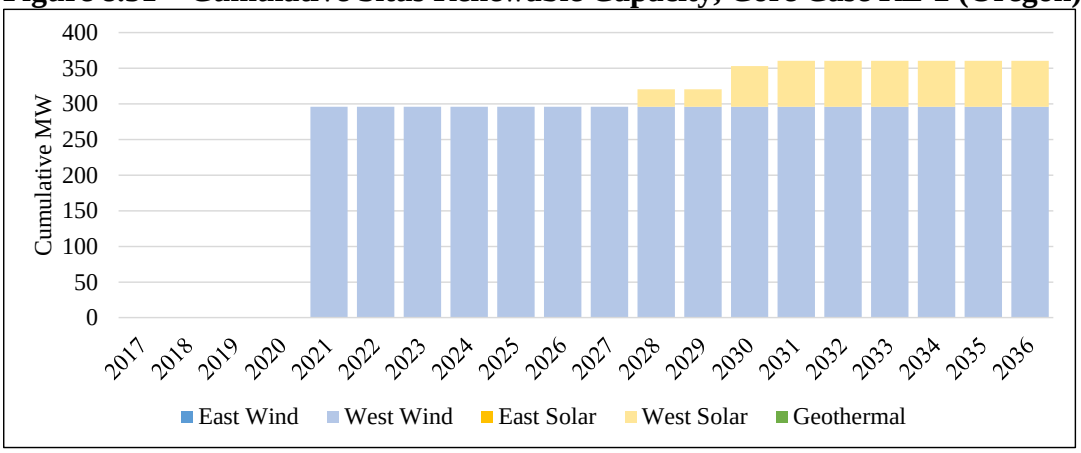


Early RPS Compliance Strategy

In the early compliance strategy, additional renewables are added to physically comply with projected Oregon RPS beginning 2021 (proxy for year-end 2020) to meet requirements throughout

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

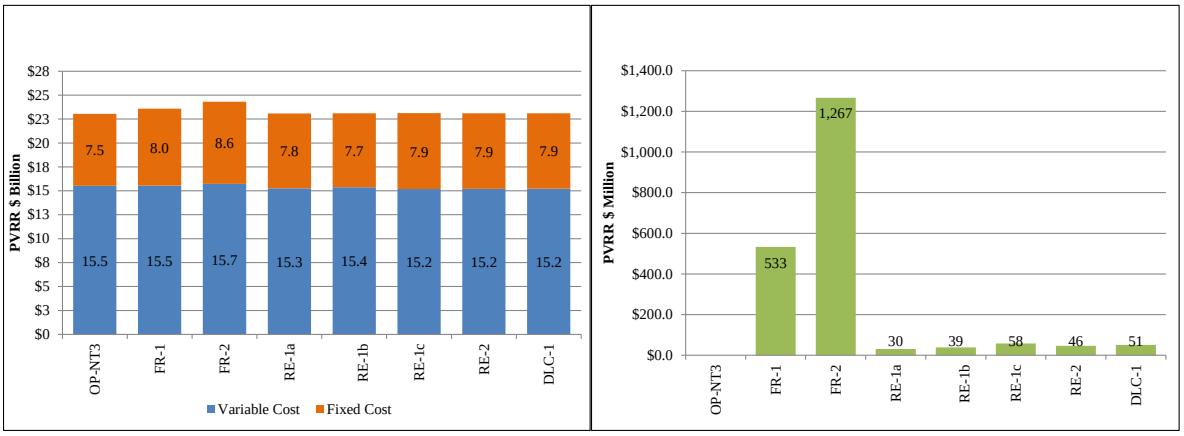
Figure 8.31 – Cumulative Situs Renewable Capacity, Core Case RE-2 (Oregon)



SO System Costs

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

Figure 8.32 – System Optimizer PVRR Costs for Core Cases



Eligible Sensitivity Portfolio Development

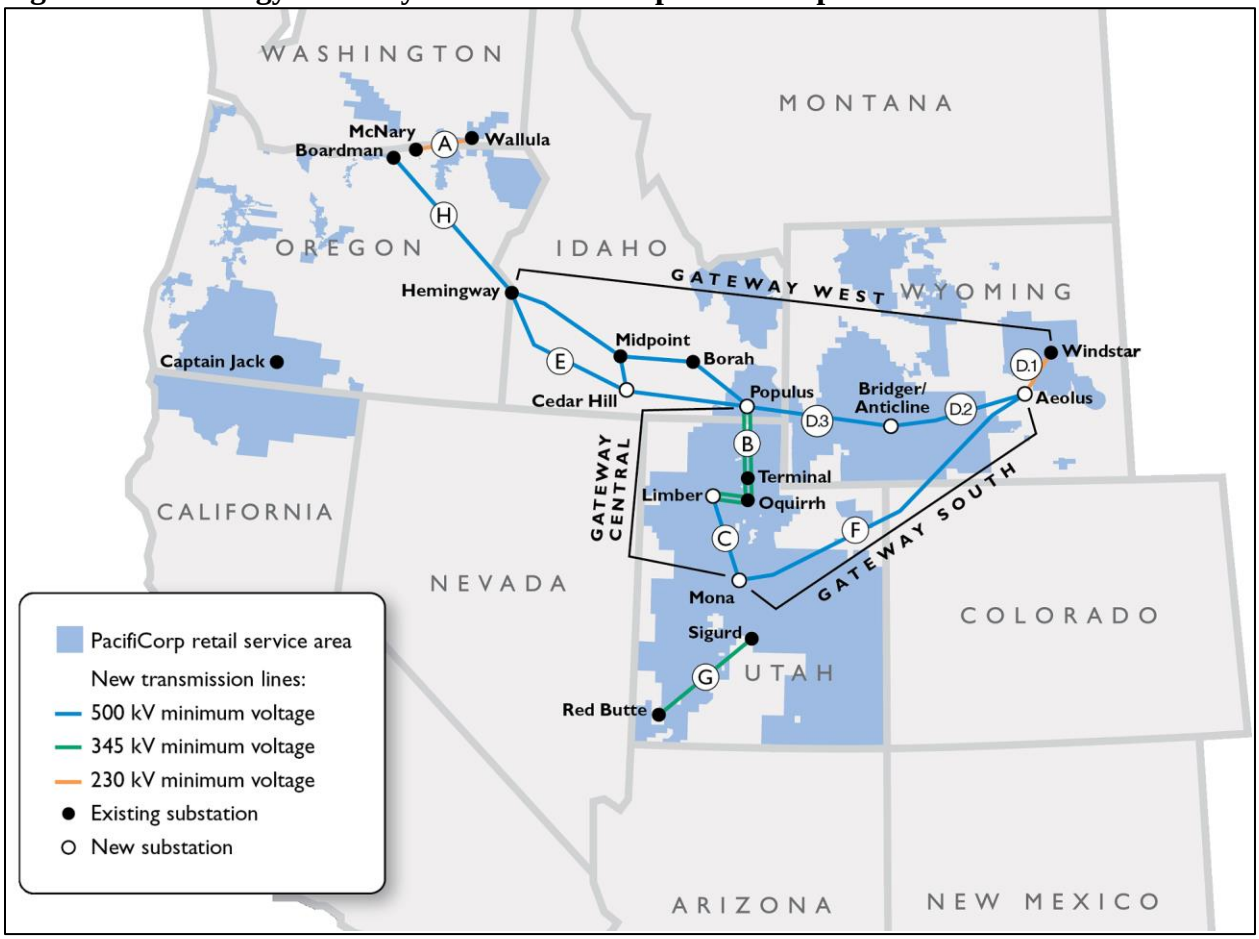
Table 8.5 lists the names and key characteristics of the wind repower and Energy Gateway transmission sensitivity cases considered for preferred portfolio consideration in screening stage two. Each case is benchmarked against OP-NT3, the selected Regional Haze case which emerged

as least-cost, least-risk in screening stage one. The OP-REP case was added as a sensitivity to evaluate, in the context of the IRP, the economic benefits of PacifiCorp's December 2016 safe-harbor wind-turbine-generator (WTG) equipment purchase, securing the option to repower existing wind facilities and re-qualifying the repower projects for PTC benefits over a 10-year period. The OP-GW4 case was added to study the cumulative impacts of layering the most favorable Energy Gateway scenario on top of the Wind Repower case. Figure 8.33 provides a high-level map of the Energy Gateway segments under consideration.

Table 8.5 – Sensitivities Considered for the Preferred Portfolio

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

Figure 8.33 – Energy Gateway Transmission Expansion Map



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

Resource Capacity Impacts and PVRR Results

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

Wind Repower (OP-REP)

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

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

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

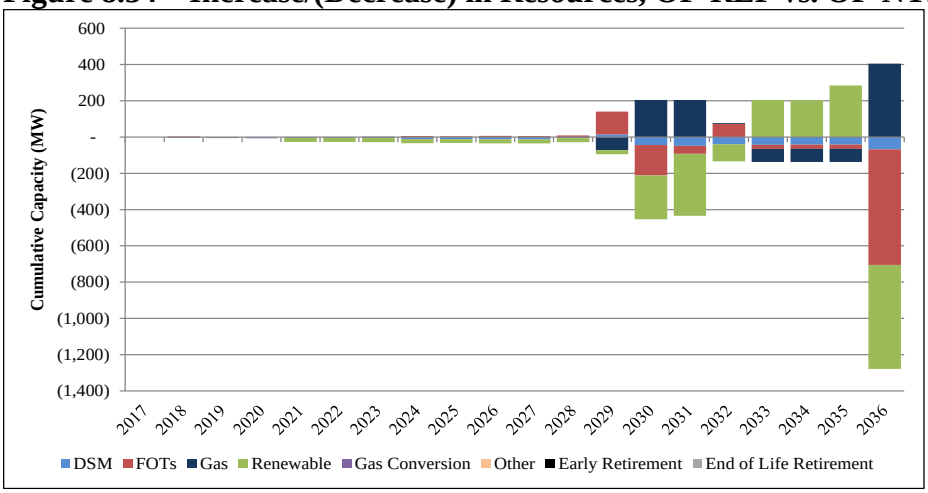
The OP-REP sensitivity assumes 905 MW of existing wind resources are repowered by the end of 2020 (Glenrock, Rolling Hills, Seven Mile Hill, High Plains, McFadden Ridge, Dunlap, Marengo, and Leaning Juniper). The repowering of wind projects across the fleet provides significant customer benefits in all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

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

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

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

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



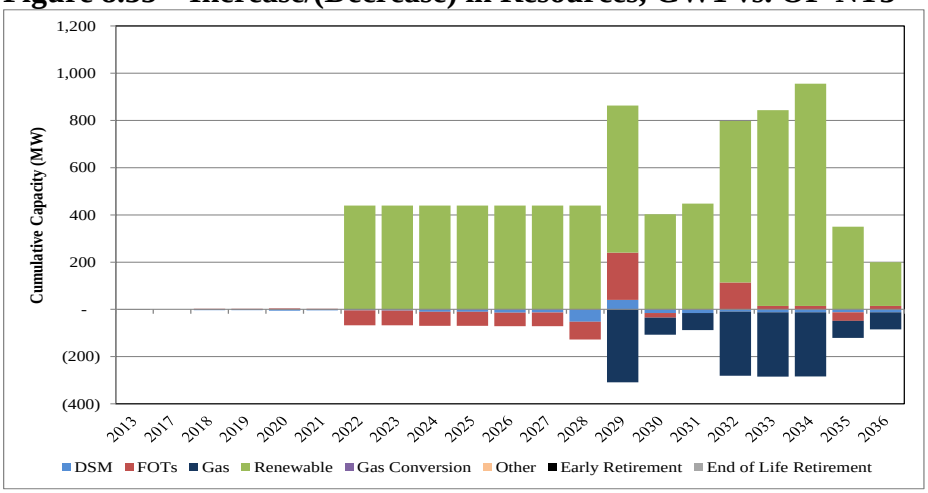
Gateway 1 (GW1)

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

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

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

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



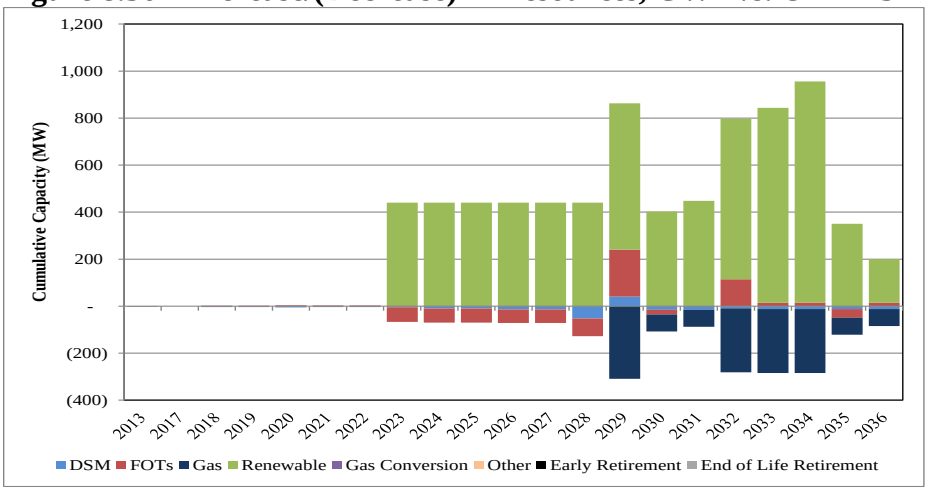
Gateway 2 (GW2)

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

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

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

Figure 8.36 – Increase/(Decrease) in Resources, GW2 vs. OP-NT3



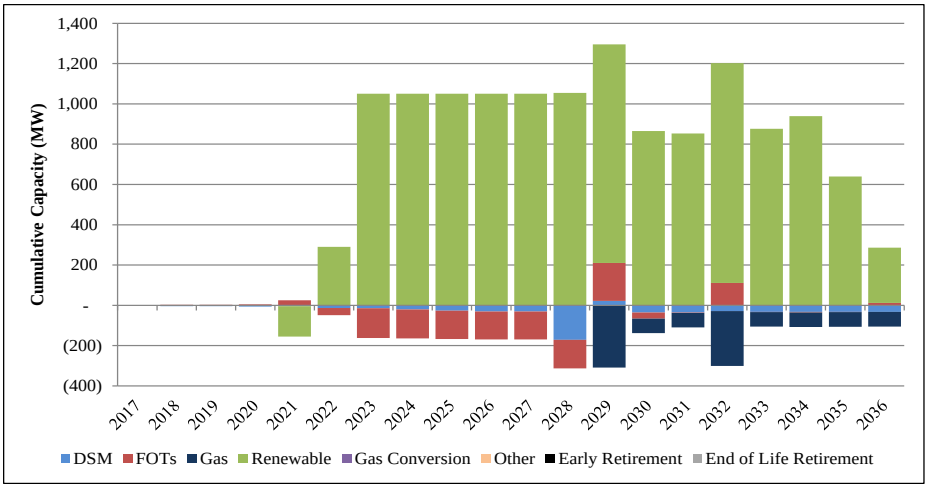
Gateway 3 (GW3)

Energy Gateway 3 assumes the addition of transmission segments D & F – Windstar to Anticline and Aeolus to Mona/Clover (assumed in-service dates in 2022 and 2023, respectively). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 440 MW of Wyoming wind additions in 2022 and 760 MW in 2023. In 2021, 150 MW of Goshen wind is eliminated. The PVRR results indicate an overall increase to system costs, higher than cases GW1 and GW2, with improving benefits under high natural gas price assumptions.

Table 8.9 – PVRR Cost/(Benefit) of GW3 vs. OP-NT3

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from OP-NT3	$1,363	$1,453	$1,316	$724	$1,452	$1,308	$726

Figure 8.37 – Increase/(Decrease) in Resources, GW3 vs. OP-NT3



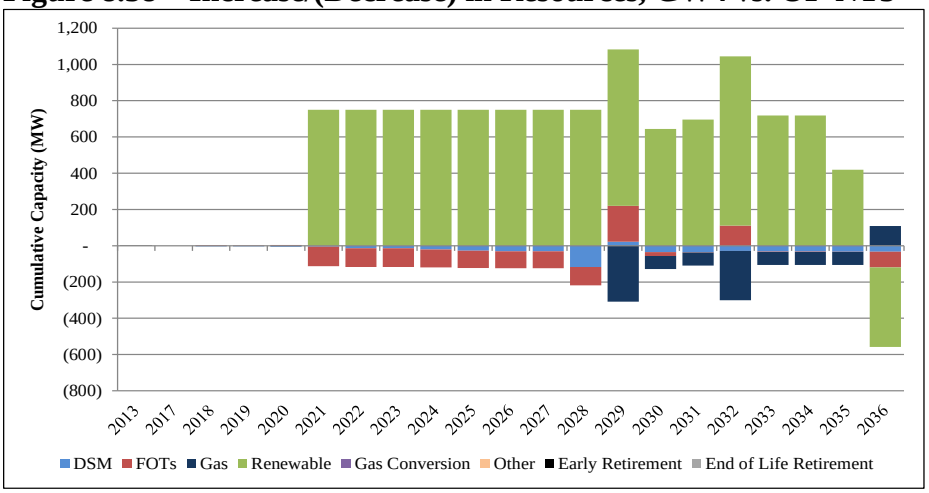
Gateway 4 (GW4)

Energy Gateway 4 assumes the addition of transmission segment D2 – Aeolus to Bridger/Anticline (assumed in service year-end 2020). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 900 MW of Wyoming wind additions in 2021 (proxy for year-end 2020). In 2021, 150 MW of Goshen wind is eliminated. This sensitivity shows improved economics relative to cases GW1, GW2, and GW3, with favorable benefits under high natural gas price assumptions.

Table 8.10 - PVRR Cost/(Benefit) of GW4 vs. OP-NT3

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from OP-NT3	$107	$295	$205	($236)	$295	$199	($234)

Figure 8.38 – Increase/(Decrease) in Resources, GW4 vs. OP-NT3



Gateway Repower (OP-GW4)

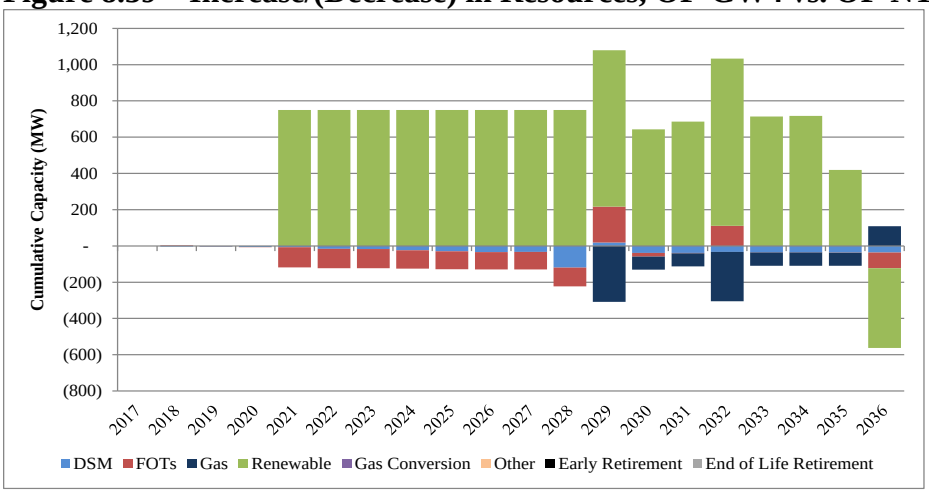
Considering the overwhelmingly favorable result of the Wind Repower sensitivity (OP-REP) and the encouraging Gateway 4 results showing favorable PVRR results in the high gas price scenarios, PacifiCorp conducted an additional Energy Gateway sensitivity. The Gateway Repower (OP-GW4) sensitivity assumes the addition of the Aeolus to Bridger/Anticline transmission segment D2 (assumed in service year-end 2020), as well as 905 MW of wind repowering represented in the OP-REP Wind Repower sensitivity.

Incremental to the 300 MW of Wyoming wind in core case OP-NT3, the increased transmission enables 900 MW of Wyoming wind additions in 2021 (proxy for year-end 2020). Compared to OP-NT3, 150 MW of Goshen wind is eliminated in 2021. This sensitivity yields improved economics relative to cases GW1, GW2, GW3, and GW4, with increasingly favorable benefits under high natural gas price assumptions.

Table 8.11 - PVRR Cost/(Benefit) of OP-GW4 vs. OP-NT3

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from OP-NT3	$71	$309	$201	($315)	$310	$196	($310)
Change from OP-NT3 (2050)	($275)	$19	($119)	($803)	$26	($120)	($775)

Figure 8.39 – Increase/(Decrease) in Resources, OP-GW4 vs. OP-NT3[1]



SO System Costs

Figure 8.40 and Figure 8.41 add sensitivities eligible for consideration to the core case results previously presented in Figure 8.32. Among the eligible cases studied in SO, the OP-REP and OP-GW4 cases produces the lowest system PVRRs. Cases FR-2 and GW3 report the highest system PVRRs. The results for the OP-REP and OP-GW4 cases include benefits for the wind repower project through 2050, accounting for the significant incremental energy benefits beyond the IRP planning period when the life of repowered wind resources is extended. During the public input process, PacifiCorp received feedback from stakeholders that including these long-term incremental benefits may distort comparisons with portfolios that do not include the wind repower project. Stakeholders requested that PacifiCorp address these concerns by including the wind repower project as part of the RE-1c and RE-2 cases. In response to these comments, PacifiCorp considered these additional sensitivity cases during the final portfolio screening stage.

[1] While Figure 8.39 is visually similar to Figure 8.38, there are differences in DSM and FOTs that are not visible at this resolution

Figure 8.40 – System Optimizer PVRR Costs for Eligible Core Cases and Sensitivities

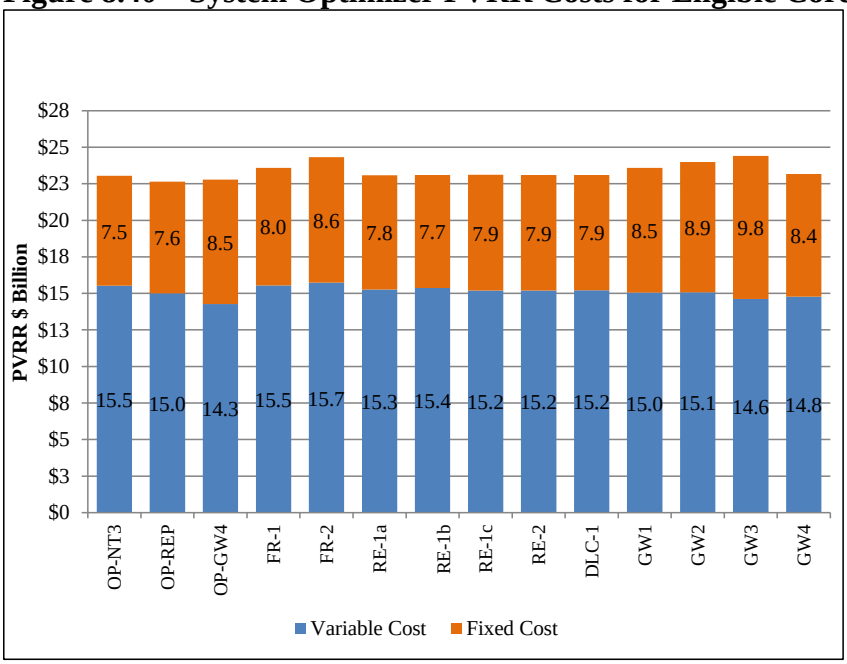
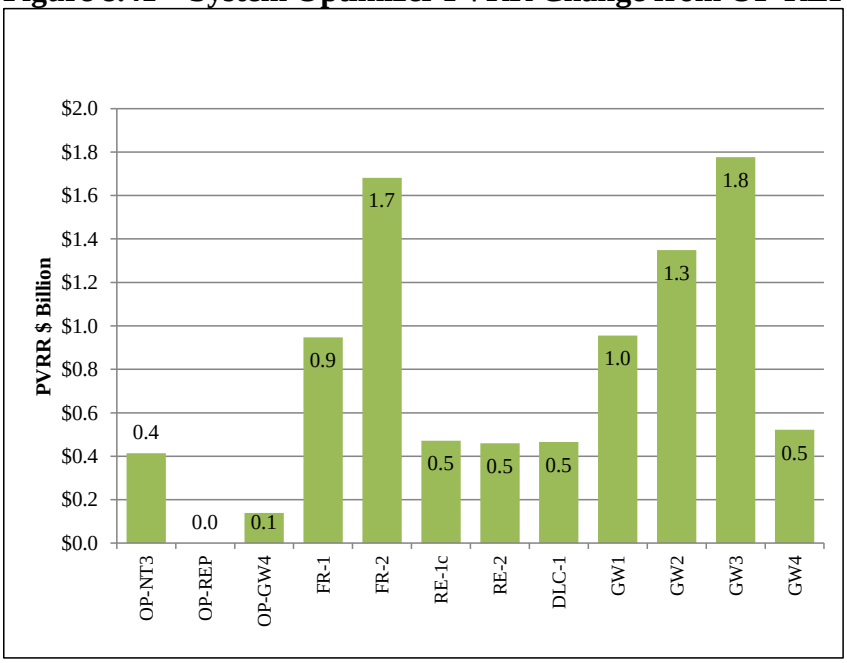


Figure 8.41 – System Optimizer PVRR Change from OP-REP



Eligible Portfolio Cost and Risk Analysis

PaR Configuration and Metrics

The PaR portfolio ranking metrics, which include mean PVRR, upper-tail PVRR, risk-adjusted PVRR, mean ENS, upper-tail ENS, and emissions, are fundamentally alike for each screening stage. As in the Regional Haze screening stage, CO_2 shadow prices from SO are input into PaR to reduce thermal dispatch, as required, and achieve mass cap emission limits. The resulting CO_2

costs reported by PaR represent the opportunity cost of the CPP, but are not real expenses, and thus they are removed in the final PVRR reporting.

Scatter plots present the mean PVRR of each unique core case and eligible sensitivity portfolio on the horizontal axis, and the upper-tail mean PVRR on the vertical axis. Portfolios toward the left-bottom corner of each scatter plot contain the least-cost, least-risk mix of resources, while portfolios toward the upper-right corner contain the highest-cost and highest-risk mix of resources. Figure 8.42 and

Figure 8.43 show the scatter plot results for eligible cases under both the Mass Cap A and Mass Cap B scenarios. As observed in the Regional Haze case results, cost and risk in the upper-tail mean are highly correlated. The OP-REP case is least-cost, least-risk under the low and medium price scenarios, and ranks second in the high gas price scenario. OP-GW4 is least-cost, least-risk in the high gas scenario. GW3 produces the highest cost and risk under each price-emission scenario, with the exception of high natural gas price scenarios, where FR-2 produces the highest- cost, highest-risk results.

Figure 8.42 – Eligible Portfolio Scatter Plots, Mass Cap B

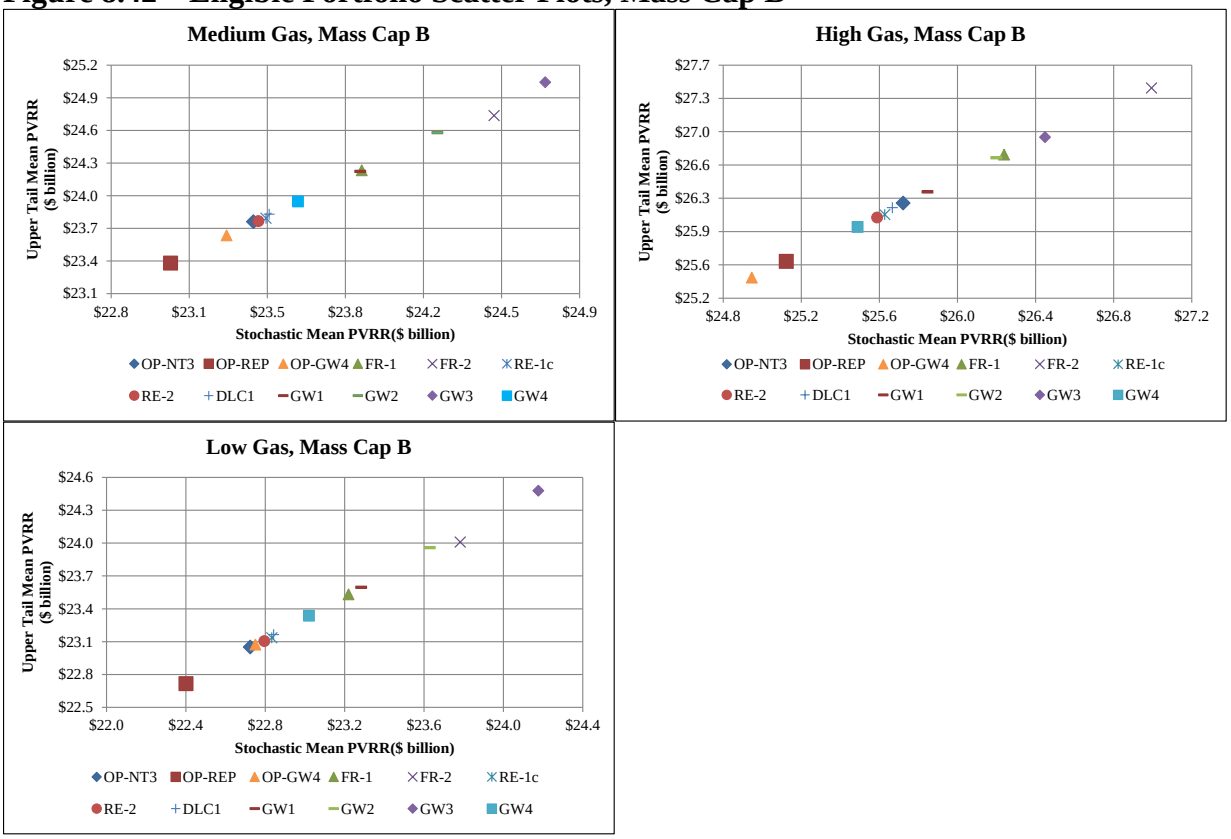
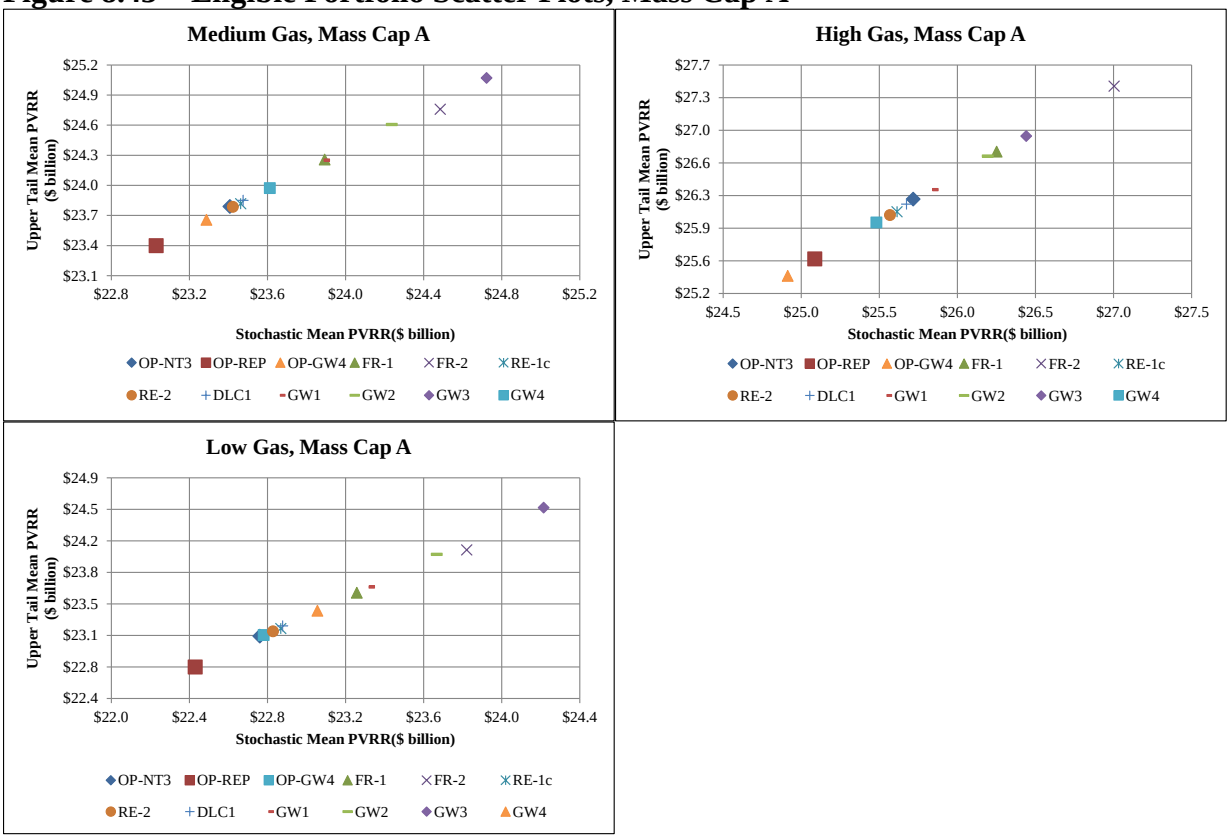


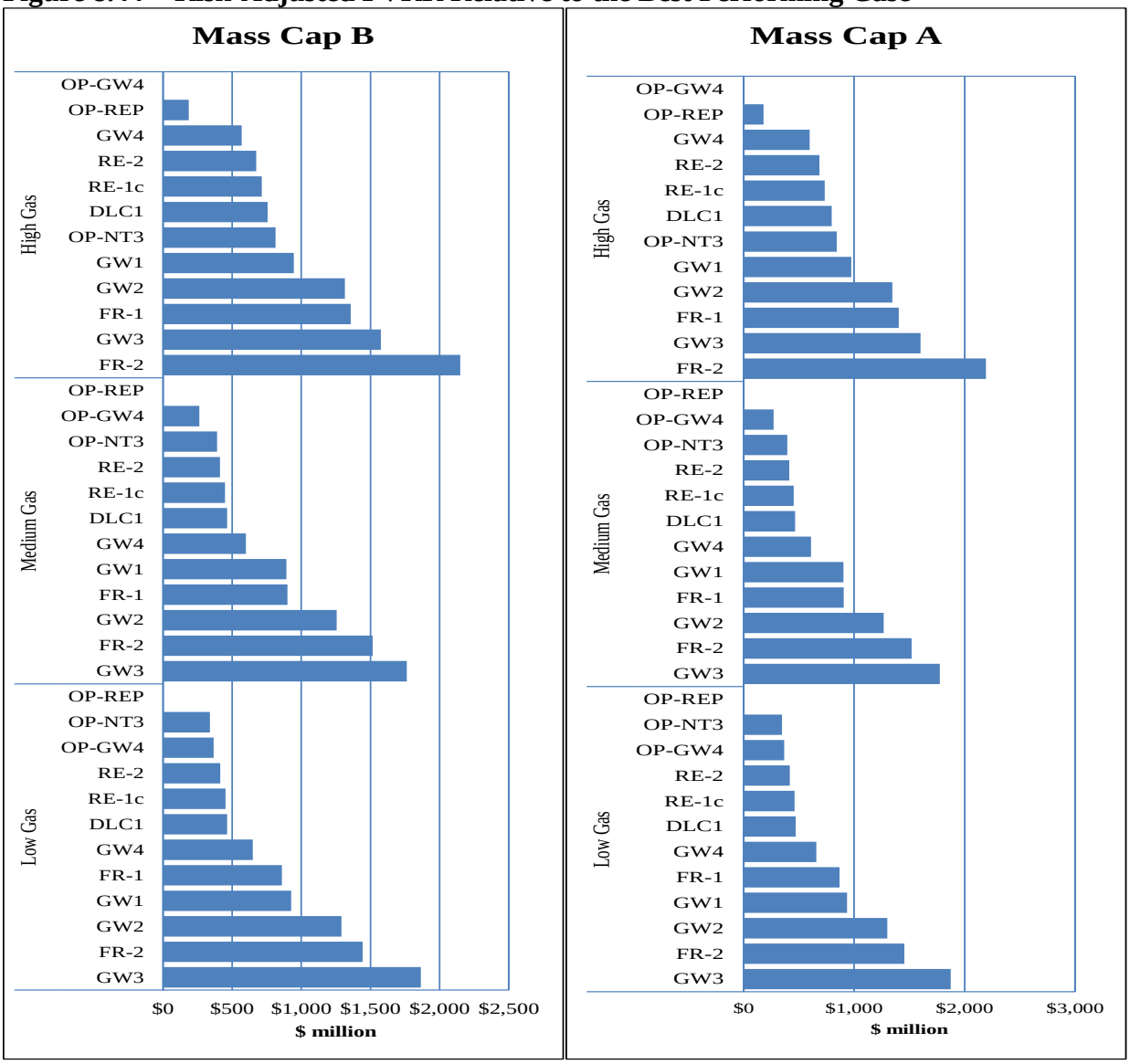
Figure 8.43 – Eligible Portfolio Scatter Plots, Mass Cap A



Risk-Adjusted PVRR

Figure 8.44 shows the stochastic mean PVRR of each case ranked against the best performing case in each price-emission scenario. OP-REP produces the lowest risk-adjusted PVRR in four out of the six price scenarios. OP-GW4 produces the most favorable risk-adjusted PVRR in the high gas price scenarios. Cases GW3 and FR-2 consistently have the highest risk-adjusted PVRR.

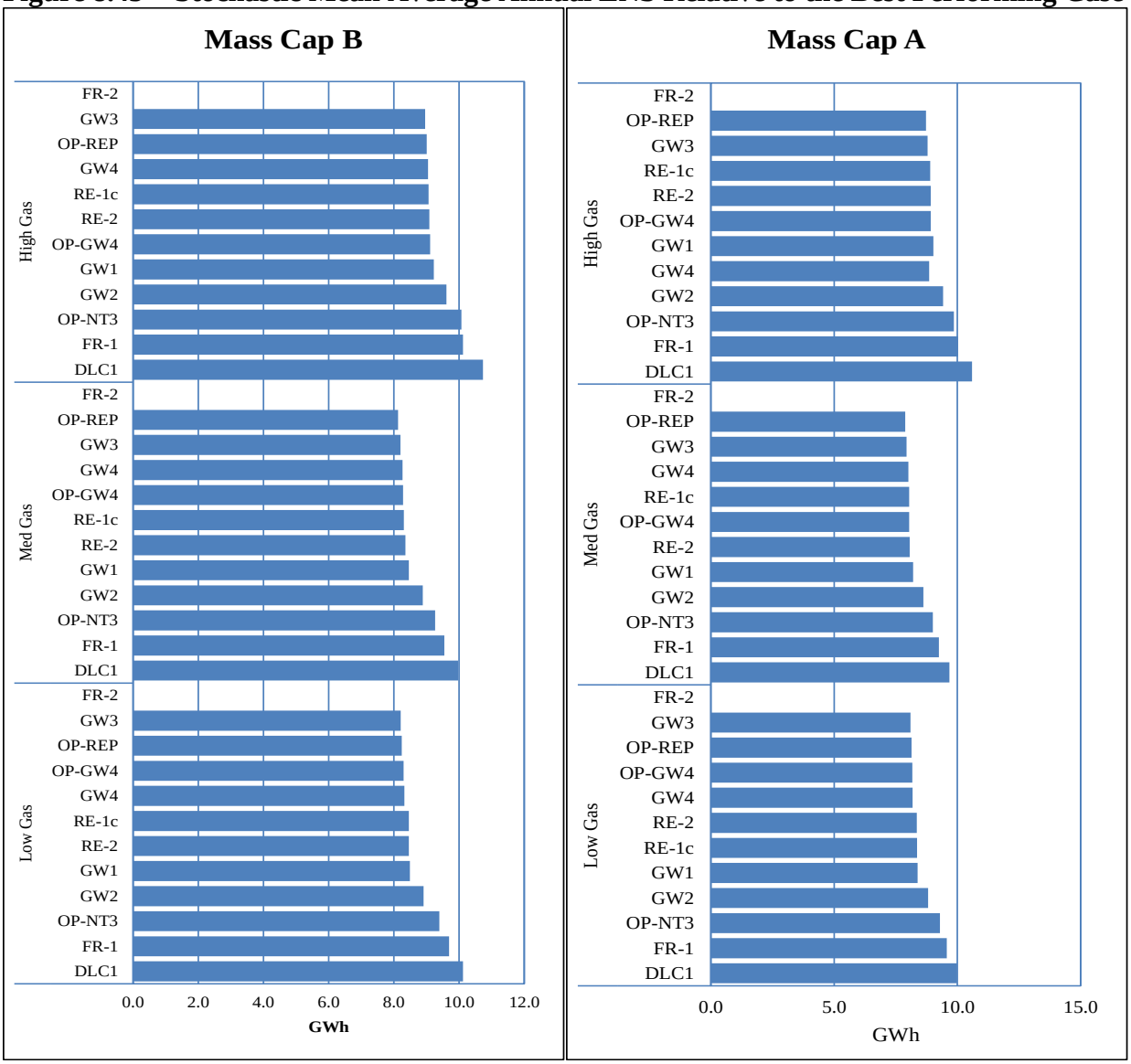
Figure 8.44 – Risk-Adjusted PVRR Relative to the Best Performing Case



Average Energy Not Served (ENS)

Figure 8.45 presents the stochastic mean average annual ENS of each eligible case ranked against the best performing case in each price-emission scenario. All cases have mean ENS levels that are a fraction of total load (annual mean ENS ranges between 2.8 and 13.8 GWh). Relative to other cases, FR-2, with incremental peaking capacity, consistently produces the lowest mean ENS levels (between 2.8 and 3.1 GWh).

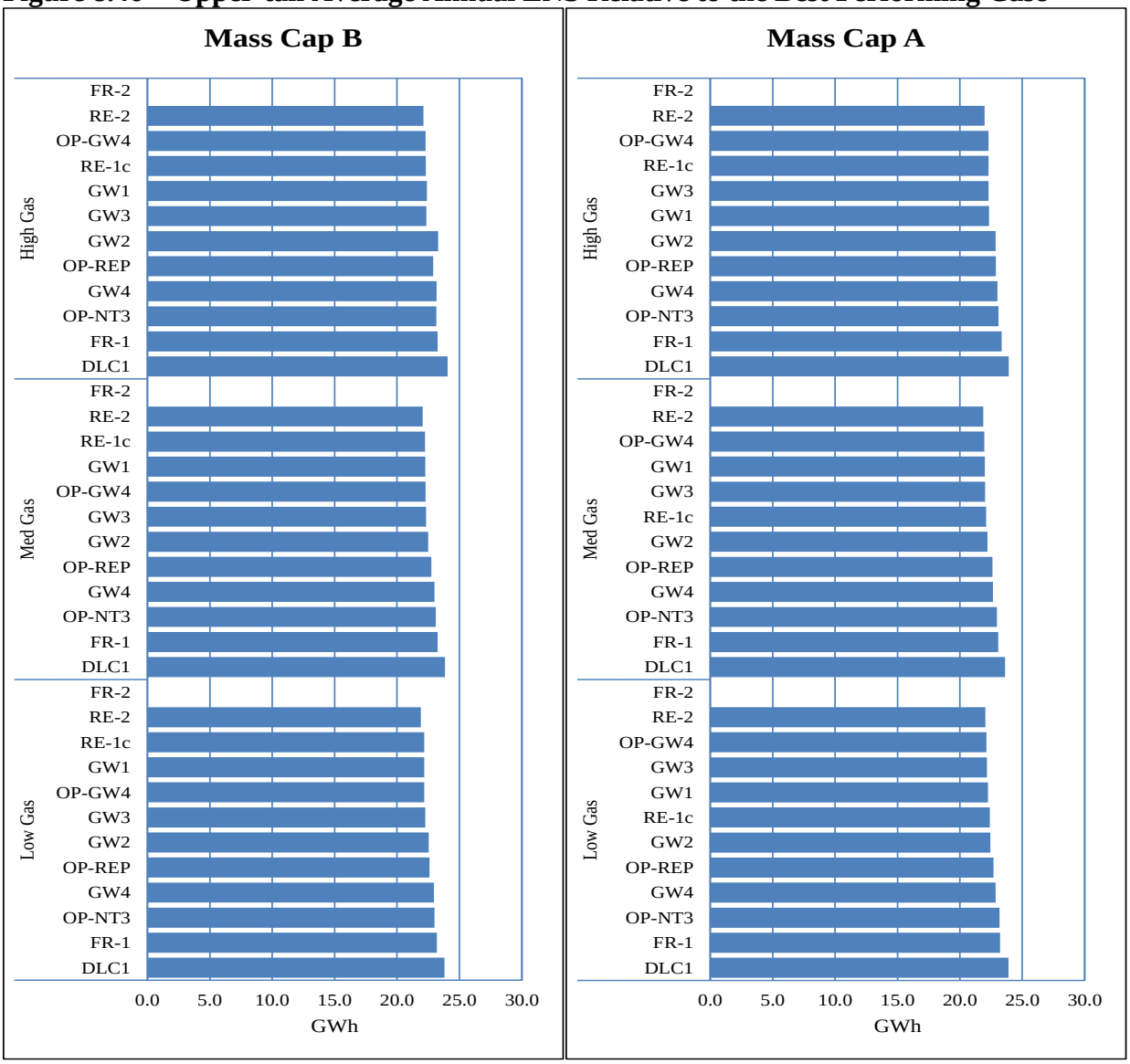
Figure 8.45 – Stochastic Mean Average Annual ENS Relative to the Best Performing Case



Upper-tail Average Energy Not Served (ENS)

Figure 8.46 shows the upper-tail average annual ENS of each eligible case ranked against the best performing case in each price-emission scenario. All cases have upper-tail ENS levels that are a fraction of total load. As with the mean ENS metric, relative to other cases, FR-2, with incremental peaking capacity, consistently produces very low upper-tail ENS levels.

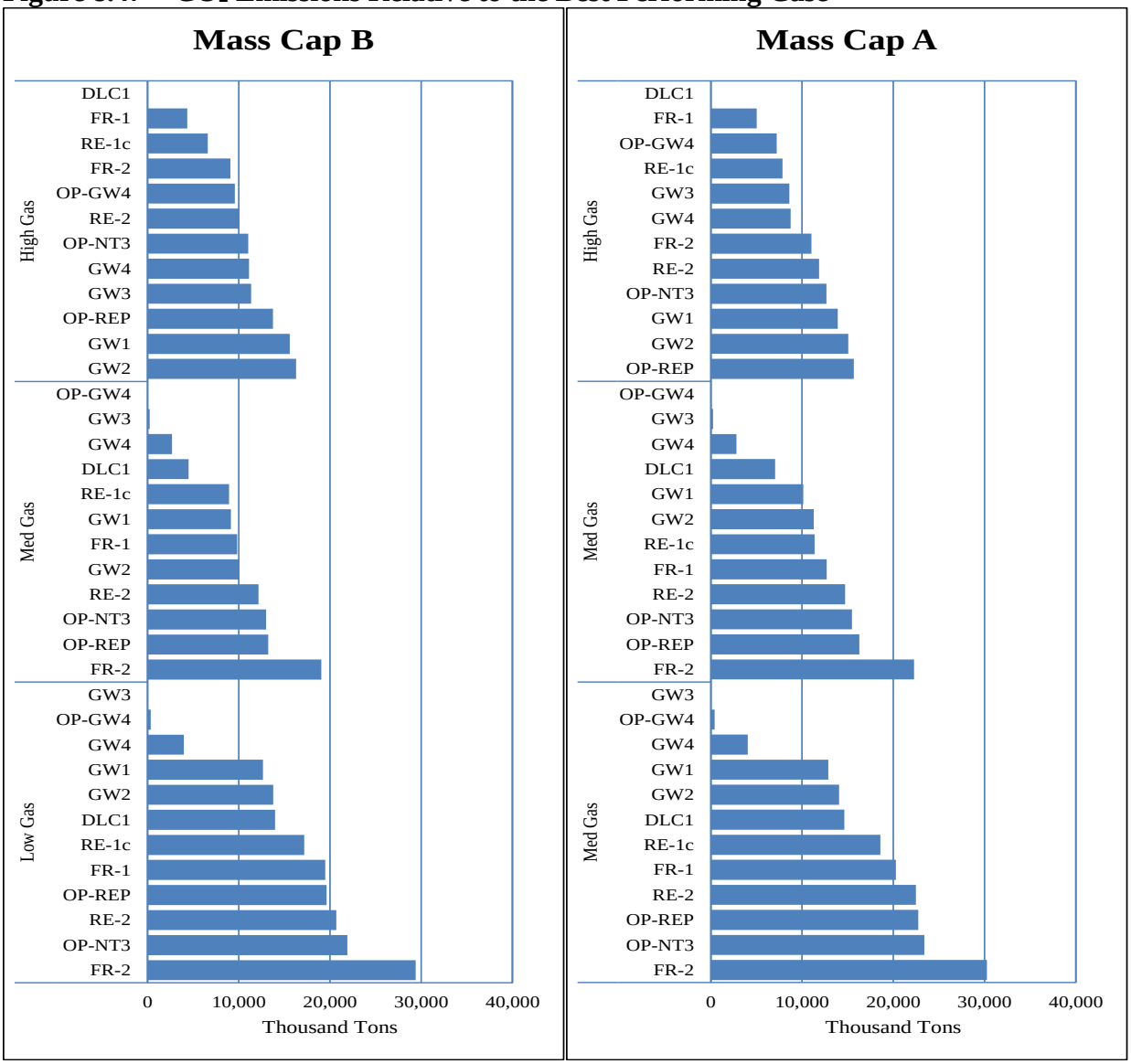
Figure 8.46 – Upper-tail Average Annual ENS Relative to the Best Performing Case



CO_2 Emissions

Figure 8.47 shows total CO_2 emissions of each eligible case ranked against the best performing case in each price-emission scenario. Case GW3 and OP-GW4, which contain the highest level of renewable resources among the cases, consistently yield the lowest emissions levels. The DLC-1 case performed most favorably in the high gas price scenarios. Case OP-REP yields mid-to-high emissions relative to other cases.

Figure 8.47 – CO_2 Emissions Relative to the Best Performing Case



Eligible Portfolio Selection

The metrics described in the cost and risk analysis are condensed into Table 8.12. The OP-REP case ranks first in the risk adjusted PVRR metric, second in the average ENS metric, eighth in the upper-tail ENS metric, and eleventh on emissions. The rankings, while indicative of order, tend to obscure how close some of the outcomes are in terms of raw measures (e.g., total CO_2 emissions). Case OP-REP performs very well in comparison to other top candidates eligible for consideration as the preferred portfolio.

Table 8.12 - Risk-adjusted PVRR among Top Performing Portfolios, Phase Two

	Risk Adjusted[1]			ENS Scenario Average			ENS Upper Tail Average			CO_2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2017-2036 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2017-2036 (GWh)	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2017-2036 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
OP-NT3	25,167	$461	4	12.5	9.5	10	31.4	23.1	10	770,651	13,323	10
OP-REP	24,706	$0	1	11.3	8.4	2	31.0	22.7	8	771,283	13,956	11
OP-GW4	24,857	$150	2	11.5	8.5	5	30.5	22.2	3	757,327	0	1
FR-1	25,695	$988	9	12.7	9.7	11	31.5	23.2	11	766,344	9,017	6
FR-2	26,358	$1,652	11	3.0	0.0	1	8.3	0.0	1	774,577	17,250	12
RE-1c	25,189	$483	5	11.5	8.5	6	30.5	22.3	6	766,154	8,827	5
RE-2	25,148	$441	3	11.5	8.5	7	30.3	22.0	2	769,738	12,411	9
DLC1	25,215	$509	6	13.2	10.2	12	32.1	23.9	12	761,095	3,768	4
GW1	25,575	$869	8	11.6	8.6	8	30.5	22.2	4	766,789	9,461	7
GW2	25,941	$1,234	10	12.0	9.0	9	30.9	22.6	7	767,825	10,498	8
GW3	26,388	$1,681	12	11.4	8.4	3	30.5	22.2	5	757,806	479	2
GW4	25,259	$553	7	11.4	8.4	4	31.2	22.9	9	759,964	2,636	3

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

PacifiCorp identified case OP-REP as the top performing case for phase two of the portfolio selection process. This selection is based on the following observations:

- Case OP-REP produces the lowest risk-adjusted PVRR in four out of six price scenarios and is among the top two cases in the other two price scenarios.
- All cases produce low ENS levels; case OP-REP is consistently among the top performing portfolios when ranked on mean ENS.
- All cases show similar levels of CO_2 emissions; the relative differences among cases does not warrant using the CO_2 emissions metric to select a higher-cost, higher-risk portfolio.
- Case OP-REP produces a low PVRR relative to other eligible cases based on the PVRR from SO.
- Case OP-REP and OP-GW4 are very close when evaluating the PVRR from SO, but case OP-GW4 only exhibits the lowest risk-adjusted PVRR in the high natural gas price scenarios when evaluated in PaR.

Final Portfolio Screening

Final Portfolio Development

In screening stages one and two, PacifiCorp evaluated nine Regional Haze cases (including the additional RH-2a and RH-5a Naughton Unit 3 retirement sensitivities), eight core cases (including

the expanded examination of RE-1a, RE-1b and RE-1c), and six sensitivities eligible for preferred portfolio consideration (OP-REP, GW1, GW2, GW3, GW4, and OP-GW4).

In the final portfolio screening stage, PacifiCorp conducted additional studies informed by the analysis performed during the prior screening stage. The initial results for the GW4 and OP-GW4 sensitivity cases suggest there may be potential for a time-limited opportunity to align development of Energy Gateway sub-segment D2 with wind projects that can qualify for the full value of PTCs. In the final screening stage, PacifiCorp has quantified additional benefits reasonably expected from the new transmission line, assessed how more current near-term assumptions for project capital costs and wind capacity factors affect the analysis, and completed power flow and dynamic stability analysis to refine transmission assumptions. In response to stakeholder feedback, PacifiCorp also re-evaluated the RE-1c and RE-2 cases to include the wind repower project and updated Energy Gateway sub-segment D2 transmission assumptions. This ensures final selection is performed on portfolios developed with comparable assumptions as informed by analysis completed in stage two of the screening process. Final screening portfolios receive an "FS-" designation to indicate that they are distinct from prior screening versions of cases having the same name. Table 8.13 summarizes the portfolios considered for final screening in the 2017 IRP cycle.

Table 8.13 – Final Screening Portfolios

Resource Class	Wind Repower (FS-REP)	Gateway 4 (FS-GW4)	Renewable Energy (FS-RE-1c)	Renewable Energy (FS-RE-2)
Flexible Resources	Optimized	Optimized	Optimized	Optimized
Renewable Resources	Optimized	Optimized	Just-in-Time Physical RPS Compliance (OR and WA)	Early Physical Compliance (OR)
Class 1 DSM Resources	Optimized	Optimized	Optimized	Optimized
All other Resources	Optimized	Optimized	Optimized	Optimized
Gateway 4	No	Yes	Yes	Yes

Wind Repower (FS-REP) Portfolio

After completing the original OP-REP core case studies, PacifiCorp received monthly shaping profiles for the incremental annual energy output expected for the repowered wind plants. These updated monthly profiles, which show the increased annual production associated with installing more modern equipment is higher during the summer months, when wind speeds are lower, than in the winter months, when wind speeds are higher. These monthly profiles were incorporated into the updated repower case (FS-REP) and subsequently used in all final screening portfolio studies.

Energy Gateway 4 (FS-GW4) Portfolio

At the end of screening stage two, the preferred-portfolio-eligible Gateway studies indicated potential for a time-limited opportunity to align the development of Energy Gateway sub-segment D2 with wind projects that can qualify for the full value of PTCs. During the public input process, PacifiCorp indicated its intention to further evaluate its assumptions for case OP-GW4. Since the last public input meeting, PacifiCorp completed power flow and dynamic stability analysis to

support updated transmission assumptions, updated its transmission capital cost assumptions, assessed wind cost and performance assumptions, and quantified incremental cost and benefit drivers associated with the Energy Gateway sub-segment D2 transmission line. These updates, summarized below, are used in PacifiCorp's final screening portfolio studies.

Energy Gateway Sub-Segment D2 Assumptions

Power flow and dynamic stability analysis confirmed that the Energy Gateway sub-segment D2 transmission line can accommodate new and existing wind resource interconnections at levels at or above those assumed in PacifiCorp's original OP-GW4 sensitivity case. This analysis further supports an increase in the transfer capability from 650 MW, as assumed in the original sensitivity case, to 750 MW as assumed in the updated analysis. PacifiCorp also completed a detailed review of its assumed cost to build the new transmission line. The results of this review support reducing the originally assumed capital cost of the transmission line by approximately $113m. The updated transfer capability and reduced capital costs directionally improve the economics of the transmission project.

Wind Cost and Performance Assumptions

Considering the potential to expand new wind resource capacity with addition of the transmission line, PacifiCorp reviewed the Wyoming wind cost and performance assumptions adopted for the 2017 IRP with a more detailed review of potential wind projects located in Wyoming, taking into consideration equipment costs, interconnection costs, and potential development fees. This analysis supports reducing nominal wind capital cost assumptions included in the original sensitivity case of $1,834/kW by 10.7 percent to $1,637/kW. Directionally, the updated wind capital cost assumptions improve the economics of the updated sensitivity case.

In its review of updated wind capital cost assumptions, PacifiCorp also assessed projected Wyoming wind resource capacity factors for potential projects that might connect to the new transmission line. This review supports reducing the 43.0 percent capacity factor assumed for proxy Wyoming wind resources in the 2017 IRP to 41.2 percent. Directionally, the updated wind capacity factor assumptions increase the cost of the updated sensitivity case.

Additional Cost/Benefit Drivers

The qualifying facility (QF) pricing methodology used in Wyoming includes two price streams—one with and one without incremental transmission upgrades. PacifiCorp reviewed existing qualifying facility (QF) contracts located in constrained areas of the transmission system in Wyoming to estimate the potential change to contract pricing that might be triggered by the new transmission line. Directionally, accounting for changes in QF contract pricing assumptions increases the cost of the updated sensitivity case.

A new transmission line in parallel with existing lines reduces resistance and therefore reduces line losses. With reduced line losses, an additional 12 aMW of incremental annual energy is expected to flow out of eastern Wyoming. The potential value of reduced line losses was calculated using a production cost model simulation to capture the value of this energy specific to the location on PacifiCorp's system where line loss savings would occur. Directionally, accounting for reduced line losses improves the economics of the updated sensitivity case.

A new transmission line also provides reliability benefits by reducing transmission de-rates associated with outages of transmission system elements that would not occur with the addition of the Energy Gateway sub-segment D2 line. Avoided average transmission path de-rates are estimated at 146 MW. Incremental reliability benefits were calculated using a production cost model simulation to capture the avoided transmission de-rates that account for estimated outage days for affected transmission system elements. Directionally, accounting for reduced transmission de-rates improves the economics of the updated sensitivity case.

Finally, the new transmission line is expected to provide incremental benefits in the energy imbalance market (EIM). In the EIM, power flows across the system are able to take advantage of within-the-hour available transmission of the participating EIM entities due to unscheduled or unused transmission capacity. The EIM currently includes NV Energy, Arizona Public Service Company, Puget Sound Energy, and the California Independent System Operator Corporation. The EIM is expected to include Idaho Power Company and Portland General Electric Company, which provides a significant amount of transmission capacity across the west to move power more efficiently. Due to the large number of entities in the EIM with participating transmission, there is an ability to move additional energy from Wyoming to offset higher priced generators in the PacifiCorp system both in the east and the west, or make a sale to an EIM participant. EIM benefits were estimated by simulating incremental transfer capabilities from the east to the west using a production cost simulation model, thereby capturing the incremental benefits of moving additional energy out of Wyoming to the west. Directionally, taking into consideration the ability to move low-cost energy from Wyoming to a larger market improves the economics of the updated sensitivity case.

Summary of Updated Assumptions

Table 8.14 summarizes the incremental adjustments applied to capture the impacts of updated assumptions on the net cost of the FS-GW4 sensitivity case.[2] In aggregate, the updated analysis reflects a net economic improvement ranging between $181m and $209m.

Table 8.14 – Gateway 4 Quantifiable Benefits

Gateway 4 ($ millions)	System Optimizer	PaR	PaR	PaR	PaR	PaR	PaR
Natural Gas Price Scenario	**Base**	**Low**	**Base**	**High**	**Low**	**Base**	**High**
Clean Power Plan Scenario	**Mass B**	**Mass B**	**Mass B**	**Mass B**	**Mass A**	**Mass A**	**Mass A**
Wind QF PPA Price Increase	$3	$3	$3	$3	$3	$3	$3
Wind CF Adjustment	$29	$24	$28	$45	$24	$27	$45
Wind CapEx Adjustment	($84)	($84)	($84)	($84)	($84)	($84)	($84)
Transmission CapEx Adjustment	($71)	($71)	($71)	($71)	($71)	($71)	($71)
Line Loss Value Adjustment	($22)	($19)	($22)	($37)	($19)	($22)	($36)
Reliability Value Adjustment	($17)	($14)	($17)	($27)	($14)	($16)	($27)
EIM Value Adjustment	($24)	($20)	($24)	($39)	($20)	($24)	($39)
Total Adjustments	($185)	($181)	($186)	($209)	($181)	($186)	($209)

[2] The increased transfer capability assumed in the updated analysis is captured in the SO and PaR simulations and not quantified as a specific adjustment here.

Renewable Energy (FS-R1c and FS-R2) Portfolios

Based on analysis from the prior screening stage and stakeholder feedback, PacifiCorp recognized that cases RE-1c and RE-2 should be considered for final selection when studied with comparable wind repower and Energy Gateway assumptions. Adding the wind repowering project and comparable Energy Gateway and new wind resources to these cases significantly reduces the base RPS shortfall relative to RE-1c and RE-2.

Cumulative Additional Resource Capacity

Figure 8.48 through Figure 8.51 summarize the cumulative capacity of new resources and the cumulative reduction in existing resources through 2036, as developed for the final screening cases in SO.

Figure 8.48 – Cumulative Capacity through 2036, Final Screening Case FS-REP

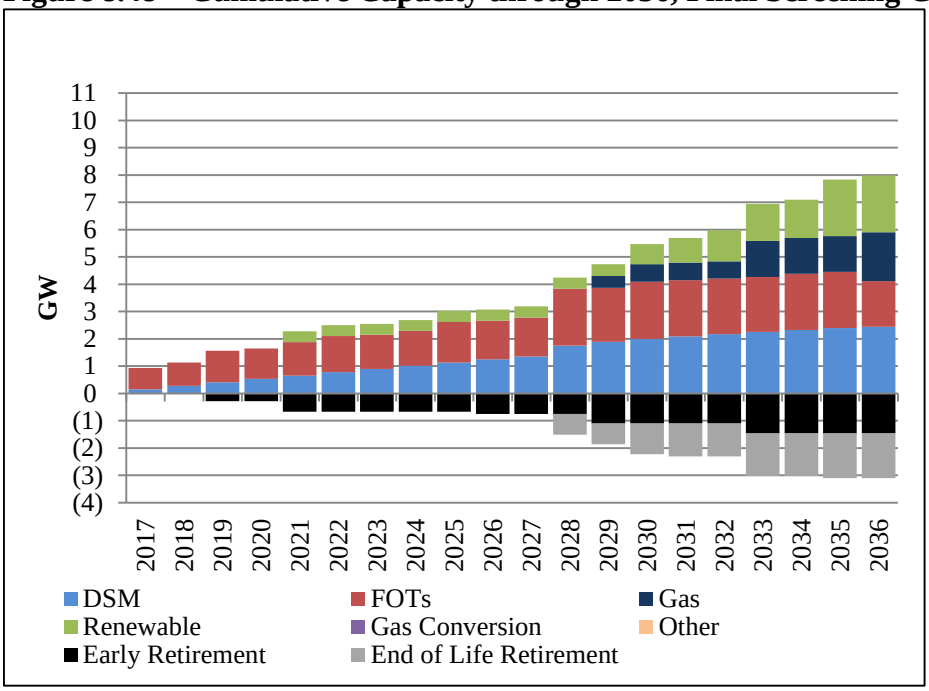


Figure 8.49 – Cumulative Capacity through 2036, Final Screening Case FS-GW4

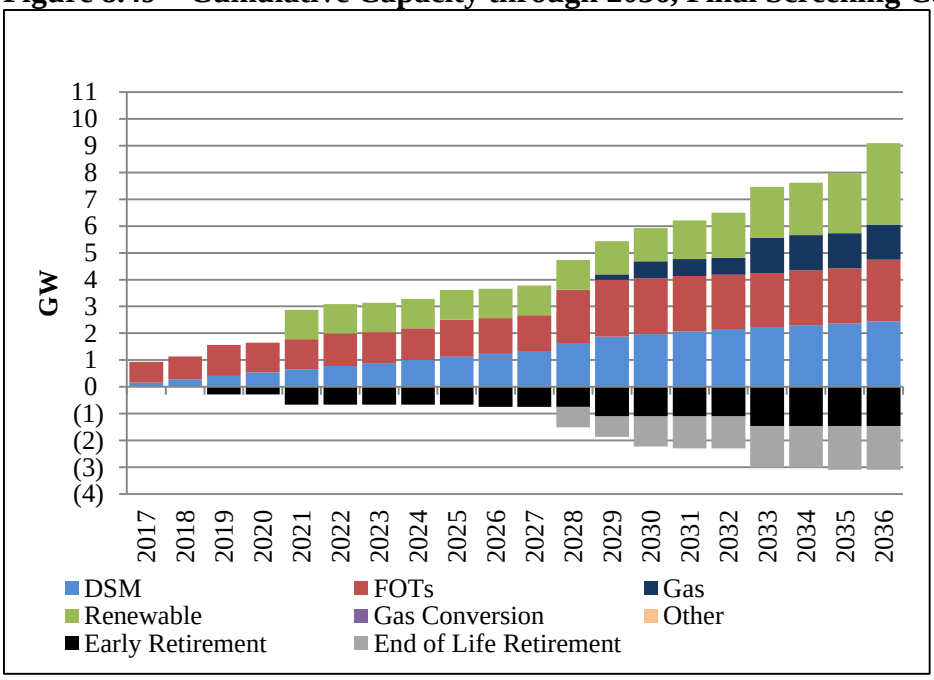


Figure 8.50 – Cumulative Capacity through 2036, Final Screening Case FS-R1c

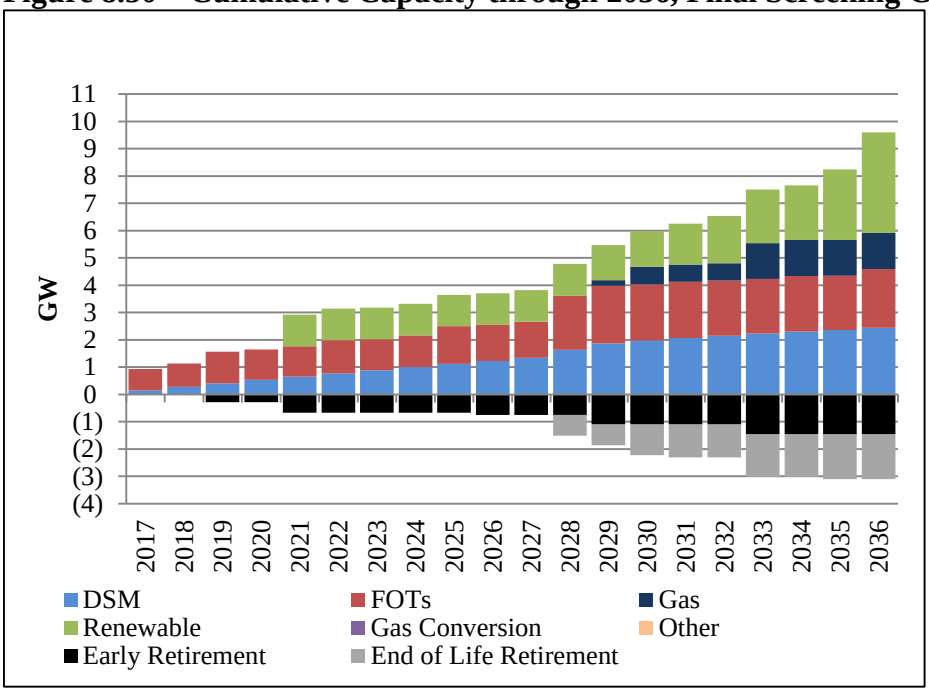
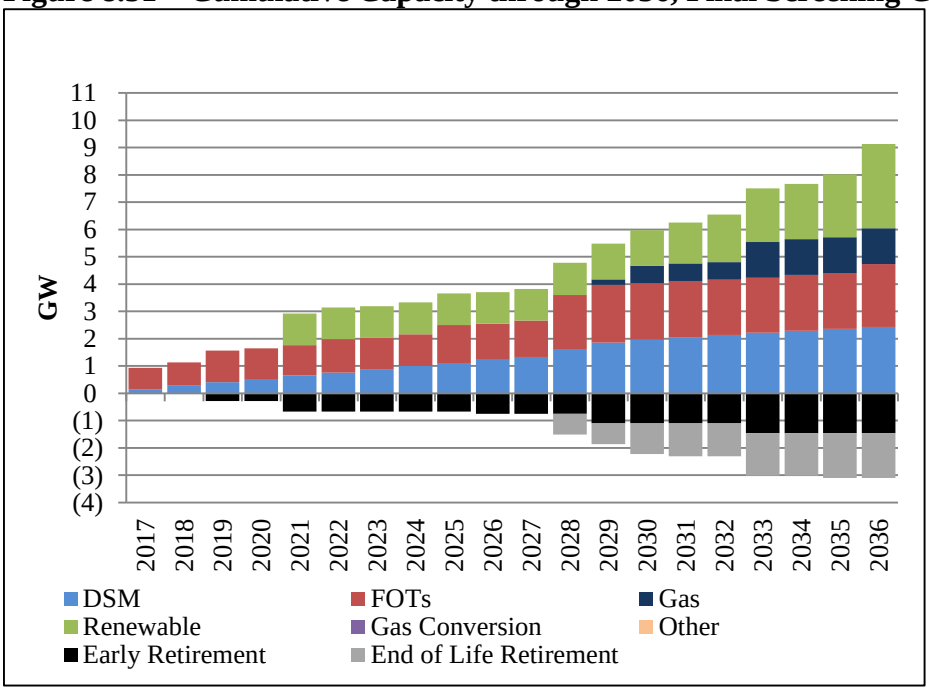


Figure 8.51 – Cumulative Capacity through 2036, Final Screening Case FS-R2



SO System Costs

Figure 8.52 and Figure 8.53 report SO system PVRR results for the final screening portfolios. In this stage of the analysis, wind repower benefits through 2050 are reported in the total PVRRs for all four cases to account for extended operational life benefits. Among the final cases studied in SO, FS-GW4 reports the lowest total PVRR, while case FS-REP reported the least favorable PVRR. The SO result for FS-GW4, representing optimum resource expansion on a capacity basis for the Gateway 4 scenario, shows a benefit $52.2m favorable compared to FS-REP.

Figure 8.52 – System Optimizer PVRR Costs for Final Cases

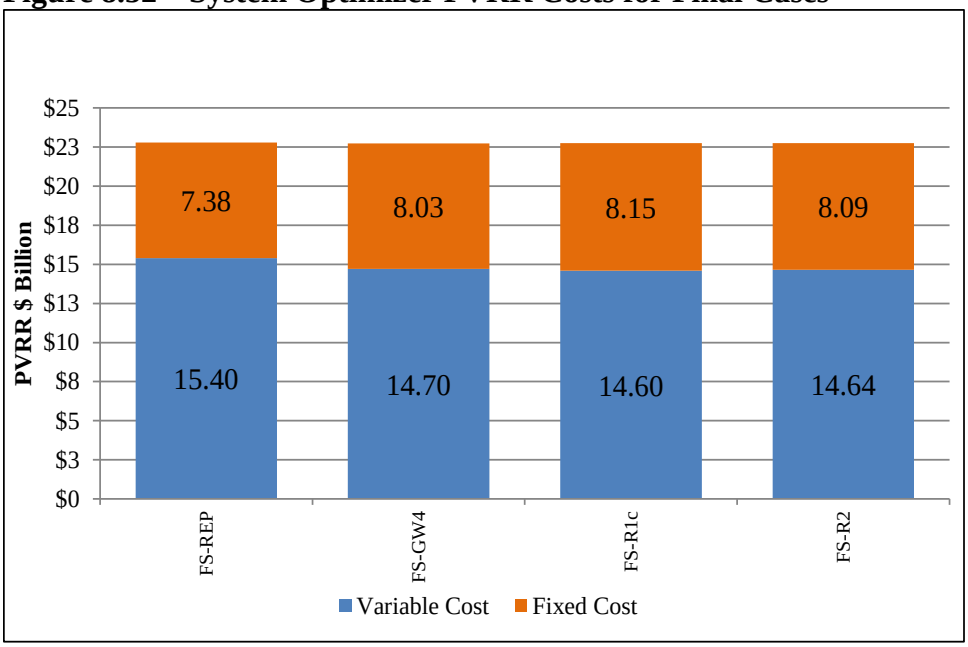


Figure 8.53 – System Optimizer PVRR Change from FS-REP for Final Cases



Final Portfolio Cost and Risk Analysis

PaR Configuration and Metrics

The PaR portfolio ranking metrics, which include mean PVRR, upper-tail PVRR, risk-adjusted PVRR, mean ENS, upper-tail ENS, and emissions, are fundamentally alike for each screening stage. As in the previous screening stages, CO_2 shadow prices from SO are input into PaR to affect thermal dispatch in a way that achieves assumed CPP mass cap emission limits. The resulting CO_2 costs reported by PaR represent the opportunity cost of the CPP, but are not real expenses, and thus they are removed in the final PVRR reporting.

Scatter plots present the mean PVRR of each unique final screening portfolio on the horizontal axis, and the upper-tail mean PVRR on the vertical axis. Portfolios toward the left-bottom corner of each scatter plot contain the least-cost, least-risk mix of resources, while portfolios toward the upper-right corner contain the highest-risk and highest-cost mix of resources. Figure 8.54 and

Figure 8.55 show the scatter plot results for eligible cases under both the Mass Cap A and Mass Cap B scenarios. As observed in the previous screening stages, cost and risk metrics are highly correlated. FS-REP is least-cost, least-risk portfolio under the low price scenario, while FS-R2 is least least-cost, least-risk portfolio under the medium and high gas price scenarios. FS-GW4 is second least-cost, least-risk portfolio under all scenarios. The difference in costs among the four cases is very small.

Figure 8.54 – Final Portfolio Scatter Plots, Mass Cap B

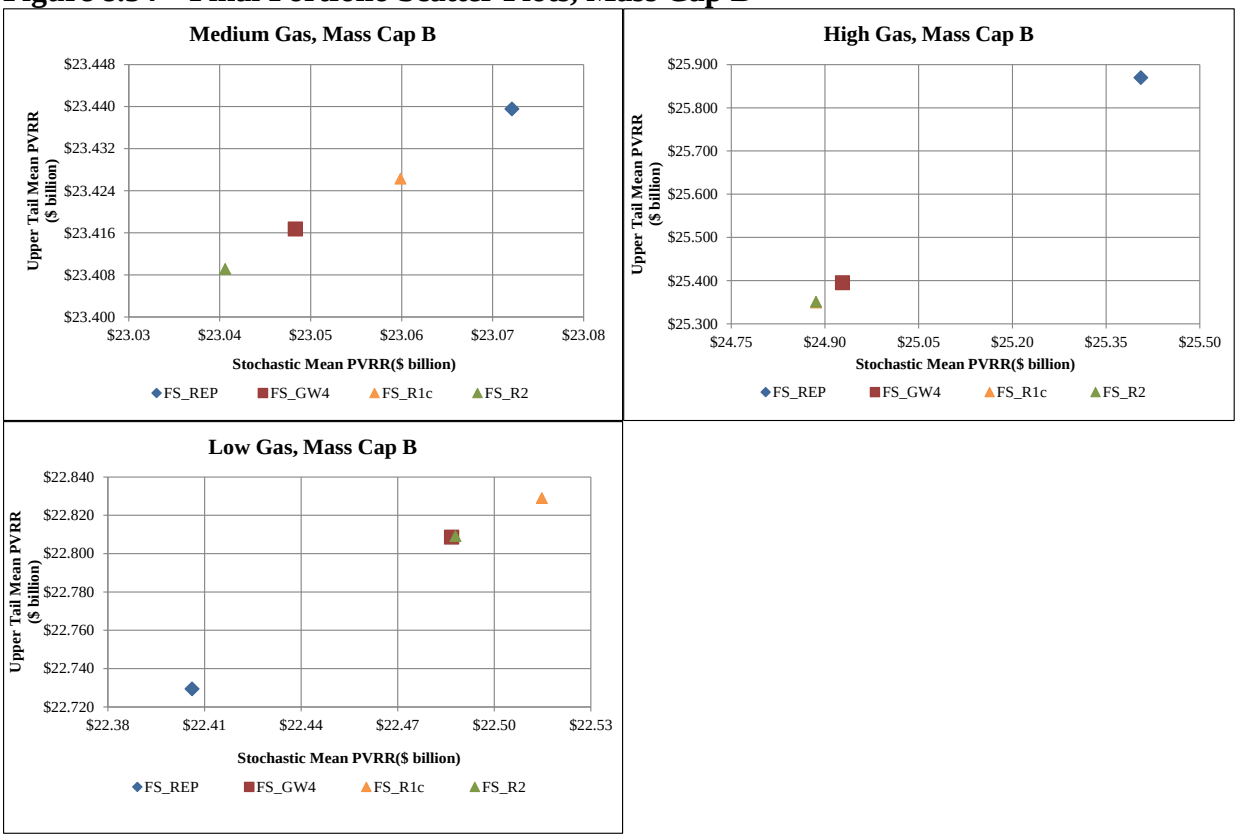
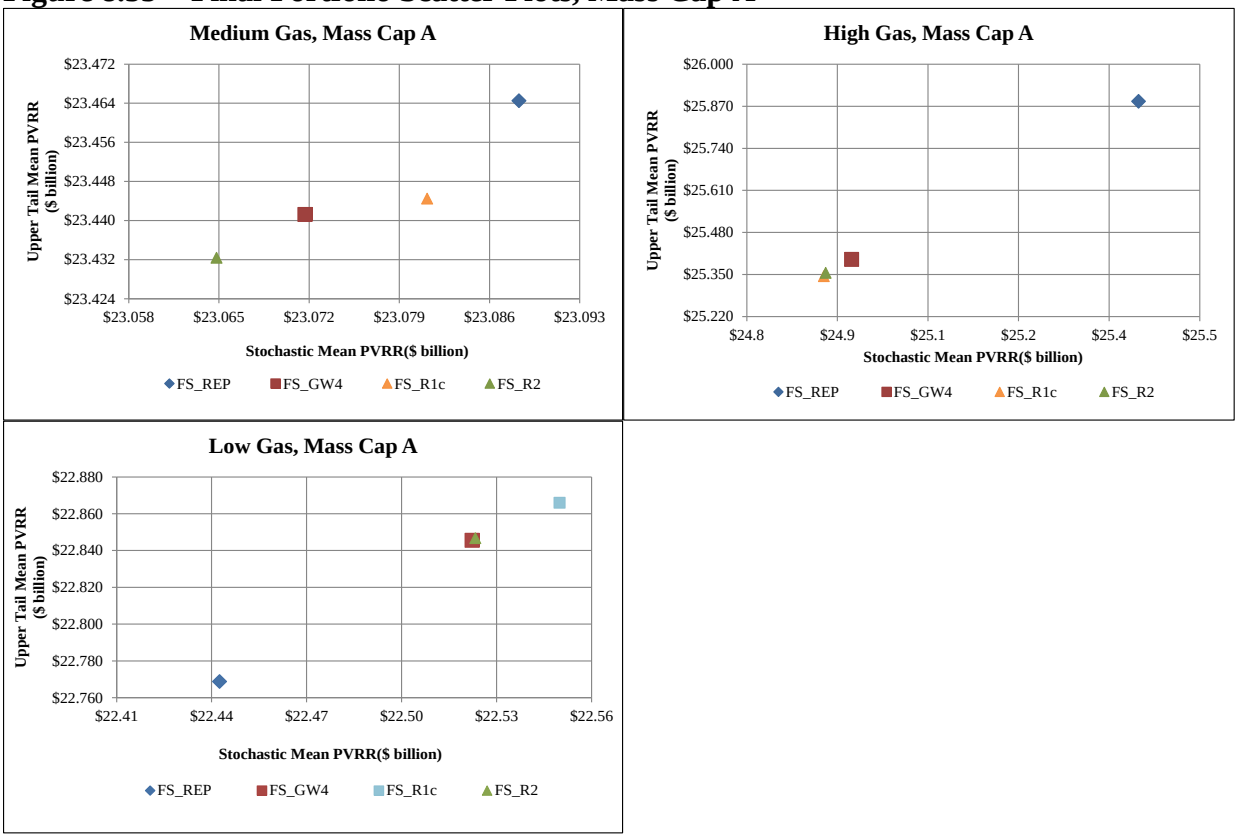


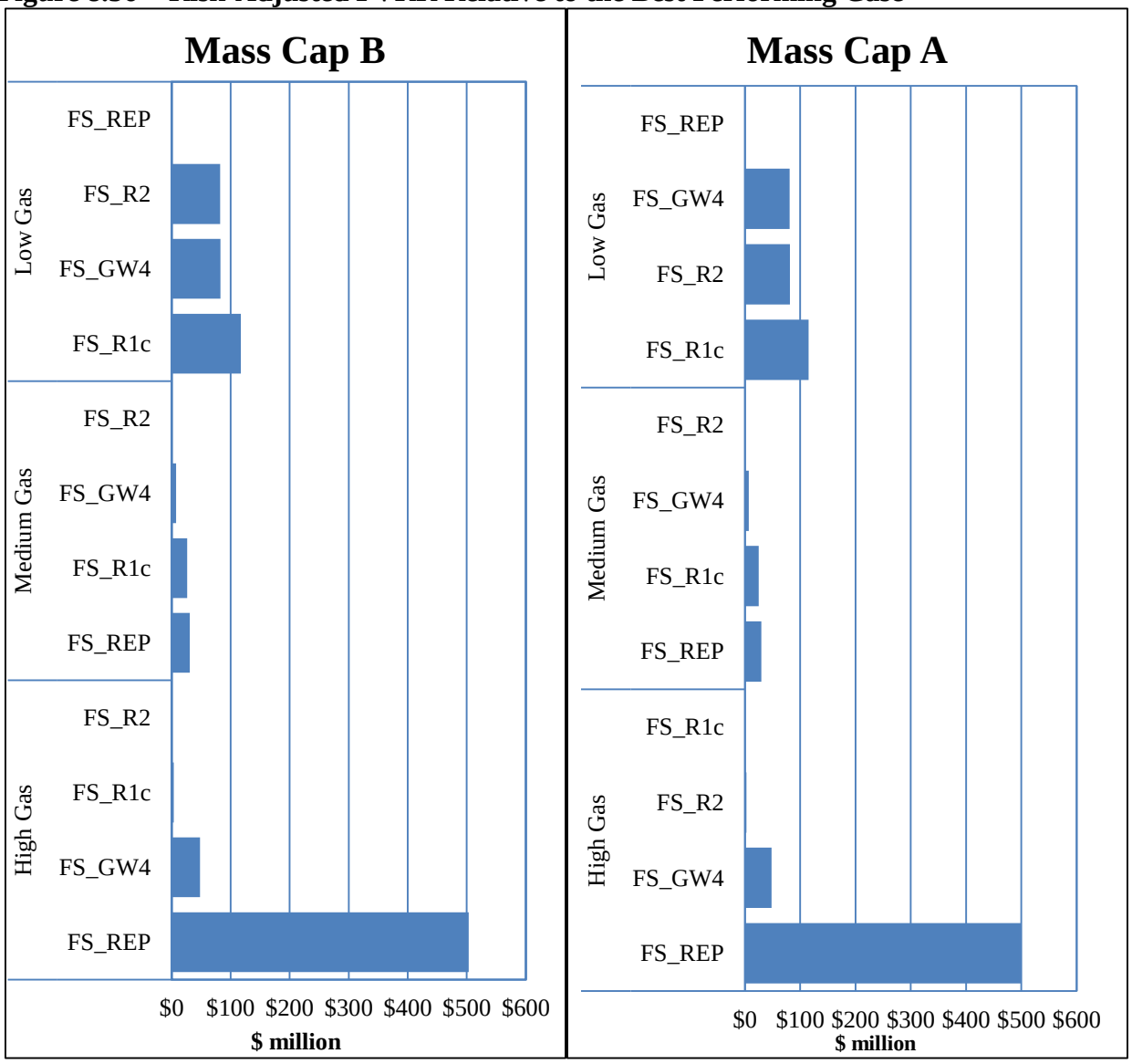
Figure 8.55 – Final Portfolio Scatter Plots, Mass Cap A



Risk-Adjusted PVRR

Figure 8.56 shows the stochastic risk-adjusted PVRR of each final screening portfolio ranked against the best performing case in each price-emission scenario. FS-REP performs the best in low natural gas price scenarios, followed by a nearly indiscernible difference between cases FS-R2 and FS-GW4. FS-R2 produces the lowest risk-adjusted PVRR in the medium natural gas price scenario, with a nearly indiscernible difference relative to case FS-GW4. Under high natural gas price scenarios, FS-R2 and FS-R1c produce slightly lower risk-adjusted PVRRs relative to FS-GW4.

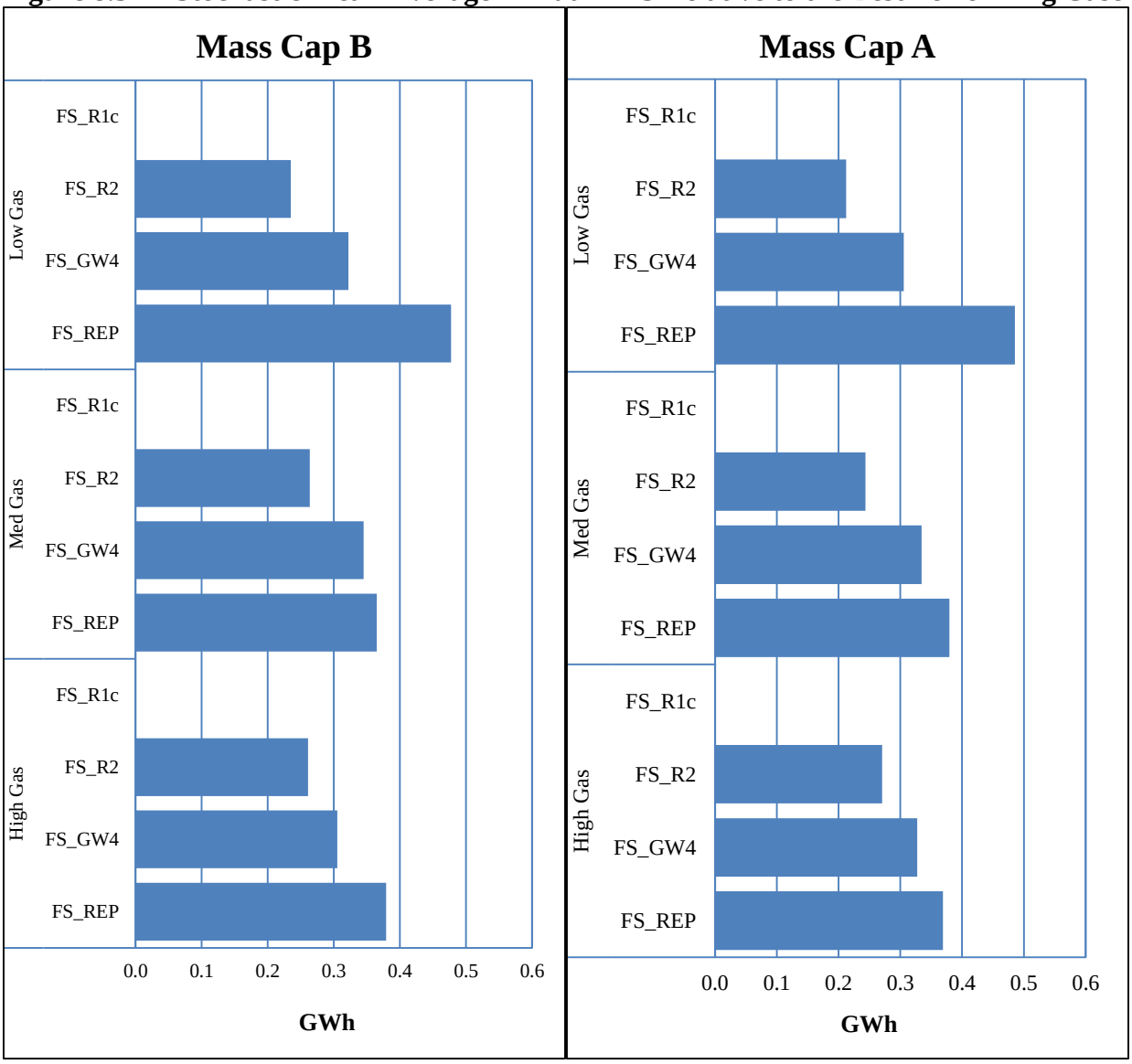
Figure 8.56 – Risk-Adjusted PVRR Relative to the Best Performing Case



Average Energy Not Served (ENS)

Figure 8.57 presents the stochastic mean average annual ENS of each final screening portfolios relative to the best performing case in each price-emission scenario. All cases have mean ENS levels that are a fraction of total load (annual mean ENS ranges between 2.8 and 13.8 GWh). Relative to other cases, FS-R1c, with additional renewables to meet RPS, consistently produces the lowest mean ENS levels (between 0.2 and 0.5 GWh).

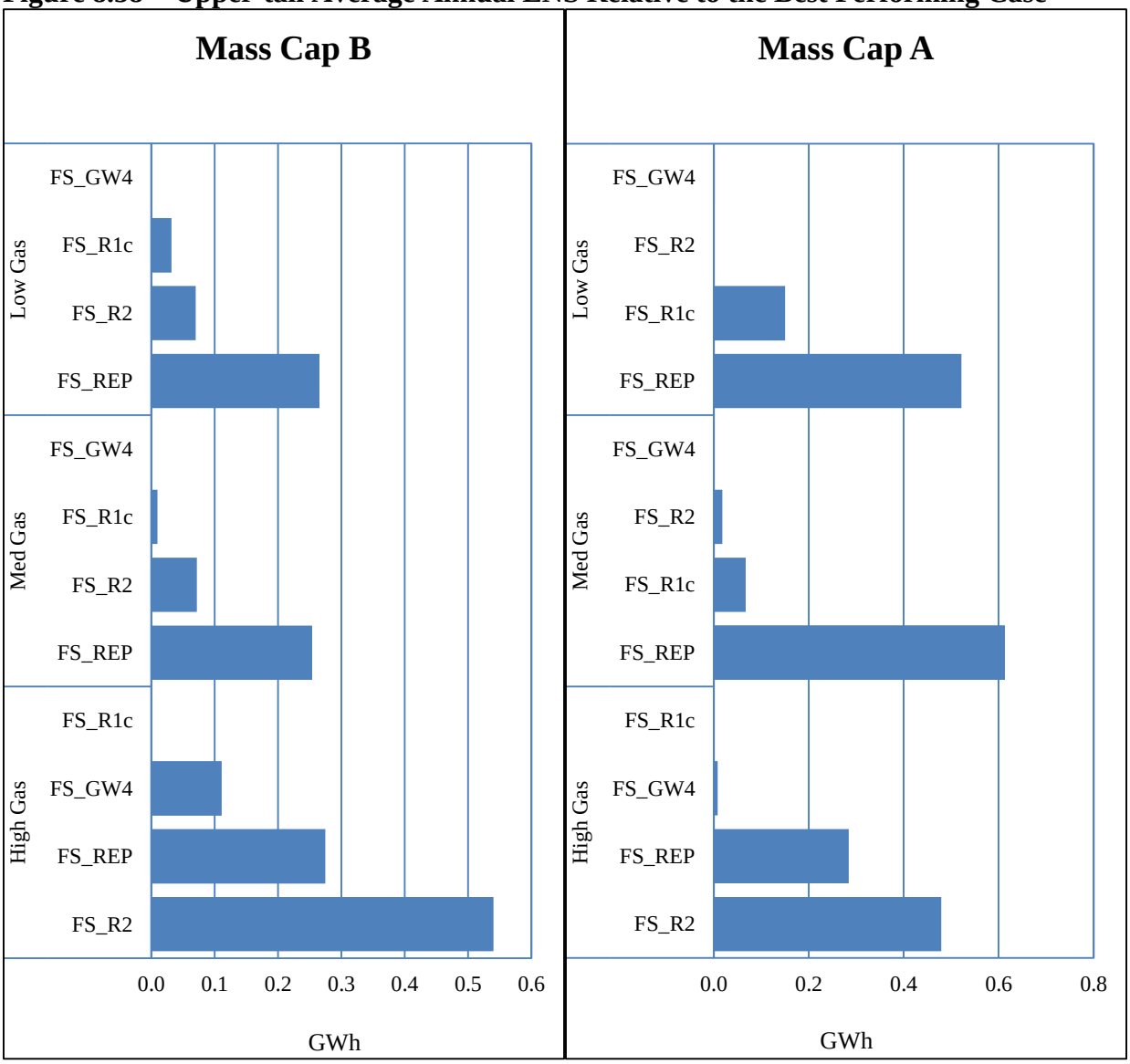
Figure 8.57 – Stochastic Mean Average Annual ENS Relative to the Best Performing Case



Upper-tail Average Energy Not Served (ENS)

Figure 8.58 shows the upper-tail average annual ENS of each final screening portfolio relative to the best performing case in each price-emission scenario. All cases have upper-tail ENS levels that are a fraction of total load. Relative to other cases, FS-GW4 consistently produces the lowest upper-tail ENS levels, except under high gas price scenarios.

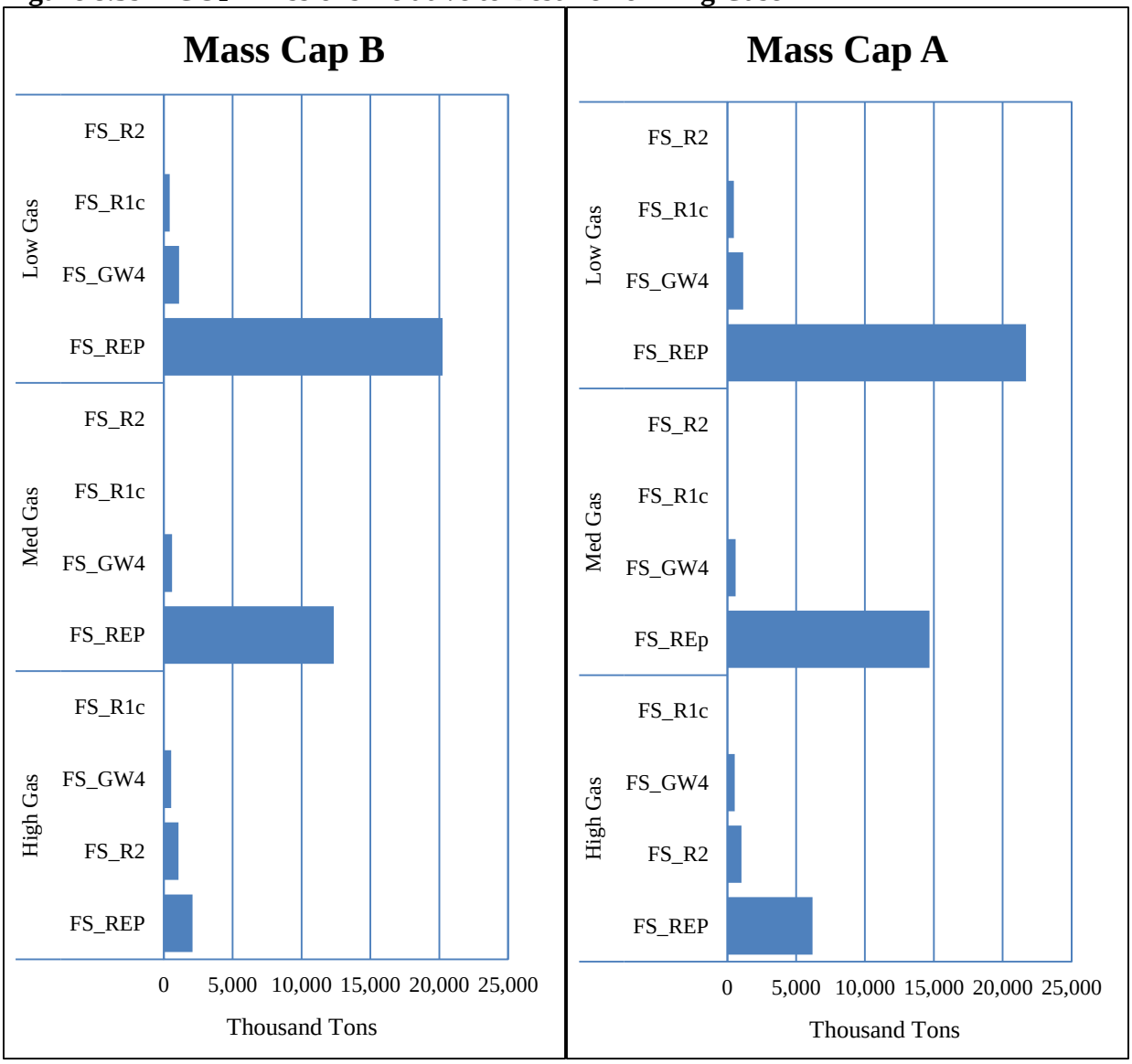
Figure 8.58 – Upper-tail Average Annual ENS Relative to the Best Performing Case



CO_2 Emissions

Figure 8.59 shows total CO_2 emissions of each final screening portfolio relative to the best performing case in each price-emission scenario. Cases FS-R2 and FS-R1c consistently yield the lowest emissions among all portfolios. Case FS-R1c performed most favorably in the high gas price scenarios. Case FS-REP yields higher emissions due to lower renewables relative to other cases.

Figure 8.59 – CO_2 Emissions Relative to Best Performing Case

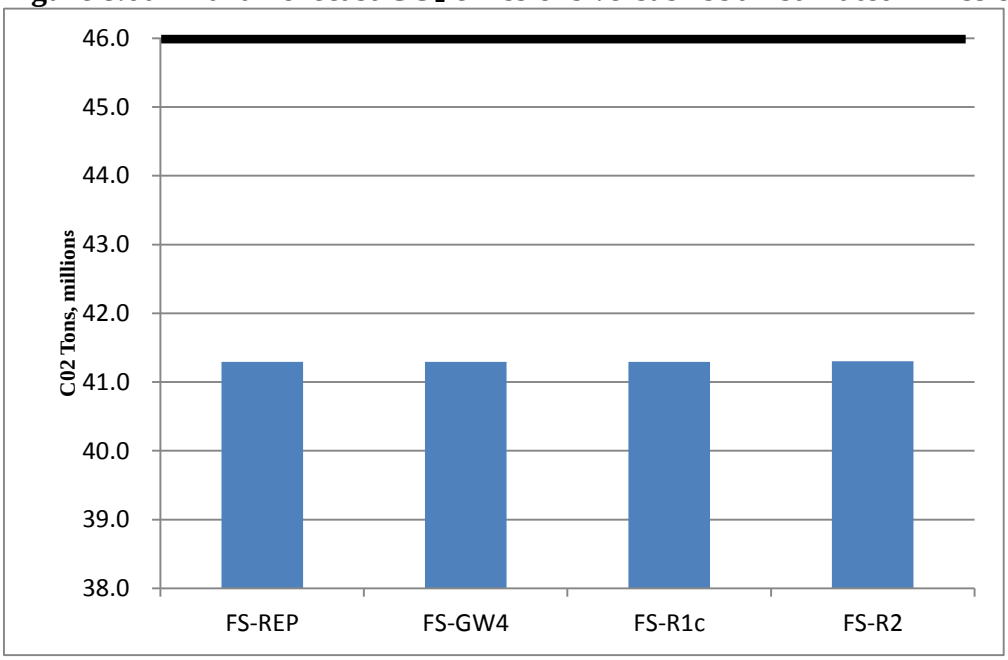


Each of these cases achieves emission goals in Oregon and Washington, which rely on 1990 emissions as a benchmark.[3] For PacifiCorp's system, the 1990 emission level was approximately

[3] Washington has a goal to reduce emissions to 1990 levels by 2020. Oregon has a goal to reduce emissions to ten percent below 1990 levels by 2020.

46 million tons. As seen in Figure 8.60, all final screening portfolios show 2020 emissions that fall well below 1990 emission levels.

Figure 8.60 – 2020 Forecast CO_2 emissions versus 1990 Estimated Emission Levels



Final Preferred Portfolio Selection

The metrics described in the cost and risk analysis are condensed into Table 8.15. FS-R2 ranks first in the risk adjusted PVRR metric, while FS-R1c ranks first in average ENS, and FS-GW4 ranks first in upper-tail ENS. The rankings, while indicative of order, tend to obscure how close some of the outcomes are in terms of raw measures. The separation among the three Energy Gateway cases on the average risk-adjusted PVRR metric is $20m, which is just 0.08 percent of the system PVRR, suggesting that these cases are essentially equivalent. All three of the Energy Gateway cases (FS-GW4, FS-R1c, and FS-R2) yield a risk-adjusted PVRR that is notably favorable to the FS-REP case.

Table 8.15 - Risk-adjusted PVRR among Top Performing Portfolios

	Risk Adjusted[1]			ENS Scenario Average			ENS Upper Tail Average			CO_2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2017-2036 (GWh)	Change from Lowest ENS Portfolio	Rank	Average Annual ENS, 2017-2036 (GWh)	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2017-2036 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
FS_REP	23,939	$150	4	11.8	0.4	4	30.6	0.3	4	770,886	12,720	4
FS_GW4	23,808	$18	2	11.7	0.3	3	30.3	0.0	1	758,774	607	3
FS_R1c	23,810	$20	3	11.4	0.0	1	30.3	0.0	2	758,167	0	1
FS_R2	23,790	$0	1	11.6	0.2	2	30.4	0.2	3	758,361	194	2

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

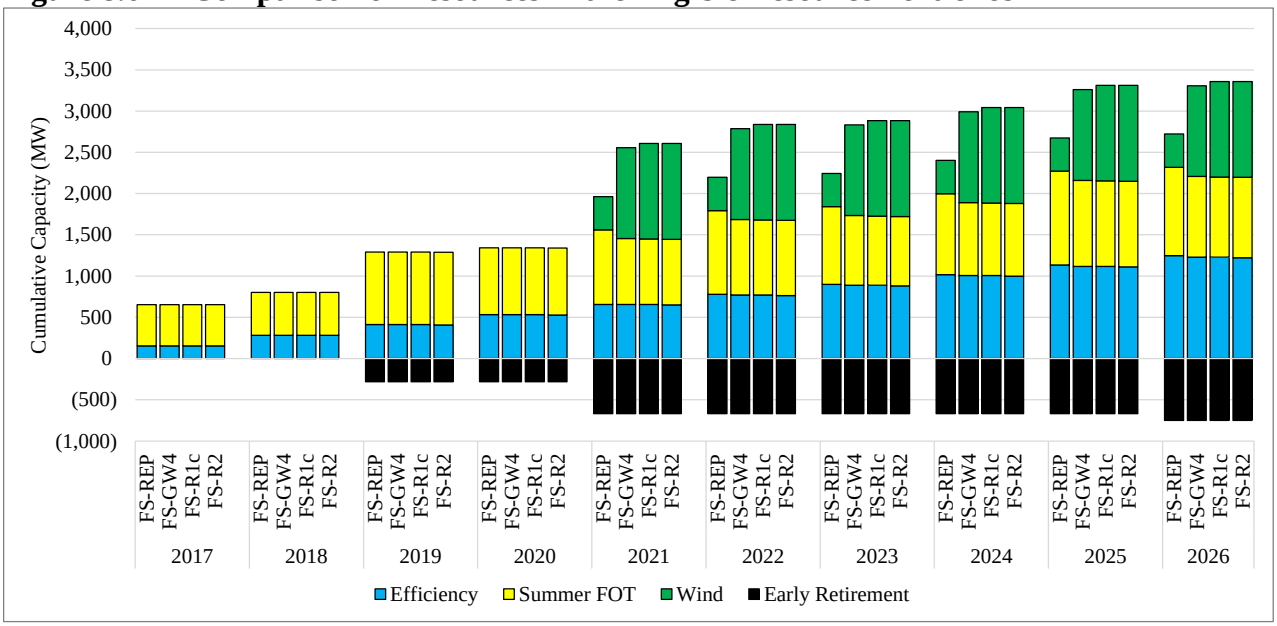
Fuel Source Diversity

Figure 8.61 summarizes the nameplate capacity of cumulative resource selection through 2026 among the portfolios considered for final selection. This figure illustrates the similarity among the

top performing portfolios through the first ten years of the planning period, when differences among portfolios are most likely to influence PacifiCorp's action plan. The FS-REP portfolio, without Energy Gateway transmission, contains less wind and more front-office transactions (FOTs). All of the Energy Gateway portfolios have nearly identical levels of energy efficiency, FOTs, and new wind resources.

The modest difference in new wind resource additions in 2021 in the FS-R1c case (57 MW of additional west-side wind) is driven by the Washington RPS program.[4] Considering banking restrictions in the Washington RPS program, the addition of this incremental 2021 west-side wind resource contributes to over-compliance for the Washington RPS later in the planning horizon when system renewable resources located in the Washington Utilities and Transportation Commission (WUTC) West Control Area (WCA) are added to the resource mix. In the FS-R2 case, an additional 61 MW of Idaho wind is added to the portfolio to offset a potential Oregon RPS shortfall that would otherwise occur beyond 2034, once accounting for system renewable resources already included in the resource mix.

Figure 8.61 – Comparison of Resources in the Eligible Resource Portfolios

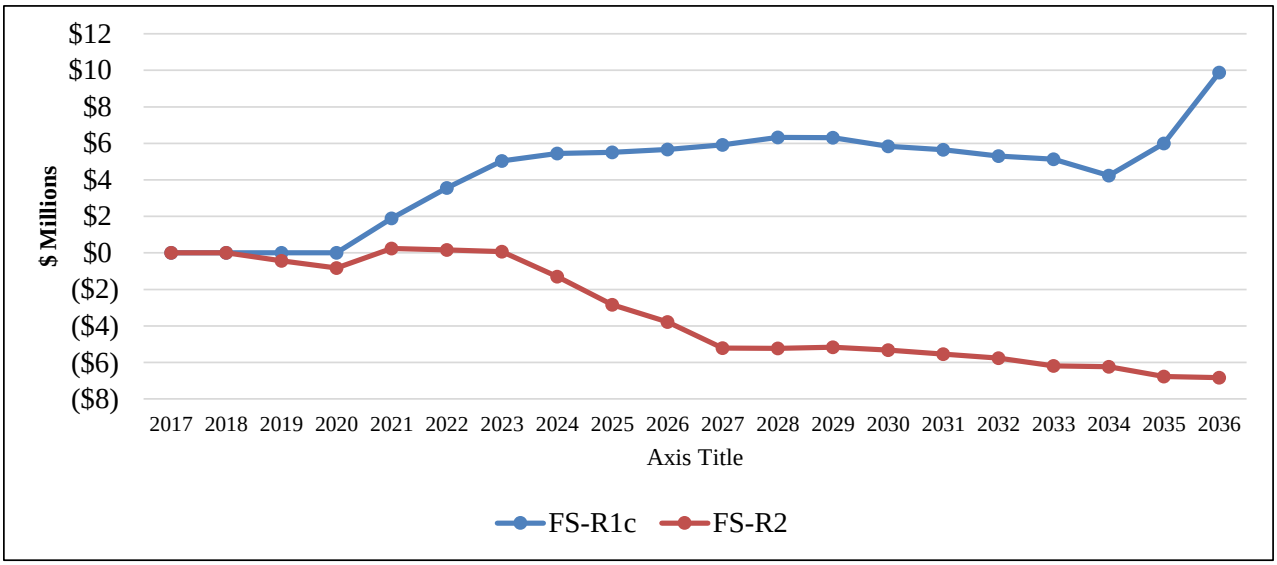


Customer Rate Impacts

Figure 8.62 shows the difference in cumulative PVRR between FS-R1c and FS-R2 relative to case FS-GW4 under base case emissions-price assumptions. Through year 2023, FS-R2 tracks closely with FS-GW4, while FS-R1c reports a higher, albeit relative small, and escalating cost. After 2023, FS-R2 improves while FS-R1c continues to be unfavorable. FS-R1c sees a spike in unfavorable PVRR in the final two years, coinciding with the addition of incremental west-side wind needed to achieve RPS requirements. Over the 20-year study horizon, FS-R2 yields a small aggregate cumulative benefit relative to FS-GW4 (~$7m PVRR, a 0.029 percent reduction relative to FS-GW4). As this benefit occurs farther out the curve, it is not only small but is also more speculative.

[4] Under FS-R1c and FS-R2, system renewable resources in the portfolio eliminate any need for incremental renewable resources in the front ten years of the planning period.

Figure 8.62 – Change in the Cumulative PVRR relative to FS-GW4



Preferred Portfolio Selection

Informed by all of the analysis used to compare resource portfolios throughout the three-stage screening process, PacifiCorp has selected case FS-GW4 as the preferred portfolio for its 2017 IRP. PacifiCorp's preferred portfolio selection is based on the following:

- The preferred portfolio reflects Regional Haze compliance assumptions consistent with least-cost, least-risk comparative analysis performed in the first screening stage of the selection process.
- The preferred portfolio incorporates the wind repowering project as supported by additional core case and sensitivity analysis performed during the second screening stage of the selection process.
- The preferred portfolio includes Energy Gateway sub-segment D2, with associated incremental new Wyoming wind resources, based on updated analysis performed during the final screening stage of the selection process.
- The risk-adjusted PVRR and other stochastic metrics among portfolios that include the Energy Gateway sub-segment D2 transmission line in the final screening stage of the planning process are closely grouped, with an average variation in the risk-adjusted PVRR that is just 0.08 percent of the average system risk-adjusted PVRR.
    - Among these cases, case FS-GW4 produces the lowest system PVRR when analyzed in SO.
    - Variations in resources among these cases within the first ten years of the planning period would not alter PacifiCorp's 2017 IRP action plan.
    - Among these cases, case FS-GW4 mitigates near-term customer rate impacts caused by Oregon and Washington state RPS programs that result in situs-assigned costs for customers in these states.

The 2017 IRP Preferred Portfolio

The 2017 IRP preferred portfolio reflects a cost-conscious transition to a cleaner energy future. Table 8.16 shows that PacifiCorp's resource needs will be met with new renewable resources, demand side management (DSM) resources, and short-term firm market purchases (labeled as front-office transactions or FOTs) through 2028. Over the 20-year planning horizon, the preferred portfolio includes 1,959 MW of new wind resources, 905 MW of upgraded ("repowered") wind resources, 1,040 MW of new solar resources, 2,077 MW of incremental energy efficiency resources, and 365 MW of new direct load control capacity.

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

Table 8.16 – 2017 IRP Preferred Portfolio Summary (Nameplate MW)

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

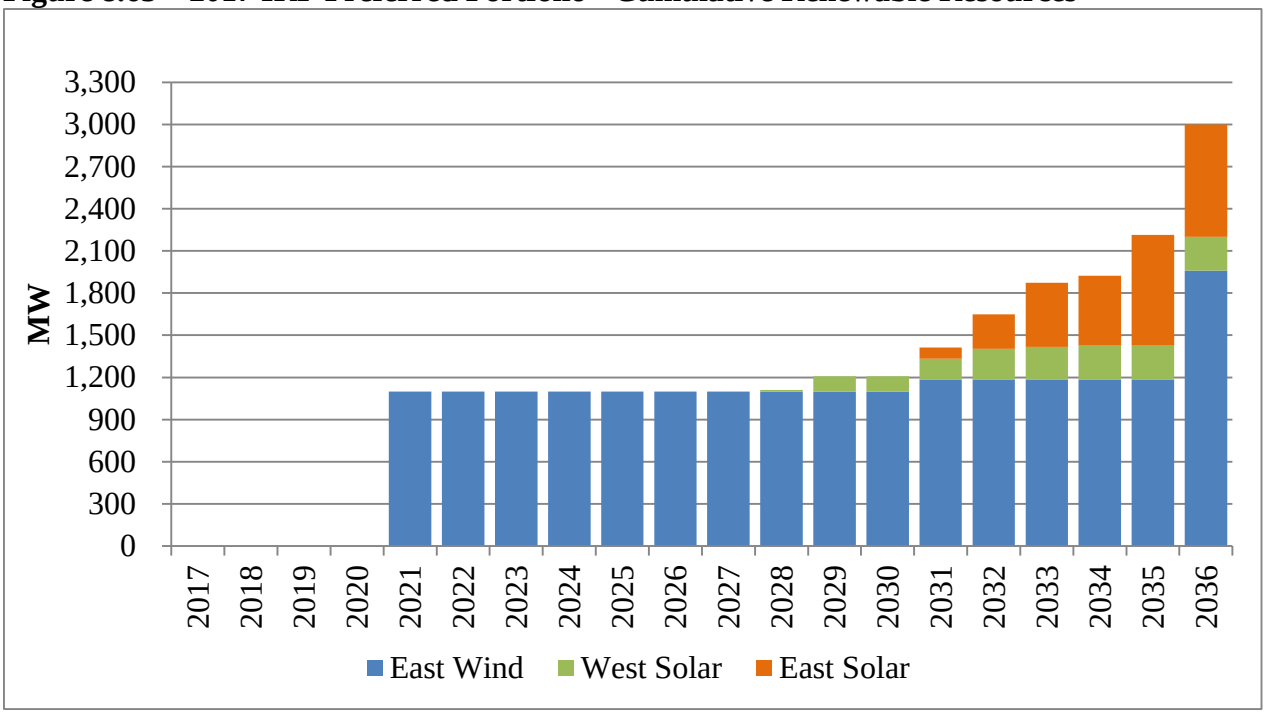
*Note: Energy efficiency resource capacity reflects projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply side resource. FOTs are short-term firm market purchases delivered only in the year shown. Reductions in existing coal and natural gas capacity are shown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

New Renewable Resources and Transmission

Figure 8.63 reports the cumulative renewables additions across the 20-year study horizon. The 2017 IRP preferred portfolio advances PacifiCorp's commitment to low-cost clean energy with plans to add 1,100 MW of new Wyoming wind resources by the end of 2020. These new zero-emission wind facilities will connect to a new 140-mile, 500 kV transmission line running from the Aeolus substation near Medicine Bow, Wyoming, to the Jim Bridger power plant (a sub-segment of the Energy Gateway West transmission project). This time-sensitive project requires that the new wind and transmission assets achieve commercial operation by the end of 2020 to maximize PTC benefits. In addition to providing significant economic benefits for PacifiCorp's customers, the wind and transmission project will provide extraordinary economic development benefits to the state of Wyoming.

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

Figure 8.63 – 2017 IRP Preferred Portfolio - Cumulative Renewable Resources



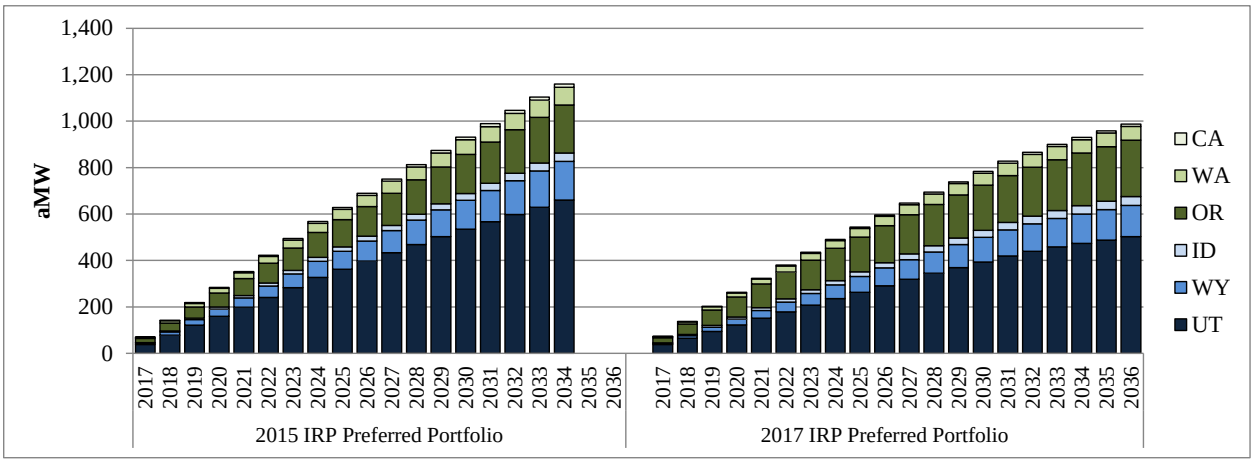
Wind Repowering

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

Demand Side Management

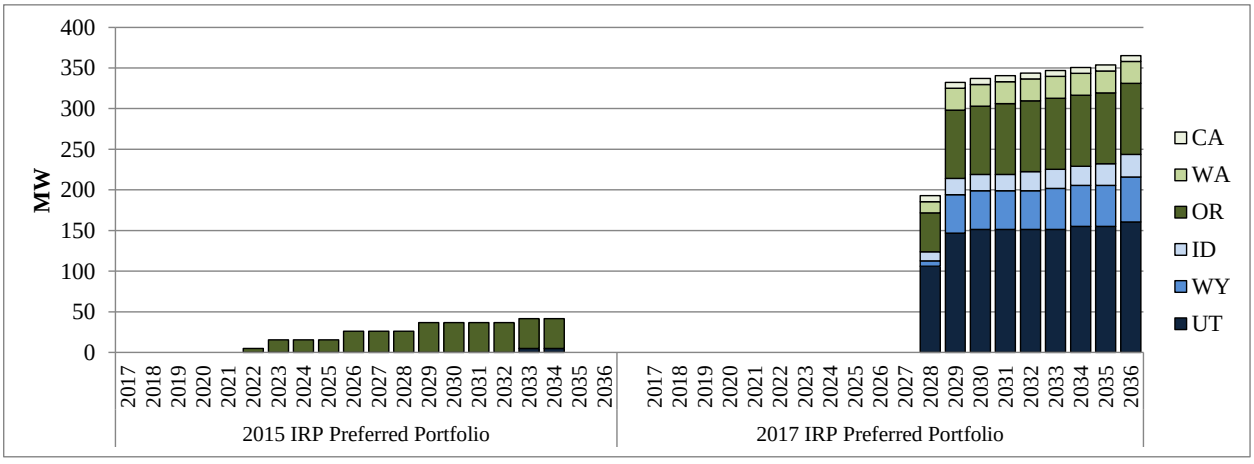
DSM resources continue to play a key role in PacifiCorp's resource mix. Over the first ten years of the planning horizon, accumulated acquisition of incremental energy efficiency resources meets 88 percent of forecasted load growth from 2017 through 2026 (up from 86 percent in the 2015 IRP). Figure 8.64 compares total energy efficiency savings by state in the 2017 IRP preferred portfolio relative to the 2015 IRP preferred portfolio. Decreased selection of energy efficiency resources relative to the 2015 IRP is driven by reduced loads and reduced costs for wholesale market power purchases and renewable resource alternatives.

Figure 8.64 – Comparison of Total Energy Efficiency Savings between the 2017 IRP Preferred Portfolio and the 2015 IRP Preferred Portfolio



In addition to continued investment in energy efficiency programs, the preferred portfolio identifies an increasing role for direct load control programs with total capacity reaching 365 MW by the end of the planning period. Figure 8.65 compares total incremental direct load control program capacity by state in the 2017 IRP preferred portfolio relative to the 2015 IRP preferred portfolio. The significant increase in direct load control capacity and expansion of programs among states is coincident with assumed coal unit retirements, signaling the importance of these capacity-based programs in PacifiCorp's transitioning resource mix.

Figure 8.65 – Comparison of Total Direct Load Control Capacity between the 2017 IRP Preferred Portfolio and the 2015 IRP Preferred Portfolio

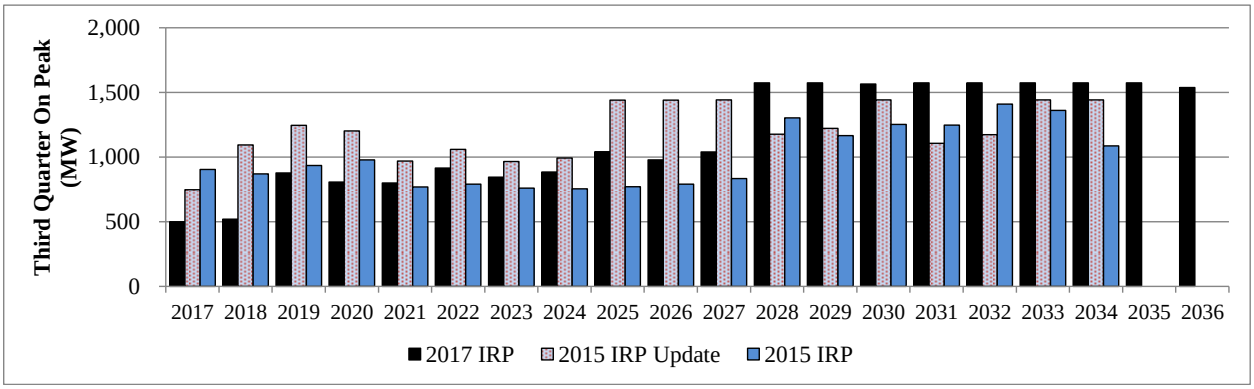


Wholesale Power Market Purchases

Figure 8.66 compares wholesale market firm purchases from the 2017 IRP preferred portfolio to the market purchases included in the preferred portfolio of recent IRPs. While market conditions for firm wholesale power purchases are favorable, reduced loads and continued investment in energy efficiency programs reduce the need for wholesale power purchases relative to the 2015 IRP Update through 2027. Over this period, average annual wholesale power purchases are down by 27 percent relative to the 2015 IRP Update and on par with wholesale power purchases projected in the 2015 IRP. Longer term, wholesale power purchases increase coincident with

assumed coal unit retirements. In this 2017 IRP, PacifiCorp has evaluated regional resource adequacy and believes its wholesale power purchase limits are reasonable. PacifiCorp will continue to monitor potential shortfalls in regional supply through its on-going planning process.

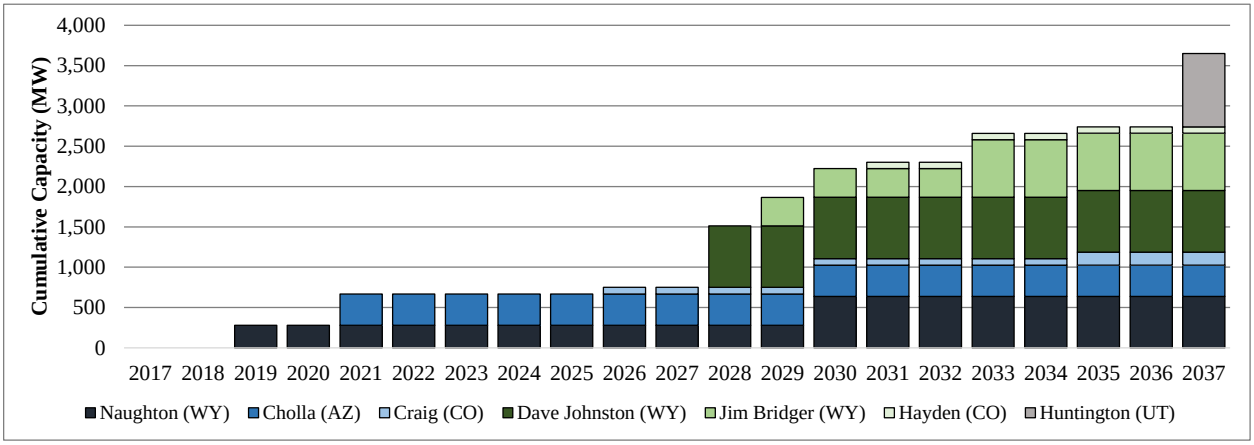
Figure 8.66 – Comparison of Summer Market Purchases among Recent IRPs



Existing Coal Resources

Supported by analysis of potential Regional Haze compliance alternatives, the 2017 IRP preferred portfolio does not include any incremental SCR equipment throughout the planning horizon. Avoiding installation of this equipment will save customers hundreds of millions of dollars and retain compliance-planning flexibility associated with the CPP or other potential state and federal environmental policies. As in past IRPs, the 2017 IRP studies a range of Regional Haze compliance scenarios, reflecting potential bookend alternatives that consider early retirement outcomes as a means to avoid installation of expensive SCR equipment. The individual unit-specific outcomes assumed in the 2017 IRP preferred portfolio will ultimately be determined by on-going rulemaking, results of litigation, and future negotiations with state and federal agencies, partner plant owners, and other vested stakeholders. Consequently, individual unit retirements reflected in the preferred portfolio, while reasonable for planning purposes, are not firm commitments for early unit closures. Figure 8.67 summarizes coal unit retirements assumed in the preferred portfolio. By the end of the planning horizon, PacifiCorp assumes 3,650 MW of existing coal capacity will be retired.

Figure 8.67 – 2017 IRP Preferred Portfolio Coal Unit Retirements



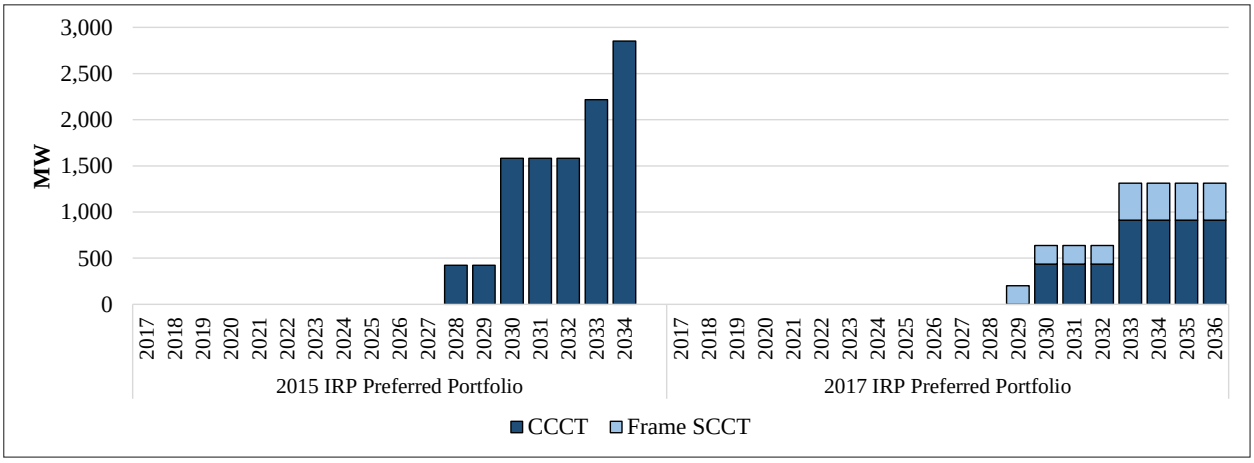
*Note: Retired capacity is reported in the first year in which the unit is no longer available to meet summer coincident peak load.

Reflecting an updated operating permit from the state of Wyoming, PacifiCorp assumes Naughton Unit 3 retires at the end of 2018—one year later than in the 2015 IRP Update. PacifiCorp will continue to review emerging technologies, re-assess traditional gas conversion technologies and costs, and consider other potential alternatives that could be applied to Naughton Unit 3 to allow continued operation beyond year-end 2018 if proven to be cost effective for customers. PacifiCorp's analysis also assumes Cholla Unit 4 retires at the end of 2020. This early closure assumption was considered in PacifiCorp's Regional Haze compliance analysis to account for changes in market conditions, characterized by reduced loads and wholesale power prices. As with Naughton Unit 3, PacifiCorp will continue to analyze potential early closure scenarios for Cholla Unit 4 as part of its on-going planning process. Longer term, the preferred portfolio reflects an early retirement of Craig Unit 1 at the end of 2025, Jim Bridger Unit 1 at the end of 2028, and Jim Bridger Unit 2 at the end of 2032. Assumed end-of-life retirements include four units at the Dave Johnston plant at the end of 2027, Naughton Units 1 and 2 at the end of 2029, Hayden at the end of 2030, Craig Unit 2 at the end of 2034, and two units at the Huntington plant at the end of 2036.

Natural Gas Resources

Figure 8.68 compares total new natural gas-fired resource capacity in the 2017 IRP preferred portfolio relative to the 2015 IRP preferred portfolio. The first natural gas resource, a 200 MW frame simple cycle combustion turbine (SCCT), is added to the portfolio in 2029—one year later than the first natural gas resource in the 2015 IRP. The first CCCT, a 436 MW G-class 1x1, is added to the system in 2030—two years later than the first CCCT in the 2015 IRP. In aggregate, the 2017 IRP preferred portfolio includes 1,313 MW of new natural gas-fired capacity, a reduction of 1,540 MW of natural gas resources relative to the 2015 IRP preferred portfolio. Reduced loads, on-going investment in energy efficiency programs, and increased renewables reduce the need for new natural gas resources in the 2017 IRP. Recognizing the long time horizon before the first natural gas plant is added, PacifiCorp will continue to evaluate potential long-term supply alternatives, including the potential penetration of energy storage, through its on-going resource planning efforts.

Figure 8.68 – Comparison of Total New Natural Gas Resources between the 2017 IRP Preferred Portfolio and the 2015 IRP Preferred Portfolio



Capacity and Energy

Figure 8.69 graphically displays how preferred portfolio resources meet PacifiCorp's capacity needs over time. Through 2026, PacifiCorp meets its capacity needs, including a 13 percent target planning reserve margin, through incremental acquisition of new DSM and wind resources and through wholesale power market purchases.

Figure 8.69 – Meeting PacifiCorp's Capacity Needs with Preferred Portfolio Resources

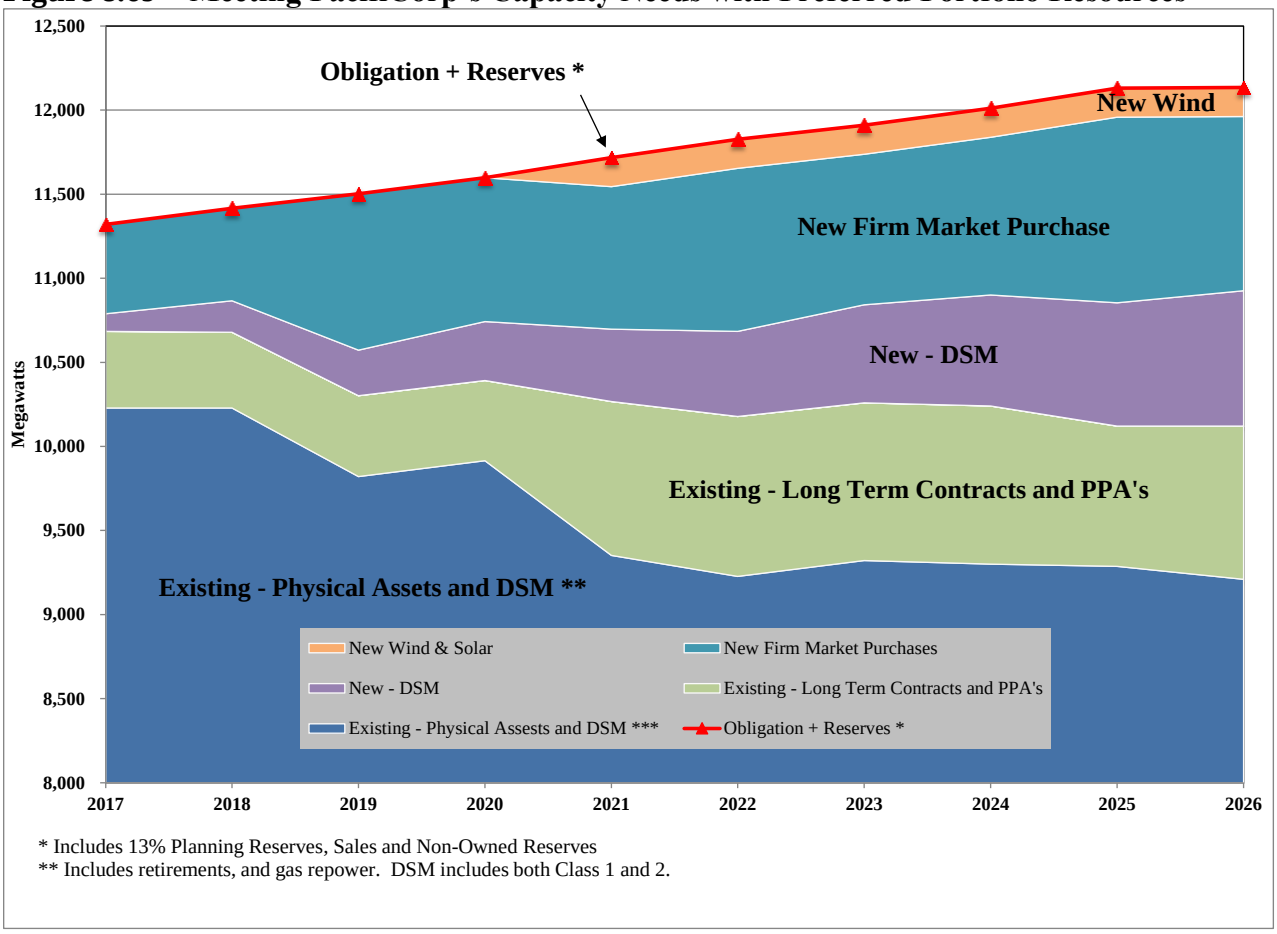


Figure 8.70 and Figure 8.71 show how PacifiCorp's system energy and nameplate capacity mix is projected to change over time. In developing these figures, purchased power is reported in identifiable resource categories where possible. Energy mix figures are based upon base price curve assumptions. Renewable capacity and generation reflect categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.[5] On an energy basis, coal generation drops below 50 percent by 2025, falls to 38 percent by 2030, and declines to 32 percent by the end of the planning period. On a capacity basis, coal resources drop

[5]The projected PacifiCorp 2017 IRP preferred portfolio "energy mix" is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with wind, biomass, geothermal and qualifying hydro facilities in PacifiCorp's energy mix may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements; (b) sold to third parties in the form of renewable energy credits or other environmental commodities; or (c) excluded from energy purchased. PacifiCorp's 2017 IRP preferred portfolio energy mix includes owned resources and purchases from third parties.

to 31 percent by 2025, fall to 21 percent by 2030, and decline to 16 percent by the end of the planning period. Reduced energy and capacity from coal is offset primarily by increased energy and capacity from renewable resources, DSM resources, and longer-term, new natural gas resources.

Figure 8.70 – Projected Energy Mix with Preferred Portfolio Resources

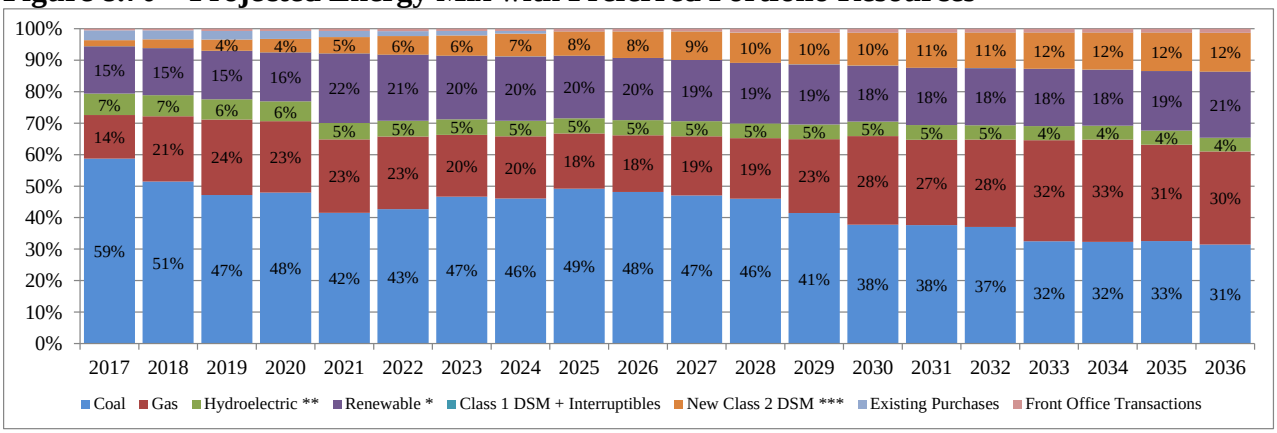
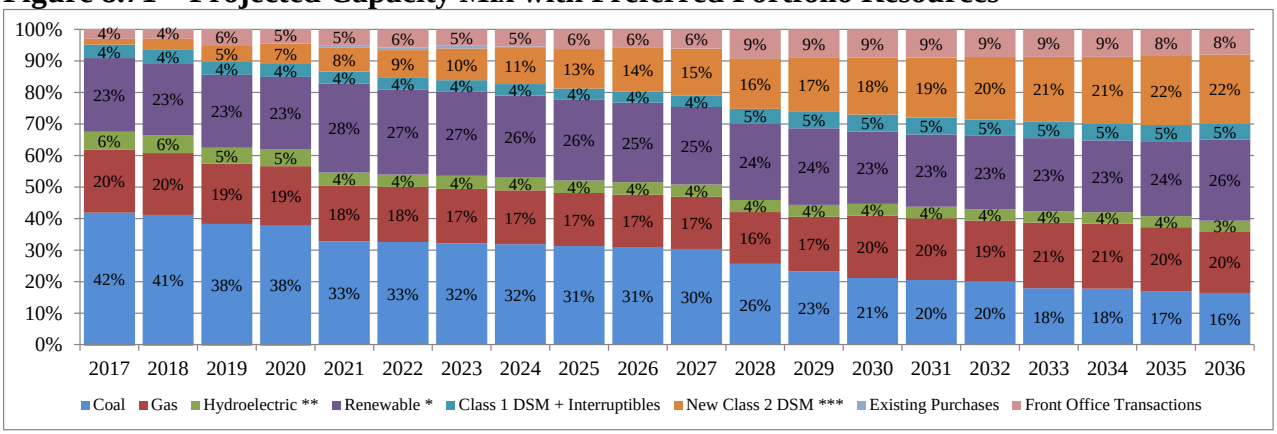


Figure 8.71 – Projected Capacity Mix with Preferred Portfolio Resources



Renewable Portfolio Standards

Figure 8.72 shows PacifiCorp's RPS compliance forecast for California, Oregon, and Washington after accounting for the wind repower project and new renewable resources in the preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources, they also contribute to meeting RPS targets in PacifiCorp's western states.

Oregon RPS compliance is achieved through 2034 with the addition of repowered wind and new renewable resources and transmission in the 2017 IRP preferred portfolio. A small increment of annual unbundled REC purchases, labeled "Unbundled Surrendered" in Figure 8.72 below, beginning at under 160,000 RECs in 2018 is required to achieve Oregon RPS compliance through 2036.

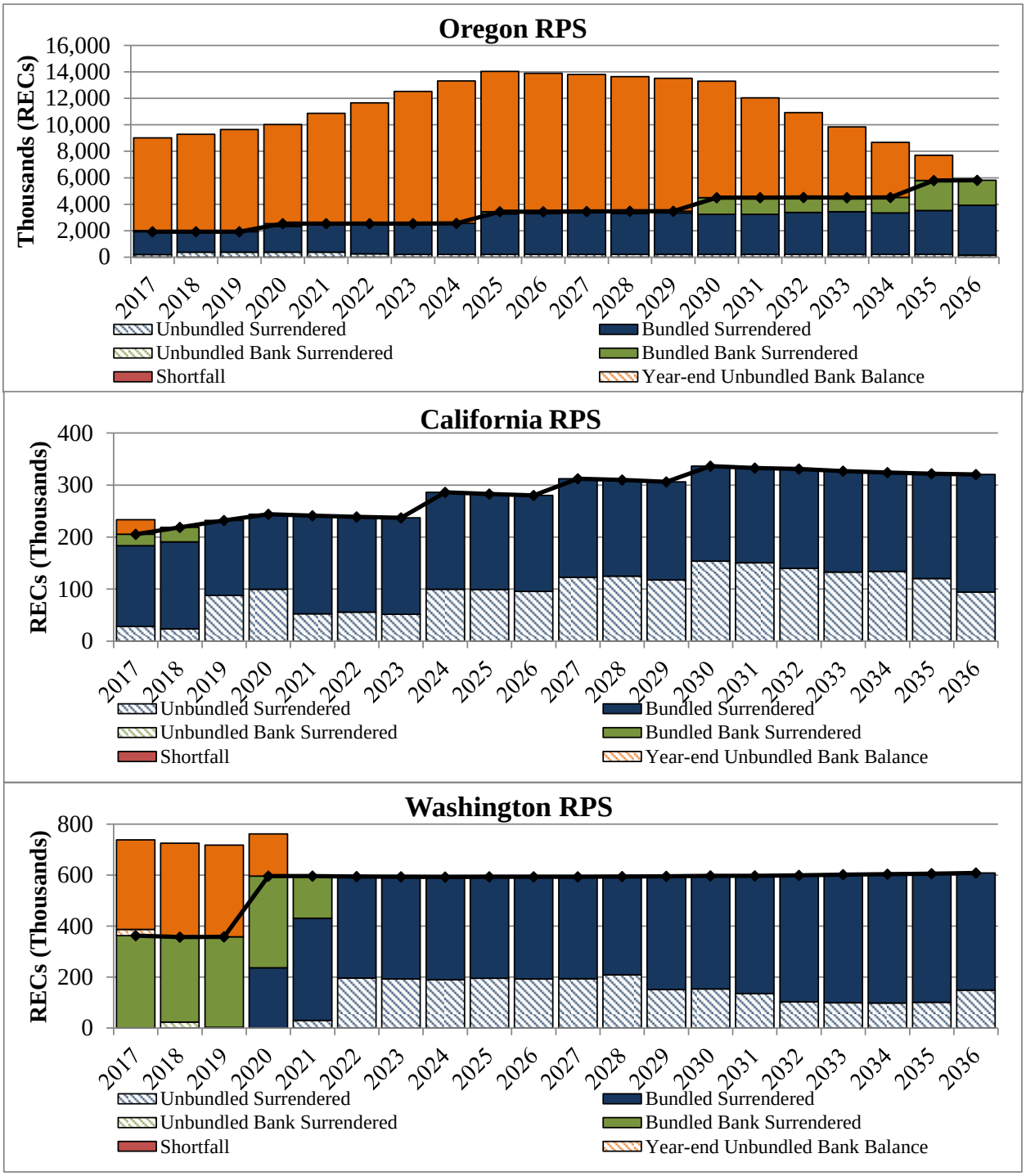
The California RPS compliance position is also improved by the addition of repowered wind, new renewable resources and transmission in the 2017 IRP preferred portfolio and similarly requires a

small amount of unbundled REC purchases under 150,000 RECs per year to achieve compliance through the planning horizon.

Washington RPS compliance is achieved with the benefit of the repowered wind assets located in the west side, Marengo and Leaning Juniper, new renewable resources added to the west side beginning 2028, and unbundled REC purchases under 200,000 RECs per year. Under current allocation mechanisms, Washington customers do not benefit from the repowered wind and new renewable resources added to the east side of PacifiCorp's system. Under an alternative allocation mechanism, in which Washing receives its system-allocated share of repowered wind and new wind located in Wyoming, Washington RPS targets would be met without the need for any incremental unbundled REC purchases throughout the 20-year planning period.

While not shown in Figure 8.72, PacifiCorp meets the Utah 2025 state target to supply 20 percent of adjusted retail sales with eligible renewable resources with existing owned and contracted resources before considering the addition of repowered wind, new renewable resources and transmission in the 2017 IRP preferred portfolio.

Figure 8.72 – Annual State RPS Compliance Forecast

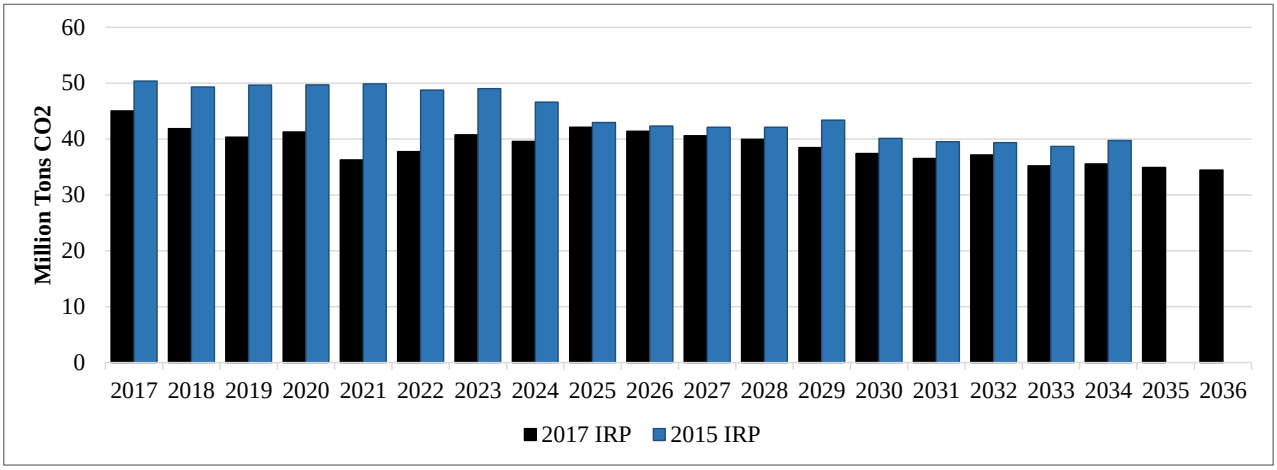


Carbon Dioxide Emissions

The 2017 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean energy solutions for our customers and accordingly reflects a continued trajectory of declining CO_2 emissions. PacifiCorp's emissions have been declining and continue to decline as a result of a number of factors including, PacifiCorp's participation in the EIM that reduces customer costs and maximizes use of clean energy, PacifiCorp's on-going expansion of renewable resources

and transmission, and Regional Haze compliance that leverages flexibility. Figure 8.73 compares projected annual CO_2 emissions between the 2017 IRP and 2015 IRP preferred portfolios (as reported by PaR). Over the first 10 years of the planning horizon, average annual CO_2 emissions are down by over 10.5 million tons (21 percent) relative to the 2015 IRP. By the end of the planning horizon, system CO_2 emissions are projected to fall from 43.8 million tons in 2017 to 33.1 million tons in 2036—a reduction of 24.5 percent.

Figure 8.73 – Comparison of CO_2 Emission Forecasts between the 2017 IRP Preferred Portfolio and the 2015 IRP Preferred Portfolio



Detailed Preferred Portfolio

Table 8.17 provides line-item detail of PacifiCorp's 2017 IRP preferred portfolio showing new resource capacity along with changes in existing resource capacity through the 20-year planning horizon. Table 8.18 and Table 8.19 show line-item detail of PacifiCorp's peak load and resource capacity balance for summer and winter (respectively) including preferred portfolio resources, through the first ten years of the planning horizon.

Table 8.17 – PacifiCorp's 2017 IRP Preferred Portfolio[6]

		Capacity (MW)																				Resource Totals 1/	
	Resource	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	774	-	774
	Wind, WYAE	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,100	1,100
	Total Wind	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	85	-	-	-	-	774	1,100	1,959
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	79	167	210	41	291	13	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	34.8	40.5	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	123.8	90.5	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	63	65	65	61	57	57	59	49	44	37	34	35	642	1,139
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	11	11	11	11	9	8	7	7	7	121	216
	DSM, Class 2 Total	97	74	79	75	81	77	85	85	82	84	82	77	73	73	74	62	55	47	44	44	819	1,450
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	300	291	300	300	300	300	300	300	3	137
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	11	97	-	38	70	16	8	-	-	-	240
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	49.1	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	10	9	9	9	8	8	7	7	6	5	5	4	3	3	2	2	88	132
	DSM, Class 2 Total	57	53	52	46	42	37	33	33	29	27	27	25	23	23	22	21	20	19	19	18	410	627
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	3	-	-	41	-	10	167	76	137	400	400	400	400	400	400	400	400	364	30	200
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	21	375	307	299	375	344	375	375	375	375	375	375	375	375	375	375	375	375	375	285	330
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	332	273	307	-	308	-	287	295	-	-	-	400	41	390	351	-	377	4	291	208	197
	FOT MidColumbia - WTR2	-	-	-	-	319	-	306	-	-	297	289	312	51	375	-	-	337	-	375	375	92	152
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	1,223	114	118	118	112	111	109	306	563	536	303	323	980	117	356	861		
	Annual Additions, Short Term Resources	781	853	1,151	1,115	1,118	1,223	1,150	1,172	1,390	1,329	1,336	1,987	2,126	2,081	2,065	2,026	2,012	2,052	2,054	2,305		
	Total Annual Additions	935	981	1,282	1,236	2,341	1,337	1,268	1,289	1,501	1,440	1,445	2,293	2,688	2,618	2,368	2,349	2,992	2,169	2,411	3,166		

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

[6] The 2017 Preferred Portfolio includes repowering 905 MW of existing wind resources, not shown in the table

Table 8.18 – Preferred Portfolio Summer Capacity Load and Resource Balance

Calendar Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
East										
Thermal	6,406	6,406	6,126	6,126	5,739	5,739	5,739	5,739	5,739	5,656
Hydroelectric	103	106	113	113	113	113	113	92	92	92
Renewable	199	193	200	201	199	191	191	191	191	181
Purchase	249	249	249	249	221	221	221	221	121	121
Qualifying Facilities	656	646	689	681	672	661	657	603	598	594
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sale	(652)	(652)	(652)	(652)	(172)	(172)	(172)	(146)	(146)	(63)
Non-Owned Reserves	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)
Transfers	286	315	505	544	360	412	420	485	630	543
East Existing Resources	**7,532**	**7,547**	**7,516**	**7,548**	**7,417**	**7,450**	**7,454**	**7,472**	**7,512**	**7,410**
Front Office Transactions	0	0	0	0	0	0	0	0	0	29
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	174	174	174	174	174	174
Solar	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**0**	**0**	**0**	**0**	**174**	**174**	**174**	**174**	**174**	**203**
East Total Resources	**7,532**	**7,547**	**7,516**	**7,548**	**7,591**	**7,624**	**7,628**	**7,646**	**7,685**	**7,612**
Load	7,008	7,093	7,141	7,231	7,331	7,420	7,485	7,564	7,661	7,663
Distributed Generation	(33)	(51)	(72)	(80)	(86)	(91)	(94)	(98)	(104)	(112)
Existing Resources:										
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
Class 2 DSM	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)
New Resources:										
Class 2 DSM	(72)	(124)	(179)	(232)	(289)	(343)	(402)	(461)	(518)	(575)
East obligation	**6,643**	**6,657**	**6,629**	**6,657**	**6,695**	**6,725**	**6,728**	**6,744**	**6,779**	**6,714**
Planning Reserves (13%)	889	891	887	891	896	900	900	902	907	898
East Reserves	**889**	**891**	**887**	**891**	**896**	**900**	**900**	**902**	**907**	**898**
East Obligation + Reserves	**7,532**	**7,547**	**7,516**	**7,548**	**7,591**	**7,624**	**7,628**	**7,646**	**7,685**	**7,612**
East Position	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
East Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
West										
Thermal	2,247	2,247	2,247	2,247	2,247	2,247	2,247	2,247	2,247	2,247
Hydroelectric	855	859	717	806	635	549	644	648	634	651
Renewable	92	91	91	95	95	65	65	60	60	59
Purchase	18	18	1	1	1	1	1	1	1	1
Qualifying Facilities	195	200	202	207	198	195	186	185	184	182
Class 1 DSM	3	3	3	3	0	0	0	0	0	0
Sale	(165)	(165)	(165)	(165)	(161)	(110)	(110)	(80)	(80)	(80)
Non-Owned Reserves	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Transfers	(287)	(316)	(506)	(545)	(361)	(413)	(421)	(486)	(631)	(544)
West Existing Resources	**2,957**	**2,935**	**2,589**	**2,648**	**2,653**	**2,531**	**2,610**	**2,573**	**2,413**	**2,515**
Front Office Transactions	532	552	931	856	847	971	895	938	1,105	1,008
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**532**	**552**	**931**	**856**	**847**	**971**	**895**	**938**	**1,105**	**1,008**
West Total Resources	**3,489**	**3,487**	**3,520**	**3,504**	**3,501**	**3,502**	**3,504**	**3,510**	**3,518**	**3,523**
Load	3,159	3,190	3,250	3,264	3,286	3,310	3,332	3,358	3,384	3,405
Distributed Generation	(5)	(7)	(10)	(11)	(13)	(15)	(17)	(19)	(22)	(24)
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
Class 2 DSM	(34)	(34)	(34)	(34)	(34)	(34)	(34)	(34)	(34)	(34)
New Resources:										
Class 2 DSM	(33)	(63)	(92)	(118)	(142)	(162)	(180)	(199)	(215)	(230)
West obligation	**3,087**	**3,086**	**3,115**	**3,101**	**3,098**	**3,099**	**3,101**	**3,106**	**3,114**	**3,117**
Planning Reserves (13%)	401	401	405	403	403	403	403	404	405	405
West Reserves	**401**	**401**	**405**	**403**	**403**	**403**	**403**	**404**	**405**	**405**
West Obligation + Reserves	**3,488**	**3,487**	**3,519**	**3,504**	**3,501**	**3,502**	**3,505**	**3,510**	**3,518**	**3,523**
West Position	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
West Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
System										
Total Resources	11,020	11,035	11,035	11,052	11,091	11,126	11,132	11,156	11,203	11,135
Obligation	9,730	9,743	9,743	9,758	9,793	9,824	9,829	9,850	9,892	9,831
Reserves	1,290	1,292	1,292	1,294	1,298	1,302	1,303	1,306	1,311	1,303
Obligation + Reserves	11,020	11,035	11,035	11,052	11,092	11,126	11,132	11,156	11,203	11,135
System Position	0	0	0	0	0	0	0	0	0	0
Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%

Table 8.19 – Preferred Portfolio Winter Capacity Load and Resource Balance

Calendar Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
East										
Thermal	6,514	6,514	6,234	6,234	5,847	5,847	5,847	5,847	5,847	5,764
Hydroelectric	71	72	72	72	72	72	72	72	72	72
Renewable	199	193	201	199	191	191	191	191	191	181
Purchase	734	734	734	734	235	235	235	121	121	121
Qualifying Facilities	647	688	680	676	668	658	604	600	595	591
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(170)	(170)	(170)	(170)	(170)	(170)	(170)	(146)	(146)	(63)
Non-Owned Reserves	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)
Transfers	100	27	(52)	48	(4)	(29)	(16)	(22)	(144)	(135)
East Existing Resources	**8,057**	**8,021**	**7,661**	**7,756**	**6,801**	**6,766**	**6,725**	**6,627**	**6,499**	**6,495**
Front Office Transactions	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	174	174	174	174	174	174
Solar	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**0**	**0**	**0**	**0**	**174**	**174**	**174**	**174**	**174**	**174**
East Total Resources	**8,057**	**8,021**	**7,661**	**7,756**	**6,975**	**6,940**	**6,899**	**6,800**	**6,673**	**6,669**
Load	5,550	5,617	5,686	5,597	5,770	5,847	5,923	5,956	5,919	5,924
Distributed Generation	(11)	(17)	(24)	(28)	(31)	(32)	(33)	(35)	(37)	(40)
Existing Resources:										
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
Class 2 DSM	(44)	(44)	(44)	(44)	(44)	(44)	(44)	(44)	(44)	(44)
New Resources:										
Class 2 DSM	(48)	(88)	(129)	(169)	(212)	(253)	(296)	(339)	(382)	(425)
East obligation	**5,252**	**5,274**	**5,294**	**5,161**	**5,288**	**5,323**	**5,355**	**5,343**	**5,262**	**5,220**
Planning Reserves (13%)	708	711	714	696	713	717	721	720	709	704
East Reserves	**708**	**711**	**714**	**696**	**713**	**717**	**721**	**720**	**709**	**704**
East Obligation + Reserves	**5,961**	**5,985**	**6,007**	**5,857**	**6,001**	**6,040**	**6,076**	**6,063**	**5,971**	**5,924**
East Position	**2,096**	**2,036**	**1,654**	**1,898**	**974**	**900**	**822**	**737**	**702**	**745**
East Reserve Margin	53%	52%	45%	50%	32%	30%	29%	27%	27%	28%
West										
Thermal	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308
Hydroelectric	993	915	943	937	784	782	783	779	786	786
Renewable	92	91	95	95	95	65	65	60	59	58
Purchase	6	1	1	1	1	1	1	1	1	1
Qualifying Facilities	200	192	195	197	190	183	177	176	175	171
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(162)	(162)	(162)	(154)	(154)	(113)	(113)	(81)	(81)	(81)
Non-Owned Reserves	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Transfers	(101)	(28)	51	(49)	3	28	15	21	143	134
West Existing Resources	**3,335**	**3,316**	**3,431**	**3,335**	**3,227**	**3,251**	**3,233**	**3,262**	**3,389**	**3,375**
Front Office Transactions	298	352	289	326	338	326	324	304	368	372
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**298**	**352**	**289**	**326**	**338**	**326**	**324**	**304**	**368**	**372**
West Total Resources	**3,633**	**3,668**	**3,720**	**3,661**	**3,565**	**3,577**	**3,558**	**3,566**	**3,758**	**3,747**
Load	3,264	3,290	3,305	3,416	3,359	3,378	3,399	3,416	3,540	3,557
Distributed Generation	(1)	(2)	(2)	(3)	(3)	(3)	(4)	(4)	(5)	(6)
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
Class 2 DSM	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)
New Resources:										
Class 2 DSM	(37)	(72)	(107)	(137)	(164)	(188)	(210)	(231)	(249)	(267)
West obligation	**3,188**	**3,180**	**3,160**	**3,239**	**3,155**	**3,149**	**3,149**	**3,144**	**3,249**	**3,247**
Planning Reserves (13%)	414	413	411	421	410	409	409	409	422	422
West Reserves	**414**	**413**	**411**	**421**	**410**	**409**	**409**	**409**	**422**	**422**
West Obligation + Reserves	**3,603**	**3,593**	**3,571**	**3,661**	**3,565**	**3,559**	**3,558**	**3,553**	**3,671**	**3,670**
West Position	**30**	**75**	**149**	**0**	**0**	**19**	**0**	**13**	**87**	**77**
West Reserve Margin	14%	15%	18%	13%	13%	14%	13%	13%	16%	15%
System										
Total Resources	11,690	11,688	11,381	11,416	10,540	10,517	10,456	10,366	10,431	10,415
Obligation	8,441	8,453	8,453	8,400	8,443	8,472	8,503	8,487	8,511	8,467
Reserves	1,123	1,124	1,124	1,117	1,123	1,127	1,131	1,129	1,132	1,126
Obligation + Reserves	9,564	9,578	9,578	9,518	9,566	9,599	9,634	9,616	9,643	9,593
System Position	2,126	2,111	1,803	1,898	974	919	822	750	788	822
Reserve Margin	38%	38%	35%	36%	25%	24%	23%	22%	23%	23%

Additional Sensitivity Analysis

In addition to the resource portfolios developed and studied as part of the three-step screening process used to select the preferred portfolio, a number of additional sensitivity cases were completed to better understand how certain modeling assumptions influence the resource mix and timing of future resource additions. These sensitivity cases are useful in understanding how PacifiCorp's resource plan would be affected by changes to uncertain planning assumptions and to address how alternative resources and planning paradigms affect system costs and risk.

Table 8.20 lists additional sensitivity studies performed for the 2017 IRP. To isolate the impact of a given planning assumption, each sensitivity case is compared to a benchmark, which was established during different stages of the portfolio development and selection processes outlined earlier in this chapter. Each benchmark case coincides with a resource portfolio developed during the three-stage portfolio selection process adopted for the 2017 IRP. Sensitivities benchmarked to the case labeled as "OP-1" in the table below, were performed before selecting the top performing portfolio from the first screening stage used to establish the 2017 IRP Regional Haze compliance assumptions. The OP-1 case is Regional Haze case 5 (RH-5), the top performing portfolio from the initial screening process before adopting alternative Regional Haze compliance assumptions for Naughton Unit 3 as used in Regional Haze case 5a (which became case OP-NT3 in the second stage of the portfolio selection process).

Table 8.20 – Summary of Additional Sensitivity Cases

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

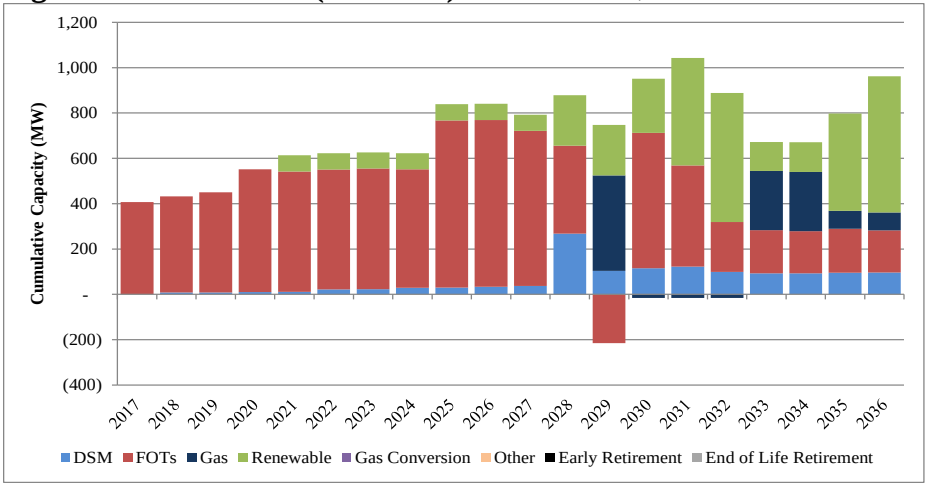
1-in-20 Load Growth Sensitivity (Case LD-1)

Table 8.21 shows the PVRR impacts of the LD-1 sensitivity relative to case OP-1. This sensitivity assumes 1-in-20 extreme weather conditions during the summer (July) for each state. System costs are higher due to requirements to meet additional peak load. Figure 8.74 summarizes resource portfolio impacts. Higher peak loads require more FOTs, renewables (+600 MW), DSM (+96 MW), and natural gas resources (+79 MW) by end of study period.

Table 8.21 – PVRR Cost/(Benefit) of LD-1 vs. OP-1

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
Change from Case 1 (OP-1)	$187	$266

Figure 8.74 – Increase/(Decrease) in Resources, LD-1 vs. OP-1



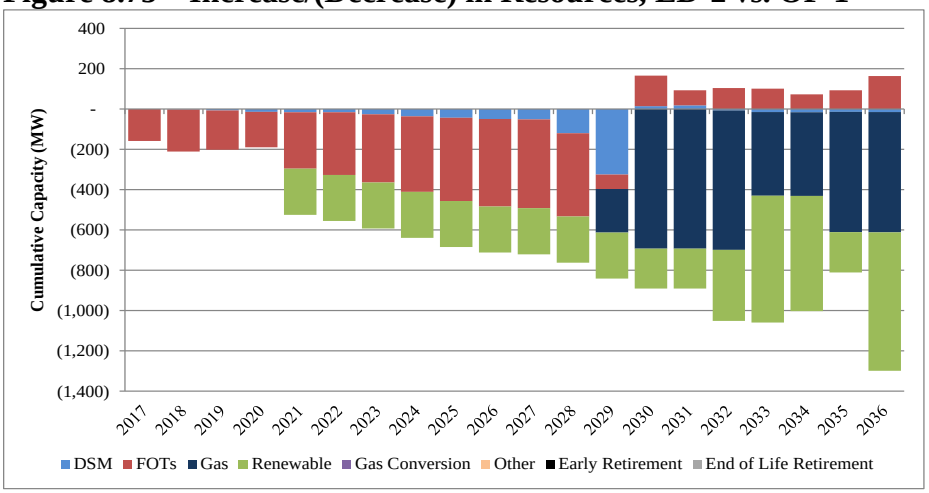
Low Load Growth Sensitivity (Case LD-2)

Table 8.22 shows the PVRR impacts of the LD-2 sensitivity relative to case OP-1. The reduced loads lower system costs significantly over the 20-year study period. Figure 8.75 summarizes portfolio impacts. FOTs are reduced by an average of 294 MW through 2029, and increase by an average of 109 MW thereafter with reduced gas and renewable resources. Renewable resources are reduced by 687 MW by the end of the study period. Natural gas resource capacity is down by 597 MW by the end of the study period.

Table 8.22 – PVRR Cost/(Benefit) of LD-2 vs. OP-1

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
Change from Case 1 (OP-1)	($1,610)	($1,771)

Figure 8.75 – Increase/(Decrease) in Resources, LD-2 vs. OP-1



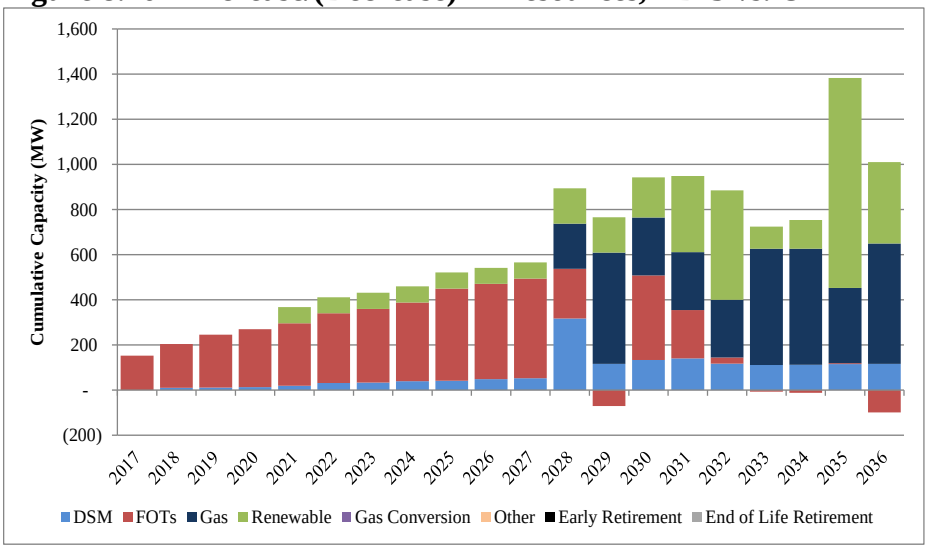
High Load Growth Sensitivity (Case LD-3)

Table 8.23 shows the PVRR impacts of the LD-3 sensitivity relative to case OP-1. Higher loads result in significantly increased system costs. Figure 8.76 summarizes resource portfolio impacts. FOTs increase by an average of 299 MW through 2028 while renewable resources increase by 71 MW in 2021 and rise to an additional 360 MW by the end of the study period. An additional 200 MW of natural gas capacity shows up in 2028, with 533 MW of additional gas-fired capacity by 2036. DSM increases by 116 MW by the end of the study period.

Table 8.23 – PVRR Cost/(Benefit) of LD-3 vs. OP-1

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
Change from Case 1 (OP-1)	$1,641	$1,799

Figure 8.76 – Increase/(Decrease) in Resources, LD-3 vs. OP-1



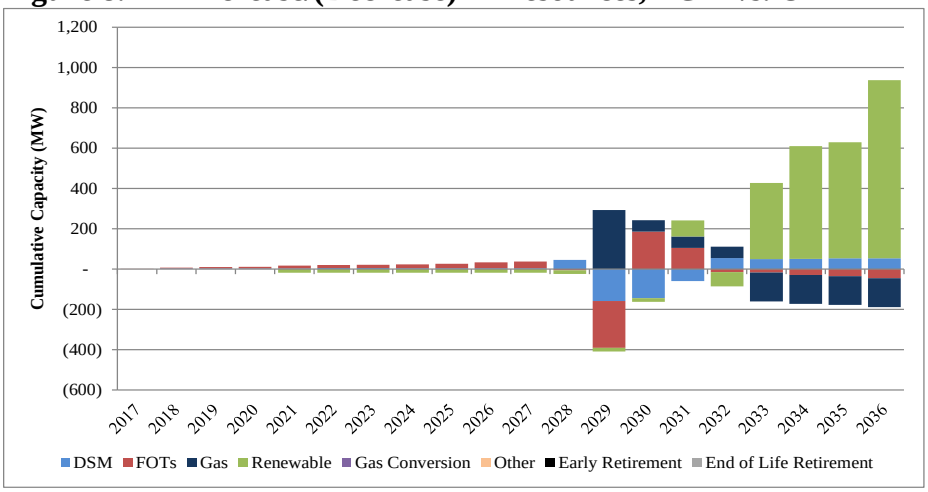
Low Private Generation Sensitivity (Case PG-1)

Table 8.24 shows the PVRR impacts of the PG-1 sensitivity relative to case OP-1. The lower private generation assumption results in higher net loads increasing system costs. Figure 8.77 summarizes portfolio impacts, which are minor through 2028. Over the long-term, this sensitivity produces more renewable capacity (883 MW) and less natural gas capacity (143 MW).

Table 8.24 – PVRR Cost/(Benefit) of PG-1 vs. OP-1

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
Change from Case 1 (OP-1)	$127	$168

Figure 8.77 – Increase/(Decrease) in Resources, PG-1 vs. OP-1



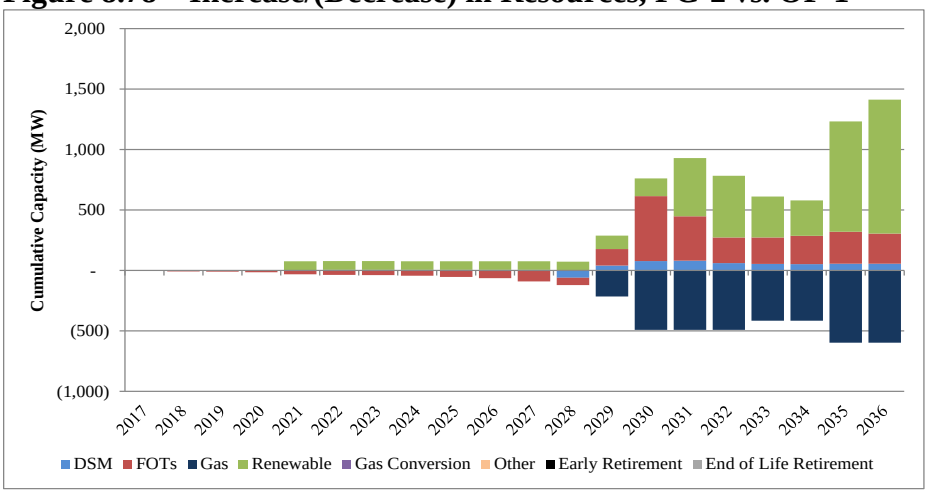
High Private Generation Sensitivity (Case PG-2)

Table 8.25 shows the PVRR impacts of the PG-2 sensitivity relative to case OP-1. The higher private generation assumptions decrease net load, which in turn decreases system costs. Figure 8.78 summarizes portfolio impacts, which are minor through 2028. Over the long-term, there is more renewable capacity (1,108 MW) and less natural gas-fired capacity (597 MW).

Table 8.25 – PVRR Cost/(Benefit) of PG-2 vs. OP-1

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
Change from Case 1 (OP-1)	($278)	($273)

Figure 8.78 – Increase/(Decrease) in Resources, PG-2 vs. OP-1



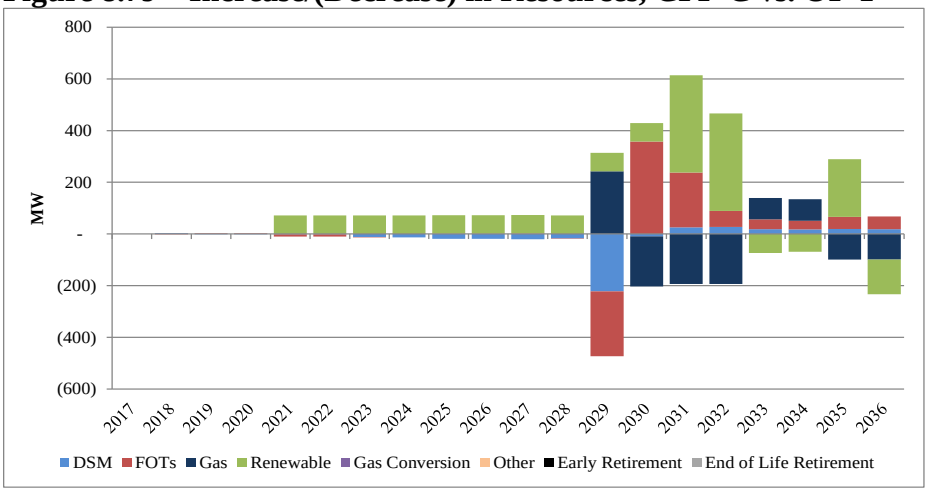
CPP Mass Cap C Sensitivity (Case CPP-C)

Table 8.26 shows the PVRR impacts of the CPP-C sensitivity relative to case OP-1. For the Mass Cap C sensitivity, PacifiCorp does not receive any allocation of set-asides and the emissions cap is assumed to only apply to existing resources. High natural gas prices put upward pressure on the mass cap (higher coal dispatch), which increases the cost of this sensitivity relative to case OP-1 under high natural gas price scenarios. As shown in Figure 8.79, renewables increase by 71 MW in 2021, but 135 MW fewer renewables are added by 2036. Timing of natural gas resources is accelerated by one year, but reduced by 99 MW by 2036—combined cycles replace gas-fired peaking resources.

Table 8.26 – PVRR Cost/(Benefit) of CPP-C vs. OP-1

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from Case 1 (OP-1)	$91	$50	$69	$286	$47	$74	$471

Figure 8.79 – Increase/(Decrease) in Resources, CPP-C vs. OP-1



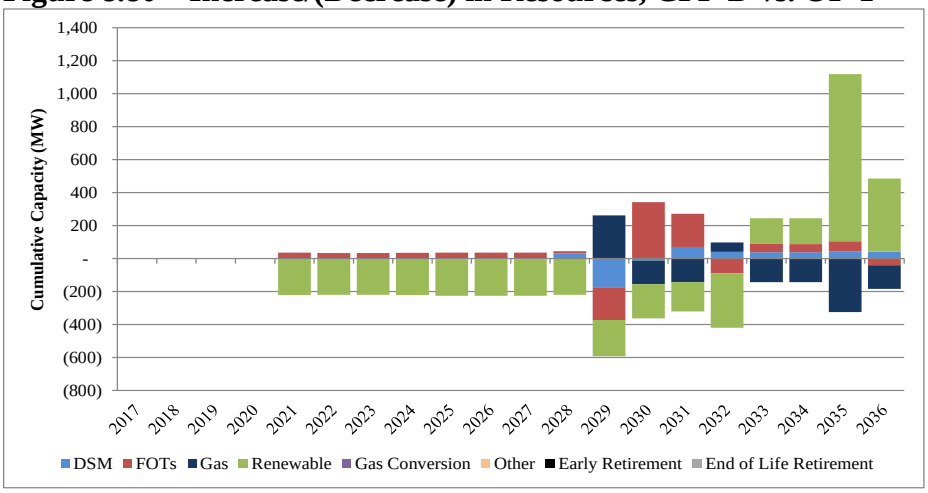
CPP Mass Cap D Sensitivity (Case CPP-D)

Table 8.27 shows the PVRR impacts of the CPP-D sensitivity relative to case OP-1. With a higher cap to accommodate new resources, dispatch costs are reduced, lowering system costs—most notably with higher gas prices. New CCCTs are assumed to be covered by the emissions cap, and there are no set-asides. As shown in Figure 8.80, there are 220 MW fewer renewables added in 2021, but 443 MW additional renewables are added by 2036. Timing of natural gas resource additions is altered, with a reduction of 143 MW by 2036.

Table 8.27 – PVRR Cost/(Benefit) of CPP-D vs. OP-1

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from Case 1 (OP-1)	($76)	($64)	($80)	($320)	($69)	($100)	($357)

Figure 8.80 – Increase/(Decrease) in Resources, CPP-D vs. OP-1



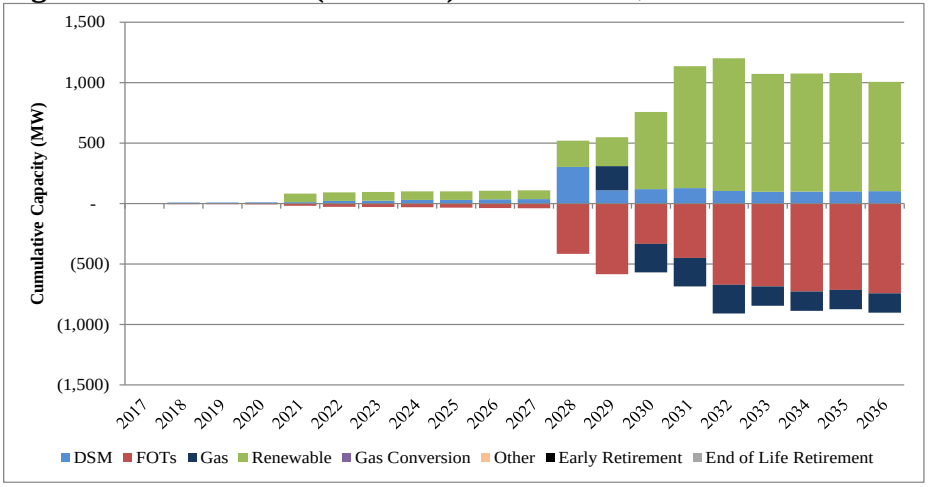
Limited FOT Sensitivity (Case FOT-1)

Table 8.28 shows the PVRR impacts of the FOT-1 sensitivity to case OP-1. In the FOT-1 sensitivity, FOTs are eliminated at Mona (300 MW) and NOB (100 MW) for both the summer and winter seasons beginning in 2021. Eliminating access to market by 400 MW increases system costs, particularly over the long-term—economics improve as gas prices rise, which improves the value of incremental renewable resource additions. As shown in Figure 8.81, new renewable resources increase by 71 MW in 2021 and increase by 905 MW by 2036. Over the study period, DSM resources increased by 102 MW. More natural gas capacity is needed in 2029, but overall gas resource additions are lower by 160 MW at the end of the study period.

Table 8.28 – PVRR Cost/(Benefit) of FOT-1 vs. OP-1

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from Case 1 (OP-1)	$169	$286	$237	$74	$282	$232	$47

Figure 8.81 – Increase/(Decrease) in Resources, FOT-1 vs. OP-1



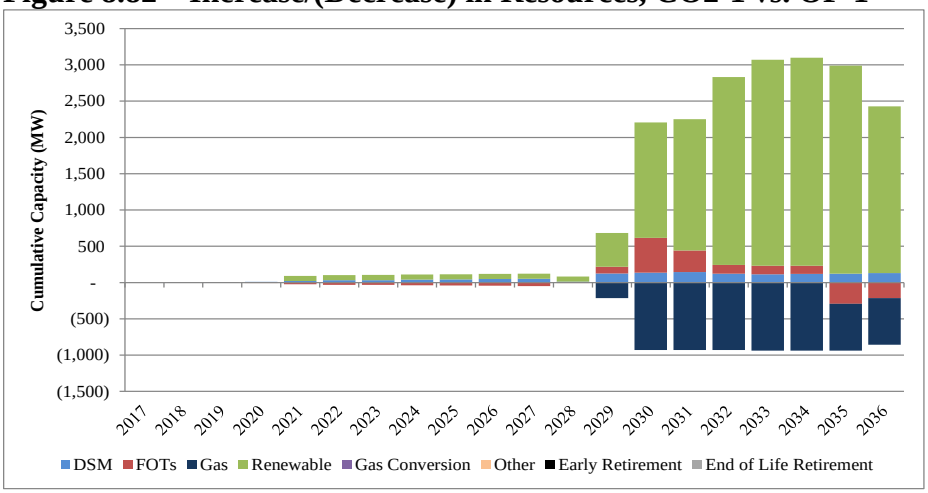
CO_2 Price Sensitivity (Case CO2-1)

Table 8.29 shows the PVRR impacts of the CO2-1 sensitivity relative to case OP-1. When compared to case OP-1, system costs are higher in all but the high gas price scenarios since the value of additional renewable resources increases with higher gas prices. As summarized in Figure 8.82, additional renewable resources are added to the system, particularly in the out years when the CO_2 price rises above $25/ton. The additional renewable resources displace natural gas resources over the long-term. When compared to case OP-1, system costs are higher in all but the high gas price scenarios since the value of additional renewable resources increases with higher gas prices.

Table 8.29 – PVRR Cost/(Benefit) of CO2-1 vs. OP-1

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean					
	Mass B	Mass A			Mass B		
	Medium Gas	Low Gas	Medium Gas	High Gas	Low Gas	Medium Gas	High Gas
Change from Case 1 (OP-1)	$928	$1,028	$862	($368)	$1,018	$830	($353)

Figure 8.82 – Increase/(Decrease) in Resources, CO2-1 vs. OP-1



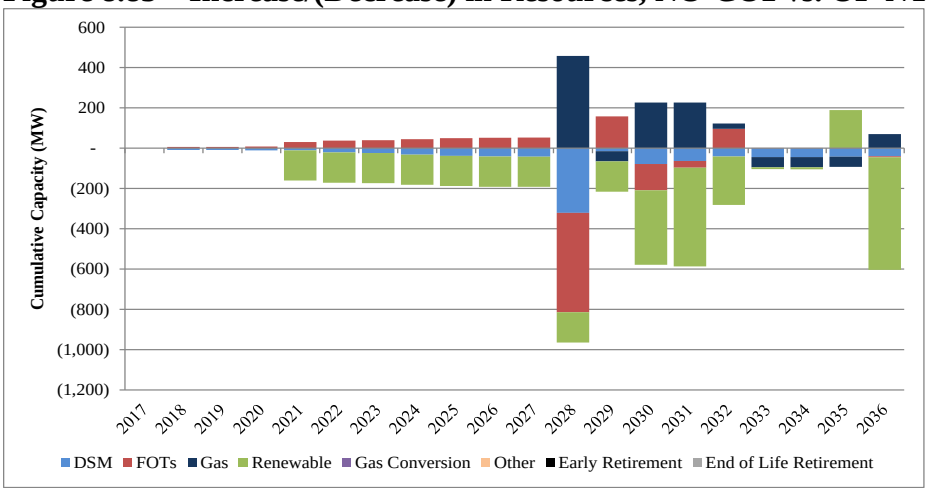
No CO_2 Policy Sensitivity (Case NO-CO2)

Table 8.30 shows the PVRR impacts of the NO-CO2 sensitivity relative to case OP-NT3. As requested by stakeholders, the NO-CO2 case examines the impact of having no incremental state or federal CO_2 emissions policy in place throughout the 2017-2036 study period. Overall, system costs decrease by between $161m (SO) and $194m (PaR). Figure 8.83 summarizes portfolio impacts. In this study, 150 MW of 2021 wind in Idaho is eliminated; however, the 300 MW of wind in Wyoming included in the OP-NT3 case remains cost effective absent a CO_2 policy assumption.

Table 8.30 – PVRR Cost/(Benefit) of NO-CO2 vs. OP-NT3

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
Change from OP-NT3	($161)	($194)

Figure 8.83 – Increase/(Decrease) in Resources, NO-CO2 vs. OP-NT3



Business Plan Sensitivity (Case BP)

Table 8.31 shows the PVRR impacts of the Business Plan sensitivity relative to case OP-NT3. System costs increase by $146m when studied in SO and $108m when analyzed using PaR. This sensitivity complies with Utah requirements to perform a business plan sensitivity consistent with the Public Service Commission of Utah's order in Docket No. 15-035-04, summarized as follows:

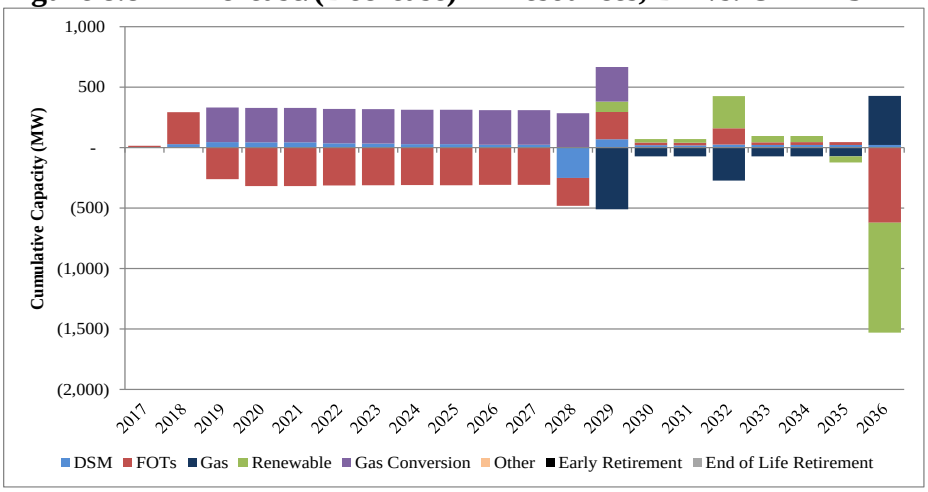
- Over the first three years, resources align with those assumed in PacifiCorp's fall 2016 Business Plan.
- Beyond the first three years of the study period, unit retirement assumptions are aligned with the preferred portfolio.
- All other resources are optimized.

Figure 8.84 summarizes resource portfolio impacts, showing differences associated with Naughton Unit 3 (assumed to convert to natural gas in the business plan) offset by reduced FOTs through 2027. Longer term, there is a difference in the timing of new natural gas resources, renewable resources, and FOTs.

Table 8.31 – PVRR Cost/(Benefit) of BP vs. OP-NT3

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
Change from OP-NT3	$146	$108

Figure 8.84 – Increase/(Decrease) in Resources, BP vs. OP-NT3



Energy Storage Sensitivities

In the 2017 IRP, storage resources available to the models include pumped storage, compressed air energy storage (CAES), and lithium and flow batteries. Interest in storage resources continues to grow as these technologies advance. PacifiCorp recognizes that there are stacked benefits from storage systems, that certain benefit categories are difficult to value with existing IRP modeling tools, and that improving storage analytics is a priority. With this in mind, PacifiCorp continues to explore options for modeling storage resources that are capable of capturing additional benefit

streams, including voltage support, renewable resource integration, and deferral of transmission and distribution upgrades. While the sensitivity cases conducted in the 2017 IRP cycle are limited in scope, PacifiCorp plans to leverage work being performed in its review of distribution level studies when evaluating storage applications in future IRPs.

PacifiCorp currently evaluates the economics for selection of specific energy storage projects, with a focus on distribution-level applications, outside of the IRP process. In this context, PacifiCorp considered procuring an energy storage project in Washington under the Clean Energy Fund 2, but ultimately withdrew its application. A combined energy storage plus solar project is being procured in Utah with a targeted in-service date mid-2018. In Oregon, PacifiCorp is working to meet the requirements of HB 2193, which will result in proposing one or more energy storage projects in Oregon.

For the 2017 IRP, two utility-scale energy storage sensitivities (battery storage and CAES) were conducted, using updated cost assumptions. The two energy storage sensitivities were based on the energy storage studies described in Volume II, Appendix P. The energy storage studies include analysis of benefits associated with ancillary services and updated prices. The battery energy storage study also includes forecasted price trends.

Storage – Battery Sensitivity (Case Battery)

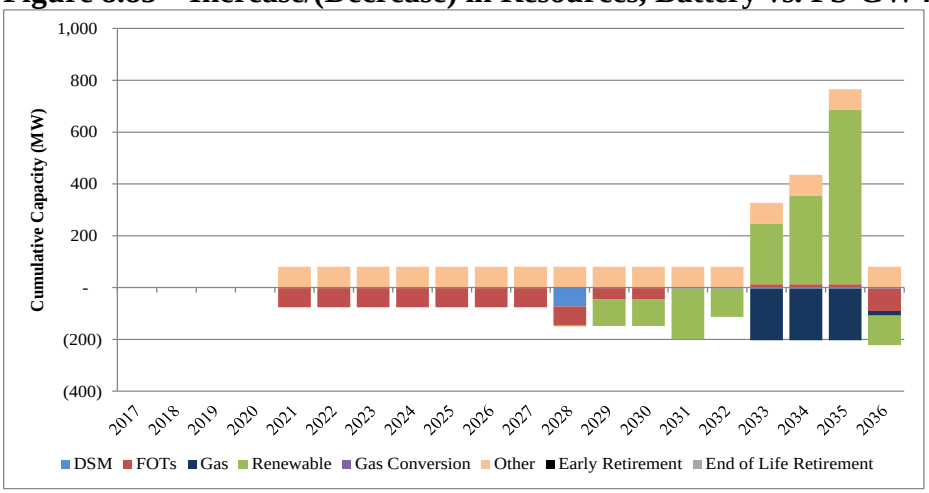
In this sensitivity, PacifiCorp added an 80 MW battery storage resource in 2021, coinciding with the incremental addition of new wind resources included in the preferred portfolio. Table 8.32 shows the PVRR impacts of the Battery sensitivity relative to the FS-GW4 case. System costs increase by $172m (SO) and $151m (PaR).

Table 8.32 – PVRR Cost/(Benefit) of Battery vs. FS-GW4

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
Change from FS-GW4	$172	$151

Figure 8.85 shows the resource portfolio impacts of this sensitivity relative to the FS-GW4 benchmark. The added battery storage resource primarily defers FOTs through 2027. In the out years of the planning horizon, introduction of the storage system influences timing of new resources. Given changes to the resource mix over time, by the end of the study period, the battery storage system results in reduced FOTs and a slight reduction in overall renewable resource capacity.

Figure 8.85 – Increase/(Decrease) in Resources, Battery vs. FS-GW4



Storage – Compressed Air Energy Sensitivity (Case CAES)

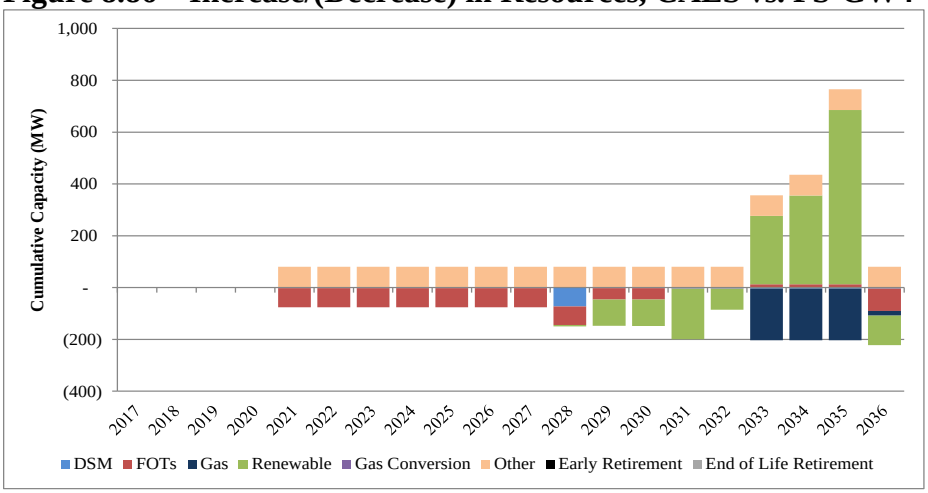
In this sensitivity, PacifiCorp added an 80 MW CAES resource in 2021, coinciding with the incremental addition of new wind resources included in the preferred portfolio. Table 8.33 shows the PVRR impacts of the CAES sensitivity relative to the FS-GW4 benchmark case. As in the Battery sensitivity, adding the CAES resources increases system costs. Overall system costs increase by between $131m (SO) and $110m (PaR), less of an increase than seen in the Battery sensitivity case.

Table 8.33 – PVRR Cost/(Benefit) of CAES vs. FS-GW4

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
Change from FS-GW4	$131	$110

Figure 8.86 shows the resource portfolio impacts of this sensitivity relative to the FS-GW4 benchmark. The portfolio impacts are nearly identical to those seen in the Battery sensitivity case. The added CAES resource primarily defers FOTs through 2027. In the out years of the planning horizon, introduction of the storage system influences timing of new resources. Given changes to the resource mix over time, by the end of the study period, the CAES resource results in reduced FOTs and a slight reduction in overall renewable resource capacity.

Figure 8.86 – Increase/(Decrease) in Resources, CAES vs. FS-GW4



East/West Split Sensitivity (Case WCA)

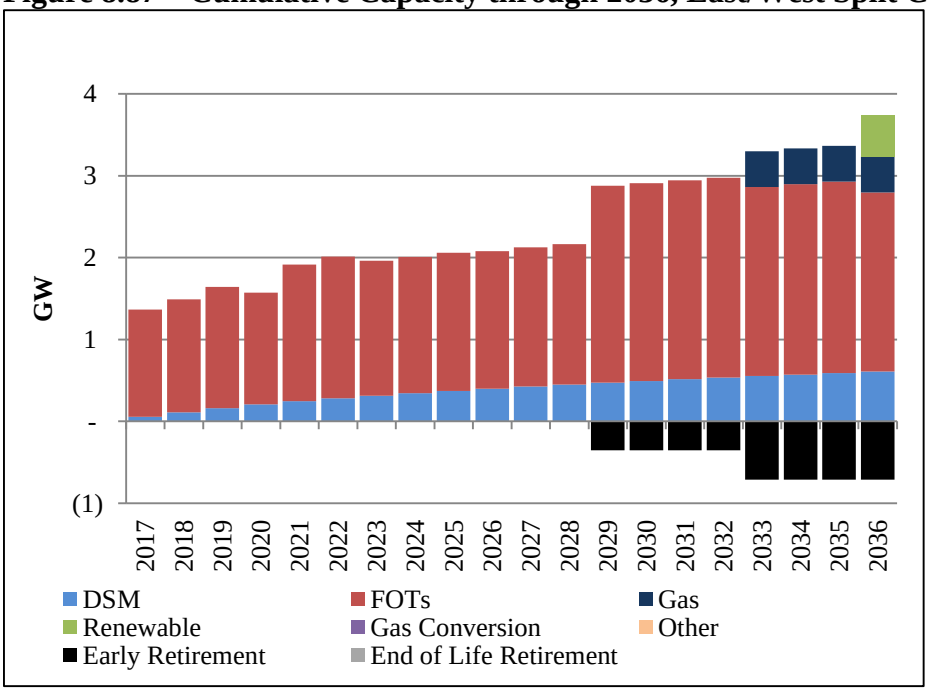
In response to the Washington Utilities and Transportation Commission (WUTC), PacifiCorp updated its West Control Area (WCA) sensitivity for the 2017 IRP to compare the impact of planning for the WCA as a stand-alone system on a WCA-to-WCA basis, rather than on a system-to-system basis as was done in the 2015 IRP. Table 8.34 shows the PVRR impacts of the East/West Split (WCA) sensitivity relative to the benchmark case, FS-REP, reported on a WCA-basis. Overall system costs increase by between $1,019m (SO) and $203m (PaR) when compared to the FS-REP benchmark case, reported on a WCA-basis, indicating that the WCA benefits from east-side resources.

Table 8.34 – PVRR Cost/(Benefit) of WCA vs. FS-REP

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
West (FS-REP)	$6,509	$6,863
West (WCA)	$7,528	$7,066
Change from FS-REP	$1,019	$203

Figure 8.87 shows the resource portfolio from the WCA case. When the east side of the system is eliminated from the planning study, the WCA-system relies on FOTs and incremental DSM resources through 2032. A 1x1 G-class 436 MW natural gas CCCT is added in 2033, coinciding with the assumed retirement of Jim Bridger Unit 2 and the end of 2032, and 500 MW of west-side wind is added in 2036. Without east-side resources in the energy mix, the WCA system is heavily reliant on wholesale power market purchases.

Figure 8.87 – Cumulative Capacity through 2036, East/West Split Case – WCA



PacifiCorp calculated the FOT values as a percentage of peak load over both the 10-year period (2017-2026) and 20-year period (2017-2036) for both the WCA case and the benchmark case. This analysis shows that WCA reliance on FOTs as a percentage of peak load is nearly double that of the integrated system, as shown Table 8.35. This results in increased market risk exposure under a WCA structure when compared to the integrated system. Alleviating this market risk would require accelerating the timing for new generating resources and significantly increase the cost of this sensitivity relative to the benchmark.

Table 8.35 – FOTs as a Percentage of Net Peak Load

	Summer		Winter	
	10 year	20 year	10 year	20 year
WCA	26%	31%	23%	28%
WCA-RPS	26%	31%	23%	28%
System	9%	12%	10%	14%

East/West Split RPS Sensitivity (Case WCA-RPS)

In this variant of the WCA sensitivity, additional renewable resources are added to the WCA system to achieve physical compliance with Washington RPS targets. Table 8.36 shows the PVRR impacts of the WCA-RPS relative to the FS-REP case, reported on a WCA-basis. Overall system costs increase by between $1,030m (SO) and $216m (PaR) when compared to the FS-REP case, reported on a WCA-basis.

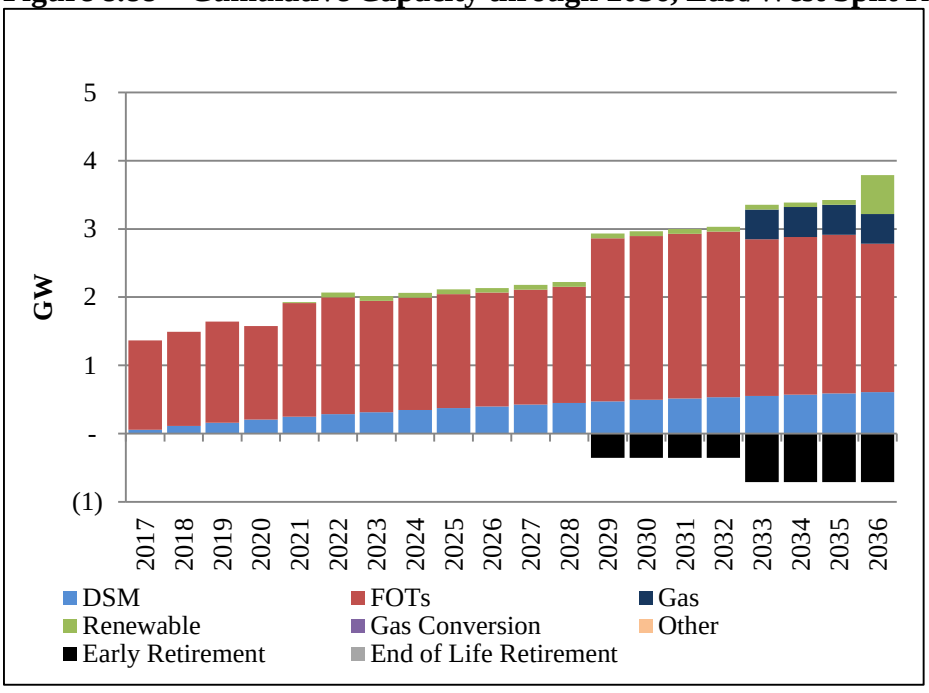
Table 8.36 – PVRR Cost/(Benefit) of WCA-RPS vs. FS-REP

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer	PaR Stochastic Mean
	Mass B	
	Medium Gas	
West (FS-REP)	$6,509	$6,863
West (WCA-RPS)	$7,539	$7,079
Change from FS-REP	$1,030	$216

Figure 8.88 shows the resource portfolio from the WCA-RPS case. When the east side of the system is eliminated from the planning study and additional renewable resources are added to achieve Washington RPS targets, the WCA system relies on FOTs and incremental DSM resources through 2020. Additional west-side wind resources are added in 2021 and 2022 (70 MW), with an incremental 500 MW of wind added in 2036. As in the WCA sensitivity case, a 1x1 G-class 436 MW natural gas CCCT is added in 2033, coinciding with the assumed retirement of Jim Bridger Unit 2 and the end of 2032.

The additional renewable resources do not alleviate the reliance on FOTs described in the WCA case, and the market risk associated with such a portfolio described for the WCA case also applies to the WCA-RPS case.

Figure 8.88 – Cumulative Capacity through 2036, East/West Split RPS Case – WCA-RPS



2015 IRP WCA Sensitivity Discussion

PacifiCorp conducted a WCA sensitivity in the 2015 IRP that modeled separate east and west balancing authority areas (Sensitivity S-10 Separate East/West BAAs) in accordance with a

request from the WUTC in its 2013 IRP Acknowledgement Letter.[7] Results of this analysis showed a need for additional resources in the west BAA during the study period. Following, in the WUTC's 2015 IRP Acknowledgement Letter, the Commission indicated that sensitivity case S-10 did not meet its request and that cost impacts should be presented at the BAA level rather than the system level as a means of quantifying the benefits of system integration to the individual BAAs.[8] As described earlier, PacifiCorp's 2017 IRP WCA sensitivity cases compare system cost impacts on a WCA-to-WCA basis. Additionally, the Acknowledgement Letter discusses subsequent analysis conducted by WUTC staff as part of the Multi-State Process for interstate cost allocations that included staff analysis of power flows across the Company's system. Based on this analysis, WUTC staff concluded that the west BAA is capable of meeting its peak load needs independent of any transfers from the east BAA, and thereby concluded that the west BAA would not need to add capacity resources as shown in the Company's S-10 analysis. The WUTC requested that the 2017 IRP repeat the analysis and that inputs consistent with the flow data used by WUTC staff be applied, or that the Company explain why different inputs are more appropriate.

As presented in the preceding sections, in both of PacifiCorp's 2017 IRP WCA sensitivities, additional resources are needed in the west BAA, and system costs are higher when compared to WCA costs derived from an integrated system. The WUTC staff analysis conducted in the Multi-State Process for interstate cost allocation was based on the scheduled delivery or receipt of energy based on e-Tag information across PacifiCorp's system. While this analysis showed that the west BAA is capable of meeting its peak load needs independent of any transfers from the east BAA, WUTC staff's analysis was limited, as it did not take into account the reserve and capacity requirements of the west BAA. Specifically, PacifiCorp must meet its load requirements both on an energy and capacity basis, holding contingency reserves equal to three percent of generation plus three percent of load, and regulating reserve requirements for ramping and deviations in load and variable energy resources. There are a limited number of resources in the west BAA that can hold contingency and regulating reserves, and in operating practice, it is common for the west BAA to rely on the east BAA for reserves as the most economical practice.

From an operational standpoint, hydro resources are advantageous resources for carrying reserves due to the high ramp capability of these generating units. However, due to operational limitations such as minimum flow requirements during high run-off periods or Endangered Species Act (ESA) mandated flow requirements, it is not always possible to hold reserves on these hydro resources during many hours of the year, primarily the winter and spring periods. The remaining resources in the west BAA that can hold contingency reserves limited to the Jim Bridger coal plant, the Hermiston gas plant, and the Chehalis gas plant. Reserves are economically held on the marginal unit on the system while energy is provided with the least expensive resources on the system. PacifiCorp is able to balance its reserve requirements across the east and west BAAs by holding reserves in a manner that is most economic. For example, if the Jim Bridger coal plant is less expense than a gas unit, but the east BAA gas units are less expensive than the west BAA gas units, PacifiCorp will make the economic decision to displace the west BAA gas unit and hold reserves on an east BAA gas unit while transferring energy from Jim Bridger to the east BAA and free up capacity. It is also reasonable to transfer energy to the east BAA form the Jim Bridger coal

[7] Docket UE-120416, Pacific Power & Light Company 2013 IRP Acknowledgement Letter Attachment (Nov. 25, 2013) at pages 5-6.
[8] Docket UE-140546, Pacific Power & Light Company 2015 IRP Acknowledgement Letter Attachment (Nov. 13, 2015) at pages 3-4.

plant, due to the fact that it can only hold a limited amount of contingency reserves due to ramp limitations, while the ability of a gas unit to hold reserves is only limited by its capacity. PacifiCorp conducted an analysis of January 2013, the time period in WUTC staff's analysis referenced in the 2015 IRP Acknowledgement Letter, which showed the west BAA relied on the east BAA for reserves in 58 percent of the hours, assuming a regulating requirement of 120 MW. This further supports the importance of considering energy and capacity needs for contingency reserves and regulating purposes when evaluating a split of the west and east BAAs.

PacifiCorp has consistently held reserves in its east BAA for the west BAA due to economics and limited generation capacity resulting from hydro operational constraints or planned or forced outages of west BAA gas plants. While WUTC staff's analysis accurately accounted for the scheduled delivery and receipt of energy through e-Tags across PacifiCorp's system, it was limited and did not take into consideration capacity needs of the west and east BAAs for contingency reserves and regulating purposes, which explains why staff's analysis appeared to be inconsistent with PacifiCorp's WCA sensitivity case presented in the 2015 IRP.

CHAPTER 9 – ACTION PLAN AND RESOURCE PROCUREMENT

CHAPTER HIGHLIGHTS

- The 2017 IRP action plan identifies steps to be taken during the next two to four years to deliver resources in the preferred portfolio.
- PacifiCorp's 2017 IRP action plan includes action items for renewable resources, transmission, short-term firm market purchases (front office transactions or FOTs), demand side management resources, and coal resources.
- The 2017 IRP acquisition path analysis provides insight on how changes in the planning environment might influence future resource procurement activities. Key uncertainties addressed in the acquisition path analysis include load, distributed generation, CO_2 emission polices, Regional Haze outcomes, and availability of purchases from the market.
- Differences between the 2017 IRP preferred portfolio and the 2015 IRP Update and fall ten-year business plan portfolios are primarily driven by changes in load forecasts, the cost for renewable resource alternatives, and other model assumption updates reflecting changes in the planning environment.
- PacifiCorp further discusses how it can mitigate procurement delay risk, summarizes planned procurement activities tied to the action plan, assesses trade-offs between owning or purchasing third-party power, discusses its hedging practices, and identifies the types of risks borne by customers and the types of risks borne by shareholders.

Introduction

PacifiCorp's 2017 IRP action plan identifies the steps the Company will take during the next two to four years to deliver its preferred portfolio of resources with a focus on the front ten years of the planning horizon. Associated with the action plan is an acquisition path analysis that anticipates potential major regulatory actions and other trigger events during the action plan time frame that could materially impact resource acquisition strategies.

Resources included in the 2017 IRP preferred portfolio help define the actions included in the action plan, focusing on the size, timing and type of resources needed to meet load obligations, and current and potential future state regulatory requirements. The preferred portfolio resource combination was determined to be the lowest cost on a risk-adjusted basis accounting for cost, risk, reliability, regulatory uncertainty and the long-run public interest.

The 2017 IRP action plan is based upon the latest and most accurate information available at the time portfolios are being developed and analyzed on cost and risk metrics. PacifiCorp recognizes that the preferred portfolio, upon which the action plan is based, is developed in an uncertain planning environment and that resource acquisition strategies need to be regularly evaluated as planning assumptions change.

Resource information used in the 2017 IRP, such as capital and operating costs, are based upon recent cost and performance data. However, it is important to recognize that the resources identified in the plan are proxy resources, which act as a guide for resource procurement and not as a commitment. Resources evaluated as part of procurement initiatives may vary from th proxy

resource identified in the plan with respect to resource type, timing, size, cost and location. PacifiCorp recognizes the need to support and justify resource acquisitions consistent with then-current laws, regulatory rules and commission orders.

In addition to presenting the 2017 IRP action plan, reporting on progress in delivering the prior action plan, and presenting the 2017 IRP acquisition path analysis, Chapter 9 covers the following resource procurement topics:

- Procurement delays;
- IRP action plan linkage to the business plan;
- Resource procurement strategy;
- Assessment of owning assets vs. purchasing power;
- Managing carbon risk for existing plants;
- Purpose of hedging; and
- Treatment of customer and investor risks.

The 2017 IRP Action Plan

The 2017 IRP Action Plan identifies specific actions the Company will take over the next two to four years. Action items are based on the type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2017 IRP process. Table 9.1 details specific 2017 IRP action items by category.

Table 9.1 – 2017 IRP Action Plan

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

	– November-December, 2017, complete initial shortlist bid evaluation. – By January 2018, complete final shortlist bid evaluation, seek acknowledgement of the final shortlist from the Public Utility Commission of Oregon, and seek approval of winning bids from the Utah Public Service Commission. – By March 2018, receive CPCN approval from the Wyoming Public Service Commission. – Complete construction of new wind projects by December 31, 2020.
1c	**Renewable Portfolio Standard Compliance** • PacifiCorp will issue unbundled REC request for proposals (RFP) to meet its state RPS compliance requirements. – As needed, issue RFPs seeking then-current-year or forward-year vintage unbundled RECs that will qualify in meeting California renewable portfolio standard targets through 2020. – As needed, issue RFPs seeking low-cost then-current-year, forward-year, or older vintage unbundled RECs that will qualify in meeting Oregon renewable portfolio standard targets, deferring the currently projected 2035 initial shortfall after accounting for preferred portfolio renewable resources.
1d	**Renewable Energy Credit Optimization** • Before filing the 2017 IRP Update, evaluate potential opportunities to re-allocate RECs from Utah, Wyoming, and Idaho to Oregon, Washington, or California. • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.
Action Item	**2. Transmission Actions**
2a	**Aeolus to Bridger/Anticline** • By December 31, 2020, PacifiCorp will build the 140-mile, 500 kV transmission line running from the Aeolus substation near Medicine Bow, Wyoming, to the Jim Bridger power plant (a sub-segment of the Energy Gateway West transmission project). This includes pursuing regulatory review and approval as necessary. – June-July 2017, file a CPCN application with the Public Service Commission of Wyoming. – By March 2018, receive conditional CPCN approval from the Wyoming Public Service Commission pending acquisition of rights of way. – By December 2018, obtain Wyoming Industrial Siting permit and issue EPC limited notice to proceed. – By April 2019, issue EPC final notice to proceed. – Complete construction of the transmission line by December 31, 2020.
2b	**Energy Gateway Permitting** • Continue permitting for the Energy Gateway transmission plan, with the following near-term targets: – For Segments D1, D3, E, and F, continue funding of the required federal agency permitting environmental

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

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

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

Progress on Previous Action Plan Items

This section describes progress that has been made on previous active action plan items documented in the 2015 Integrated Resource Plan and 2015 Integrated Resource Plan Update reports filed with the state commissions on March 31, 2015 and March 31, 2016, respectively. Many of these action items have been superseded in some form by items identified in the current IRP action plan. The status for all action items is summarized in Table 9.2.

Table 9.2 – 2015 IRP Action Plan Status Update

Action Item	Activity	Status
1a	**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.	Consistent with the action plan in its 2015 IRP Update, which revised Action 1a, PacifiCorp issued a renewable resource and REC RFP in 2016. As a result of this RFP process, PacifiCorp executed REC purchase agreements in 2016 to acquire RECs eligible for the Washington, Oregon, and California RPS programs. For the California renewable portfolio standard requirements, the Company issued a REC RFP on March 13, 2017 with bids due April 3, 2017. Any offers that meet the Company's needs and specific pricing criteria will be selected and then submitted to the California Public Utilities Commission for review.
1b	**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.	The Company issued a reverse RFP in December 2016 to sell RECs. The Company will continue to issue reverse RFPs in 2017 to seek REC sale opportunities for RECs allocated to states that do not have a state RPS

Action Item	Activity	Status
		compliance need.
1c	**Oregon Solar Capacity Standard** • Conclude negotiations with shortlisted bids from the 2013 Request for Proposals (RFP), seeking up to 7 MW of competitively priced capacity from qualifying solar systems that will be used to satisfy PacifiCorp's obligation under Oregon's 2020 solar capacity standard.	The Oregon Solar Capacity Standard was eliminated with the passage of Oregon Senate Bill 1547-B. This action item was deleted from the updated action plan presented in the Executive Summary of the 2015 IRP Update.
2a	**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: – Balance of month and day-ahead brokered transactions in which the broker provides the service of providing a competitive price. – Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as Intercontinental Exchange (ICE), in which the exchange provides the service of providing a competitive price. – Prompt month forward, balance of month, day-ahead, and hour-ahead non-brokered transactions.	For 2016, PacifiCorp acquired approximately 1,025 MW to 3,360 MW of short-term firm market purchases explicitly for delivery during the on-peak summer period. For 2017, as of mid-March 2017, the Company has acquired approximately 450 MW to 700 MW of short-term firm market purchases explicitly for delivery during the on-peak summer period. For 2018, as of mid-March 2017, the Company has not procured any short-term firm market purchases explicitly for delivery during the on-peak summer period.
3a	**Class 1 DSM** • Pursue a west-side irrigation load control pilot beginning 2016 to test the feasibility of program design. Additional information on the proposed pilot is provided in the implementation plan section of Appendix D in Volume II of the 2015 IRP.	On March 4, 2016, PacifiCorp filed with the Oregon Public Utilities Commission to implement an Irrigation Load Control pilot program. The pilot program was approved on May 4, 2016, and called its first event on August 19, 2016.

<table>
<tr><th>Action Item</th><th>Activity</th><th>Status</th></tr>
<tr><td>3b</td><td><u>Class 2 DSM</u>
• Acquire cost effective Class 2 DSM (energy efficiency) resources targeting annual system energy and capacity selections from the preferred portfolio as summarized in the following table. PacifiCorp’s implementation plan to acquire cost effective energy efficiency resources is provided in Appendix D in Volume II of the 2015 IRP.

<table>
<tr><th>Year</th><th>Annual Incremental Energy (GWh)</th><th>Annual Incremental Capacity* (MW)</th></tr>
<tr><td>2015</td><td>551</td><td>133</td></tr>
<tr><td>2016</td><td>584</td><td>139</td></tr>
<tr><td>2017</td><td>616</td><td>146</td></tr>
<tr><td>2018</td><td>634</td><td>146</td></tr>
</table>
*Class 2 DSM capacity figures reflect projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply side resource.</td><td>Initial review indicates that in 2015, PacifiCorp acquired 589 GWh of Class 2 DSM, 7 percent above the Action Plan target. Preliminary results for 2016 indicate PacifiCorp acquired 615 GWh of Class 2 DSM, 5 percent above the 2015 IRP target.</td></tr>
<tr><td>4a</td><td><u>Naughton Unit 3</u>
• Issue an RFP to procure gas transportation and resume engineering, procurement, and construction (EPC) contract procurement activities for the Naughton Unit 3 natural gas conversion in the first quarter of 2016.
• PacifiCorp may update its economic analysis of natural gas conversion in conjunction with the RFP processes to align gas transportation and EPC cost assumptions with market bids.</td><td>PacifiCorp updated its economic analysis for the 2017 IRP that reflects higher economic benefits to customers for PacifiCorp to continue to operate Naughton Unit 3 through year-end 2018 as a coal-fueled resource with a subsequent unit retirement. The Company will continue to analyze the economics surrounding Naughton Unit 3 retirement and/or natural gas conversion to achieve the most economic outcome for customers while complying with permits and compliance plans, as described in the 2017 IRP Action Items above.</td></tr>
<tr><td>4b</td><td><u>Dave Johnston Unit 3</u>
• The portion of EPA’s final Regional Haze Federal Implementation Plan (FIP) requiring the installation of selective catalytic reduction (SCR) at Dave Johnston Unit 3, or a</td><td>The Company’s commitment to shutting down Dave Johnson by the end of 2027 must be promulgated via permit prior to the 2019 compliance deadline. PacifiCorp will update its economic analysis of the commitment as</td></tr>
</table>

Action Item	Activity	Status
	commitment to shut down Dave Johnston Unit 3 by the end of 2027, is currently under appeal by the State of Wyoming in the U.S. Tenth Circuit Court of Appeals. • If following appeal, EPA's final FIP as it pertains to Dave Johnston Unit 3 is upheld, PacifiCorp will commit to shutting down Dave Johnston Unit 3 by the end of 2027. • If following appeal, EPA's final FIP as it pertains to Dave Johnston Unit 3 is or will be modified, PacifiCorp will evaluate alternative compliance strategies that will meet any new requirements, as applicable, and provide the associated analysis in a future IRP or IRP Update.	part of its 2017 IRP Update.
4c	**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.	PacifiCorp is still awaiting results of appeal of EPA's final regional haze FIP.
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.	On March 16, 2017, Arizona Regional Haze State Implementation Plan was approved incorporating the alternative compliance approach described in this action item. The EPA's approval will be published in the Federal Register in the coming weeks and become effective thirty days after publication.
5a	**Energy Gateway Permitting** • Continue permitting for the Energy Gateway transmission plan, with near term targets as follows:	PacifiCorp continues to fund the required federal agency permitting environmental consultant as actions to achieve final federal permits. – A final Environmental Impact Statement (EIS) for the

Action Item	Activity	Status
	– For Segments D, E, and F, continue funding of the required federal agency permitting environmental consultant as actions to achieve final federal permits. – For Segments D, E, and F, continue to support the federal permitting process by providing information and participating in public outreach. – For Segment H (Boardman to Hemingway), continue to support the project under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement.	Gateway South project, Segment F, was published May 2016 and the final Record of Decision was issued in December 2016. – A draft supplemental EIS for the deferred portions of Segment E for the Gateway West project was released in March 2016 and the final supplemental EIS was published in October 2016. A final Record of Decision was signed in January 2017. – The Record of Decisions and right-of-way grants contain many conditions and stipulations that must be met and accepted before the project can move to construction. PacifiCorp will continue the work necessary to meet these requirements and will continue to meet regularly with the Bureau of Land Management to review progress. – PacifiCorp continues to support the Boardman to Hemingway project consistent with the project Joint Permit Funding Agreement. As a participant in the project PacifiCorp continues to collaborate with Idaho Power, the lead organization in the permitting process, by providing guidance of activities and plans associated with the permitting phase of the project.
5b	**<u>Wallula to McNary 230 kilovolt Transmission Line</u>** • Complete Wallula to McNary project construction per plan with 2017 expected in-service date. Continue to support the permitting process for Walla Walla to McNary.	Updates on the construction are as follows: – Received the Umatilla County Conditional Use Permit December 2015. – Received right-of-way agreement and grant from Bureau of Indian Affairs and Confederated Tribes of the Umatilla Indian Reservation in February 2017. – Continue permitting efforts with the Bureau of Land Management and the U.S. Fish and Wildlife agencies. – Bonneville Power Administration continues work on the studies and the development of the plan of service

Action Item	Activity	Status
		required to interconnect at the McNary substation. – Right-of-way appraisal work is scheduled for first quarter 2016. – Note that all permitting documentation as required by each agency has been submitted and that various agencies are working through their required processes.

Acquisition Path Analysis

Resource and Compliance Strategies

PacifiCorp worked with stakeholders to define portfolio cost and risk analysis in the 2017 IRP. This analysis reflects a combination of specific planning assumptions related to CO_2 emission policies, compliance under the Clean Power Plan (CPP), potential Regional Haze compliance outcomes, state RPS compliance strategies, and DSM acquisition levels. PacifiCorp further analyzed sensitivity cases on planning assumptions related to load forecasts, private generation penetration levels, Energy Gateway transmission projects, and CO_2 emission policy variants. The array of planning assumptions that define the studies used to develop resource portfolios provides the framework for a resource acquisition path analysis by evaluating how resource selections are impacted by changes to planning assumptions.

Given current load expectations, portfolio modeling performed for the 2017 IRP shows the resource acquisition path in the preferred portfolio is robust among a wide range of policy and market conditions, particularly in the near-term, when cost-effective renewable resources that qualify for federal income tax credits, FOTs, and energy efficiency resources are consistently selected. With regard to renewable resource acquisition, the portfolio development modeling performed in the 2017 IRP shows that new renewable resource needs are driven economics, and potential CPP outcomes, and over the long-term, state RPS compliance requirements. Beyond load, the most significant driver affecting resource selection in the 2017 IRP are potential compliance outcomes related to future Regional Haze requirements that might trigger early coal unit retirements. CO_2 policy uncertainty, whether related to the CPP or some other future policy targeting electric sector emission reductions, also influences resource selections in the 2017 IRP. For these reasons, the acquisition path analysis focuses on load trigger events and environmental policy trigger events that would require alternative resource acquisition strategies. For each trigger event, PacifiCorp identifies the planning scenario assumption affecting both short-term (2017-2026) and long-term (2027-2036) resource strategies.

Acquisition Path Decision Mechanism

The Utah Commission requires that PacifiCorp provide "[a] plan of different resource acquisition paths with a decision mechanism to select among and modify as the future unfolds."[1] PacifiCorp's decision mechanism is centered on the business planning and IRP processes, which together constitute the decision framework for making resource investment decisions. The IRP models are used on a macro-level to evaluate alternative portfolios and futures as part of the IRP process, and then on a micro-level to evaluate the economics and system benefits of individual resources as part of the supply-side resource procurement and DSM target-setting/valuation processes. PacifiCorp uses the IRP and business plan to serve as decision support tools that can be used to guide prudent resource acquisition paths that maintain system reliability at a reasonable cost. Table 9.3 summarizes PacifiCorp's 2017 IRP acquisition path analysis, which provides insight on how changes in the planning environment might influence future resource procurement activities. Changes in procurement activities driven by changes in the planning

[1] Public Service Commission of Utah, In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp, Report and Order, Docket No. 90-2035-01, June 1992, p. 28.

environment will ultimately be reflected in future IRPs and will be incorporated in PacifiCorp's annual business planning process.

Table 9.3 – Near-term and Long-term Resource Acquisition Paths

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2017-2026)	Long Term Resource Acquisition Strategy (2027-2036)
Higher sustained load growth	High economic drivers and increased demand from industrial customers	• Increase acquisition of west side FOTs • Escalate acquisition of Class 2 DSM	• Increase acquisition of gas-fired thermal resources; accelerate acquisition of selected thermal resource by up to 5 years • Balance timing of thermal and renewable resource acquisition with FOTs and cost-effective Class 2 DSM energy efficiency resources • Increase acquisition of Class 2 DSM
Lower sustained load growth	Low economic drivers suppress load requirements with reduced demand from industrial customers	• Reduce acquisition of FOTs • Reduce acquisition of renewable resources	• Reduce and defer acquisition of gas-fired thermal resources • Balance timing of thermal resource and renewable acquisition with FOTs • Reduce Class 2 DSM energy efficiency resources (particularly in 2029)
Higher sustained private generation penetration levels	More aggressive technology cost reductions, improved technology performance, and higher electricity retail rates	• Small reduction in acquisition of FOTs • Continue to pursue Class 2 DSM energy efficiency resources	• Reduce and defer acquisition of gas-fired thermal resources • Balance timing of thermal resource and renewable acquisition with FOTs and Class 2 DSM energy efficiency resources
Lower sustained private generation penetration levels	Less aggressive technology cost reductions, reduced technology performance, and lower electricity retail rates	• Continue to pursue Class 2 DSM energy efficiency resources • Small increase in FOTs	• Accelerate acquisition of gas-fired thermal resources by four years (addition in 2029) • Balance timing of thermal resources with FOTs and cost-effective Class 2 DSM • Evaluate cost effective RPS compliance strategies in 2033-2036, including tradeoffs between increased renewable resource acquisition and use of compliance flexibility mechanisms like banking and use of unbundled RECs

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2017-2026)	Long Term Resource Acquisition Strategy (2027-2036)
State implementation of Clean Power Plan Mass Cap	Mass Cap C or D applied to PacifiCorp's system covering CO_2 emissions from existing and new fossil-fired generation beginning 2022	• Increase acquisition of Class 2 DSM resources • Balance timing of thermal resource acquisition and renewable resource acquisition with FOTs • Continue to pursue Class 2 DSM energy efficiency resources	• Increase acquisition of Class 2 DSM resources • Balance timing of thermal resource acquisition, Class 2 DSM resource acquisition and renewable resource acquisition with FOTs
New CO_2 policy replacing Clean Power Plan	Fossil-fired generation is faced with a CO2 emissions cost beginning in 2025 at $4.75/ton and reaching $38.02/ton by 2036	• Continue to pursue Class 2 DSM energy efficiency resources	• Procure increased renewable resource in 2029, increasing each year through 2036 • Balance timing of Class 2 DSM resource acquisition and renewable resource acquisition with FOTs
No CO_2 policy	Clean Power Plan and Washington CAR are never enacted; assumes no replacement policies are adopted	• Evaluate cost effective renewables strategies, including tradeoffs between renewable resource acquisition, REC purchases, and banking strategies	• Increased acquisition of fossil-fired assets offsetting decreased Class 2 DSM and FOT resources (particularly in 2028, concurrent with assumed Dave Johnston unit retirements) • Balance timing of thermal resource acquisition with reduced renewable, Class 2 DSM and FOT resources
Regional Haze outcome with varying coal retirements and emission controls	Potential Regional Haze inter-temporal and fleet trade-off compliance scenario with coal unit assumptions as defined in Regional Haze cases 1 through 4, and case 6 (see Volume I, Chapters 7 and 8)	• Balance timing of thermal and renewable resource acquisition with FOTs, cost-effective Class 2 DSM energy efficiency resources • Evaluate cost effective renewables strategies, including tradeoffs between renewable resource acquisition, REC purchases, and banking strategies	• Balance timing of thermal and renewable resource acquisition with FOTs, cost-effective Class 2 DSM energy efficiency resources • Evaluate cost effective renewables strategies, including tradeoffs between renewable resource acquisition, REC purchases, and banking strategies
Limited availability of FOTs	Eliminates availability of FOTs at NOB (100 MW) and Mona (300 MW) beginning 2019	• Continue to pursue Class 2 DSM energy efficiency resources	• Strategic REC and renewable resource acquisition to maintain RPS compliance, balanced with reduced FOTs and accelerated timing of thermal resource acquisition • Increase acquisition of Class 2 DSM resource

Procurement Delays

The main procurement risk is an inability to procure resources in the required timeframe to meet the least-cost, least-risk mix of resources identified in the preferred portfolio. There are various

reasons why a particular proxy resource cannot be procured in the timeframe identified in the 2017 IRP. There may not be any cost-effective opportunities available through an RFP, the successful RFP bidder may experience delays in permitting and/or default on their obligations, or there might be a material and sudden change in the market for fuel and materials. Moreover, there is always the risk of unforeseen environmental or other electric utility regulations that may influence the PacifiCorp's entire resource procurement strategy.

Possible paths PacifiCorp could take in the event of a procurement delay or sudden change in procurement need can include combinations of the following:

- In circumstances where the Company is engaged in an active RFP where a specific bidder is unable to perform, alternative bids can be pursued.
- PacifiCorp can issue an emergency RFP for a specific resource and with specified availability.
- PacifiCorp can seek to negotiate an accelerated delivery date of a potential resource with the supplier/developer.
- PacifiCorp can seek to procure near-term purchased power and transmission until a longer-term alternative is identified, acquired through customized market RFPs, exchange transactions, brokered transactions or bi-lateral, sole source procurement.
- Accelerate acquisition timelines for direct load control programs.
- Procure and install temporary generators to address some or all of the capacity needs.
- Temporarily drop below the target 13 percent planning reserve margin.
- Implement load control initiatives, including calls for load curtailment via existing load curtailment contracts.

IRP Action Plan Linkage to Business Planning

Primary drivers in the resource differences between PacifiCorp's 2017 IRP and the 2015 IRP Update include decreased load forecasts and lower power prices. The 2017 IRP preferred portfolio assumes Naughton Unit 3 retires at the end of 2018, reflecting updated operating permits, instead of the end of 2017 as assumed in the 2015 IRP Update. The 2017 IRP preferred portfolio also assumes Cholla Unit 4 retires at the end of 2020 and Craig Unit 1 at the end of 2025. In the 2015 IRP Update, the preferred portfolio assumed Cholla Unit 4 would continue operating through the end of 2024 and that Craig Unit 1 would continue operating through the end of 2034. Finally, the 2017 IRP includes an updated DSM conservation potential assessment, which, when combined with an updated load forecast, informs changes to DSM acquisition targets relative to the 2015 IRP and 2015 IRP Update. Other changes in the portfolio reflect changes to renewable resource acquisition levels driven by investment in new transmission infrastructure and availability of federal income tax incentives.

Table 9.4 compares the 2017 IRP preferred portfolio with the 2015 IRP Update portfolio for the front ten years of the 2017 IRP planning period (2017-2026). The table shows year-by-year capacity differences by major resource categories (yellow highlighted table).

Table 9.4 – Comparison of the 2017 IRP Preferred Portfolio with the 2015 IRP Update Portfolio

2017 IRP vs 2015 IRP Update

2017 IRP Preferred Portfolio

	Capacity (MW)											Resource Totals
Resource	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017-2026**
Expansion Options												
Gas - CCCT		-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking		-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency		154	128	131	122	123	114	118	118	112	111	**1,229**
DSM - Load Control		-	-	-	-	-	-	-	-	-	-	-
Renewable - Wind		-	-	-	-	1,100	-	-	-	-	-	**1,100**
Renewable - Geothermal		-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar		-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass		-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro		-	-	-	-	-	-	-	-	-	-	-
Storage - CAES		-	-	-	-	-	-	-	-	-	-	-
Storage - Other		-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions		781	853	1,151	1,115	1,118	1,223	1,150	1,172	1,390	1,329	**1,128**
Existing Unit Changes												
Coal Early Retirement/Conversions		-	-	(280)	-	(387)	-	-	-	-	(82)	**(749)**
Thermal Plant End-of-life Retirements		-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions		-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades		-	-	-	-	-	-	-	-	-	-	-
Total		-	-	-	-	-	-	-	-	-	-	

Study includes Naughton 3 retirement at the end of 2018
FOT in resource total are 10-year averages, and include Winter FOTs in the 2017 IRP.

2017 IRP Preferred Portfolio less 2015 IRP Update

	Capacity (MW)											Resource Totals
Resource	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017-2026**
Expansion Options												
Gas - CCCT		-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking		-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency		16	(19)	(27)	(21)	(27)	(41)	(43)	(45)	(23)	(24)	**(254)**
DSM - Load Control		-	-	-	-	-	-	-	-	(39)	(24)	**(63)**
Renewable - Wind		-	-	-	-	1,100	-	-	-	-	-	**1,100**
Renewable - Geothermal		-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar		-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass		-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro		-	-	-	-	-	-	-	-	-	-	-
Storage - CAES		-	-	-	-	-	-	-	-	-	-	-
Storage - Other		-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions		33	(241)	(95)	(88)	148	163	185	179	(51)	(111)	**12**
Existing Unit Changes												
Coal Early Retirement/Conversions		-	280	(280)	-	(387)	-	-	-	387	(82)	**(82)**
Thermal Plant End-of-life Retirements		-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions		-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades		-	-	-	-	-	-	-	-	-	-	-
Total		**(886)**	**(960)**	**(1,403)**	**(1,345)**	**(1,120)**	**(1,215)**	**(1,126)**	**(1,155)**	**(1,227)**	**(1,600)**	

FOT in resource total are 10-year averages

2015 IRP Update

	Capacity (MW)											Resource Totals
Resource	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017-2026**
Expansion Options												
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	128	138	146	158	142	149	155	161	162	135	136	**1,483**
DSM - Load Control	-	-	-	-	-	-	-	-	-	39	24	**63**
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions	903	748	1,094	1,246	1,203	970	1,060	965	993	1,440	1,440	**1,116**
Existing Unit Changes												
Coal Early Retirement/Conversions	-	-	(280)	-	-	-	-	-	-	(387)	-	**(667)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-
Total	1,031	**886**	**960**	**1,403**	**1,345**	**1,120**	**1,215**	**1,126**	**1,155**	**1,227**	**1,600**	

Study includes Naughton 3 gas conversion in 2015
FOT in resource total are 10-year averages

Table 9.5 compares the fall 2016 ten-year business plan portfolio with the 2017 IRP preferred portfolio. Differences between the two portfolios are driven by changes to coal unit retirement and natural gas conversion assumptions, changes to load projections, updated DSM supply curve assumptions, and changes to renewable resource costs driven by the availability of federal income tax incentives. The 2017 IRP preferred portfolio assumes Naughton Unit 3 retires at the end of 2018, reflecting updated operating permits, instead of a natural gas conversion implemented by the summer of 2018 as assumed in the fall 2016 business plan. The 2017 IRP preferred portfolio also assumes the retirement of both Cholla Unit 4 at the end of 2020 and Craig Unit 1 at the end of 2025. In the fall 2016 business plan, the resource portfolio assumed Cholla Unit 4 would continue operating through the end of 2024 and that Craig Unit 1 would continue operating through the end of 2034. Finally, the 2017 IRP includes an updated DSM conservation potential assessment, which, when combined with an updated load forecast, informs changes to DSM acquisition targets relative to the fall 2016 business plan. Other changes in the portfolio reflect changes to renewable resource acquisition levels driven by investment in new transmission infrastructure and availability of federal income tax incentives.

Table 9.5 – Comparison of the 2017 IRP Preferred Portfolio with the Fall 2016 Business Plan Portfolio

2017 IRP vs Fall 2016 Ten-Year Business Plan sensitivity

2017 IRP Preferred Portfolio

	Capacity (MW)											Resource Totals
Resource	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017-2026**
Expansion Options												
Gas - CCCT		-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking		-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency		154	128	131	122	123	114	118	118	112	111	**1,229**
DSM - Load Control		-	-	-	-	-	-	-	-	-	-	-
Renewable - Wind		-	-	-	-	1,100	-	-	-	-	-	**1,100**
Renewable - Geothermal		-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar		-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass		-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro		-	-	-	-	-	-	-	-	-	-	-
Storage - CAES		-	-	-	-	-	-	-	-	-	-	-
Storage - Other		-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions		781	853	1,151	1,115	1,118	1,223	1,150	1,172	1,390	1,329	**1,128**
Existing Unit Changes												
Coal Early Retirement/Conversions		-	-	(280)	-	(387)	-	-	-	-	(82)	**(749)**
Thermal Plant End-of-life Retirements		-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions		-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades		-	-	-	-	-	-	-	-	-	-	-
Total		-	-	-	-	-	-	-	-	-	-	

Study includes Naughton 3 retirement at the end of 2018
FOT in resource total are 10-year averages

2017 IRP Preferred Portfolio less Fall 2016 Ten-Year Business Plan sensitivity

	Capacity (MW)											Resource Totals
Resource	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017-2026**
Expansion Options												
Gas - CCCT		-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking		-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency		(4)	(29)	(17)	-	1	-	(0)	(1)	(6)	-	**(56)**
DSM - Load Control		-	-	-	-	-	-	-	-	-	-	-
Renewable - Wind		-	-	-	-	650	-	-	-	-	-	**650**
Renewable - Geothermal		-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar		-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass		-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro		-	-	-	-	-	-	-	-	-	-	-
Storage - CAES		-	-	-	-	-	-	-	-	-	-	-
Storage - Other		-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions		(10)	(250)	263	317	219	219	219	220	225	225	**165**
Existing Unit Changes												
Coal Early Retirement/Conversions		-	-	-	-	-	-	-	-	-	-	-
Thermal Plant End-of-life Retirements		-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions		-	-	(285)	-	-	-	-	-	-	-	**(285)**
Turbine Upgrades		-	-	-	-	-	-	-	-	-	-	-
Total		**(949)**	**(1,260)**	**(1,041)**	**(919)**	**(1,084)**	**(1,118)**	**(1,049)**	**(1,071)**	**(1,282)**	**(1,133)**	

FOT in resource total are 10-year averages

Fall 2016 Ten-Year Business Plan sensitivity

	Capacity (MW)											Resource Totals
Resource	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2017-2026**
Expansion Options												
Gas - CCCT		-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking		-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency		158	157	148	122	122	114	118	119	118	111	**1,286**
DSM - Load Control		-	-	-	-	-	-	-	-	-	-	-
Renewable - Wind		-	-	-	-	450	-	-	-	-	-	**450**
Renewable - Geothermal		-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar		-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass		-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro		-	-	-	-	-	-	-	-	-	-	-
Storage - CAES		-	-	-	-	-	-	-	-	-	-	-
Storage - Other		-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions		791	1,103	887	798	899	1,004	931	952	1,165	1,104	**963**
Existing Unit Changes												
Coal Early Retirement/Conversions		-	-	(280)	-	(387)	-	-	-	-	(82)	**(749)**
Thermal Plant End-of-life Retirements		-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions		-	-	285	-	-	-	-	-	-	-	**285**
Turbine Upgrades		-	-	-	-	-	-	-	-	-	-	-
Total		**949**	**1,260**	**1,041**	**919**	**1,084**	**1,118**	**1,049**	**1,071**	**1,282**	**1,133**	

Study includes Naughton 3 gas conversion at the end of 2018
FOT in resource total are 10-year averages

PacifiCorp's 2017 IRP preferred portfolio will serve as the starting point for resource assumptions in the fall 2017 ten-year business plan. Changes to the portfolio may be influenced by assumptions such as updated load forecast inputs, updated price curve inputs, an updated load and resource balance, and updated environmental policy developments.

Resource Procurement Strategy

To acquire resources outlined in the 2017 IRP action plan, PacifiCorp intends to continue using competitive solicitation processes in accordance with applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. PacifiCorp will also continue to pursue opportunistic acquisitions identified outside of a competitive procurement process that provide clear economic benefits to customers. Regardless of the method for acquiring resources, PacifiCorp will support its resource procurement activities with the appropriate financial analysis using then-current assumptions for inputs such as load forecasts, commodity prices, resource costs, and policy developments. Any such financial analysis will account for any applicable long-term system benefits with business planning goals in mind. The sections below profile the general procurement approaches for the key resource categories covered in the 2017 IRP action plan.

Renewable Resources

PacifiCorp uses competitive request for proposals (RFPs) to procure renewable resources consistent applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. In Oregon and Utah, these state requirements involve the oversight of an independent evaluator. The renewable resource RFPs outline the types of resources being pursued, defines specific information required of potential bidders and details both price and non-price scoring metrics that will be used to evaluate proposals.

Renewable Energy Credits

The Company uses shelf RFPs as the primary mechanism under which REC RFPs and reverse REC RFPs will be issued to the market. The shelf RFPs are updated to define the product definition, timing, and volume and further provide schedule and other applicable criteria to bidders.

Demand-side Management

In 2016, through competitive procurement processes, the Company selected vendors to continue and adaptively manage the successful, cost-effective delivery of its two largest Class 2 DSM programs: Home Energy Savings and wattsmart Business. In 2017, The Company will evaluate and re-procure, as appropriate, the delivery contract(s) for residential behavior program(s).

Assessment of Owning Assets versus Purchasing Power

As PacifiCorp acquires new resources, it will need to determine whether it is better to own a resource or purchase power from another party. While the ultimate decision will be made at the

time resources are acquired, and will primarily be based on cost, there are other considerations that may be relevant.

With owned resources, PacifiCorp is in a better position to control costs, make life extension improvements, as being implemented with the wind repower project analyzed in the 2017 IRP, use the site for additional resources in the future, change fueling strategies or sources, efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and utilize the plant at embedded cost as long as it remains economic. In addition, by owning a plant, PacifiCorp can hedge itself from the uncertainty of the ability to perform consistent with the terms and conditions outlined in a power purchase agreement over time.

Depending on contract terms, purchasing power from a third party in a long term contract may help mitigate and may avoid liabilities associated with closure of a plant. A long-term power purchase agreement relinquishes control of construction cost, schedule, ongoing costs and compliance to a third party, and exposes the buyer to default events and contract remedies that will not likely cover the potential negative impacts. Finally, credit rating agencies impute debt associated with long-term resource contracts that may result from a competitive procurement process, and such imputation may affect PacifiCorp's credit ratios and credit rating.

Managing Carbon Risk for Existing Plants

CO_2 reduction regulations at the federal, regional, or state levels could prompt PacifiCorp to continue to look for measures to lower CO_2 emissions of fossil-fired power plants through cost-effective means. The cost, timing, and compliance flexibility afforded by CO_2 reduction rules will impact what types of measures that might be cost-effective and practical from operational and regulatory perspectives. As evident in the 2017 IRP, known and prospective environmental regulations can impact utilization of resources and investment decisions.

Under the CPP, compliance strategies will be affected by how states choose to implement the rule and on-going legal challenges to the rule. Alternative policies could impute a carbon tax or implement a cap-and-trade framework. Under a cap-and-trade policy framework, examples of factors affecting carbon compliance strategies include the allocation of emission allowances, the cost of allowances in the market, and any flexible compliance mechanisms such as opportunities to use carbon offsets, allowance/offset banking and borrowing, and safety valve mechanisms. Under a CO_2 tax framework, the tax level and details around how the tax might be assessed would affect compliance strategies.

To lower the emission levels for existing fossil-fired power plants, options include early retirement, changes in plant dispatch, changing the fuel type, repowering with more efficient generation equipment, lowering the plant heat rate so it is more efficient, and adoption of new technologies such as CO_2 capture with sequestration, when commercially proven. Indirectly, plant CO_2 emission risk can be addressed by acquiring offsets or other environmental attributes that might become available in the market. Under an aggressive CO_2 regulatory environment, and depending on fuel costs, coal plant idling and replacement strategies may become tenable options.

High CO_2 costs would shift technology preferences both for new resources and existing resources to those with more efficient heat rates and also away from coal, unless carbon is sequestered. There may be opportunities to repower some of the existing coal fleet with a different less carbon-intensive fuel such as natural gas, as has been evaluated for the Naughton Unit 3 and Cholla Unit 4 generating units. An ongoing consideration is whether new technologies will be available that can be exchanged for existing coal economically, particularly if market and policy drivers lead to large scale and abrupt early retirements across the region and the U.S. as a whole.

Purpose of Hedging

While PacifiCorp focuses every day on minimizing net power costs for customers, the Company also focuses every day on mitigating price risk to customers, which is done through hedging consistent with a robust risk management policy. For years PacifiCorp has followed a consistent hedging program that limits risk to customers, has tracked risk metrics assiduously and has diligently documented hedging activities. The Company's risk management policy and hedging program exists to achieve the following goals: (1) ensure reliable sources of electric power are available to meet PacifiCorp's customers' needs; (2) reduce volatility of net power costs for PacifiCorp's customers. The purpose is solely to reduce customer exposure to net power cost volatility and adverse price movement. PacifiCorp does not engage in a material amount of proprietary trading activities. Hedging is done solely for the purpose of limiting financial losses due to unfavorable wholesale market changes. Hedging modifies the potential losses and gains in net power costs associated with wholesale market price changes. The purpose of hedging is not to reduce or minimize net power costs. PacifiCorp cannot predict the direction or sustainability of changes in forward prices. Therefore, the Company hedges, in the forward market, to reduce the volatility of net power costs consistent with good industry practice as documented in the Company's risk management policy.

Risk Management Policy and Hedging Program

PacifiCorp's risk management policy and hedging program were designed to follow electric industry best practices and are periodically reviewed at least annually by the Company's risk oversight committee. The risk oversight committee includes Company representatives from the front office, finance, risk management, treasury, and legal department. The risk oversight committee makes recommendations to the president of Pacific Power, who ultimately must approve any change to the risk management policy. PacifiCorp's current policy is also consistent with the guidelines that resulted from collaborative hedging workshops with parties in Utah, Oregon, Idaho and Wyoming that took place in 2011 and 2012.

The main components of the Company's risk management policy and hedging program are natural gas percent hedged volume limits, value-at-risk (VaR) limits and time to expiry VaR (TEVaR) limits. These limits force PacifiCorp to monitor the open positions it holds in power and natural gas on behalf of its customers on a daily basis and limit the size of these open positions by prescribed time frames in order to reduce customer exposure to price concentration and price volatility. The hedge program requires purchases of natural gas at fixed prices in gradual stages in advance of when it is required to reduce the size of this short position and associated customer risk. Likewise, on the power side, PacifiCorp either purchases or sells power

in gradual stages in advance of anticipated open short or long positions to manage price volatility on behalf of customers.

Since 2003, PacifiCorp's hedge program has employed a portfolio approach of dollar cost averaging to progressively reduce net power cost risk exposure over a defined time horizon while adhering to best practice risk management governance and guidelines. The Company's current portfolio hedging approach is defined by increasing risk tolerance levels represented by progressively increasing percentage of net power costs across the forward hedging period. PacifiCorp incorporated a time to expiry value at risk (TEVaR) metric in May 2010. In May 2012, as a result of multiple hedging collaboratives, the Company reintroduced natural gas percent hedge volume limits of forecast requirements into its policy. There has been no conflict to-date between the new volume limits and the Company's VaR and TEVaR limits, although the volume limits would supersede in such conflict, consistent with the guidelines from the hedging collaboratives.

The primary governance of PacifiCorp's hedging activities is documented in the Company's Risk Management Policy. In May 2010, PacifiCorp moved from hedging targets based on volume percentages to targets based on the "to expiry value-at-risk" or TEVaR metric. The primary goal of this change was to increase the transparency of the combined natural gas and power exposure by period. It enhances the progressive approach to hedging that the Company has employed for many years and provides the benefit of a more sophisticated measure of risk that responds to changes in the market and changes in open natural gas and power positions. Importantly, the TEVaR metric automatically reduces hedge requirements as commodity price volatility decreases and increases hedge requirements as correlations among commodities diverge, all the while maintaining the same customer risk exposure.

Dollar cost averaging is the term used to describe gradually hedging over a period of time rather than all at once. This method of hedging, which is widely used by many utilities, captures time diversification and eliminates speculative bursts of market timing activity. Its use means that at times the Company buys at relatively higher prices and at other times relatively lower prices, essentially capturing an array of prices at many levels. While doing so, PacifiCorp steadily and adaptively meets its hedge goals through the use of this technique while staying within VaR and TEVaR and natural gas percent hedge volume limits.

The result of these program changes in combination with changes in the market (such as reduced volatility to which the Company's program automatically responds), has been a significant decrease in PacifiCorp's longer-dated hedge activity, *i.e.*, four years forward on a rolling basis.

As a result of the hedging collaboratives, PacifiCorp made the following material changes to its policy in May 2012: (l) a reduction in the standard hedge horizon from 48 months to 36 months and (2) a percent hedged range guideline for natural gas for each of the three forward l2-month periods, which includes a minimum natural gas open position in each of the forward 12-month periods. The percent hedged range guideline is greater for the first rolling twelve months and gradually smaller for the second and third rolling twelve-month periods. PacifiCorp also agreed to provide a new confidential semi-annual hedging report.

Cost Minimization

While hedging does not minimize net power costs, PacifiCorp takes many actions to minimize net power costs for customers. First, the Company is engaged in integrated resource planning to plan resource acquisitions that are anticipated to provide the lowest cost resources to our customers in the long-run. PacifiCorp then issues competitive requests for proposals to assure that the resources we acquire are the lowest cost resources available on a risk-adjusted basis. In operations, PacifiCorp optimizes its portfolio of resources on behalf of customers by maintaining and operating a portfolio of assets that diversifies customer exposure to fuel, power market and emissions risk and utilize an extensive transmission network that provides access to markets across the western United States. Independent of any natural gas and electric price hedging activity, to provide reliable supply and minimize net power costs for customers, the Company commits generation units daily, dispatches in real time all economic generation resources and all must-take contract resources, serves retail load, and then sells any excess generation to generate wholesale revenue to reduce net power costs for customers. PacifiCorp also purchases power when it is less expensive to purchase power than to generate power from our owned and contracted resources.

Hedging cannot be used to minimize net power costs. Hedging does not produce a different expected outcome than not hedging and therefore cannot be considered a cost minimization tool. Hedging is solely a tool to mitigate customer exposure to net power cost volatility and the risk of adverse price movement. However, PacifiCorp does minimize the cost of hedging by transacting in liquid markets and utilizing robust protections to mitigate the risk of counterparty default. In addition, PacifiCorp reduces the amount of hedging required to achieve a given risk tolerance through its portfolio hedge management approach, which takes into account offsetting exposures when these commodities are correlated, as opposed to hedging commodity exposures to natural gas and power in isolation without regard for offsets.

Portfolio

PacifiCorp has a short position in natural gas because of its ownership of gas-fired electric generation that requires it to purchase large quantities of natural gas to generate electricity to serve its customers. PacifiCorp may have short or long positions in power depending on the shortfall or excess of the Company's total economic generation relative to customer load requirements at a given point in time.

The Company hedges its net energy (combined natural gas and power) position on a portfolio basis to take full advantage of any natural offsets between its long power and short natural gas positions. Analysis has shown that a "hedge only power" or "hedge only natural gas" approach results in higher risk (*i.e.,* a wider distribution of outcomes). There is a natural need for an electric company with natural gas fired electricity generation assets to have a hedge program that simultaneously manages natural gas and power open positions with appropriate coordinated metrics. PacifiCorp's risk management department incorporates daily updates of forward prices for natural gas, power, volatilities and correlations to establish daily changes in open positions and risk metrics which inform the hedging decisions made every day by Company traders.

PacifiCorp's hedge program does not rely on a long power position. However, the Company's hedge program takes into account its full portfolio and utilizes continuously updated correlations

of natural gas and power prices and thereby takes advantage of offsetting natural gas and power positions in circumstances when prices are correlated and a forecast long power position offsets a forecast short natural gas position. This has the effect of reducing the amount of natural gas hedging that the Company would otherwise pursue. Ignoring this correlation would instead result in the need for more natural gas hedges to achieve the same level of customer risk reduction.

PacifiCorp's customers have benefited from offsetting power and natural gas positions. Power and natural gas prices are closely related because natural gas is often the fuel on the margin in efficient dispatch, as is practiced throughout the western U.S. This means power sales tend to be more valuable in periods when natural gas is high cost, producing revenues that are a credit or offset to the high cost fuel. If spot natural gas prices depart from prior forward prices, power prices will tend to do so in the same direction, thereby naturally hedging some of the unexpected cost variance.

Effectiveness Measure

The goal of the hedging program is to reduce volatility in the Company's net power costs primarily due to changes in market prices. The goal is not to "beat the market" and, therefore, should not be measured on the basis of whether it has made or lost money for customers. This reduction in volatility is calculated and reported in the Company's confidential semi-annual hedging report which it began producing as a result of the hedging collaborative.

Instruments

The Company's hedging program allows the use of several instruments including financial swaps, fixed price physical and options for these products. PacifiCorp chooses instruments that generally have greater liquidity and lower transaction costs. The Company also considers, with respect to options, the likelihood of disallowance of the option premium in its six jurisdictions. There is no functional difference between financial swaps and fixed price physical transactions; both instruments are equally effective in hedging the Company's fixed price exposure.

Treatment of Customer and Investor Risks

The IRP standards and guidelines in Utah require that PacifiCorp "identify which risks will be borne by ratepayers and which will be borne by shareholders." This section addresses this requirement. Three types of risk are covered: stochastic risk, capital cost risk, and scenario risk.

Stochastic Risk Assessment

Several of the uncertain variables that pose cost risks to different IRP resource portfolios are quantified in the IRP production cost model using stochastic statistical tools. The variables addressed with such tools include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long-term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not reflected in rates, and are therefore borne by investors unless specific regulatory mechanisms provide otherwise. Consequently, over time, these risks are shared between customers and investors. Between rate

cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

Capital Cost Risks

The actual cost of a generating or transmission asset is expected to vary from the cost assumed in the IRP. State commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risk of such a determination is borne by investors. To the extent that capital costs vary from those assumed in this IRP for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

Scenario Risk Assessment

Scenario risk assessment pertains to abrupt or fundamental changes to variables that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risks of this type facing PacifiCorp continues to be government actions related to emissions and changes in load and transmission infrastructure. These scenario risks relate to the uncertainty in predicting the scope, timing, and cost impact of emission and policies and renewable standard compliance rules.

To address these risks, PacifiCorp evaluates resources in the IRP and for competitive procurements using a range of CO_2 policy assumptions consistent with the scenario analysis methodology adopted for PacifiCorp's 2017 IRP portfolio development and evaluation process. The Company's use of IRP sensitivity analysis covering different resource policy and cost assumptions also addresses the need for consideration of scenario risks for long-term resource planning. The extent to which future regulatory policy shifts do not align with PacifiCorp's resource investments determined to be prudent by state commissions is a risk borne by customers.

2017 INTEGRATED RESOURCE PLAN

Volume II - Appendices

April 4, 2017



PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY











This 2017 Integrated Resource Plan Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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

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

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APPENDIX A – LOAD FORECAST DETAILS

Introduction

This appendix reviews the load forecast used in the modeling and analysis of the 2017 Integrated Resource Plan ("IRP"), including scenario development for case sensitivities. The load forecast used in the IRP is an estimate of the energy sales, and peak demand over a 20-year period. The 20-year horizon is important to anticipate electricity demand in order to develop timely response of resources.

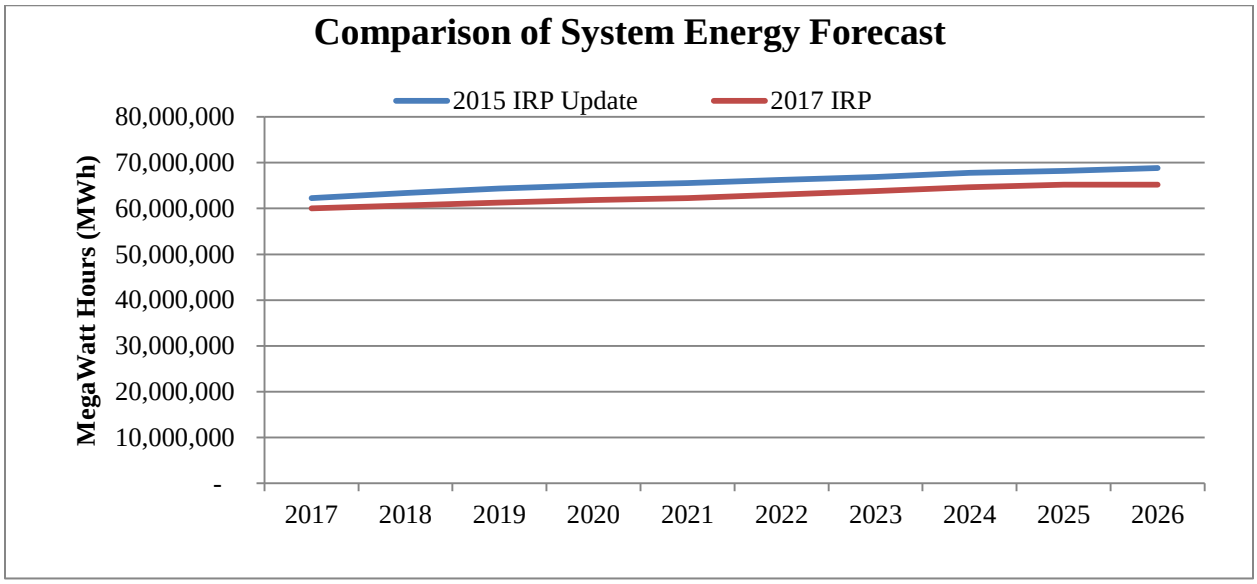
In the development of its load forecast PacifiCorp employs econometric models that use historical data and inputs such as regional and national economic growth, weather, seasonality, and other customer usage and behavior changes. The forecast is divided into classes that use energy for similar purposes and at comparable retail rates. These separate customer classes include residential, commercial, industrial, irrigation, lighting, and public authority customer classes. The classes are modeled separately using variables specific to their usage patterns. For residential customers, typical energy uses include space heating, water heating, lighting, cooking, refrigeration, dish washing, laundry washing, televisions and various other end use appliances. Commercial and industrial customers use energy for production and manufacturing processes, space heating, air conditioning, lighting, computers and other office equipment.

Jurisdictional peak load forecasts are developed using econometric equations that relate observed monthly peak loads, peak producing weather and the weather-sensitive loads for all classes. The system coincident peak forecast, which is used in portfolio development, is the maximum load required on the system in any hourly period and is extracted from the hourly forecast model.

Summary Load Forecast

The Company updated its load forecast in December 2016. The average annual energy growth rate for the 10-year period (2017 through 2026) is 0.91 percent. Relative to the load forecast prepared for the 2015 IRP update, PacifiCorp 2026 energy forecasted energy requirement decreased in all jurisdictions other than Idaho, while PacifiCorp system energy requirement decreased approximately 5.3 percent. Figure A.1 has a comparison of energy forecasts from the 2017 IRP compared to the 2015 IRP Update.

Figure A.1 - PacifiCorp System Energy Load Forecast Change, at Generation, pre-DSM



Tables A.1 and A.2 show the annual load and coincident peak load forecast when not reducing load projections to account for new energy efficiency measures (Class 2 DSM).[1] Tables A.3 and A.4 show the forecast changes relative to the 2015 IRP Update load forecast for loads and coincident system peak, respectively.

Table A.1 – Forecasted Annual Load Growth, 2017 through 2026 (Megawatt-hours), at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2017	60,061,400	14,605,160	4,458,290	905,140	26,276,610	10,004,230	3,811,970	-
2018	60,670,450	14,736,700	4,497,430	904,220	26,637,690	10,050,920	3,843,490	-
2019	61,301,370	14,881,630	4,536,810	901,890	26,956,500	10,150,590	3,873,950	-
2020	61,863,300	14,951,780	4,563,240	897,830	27,260,420	10,292,840	3,897,190	-
2021	62,297,200	15,019,870	4,585,510	892,140	27,547,010	10,334,140	3,918,530	-
2022	63,007,030	15,144,810	4,615,090	889,900	27,962,140	10,445,060	3,950,030	-
2023	63,799,730	15,276,170	4,646,900	887,920	28,398,470	10,606,930	3,983,340	-
2024	64,610,360	15,448,030	4,692,480	888,010	28,896,420	10,663,800	4,021,620	-
2025	65,171,560	15,534,760	4,720,510	882,810	29,224,630	10,763,560	4,045,290	-
2026	65,182,980	15,634,920	4,753,180	879,280	28,894,200	10,947,860	4,073,540	-
Average Annual Growth Rate for 2017-2026								
2017 - 2026	**0.91%**	**0.76%**	**0.71%**	**-0.32%**	**1.06%**	**1.01%**	**0.74%**	

[1] Class 2 DSM load reductions are included as resources in the System Optimizer model.

Table A.2 - Forecasted Annual Coincident Peak Load (Megawatts) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2017	10,130	2,285	718	151	5,012	1,246	719	-
2018	10,225	2,308	724	151	5,071	1,248	724	-
2019	10,310	2,349	739	152	5,097	1,245	727	-
2020	10,403	2,359	742	152	5,152	1,267	731	-
2021	10,518	2,374	747	151	5,217	1,279	750	-
2022	10,624	2,391	752	151	5,281	1,292	756	-
2023	10,706	2,407	757	151	5,341	1,303	747	-
2024	10,804	2,425	763	151	5,409	1,305	752	-
2025	10,920	2,443	768	151	5,483	1,318	757	-
2026	10,931	2,457	773	150	5,446	1,343	762	-
Average Annual Growth Rate for 2017-2026								
2017 - 2026	**0.85%**	**0.81%**	**0.82%**	**-0.06%**	**0.93%**	**0.84%**	**0.65%**	

Table A.3 – Annual Load Growth Change: December 2016 Forecast less October 2015 Forecast (Megawatt-hours) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2017	(2,207,700)	(282,280)	(216,490)	18,670	(1,306,230)	(447,850)	26,480	-
2018	(2,711,610)	(404,400)	(213,910)	16,230	(1,595,750)	(549,600)	35,820	-
2019	(3,080,850)	(415,220)	(210,950)	13,080	(1,914,340)	(596,700)	43,280	-
2020	(3,219,990)	(429,430)	(214,930)	9,540	(2,136,110)	(499,850)	50,790	-
2021	(3,275,870)	(410,960)	(204,530)	7,180	(2,246,040)	(479,490)	57,970	-
2022	(3,231,080)	(396,300)	(200,300)	5,500	(2,309,120)	(397,770)	66,910	-
2023	(3,104,490)	(393,620)	(193,660)	6,790	(2,351,250)	(248,360)	75,610	-
2024	(3,150,500)	(397,080)	(186,540)	10,390	(2,400,790)	(260,370)	83,890	-
2025	(3,065,130)	(397,820)	(168,980)	15,410	(2,451,900)	(151,930)	90,090	-
2026	(3,674,160)	(424,310)	(161,420)	17,830	(3,226,920)	24,970	95,690	-

Table A.4 – Annual Coincident Peak Growth Change: July 2016 Forecast less October 2015 Forecast (Megawatts) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2017	(153)	(23)	(25)	4	7	(111)	(4)	-
2018	(245)	(29)	(26)	4	(66)	(125)	(2)	-
2019	(306)	(6)	(15)	4	(145)	(143)	(2)	-
2020	(319)	(11)	(18)	6	(177)	(126)	6	-
2021	(323)	(9)	(17)	5	(199)	(118)	14	-
2022	(326)	(6)	(17)	5	(215)	(108)	16	-
2023	(343)	(5)	(16)	4	(231)	(99)	3	-
2024	(350)	1	(15)	6	(244)	(104)	5	-
2025	(333)	(5)	(16)	10	(258)	(91)	27	-
2026	(438)	(7)	(16)	12	(375)	(67)	14	-

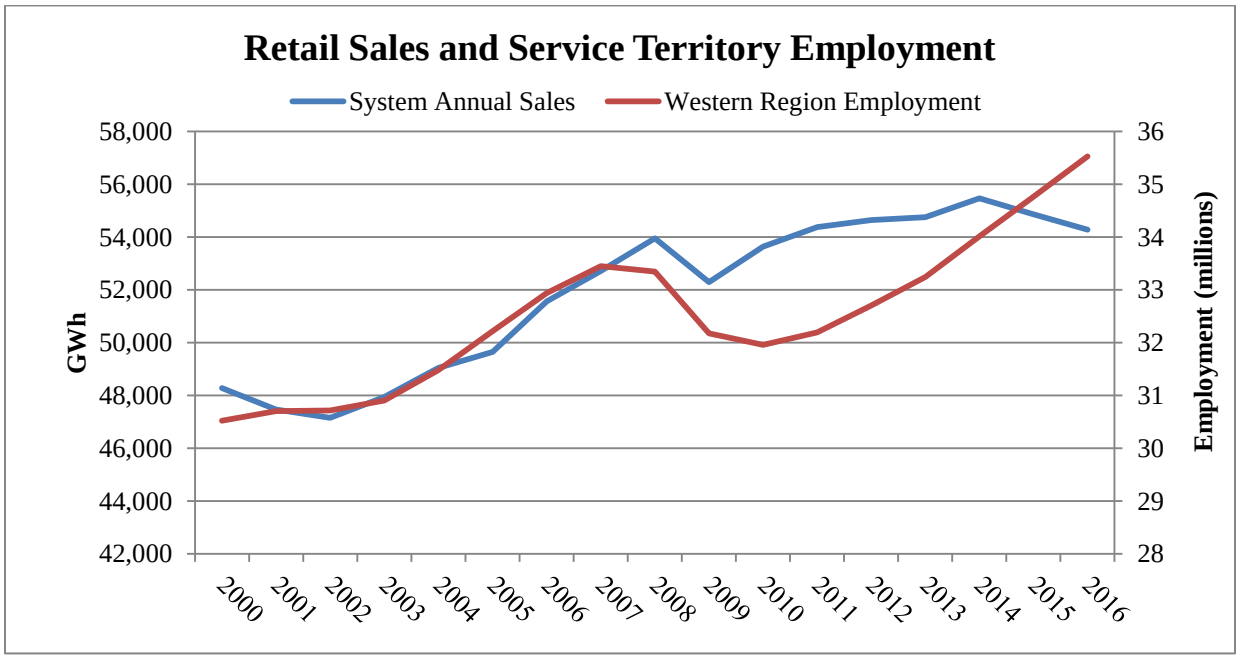
Load Forecast Assumptions

Regional Economy by Jurisdiction

The PacifiCorp electric service territory is comprised of six states and within these states the Company serves customers in a total of 88 counties. The level of retail sales for each state and county is correlated with economic conditions and population statistics in each state. The Company uses both economic data, such as employment, and population data, to forecast its

retail sales. Looking at historical sales and employment data for PacifiCorp's service territory, 2000 through 2016, in Figure A.2, it is apparent that the Company's retail sales generally follow economic conditions in its service territory, and most recently the 2008-2009 recession.

Figure A.2 - PacifiCorp Annual Retail Sales 2000 through 2016 and Western Region Employment

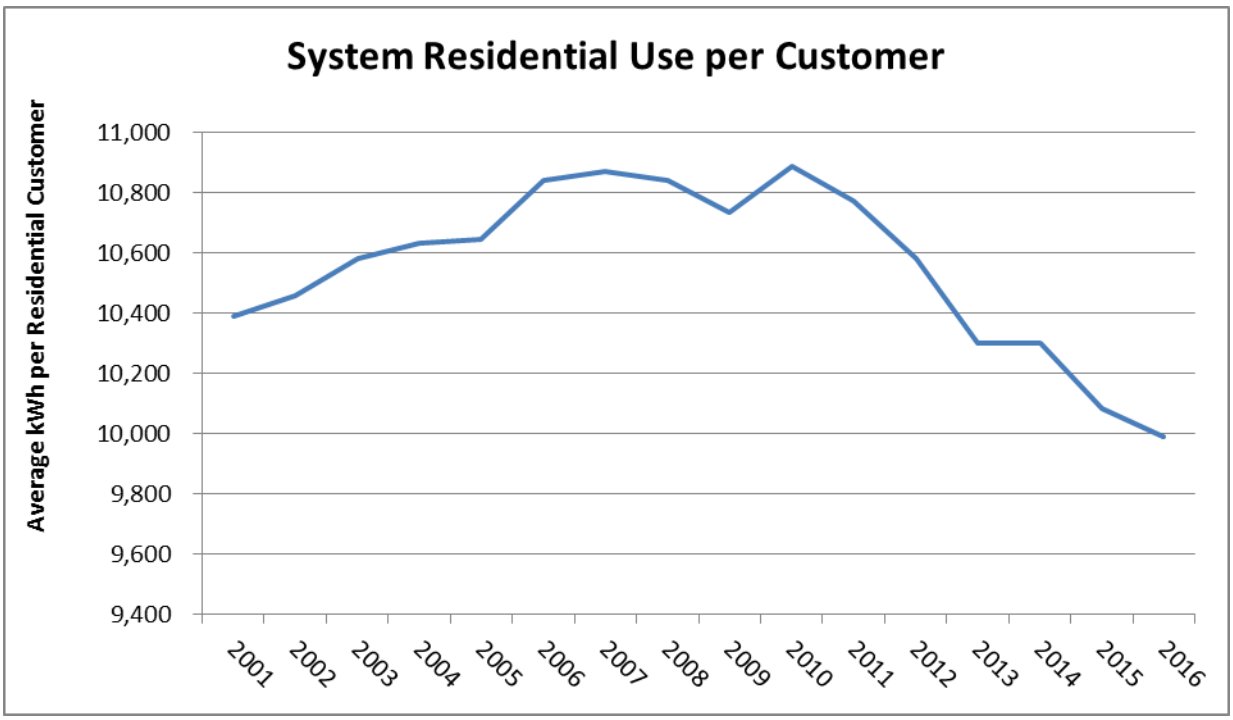


Sources: PacifiCorp and United States Department of Labor, Bureau of Labor Statistics

As discussed below, although both the economic and demographic forecast is relatively unchanged from the 2015 IRP Update, the load forecast has decreased. There are two changes which are driving the 2017 IRP load and peak forecast down. First, the relationship between the economic variable and sales has "flattened", meaning electric usage has become less responsive to the economic variable as seen in years 2015 and 2016 in Figure A.2 above. Second, there have been changes in expected sales to our customers due in large part to lower commodity prices.

Figure A.3 shows the weather normalized average system residential use per customer. As illustrated, residential use per customer has been decreasing since 2010.

Figure A.3 - PacifiCorp Annual Residential Use per Customer 2001 through 2016

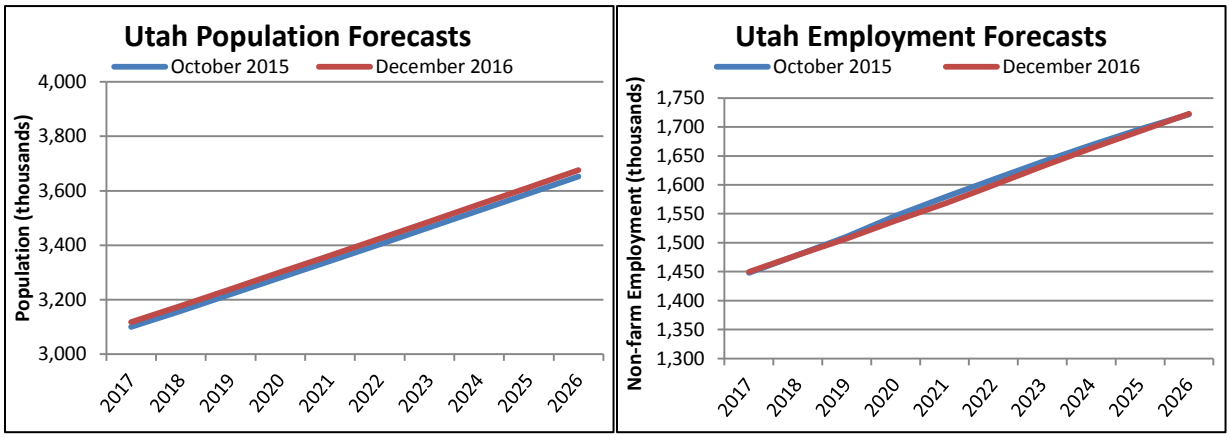


Residential use per customer across all six of PacifiCorp's states is changing due to increased energy efficiency driven primarily by lighting efficiency standards resulting from the 2007 Federal Energy legislation. In addition, there has been a shift from single-family and manufactured housing to multi-dwelling units and a trend of replacing older electric appliances with more energy efficient appliances.

Utah

PacifiCorp serves 25 of the 29 counties in the state of Utah, with Salt Lake City being the largest metropolitan area served by the Company within the state. Utah is expected to experience a 1.9 percent increase in non-farm employment over the next 10 years. Figure A.4 shows the change in population and employment forecasts between the 2015 IRP Update relative to the 2017 IRP forecast. This figure illustrates that the population forecast is slightly higher while the employment forecasts is slightly lower. Relative to the load forecast prepared for the 2015 IRP update, the Utah 2026 retail load forecast decreased approximately 6.7 percent. This decrease is attributable to the projected impact of additional private generation and the impact of a relatively less favorable economic outlook compared to the 2015 IRP Update.

Figure A.4 – IHS Global Insight Utah Household and Employment forecasts from the October 2015 load forecast and the December 2016 load forecast

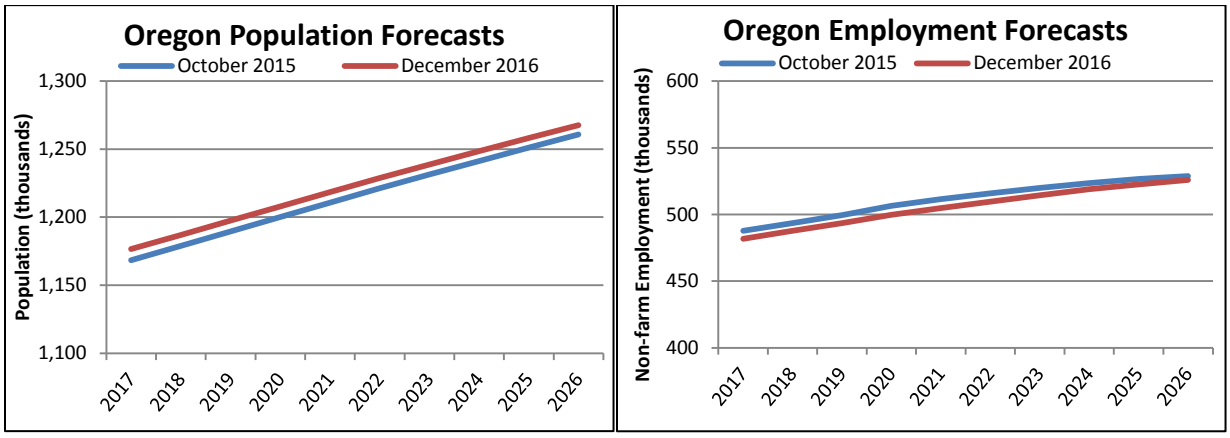


A risk to the Utah forecast is commodity prices, such as oil and natural gas, where volatility in prices and profitability can lead to swings in production and employment potentially translating to swings in the retail sales forecast.

Oregon

PacifiCorp serves 25 of the 36 counties in Oregon, but provided only 27.2 percent of ultimate electric retail sales in the state of Oregon in 2015.[2] In 2014 and 2015, Oregon employment growth has outpaced national employment by approximately one percentage point.[3] Figure A.5 shows the change in population and employment forecasts for the 2015 IRP Update relative to the 2017 IRP forecast. This figure illustrates that the Oregon forecast of population has increased slightly, while the employment forecast has decreased slightly. Relative to the load forecast prepared for the 2015 IRP Update, the Oregon 2026 retail load forecast has decreased approximately 2.6 percent.

Figure A.5 – IHS Global Insight Oregon Household and Employment forecasts from the October 2015 load forecast and the December 2016 load forecast

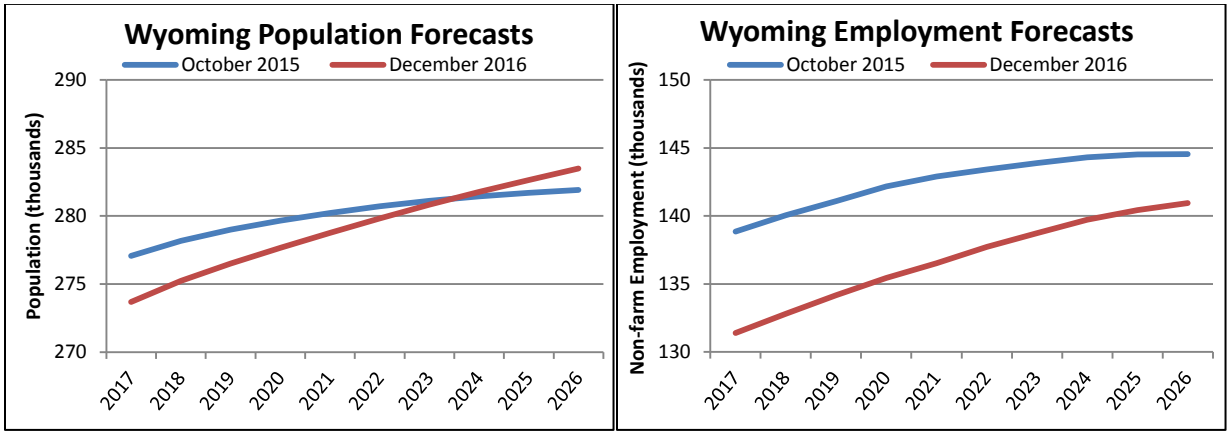


[2] Source: Oregon Public Utility Commission, 2015 Oregon Utility Statistics.
[3] Source: Bureau of Labor Statistics.

Wyoming

The Company serves 15 of the 23 counties in Wyoming, with Casper being the largest metropolitan area served by the Company in the state. Industrial sales make up approximately 73 percent of the Company's Wyoming sales. Figure A.6 shows the change in population and employment forecasts for the 2015 IRP Update relative to the 2017 IRP forecast. This figure illustrates that the Wyoming population forecast has decreased over the 2017 to 2022 timeframe, while it increased over the 2023 to 2026 period. The employment forecast has decreased. Relative to the load forecast prepared for the 2015 IRP Update, the Wyoming 2026 retail load forecast increased approximately 1.2 percent.

Figure A.6 – IHS Global Insight Wyoming Household and Employment forecasts from the October 2015 load forecast and the December 2016 load forecast

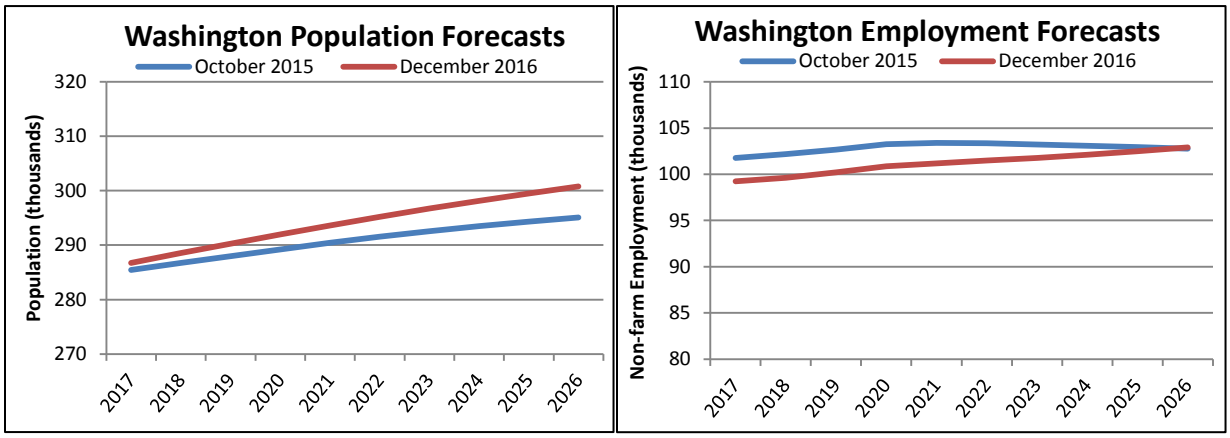


A risk to the Wyoming forecast is commodity prices, such as oil and natural gas, where volatility in prices and profitability can lead to swings in production and employment which translates to potential swings in the retail sales forecast.

Washington

PacifiCorp serves the following counties in Washington State: Benton, Columbia, Garfield, Klickitat, Walla Walla, and Yakima. Yakima is the most populated county that the Company serves in Washington State and has a large concentration of agriculture and food processing businesses. Residential and commercial sales are roughly equal in size each making up approximately 38 percent of the Company's Washington sales. Figure A.7 shows the change in population and employment forecasts for the 2015 IRP Update relative to the 2017 IRP forecast. This figure illustrates that the population forecast is higher and the employment forecast has decreased. Relative to the load forecast prepared for the 2015 IRP Update, the Washington 2026 retail load forecast decreased approximately 1.3 percent.

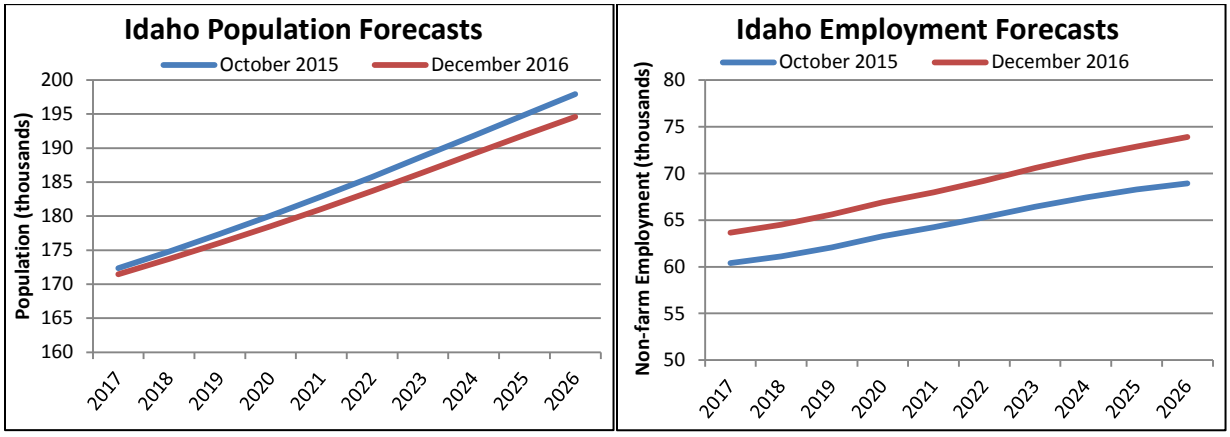
Figure A.7 – IHS Global Insight Washington Household and Employment forecasts from the October 2015 load forecast and the December 2016 load forecast



Idaho

The Company serves 13 of the 44 counties in the state of Idaho, with the majority of the Company's service territory in rural Idaho. Industrial sales make up approximately 47 percent of the Company's Idaho sales. Figure A.8 shows the change in population and employment forecasts for the 2015 IRP Update relative to the 2017 IRP forecast. This figure illustrates that the forecast for population has decreased, while the employment forecast has increased. Relative to the load forecast prepared for the 2015 IRP Update, the Idaho 2026 retail load forecast increased approximately 3.0 percent.

Figure A.8 – IHS Global Insight Idaho Household and Employment forecasts from the October 2015 load forecast and the December 2016 load forecast

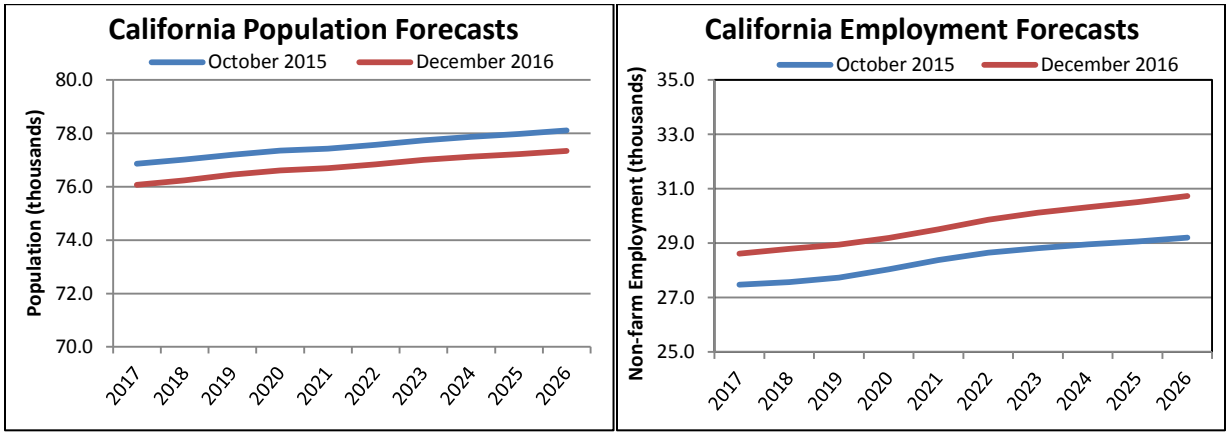


California

The four northern California counties served by PacifiCorp are largely rural, which include Del Norte, Modoc, Shasta and Siskiyou Counties. Crescent City is the largest metropolitan area served by the Company in California. Residential sales make up approximately 49 percent of the Company's California sales. Figure A.9 shows the change in population and employment forecasts for the 2015 IRP Update relative to the 2017 IRP forecast. This figure illustrates that the population forecast has decreased, while the employment forecast had increased. Relative to

the load forecast prepared for the 2015 IRP Update, the California 2026 retail load forecast increased approximately 6.5 percent.

Figure A.9 – IHS Global Insight California Household and Employment forecasts from the October 2015 load forecast and the December 2016 load forecast

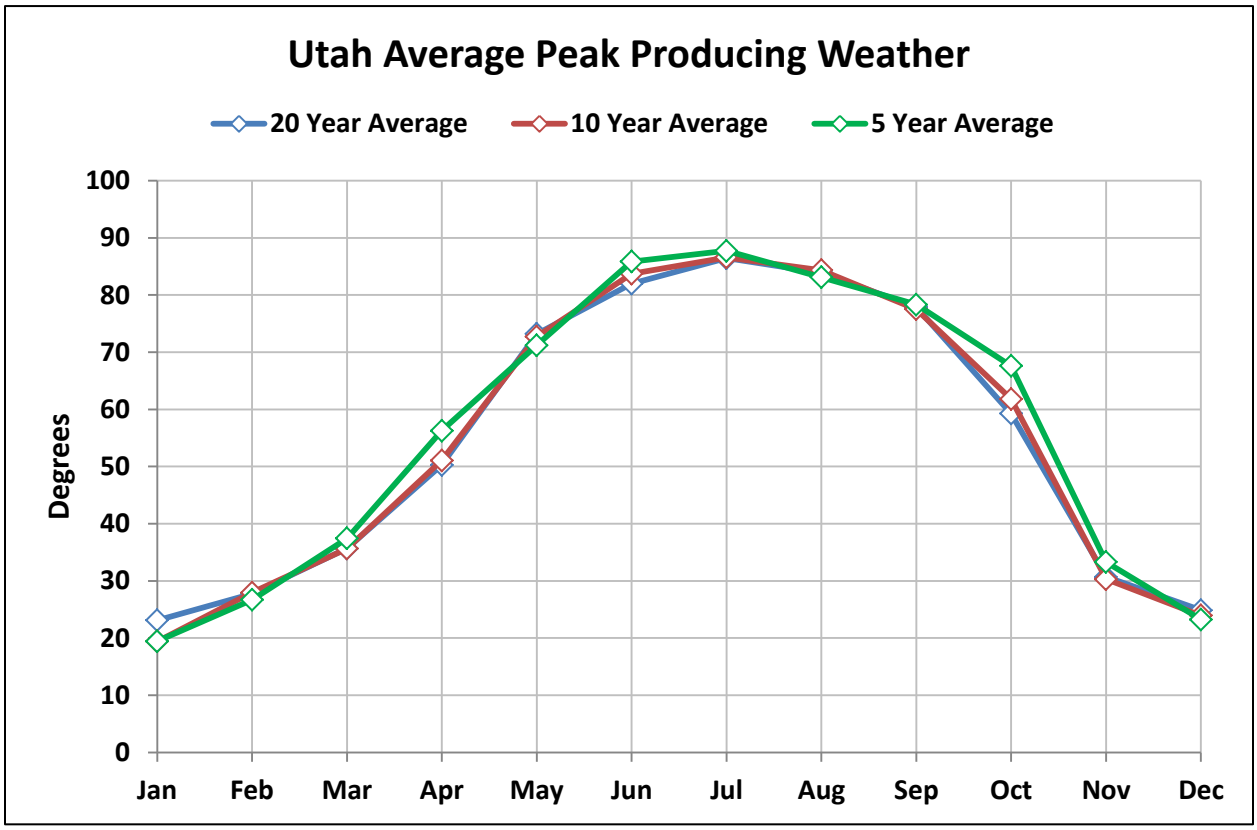


Weather

The Company's load forecast is based on normal weather defined by the 20-year time period of 1996-2015. The Company updated its temperature spline models to the five-year time period of 2011-2015. The Company's spline models are used to model the commercial and residential class temperature sensitivity at varying temperatures.

The Company has reviewed the appropriateness of using the average weather from a shorter time period as its "normal" peak weather. Figure A.10 indicates that peak producing weather does not change significantly when comparing five, 10, or 20 year average weather.

Figure A.10 - Comparison of Utah 5, 10, and 20 Year Average Peak Producing Temperatures



Statistically Adjusted End-Use (SAE)

The Company models sales per customer for the residential class using the SAE model, which combines the end-use modeling concepts with traditional regression analysis techniques. Major drivers of the SAE-based residential model are heating and cooling related variables, equipment shares, saturation levels and efficiency trends, and economic drivers such as household size, income and energy price. The Company uses ITRON for its load forecasting software and services, as well as SAE. To predict future changes in the efficiency of the various end uses for the residential class, an excel spreadsheet model obtained from ITRON was utilized; the model includes appliance efficiency trends based on appliance life as well as past and future efficiency standards. The SAE model reflects the US Department of Energy's Energy Information Administration (EIA) assumptions for changes in energy efficiency of each appliance category, which are updated annually to take into consideration for new codes and standards including lighting standards from the Energy Independence and Security Act of 2007. The EIA estimates the efficiency of appliance stocks and the saturation of appliances at the national level and for individual Census Regions. The model embeds all currently applicable laws and regulations regarding appliance efficiency, along with life cycle models of each appliance. The life cycle models, based on the decay and replacement rate are necessary to estimate how fast the existing stock of any given appliance turns over, i.e. newer more efficient equipment replacing older less efficient equipment.

Individual Customer Forecast

The Company updated its load forecast for a select group of large industrial customers, self-generation facilities of large industrial customers, and data center forecasts within the respective jurisdictions. Customer forecasts are provided by the customer to the Company through a regional business manager (RBM).

Actual Load Data

With the exception of the industrial class, the Company uses actual load data from January 2000 through February 2016. The historical data period used to develop the industrial monthly sales is from January 2000 through February 2016 in Utah and Wyoming, January 2002 through February 2016 in Idaho, and Washington, and January 2003 through February 2016 in California and Oregon.

The following tables are the annual actual retail sales, non-coincident peak, and coincident peak by state used in calculating the 2017 IRP retail sales forecast.

Table A.5 - Weather Normalized Jurisdictional Retail Sales 2000 through 2016

System Retail Sales - Megawatt-hours (MWh)*							
Year	California	Idaho	Oregon	Utah	Washington	Wyoming	**System**
2000	776,665	3,077,264	14,194,244	18,793,616	4,091,310	7,347,453	**48,280,553**
2001	778,162	2,976,494	13,523,805	18,484,442	4,026,937	7,680,809	**47,470,649**
2002	799,939	3,232,113	13,085,474	18,620,633	4,013,855	7,406,900	**47,158,914**
2003	819,108	3,227,070	13,108,396	19,249,531	4,067,382	7,471,050	**47,942,536**
2004	844,582	3,304,254	13,156,747	19,832,347	4,100,463	7,814,422	**49,052,814**
2005	835,402	3,222,870	13,160,345	20,214,262	4,213,148	8,009,888	**49,655,914**
2006	859,303	3,344,385	13,910,585	21,079,795	4,126,393	8,254,237	**51,574,698**
2007	874,819	3,358,414	13,973,359	21,962,447	4,071,975	8,482,587	**52,723,603**
2008	867,587	3,402,821	13,775,175	22,636,955	4,064,372	9,213,810	**53,960,720**
2009	829,879	2,962,976	13,116,677	22,094,266	4,037,211	9,259,753	**52,300,763**
2010	840,479	3,395,472	13,122,473	22,570,702	4,051,355	9,664,607	**53,645,087**
2011	803,948	3,432,628	13,000,020	23,357,025	4,017,580	9,766,930	**54,378,131**
2012	785,803	3,494,537	13,024,670	23,814,679	4,046,167	9,479,742	**54,645,597**
2013	774,660	3,517,060	13,061,037	23,794,419	4,058,252	9,552,400	**54,757,828**
2014	774,113	3,524,860	13,123,680	24,352,495	4,113,824	9,589,358	**55,478,330**
2015	746,136	3,459,937	13,082,915	24,081,112	4,114,642	9,379,936	**54,864,679**
2016	757,816	3,475,328	13,019,288	23,782,480	4,055,425	9,195,353	**54,285,689**
Average Annual Growth Rate							
2000-16	**-0.15%**	**0.76%**	**-0.54%**	**1.48%**	**-0.06%**	**1.41%**	**0.74%**

*System retail sales do not include sales for resale

Table A.6 - Non-Coincident Jurisdictional Peak 2000 through 2016

Non-Coincident Peak - Megawatts (MW)*							
Year	California	Idaho	Oregon	Utah	Washington	Wyoming	**System**
2000	176	686	2,603	3,684	785	1,062	**8,995**
2001	162	616	2,739	3,480	755	1,124	**8,876**
2002	174	713	2,639	3,773	771	1,113	**9,184**
2003	169	722	2,451	4,004	788	1,126	**9,260**
2004	193	708	2,524	3,862	920	1,111	**9,318**
2005	189	753	2,721	4,081	844	1,224	**9,811**
2006	180	723	2,724	4,314	822	1,208	**9,970**
2007	187	789	2,856	4,571	834	1,230	**10,466**
2008	187	759	2,921	4,479	923	1,339	**10,609**
2009	193	688	3,121	4,404	917	1,383	**10,705**
2010	176	777	2,552	4,448	893	1,366	**10,213**
2011	177	770	2,686	4,596	854	1,404	**10,486**
2012	159	800	2,550	4,732	797	1,338	**10,376**
2013	182	814	2,980	5,091	886	1,398	**11,351**
2014	161	818	2,598	5,024	871	1,360	**10,831**
2015	157	843	2,598	5,226	837	1,326	**10,986**
2016	155	848	2,584	5,018	819	1,300	**10,724**
Average Annual Growth Rate							
2000-16	**-0.78%**	**1.33%**	**-0.05%**	**1.95%**	**0.27%**	**1.28%**	**1.11%**

*Non-coincident peaks do not include sales for resale

Table A.7 - Jurisdictional Contribution to Coincident Peak 2000 through 2016

Coincident Peak - Megawatts (MW)*							
Year	California	Idaho	Oregon	Utah	Washington	Wyoming	**System**
2000	154	523	2,347	3,684	756	979	**8,443**
2001	124	421	2,121	3,479	627	1,091	**7,863**
2002	162	689	2,138	3,721	758	1,043	**8,511**
2003	155	573	2,359	4,004	774	1,022	**8,887**
2004	120	603	2,200	3,831	740	1,094	**8,588**
2005	171	681	2,238	4,015	708	1,081	**8,895**
2006	156	561	2,684	3,972	816	1,094	**9,283**
2007	160	701	2,604	4,381	754	1,129	**9,730**
2008	171	682	2,521	4,145	728	1,208	**9,456**
2009	153	517	2,573	4,351	795	987	**9,375**
2010	144	527	2,442	4,294	757	1,208	**9,373**
2011	143	549	2,187	4,596	707	1,204	**9,387**
2012	156	782	2,163	4,731	749	1,225	**9,806**
2013	156	674	2,407	5,091	797	1,349	**10,474**
2014	150	630	2,345	5,024	819	1,294	**10,263**
2015	152	805	2,472	5,081	833	1,259	**10,601**
2016	139	575	2,462	4,940	817	1,201	**10,135**
Average Annual Growth Rate							
2000-16	**-0.63%**	**0.59%**	**0.30%**	**1.85%**	**0.49%**	**1.29%**	**1.15%**

*Coincident peaks do not include sales for resale

System Losses

Line loss factors are derived using the five-year average of the percent difference between the annual system load by jurisdiction and the retail sales by jurisdiction. System line losses were updated to reflect actual losses for the five-year period ending December 31, 2015.

Forecast Methodology Overview

Class 2 Demand-side Management (DSM) Resources in the Load Forecast

PacifiCorp modeled Class 2 DSM as a resource option to be selected as part of a cost-effective portfolio resource mix using the Company's capacity expansion optimization model, System Optimizer. The load forecast used for IRP portfolio development excluded forecasted load reductions from Class 2 DSM; System Optimizer then determines the amount of Class 2 DSM—expressed as supply curves that relate incremental DSM quantities with their costs—given the other resource options and inputs included in the model. The use of Class 2 DSM supply curves, along with the economic screening provided by System Optimizer, determines the cost-effective mix of Class 2 DSM for a given scenario.

Modeling overview

The load forecast is developed by forecasting the monthly sales by customer class for each jurisdiction. The residential sales forecast is developed as a use-per-customer forecast multiplied by the forecast number of customers.

The customer forecasts are based on a combination of regression analysis and exponential smoothing techniques using historical data from January 2000 to February 2016. For the residential class, the Company forecasts the number of customers using IHS Global Insight's forecast of each state's number of population as the major driver.

The Company models sales per customer for the residential class using the SAE model discussed above, which combines the end-use modeling concepts with traditional regression analysis techniques.

For the commercial class, the Company forecasts sales using regression analysis techniques with non-manufacturing employment and non-farm employment designated as the major economic drivers, in addition to weather-related variables. Monthly sales for the commercial class are forecast directly from historical sales volumes, not as a product of the use per customer and number of customers. The development of the forecast of monthly commercial sales involves an additional step; to reflect the addition of a large "lumpy" change in sales such as a new data center, monthly commercial sales are increased based on input from the Company's RBM's. Although the scale is much smaller, the treatment of large commercial additions is similar to the methodology for large industrial customer sales, which is discussed below.

Monthly sales for irrigation and street lighting are forecast directly from historical sales volumes, not as a product of the use per customer and number of customers.

The majority of industrial sales are modeled using regression analysis with trend and economic variables. Manufacturing employment is used as the major economic driver in all states with exception of Utah, in which an Industrial Production Index is used. For a small number of the very largest industrial customers, the Company prepares individual forecasts based on input from the customer and information provided by the RBM's.

After the Company develops the forecasts of monthly energy sales by customer class, a forecast of hourly loads is developed in two steps. First, monthly peak forecasts are developed for each state. The monthly peak model uses historical peak producing weather for each state, and incorporates the impact of weather on peak loads through several weather variables that drive heating and cooling usage. The weather variables include the average temperature on the peak day and lagged average temperatures from up to two days before the day of the forecast. The peak forecast is based on average monthly historical peak-producing weather for the 20-year period, 1996 through 2015. Second, the Company develops hourly load forecasts for each state using hourly load models that include state-specific hourly load data, daily weather variables, the 20-year average temperatures as identified above, a typical annual weather pattern, and day-type variables such as weekends and holidays as inputs to the model. The hourly loads are adjusted to match the monthly peaks from the first step above. Hourly loads are then adjusted so the monthly sum of hourly loads equals monthly sales plus line losses.

After the hourly load forecasts are developed for each state, hourly loads are aggregated to the total system level. The system coincident peaks can then be identified, as well as the contribution of each jurisdiction to those monthly peaks.

Sales Forecast at the Customer Meter

This section provides total system and state-level forecasted retail sales summaries measured at the customer meter by customer class including load reduction projections from new energy efficiency measures from the 2017 IRP preferred portfolio.

Table A.8 – System Annual Retail Sales Forecast 2017 through 2026, post-DSM

System Retail Sales – Megawatt-hours (MWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Public Authority	**Total**
2017	15,760,322	16,973,309	19,610,575	1,402,815	142,837	280,969	**54,170,827**
2018	15,665,011	17,100,676	19,507,344	1,392,957	143,073	280,959	**54,090,019**
2019	15,535,613	17,165,098	19,643,268	1,381,347	143,191	280,959	**54,149,477**
2020	15,362,775	17,233,844	19,795,688	1,369,343	143,651	281,715	**54,187,017**
2021	15,210,722	17,262,252	19,845,887	1,357,840	143,273	280,959	**54,100,934**
2022	15,217,032	17,346,947	19,968,520	1,347,604	143,286	280,959	**54,304,348**
2023	15,222,916	17,445,564	20,161,584	1,336,707	143,293	280,959	**54,591,023**
2024	15,313,009	17,579,119	20,252,811	1,322,691	143,701	281,715	**54,893,047**
2025	15,205,483	17,645,518	20,422,452	1,291,633	143,297	280,959	**54,989,343**
2026	15,213,345	17,741,890	19,943,873	1,243,850	143,298	280,959	**54,567,215**
Average Annual Growth Rate							
2017-26	**-0.4%**	**0.5%**	**0.2%**	**-1.3%**	**0.0%**	**0.0%**	**0.1%**

Residential

Over the 2017-2026 timeframe, the average annual growth of the residential class sales forecast declined from -0.1 percent in the 2015 IRP Update to -0.4 percent in the 2017 IRP. The number of residential customers across PacifiCorp's system is expected to grow at an annual average rate of 1.0 percent, reaching approximately 1.8 million customers in 2026, with Rocky Mountain Power states adding 1.4 percent per year and Pacific Power states adding 0.4 percent per year. New customers on PacifiCorp's system will also contribute to declining average use of the residential class. It is expected that new single-family homes are likely to use more efficient appliances and use gas instead of electricity for both space and water heating.

Commercial

Average annual growth of the commercial class sales forecast increased from 0.0 percent annual average growth in the 2015 IRP Update to 0.5 percent expected average annual growth. The number of commercial customers across PacifiCorp's system is expected to grow at an annual average rate of 0.9 percent, reaching approximately 223,000 customers in 2026, with Rocky Mountain Power states adding 1.2 percent per year and Pacific Power states adding 0.4 percent per year. The Company lowered its commercial load expectations in Oregon, Wyoming and Washington in the 2017 IRP load forecast due to lower than expected loads and adverse economic conditions for particular commercial sectors.

Industrial

Average annual growth of the industrial class sales forecast declined from 0.5 percent annual average growth in the 2015 IRP Update to 0.2 percent expected annual growth. A portion of the Company's industrial load is in the extractive industry in Utah and Wyoming; therefore, changes in commodity prices can impact the Company's load forecast. The Company has seen several large industrial customers cancel expected new load when prices have fallen. The risk to the Company's load forecast due to commodity price changes is reflected in the high and low economic growth scenarios discussed below.

State Summaries

Oregon

Table A.9 summarizes Oregon state forecasted retail sales growth by customer class.

Table A. 9 – Forecasted Retail Sales Growth in Oregon, post-DSM

Oregon Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2017	5,408,380	5,076,308	1,849,639	330,637	37,893	**12,702,857**
2018	5,393,855	5,115,251	1,769,573	327,078	37,923	**12,643,680**
2019	5,378,539	5,098,874	1,763,691	322,898	37,934	**12,601,937**
2020	5,293,038	5,103,759	1,762,377	318,439	38,046	**12,515,659**
2021	5,223,123	5,104,908	1,770,168	313,909	37,941	**12,450,049**
2022	5,229,132	5,103,511	1,774,498	309,780	37,941	**12,454,862**
2023	5,234,327	5,106,544	1,794,852	305,586	37,942	**12,479,251**
2024	5,263,095	5,136,531	1,803,903	300,173	38,049	**12,541,752**
2025	5,236,271	5,145,302	1,826,703	294,032	37,942	**12,540,250**
2026	5,230,030	5,155,635	1,844,084	287,757	37,942	**12,555,448**
Average Annual Growth Rate						
2017-26	**-0.37%**	**0.17%**	**-0.03%**	**-1.53%**	**0.01%**	**-0.13%**

Washington

Table A.10 summarizes Washington state forecasted retail sales growth by customer class.

Table A.10 – Forecasted Retail Sales Growth in Washington, post-DSM

Washington Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2017	1,575,461	1,415,068	772,436	157,910	10,231	**3,931,105**
2018	1,572,606	1,430,519	764,944	157,185	10,227	**3,935,480**
2019	1,568,255	1,449,111	754,477	156,282	10,228	**3,938,353**
2020	1,562,912	1,460,871	742,346	155,494	10,256	**3,931,880**
2021	1,549,095	1,476,203	726,969	154,890	10,227	**3,917,385**
2022	1,544,682	1,495,077	707,110	154,532	10,227	**3,911,628**
2023	1,539,012	1,517,008	689,349	154,010	10,227	**3,909,606**
2024	1,542,678	1,537,227	676,877	152,734	10,256	**3,919,772**
2025	1,531,595	1,557,097	666,360	151,066	10,227	**3,916,346**
2026	1,528,077	1,576,410	655,792	149,274	10,227	**3,919,780**
Average Annual Growth Rate						
2017-26	**-0.34%**	**1.21%**	**-1.80%**	**-0.62%**	**0.00%**	**-0.03%**

California

Table A.11 summarizes California state forecasted sales growth by customer class.

Table A.11 – Forecasted Retail Sales Growth in California, post-DSM

California Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2017	363,268	233,137	59,312	96,753	2,421	**754,891**
2018	361,543	228,011	59,389	96,523	2,415	**747,882**
2019	360,225	223,517	59,337	96,063	2,415	**741,557**
2020	360,738	216,437	58,516	95,553	2,422	**733,666**
2021	357,443	211,498	58,100	94,980	2,415	**724,437**
2022	356,265	207,254	57,817	94,489	2,415	**718,240**
2023	354,361	204,046	57,719	93,948	2,415	**712,489**
2024	354,910	200,624	57,479	93,239	2,422	**708,674**
2025	351,419	197,037	57,138	92,501	2,415	**700,511**
2026	349,167	193,931	56,803	91,810	2,415	**694,126**
Average Annual Growth Rate						
2017-26	**-0.44%**	**-2.03%**	**-0.48%**	**-0.58%**	**-0.03%**	**-0.93%**

Utah

Table A.12 summarizes Utah state forecasted sales growth by customer class.

Table A.12 – Forecasted Retail Sales Growth in Utah, post-DSM

Utah Retail Sales – Megawatt-hours (MWh)							
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Public Authority	**Total**
2017	6,696,419	8,402,810	8,329,787	199,895	77,765	280,969	**23,987,646**
2018	6,625,352	8,470,814	8,317,408	196,470	77,982	280,959	**23,968,985**
2019	6,526,580	8,528,238	8,422,789	192,466	78,087	280,959	**24,029,121**
2020	6,454,747	8,575,851	8,504,675	188,368	78,358	281,715	**24,083,714**
2021	6,410,141	8,588,882	8,572,928	184,763	78,164	280,959	**24,115,838**
2022	6,420,793	8,648,462	8,671,514	181,250	78,176	280,959	**24,281,155**
2023	6,433,763	8,713,821	8,773,258	177,495	78,182	280,959	**24,457,479**
2024	6,484,638	8,788,396	8,884,190	173,538	78,404	281,715	**24,690,881**
2025	6,440,021	8,839,447	8,984,607	154,147	78,186	280,959	**24,777,368**
2026	6,463,388	8,896,420	8,396,408	118,936	78,187	280,959	**24,234,297**
Average Annual Growth Rate							
2017-26	**-0.39%**	**0.64%**	**0.09%**	**-5.61%**	**0.06%**	**0.00%**	**0.11%**

Idaho

Table A.13 summarizes Idaho state forecasted sales growth by customer class.

Table A.13 – Forecasted Retail Sales Growth in Idaho, post-DSM

Idaho Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2017	690,259	474,749	1,735,017	594,801	2,634	**3,497,459**
2018	689,058	485,148	1,735,211	593,351	2,634	**3,505,401**
2019	686,683	495,579	1,735,443	591,908	2,634	**3,512,247**
2020	677,472	508,489	1,736,923	590,466	2,641	**3,515,992**
2021	672,104	516,761	1,736,760	589,043	2,634	**3,517,301**
2022	672,994	528,327	1,737,300	587,953	2,634	**3,529,207**
2023	675,008	541,033	1,737,637	586,913	2,634	**3,543,225**
2024	680,047	553,976	1,738,600	585,564	2,641	**3,560,828**
2025	678,023	562,833	1,737,847	584,140	2,634	**3,565,476**
2026	678,865	572,063	1,737,599	582,674	2,634	**3,573,835**
Average Annual Growth Rate						
2017-26	**-0.18%**	**2.09%**	**0.02%**	**-0.23%**	**0.00%**	**0.24%**

Wyoming

Table A.14 summarizes Wyoming state forecasted sales growth by customer class.

Table A.14 – Forecasted Retail Sales Growth in Wyoming, post-DSM

Wyoming Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2017	1,026,536	1,371,237	6,864,383	22,819	11,893	**9,296,868**
2018	1,022,597	1,370,933	6,860,818	22,349	11,893	**9,288,592**
2019	1,015,332	1,369,779	6,907,530	21,730	11,893	**9,326,263**
2020	1,013,869	1,368,436	6,990,851	21,023	11,928	**9,406,107**
2021	998,816	1,363,999	6,980,961	20,255	11,893	**9,375,925**
2022	993,165	1,364,316	7,020,281	19,600	11,893	**9,409,255**
2023	986,444	1,363,112	7,108,770	18,754	11,893	**9,488,973**
2024	987,641	1,362,366	7,091,762	17,442	11,928	**9,471,139**
2025	968,155	1,343,801	7,149,796	15,747	11,893	**9,489,391**
2026	963,818	1,347,430	7,253,188	13,399	11,893	**9,589,729**
Average Annual Growth Rate						
2017-26	**-0.70%**	**-0.19%**	**0.61%**	**-5.74%**	**0.00%**	**0.35%**

Alternative Load Forecast Scenarios

The purpose of providing alternative load forecast cases is to determine the resource type and timing impacts resulting from a change in the economy or system peaks as a result of higher than normal temperatures.

The December 2016 forecast is the baseline scenario. For the high and low economic growth scenarios assumptions from IHS Global Insight were applied to the economic drivers in the

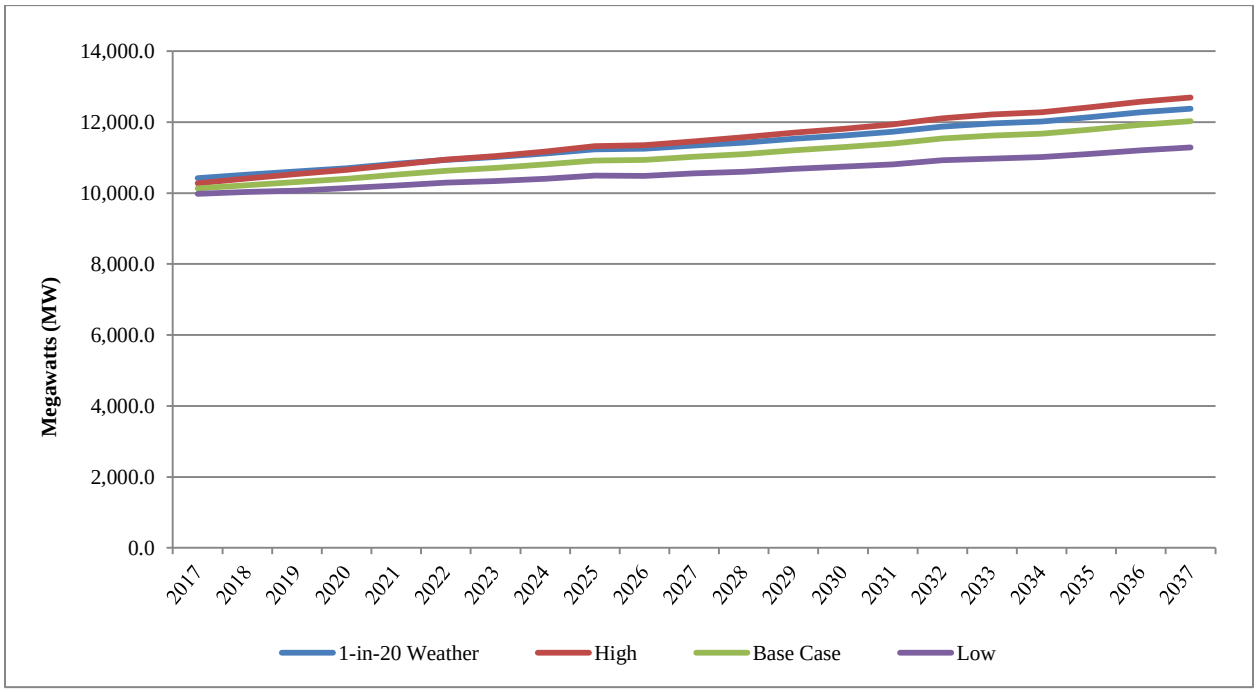
Company's load forecasting models. These growth assumptions were extended for the entire forecast horizon.

Recognizing the volatility associated with the oil and gas extraction industries, PacifiCorp applied additional assumptions for the Utah and Wyoming industrial class load forecasts in the high and low scenario. Specifically, the Company focused on the increased uncertainty of the industrial load forecast as it moves further out in time. In order to capture this increased uncertainty the Company modeled 1,000 possible annual loads for each year based on the standard error of the medium scenario regression equation. The 1,000 load values are then ranked and the Company selected the 95th percentile and 5th percentile of the Utah and Wyoming industrial loads for both the low and high growth scenarios.

For the 1-in-20 year (5 percent probability) extreme weather scenario, the Company used 1-in-20 year peak weather for summer (July) months for each state. 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.

Figure A.11 shows the comparison of the above scenarios relative to the base case scenario.

Figure A.11 – Load Forecast Scenarios for 1-in-20 Weather, High, Base Case and Low, pre-DSM



APPENDIX B – IRP REGULATORY COMPLIANCE

Introduction

This appendix describes how PacifiCorp's 2017 IRP complies with (1) the various state commission IRP standards and guidelines, (2) specific analytical requirements stemming from acknowledgment orders for the Company's last IRP ("2015 IRP"), and (3) state commission IRP requirements stemming from other regulatory proceedings.

Included in this appendix are the following tables:

- Table B.1 – Provides an overview and comparison of the rules in each state for which IRP submission is required.[1]
- Table B.2 – Provides a description of how PacifiCorp addressed the 2015 IRP acknowledgement requirements and other commission directives.
- Table B.3 – Provides an explanation of how this plan addresses each of the items contained in the Oregon IRP guidelines.
- Table B.4 – Provides an explanation of how this plan addresses each of the items contained in the Public Service Commission of Utah IRP Standard and Guidelines issued in June 1992.
- Table B.5 – Provides an explanation of how this plan addresses each of the items contained in the Washington Utilities and Trade Commission IRP guidelines issued in January 2006.
- Table B.6 – Provides an explanation of how this plan addresses each of the items contained in the Wyoming Public Service Commission IRP guidelines updated in March 2016.

General Compliance

PacifiCorp prepares the IRP on a biennial basis and files the IRP with state commissions. The preparation of the IRP is done in an open public process with consultation between all interested parties, including commissioners and commission staff, customers, and other stakeholders. This open process provides parties with a substantial opportunity to contribute information and ideas in the planning process, and also serves to inform all parties on the planning issues and approach. The public input process for this IRP, described in Volume I, Chapter 2 (Introduction), as well as Volume II, Appendix C (Public Input Process) fully complies with IRP Standards and Guidelines.

The IRP provides a framework and plan for future actions to ensure PacifiCorp continues to provide reliable and least-cost electric service to its customers. The IRP evaluates, over a twenty-year planning period, the future loads of PacifiCorp customers and the resources required to meet this load.

To fill any gap between changes in loads and existing resources, while taking into consideration potential early retirement of existing coal units as an alternative to investments that achieve compliance with environmental regulations, the IRP evaluates a broad range of available resource

[1] California guidelines exempt a utility with less than 500,000 customers in the state from filing an IRP. However, PacifiCorp files its IRP and IRP supplements with the California Public Utilities Commission to address the Company plan for compliance with the California RPS requirements.

options, as required by state commission rules. These resource alternatives include supply-side, demand-side, and transmission alternatives. The evaluation of the alternatives in the IRP, as detailed in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and Chapter 8 (Modeling and Portfolio Selection Results) meets this requirement and includes the impact to system costs, system operations, supply and transmission reliability, and the impacts of various risks, uncertainties and externality costs that could occur. To perform the analysis and evaluation, PacifiCorp employs a suite of models that simulate the complex operation of the PacifiCorp system and its integration within the Western interconnection. The models allow for a rigorous testing of a reasonably broad range of commercially feasible resource alternatives available to PacifiCorp on a consistent and comparable basis. The analytical process, including the risk and uncertainty analysis, fully complies with IRP Standards and Guidelines, and is described in detail in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).

The IRP analysis is designed to define a resource plan that is least cost, after consideration of risks and uncertainties. To test resource alternatives and identify a least-cost, risk adjusted plan, portfolio resource options were developed and tested against each other. This testing included examination of various tradeoffs among the portfolios, such as average cost versus risk, reliability, customer rate impacts, and average annual CO_2 emissions. This portfolio analysis and the results and conclusions drawn from the analysis are described in Volume I, Chapter 8 (Modeling and Portfolio Selection Results).

Consistent with the IRP Standards and Guidelines of Oregon, Utah, and Washington, this IRP includes an Action Plan in Volume I, Chapter 9 (Action Plan). The Action Plan details near-term actions that are necessary to ensure PacifiCorp continues to provide reliable and least-cost electric service after considering risk and uncertainty. The Action Plan also provides a progress report on action items contained in the 2015 IRP and 2015 IRP Update.

The 2017 IRP and related Action Plan are filed with each commission with a request for acknowledgment. Acknowledgment means that a commission recognizes the IRP as meeting all regulatory requirements at the time of acknowledgment. In the case where a commission acknowledges the IRP in part or not at all, PacifiCorp works with the commission to modify and re-file an IRP that meets their acknowledgment standards.

State commission acknowledgment orders or letters typically stress that an acknowledgment does not indicate approval or endorsement of IRP conclusions or analysis results. Similarly, an acknowledgment does not imply that favorable ratemaking treatment for resources proposed in the IRP will be given.

California

Public Utilities Code Section 454.52, mandates that the California Public Utilities Commission (CPUC) adopt a process for load serving entities to file an IRP beginning in 2017. In February 2016, the CPUC opened a rulemaking to adopt an IRP process and address the scope of the IRP to be filed with the CPUC. As of the date PacifiCorp's 2017 IRP was finalized, the CPUC has not adopted any IRP requirements.

Idaho

The Idaho Public Utilities Commission's Order No. 22299, issued in January 1989, specifies integrated resource planning requirements. The Order mandates that PacifiCorp submit a Resource Management Report (RMR) on a biennial basis. The intent of the RMR is to describe the status of IRP efforts in a concise format, and cover the following areas:

> *Each utility's RMR should discuss any flexibilities and analyses considered during comprehensive resource planning, such as: (1) examination of load forecast uncertainties; (2) effects of known or potential changes to existing resources; (3) consideration of demand and supply side resource options; and (4) contingencies for upgrading, optioning and acquiring resources at optimum times (considering cost, availability, lead time, reliability, risk, etc.) as future events unfold.*

This IRP is submitted to the Idaho PUC as the Resource Management Report for 2017, and fully addresses the above report components.

Oregon

This IRP is submitted to the Oregon PUC in compliance with its planning guidelines issued in January 2007 (Order No. 07-002). The Commission's IRP guidelines consist of substantive requirements (Guideline 1), procedural requirements (Guideline 2), plan filing, review, and updates (Guideline 3), plan components (Guideline 4), transmission (Guideline 5), conservation (Guideline 6), demand response (Guideline 7), environmental costs (Guideline 8, Order No. 08-339), direct access loads (Guideline 9), multi-state utilities (Guideline 10), reliability (Guideline 11), distributed generation (Guideline 12), resource acquisition (Guideline 13), and flexible resource capacity (Order No. 12-013[2]). Consistent with the earlier guidelines (Order 89-507), the Commission notes that acknowledgment does not guarantee favorable ratemaking treatment, only that the plan seems reasonable at the time acknowledgment is given. Table B.3 provides detail on how this plan addresses each of the requirements.

Utah

This IRP is submitted to the Public Service Commission of Utah in compliance with its 1992 Order on Standards and Guidelines for Integrated Resource Planning (Docket No. 90-2035-01, "Report and Order on Standards and Guidelines"). Table B.4 documents how PacifiCorp complies with each of these standards.

Washington

This IRP is submitted to the Washington Utilities and Transportation Commission (WUTC) in compliance with its rule requiring least cost planning (Washington Administrative Code 480-100-238) (as amended, January 2006). In addition to a least cost plan, the rule requires provision of a two-year action plan and a progress report that "relates the new plan to the previously filed plan."

The rule requires PacifiCorp to submit a work plan for informal commission review not later than 12 months prior to the due date of the plan. The work plan is to lay out the contents of the IRP, the

2 Public Utility Commission of Oregon, Order No. 12-013, Docket No. 1461, January 19, 2012.

resource assessment method, and timing and extent of public participation. PacifiCorp filed a work plan with the Commission on March 30, 2016, in Docket UE-160353. Table B.5 provides detail on how this plan addresses each of the rule requirements.

Wyoming

Wyoming Public Service Commission issued new rules that replaced the previous set of rules on March 21, 2016. Chapter 3, Section 33 outlines the requirements on filing IRPs for any utility serving Wyoming customers. The rule, shown below, went into effect in March 2016. Table B.6 provides detail on how this plan addresses the rule requirements.

> ***Section 33. Integrated Resource Plan (IRP).***
> *Each utility serving in Wyoming that files an IRP in another jurisdiction shall file that IRP with the Commission. The Commission may require any utility to file an IRP.*

Table B.1 – Integrated Resource Planning Standards and Guidelines Summary by State

Topic	Oregon	Utah	Washington	Idaho	Wyoming
Source	Order No. 07-002, *Investigation Into Integrated Resource Planning*, January 8, 2007, as amended by Order No. 07-047. Order No. 08-339, *Investigation into the Treatment of CO2 Risk in the Integrated Resource Planning Process*, June 30, 2008. Order No. 09-041, New Rule OAR 860-027-0400, implementing Guideline 3, "Plan Filing, Review, and Updates". Order No. 12-013, "Investigation of Matters related to Electric Vehicle Charging", January 19, 2012.	Docket 90-2035-01 *Standards and Guidelines for Integrated Resource Planning* June 18, 1992.	WAC 480-100-251 Least cost planning, May 19, 1987, and as amended from WAC 480-100-238 *Least Cost Planning Rulemaking*, January 9, 2006 (Docket # UE-030311)	Order 22299 *Electric Utility Conservation Standards and Practices* January, 1989.	Wyoming Electric, Gas and Water Utilities, Chapter 3, Section 33, March 21, 2016.
Filing Requirements	Least-cost plans must be filed with the Commission.	An Integrated Resource Plan (IRP) is to be submitted to Commission.	Submit a least cost plan to the Commission. Plan to be developed with consultation of Commission staff, and with public involvement.	Submit "Resource Management Report" (RMR) on planning status. Also file progress reports on conservation, low-income programs, lost opportunities and capability building.	Each utility serving in Wyoming that files and IRP in another jurisdiction, shall file the IRP with the Commission.

Frequency	Plans filed biennially, within two years of its previous IRP acknowledgment order. An annual update to the most recently acknowledged IRP is required to be filed on or before the one-year anniversary of the acknowledgment order date. While informational only, utilities may request acknowledgment of proposed changes to the action plan.	File biennially.	File biennially.	RMR to be filed at least biennially. Conservation reports to be filed annually. Low income reports to be filed at least annually. Lost Opportunities reports to be filed at least annually. Capability building reports to be filed at least annually.	The Commission may require any utility to file an IRP.
Commission Response	Least-cost plan (LCP) *acknowledged* if found to comply with standards and guidelines. A decision made in the LCP process does not guarantee favorable rate-making treatment. The OPUC may direct the utility to revise the IRP or conduct additional analysis before an acknowledgment order is issued. Note, however, that Rate Plan legislation allows pre-approval of near-term resource investments.	IRP acknowledged if found to comply with standards and guidelines. Prudence reviews of new resource acquisitions will occur during rate making proceedings.	The plan will be considered, with other available information, when evaluating the performance of the utility in rate proceedings. WUTC sends a letter discussing the report, making suggestions and requirements and acknowledges the report.	Report does not constitute pre-approval of proposed resource acquisitions. Idaho sends a short letter stating that they accept the filing and acknowledge the report as satisfying Commission requirements.	Commission advisory staff reviews the IRP as directed by the Commission and drafts a memo to report its findings to the Commission in an open meeting or technical conference.

Process	The public and other utilities are allowed significant involvement in the preparation of the plan, with opportunities to contribute and receive information. Order 07-002 requires that the utility present IRP results to the OPUC at a public meeting prior to the deadline for written public comments. Commission staff and parties should complete their comments and recommendations within six months after IRP filing. Competitive secrets must be protected.	Planning process open to the public at all stages. IRP developed in consultation with the Commission, its staff, with ample opportunity for public input.	In consultation with Commission staff, develop and implement a public involvement plan. Involvement by the public in development of the plan is required. PacifiCorp is required to submit a work plan for informal commission review not later than 12 months prior to the due date of the plan. The work plan is to lay out the contents of the IRP, resource assessment method, and timing and extent of public participation.	Utilities to work with Commission staff when reviewing and updating RMRs. Regular public workshops should be part of process.	The review may be conducted in accordance with guidelines set from time to time as conditions warrant. The Public Service Commission of Wyoming, in its Letter Order on PacifiCorp's 2008 IRP (Docket No. 2000-346-EA-09) adopted Commission Staff's recommendation to expand the review process to include a technical conference, an expanded public comment period, and filing of reply comments.
Focus	20-year plan, with end-effects, and a short-term (two-year) action plan. The IRP process should result in the selection of that mix of options which yields, for society over the long run, the best combination of expected costs and variance of costs.	20-year plan, with short-term (four-year) action plan. Specific actions for the first two years and anticipated actions in the second two years to be detailed. The IRP process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.	20-year plan, with short-term (two-year) action plan. The plan describes mix of resources sufficient to meet current and future loads at "lowest reasonable" cost to utility and ratepayers. Resource cost, market volatility risks, demand-side resource uncertainty, resource dispatchability, ratepayer risks, policy impacts, and environmental risks, must be considered.	20-year plan to meet load obligations at least-cost, with equal consideration to demand side resources. Plan to address risks and uncertainties. Emphasis on clarity, understandability, resource capabilities and planning flexibility.	Identification of least-cost/least-risk resources and discussion of deviations from least-cost resources or resource combinations.

Elements	Basic elements include: • All resources evaluated on a consistent and comparable basis. • Risk and uncertainty must be considered. • The primary goal must be least cost, consistent with the long-run public interest. • The plan must be consistent with Oregon and federal energy policy. • External costs must be considered, and quantified where possible. OPUC specifies environmental adders (Order No. 93-695, Docket UM 424). • Multi-state utilities should plan their generation and transmission systems on an integrated-system basis. • Construction of resource portfolios over the range of identified risks and uncertainties. • Portfolio analysis shall include fuel transportation and	IRP will include: • Range of forecasts of future load growth • Evaluation of all present and future resources, including demand side, supply side and market, on a consistent and comparable basis. • Analysis of the role of competitive bidding • A plan for adapting to different paths as the future unfolds. • A cost effectiveness methodology. • An evaluation of the financial, competitive, reliability and operational risks associated with resource options, and how the action plan addresses these risks. • Definition of how risks are allocated between ratepayers and shareholders	The plan shall include: • A range of forecasts of future demand using methods that examine the effect of economic forces on the consumption of electricity and that address changes in the number, type and efficiency of electrical end-uses. • An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements. • Assessment of a wide range of conventional and commercially available nonconventional generating technologies • An assessment of transmission system capability and reliability. • A comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using	Discuss analyses considered including: • Load forecast uncertainties; • Known or potential changes to existing resources; • Equal consideration of demand and supply side resource options; • Contingencies for upgrading, optioning and acquiring resources at optimum times; • Report on existing resource stack, load forecast and additional resource menu.	Proposed Commission Staff guidelines issued July 2016 cover: • Sufficiency of the public comment process • Utility strategic goals, resource planning goals and preferred resource portfolio • Resource need over the near-term and long-term planning horizons • Types of resources considered • Changes in expected resource acquisitions and load growth from the previous IRP • Environmental impacts considered • Market purchase evaluation • Reserve margin analysis • Demand-side management and conservation options

	transmission requirements. • Plan includes conservation potential study, demand response resources, environmental costs, and distributed generation technologies. • Avoided cost filing required within 30 days of acknowledgment.		"lowest reasonable cost" criteria. • Integration of the demand forecasts and resource evaluations into a long-range (at least 10 years) plan. • All plans shall also include a progress report that relates the new plan to the previously filed plan.		

Table B.2 – Handling of 2015 IRP Acknowledgment and Other IRP Requirements

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2017 IRP
Idaho		
Case No. PAC-E-15-04, Order No. 33396	Suggests the Company consider conducting a reasonable evaluation, similar to the Wind Integration Study previously commissioned, of the costs and benefits associated with the integration of additional solar resources into its system.	PacifiCorp has included analysis of solar integration as part of Volume II, Appendix H (Flexible Reserve Study) of the 2017 IRP.
Oregon		
Order No. 14-252, p. 3	Beginning in the third quarter of 2014, PacifiCorp will appear before the Commission to provide quarterly updates on coal plant compliance requirements, legal proceedings, pollution control investments, and other major capital expenditures on its coal plants or transmission projects. PacifiCorp may provide a written report and need not appear if there are no significant changes between the quarterly updates.	Order No. 14-288 modified the requirements, moving the date of the first meeting from the third quarter of 2014 to the fourth quarter of 2014. Order No. 16-071 further streamlined this requirement by requiring the company to continue to provide twice yearly updates on the status of DSM IRP acquisition goals at public meetings and include in these updates information on future coal plant and transmission investment decisions. Also include information on 111(d) rule compliance analysis; Environmental/coal and transmission expenditures quarterly presentations were made at Commission special public meetings on October 28, 2014 and March 16, 2015. Quarterly presentations via written reports were provided on June 30, 2015 and October 1, 2015. The 2015 fourth quarter presentation was made at the Commission special public meeting on December 17, 2015. A biannual DSM update was provided at the Commission public meetings on March 10, 2015 and December 15, 2015 Biannual presentations for both Environmental/coal and transmission expenditures/111(d) and DSM were provided on August 30, 2016 and December 20, 2016. Please see Commission website for public meeting history and Docket RE 163 for presentations and written reports provided.
Order No. 14-252, p. 3	In future IRPs, PacifiCorp will provide: • Timelines and key decision points for expected pollution control options and transmission investments; and • Tables detailing major planned expenditures with estimated costs in each year for each plant or transmission project, under different modeled scenarios.	PacifiCorp has included seven Regional Haze scenarios in its 2017 IRP. See case study fact sheets (Volume II, Appendix M (Case Study Fact Sheets) for discussion on specific Regional Haze assumptions. For modeling purposes PacifiCorp has included incremental transmission costs associated with specific resources. See Volume I, Chapter 6

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2017 IRP
		(Resource Options) for discussion of these potential costs. Additional detail is provided on the data discs included with the 2017 IRP filing.
Order No. 14-252, p. 13	In the acknowledgement order the Commission provided the following recommendation: As part of the 2015, 2017, and 2019 IRPs, PacifiCorp will provide an updated version of the screening tool spreadsheet model that was provided to participants in the 2011 (docket LC 52) IRP Update.	The screening tool is no longer used to model competing retirement scenarios. The variety of retirement scenarios represented by the Regional Haze cases and the addition of an endogenous retirement case in the 2017 IRP has made the use of this tool unnecessary.
Order No. 14-252, p. 16	In future IRPs, PacifiCorp will provide yearly Class 1 and Class 2 DSM acquisition targets in both GWh and MW for each year in the planning period, by state.	See Volume II, Appendix D (Demand-Side Management Resources) for the breakdown by state and year for both energy and capacity selected for the preferred portfolio.
Order No. 16-071, Appendix A, p.1 (action item 1a-1c)	Include sensitivity studies around solar costs. Provide analysis of the system benefits of storage.	See Volume II, Appendix N (Wind and Solar Capacity Contribution Study), and two energy storage sensitivities (Storage – Battery, Storage – CAES) described in Volume I, Chapter 8 (Modeling and Portfolio Selection Results).
Order No. 16-071, p. 4	If HB 4036 (passed as SB 1547) is enacted, PacifiCorp will revisit action item 1c, to conclude negotiations with shortlisted bids from the Company's 2013 RFP seeking up to 7 MW of qualifying solar capacity, and bring forth its recommendation for Commission review.	The Oregon Solar Capacity Standard was eliminated with the passage of Oregon Senate Bill 1547. This action item was deleted from the updated action plan presented in PacifiCorp's 2015 IRP Update.
Order No. 16-071, p. 4	The Commission expects the company to update its Clean Power Plan modeling in its 2015 IRP update or its next IRP (depending on when Oregon's compliance plan is known) to correctly reflect the final rule and Oregon's implementation plan.	PacifiCorp's 2017 IRP reflects the final version of the Clean Power Plan, however, at the time of the 2017 IRP, the rule is stayed and Oregon has not issued a draft or final implementation plan therefore Oregon's compliance plan is not known and not reflected in the 2017 IRP. The 2017 IRP does include two Clean Power Plan modeling assumptions (CPP(a) and CPP(b)) plus two Clean Power Plan sensitivities (Mass Cap C and Mass Cap D), described in Volume I, Chapter 8 (Modeling and Portfolio Selection Results).
Order No. 16-071, Appendix A, p.1 (action item 2a) Order No. 16-071, p. 5	Provide quantitative justification for assumed levels of trading hub liquidity and depth. The Commission noted that the Company has committed to conducting a market reliance risk analysis and urge the Company to also address concerns about reliance on Front Office Transactions in its analysis.	See Volume II, Appendix J (Western Resource Adequacy Evaluation).
Order No. 16-071, Appendix A, p.1 (action item 3a)	Present at a public meeting within six months of this order, potential demand response pilot programs including: a time-varying rate pilot, peak-time rebate, and direct load control programs for other	PacifiCorp presented this information to the Commission at the August 16, 2016 public meeting. Ongoing. The Company engaged stakeholders in the development of its proposed transportation electrification pilot programs, including

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2017 IRP
	sectors. The company may also consider demand bidding programs. Engage Oregon stakeholders in an informal process to address increased voluntary participation in time-of-use pricing and present the outcome of this informal process to the Portfolio Options Committee.	considerations for time-of-use rates for electric vehicle owners. The Company plans to promote the benefits of time-of-use rates to customers through its proposed Outreach and Education program, if approved. After program approval, the Company will present initial strategies to promote time-of-use rates to current and potential electric vehicle owners to the POC.
Order No. 16-071, p. 5	In addition to the action item 3a irrigation pilot program, the Commission directs PacifiCorp to design and present additional pilots.	PacifiCorp presented information on potential demand response pilot opportunities at the Commission's August 16, 2016 public input meeting and explained that the 2017 IRP would inform whether the Company would propose additional pilot programs.
Order No. 16-071, Appendix A, p.1 (action item 3b)	Continue to provide twice yearly updates on the status of DSM IRP acquisition goals at public meetings. Include in these updates information on future coal plant and transmission investment decisions, as a streamlined continuation of Order No. 14-288. Also include information on 111 (d) rule compliance analysis; Provide more risk analysis on portfolios that include accelerated energy efficiency as a resource; Include annual incremental summer and winter peak demand capacity (MW) corresponding to 2015 through 2018 Class 2 DSM annual energy savings targets; For the 2015 IRP Update, provide model run results of the preferred portfolio with base case DSM and with accelerated DSM for comparison purposes; Perform stochastic modeling on all portfolios with accelerated DSM.	PacifiCorp provided updates on the status of DSM acquisition goals to the Commission on August 30, 2016 and December 20, 2016. PacifiCorp did not conduct a sensitivity on accelerated DSM in the 2017 IRP. See Volume I, Chapter 8 (Modeling Portfolio Selection Results) for the annual summer and winter peak demand capacity (MW) for Class 2 DSM. PacifiCorp provided a portfolio comparison of its accelerated DSM study and the 2015 IRP Update preferred portfolio in Chapter 5 (Portfolio Development) of the 2015 IRP Update. See response to the second item above. PacifiCorp did not conduct a sensitivity on accelerated DSM in the 2017 IRP.
Order No. 16-071, Appendix A, p.2 (action item 5a) and Order No. 16-071, p. 9.	Continue permitting Energy Gateway Segments D, E, F, and H until PacifiCorp files its 2017 IRP. The Commission acknowledges this action item only to the extent of PacifiCorp's permitting actions. The Commission expects to see updated analysis in the next IRP or before the Company makes significant commitments to these transmission lines.	See Chapter 4 (Transmission), Chapter 7 (Modeling and Portfolio Evaluation Approach), Chapter 8 (Modeling and Portfolio Selection Results), and Chapter 9 (Action Plan) for updated analysis on the Company's Energy Gateway transmission segments.
Order No. 16-071, Appendix A, p.2 (action item 5b)	1. In the next IRP, evaluate the benefits of freed-up transmission due to plant closures;	1. Seven Regional Haze cases are examined in the 2017 IRP, representing alternate retirement scenarios and accounting for the PVRR costs and benefits applicable to new resources selected at closure sites. PacifiCorp's modeling

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2017 IRP
	2. Update the available dynamic transfer capability between east and west balancing authority areas (BAAs) in modeling; 3. Incorporate an analysis of California Independent System Operator (CAISO) membership in the 2017 IRP as appropriate.	approach captures any benefits associated with freed-up transmission due to assumed plant/unit closures. 2. The transfer capability of west/east transmission availability (the 'overlay') is recognized in 2017 IRP modeling, consistent with the most current assumptions tied to operational practice. 3. California Senate Bill No. 350, which was passed in October 2015, authorizes the California legislature to consider making changes to current laws that would create an independent governance structure for a regional ISO up until the conclusion of the 2017 legislative session which ends September 15, 2017. In the event that legislation is passed, PacifiCorp will coordinate with its state regulatory authorities on evaluation of next steps. As such, an analysis of participation in a regional ISO is not included in the 2017 IRP.
Order No. 16-071, Appendix A, p.2 (additional actions - modeling)	1. Include more robust analysis regarding the west BAA winter peak load/resource balance and portfolios to meet this peak load; 2. Provide quantitative justification for the planning reserve margin of 13 percent; 3. Utilize the Balancing Authority's Area Control Error (ACE) Limit (BAAL) NERC standard in forthcoming wind integration studies, and confirm and demonstrate that the study is based on implementation of the BAAL standard; 4. Use the same regional haze assumptions when directly comparing portfolios.	1. See Volume I, Chapter 8 (Modeling and Portfolio Selection Results) including winter and summer peak load and resource tables. 2. See Volume II, Appendix I (Planning Reserve Margin Study). The study concludes with a planning criteria that meets one day in 10 year planning targets at the lowest reasonable cost. 3. The Company's Flexible Reserve Study (Appendix H) incorporates the specific requirements of the BAAL standard (BAL-001-2). 4. In the 2017 IRP, the least-cost, least-risk Regional Haze case is assumed for all subsequent portfolios.
Order No. 16-071, Appendix A, p.3 (additional actions – Clean Power Plan Analysis)	1. Provide alternate 111(d) rule compliance paths, including mass-based solutions, with stochastic analysis for each; 2. Include the constraints needed for 111(d) rule compliance in all cost risk analysis ("PaR" analyses); 3. Estimate the effects of 111(d) rule compliance on western wholesale power prices;	1. The 2017 IRP includes two distinct Clean Power Plan modeling strategies (CPP(a) and CPP(b)) plus two Clean Power Plan sensitivities (Mass Cap C and Mass Cap D), described in Volume I, Chapter 8 (Modeling and Portfolio Selection Results) of the 2017 IRP. Portfolios are evaluated on the basis of stochastic modeling, analysis and metrics. 2. PaR uses optimized shadow prices to drive stochastic model behavior. Please refer to Volume I, Chapter 8 (Modeling and Portfolio Selection Results) for discussion.

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2017 IRP
	4. Provide additional analysis in the IRP update on 111 (d) rule compliance alternatives that do not double count Renewable Energy Credits (RECs) and the Emission Rate Credits (ERCs).	3. The price curves developed for CPP(a) and CPP(b) capture the effects of emissions policy on power prices. CO_2 emissions, and therefore developed prices, are not significantly constrained by Clean Power Plan limits except under high gas price conditions. Please refer to Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach). 4. Clean Power Plan modeling for the 2017 IRP assumes a fixed cap on emissions, unaffected by RECs or ERCs.
Order No. 16-071, p. 10.	The Company is directed to confirm and demonstrate that its upcoming wind integration study is based on implementation of the BAAL standard.	The Company's Flexible Reserve Study (Appendix H) incorporates the specific requirements of the BAAL standard (BAL-001-2).
Utah		
Order, Docket No. 15-035-04, p.18	If PacifiCorp plans to use the System Benefit Tool type of transmission analytical tool in future IRPs, PacifiCorp should introduce and vet the tool in an IRP workshop setting prior to utilizing the tool.	The System Benefit Tool is not used in the 2017 IRP.
Order, Docket No. 15-035-04, p.19	Encourage PacifiCorp in future IRP processes, to provide a stronger demonstration of the reasonableness of the range of renewable resource costs analyzed.	PacifiCorp discussed its 2017 IRP supply-side resource table and inputs at the August 25-26, 2016 public input meeting. The supply-side resource table was updated based on stakeholder feedback.
Order, Docket No. 15-035-04, p.20	Direct PacifiCorp to identify the amount of distributed generation in the baseload forecast in its load and resource table, as it does for existing DSM and curtailment.	See Volume I, Chapter 5 (Load and Resource Balance), which breaks out private generation in the same manner as DSM and interruptible load curtailment.
Order, Docket No. 15-035-04, p.21	Direct PacifiCorp to continue to evaluate the depth of the western wholesale market, and to use sensitivity cases and acquisition path analysis, including development of a contingency plan, to monitor the feasibility of long-term reliance on Front Office Transactions to meet near-term load growth.	See Volume II, Appendix J (Western Resource Adequacy Evaluation) for an evaluation of market depth, and also the Front Office Transaction sensitivity provided in Volume I, Chapter 8 (Modeling and Portfolio Selection Results). Also refer to acquisition path analysis for contingencies in Volume I, Chapter 9 (Action Plan).
Order, Docket No. 15-035-04, p.21	Recommend continued analysis of the planning reserve margin in future IRPs using results from both loss of load probability studies and analysis of the tradeoffs between reliability and cost.	See Volume II, Appendix I (Planning Reserve Margin Study). The study concludes with a planning criteria that meets one day in 10 year planning targets at the lowest reasonable cost.
Order, Docket No. 15-035-04, p.25	Analysis behind Near-Term and Long-Term Resource Acquisition Paths (Table 9.3 in the 2015 IRP) could be improved in terms of identifying potential exogenous changes that would cause a significant change in acquisition path. Encourage PacifiCorp in future IRPs to further define the critical contingencies it is monitoring	See acquisition path analysis for contingencies in Volume I, Chapter 9 (Action Plan).

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2017 IRP
	and identify the magnitude of changes that would be required to potentially trigger movement to any of the different paths listed in the table.	
Order, Docket No. 15-035-04, p.25	Encourage PacifiCorp to file an update of the energy storage screening study in its 2017 IRP, update the storage cost assumptions, and consider modeling changes for energy storage following discussion with stakeholders. Request that PacifiCorp present the findings of the updated study, with the study authors accessible for stakeholder questions and discussion, at a public input meeting.	See Volume II, Appendix P (Energy Storage Studies). PacifiCorp presented results of its updated Energy Storage Studies at the August 25-26, 2017 public input meeting with the study authors participating via phone.
Order, Docket No. 15-035-04, p.26	The Commission is interested in examining the impact on Present Value Revenue Requirement and investment decisions of varying levels of Qualifying Facilities on the system. Direct PacifiCorp to develop a set of sensitivity runs addressing this issue following discussion with interested stakeholders.	PacifiCorp continues to assume that executed qualifying facility contracts, as of the time modeling assumptions are locked down, are considered in the resource mix when performing 2017 IRP analysis. Stakeholders did not request additional sensitivity cases to assess alternative qualifying facility penetration scenarios during the public input process. Such sensitivities would be difficult to produce, as it is not reasonably feasible to derive avoided cost pricing for hypothetical qualifying facility projects on the system as there is no information on project location or technology type. Without a sound avoided cost price estimate, which would significantly influence system costs under a qualifying facility sensitivity, PVRR cost implications could be misleading.
Order, Docket No. 15-035-04, p.28	Encourage PacifiCorp to explain in the 2017 IRP how the effects of the federal standards on lighting technologies are accounted for in updated potentials studies or load forecasts.	See Volume II, Appendix A (Load Forecast Details).
Order, Docket No. 15-035-04, p.31	Remind PacifiCorp of the requirement to future IRPs to present the Business Plan as a sensitivity case. If PacifiCorp has substantive objections to this requirement, PacifiCorp should file a motion for Commission action within 90 days of this order explaining the objection and requesting relief.	Please refer to the Business Plan sensitivity (BP) presented in Volume I, Chapter 8 (Modeling and Portfolio Selection Results) consistent with the Order in Docket No. 15-035-04.
Washington		
UE-140546, Acknowledgement Letter, p.1	Encourage the Company to continue the practice of including data discs with the filing in future IRP filings.	Data discs have been included with the 2017 IRP filing.
UE-140546, Acknowledgement Letter, p.2	Encourage the Company to continue to evaluate how its method of developing capacity value of renewable resources compares to the effective load carrying capability method on which it was based, to ensure that the Company's model is yielding accurate results.	See Volume II, Appendix N (Wind and Solar Capacity Contribution Study), analyzing updated hourly profiles and transmission availability impacts to determine effectiveness in meeting system load. The 2017 IRP also adds winter peak (in addition to summer peak) in its assumptions, allowing enhanced insight into solar penetration concerns.

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2017 IRP
UE-140546, Acknowledgement Letter, p.3	Requests the Company model a sensitivity for both a trading system and carbon tax system in its 2017 IRP, and consult with commission staff regarding the appropriate assumptions and inputs.	PacifiCorp included Clean Power Plan modeling studies and an alternative CO_2 price sensitivity. The CO_2 price sensitivity reflects an alternative policy mechanism, without defining whether that policy is implemented as a tax or trading system, than what is contemplated in the Clean Power Plan. The effects of the policy (tax vs. trading system) would not influence the impacts on system variable costs. Under a CO_2 tax, PacifiCorp would incur a direct cost for CO_2 emissions. Under a CO_2 trading system, presumably with some type of allowance allocation, PacifiCorp would be faced with either the direct cost of buying allowances from the market if its emissions were higher than its allowance allocation or the opportunity cost of not selling allowances into the market if its emissions were below its allowance allocation. Consequently, the impact on system dispatch and the associated variable costs is the same under a tax or trading system policy approach.
UE-140546, Acknowledgement Letter, p.3	It would be useful for the Company to develop a supply curve of emissions abatement. This supply curve would identify, specific to Pacific Power, the available technologies and their associated costs that could reach a given emissions goal. This type of tool would lend increased transparency to the issue, and would allow the Company, regulators and stakeholders to engage in meaningful and informed conversations regarding the costs and benefits of reducing Pacific Power's emissions.	The company did not develop a cost abatement curve, as linear model optimizations are ideally suited to endogenously and simultaneously assess finely detailed and incremental trade-offs among resources, requirements and constraints to achieve least-cost least-risk outcomes influenced by dynamic market conditions. Emissions constraints are included in the simultaneous optimization of all resource (technology) selections, reflecting a PacifiCorp-specific marginal cost of compliance expressed in dollars per ton. In addition, six price-emissions scenarios were evaluated in each Regional Haze and core case. Variant CO_2 sensitivities are also included in the 2017 IRP.
UE-140546, Acknowledgement Letter, p.3	Appreciate sensitivity case in the 2015 IRP S-15, but question approach in assuming the only compliance alternative would be to shut down Chehalis gas plant. It would be more appropriate to allow the model to conduct a full run to see if it can identify some other combination of compliance options consistent with the final CPP that would allow the Company to meet its obligations without have to double allocate renewable energy. Request that the Company provide such an analysis with the 2015 IRP Update.	These concerns were addressed in the 2015 IRP Update covering both Chehalis shutdown assumptions and the potential double-counting issue based on ERCs (2015 IRP Update, pages 61-62). ERCs are not explicitly included 2017 IRP analytics.
UE-140546, Acknowledgement Letter, p.4	The cost impacts in S-10 in the 2015 IRP were on a system basis and the commission would like to see them on a balancing authority area basis. Requests the analysis be redone in the 2017 IRP and that the Company use inputs consistent	See Volume I, Chapter 8 (Modeling and Portfolio Selection Results) for a description regarding the West and East balancing authority area sensitivities and response to this request.

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2017 IRP
	with the staff MSP power flow data or explain why different inputs are more appropriate. Request that the Company incorporate the balancing area analysis in all future IRPs.	
UE-140546, Acknowledgement Letter, p.5	Expect the Company to conduct a more in-depth analysis of energy storage in its 2017 IRP. Analysis should include benefits associated with ancillary services such as frequency regulation and include batteries and other forms of storage. It should also value specific projects on Pacific Power's system both at the transmission and distribution levels and ensure cost assumptions are based on current price trends.	Two energy storage sensitivities (Storage – Battery and Storage – CAES) were conducted for the 2017 IRP, using updated cost assumptions. Please refer to Volume I, Chapter 8 (Modeling and Portfolio Selection Results) for a discussion of these sensitivity cases and energy storage. See also Volume II, Appendix P (Energy Storage Studies).
UE-140546, Acknowledgement Letter, p.6	Request that the 2017 IRP re-assess the overall potential and levelized costs for demand response and add a sensitivity analysis that evaluates the portfolio impact of adding additional demand response resources. Encourage the Company to consider demand response along with traditional energy efficiency programs in the context of Clean Power Plan compliance planning.	In the 2017 IRP, demand response programs, which do not produce emissions, and with their selection in any portfolio, potentially defer emissions from alternative generating resources, are directly competitive with alternate strategies to keep total emissions below CPP limits. Also, in the 2017 IRP, core case DLC-1 includes the forced addition of Class 1 DSM resources equal to 5 percent of the incremental L&R balance estimated at the time the study was prepared. Please refer to Chapter 7 (Modeling and Portfolio Evaluation Approach) and Chapter 8 (Modeling and Portfolio Selection Results).
UR-140546, Acknowledgement Letter, p.7	Request that the Company update its RPS compliance analysis in the 2015 IRP Update based on a more accurate projection of Washington's future renewable energy allocations.	PacifiCorp met this requirement in its 2015 IRP Update, page 57.
UE-140546, Acknowledgement Letter, p.7	Note that the Company agreed, as a condition of the commission's granting of the waivers requested in Docket UE-151694, to conduct a market reliance risk assessment in conjunction with the 2017 IRP. Encourage the Company to work with staff on the design of that analysis.	Please see Volume II, Appendix J (Western Resource Adequacy Evaluation) for an evaluation of market depth, and also the Front Office Transaction sensitivity provided in Volume I, Chapter 8 (Modeling and Portfolio Selection Results).
UE-140546, Acknowledgement Letter, p.8	Encourage the Company to continue to integrate the EIM into its IRP model, in particular to develop modeling capability to capture how different resources with different generation profiles would interact with the EIM, based on the Company's experience with the market. Also expect the Company to work with staff on incorporating an analysis of CAISO membership in the 2017 IRP as appropriate.	PacifiCorp incorporated flexible ramping procurement diversity savings from the EIM in its Flexible Reserve Study. See Volume II, Appendix H (Flexible Reserve Study). California Senate Bill No. 350, which was passed in October 2015, authorizes the California legislature to consider making changes to current laws that would create an independent governance structure for a regional ISO up until the conclusion of the 2017 legislative session which ends September 15, 2017. In the event that legislation is passed, PacifiCorp will coordinate with its state regulatory authorities on evaluation of next steps. As such, an

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2017 IRP
		analysis of participation in a regional ISO is not included in the 2017 IRP. This is discussed further in Volume I, Chapter 3 (Planning Environment) of the 2017 IRP.
Wyoming		
The Wyoming Public Service Commission provided the following comment in its Letter Order (Docket No. 20000-474474-EA-15, record No. 14089, dated January 11, 2015) on PacifiCorp's 2015 IRP: *Pursuant to open meeting action taken on December 29, 2015, Rocky Mountain Power's 2015 Integrated Resource Plan is hereby placed in the Commission's files. No further action will be taken and this matter is closed.*		

Table B.3 – Oregon Public Utility Commission IRP Standard and Guidelines

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
Guideline 1. Substantive Requirements		
1.a.1	All resources must be evaluated on a consistent and comparable basis: All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.	PacifiCorp considered a wide range of resources including renewables, demand-side management, energy storage, power purchases, thermal resources, and transmission. Volume I, Chapter 4 (Transmission Planning), Chapter 6 (Resource Options), and Chapter 7 (Modeling and Portfolio Evaluation Approach) document how PacifiCorp developed these resources and modeled them in its portfolio analysis. All these resources were established as resource options in the Company's capacity expansion optimization model, System Optimizer, and selected by the model based on load requirements, relative economics, resource size, availability dates, and other factors.
1.a.2	All resources must be evaluated on a consistent and comparable basis: Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	All portfolios developed with System Optimizer were subjected to Monte Carlo production cost simulation. These portfolios contained a variety of resource types with different fuel types (coal, gas, biomass, nuclear fuel, "no fuel" renewables), lead-times (ranging from front office transactions to nuclear plants), in-service dates, operational lives, and locations. See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), Chapter 8 (Modeling and Portfolio Selection Results), and Volume II, Appendix K (Detailed Capacity Expansion Results) and Appendix L (Stochastic Production Cost Simulation Results).
1.a.3	All resources must be evaluated on a consistent and comparable basis: Consistent assumptions and methods should be used for evaluation of all resources.	PacifiCorp fully complies with this requirement. The company developed generic supply-side resource attributes based on a consistent characterization methodology. For demand-side resources, the company used the Applied Energy Group's supply curve data developed for this IRP for representation of DSM resources. The study was based on a consistently applied methodology for determining technical, market, and achievable DSM potentials. All portfolio resources were evaluated using the same sets of price and load forecast inputs. These inputs are documented in Volume I, Chapter 5 (Load and

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
		Resource Balance), Chapter 6 (Resource Alternatives), and Chapter 7 (Modeling and Portfolio Evaluation Approach) as well as Volume II, Appendix D (Demand-Side Management and Supplemental Resources).
1.a.4	All resources must be evaluated on a consistent and comparable basis: The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	PacifiCorp applied its nominal after-tax WACC of 6.57 percent to discount all cost streams.
1.b.1	Risk and uncertainty must be considered: At a minimum, utilities should address the following sources of risk and uncertainty: 1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.	Each of the sources of risk identified in this guideline is treated as a stochastic variable in Monte Carlo production cost simulation with the exception of CO_2 emission compliance costs, which are treated as a scenario risk and evaluated via the 111(d) modeling approach. Additional scenario risk is used to evaluate load sensitivities. See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).
1.b.2	Risk and uncertainty must be considered: Utilities should identify in their plans any additional sources of risk and uncertainty.	Resource risk mitigation is discussed in Volume I, Chapter 9 (Action Plan). Regulatory and financial risks associated with resource and transmission investments are highlighted in several areas in the IRP document, including Volume I, Chapter 3 (The Planning Environment), Chapter 4 (Transmission), Chapter 7 (Modeling and Portfolio Evaluation Approach), and Chapter 8 (Modeling and Portfolio Selection Results).
1.c	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers ("best cost/risk portfolio").	PacifiCorp evaluated cost/risk tradeoffs for each of the portfolios considered. See Volume I, Chapter 8 (Modeling and Portfolio Selection Results), Chapter 9 (Action Plan), and Volume II, Appendix K (Detailed Capacity Expansion Results) and Appendix L (Stochastic Production Cost Simulation Results) for the Company's portfolio cost/risk analysis and determination of the preferred portfolio.
1.c.1	The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	PacifiCorp used a 20-year study period (2017-2036) for portfolio modeling, and a real levelized revenue requirement methodology for treatment of end effects.
1.c.2	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) provides a description of the PVRR methodology.
1.c.3.1	To address risk, the plan should include, at a minimum:	PacifiCorp uses the standard deviation of stochastic production costs as the measure of cost variability. For the severity of bad outcomes, the company calculates

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
	1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.	several measures, including stochastic upper-tail mean PVRR (mean of highest three Monte Carlo iterations) and the 95th percentile stochastic production cost PVRR.
1.c.3.2	To address risk, the plan should include, at a minimum: 2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	A discussion on hedging is provided in Volume I, Chapter 9 (Action Plan).
1.c.4	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Volume I, Chapter 8 (Modeling and Portfolio Selection Results) summarizes the results of PacifiCorp's cost/risk tradeoff analysis, and describes what criteria the Company used to determine the best cost/risk portfolios and the preferred portfolio.
1.d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	PacifiCorp considered both current and potential state and federal energy/pollutant emission policies in portfolio modeling. Volume I, Chapter 7 describes the decision process used to derive portfolios, which includes consideration of state and federal resource policies and regulations that are summarized in Volume I, Chapter 3 (The Planning Environment). Volume I, Chapter 8 (Modeling and Portfolio Selection Results) provides the results. Volume I, Chapter 9 (Action Plan) presents an acquisition path analysis that describes resource strategies based on regulatory trigger events.
Guideline 2. Procedural Requirements		
2.a	The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.	PacifiCorp fully complies with this requirement. Volume I, Chapter 2 (Introduction) provides an overview of the public process, all public meetings held for the 2017 IRP, which are documented in Volume II, Appendix C (Public Input Process). PacifiCorp also made use of a Feedback Form for stakeholders to provide comments and offer suggestions. Feedback Forms along with the public meeting presentations and handouts are available on PacifiCorp's webpage at: http://www.pacificorp.com/es/irp.html
2.b	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.	2017 IRP Volumes I and II provide non-confidential information the Company used for portfolio evaluation, as well as other data requested by stakeholders. PacifiCorp also provided stakeholders with non-confidential information to support public meeting discussions via email. Data discs will be available with public data. Additionally, data discs with confidential data will be protected through use of a protective order.
2.c	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	PacifiCorp distributed draft IRP materials for external review throughout the process prior to each of the public input meetings and solicited/and received feedback at various times when developing the 2017 IRP. The materials shared with stakeholders at these

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
		meetings, outlined in Volume I Chapter 2 (Introduction), is consistent with materials presented in Volumes I and II of the 2017 IRP report. PacifiCorp requested and responded to comments from stakeholders in developing core case and sensitivity definitions. The Company considered comments received via Feedback Forms in developing its final plan.
Guideline 3: Plan Filing, Review, and Updates		
3.a	A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.	The 2017 IRP complies with this requirement.
3.b	The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.	This activity will be conducted subsequent to filing this IRP.
3.c	Commission staff and parties should complete their comments and recommendations within six months of IRP filing.	This activity will be conducted subsequent to filing this IRP.
3.d	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the IRP before issuing an acknowledgment order.	This activity will be conducted subsequent to filing this IRP.
3.e	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	Not applicable.
3.f	(a) Each energy utility must submit an annual update on its most recently acknowledged IRP. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.	This activity will be conducted subsequent to filing this IRP.
3.g	Unless the utility requests acknowledgment of changes in proposed actions, the annual update is an informational filing that: • Describes what actions the utility has taken to implement the plan;	This activity will be conducted subsequent to filing this IRP.

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
	• Provides an assessment of what has changed since the acknowledgment order that affects the action plan to select best portfolio of resources, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and • Justifies any deviations from the acknowledged action plan.	
Guideline 4. Plan Components: At a minimum, the plan must include the following elements		
4.a	An explanation of how the utility met each of the substantive and procedural requirements.	The purpose of this table is to comply with this guideline.
4.b	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions.	PacifiCorp developed low, high, and extreme peak temperature (one-in-twenty probability) load growth forecasts for scenario analysis using the System Optimizer model. Stochastic variability of loads was also captured in the risk analysis. See Volume I, Chapters 5 (Load and Resource Balance) and Chapter 7 (Modeling and Portfolio Evaluation Approach), and Volume II, Appendix A (Load Forecast) for load forecast information.
4.c	For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested.	See Chapter 5 (Load and Resource Balance) for details on annual capacity and energy balances. Existing transmission rights are reflected in the IRP model topologies. Future transmission additions used in analyzing portfolios are summarized in Volume I, Chapter 4 (Transmission) and Chapter 7 (Modeling and Portfolio Evaluation Approach)
4.d	For gas utilities only.	Not applicable.
4.e	Identification and estimated costs of all supply-side and demand side resource options, taking into account anticipated advances in technology.	Volume I, Chapter 6 (Resource Options) identifies the resources included in this IRP, and provides their detailed cost and performance attributes. Additional information on energy efficiency resource characteristics is available in Volume II, Appendix D (Demand-Side Management and Supplemental Resources) referencing additional information on PacifiCorp's IRP Web, site see footnote 3 of this Appendix B.
4.f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs.	In addition to incorporating a 13 percent planning reserve margin for all portfolios evaluated, as supported by an updated Stochastic Loss of Load Study in Volume II, Appendix I), the Company used several measures to evaluate relative portfolio supply reliability. These measures (Energy Not Served and Loss of Load Probability) are described in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).
4.g	Identification of key assumptions about the future (e.g., fuel prices and environmental	Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) describes the key assumptions and alternative scenarios used in this IRP. Volume II,

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
	compliance costs) and alternative scenarios considered.	Appendix M (Case Study Fact Sheets) includes summaries of assumptions used for each case definition analyzed in the 2017 IRP.
4.h	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system.	This Plan documents the development and results of portfolios designed to determine resource selection under a variety of input assumptions in Volume I, Chapters7 (Modeling and Portfolio Evaluation Approach) and Chapter 8 (Modeling and Portfolio Selection Results).
4.i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties.	Volume I, Chapter 8 (Modeling and Portfolio Selection Results) presents the stochastic portfolio modeling results, and describes portfolio attributes that explain relative differences in cost and risk performance.
4.j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	Volume I, Chapter 8 (Modeling and Portfolio Selection Results) provides tables and charts with performance measure results, including rank ordering.
4.k	Analysis of the uncertainties associated with each portfolio evaluated.	See responses to 1.b.1 and 1.b.2 above.
4.l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers.	See 1.c above.
4.m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation.	This IRP is designed to avoid inconsistencies with state and federal energy policies therefore none are currently identified.
4.n	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	Volume I Chapter 9 (Action Plan) presents the 2017 IRP action plan.
Guideline 5: Transmission		
5	Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	PacifiCorp evaluated four sensitivities on Energy Gateway transmission project configurations on a consistent and comparable basis with respect to other resources. Where new resources would require additional transmission facilities the associated costs were factored into the analysis. Fuel transportation costs were factored into resource costs.
Guideline 6: Conservation		
6.a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	A multi-state demand-side management potential study was completed in 2017, and those results were incorporated into this plan.

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
6.b	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	PacifiCorp's energy efficiency supply curves incorporate Oregon resource potential. Oregon potential estimates were provided by the Energy Trust of Oregon. See the demand-side resource section in Volume I, Chapter 6 (Resource Alternatives), the results in Volume I, Chapter 8 (Modeling and Portfolio Selection Results), the targeted amounts in Volume I, Chapter 9 (Action Plan) and the implementation steps outlined in Volume II, Appendix D.
6.c	To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should: 1. Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and 2. Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	See the response for 6.b above.
Guideline 7: Demand Response		
7	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	PacifiCorp evaluated demand response resources (Class 1 DSM) on a consistent basis with other resources.
Guideline 8: Environmental Costs		
8.a	Base case and other compliance scenarios: The utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. The utility should develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities. Each compliance scenario should include a time profile of CO_2 compliance requirements. The utility should identify whether the basis of those requirements, or "costs," would be CO_2 taxes, a ban on certain types of resources, or CO_2 caps (with or without flexibility mechanisms such as allowance or credit trading as a safety valve). The analysis should recognize significant and important upstream emissions that would likely have a significant impact on resource decisions. Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs.	See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach). For the 2017 IRP PacifiCorp used the EPA's proposed 11(d) rule as the basis for future regulations. The proposed rules limit carbon emissions either through a state-level rate per MWh, or a hard cap amount. PacifiCorp looked at both approaches in determining portfolio selections. PacifiCorp examined compliance through EPA's 111(d) along with a carbon tax adder.

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
8.b	Testing alternative portfolios against the compliance scenarios: The utility should estimate, under each of the compliance scenarios, the present value revenue requirement (PVRR) costs and risk measures, over at least 20 years, for a set of reasonable alternative portfolios from which the preferred portfolio is selected. The utility should incorporate end-effect considerations in the analyses to allow for comparisons of portfolios containing resources with economic or physical lives that extend beyond the planning period. The utility should also modify projected lifetimes as necessary to be consistent with the compliance scenario under analysis. In addition, the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection.	Volume II, Appendix L (Stochastic Production Costs Simulation Results) provides the Stochastic mean PVRR versus upper tail mean less stochastic mean PVRR scatter plot diagrams that for a broad range of portfolios developed with a range of compliance scenarios as summarized in 8.a above. The Company considers end-effects in its use of Real Levelized Revenue Requirement Analysis, as summarized in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and uses a 20-year planning horizon. Early retirement and gas conversion alternatives to coal unit environmental investments were considered in the development of all resource portfolios. Alternate scenarios were applied in the 2017 IRP to capture the possibility of more stringent Regional Haze compliance obligations.
8.c	Trigger point analysis: The utility should identify at least one CO_2 compliance "turning point" scenario, which, if anticipated now, would lead to, or "trigger" the selection of a portfolio of resources that is substantially different from the preferred portfolio. The utility should develop a substitute portfolio appropriate for this trigger-point scenario and compare the substitute portfolio's expected cost and risk performance to that of the preferred portfolio – under the base case and each of the above CO_2 compliance scenarios. The utility should provide its assessment of whether a CO_2 regulatory future that is equally or more stringent that the identified trigger point will be mandated.	See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) for a description of core case definitions. Regional Haze cases were developed to represent "triggered" portfolios with coal unit retirements and gas conversions that differ substantially from the preferred portfolio. PacifiCorp also performed CO_2 price sensitivities showing portfolios that differ significantly from the preferred portfolio. Comparative analysis of these case results is included in Volume I, Chapter 8 (Modeling and Portfolio Selection Results).
8.d	Oregon compliance portfolio: If none of the above portfolios is consistent with Oregon energy policies (including state goals for reducing greenhouse gas emissions) as those policies are applied to the utility, the utility should construct the best cost/risk portfolio that achieves that consistency, present its cost and risk parameters, and compare it to those in the preferred and alternative portfolios.	Several portfolios yield system emissions aligned with state goals for reducing greenhouse gas emissions. These cases are summarized in Volume I, Chapter 8 (Modeling and Portfolio Selection Results).
Guideline 9: Direct Access Loads		
9	An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	Oregon docket UE 267 established a long-term opt out option for eligible PacifiCorp customers. Going forward PacifiCorp will cease planning for customers who elect direct-access service on a long-term basis (i.e. five-year opt out customers).
Guideline 10: Multi-state Utilities		

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
10	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated system basis that achieves a best cost/risk portfolio for all their retail customers.	The 2017 IRP conforms to the multi-state planning approach as stated in Volume I, Chapter 2 under the section "The Role of PacifiCorp's Integrated Resource Planning". The Company notes the challenges in complying with multi-state integrated planning given differing state energy policies and resource preferences.
Guideline 11: Reliability		
11	Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.	See the response to 1.c.3.1 above. Volume I, Chapter 8 (Modeling and Portfolio Selection Results) walks through the role of reliability, cost, and risk measures in determining the preferred portfolio. Scatter plots of portfolio cost versus risk at different CO_2 cost levels were used to inform the cost/risk tradeoff analysis.
Guideline 12: Distributed Generation		
12	Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	PacifiCorp contracted with Navigant to provide estimates of expected private generation penetration. The study was incorporated in the analysis as a deduction to load. Sensitivities looked at both high and low penetration rates for private generation. The study is included in Volume II, Appendix P (Energy Storage Studies).
Guideline 13: Resource Acquisition		
13.a	An electric utility should, in its IRP: 1. Identify its proposed acquisition strategy for each resource in its action plan. 2. Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party. 3. Identify any Benchmark Resources it plans to consider in competitive bidding.	Chapter 9 (Action Plan) outlines the procurement approaches for resources identified in the preferred portfolio. A discussion of the advantages and disadvantages of owning a resource instead of purchasing it is included in Chapter 9 (Action Plan). PacifiCorp has not at this time identified any specific benchmark resources it plans to consider in the competitive bidding process summarized in the 2017 IRP action plan.
13.b	For gas utilities only.	Not applicable.
Flexible Capacity Resources		
1	Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period.	See Volume II, Appendix F (Flexible Reserve Study).

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
2	Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period.	See Volume II, Appendix F (Flexible Reserve Study).
3	Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.	See Volume II, Appendix F (Flexible Reserve Study).

Table B.4 – Utah Public Service Commission IRP Standard and Guidelines

No.	Requirement	How the Standards and Guidelines are Addressed in the 2017 IRP
Procedural Issues		
1	The Commission has the legal authority to promulgate Standards and Guidelines for integrated resource planning.	Not addressed; this is a Public Service Commission of Utah responsibility.
2	Information Exchange is the most reasonable method for developing and implementing integrated resource planning in Utah.	Information exchange has been conducted throughout the IRP process.
3	Prudence reviews of new resource acquisitions will occur during ratemaking proceedings.	Not an IRP requirement as the Commission acknowledges that prudence reviews will occur during ratemaking proceedings, outside of the IRP process.
4	PacifiCorp's integrated resource planning process will be open to the public at all stages. The Commission, its staff, the Division, the Committee, appropriate Utah state agencies, and other interested parties can participate. The Commission will pursue a more active-directive role if deemed necessary, after formal review of the planning process.	PacifiCorp's public process is described in Volume I, Chapter 2 (Introduction). A record of public meetings is provided in Volume II, Appendix C (Public Input Process).
5	Consideration of environmental externalities and attendant costs must be included in the integrated resource planning analysis.	PacifiCorp used a scenario analysis approach along with externality cost adders to model environmental externality costs. See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) for a description of the methodology employed, including how CO_2 cost uncertainty is factored into the determination of relative portfolio performance.
6	The integrated resource plan must evaluate supply-side and demand-side resources on a consistent and comparable basis.	Supply, transmission, and demand-side resources were evaluated on a comparable basis using PacifiCorp's capacity expansion optimization model. Also see the response to number 4.b.ii below.
7	Avoided cost should be determined in a manner consistent with the Company's Integrated Resource Plan.	Consistent with the Utah rules, PacifiCorp determination of avoided costs in Utah will be handled in a manner consistent with the IRP, with the

No.	Requirement	How the Standards and Guidelines are Addressed in the 2017 IRP
		caveat that the costs may be updated if better information becomes available.
8	The planning standards and guidelines must meet the needs of the Utah service area, but since coordination with other jurisdictions is important, must not ignore the rules governing the planning process already in place in other jurisdictions.	This IRP was developed in consultation with parties from all state jurisdictions, and meets all formal state IRP guidelines.
9	The Company's Strategic Business Plan must be directly related to its Integrated Resource Plan.	Volume I, Chapter 9 (Action Plan) describes the linkage between the 2017 IRP preferred portfolio and fall 2016 business plan resources. Significant resource differences are highlighted. The business plan portfolio was run consistent with requirements outlined in the Order issued by the Utah Public Service Commission on September 16, 2016, Docket No. 15-035-04.
Standards and Guidelines		
1	Definition: Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, in order to meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.	Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) outlines the portfolio performance evaluation and preferred portfolio selection process, while Chapter 8 (Modeling and Portfolio Selection Results) chronicles the modeling and preferred portfolio selection process. This IRP also addresses concerns expressed by Utah stakeholders and the Utah commission concerning comprehensiveness of resources considered, consistency in applying input assumptions for portfolio modeling, and explanation of PacifiCorp's decision process for selecting top-performing portfolios and the preferred portfolio.
2	The Company will submit its Integrated Resource Plan biennially.	The company submitted its last IRP on March 31, 2015, and filed this IRP on April 4, 2017 meeting the requirement.
3	IRP will be developed in consultation with the Commission, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies and interested parties. PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan.	PacifiCorp's public process is described in Volume I, Chapter 2 (Introduction). A record of public meetings is provided in Volume II, Appendix C (Public Input Process).
4.a	PacifiCorp's integrated resource plans will include: a range of estimates or forecasts of load growth, including both capacity (kW) and energy (kWh) requirements.	PacifiCorp implemented a load forecast range for both capacity expansion optimization scenarios as well as for stochastic variability, covering both capacity and energy. Details concerning the load forecasts used in the 2017 IRP are provided in Volume I, Chapter 5 (Load and Resource Balance) and Volume II, Appendix A (Load Forecast Details).
4.a.i	The forecasts will be made by jurisdiction and by general class and will differentiate energy and capacity requirements. The Company will include in its forecasts all on-system loads and those off-system loads which they have a contractual obligation to fulfill. Non-firm off-system sales are uncertain and should not be explicitly	Load forecasts are differentiated by jurisdiction and differentiate energy and capacity requirements. See Volume I, Chapter 5 (Load and Resource Balance) and Volume II, Appendix A (Load Forecast Details). Non-firm off-system sales are not incorporated into the load forecast. Off-system sales markets are

No.	Requirement	How the Standards and Guidelines are Addressed in the 2017 IRP
	incorporated into the load forecast that the utility then plans to meet. However, the Plan must have some analysis of the off-system sales market to assess the impacts such markets will have on risks associated with different acquisition strategies.	included in IRP modeling and are used for system balancing purposes.
4.a.ii	Analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads.	Volume II, Appendix A (Load Forecast Details) documents how demographic and price factors are used in PacifiCorp's load forecasting methodology.
4.b	An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis.	Resources were evaluated on a consistent and comparable basis using the System Optimizer model and Planning and Risk production cost model using both supply side and demand side alternatives. See explanation in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and the results in Volume I, Chapter 8 (Modeling and Portfolio Selection Results). Resource options are summarized in Volume I, Chapter 6 (Resource Options).
4.b.i	An assessment of all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation.	PacifiCorp included supply curves for Class 1 DSM (dispatchable/schedulable load control) and Class 2 DSM (energy efficiency measures) in its capacity expansion model. Details are provided in Volume I, Chapter 6 (Resource Options).
4.b.ii	An assessment of all technically feasible generating technologies including: renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources.	PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), power purchases, thermal resources, energy storage, and Energy Gateway transmission configurations. Volume I, Chapters 6 (Resource Options) and 7 (Modeling and Portfolio Evaluation Approach) contain assumptions and describe the process under which PacifiCorp developed and assessed these technologies and resources.
4.b.iii	The resource assessments should include: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility, efficiency of the resource and opportunities for customer participation.	PacifiCorp captures and models these resource attributes in its IRP models. Resources are defined as providing capacity, energy, or both. The DSM supply curves used for portfolio modeling explicitly incorporate estimated rates of program and event participation. The private generation study, modeled as a reduction to load, also considered rates of participation. Replacement capacity is considered in the case of early coal unit retirements as evaluated in this IRP as an alternative to coal unit environmental investments. Dispatchability is accounted for in both IRP models used; however, the Planning and Risk model provides a more detailed representation of unit dispatch than System Optimizer, and includes modeling of unit commitment and reserves.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2017 IRP
4.c	An analysis of the role of competitive bidding for demand-side and supply-side resource acquisitions	A description of the role of competitive bidding and other procurement methods is provided in Volume I, Chapter 9 (Action Plan).
4.d	A 20-year planning horizon.	This IRP uses a 20-year study horizon (2017-2036)
4.e	An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan. The action plan will span a four-year horizon and will describe specific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will include a status report of the specific actions contained in the previous action plan.	The IRP action plan is provided in Volume I, Chapter 9 (Action Plan). A status report of the actions outlined in the previous action plan (2015 IRP Update) is provided in Volume I, Chapter 9 (Action Plan). In Volume I, Chapter 9 (Action Plan) Table 9.1 identifies actions anticipated in the next two years and in the next four years.
4.f	A plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds.	Volume I, Chapter 9 (Action Plan) includes an acquisition path analysis that presents broad resource strategies based on regulatory trigger events, change in load growth, extension of federal renewable resource tax incentives and procurement delays.
4.g	An evaluation of the cost-effectiveness of the resource options from the perspectives of the utility and the different classes of ratepayers. In addition, a description of how social concerns might affect cost effectiveness estimates of resource options.	PacifiCorp provides resource-specific utility and total resource cost information in Volume I, Chapter 6 (Resource Options). The IRP document addresses the impact of social concerns on resource cost-effectiveness in the following ways: ● Portfolios were evaluated using a range of CO_2 compliance methods, most included emissions rate targets, but there was examination of additional CO_2 tax adders. ● A discussion of environmental policy status and impacts on utility resource planning is provided in Volume I, Chapter 3 (The Planning Environment). ● State and proposed federal public policy preferences for clean energy are considered for development of the preferred portfolio, which is documented in Volume I, Chapter 8 (Modeling and Portfolio Selection Results). ● Volume II, Appendix G (Plant Water Consumption) of reports historical water consumption for PacifiCorp's thermal plants.
4.h	An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. The Company will identify who should bear such risk, the ratepayer or the stockholder.	The handling of resource risks is discussed in Volume I, Chapter 9 (Action Plan), and covers managing environmental risk for existing plants, risk management and hedging and treatment of customer and investment risk. Transmission expansion risks are discussed in Chapter 4 (Transmission). Resource capital cost uncertainty and technological risk is addressed in Volume I, Chapter 6 (Resource Options).

No.	Requirement	How the Standards and Guidelines are Addressed in the 2017 IRP
		For reliability risks, the stochastic simulation model incorporates stochastic volatility of forced outages for new thermal plants and hydro availability. These risks are factored into the comparative evaluation of portfolios and the selection of the preferred portfolio upon which the action plan is based. Identification of the classes of risk and how these risks are allocated to ratepayers and investors is discussed in Volume I, Chapter 9 (Action Plan).
4.i	Considerations permitting flexibility in the planning process so that the Company can take advantage of opportunities and can prevent the premature foreclosure of options.	Flexibility in the planning and procurement processes is highlighted in Volume I, Chapter 9 (Action Plan), specifically, Table 9.1.
4.j	An analysis of tradeoffs; for example, between such conditions of service as reliability and dispatchability and the acquisition of lowest cost resources.	PacifiCorp examined the trade-off between portfolio cost and risk, taking into consideration a broad range of resource alternatives defined with varying levels of dispatchability. This trade-off analysis is documented in Volume I, Chapter 8 (Modeling and Portfolio Selection Results), and highlighted through the use of scatter-plot graphs showing the relationship between stochastic mean and upper-tail mean stochastic PVRR.
4.k	A range, rather than attempts at precise quantification, of estimated external costs which may be intangible, in order to show how explicit consideration of them might affect selection of resource options. The Company will attempt to quantify the magnitude of the externalities, for example, in terms of the amount of emissions released and dollar estimates of the costs of such externalities.	PacifiCorp incorporated environmental externality costs for CO_2 and costs for complying with current and proposed U.S. EPA regulatory requirements. For CO_2 externality costs, the company used scenarios with various compliance requirements to capture a reasonable range of cost impacts. These modeling assumptions are described in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).
4.l	A narrative describing how current rate design is consistent with the Company's integrated resource planning goals and how changes in rate design might facilitate integrated resource planning objectives.	See Volume I, Chapter 3 (The Planning Environment). The role of Class 3 DSM (price response programs) at PacifiCorp and how these resources are modeled in the IRP are described in Volume I, Chapter 6 (Resource Options).
5	PacifiCorp will submit its IRP for public comment, review and acknowledgment.	PacifiCorp distributed draft IRP materials for external review throughout the process prior to each of the public input meetings and solicited/and received feedback at various times when developing the 2017 IRP. The materials shared with stakeholders at these meetings, outlined in Volume I Chapter 2 (Introduction), is consistent with materials presented in Volumes I and II of the 2017IRP report. PacifiCorp requested and responded to comments from stakeholders in developing core case and sensitivity definitions. The Company also considered comments received via Feedback Forms in developing its final plan.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2017 IRP
6	The public, state agencies and other interested parties will have the opportunity to make formal comment to the Commission on the adequacy of the Plan. The Commission will review the Plan for adherence to the principles stated herein, and will judge the merit and applicability of the public comment. If the Plan needs further work the Commission will return it to the Company with comments and suggestions for change. This process should lead more quickly to the Commission's acknowledgment of an acceptable Integrated Resource Plan. The Company will give an oral presentation of its report to the Commission and all interested public parties. Formal hearings on the acknowledgment of the Integrated Resource Plan might be appropriate but are not required.	Not addressed; this is a post-filing activity.
7	Acknowledgment of an acceptable Plan will not guarantee favorable ratemaking treatment of future resource acquisitions.	Not addressed; this is not a PacifiCorp activity.
8	The Integrated Resource Plan will be used in rate cases to evaluate the performance of the utility and to review avoided cost calculations.	Not addressed; this refers to a post-filing activity.

Table B.5 – Washington Utilities and Transportation Commission IRP Standard and Guidelines (RCW 19.280.030 and WAC 480-100-238)

No.	Requirement	How the Standards and Guidelines are Addressed in the 2017 IRP
Requirements prior to IRP Filing		
(4)	Work plan filed no later than 12 months before next IRP due date.	PacifiCorp filed the 2017 IRP work plan on March 30, 2016 in Docket No. UE-160353, given an anticipated IRP filing date of March 31, 2017. PacifiCorp was granted approval in Docket No. UE-160353 on March 29, 2017 to file the IRP April 4, 2017.
(4)	Work plan outlines content of IRP.	See pages 1-2 of the Work Plan document for a summarization of anticipated IRP contents.
(4)	Work plan outlines method for assessing potential resources. (See LRC analysis below)	See pages 3-5 of the Work Plan document for a summarization of anticipated resource analysis.
(5)	Work plan outlines timing and extent of public participation.	See pages 5-6 of the Work Plan. Table 1, page 6, document for the anticipated IRP schedule. PacifiCorp was granted approval in Docket No. UE-160353 on March 29, 2017 to file the IRP April 4, 2017.
(4)	Integrated resource plan submitted within two years of previous plan.	The Commission issued an Order on December 11, 2008, under Docket No. UE-070117, granting the Company permission to file its IRP on March 31 of each odd numbered year. PacifiCorp filed the 2015 IRP on March 31, 2015. PacifiCorp was granted approval in Docket No. UE-160353 on March 29, 2017 to file the IRP April 4, 2017.
(5)	Commission issues notice of public hearing after company files plan for review.	This activity is conducted subsequent to filing this IRP.
(5)	Commission holds public hearing.	This activity is conducted subsequent to filing this IRP.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2017 IRP
Requirements specific to IRP filing		
(2)(a)	Plan describes the mix of energy supply resources.	Volume I, Chapter 5 (Load and Resource Balance) describes the mix of existing resources, while Volume I, Chapter 8 (Modeling and Portfolio Selection Results) describes the 2015 IRP preferred portfolio.
(2)(a)	Plan describes conservation supply.	See Volume I, Chapter 6 (Resource Options) for a description of how conservation supplies are represented and modeled, and Volume I, Chapter 8 (Modeling and Portfolio Selection Results) for conservation supply in the preferred portfolio. Additional information on energy efficiency resource characteristics is available on PacifiCorp's IRP Web site.
(2)(a)	Plan addresses supply in terms of current and future needs at the lowest reasonable cost to the utility and its ratepayers.	The 2017 IRP preferred portfolio was based on a resource needs assessment that accounted for forecasted load growth, expiration of existing power purchase contracts, resources under construction, contract, or reflected in the Company's capital budget, as well as a capacity planning reserve margin. Details on PacifiCorp's findings of resource need are described in Volume I, Chapter 5 (Load and Resource Balance).
(2)(b)	Plan uses lowest reasonable cost (LRC) analysis to select the mix of resources.	PacifiCorp uses portfolio performance measures based on the Present Value of Revenue Requirements (PVRR) methodology. See the section on portfolio performance measures in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and Volume I Chapter 8 (Modeling and Portfolio Selection Results).
(2)(b)	LRC analysis considers resource costs.	Volume I, Chapter 6 (Resource Options), provides detailed information on costs and other attributes for all resources analyzed for the IRP.
(2)(b)	LRC analysis considers market-volatility risks.	PacifiCorp employs Monte Carlo production cost simulation with a stochastic model to characterize market price and gas price volatility. Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) provides a summary of the modeling approach.
(2)(b)	LRC analysis considers demand side resource uncertainties.	PacifiCorp captured demand-side resource uncertainties through the development of numerous portfolios based on different sets of input assumptions.
(2)(b)	LRC analysis considers resource dispatchability.	PacifiCorp uses two IRP models that simulate the dispatch of existing and future resources based on such attributes as heat rate, availability, fuel cost, and variable O&M cost. The chronological production cost simulation model also incorporates unit commitment logic for handling start-up, shutdown, ramp rates, minimum up/down times, and run up rates, and reserve holding characteristics of individual generators.
(2)(b)	LRC analysis considers resource effect on system operation.	PacifiCorp's IRP models simulate the operation of its entire system, reflecting dispatch/unit commitment, forced/unforced outages, access to markets, and system reliability and transmission constraints.
(2)(b)	LRC analysis considers risks imposed on ratepayers.	PacifiCorp explicitly models risk associated with uncertain CO_2 regulatory regimes, wholesale electricity and natural gas price escalation and volatility, load growth uncertainty, resource reliability, renewable portfolio standard requirement uncertainty, plant construction cost escalation, and resource affordability. These risks and uncertainties are handled through stochastic modeling and scenarios depicting alternative futures. In addition to risk modeling, the IRP discusses a number of resource risk topics not addressed in the IRP system simulation models. For example, Volume I, Chapter 9 (Action Plan) covers the following

No.	Requirement	How the Standards and Guidelines are Addressed in the 2017 IRP
		topics: (1) managing carbon risk for existing plants, (2) assessment of owning vs. purchasing power, (3) purpose of hedging, (4) procurement delays and (5) treatment of customer and investor risks. Volume I, Chapter 4 (Transmission) covers similar risks associated with transmission system expansion.
(2)(b)	LRC analysis considers public policies regarding resource preference adopted by Washington state or federal government.	In Volume I, Chapter 7 (Modeling and Portfolio Evaluation) the IRP modeling incorporates resource expansion constraints tied to renewable portfolio standards (RPS) currently in place for Washington. PacifiCorp also evaluated various CO_2 regulatory schemes, and future Regional Haze compliance requirements. The I-937 conservation requirements are also explicitly accounted for in developing Washington conservation resource costs.
(2)(b)	LRC analysis considers cost of risks associated with environmental effects including emissions of carbon dioxide.	See (2)(b) above.
(2)(c)	Plan defines conservation as any reduction in electric power consumption that results from increases in the efficiency of energy use, production, or distribution.	A description of how PacifiCorp classifies and defines energy conservation is provided in Volume I, Chapter 6 (Resource Options).
(3)(a)	Plan includes a range of forecasts of future demand.	PacifiCorp implemented a load forecast range. Details concerning the load forecasts used in the 2017 IRP (high, low, and extreme peak temperature) are provided in Volume II, Appendix A (Load Forecast Details).
(3)(a)	Plan develops forecasts using methods that examine the effect of economic forces on the consumption of electricity.	PacifiCorp's load forecast methodology employs econometric forecasting techniques that include such economic variables as household income, employment, and population. See Volume II, Appendix A (Load Forecast Details) for a description of the load forecasting methodology.
(3)(a)	Plan develops forecasts using methods that address changes in the number, type and efficiency of electrical end-uses.	Residential sector load forecasts use a statistically-adjusted end-use model that accounts for equipment saturation rates and efficiency. See Volume II, Appendix A (Load Forecast Details), for a description of the residential sector load forecasting methodology.
(3)(b)	Plan includes an assessment of commercially available conservation, including load management.	PacifiCorp updated the system-wide demand-side management potential study in the 2017 IRP, which served as the basis for developing DSM resource supply curves for resource portfolio modeling. The supply curves account for technical and achievable (market) potential, while the IRP capacity expansion model identifies a cost-effective mix of DSM resources based on these limits and other model inputs. The DSM potential study is included on the data disc, and available on PacifiCorp's IRP website at: http://www.pacificorp.com/es/irp/irpsupport.html.
(3)(b)	Plan includes an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	A description of the current status of DSM programs and on-going activities to implement current and new programs is provided in Volume I, Chapter 5 (Load and Resource Balance).
(3)(c)	Plan includes an assessment of a wide range of conventional and commercially available nonconventional generating technologies.	PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), customer standby generation, power purchases, thermal resources, energy storage, and transmission. Volume I, Chapters 6 (Resource Options and Chapter 7 (Modeling and Portfolio Evaluation Approach) document how PacifiCorp developed and assessed these technologies.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2017 IRP
(3)(d)	Plan includes an assessment of transmission system capability and reliability; to the extent such information can be provided consistent with applicable laws.	PacifiCorp modeled transmission system capability to serve its load obligations, factoring in updates to the representation of major load and generation centers, regional transmission congestion impacts, import/export availability, external market dynamics, and significant transmission expansion plans explained in Volume I, Chapter 4 (Transmission) and Chapter 7 (Modeling and Portfolio Evaluation Approach). System reliability given transmission capability was analyzed using stochastic production cost simulation and measures of insufficient energy and capacity for a load area (Energy Not Served and Unmet Capacity, respectively).
(3)(e)	Plan includes a comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using LRC.	PacifiCorp's capacity expansion optimization model (System Optimizer) is designed to compare alternative resources—including transmission expansion options—for the least-cost resource mix. System Optimizer was used to develop numerous resource portfolios for comparative evaluation on the basis of cost, risk, reliability, and other performance attributes. Potential energy savings associated with conservation voltage reduction are discussed in Chapter 5.
(3)(f)	Plan includes integration of the demand forecasts and resource evaluations into a long range integrated resource plan describing the mix of resources that is designated to meet current and project future needs at the lowest reasonable cost to the utility and its ratepayers.	PacifiCorp integrates demand forecasts, resources, and system operations in the context of a system modeling framework described in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach). The portfolio evaluation covers a 20-year period (2017-2036). PacifiCorp developed its preferred portfolio of resources judged to be least-cost after considering load requirements, risk, uncertainty, supply adequacy/reliability, and government resource policies in accordance with this rule.
(3)(g)	Plan includes a two-year action plan that implements the long range plan.	See Table 9.1 in Volume I, Chapter 9 (Action Plan), for PacifiCorp's 2017 IRP action plan.
(3)(h)	Plan includes a progress report on the implementation of the previously filed plan.	See Table 9.2 for a status report on action plan implementation in Volume I, Chapter 9 (Action Plan).
Requirements from RCW 19.280.030 not discussed above		
(1)(e)	An assessment of methods, commercially available technologies, or facilities for integrating renewable resources, and addressing overgeneration events, if applicable to the utility's resource portfolio;	Volume I, Chapter 6 for discussion of options available for selection in the 2017 IRP. Also see Volume II, Appendix H (Wind and Solar Integration Study).
(1)(f)	The integration of the demand forecasts and resource evaluations into a long-range assessment describing the mix of supply side generating resources and conservation and efficiency resources that will meet current and projected needs, including mitigating overgeneration events, at the lowest reasonable cost and risk to the utility and its ratepayers;	See Volume II, Appendix A for a discussion of the load forecasts, Supply-side and demand-side are discussed in Volume I, Chapter 6. Also included is a discussion of DSM in Volume II, Appendix D are included in Volume I, Chapters 7 and 8 go through the modeling methodology and discussion of selecting the preferred portfolio using least cost/least risk metrics.

Table B.6 – Wyoming Public Service Commission Guidelines Regarding Electric IRP

No.	Requirement	How the Guideline is Addressed in the 2017 IRP
A	The public comment process employed as part of the formulation of the utility's IRP, including a description, timing and weight given to the public process;	PacifiCorp's public process is described in Volume I, Chapter 2 (Introduction) and in Volume II, Appendix C (Public Input Process).
B	The utility's strategic goals and resource planning goals and preferred resource portfolio;	Volume I, Chapter 8 (Modeling and Portfolio Selection Results) documents the preferred resource portfolio and rationale for selection. Volume I, Chapter 9 (Action Plan) constitutes the IRP action plan and the descriptions of resource strategies and risk management.
C	The utility's illustration of resource need over the near-term and long-term planning horizons;	See Volume I, Chapter 5 (Load and Resource Balance).
D	A study detailing the types of resources considered;	Volume, I Chapter 6 (Resource Options), presents the resource options used for resource portfolio modeling for this IRP.
F	Changes in expected resource acquisitions and load growth from that presented in the utility's previous IRP;	A comparison of resource changes relative to the 2015 IRP Update is presented in Volume I, Chapter 9 (Action Plan). A chart comparing the peak load forecasts for the 2015 IRP, 2015 IRP Update, and 2017 IRP is included in Volume II, Appendix A (Load Forecast Details).
G	The environmental impacts considered;	Portfolio comparisons for CO_2 and a broad range of environmental impacts are considered, including prospective early retirement and gas conversions of existing coal units as alternatives to environmental investments. See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and Chapter 8 (Modeling and Portfolio Selection) as well as Volume II, Appendix L (Stochastic production Cost Simulation Results).
H	Market purchases evaluation;	Modeling of firm market purchases (front office transactions) and spot market balancing transactions is included in this IRP.
I	Reserve Margin analysis; and	PacifiCorp's planning reserve margin study, which documents selection of a capacity planning reserve margin is in Volume I, Appendix I (Stochastic Loss of Load Study).
J	Demand-side management and conservation options;	See Volume I, Chapter 6 (Resource Options) for a detailed discussion on DSM and conservation resource options. Additional information on energy efficiency resource characteristics is available on the Company's website.

APPENDIX C – PUBLIC INPUT PROCESS

A critical element of this Integrated Resource Plan (IRP) is the public input process. PacifiCorp has pursued an open and collaborative approach involving the Commissions, customers and other stakeholders in PacifiCorp's IRP prior to making resource planning decisions. Since these decisions can have significant economic and environmental consequences, conducting the IRP with transparency and full participation from interested and affected parties is essential.

Stakeholders have been involved in the development of the 2017 IRP from the beginning. The public input meetings (PIM) held beginning in June 2016 were the cornerstone of the direct public input process. There were a total of seven PIM, with four lasting two days, the remainder being single days. Meetings were held jointly in both Salt Lake City, Utah and Portland, Oregon via video conference, with expanded video conference locations in Denver, Colorado and Cheyenne, Wyoming. One meeting was held via phone conference. For all meetings, attendees off-site for were able to conference in via phone.

The IRP public input process also included state-specific stakeholder dialogue sessions held in June 2016. The goal of these sessions was to capture key IRP issues of most concern to each state, as well as discuss how to tackle these from a system planning perspective. PacifiCorp also wanted to ensure that stakeholders understood IRP planning principles. These meetings continued to enhance interaction with stakeholders in the planning cycle, and provided a forum to directly address stakeholder concerns regarding equitable representation of state interests during public input meetings.

PacifiCorp solicited agenda item recommendations from the state stakeholders in advance of the state meetings. There was additional open time to ensure that participants had adequate time for dialogue.

PacifiCorp's comment website housed the feedback form discussed earlier in Chapter 2 - Introduction. This standardized form allowed stakeholders opportunities to provide comments, questions, and suggestions. Feedback forms can be found via the following link: (http://www.pacificorp.com/es/irp/irpcomments.html).

Participant List

PacifiCorp's 2017 IRP was a robust process involving input from many parties throughout. Organizations actively participated in the development of material, modeling process, and public meetings. Participants included Commissions, stakeholders, and industry experts. Among the organizations that were represented and actively involved in this collaborative effort were:

Commissions

- Idaho Public Utilities Commission
- Oregon Public Utilities Commission
- Public Service Commission of Utah
- Washington Utilities and Transportation Commission

- Wyoming Public Service Commission

Stakeholders and Industry Experts

- ABB Enterprise Software Inc. (formerly known as Ventyx Inc.)
- Applied Energy Group
- Avista Utilities
- Black & Veatch
- Blue Castle Holdings, Inc.
- Citizen's Utility Board of Oregon
- Energy Trust of Oregon
- DNV-GL
- Idaho Conservation League
- Idaho Power Company
- Individual Customers
- Industrial Customers of Northwest Utilities
- Intermountain Wind
- Interwest Energy Alliance
- Mitsubishi
- National Renewable Energy Laboratory
- Natural Resources Defense Council
- Navigant Consulting, Inc.
- Northwest Power and Conservation Council
- Northwest Pipeline GP
- NW Energy Coalition
- Oregon Department of Energy
- Oregon Department of Environmental Quality
- Portland General Electric
- Powder River Basin Resource Council
- Renewable Energy Coalition
- Renewables Northwest
- Sierra Club
- Siemens
- For Utah Association of Energy Users
- Utah Clean Energy
- Utah Division of Public Utilities
- Utah Industrial Energy Consumers
- Utah Office of Consumer Services
- Utah Office of Energy Development
- Western Clean Energy Campaign
- Western Electricity Coordination Council
- Western Resource Advocates
- Wyoming Industrial Energy Consumers
- Wyoming Office Of Consumer Advocate

PacifiCorp extends its gratitude for the time and energy participants have given to the IRP process. Their participation has contributed significantly to the quality of this plan, and their continued participation will help PacifiCorp as it strives to improve its planning efforts going forward.

Public Input Meetings

As mentioned above, PacifiCorp hosted seven public input meetings, as well as five state meetings during the public input process. During the 2017 IRP public input process presentations and discussions covered various issues regarding inputs, assumptions, risks, modeling techniques, and analytical results. Below are the agendas from the public input meetings; the presentations may be found on the PacifiCorp website at: http://www.pacificorp.com/es/irp.html.

General Meetings

June 21, 2016 – General Public Meeting

- Introductions
- 2017 IRP Timeline
- 2015 IRP Update Highlights
- Overview of Changes Since 2015 IRP
- 2015 IRP Order Requirements
- 2015 IRP Action Plan status updates

July 20, 2016 – General Public Meeting

Day One

- Introductions
- Environmental Policy
- Transmission and Regional Integration
- Renewable Portfolio Standards and Request for Proposals

August 25-26, 2016 – General Public Meeting

Day 1

- Introductions
- Portfolio Development
- Private Generation Study
- Supply-Side Resources
- Energy Storage

Day 2

- Update on Renewable Portfolio Standards and Request for Proposals
- Conservation Potential Assessment
- Load Forecast

September 22-23, 2016 – General Public Meeting

Day 1

- Introductions
- Portfolio Development
- Stochastic Modeling & Portfolio Selection Process
- Resource Adequacy and Front Office Transactions

- Loss of Load Probability and Planning Reserve Margin
- Capacity Contribution Study

Day 2
- Load and Resource Balance
- Flexible Capacity Reserve Study
- Smart Grid Update

November 17, 2016 – General Public Meeting
- Introductions
- Updated Capacity Contribution Study
- Official Forward Price Curve

January 26-27, 2017 – General Public Meeting

Day 1
- Portfolio Summaries

Day 2
- Sensitivity Studies

March 2-3, 2017 – General Public Meeting

Day 1
- Draft Preferred Portfolio Overview
- Market Price Scenarios
- Regional Haze and Core Cases

Day 2
- Sensitivity Studies
- Preferred Portfolio Selection Process

State Meetings

June 6, 2016 – Washington State Stakeholder Meeting
June 7, 2016 – Idaho State Stakeholder Meeting
June 10, 2016 – Oregon State Stakeholder Meeting
June 13, 2016 – Utah State Stakeholder Meeting
June 14, 2016 – Wyoming State Stakeholder Meeting

Stakeholder Comments

For the 2017 IRP, PacifiCorp provided a Feedback Form which offered stakeholders a direct opportunity to provide comments, questions, and suggestions outside the public input meetings. PacifiCorp recognizes the importance of stakeholder feedback to the IRP public input process. A blank form, as well as those submitted by stakeholders, is housed on the PacifiCorp website at the IRP comments webpage at: http://www.pacificorp.com/es/irp/irpcomments.html

The Feedback Form allowed the Company to review and summarize issues by topic as well as identify specific recommendations that were provided. Information collected was used to inform issues included in the 2017 IRP, including, process improvements, and input assumptions, as well as responding directly to stakeholder questions. Feedback Forms were received from the following stakeholders:

- HEAL Utah
- Idaho Conservation League
- Interwest Energy Alliance
- Natural Resources Defense Council
- NW Energy Coalition
- Oregon Public Utility Commission
- Powder River Basin Resource Council
- Renewable Energy Coalition
- Renewable Northwest
- Sierra Club
- Utah Clean Energy
- Utah Division of Public Utilities
- Western Clean Energy Campaign
- Western Resource Advocates

Some topics of note addressed in the forms include:

- Modeling of EPA's 111(d) rules
- Supply-side resources
- Demand Side Management
- Energy Storage
- Renewable Portfolio Standards
- Load forecast
- Renewable capacity values
- Wholesale power availability
- Portfolios and sensitivity cases
- IRP Public Input Meeting Process

Contact Information

PacifiCorp's IRP website contains many of the documents and presentations that support recent Integrated Resource Plans. To access it, please visit the company's website at http://www.pacificorp.com/es/irp.html

PacifiCorp requests that any informal request be sent in writing to the following address or email address below.

PacifiCorp
IRP Resource Planning Department
825 N.E. Multnomah, Suite 600
Portland, Oregon 97232

Email Address:
IRP@PacifiCorp.com

Phone Number:
(503) 813-5245

APPENDIX D – DEMAND-SIDE MANAGEMENT RESOURCES

Introduction

Appendix D reviews the studies and reports used to support the demand-side management (DSM) resource information used in the modeling and analysis of the 2017 Integrated Resource Plan (IRP). In addition, it provides information on the economic DSM selections in the 2017 IRP's Preferred Portfolio, a summary of existing DSM program services and offerings, and an overview of the DSM planning process in each of PacifiCorp's service areas.

Demand-Side Resource Potential Assessments for 2017-2036

Since 1989, PacifiCorp has developed biennial IRPs to identify an optimal mix of resources that balance considerations of cost, risk, uncertainty, supply reliability/deliverability, and long-run public policy goals. The optimization process accounts for capital, energy, and ongoing operation costs as well as the risk profiles of various resource alternatives, including: traditional generation and market purchases, renewable generation, and DSM resources such as energy efficiency, and demand response or capacity-focused resources. Since the 2008 IRP, DSM resources have competed directly against supply-side options, allowing the IRP model to guide decisions regarding resource mixes, based on cost and risk.

The Demand-side Resource Potential Assessment for 2017-2036[1] study, conducted by Applied Energy Group (AEG), primarily seeks to develop reliable estimates of the magnitude, timing, and costs of DSM resources likely available to PacifiCorp over a 20-year planning horizon, beginning in 2017. The study focuses on resources realistically achievable during the planning horizon, given normal market dynamics that may hinder resource acquisition. Study results were incorporated into PacifiCorp's 2017 IRP and will be used to inform subsequent DSM planning and program design efforts. This study serves as an update of similar studies completed in 2007, 2011, 2013 and 2015.

For resource planning purposes, PacifiCorp classifies DSM resources into four classifications, differentiated by two primary characteristics: reliability and customer choice. These resources classifications can be defined as: Class 1 DSM (firm, capacity focused), Class 2 DSM (energy efficiency), Class 3 DSM (non-firm, capacity focused), and Class 4 DSM (educational).

From a system-planning perspective, Class 1 DSM resources can be considered the most reliable, as they can be dispatched by the utility. In contrast, behavioral changes, resulting from voluntary educational programs included in Class 4 DSM, tend to be the least reliable. With respect to customer choice, Class 1 DSM and Class 2 DSM resources should be considered involuntary in that, once equipment and systems have been put in place, savings can be expected to occur over a certain period of time. Class 3 and Class 4 DSM activities involve greater customer choice and control. This assessment estimates potential from Class 1, 2, and 3 DSM.

[1] PacifiCorp's Demand-Side Resource Potential Assessment for 2017-2036, completed by AEG, can be found at: http://www.pacificorp.com/es/dsm.html

This study excludes an assessment of Oregon's Class 2 DSM resource potential, as this work is performed by the Energy Trust of Oregon, which provides energy-efficiency potential in Oregon to PacifiCorp for resource planning purposes.

Current DSM Program Offerings by State

Currently there are two Class 1 DSM programs running within PacifiCorp's six-state service area; Utah's "Cool Keeper" residential and small commercial air conditioner load control program and the irrigation load control program in Utah, Idaho, and Oregon.[2] The two programs contribute approximately 308 MW of load reduction capability, helping the Company better manage demand during peak periods.[3]

In addition to the Class 1 DSM products, the Company offers a robust portfolio of distinct Class 2 DSM programs and initiatives, most of which are offered in multiple states, depending on size of opportunity and need. Table D.1 provides an overview of the breadth of Class 1 and 2 DSM program services and offerings available by Sector and State. Energy efficiency services listed for Oregon, except for low income weatherization services, are provided in collaboration with the Energy Trust of Oregon.[4]

[2] The Oregon Irrigation Load Control Pilot was approved in May of 2016.

[3] Actual reductions may vary by event (temperature and month and time dependent), cited load reduction represents the sum of the highest event performance available across the three states for the two programs and account for line losses (are "at generator" values). In addition to these two programs, the Company has additional interruptible load under contract with select Utah and Idaho special contract customers, see Table 5.12 in the 2015 IRP for additional detail.

[4] Funds for low-income weatherization services are forwarded to Oregon Housing and Community Services.

Table D.1– Current Class 1 and 2 DSM Program Services and Offerings by Sector and State

Program Services & Offerings by Sector and State	California	Oregon	Washington	Idaho	Utah	Wyoming
Residential Sector						
Air Conditioner Direct Load Control					√	
Lighting Incentives	√	√	√	√	√	√
New Appliance Incentives	√	√	√	√		√
Heating And Cooling Incentives	√	√	√	√	√	√
Weatherization Incentives - Windows, Insulation, Duct Sealing, etc.	√	√	√	√	√	√
New Homes	√	√	√	√	√	√
Low-Income Weatherization	√	√	√	√	√	√
Home Energy Reports			√	√	√	√
School Curriculum		√	√		√	
Energy Saving Kits	√	√	√	√	√	√
Financing Options With On-Bill Payments		√				
Trade Ally Outreach	√	√	√	√	√	√
Non-Residential Sector						
Air Conditioner Direct Load Control					√	
Irrigation Load Control		√		√	√	
Standard Incentives	√	√	√	√	√	√
Energy Engineering Services	√	√	√	√	√	√
Billing Credit Incentive (offset to DSM charge)		√			√	√
Energy Management	√	√	√	√	√	√
Energy Profiler Online	√	√	√	√	√	√
Business Solutions Toolkit	√	√	√	√	√	√
Trade Ally Outreach	√	√	√	√	√	√
Small Business Lighting	√	√	√	√	√	√
Lighting instant incentives		√	√	√	√	√
Small to Mid-Sized Business Facilitation	√	√	√	√	√	√
DSM Project Managers Partner With Customer Account Managers	√	√	√	√	√	√

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 and Utah) and residential year-round inverted block rates (California, Oregon, Washington, and Wyoming). System-wide, approximately 18,700 customers were participating in metered time-of-day and time-of-use programs as of December 31, 2014.[5] All of the Company's residential customers not opting for a time-of-use rates are

[5] Year-end 2014 participation data was used in the development of the 2017 DSM Potential Study. By the end of 2015, participation levels had declined slightly to approximately 18,300 participants.

currently subject to seasonal or year-round inverted block rate plans. Savings associated with these resources are captured within the Company's load forecast 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.

Educating customers regarding energy efficiency and load management opportunities is an important component of the Company's long-term resource acquisition plan. A variety of channels are used to educate customers including television, radio, newspapers, bill inserts and messages, newsletters, school education programs, and personal contact. Load reductions due to Class 4 DSM activity will show up in Class 1 and Class 2 DSM program results and non-program reductions in the load forecast over time. Table D.2 provides an overview of DSM related ***watt***smart Outreach and Communication activities (Class 4 DSM activities) by state.

Table D.2 – Current wattsmart Outreach and Communications Activities

wattsmart Outreach & Communications (incremental to program specific advertising)	California	Oregon	Washington	Idaho	Utah	Wyoming
Advertising		√	√	√	√	√
Sponsorships		√			√	
Social Media	√	√	√	√	√	√
Contests (video)					√	
Public Relations (Habitat for Humanity, other)		√	√		√	√
Business Advocacy (awards at customer meetings, sponsorships, chamber partnership, university partnership)		√		√	√	√
wattsmart Workshops		√				
Rockin wattsmart Assemblies					√	

Preferred Portfolio DSM Resource Selections

The following tables shows the economic DSM resource selections by state and year in the 2017 IRP preferred portfolio, OP_GW4b.

Table D.3 – Incremental and Cumulative Class 1 DSM Resource Selections (2017 IRP Preferred Portfolio)

State/Product by Year	2028	2029	2030	2032	2033	2034	2035	Total/Products (MW)
California Load Control - Res./Com./Indust. Cooling & Wtr Htg	2.4							2.4
California Curtailment Agreements	1.2							1.2
California Load Control - Irrigation	3.7							3.7
Oregon Load Control - Res./Com./Indust. Cooling & Wtr Htg	11.4	24.7		3.3				39.4
Oregon Curtailment Agreements	35.0							35.0
Oregon Load Control - Irrigation	12.8							12.8
Washington Load Control - Res./Com./Indust. Cooling & Wtr Htg	3.8	9.2						13.0
Washington Curtailment Agreements	9.1							9.1
Washington Load Control - Irrigation	4.8							4.8
Utah Load Control - Res./Com./Indust. Cooling & Wtr Htg	68.4							68.4
Utah Curtailment Agreements	75.3		4.8			3.7		83.7
Utah Load Control - Irrigation	3.1							3.1
Idaho Load Control - Res./Com./Indust. Cooling & Wtr Htg		3.4						3.4
Idaho Curtailment Agreements		1.9						1.9
Idaho Load Control - Irrigation	10.9	3.9		3.4			3.1	21.3
Wyoming Load Control - Res./Com./Indust. Cooling & Wtr Htg	4.8							4.8
Wyoming Curtailment Agreements	40.7				3.1			43.8
Wyoming Load Control - Irrigation	1.9							1.9
Cumulative Total by Year (MW)	**289.3**	**43.1**	**4.8**	**6.7**	**3.1**	**3.7**	**3.1**	**353.6**

Table D.4 – Incremental Class 2 DSM Resource Selections (2017 IRP Preferred Portfolio)

Energy Efficiency Energy (MWh) Selected by State and Year										
State	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
CA	7,450	7,340	5,130	5,250	5,190	5,070	4,800	4,590	4,420	4,000
OR	198,680	197,720	191,550	166,590	141,410	119,530	104,130	102,010	88,400	83,220
WA	44,600	34,300	36,170	33,650	38,370	35,970	34,060	34,300	31,830	28,860
UT	333,400	240,790	255,190	245,260	253,480	239,730	249,190	249,390	237,350	246,620
ID	17,570	22,950	23,060	19,200	19,920	18,630	18,160	19,280	18,640	19,220
WY	43,800	56,030	59,550	56,690	74,090	75,440	76,460	76,450	80,390	76,950
Total System	645,500	559,130	570,650	526,640	532,460	494,370	486,800	486,020	461,030	458,870

Energy Efficiency Energy (MWh) Selected by State and Year										
State	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
CA	4,880	4,320	3,880	4,190	3,830	3,080	2,690	2,200	1,240	1,060
OR	82,810	76,970	73,750	73,890	71,890	74,280	68,090	67,880	72,400	72,350
WA	27,160	24,780	22,300	20,360	19,630	15,260	12,870	9,860	8,590	6,760
UT	241,950	228,310	213,700	216,120	220,390	182,340	161,080	135,140	124,270	127,670
ID	18,120	17,080	16,590	16,000	15,510	13,010	12,190	9,970	8,910	9,180
WY	69,050	62,320	62,910	58,670	56,430	47,440	40,530	36,690	36,310	36,460
Total System	443,970	413,780	393,130	389,230	387,680	335,410	297,450	261,740	251,720	253,480

For the 20-year assumed nameplate capacity contributions (MW impacts) by state and year associated with the Class 2 DSM resource selections above, see Table 8.7 – PacifiCorp's 2017 IRP Preferred Portfolio, in Volume I of the 2017 IRP.

State-Specific DSM Planning Processes

PacifiCorp offers robust portfolios of DSM resource options in each of its state service areas. A summary of the DSM planning process in each state is provided below.

Washington
The Company is one of three investor-owned utilities required to comply with the Energy Independence Act (also referred to as I-937) approved in November 2006. The Act requires utilities to pursue all conservation that is cost-effective, reliable, and feasible. Every two years, each utility must identify its 10-year conservation potential and two-year acquisition target based on its IRP and using methodologies that are consistent with those used by the Northwest Power and Conservation Council. Each utility must maintain and use an external conservation stakeholder group to advise on a range of issues including conservation programs, development of conservation potential assessments, program marketing, incentive levels, budgets, adaptive management and the development of new and pilot programs. During 2017, the Company will be working with stakeholders to establish the conservation target for 2018-2019.

California
The Company has historically structured its energy efficiency programs on a multi-year cycle to align with the three large California investor-owned utilities' portfolio and budget schedules when possible.[6] In October 2015, the California Public Utility Commission (CPUC) issued Decision D.15-10-028, which imposes a new rolling portfolio review process on the large investor-owned utilities' energy efficiency program. In addition to the Commission's new review process, California Senate Bill (SB) 350 requires the California Energy Commission (CEC) to set annual targets for statewide energy efficiency savings that will cumulatively double energy efficiency by 2030. In 2016, the Company filed to extend its existing energy efficiency programs through 2017 and during 2017, the Company will file with the CPUC to transition into the new multi-year program cycle, incorporating components of SB 350, as appropriate.

Utah, Wyoming and Idaho
The Company's biennial IRP and associated action plan provides the foundation for DSM acquisition targets in each state Where appropriate, the Company maintains and uses external stakeholder groups and vendors to advise on a range of issues including annual goals for conservation programs, development of conservation potential assessments, program marketing, incentive levels, budgets, adaptive management and the development of new and pilot programs.

Oregon
Energy efficiency programs for Oregon customers are planned and delivered by the Energy Trust of Oregon in collaboration with PacifiCorp. The Energy Trust's planning process is comparable to PacifiCorp's other states, including establishing resource acquisition targets based on resource assessment and integrated resource planning, developing programs based on local market conditions, and coordinating with stakeholders and regulators to ensure efficient and cost-effective delivery of energy efficiency resources.

[6] In California, the company is considered to be a small multi-jurisdictional utility and is not typically required to comply with the energy efficiency requirements of the three large investor owned electric utilities.

APPENDIX E – SMART GRID

Introduction

The smart grid is the application of advanced communications and controls to the electric power system. Areas of installation include generation, transmission, distribution, and customer facilities. A wide array of applications can be defined under the smart grid umbrella. Smart grid includes technologies such as dynamic line rating, phasor measurement units (synchrophasors), energy storage, power line sensors, distribution automation, integrated volt/var optimization, advanced metering infrastructure, automated demand response, and smart renewable and/or distributed generation controls (e.g., smart inverters).

PacifiCorp has reviewed relevant smart grid technologies for transmission, substation, and distribution systems. When considering smart grid technologies, the communications network is often the most critical infrastructure decision. This network must have high speed, reliability, and security. It must be interoperable for many device types, manufacturers, and generations of technology and must be scalable in order to support PacifiCorp's entire service territory.

PacifiCorp regularly evaluates integrating smart grid technologies and implements those that show a positive net benefit for its customers. PacifiCorp has tested or implemented smart grid devices and functions such as dynamic line rating, synchrophasors, and communicating faulted circuit indicators. Advanced metering infrastructure, distribution automation, and distributed energy resource systems (including electric vehicles) are also underway or under consideration.

PacifiCorp will leverage smart grid technologies to align investments with the least-cost/least-risk goals of the Integrated Resource Plan (IRP). This will optimize the electrical grid when and where it is economically feasible, operationally beneficial, and in the best interest of customers. PacifiCorp is committed to consistently evaluating the value of emerging technologies and recommend them for demonstration or integration if they are found to be appropriate investments. PacifiCorp is working with state commissions to improve reliability, energy efficiency, customer service, and integration of renewable resources by analyzing the total cost of ownership, performing thorough cost-benefit analyses, and reaching out to customers concerning smart grid applications and technologies. As technology advances and development continues, PacifiCorp is able to improve estimates of the costs and benefits of smart grid technologies. Progressing large-scale deployments and demonstration projects will reveal the effect of large-scale rollouts and assist PacifiCorp in identifying the best suited technologies for implementation.

Transmission System Efforts

Dynamic Line Rating

Dynamic line rating is the application of sensors to transmission lines to indicate the real-time current-carrying capacity of the lines in relation to thermal restrictions. Transmission line ratings are typically based on line loading calculations given a set of worst-case weather assumptions,

such as high ambient temperatures and very low wind speeds. Dynamic line rating allows an increase in current-carrying capacity when more favorable weather conditions are present and the transmission path is not constrained by other operating elements. Two dynamic line rating projects were implemented in 2014, Miners-Platte and West-of-Populus.

The Miners-Platte project uses a dynamic line rating system to determine the resulting cooling effect of the wind on the line. The current carrying capacity is then updated to a new weather dependent line rating. The Miners-Platte 230 kV transmission line was one of the limitations of the TOT4A transmission path with wind farms significantly impacting the loading of the line. As a result of this project, the TOT4A WECC non-simultaneous path rating was increased.

The West-of-Populus project was the second dynamic line rating project in 2014. The dynamic line rating enabled lines experienced low line loading due to peak loads between Pacific Power and Rocky Mountain Power coinciding over time. As a result of this low loading, the thermal reading of the lines is dependent upon ambient weather conditions without being greatly affected by line loading. Until higher line loading is experienced from high flow scenarios or outages, conclusions concerning the dynamic line rating project in West-of-Populus are difficult to ascertain. PacifiCorp will continue to collect and analyze future data as high line loading is experienced.

Dynamic line rating will be considered for all future transmission needs as a means for increasing capacity in relation to traditional construction methods. Dynamic line rating is only applicable for thermal constraints and only provides additional site-dependent capacity during finite time periods. It may or may not align with the expected transmission need of future projects. PacifiCorp will continue to look for opportunities to cost-effectively employ dynamic line rating systems.

Thermal Replicating Relays

PacifiCorp extensively considered a project to install thermal replicating relays to adhere to protection and control compliance standards in the Soda Springs area of Idaho. Thermal replicating relays utilize dynamic line rating to monitor the thermal properties of the line, then send a trip signal if the thermal limit has been exceeded. These relays may only be used where line tripping will not cause cascading outages. A remedial action scheme (RAS) was also analyzed as an alternative to thermal replicating relays for the Soda Springs area. In this particular case, because the remedial action scheme was deemed more cost-effective, the thermal replicating relay project alternative will not be employed.

Synchrophasors

Synchrophasors, also called phasor measurement units, can lead to a more reliable transmission network by comparing phase angles of certain network elements with a base element measurement. Phasor measurement units can also be used to increase reliability by relaying line condition data through the communication network quickly. Phasor measurement unit implementation may enable transmission operators to integrate variable resources and energy storage more effectively while minimizing service disruptions.

PacifiCorp participated in the Western Interconnection Synchrophasor Project (WISP). The project resulted in eight phasor measurement units installed in eight PacifiCorp substations. These devices are currently collecting data and will support PacifiCorp's and Peak Reliability's[1] goal of maintaining power system stability. The system of synchrophasors will be used to identify and analyze system vulnerabilities and disturbances. It will also assist in preventing system blackouts and provide historical data for the analysis of any future power system failure. Peak Reliability is continuing to develop data access for utility participants. PacifiCorp has discontinued sending data to Peak Reliability as part of their WISP program since they currently do not operationally utilize the data. Once Peak Reliability has their advanced application functionality enabled, which is expected in 2017, PacifiCorp expects to reinitiate data flow to Peak Reliability.

Phasor measurement units will also be used to satisfy the validation requirements in NERC-MOD-033, a reliability standard proposed to improve accurate data collection and planning models. Planning models analyzing the transmission system reliability are required to compare model results to real-world values in order to meet model validation requirements.

Distribution System Efforts

Distribution Automation

Distribution automation (DA) is a wide field of smart grid technology and applications, which focuses on using sensors and data collection on the distribution system, as well as automatically adjusting the system to optimize performance. It can also provide operational efficiency, peak load management, equipment failure prediction, and decreased restoration times after failure. PacifiCorp is working on several distribution automation initiatives.

- In Oregon, PacifiCorp has identified 40 circuits on which a DA cost benefit analysis will be performed. These 40 circuits were selected based on a set of criteria intended to minimize the cost of implementation and maximize the reliability benefit. The feasibility of utilizing an advanced metering infrastructure network for the communications of the distribution automation system will also be addressed.
- PacifiCorp has installed Fusesaver™ devices and electronic reclosers with the capability of enabling communications through a retrofit in the future.
- A pilot project in Walla Walla, Washington is underway to demonstrate the feasibility and effectiveness of distribution automation, including a fault location isolation and restoration application.
- A feasibility study to determine the cost and benefit of retrofitting an existing source/transfer scheme to a distribution automation scheme is underway in Salt Lake City, Utah.
- PacifiCorp installed communicating faulted circuit indicators on five circuits in eastern Utah in March 2014. These devices have proven capable of improving reliability by reducing the time required to report and locate a fault. PacifiCorp is still evaluating the cost and feasibility of integrating these devices in its outage management system before further deployment.

[1] Peak Reliability (Peak) is a company wholly independent of WECC that performs the Reliability Coordinator (RC) function in its RC Area in the Western Interconnection.

Customer Information Efforts

Advanced Metering Infrastructure

A key effort for PacifiCorp in 2016 was the development of a detailed business case for advanced metering infrastructure in Oregon. Advanced metering infrastructure is an integrated system of smart meters, communications networks, and data management systems with two-way communication. PacifiCorp's objectives were to identify a solution and strategy that would deliver tangible projected benefits to our customers and deliver economically-driven financial results while minimizing the impact on consumer rates. A request for information followed by a request for proposals was solicited to further evaluate the economics and impacts of an advanced metering infrastructure rollout in Oregon. The financial analysis of proposals indicated a positive business case due to decreasing costs of advance metering technology and increasing operations and maintenance costs. As a result, Pacific Power committed to proceed with deployment of an advanced metering infrastructure system in Oregon.

The advanced metering infrastructure program in Oregon will replace 590,000 existing customer meters with smart meters and install an advanced metering system to remotely read and operate customer meters. The project will provide a web portal for customers, capture hourly meter data, perform on demand meter reads, remotely connect and disconnect power, verify outage inquiries, remotely reprogram meters, and collect data on power quality and tampering. This advanced metering infrastructure project will provide a network and metering infrastructure to improve customer service and enable future smart grid applications. Project benefits include reduced operations and maintenance costs, a platform for future smart grid applications, increased worker safety, reduced emissions, and increased data for efficient management of the network. Meter installations begin in 2017 and the project completion date is scheduled for the end of 2019.

Future Smart Grid

PacifiCorp is continuing to evaluate smart grid technologies and piloted projects that might benefit customers. PacifiCorp regularly develops smart grid reports to examine the quantifiable costs and benefits of individual components of the smart grid. While the net present value of implementing a comprehensive smart grid system throughout PacifiCorp is negative at this time, PacifiCorp has implemented specific projects and programs that have positive benefits for customers, and continues to explore pilot projects in other areas of interest. In order to reduce risks to the company, grid, customers, and supporting systems, it is essential to identify affordable leading technologies and implement industry best practices.

APPENDIX F – FLEXIBLE RESERVE STUDY

Introduction

This 2017 Flexible Reserve Study ("FRS") estimates the regulation reserve required to maintain PacifiCorp's system reliability and comply with North American Electric Reliability Corporation ("NERC") reliability standards as well as the incremental cost of this regulation reserve. The FRS also compares PacifiCorp's overall operating reserve requirements, including both regulation reserve and contingency reserve, to its flexible resource supply over the IRP study period.

PacifiCorp operates two Balancing Authority Areas ("BAAs") in the Western Electricity Coordinating Council ("WECC") NERC region, PacifiCorp East ("PACE") and PacifiCorp West ("PACW"). The PACE and PACW BAAs are interconnected by a limited amount of transmission across a third-party transmission system and the two BAAs are each required to comply with NERC standards. PacifiCorp must provide sufficient regulation reserve to remain within NERC's balancing authority area control error ("ACE") limit in compliance with BAL-001-2,[1] as well as the amount of contingency reserve required in order to comply with NERC standard BAL-002-WECC-2.[2] BAL-001-2 is a new regulation reserve standard that became effective July 1, 2016, and BAL-002-WECC-2 is a contingency reserve standard that became effective October 1, 2014. Regulation reserve and contingency reserve are components of operating reserve, which NERC defines as "the capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection."[3]

Apart from disturbance events that are addressed through contingency reserve, regulation reserve is necessary to compensate for changes in load demand and generation output, so as to maintain ACE within mandatory parameters established by the BAL-001-2 standard. The FRS estimates the amount of regulation reserve required to manage variations in load, variable energy resources[4] ("VERs"), and resources that are not VERs ("Non-VERs") in each of PacifiCorp's BAAs. Load, wind, solar, and Non-VERs were each studied because PacifiCorp's data indicates that these components or customer classes place different regulation reserve burdens on PacifiCorp's system due to differences in the magnitude, frequency, and timing of their variations from forecasted levels. Specifically, PacifiCorp's calculations demonstrate that the regulation reserve burden associated with wind deviations from scheduled amounts are twice the amount associated with solar, three times the amount associated with load, and four times the amount associated with Non-

1 NERC Standard BAL-001-2, http://www.nerc.com/files/BAL-001-2.pdf, which became effective July 1, 2016. ACE is the difference between a BAA's scheduled and actual interchange, and reflects the difference between electrical generation and Load within that BAA.

2 NERC Standard BAL-002-WECC-2, http://www.nerc.com/files/BAL-002-WECC-2.pdf, which became effective October 1, 2014.

3 NERC Glossary of Terms: http://www.nerc.com/files/glossary_of_terms.pdf, updated July 13, 2016.

4 VERs are resources that resources that: (1) are renewable; (2) cannot be stored by the facility owner or operator; and (3) have variability that is beyond the control of the facility owner or operator. *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246 at P 281 (2012) ("Order No. 764"); *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61,232 (2012) ("Order No. 764-A"); *order on reh'g and clarification*, Order No. 764-B, 144 FERC ¶ 61,222 at P 210 (2013) ("Order No. 764-B").

VERs. As a result, PacifiCorp attributes different levels of regulation reserve to load, wind, solar, and Non-VERs.

The FRS is based on PacifiCorp operational data recorded from January 2015 through December 2015 for load, wind, and Non-VERs. Solar generation on PacifiCorp's system was insignificant during that time period, but is expected to amount to over 1,000 MW by the end of 2017. PacifiCorp's primary analysis, focuses on the variability of load, wind, and Non-VERs during 2015. A supplemental analysis discusses how the total variability of the PacifiCorp system changes with varying levels of wind and solar capacity. The estimated regulation reserve amounts determined in this study represent the incremental capacity needed to ensure compliance with BAL-001-2 for a particular operating hour. The regulation reserve requirement for the combined portfolio is the sum of the individual requirements for load, wind, solar, and Non-VERs, less the reserve "savings" associated with diversity between the different classes, including diversity benefits realized as a result of PacifiCorp's participation in the Energy Imbalance Market ("EIM") operated by the California Independent System Operator Corporation ("CAISO").

The methodology in the FRS differs in several ways from that employed in PacifiCorp's previous regulation reserve requirement analyses.[5,6,7] First, regulation reserve requirements are now tied directly to compliance with the BAL-001-2 standard. Second, the FRS uses a portfolio wide approach to determine the overall regulation reserve requirement, including the aggregated diversity benefits for all customer classes. Third, all customer classes that contribute to the overall regulation reserve requirement are now allocated a share of the diversity benefits resulting from aggregating their requirement with that of the system as a whole. Fourth, the FRS reflects updated data based on actual operational experience, including the data and benefits from PacifiCorp's participation in the EIM.

The FRS results produce an hourly forecast of the regulation reserve requirements for each of PacifiCorp's BAAs that is sufficient to ensure the reliability of the transmission system and compliance with NERC and WECC standards. This regulation reserve forecast covers the combined deviations of the load, wind, solar and Non-VERs on PacifiCorp's system and varies as a function of the wind and solar capacity on PacifiCorp's system, as well as forecasted wind and solar output.

The regulation reserve requirements produced by the FRS were applied in the Planning and Risk (PaR) production cost model to determine the cost of the reserve requirements associated with incremental wind and solar capacity. These costs are attributed to the integration of wind and solar generation resources in the 2017 Integrated Resource Plan (IRP).

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5 2012 Wind Integration Study report, Appendix H in Volume II of PacifiCorp's 2013 IRP report: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol2-Appendices_4-30-13.pdf

6 2013 PacifiCorp Schedule 3 and 3A Study, Exhibit PAC-8 in testimony of Greg Duvall, FERC Docket No. ER13-1206 (filed April 1, 2013).

7 2014 Wind Integration Study, Appendix H in Volume II of PacifiCorp's 2015 IRP report: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol2-Appendices.pdf

Executive Summary

The FRS first estimates the regulation reserve necessary to maintain compliance with NERC Standard BAL-001-2 given a specified portfolio of wind and solar resources. The FRS next calculates the cost of holding regulation reserve for incremental wind and solar resources and the cost of using day-ahead load, wind, and solar forecasts to commit gas units. Finally, the FRS compares PacifiCorp's overall operating reserve requirements over the IRP study period, including both regulation reserve and contingency reserve, to its flexible resource supply.

The FRS estimates regulation reserve based on the specific requirements of NERC Standard BAL-001-2. It also incorporates the current timeline for EIM market processes, as well as EIM resource deviations and flexibility reserve benefits based on actual results. The FRS also includes adjustments to regulation reserve requirements to account for the changing portfolio of solar and wind resources on PacifiCorp's system and accounts for the diversity of using a single portfolio of regulation reserve resources to cover variations in load, wind, solar, and Non-VERs. The regulation reserve requirements for the various portfolios considered in this analysis including values from the 2014 Wind Integration Study for reference are shown in Table F.1.

Table F.1 - Portfolio Regulation Reserve Requirements, by Scenario

Case	Wind Capacity (MW)	Solar Capacity (MW)	Stand-alone Regulation Requirement (MW)	Portfolio Diversity Credit (%)	Regulation Requirement with Diversity (MW)
2014 WIS	2,543	n/a	n/a	n/a	626
2015 (No Solar)	2,588	0	900	37.5%	562
2017 Base Case	2,757	1,050	998	38.2%	617
Incremental Wind	3,007	1,050	1,023	38.3%	631
Incremental Solar 1	2,757	1,550	1,033	38.6%	635
Incremental Solar 2	2,757	2,050	1,074	39.2%	653

Two categories of flexible resource costs are estimated using the Planning and Risk (PaR) model: one for meeting intra-hour regulation reserve requirements, and one for inter-hour system balancing costs associated with committing gas plants using day-ahead forecasts of load, wind, and solar. Table F.2 provides the wind and solar costs on a dollar per megawatt-hour ($/MWh) of generation basis. The results of the 2014 Wind Integration Study are also included for reference.

Table F.2 - 2017 FRS Flexible Resource Costs as Compared to 2014 WIS Costs, $/MWh

	Wind 2014 WIS (2014$)	Wind 2017 FRS (2016$)	Solar 2017 FRS (2016$)
Intra-hour Reserve	$2.35	$0.43	$0.46
Inter-hour/System Balancing	$0.71	$0.14	$0.14
Total Flexible Resource Cost	**$3.06**	**$0.57**	**$0.60**

The 2017 FRS results are applied in the 2017 IRP portfolio development process as a cost for wind

and solar generation resources. Once candidate resource portfolios are developed using the SO model, the PaR model is used to evaluate portfolio risks. The PaR model inputs include regulation reserve requirements specific to the resource portfolio developed using the SO model. As a result, the IRP risk analysis using PaR includes the impact of differences in regulation reserve requirements between portfolios.

Flexible Resource Requirements

PacifiCorp's flexible resource needs are the same as its operating reserve requirements over the planning horizon for maintaining reliability and compliance with the North American Electric Reliability Corporation (NERC) regional reliability standards. Operating reserve consists of three categories: (1) contingency reserve (i.e., spinning and supplemental reserve), (2) regulation reserve, and (3) frequency response reserve. Contingency reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC regional reliability standard BAL-002-WECC-2.[8] Regulation reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC Control Performance Criteria in BAL-001-2.[9] Frequency response reserve is capacity that PacifiCorp holds available to ensure compliance with NERC standard BAL-003-1.[10] Each type of operating reserve is further defined below.

Contingency Reserve

NERC regional reliability standard BAL-002-WECC-2 specifies that each BAA must hold as contingency reserve an amount of capacity equal to three percent of load and three percent of generation in that BAA. Contingency reserve must be available within ten minutes, and at least half must be from "spinning" resources that are online and immediately responsive to system fluctuations. Contingency reserve may be deployed when unexpected outages of a generator or a transmission line occur. Contingency reserve may not be deployed to manage other system fluctuations such as changes in load or wind generation output.

Regulation Reserve

NERC standard BAL-001-2, which became effective July 1, 2016, does not specify a regulation reserve requirement based on a simple formula, but instead requires utilities to hold sufficient reserve to meet specified control performance standards. The primary requirement relates to area control error ("ACE"), which is the difference between a BAA's scheduled and actual interchange, and reflects the difference between electrical generation and load within that BAA. Requirement 2 of BAL-001-2 defines the compliance standard as follows:

> *Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit*

[8] NERC Standard BAL-002-WECC-2 – Contingency Reserve: http://www.nerc.com/files/BAL-002-WECC-2.pdf

[9] NERC Standard BAL-001-2 – Real Power Balancing Control Performance: http://www.nerc.com/files/BAL-001-2.pdf

[10] NERC Standard BAL-003-1 — Frequency Response and Frequency Bias Setting: http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.pdf

(BAAL) for more than 30 consecutive clock-minutes…

In addition, Requirement 1 of BAL-001-2 specifies that PacifiCorp's Control Performance Standard 1 ("CPS1") score must be greater than equal to 100 percent for each preceding 12 consecutive calendar month period, evaluated monthly. The CPS1 score compares PacifiCorp's ACE with interconnection frequency during each clock minute. A higher score indicates PacifiCorp's ACE is helping interconnection frequency, while a lower score indicates it is hurting interconnection frequency. Because CPS1 is averaged and evaluated on a monthly basis, it does not require a response to each and every ACE event, but rather requires that PacifiCorp meet a minimum aggregate level of performance in each month.

Regulation reserve is thus the capacity that PacifiCorp holds available to respond to changes in generation and load to manage ACE within the limits specified in BAL-001-2. Because Requirement 2 includes a 30 minute time limit for compliance, ramping capability that can be deployed within 30 minutes contributes to meeting PacifiCorp's regulation reserve requirements. PacifiCorp has not specifically evaluated reserve needs for CPS1 compliance. The reserve for CPS1 is not expected to be incremental to the need for compliance with Requirement 2, but may require that a subset of resources held for Requirement 2 be able to make frequent rapid changes to manage ACE relative to interconnection frequency. Regulation reserve requirements are discussed in more detail later on in the study.

Frequency Response Reserve

NERC standard BAL-003-1 specifies that each BAA must arrest frequency deviations and support interconnection frequency when it drops below the scheduled level. When a frequency drop occurs, each BAA is expected to deploy resources that are at least equal to its Frequency Response Obligation. The incremental requirement is based on the size of the frequency drop and the BAA's Frequency Response Obligation, expressed in MW/0.1Hz. The additional capacity must be deployed immediately, and performance is measured over a period of seconds, amounting to under a minute. To comply with the standard, a BAA's median measured frequency response during a sampling of under-frequency events must be equal to or greater than its Frequency Response Obligation. PacifiCorp's 2017 Frequency Response Obligation was 19.51 MW/0.1Hz for PACW, and 48.93 MW/0.1Hz for PACE. PacifiCorp's combined obligation amounts to 68.44 MW for a frequency drop of 0.1 Hz, or 205.32 MW for a frequency drop of 0.3 Hz.

Because the performance measurement for contingency reserve under the Disturbance Control Standard (BAL-002-1) is similar to that for BAL-003-1, frequency response capacity is effectively incremental to contingency reserve obligations. As Standard BAL-003-1 is based on median performance under selected WECC-wide events, while regulation reserve obligations under BAL-001-2 are based on minimum performance during BAA-specific events, frequency response capacity can be considered a subset of the BAL-001-2 obligation. Since median performance is adequate for BAL-003-1 compliance, BAL-001-2 compliance can take precedence, so long as the overlap is sufficiently low, i.e. BAL-001-2 events are rare and there don't have a positive correlation with BAL-003-1 events.

While frequency response reserve can meet regulation reserve requirements, the reverse is not necessarily true. Frequency response must occur very rapidly, and a generating unit's capability is limited based on the unit's size, governor controls, and available capacity, as well as the size of

the frequency drop. As a result, while a few resources could hold a large amount of regulation reserve, frequency response needs to be spread over a larger number of resources. Because PacifiCorp has excess spinning reserve capability compared to its contingency reserve obligation, the capacity and response time requirements for its frequency response obligations are expected to be met by drawing from its existing pool of regulation reserve resources. As a result, no incremental capacity requirements or resource constraints related to frequency response were included in the 2017 IRP analysis beyond those already included for contingency and regulation reserve.

Description of Data Inputs

Overview

This section describes the data used to determine PacifiCorp's regulation reserve requirements. In order to estimate PacifiCorp's required regulation reserve amount, PacifiCorp must determine the difference between the expected load and resources and actual load and resources. The difference between load and resources is calculated every four seconds and is represented by the ACE. ACE must be maintained within the limits established by BAL-001-2, so PacifiCorp must estimate the amount of regulation reserve that is necessary in order to maintain ACE within these limits.

To estimate the amount of regulation reserve that will be required in the future, the FRS identifies the scheduled use of the system as compared to the actual use of the system during the study term. For the baseline determination of scheduled use for load and resources, the FRS used hourly base schedules. Hourly base schedules are the power production forecasts used for imbalance settlement in the EIM and represent the best information available concerning the upcoming hour.[11]

The deviation from scheduled use was derived from data provided through participation in the EIM. The deviations of generation resources in EIM were measured on a five-minute basis, so the Regulation Reserve Study used five-minute intervals throughout the analysis.

EIM base schedule and deviation data for each wind and Non-VER transaction point were downloaded using the Report Explorer application to query PacifiCorp's nMarket Application database, which is populated with data provided by the CAISO. Since PacifiCorp's implementation of EIM on November 1, 2014, PacifiCorp requires certain operational forecast data from all of its transmission customers pursuant to the provisions of Attachment T to

[11] The CAISO, as the market operator for the EIM, requests base schedules at 75 minutes ("T-75") prior to the hour of delivery. PacifiCorp's transmission customers are required to submit base schedules by 77 minutes ("T-77") prior to the hour of delivery – two minutes in advance of the EIM Entity deadline. This allows all transmission customer base schedules enough time to be submitted into the EIM systems before the overall deadline of T-75 for the entirety of PacifiCorp's two BAAs. The base schedules are due again to CAISO at 55 minutes ("T-55") prior to the delivery hour and can be adjusted up until that time by the EIM Entity (i.e., PacifiCorp Grid Operations). PacifiCorp's transmission customers are required to submit updated, final base schedules no later than 57 minutes ("T-57") prior to the delivery hour. Again, this allows all transmission customer base schedules enough time to be submitted into the EIM systems before the overall deadline of T-55 for the entirety of PacifiCorp's two BAAs. Base schedules may be finally adjusted again, by the EIM Entity only, at 40 minutes ("T-40") prior to the delivery hour in response to CAISO sufficiency tests. T-55 is the base schedule time point used throughout this study because it is the deadline which most closely corresponds to the final T-57 deadline for all transmission customers to submit final base schedules.

PacifiCorp's Federal Energy Regulatory Commission ("FERC")-approved Open Access Transmission Tariff ("OATT"). This includes EIM base schedule data (or forecasts) from all resources included in the EIM network model at transaction points. EIM base schedules are submitted by transmission customers with hourly granularity, and are settled using hourly data for load, and fifteen-minute and five-minute data for resources. A primary function of the EIM is to measure load and resource imbalance (or deviations) as the difference between the hourly base schedule and the actual metered values.

A summary of the data gathered for this analysis is listed below, and a more detailed description of each type of source data is contained in the following subsections.

Source data:

- Load data
  - Five-minute interval actual Load
  - Proxy hourly base schedules developed from actual prior hour and prior week data

- VER data
  - Five-minute EIM deviations
  - Hourly base schedules

- Non-VER data
  - Five-minute EIM deviations
  - Hourly base schedules

Load Data

The Load class represents the aggregate firm demand of end users of power from the electric system. While the requirements of individual users vary, there are diurnal and seasonal patterns in aggregated demand. The Load class can generally be described to include three components: (1) average load, which is the base load during a particular scheduling period; (2) the trend, or "ramp," during the hour and from hour-to-hour; and (3) the rapid fluctuations in load that depart from the underlying trend. The need for a system response to the second and third components is the function of regulation reserve in order to ensure reliability of the system.

The PACE BAA includes several large industrial loads with unique patterns of demand. Each of these loads is either interruptible at short notice or includes behind the meter generation. Due to their large size, abrupt changes in their demand are magnified for these customers in a manner which is not representative of the aggregated demand of the large number of small customers which make up the majority of PacifiCorp's loads.

In addition, interruptible loads can be curtailed if their deviations are contributing to a resource shortfall. Because of these unique characteristics, these loads are excluded from the FRS. This treatment is consistent with that used in the CAISO load forecast methodology (used for PACE and PACW operations), which also nets these interruptible customer loads out of the PACE BAA.

Actual average load data was collected separately for the PACE and PACW BAAs for each five-minute interval over the Study Term. Load data for the Study Term was downloaded from PacifiCorp's Ranger PI system and has not been adjusted for transmission and distribution losses. Only actual load data is available from Ranger PI, not base schedule data that could be used to

determine the deviation associated with Load. Because of differences in the load defined in EIM and in the Ranger PI system, the EIM load base schedules are not consistent with the Ranger PI actual results. To address the inconsistency, PacifiCorp developed proxy load base schedules, as discussed below.

Wind Data

The Wind class includes resources that: (1) are renewable; (2) cannot be stored by the facility owner or operator; and (3) have variability that is beyond the control of the facility owner or operator.[12] Wind, in comparison to load, often has larger upward and downward fluctuations in output that impose significant and sometimes unforeseen challenges when attempting to maintain reliability. For example, as recognized by FERC in Order No. 764, "Increasing the relative amount of [VERs] on a system can increase operational uncertainty that the system operator must manage through operating criteria, practices, and procedures, *including the commitment of adequate reserves*."[13] The data included in the FRS for the Wind class includes all wind resources in PacifiCorp's BAAs, which includes: (1) third-party resources (OATT or legacy contract transmission customers); (2) PacifiCorp-owned resources; and (3) other PacifiCorp-contracted resources, such as qualifying facilities, power purchases, and exchanges. Appendix F.B, Table 1 contains the list of the wind plants included in the study. In total, the FRS includes 2,588 megawatts of wind.

Non-VER Data

The Non-VER class is a mix of thermal and hydroelectric resources and includes all resources which are not VERs, and which do not provide either contingency or regulation reserve. Non-VERs, in contrast to VERs, are often more stable and predictable. Non-VERs are thus easier to plan for and maintain within a reliable operating state. For example, in Order No. 764, FERC suggested that many of its rules were developed with Non-VERs in mind and that such generation "could be scheduled with relative precision."[14] The output of these resources is largely in the control of the resource operator, particularly when considered within the hourly timeframe of the FRS. The deviations by resources in the Non-VER class are thus significantly lower than the deviations by resources in the Wind class. The Non-VER class includes third-party resources (OATT or legacy transmission customers); many PacifiCorp-owned resources; and other PacifiCorp-contracted resources, such as qualifying facilities, power purchases, and exchanges. Appendix F.B, Table 2 contains the list of the Non-VERs included in the study. In total, the FRS includes 2,228 megawatts of Non-VERs.

In the FRS, resources that provide contingency or regulation reserve are considered a separate, dispatchable resource class. The dispatchable resource class compensates for deviations resulting from other users of the transmission system in all hours. While non-dispatchable resources may offset deviations in loads and other resources in some hours, they are not in the control of the system operator and contribute to the overall requirement in other hours. Because the dispatchable resource class is a net provider rather than a user of regulation reserve service, its stand-alone regulation reserve requirement is zero (or negative), and its share of the system regulation reserve

12 Order No. 764 at P 281; Order No. 764-B at P 210.

13 Order No. 764 at P 20 (emphasis added).

14 *Id.* at P 92.

requirement is also zero. The allocation of regulation reserve requirements and diversity benefits is discussed in more detail later on in the study..

Data Analysis and Adjustment

Overview

This section provides details on adjustments made to the data to develop base schedules that correspond to the load data, align the ACE calculation with actual operations, and address data issues.

Load Base Schedule Development

Load deviations are settled using hourly imbalance data in EIM, whereas resource deviations are settled using fifteen-minute and five-minute imbalance data. As a result, the five-minute deviations necessary to assess the regulation reserve requirements associated with Load were not available through EIM. For the FRS, PacifiCorp used actual load data from its Ranger PI system, which can provide data at a five-minute granularity. The Ranger PI system does not have the associated base schedules necessary to calculate deviations, however, so PacifiCorp developed proxy load base schedules consistent with the measured actual loads.

The load base schedule for each hour was calculated from actual load at 55 minutes prior to the hour ("T-55") in question, with a scaling factor applied based on the change in load over that same interval in the prior week. The five-minute interval ending at T-55 is the last load data point available prior to base schedule submission to CAISO at hour T-55 and represents the current state of load in the PacifiCorp BAAs. Load follows different patterns depending on season and day of the week. Using data from one week prior ensures that recent conditions on a similar day are used in the calculation of the load base schedule.

Figure F.1 below illustrates measurement of the expected load change between T-55 data and the hourly base schedule over three hours. The five-minute interval ending at 17:05 (first green column) has a load of 2,643 MW. The actual load in hour 18 averages 2,837 MW (middle solid horizontal line), an increase of 7.4 percent. Similarly, the expected load change from the five-minute interval ending at 18:05 to hour 19 is a decrease of 1.1 percent (difference between second green column and second horizontal line). Figure F.2 below shows how those load measurements are applied seven days later to determine the proxy load base schedules for hours 18 and 19. The proxy load base schedule for hour 18 is calculated as the actual load in the five-minute interval ending at 17:05, plus an additional 7.4 percent. The proxy load base schedule for hour 19 is calculated as the actual load in the five-minute interval ending at 18:05, minus 1.1 percent. Deviations are then calculated as the difference between the proxy load base schedule and actual five-minute loads over the hour.

Figure F.1 - Expected Load Change from Prior Week

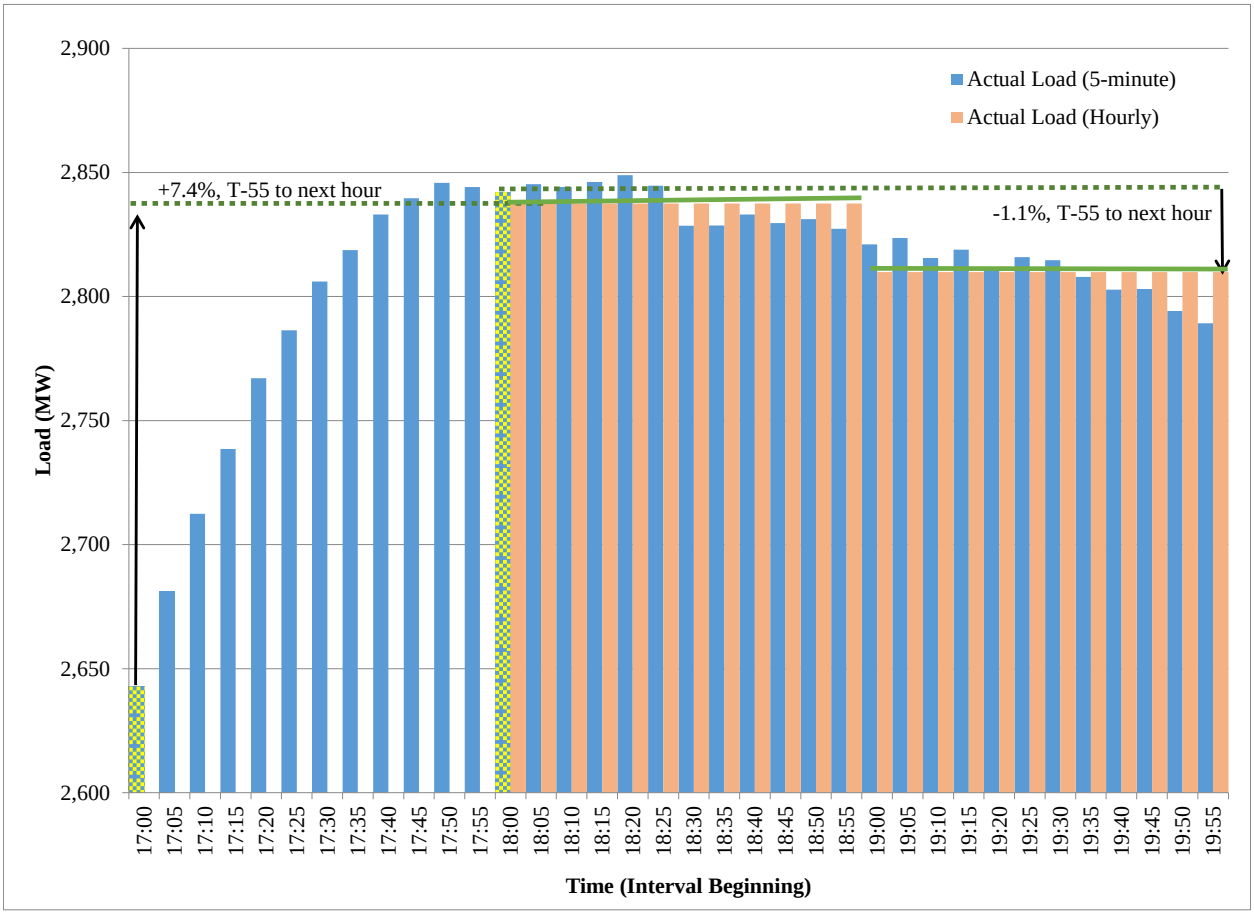
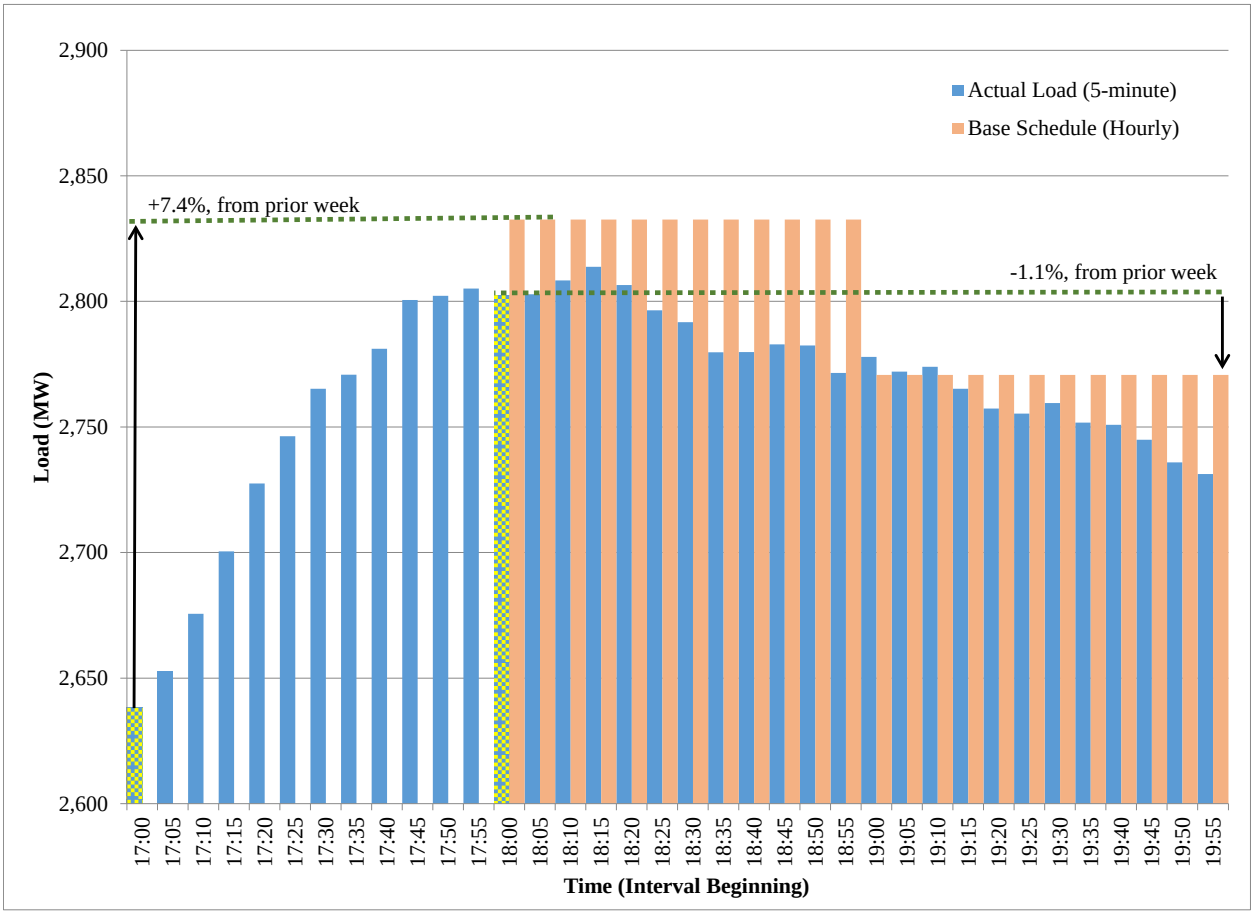


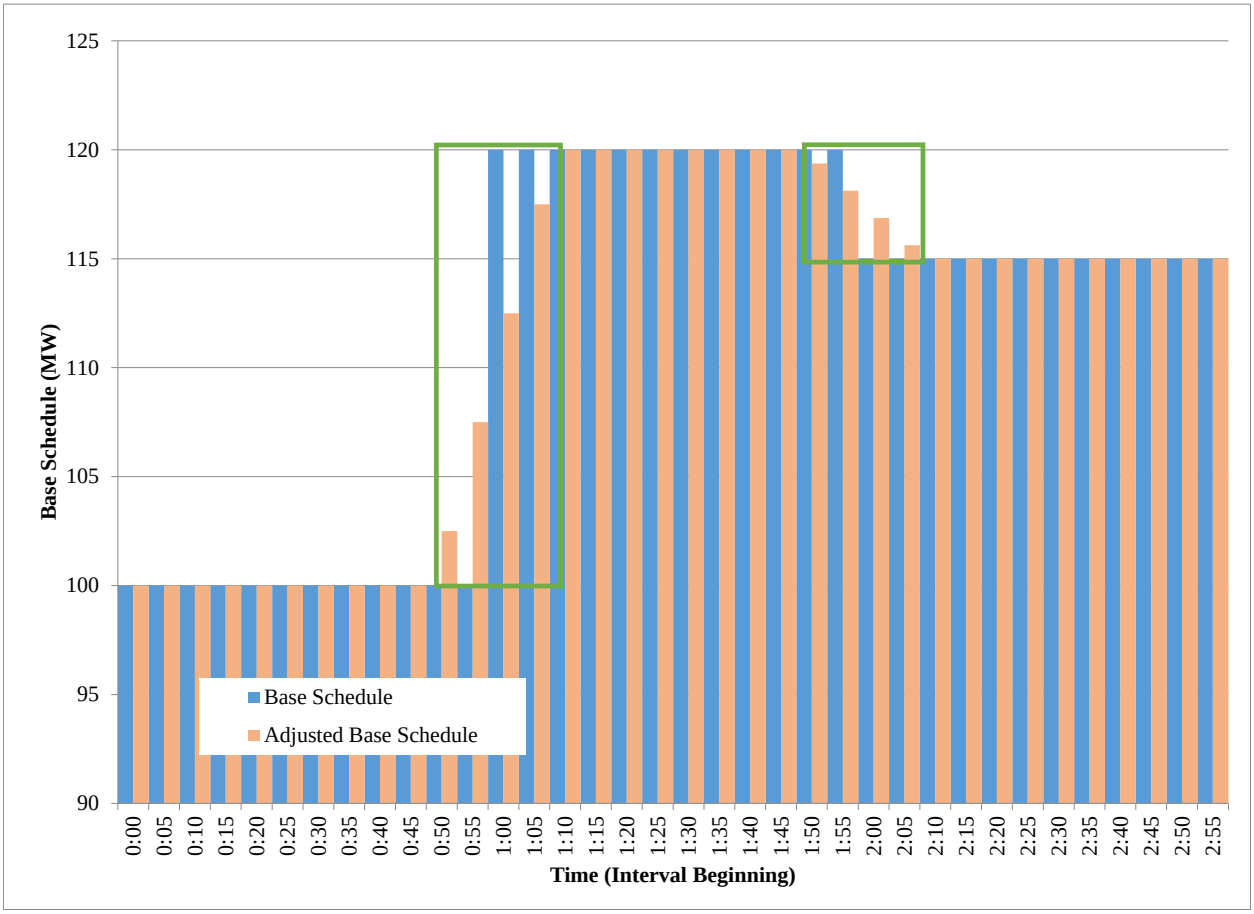
Figure F.2 - Proxy Load Base Schedule



Base Schedule Ramping Adjustment

In actual operations, PacifiCorp's ACE calculation includes a linear ramp from the base schedule in one hour to the base schedule in the next hour, starting ten-minutes before the hour and continuing until ten-minutes past the hour. The hourly base schedules used in the study are adjusted to reflect this transition from one hour to the next. This adjustment step is important because, to the extent actual load or generation is transitioning to the levels expected in the next hour, the adjusted base schedules will result in reduced deviations during these intervals, potentially reducing the regulation reserve requirement. Figure F.3 below illustrates the hourly base schedule and the ramping adjustment. The same calculation applies to all base schedules: Load, Wind, Non-VERs, and the combined portfolio.

Figure F.3 - Base Schedule Ramping Adjustment



Data Corrections

The raw data extracted from PacifiCorp's systems for Load, Wind, and Non-VERs was reviewed to identify potentially spurious data points prior to performing the regulation reserve requirement calculations contained in the next section. Hourly intervals of data were excluded from the FRS results if any five-minute interval within that hour suffered from at least one of the data anomalies that are described further below:

Load:

- Stuck meter/flat meter reading
- Telemetry spike/poor connection to meter

Wind and Non-VERs:

- Deviations missing in CAISO database
- Base schedules missing in CAISO database
- Generator trip events
- Wind curtailment events

Load in PacifiCorp's BAAs changes continuously. While a BAA could potentially maintain the exact same load levels in two five-minute intervals in a row, it is extremely unlikely for the exact same load level to persist over longer time frames. When PacifiCorp's energy management system ("EMS") load telemetry fails, updated load values may not be logged, and the last available load measurement for the BAA will continue to be reported. For instance, in one observed example, PACW BAA load remained stuck at a single level for two days beginning at 2:00 PM on January 6, 2015. The change in load relative to the prior interval was calculated for the entire test period and instances where multiple successive intervals showed no change in load were excluded from the analysis since they are not indicative of actual operating conditions.

Similarly, rapid spikes in load either up or down are also unlikely to be a result of conditions which require deployment of regulation reserve, particularly when they are transient. For example, a 637 MW drop in PACE BAA load occurred over one five-minute interval on May 15, 2015. Roughly one hour later, PACE BAA load increased by 849 MW over two five-minute intervals. Such events could be a result of a transmission or distribution outage, which would allow for the deployment of contingency reserve, and would not require deployment of regulation reserve. A similar spike on March 23, 2015, spanned just one five-minute interval, and was likely a result of a single bad load measurement. Load telemetry spike irregularities were identified by examining the intervals with the largest changes from one interval to the next, either up or down. Intervals with inexplicably large and rapid changes in load, particularly where the load reverts back within a short period, were assumed to have been covered through contingency reserve deployment or to reflect inaccurate load measurements. Because they don't reflect periods that require regulation reserve deployment, such intervals are excluded from the analysis.

The available Wind and Non-VER data also includes some data irregularities. PacifiCorp evaluated these irregularities and in some cases removed data that appears to be inaccurate. For instance, PACW wind deviation data is missing in 36 five-minute intervals out of the 105,108 intervals in the study. Deviations are directly tied to regulation reserve requirements, so the hours in which deviation data is missing are excluded from the analysis. Base schedules for PACE Non-VERs are missing in 75 hours, while the other wind and Non-VER categories have smaller amounts of missing data. While Wind base schedules are directly linked to the regulation requirement forecast, missing base schedule data in PacifiCorp's database may be indicative of inconsistencies in deviation results, which may be calculated off of a stale or erroneous base. Given the limited frequency of such events, PacifiCorp has excluded from the analysis intervals where deviations or base schedules are missing.

As with Load, certain Wind and Non-VER deviations are more likely to be a result of conditions that allow for the deployment of contingency reserve, rather than regulation reserve. In particular,

contingency reserve can be deployed to compensate for unexpected generator outages. For Non-VERs, these are relatively straightforward—namely, periods when generation drops to zero despite base schedules indicating otherwise. Certain Wind outages also qualify as contingency events. Notably, wind generators can be curtailed when wind speed exceeds the maximum rating of the equipment (sometimes referred to as "high speed cutout"). In such instances, generation is curtailed until wind speeds drop back into a safe operating range in order to protect the equipment. When wind speed oscillates above and below the cut-off point, generation may ramp down and up repeatedly. Because events which qualify for deployment of contingency reserve do not require deployment of regulation reserve they have been excluded from the analysis.

As the regulation reserve requirements are calculated using a rolling thirty-minute timeline, data from the prior hour is necessary during the first several five-minute intervals of the next hour. An error in one hour thus results in the need to remove the following hour. This is relevant to error adjustments for both Wind and Non-VERs.

For load, an hour of spurious data will prevent the calculation of the base schedule for the next hour, since the actual load at T-55 is not available. The spurious data also impacts the same two hours in the following week as the expected load change used to determine the base schedule for those hours utilizes the hour in question. For example, if the hour beginning at midnight on February 1, 2015, is found to be spurious, four hours are removed from the Study Term: the spurious hour (the hour ending midnight, February 1, 2015); the hour following the spurious hour (the hour ending 1:00 AM, February 1, 2015), which relies on the spurious hour to inform the regulation forecast; and the two corresponding hours in the following week (the hour ending at midnight, February 8, 2015 and the hour ending at 1:00 AM, February 8, 2015), each of which no longer has a valid prior-week hour from which to develop a proxy load base schedule. The description of "Load Base Schedule Development" above contains further discussion about this relationship and development of the base schedule.

After review of the data for each of the above anomaly types, and out of 105,120 five-minute intervals in the Study Term, only 5.9 percent and 3.6 percent of the total FRS term hours were removed from PACW and PACE, respectively. The system-wide error rate was 9.1 percent, slightly lower than the sum of the PACW and PACE rates due to coincident hours. While cleaning up or replacing anomalous hours could yield a more complete data set, determining the appropriate conditions in those hours would be difficult and subjective. By removing anomalies, the FRS sample is smaller but remains reflective of the range of conditions PacifiCorp actually experiences, including the impact on regulation reserve requirements of weather events experienced during the Study Term.

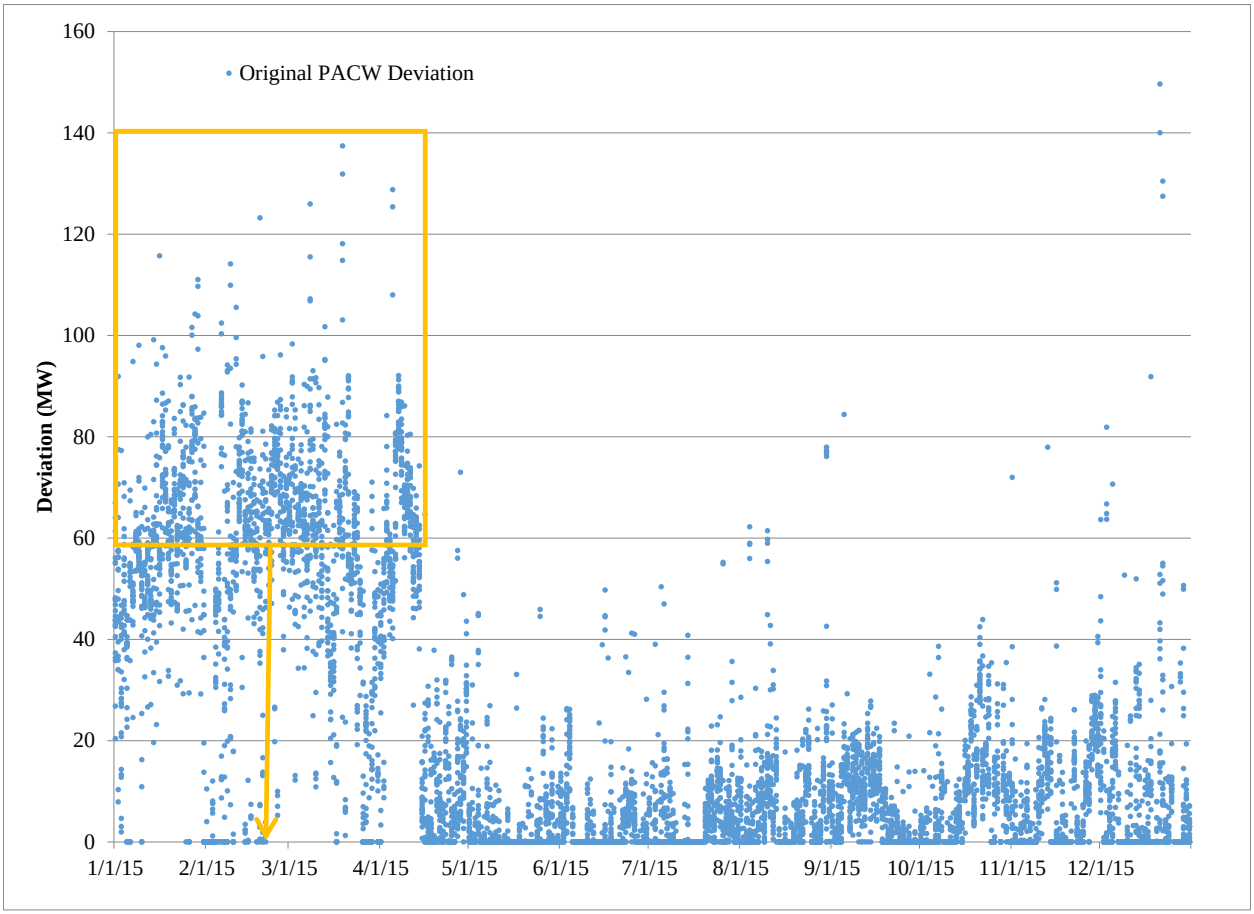
Non-VER Deviation Adjustment

The deviations associated with the Non-VER class show a clear anomaly between January 2015 and April 14, 2015. The abrupt change is evident in the hourly data for PACW shown in Figure 4 below and a comparable anomaly was seen over the same time frame for PACE (not shown). The anomaly ends abruptly at midnight on April 14, 2015, in both BAAs. PacifiCorp has concluded that this issue is a result of errors in base schedule submission rather than an actual deviation. During the early stages of the EIM there were differences between the CAISO's EIM model and PacifiCorp's EMS. The modeling of Colstrip generation was one of those differences. Within the PacifiCorp EMS, 100 percent of Colstrip generation output is pseudo-tied into the PACW BAA. However, the EIM modeled 50 percent of Colstrip generation as being in the PACW BAA and the

other 50 percent of Colstrip generation as modeled in the PACE BAA. This mismatch between the two systems resulted in the measured deviation.

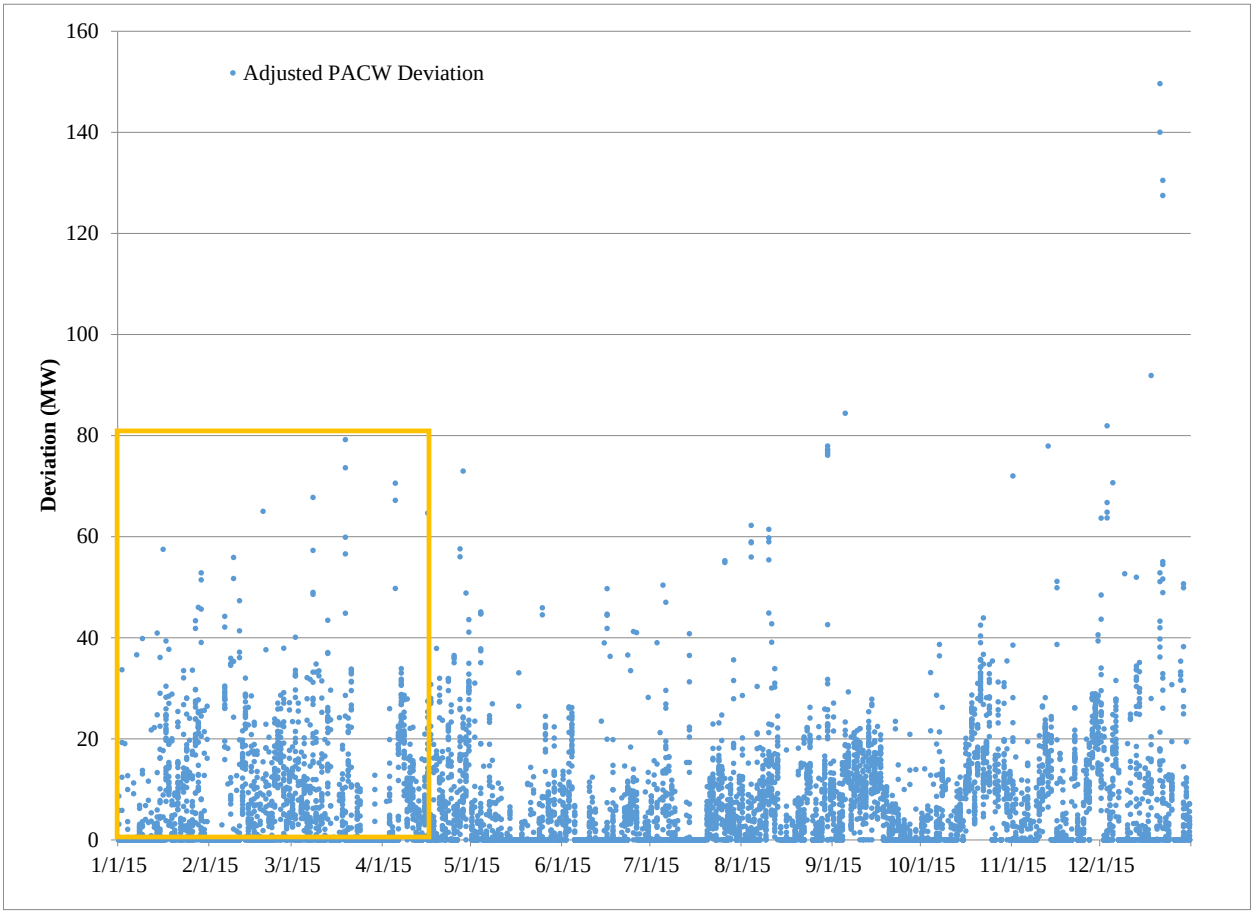
The Colstrip EIM base schedule of 50 percent to PACE and 50 percent to PACW was compared to the EMS output of 100 percent to PACW to determine the deviation. This resulted in a positive deviation to base schedule for PACW. When the EIM model mismatch was discovered it was corrected to align to PacifiCorp's EMS system. This eliminated the persistent deviation on April 14, 2015. For the purposes of the FRS, the regulation reserve requirement for this period was reduced by 58 MW such that the average requirement during this period is equal to the average in the remainder of 2015. The box in Figures F.4 and F.5 below shows the affected data before and after the adjustment is applied.

Figure F.4 - Original PACW Non-VER Deviations



The adjusted regulation reserve requirement is shown in Figure F.5 below.

Figure F.5 - Adjusted PACW Non-VER Deviations



Methodology to Determine Initial Regulation Reserve Requirement

Overview

This section presents the methodology used to determine the initial regulation reserve needed to manage the load and resource balance within PacifiCorp's BAAs. The five-minute interval load and resource deviation data described above informs a regulation reserve forecast methodology that achieves the following goals:

- Complies with NERC standard BAL-001-2;
- Minimizes regulation reserve held; and
- Uses data available at time of EIM base schedule submission at T-55.[15]

The components of the methodology are described below, and include:

- Operating Reserve: Reserve Categories;
- Calculation of Regulation Reserve Need;
- Balancing Authority ACE Limit: Allowed Deviations;
- Planning Reliability Target: Loss of Load Probability ("LOLP"); and

[15] *See* footnote 11 above for explanation of PacifiCorp's use of the T-55 base schedule time point in the FRS.

- Regulation Reserve Forecast: Amount Held.

Following the explanation below of the components of the methodology, the next section details the forecasted amount of regulation reserve for:

- Wind;
- Non-VERs; and
- Load.

Components of Operating Reserve Methodology

Operating Reserve: Reserve Categories

Operating reserve consists of three categories: (1) contingency reserve (i.e., spinning and supplemental reserve), (2) regulation reserve, and (3) frequency response reserve. These requirements must be met by resources that are incremental to those needed to meet firm system demand. The purpose of the FRS is to determine the regulation reserve requirement. The contingency reserve requirement is defined formulaically by a regional reliability standard.

Of the three categories of reserve referenced above, the FRS is primarily focused on the requirements associated with regulation reserve. Contingency reserve may not be deployed to manage other system fluctuations such as changes in load or wind generation output. Because deviations caused by contingency events are covered by contingency reserve rather than regulation reserve, they are excluded from the determination of the regulation reserve requirements. On the other hand, frequency response reserve can be considered a subset of the regulation reserve obligation, though it requires faster responding resources than those contemplated in the FRS. Because PacifiCorp has excess spinning reserve capability compared to its contingency reserve obligation, the capacity and response time requirements for its frequency response obligations are expected to be met by drawing from its existing pool of regulation reserve resources. As a result, no incremental capacity requirements or resource constraints related to frequency response were included in the FRS analysis. The types of operating reserve and relationship between them are further defined in in the Flexible Resource Requirements section above.

Regulation reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC Control Performance Criteria in BAL-001-2, which requires a BAA to carry regulation reserve incremental to contingency reserve to maintain reliability.[16] The regulation reserve requirement is not defined by a simple formula, but instead is the amount of reserve required by each BAA to meet specified control performance standards. Requirement 2 of BAL-001-2 defines the compliance standard as follows:

> *Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes…*

The BAL-001-2 standard became effective as of July 1, 2016 and, upon its effectiveness, officially replaced the BAL-001-1 standard. The new BAL-001-2 standard is a fundamentally different

[16] NERC Standard BAL-001-2, http://www.nerc.com/files/BAL-001-2.pdf

requirement than the prior standard, BAL-001-1, though it is intended to achieve a similar result. BAL-001-1 required ten-minute average ACE to be within the static L_{10} limit in at least 90 percent of non-overlapping ten-minute intervals in a month.[17] The new BAL-001-2 standard requires average ACE to be within a dynamic limit for at least one minute in 100 percent of all rolling thirty-minute intervals. PacifiCorp has been operating under BAL-001-2 since March 1, 2010, as part of a NERC Reliability-Based Control field trial in the Western Interconnection, so PacifiCorp has experience operating under the new standard, even though it did not become effective until July 1, 2016.

PacifiCorp's 2012, 2013, and 2014 studies were all based on compliance with BAL-001-1. These studies utilized deviations over ten-minute intervals and allowed deviations up to the fixed L_{10} value.[18,19] While these studies all used a 99.7 percent confidence interval, they did not necessarily achieve 99.7 percent compliance with the BAL-001-1 standard. For instance, the 2014 Wind Integration Study had a failure rate of 1.4 percent for PACE and 2.0 percent for PACW.[20] This is higher than the 90 percent compliance requirement under BAL-001-1, but significantly lower than the 100 percent compliance requirement under BAL-001-2. In addition, prior studies separately distinguished between three categories of regulation reserve, all of which were intended to capture the total potential deviation over the ten-minute interval relevant under BAL-001-1:

- Ramping – flexibility required to follow the change in actual net system Load from hour to hour;
- Regulating – flexibility required to manage forecast uncertainty over ten-minute intervals; and
- Following – flexibility required to manage forecast uncertainty over sixty-minute intervals.

The FRS fundamentally differs from the 2012, 2013, and 2014 studies because it is based on compliance with BAL-001-2. The impacts of the changes in three key elements of the new BAL-001-2 standard relative to the old standard are summarized in Table F.3 below. The three key elements shown in Table F.3 include: (1) the length of time (or "interval") used to measure compliance under the old versus new BAL standard; (2) the change in compliance threshold between the two standards, which represents the percentage of intervals that a BAA must be within the limits set in the standard; and (3) the bandwidth of acceptable deviation used under each standard to determine whether an interval is considered out of compliance. These changes are discussed in further detail below.

[17] BAL-001-1 (R2) stated: Each Balancing Authority shall operate such that its average ACE for at least 90 percent of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}.

[18] L_{10} represents a bandwidth of acceptable deviation under BAL-001-1 prescribed by WECC between the net scheduled interchange and the net actual electrical interchange of PacifiCorp's BAAs.

[19] The L_{10} for PacifiCorp's BAAs in 2015 were approximately 33.49 MW for PACW and 49.92 MW for PACE. For more information, please refer to: http://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/CPS2%20Bounds%20Reports/2015%20CPS2%20Bounds%20Report%20Final%2020150615.pdf

[20] *See* Redacted Rebuttal Testimony of Brian S. Dickman, Wyoming Public Service Commission Docket No. 20000-469-ER-15 at p. 46:1-6 (filed Sept. 16, 2015).

Table F.3 - BAL-001-1 vs BAL-001-2

	Interval (minutes)	Compliance %	Allowed Variance
BAL-001-1	10	90%	Fixed: L_{10}
BAL-001-2	30	100%	Dynamic: BAAL
Impact on Requirement	Down	Up	Varies

The first change in Table F.3 is related to the length of time used to measure compliance. Under the prior standard, BAL-001-1, compliance was measured over six, non-overlapping ten-minute intervals within each hour. If ACE was within the allowed limits for all ten minutes of an interval, that interval was in compliance, and only the maximum deviation in that interval was considered in determining compliance. Compliance under BAL-001-2 is measured over rolling thirty-minute intervals, with sixty overlapping periods per hour, some of which include parts of two clock-hours. In effect, this means that every minute of every hour is the beginning of a new, thirty-minute compliance interval under the new BAL-001-2 standard. If ACE is within the allowed limits at least once in a thirty-minute interval, that interval was in compliance, and only the minimum deviation in each thirty-minute interval is considered in determining compliance. This change reduces regulation reserve requirements because PacifiCorp does not need to hold regulation reserve for deviations with duration less than 30 minutes.

The second change in Table F.3 above is related to the compliance percentage, or the number of intervals where deviations are allowed to be outside the limits set in the standard. BAL-001-1 required 90 percent compliance, that is, 10 percent of ten minute intervals were allowed to have deviations in excess of the requirement in the standard. BAL-001-2 requires 100 percent compliance, so deviations must be maintained within the requirement set by the standard for all rolling thirty-minute intervals. Under the old standard, overall compliance could be achieved despite shortfalls in the intervals with the largest deviations. Because shortfalls are not permitted when the compliance requirement is 100 percent, this change increases regulation reserve requirements.

The third change in Table F.3 is related to the bandwidth of acceptable deviation before an interval is considered out of compliance. Under BAL-001-1, the acceptable deviation for each BAA was set at a fixed value in all intervals, referred to as L_{10}.[21] Under BAL-001-2, the acceptable deviation for each BAA is dynamic, varying as a function of the frequency deviation for the entire interconnect. The impact of this change is mixed as the limits under BAL-001-2 are generally higher, but at times can be lower than the limits under BAL-001-1.

In addition, the FRS identifies a single category of flexible capacity, rather than the three categories used in the prior studies performed in compliance with the old standard. Because deviations over ten-minute intervals are only relevant to the extent they exacerbate deviations over longer time

[21] The L_{10} for PacifiCorp's BAAs in 2015 were approximately 33.49 MW for PACW and 49.92 MW for PACE. For more information, please refer to: http://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/CPS2%20Bounds%20Reports/2015%20CPS2%20Bounds%20Report%20Final%2020150615.pdf .

frames, measuring three separate categories does not provide an accurate depiction of the requirements under BAL-001-2. In addition, while the following and regulating requirements in prior studies were statistically uncorrelated over the course of the year, the root sum square methodology used in the prior studies fails to account for the few random intervals when these components both show large requirements. Because the root sum square methodology underestimates the frequency of outlier events, it underestimates the capacity needed to cover them. The FRS eliminates complexity and distortion associated with combining multiple requirements by directly calculating a single component that allows for compliance with the BAL-001-2 standard.

Calculation of Regulation Reserve Need

The next step of the operating reserve methodology is to calculate the amount of regulation reserve required to be held under BAL-001-2. Regulation reserve requirements were calculated from five-minute EIM deviation data in a manner that emulates the requirements of the BAL-001-2 standard. The same calculation applies to all types of imbalances: Load, Wind, Non-VERs, and the combined portfolio.

First, the minimum five-minute imbalance was calculated for each thirty-minute rolling period in the Study Term. Second, for each hour, the maximum five-minute imbalance was selected from the values identified in the first step. An example is provided in the Table 2 and Figure 6 below.

In the example in Table F.4 below, the minimum five-minute imbalance in the thirty minutes beginning at 0:15 is 40 MW. This is also the maximum five-minute imbalance in any thirty-minute period in this hour. Assuming 40 MW of regulation reserve was available in this hour and the allowable ACE deviation was zero, this hour would still be compliant with the BAL-001-2 requirement—even though the imbalance exceeds the regulation reserve available for five consecutive, five-minute intervals—because the allowable ACE deviation was exceeded for less than 30 minutes.

Table F.4 - Deviation and Regulation Reserve Requirement Example

Interval	Base Schedule	Actual	5-Minute Deviation	30-Minute Deviation	Reserve Requirement
0:00	2500	2510	10	10	40
0:05		2520	20	10	40
0:10		2530	30	10	40
0:15		2540	**40**	10	40
0:20		2550	50	10	40
0:25		2560	60	10	40
0:30		2570	70	20	40
0:35		2560	60	30	40
0:40		2550	50	**40**	40
0:45		2540	40	40	40
0:50		2530	30	30	40
0:55		2520	20	20	40

As shown in Figure F.6 below, if the ACE deviations were only allowed for a ten minute interval, the requirement would be higher.

Figure F.6 - Deviation and Regulation Reserve Requirement Example

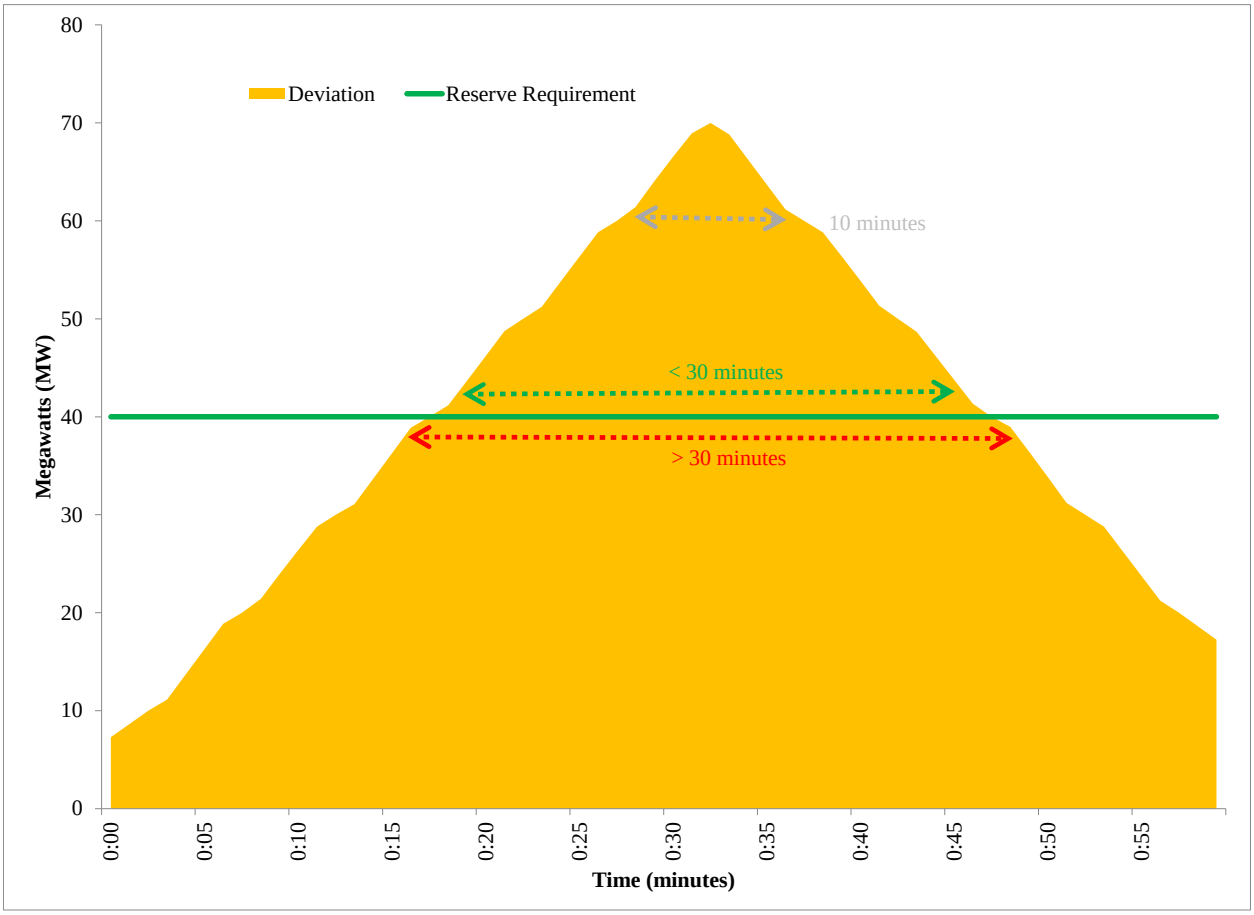
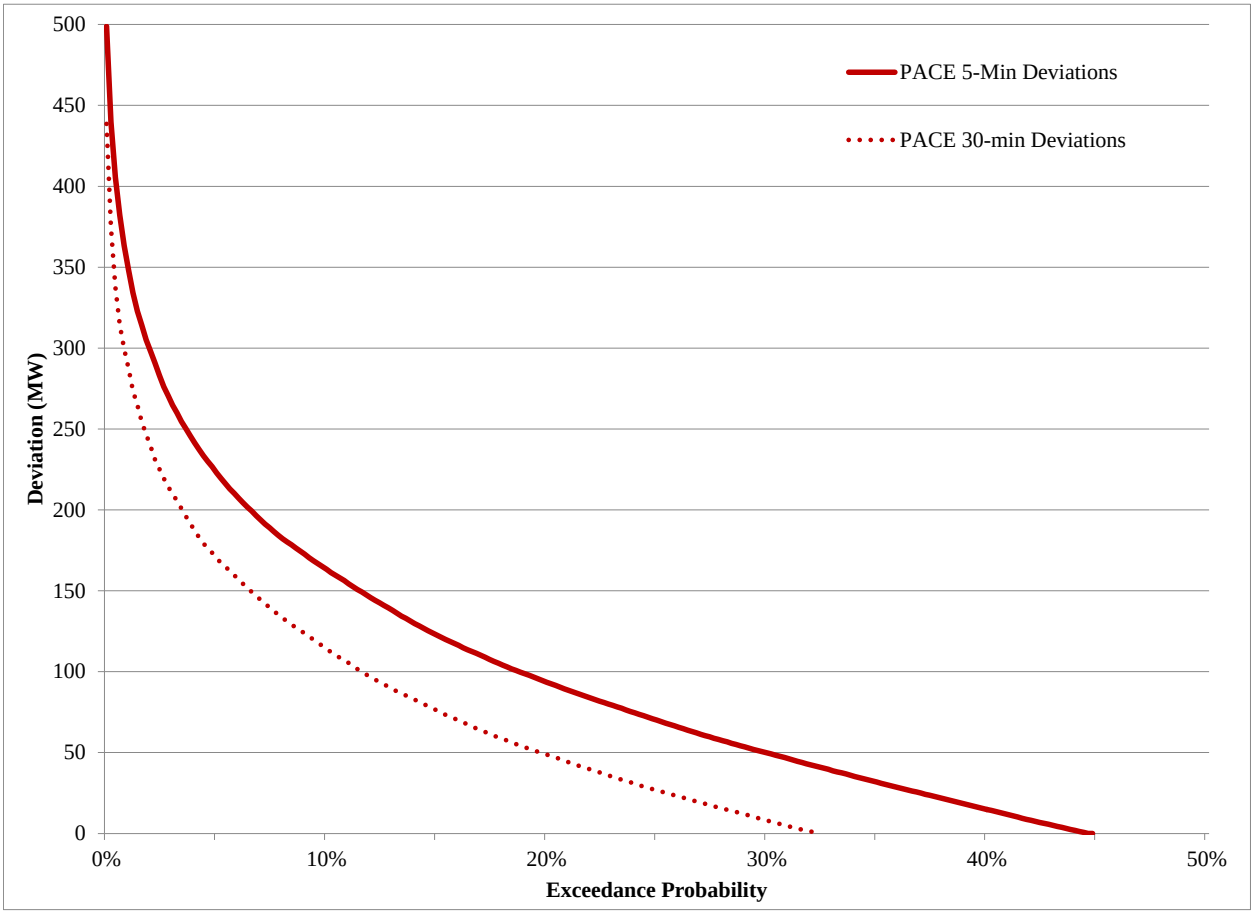


Figure F.7 below illustrates the distribution of the combined five-minute deviations for Load, Wind, and Non-VERs in PACE during 2015, as well as the distribution of thirty-minute sustained deviations relevant to the BAL-001-2 standard. The effect for PACW was comparable (not shown). The thirty-minute window for compliance reduces the regulation reserve need. The thirty-minute window can be particularly helpful with deviations in the last few intervals of each hour. This period has the longest forecast horizon (*i.e.*, the furthest out from T-55), so the potential deviations are expected to be larger. However, if the change resulting in the deviation is reflected in the base schedule for the next hour, PacifiCorp's ACE will return to zero on its own a few minutes later. Thus, so long as the duration of the deviation is less than 30 minutes, the size of the deviation in the last few intervals is irrelevant for compliance with BAL-001-2.

Figure F.7 - Probability Distribution of PACE Combined Portfolio Deviations



Balancing Authority ACE Limit: Allowed Deviations

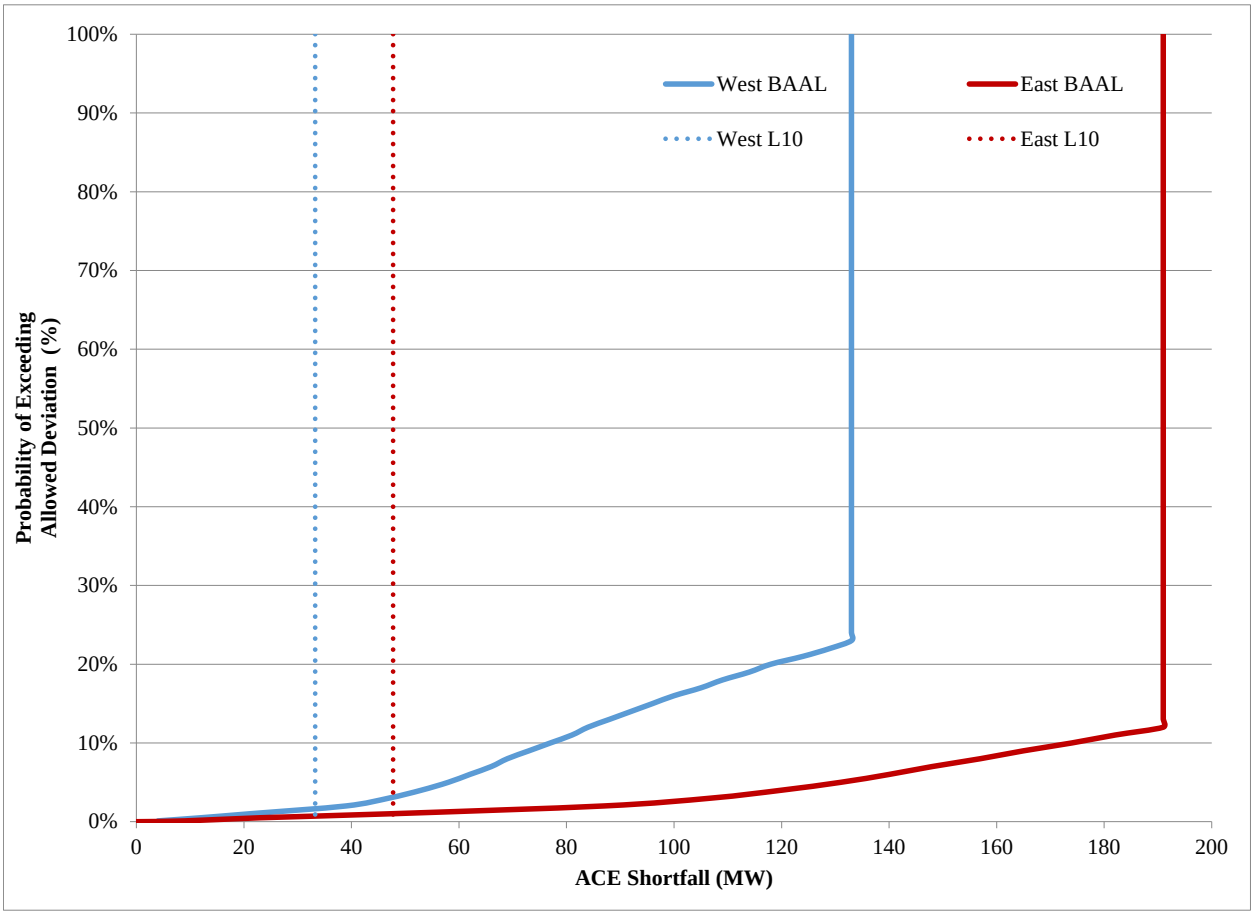
Even if insufficient regulation reserve capability is available to compensate for a thirty-minute sustained deviation, a violation of BAL-001-2 does not occur unless the deviation also exceeds the Balancing Authority ACE Limit.

The Balancing Authority ACE Limit is specific to each BAA and is dynamic, varying as a function of interconnection frequency. When WECC frequency is close to 60 Hz, the Balancing Authority ACE Limit is large and large deviations in ACE are allowed. As WECC frequency drops further and further below 60 Hz, ACE deviations are increasingly restricted for BAAs that are contributing to the shortfall, *i.e.* those BAAs with higher loads than resources. A BAA commits a BAL-001-2 reliability violation if in any thirty-minute interval it doesn't have at least one minute when its ACE is within its Balancing Authority ACE Limit.

While the specific Balancing Authority ACE Limit for a given interval cannot be known in advance, the historical probability distribution of Balancing Authority ACE Limit values is known. Figure 8 below shows the probability of exceeding the allowed deviation during a five-minute interval for a given level of ACE shortfall. For instance, a 47 MW ACE shortfall in PACE has a one percent chance of exceeding the Balancing Authority ACE Limit. The fixed value under the prior BAL-001-1 standard for L_{10} is also plotted for comparison. WECC-wide frequency can change rapidly and without notice, and this causes large changes in the Balancing Authority ACE

Limit over short time frames. Maintaining ACE within the Balancing Authority ACE Limit under those circumstances can require rapid deployment of large amounts of operating reserve. To limit the size and speed of resource deployment necessitated by variation in the Balancing Authority ACE Limit, PacifiCorp's operating practice caps permissible ACE at the lesser of the Balancing Authority ACE Limit or four times L_{10}. This also limits the occurrence of transmission flows that exceed path ratings as result of large variations in ACE.[22,23] This cap is reflected in Figure F.8.

Figure F.8 - Probability of Exceeding Allowed Deviation



In 2015, PacifiCorp's deviations and Balancing Authority ACE Limits were uncorrelated, which indicates that PacifiCorp's contribution to WECC-wide frequency is small. PacifiCorp's deviations and Balancing Authority ACE Limits were also uncorrelated when periods with large deviations were examined in isolation. If PacifiCorp's large deviations made distinguishable contributions to the Balancing Authority ACE Limit, ACE shortfalls would be more likely to exceed the Balancing Authority ACE Limit during large deviations. Since this is not the case, the probability of exceeding the Balancing Authority ACE Limit is lower, and less regulation reserve is necessary to comply with the BAL-001-2 standard.

[22] "Regional Industry Initiatives Assessment." NWPP MC Phase 3 Operations Integration Work Group. Dec. 31, 2014. Pg. 14. Available at: http://www.nwpp.org/documents/MC-Public/NWPP-MC-Phase-3-Regional-Industry-Initiatives-Assessment12-31-2014.pdf

[23] "NERC Reliability-Based Control Field Trial Draft Report." Western Electricity Coordinating Council. Mar. 25, 2015. Available at: https://www.wecc.biz/Reliability/RBC%20Field%20Trial%20Report%20Approved%203-25-2015.pdf

Planning Reliability Target: Loss of Load Probability

When conducting resource planning, it is common to use a reliability target that assumes a specified LOLP. In effect, this is a plan to curtail firm load in rare circumstances, rather than acquiring resources for extremely unlikely events. The reliability target balances the cost of additional capacity against the benefit of incrementally more reliable operation. By planning to curtail firm load in the rare event of a regulation reserve shortage, PacifiCorp can maintain the required 100 percent compliance with the BAL-001-2 standard and the Balancing Authority ACE Limit. This balances the cost of holding additional regulation reserve against the likelihood of regulation reserve shortage events.

PacifiCorp's 2015 Integrated Resource Plan ("IRP") utilized a planning reserve margin of 13 percent, which is intended to achieve 0.88 loss of load hours per year.[24] This FRS assumes that 0.88 loss of load hours per year due to regulation reserve shortages is appropriate for planning and ratemaking purposes. This is in addition to any loss of load resulting from transmission or distribution outages, resource adequacy, or other causes. The FRS applies this reliability target as follows:

- If the regulation reserve available is greater than the regulation reserve need for an hour, the LOLP is zero for that hour.
- If the regulation reserve held is less than the amount needed, the LOLP is derived from the Balancing Authority ACE Limit probability distribution. As the magnitude of the shortfall increases, the probability of exceeding the Balancing Authority ACE Limit increases. For instance, as indicated above, a 47 MW ACE shortfall in PACE has a one percent chance of exceeding the Balancing Authority ACE Limit. A one percent probability of failing to meet the Balancing Authority ACE Limit in one hour is 0.01 loss of Load hours per year. A one percent probability of failing to meet the Balancing Authority ACE Limit in eighty-eight hours would be 0.88 loss of load hours per year and corresponds to the targeted level of reliability.

Regulation Reserve Forecast: Amount Held

As previously shown in Figure 7, the instances requiring the largest amounts of regulation reserve occur infrequently, and many hours have very low requirements. If periods when requirements are likely to be low can be distinguished from periods when requirements are likely to be high, less regulation reserve is necessary to achieve a given reliability target. As described above, the regulation reserve forecast is not intended to compensate for every potential deviation. Instead, when a shortfall occurs, the size of that shortfall determines the probability of exceeding the Balancing Authority ACE Limit and a reliability violation occurring. The forecast should achieve a cumulative LOLP that corresponds to the annual reliability target.

PacifiCorp submits balanced base schedules to CAISO for its load and resources by T-55.[25] Operating reserve is intended to cover demand in excess of the balanced load and resources submitted in base schedules. Capacity to be used as operating reserve needs to be identified and

[24] 2015 IRP, Appendix I, Table I.3

[25] *See* footnote 9 for explanation of PacifiCorp's use of the T-55 base schedule time point in the Regulation Reserve Study.

set aside so that it is not utilized in the base schedule submission. Likewise, the regulation reserve forecast identifying the quantity of operating reserve to be set aside for the upcoming hour needs to be finalized by T-55.

The base schedule itself reflects the best, most up-to-date information about conditions in the upcoming hour. The next section describes how the information available can be used to forecast regulation reserve requirements for each of the regulation reserve classes while maintaining reliability. The portfolio regulation reserve requirement forecast incorporates each of the resource/load class forecasts and accounts for the reduced requirements resulting from diversity between the classes. All of these calculations are prepared separately for each of the PacifiCorp BAAs.

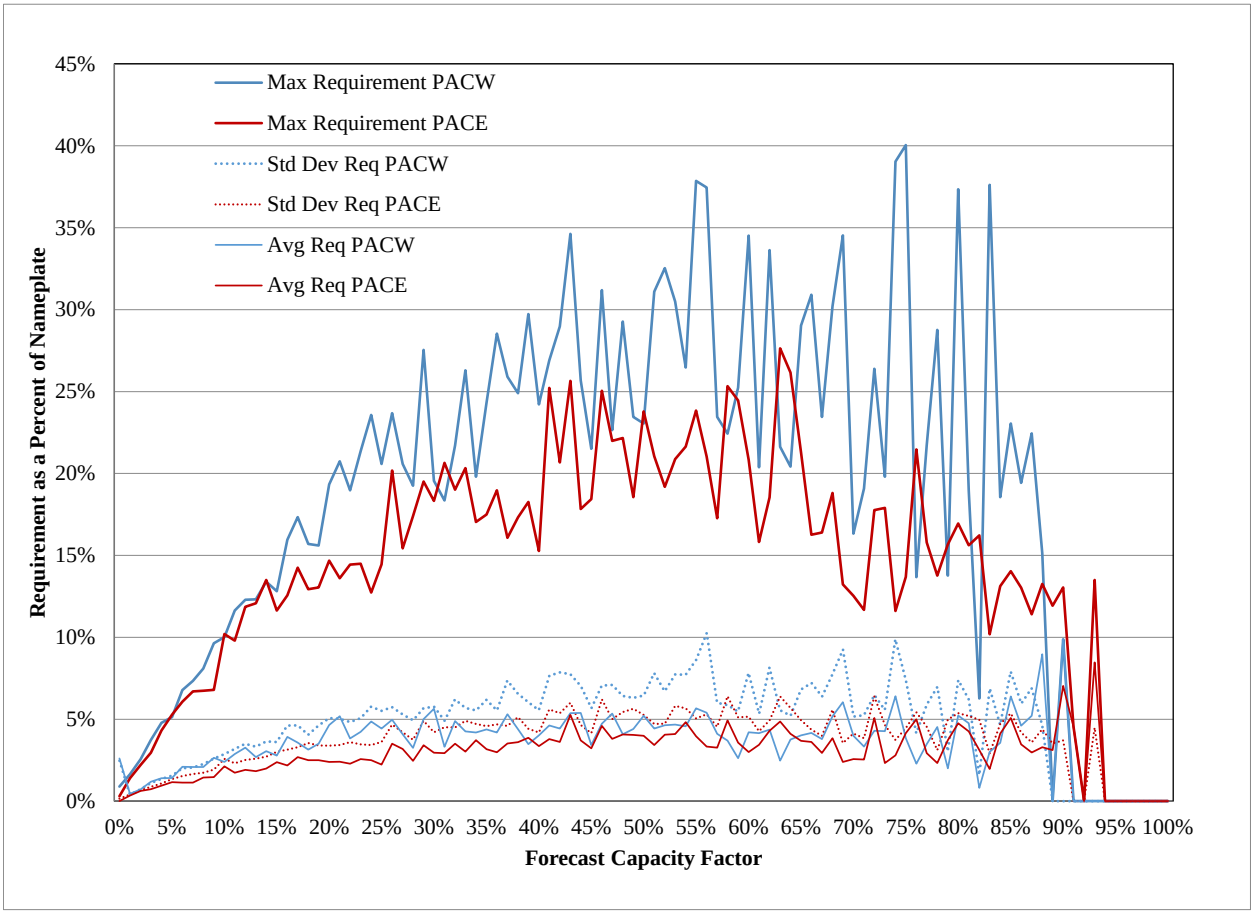
2015 Regulation Reserve Forecast

Wind

Figure F.9 illustrates the relationship between the observed regulation reserve requirements for wind during 2015 and the forecasted level of output, stated as a capacity factor (*i.e.*, a percentage of the nameplate wind capacity).

Three distinct patterns are apparent in the figure. First, for capacity factors from zero percent to approximately 20 percent, the regulation reserve requirement increases linearly. The linear relationship in this first range reflects the fact that the largest possible deviation is equal to the base schedule and a very small amount of negative generation (station service). Second, for capacity factors from approximately 20 percent to approximately 80 percent, the maximum requirement varies somewhat widely and does not exhibit significant trends. Third, as capacity factors increase above approximately 80 percent, the observed maximum requirement declines.

Figure F.9 - Wind Regulation Reserve Requirements by Forecast Capacity Factor



When evaluating the distribution of maximum requirements above an approximately 20 percent capacity factor, it is important to consider the characteristics of an observed maximum within a sample. The mean of a sample may be higher or lower than the mean of the population from which it is drawn, but it is not expected to vary systematically with sample size. This is not the case for the maximum of a sample, which will always be less than or equal to the maximum of the population from which it is drawn. In addition, the expected value of the sample maximum increases as the sample size increases.

The sample size of each forecasted capacity factor varies, with very high capacity factors occurring less frequently. With this consideration in mind, the decline in observed maximum requirements at high capacity factors can be viewed as an artifact of the sample rather than a real trend related to the behavior of wind under those specific conditions. This view is reinforced by the fact that the average and standard deviation of the requirements are relatively constant at forecasted capacity factors above roughly 20 percent. Because the probability of a large deviation doesn't vary for capacity factors above roughly 20 percent, a single regulation reserve requirement is a reasonable forecast for that range.

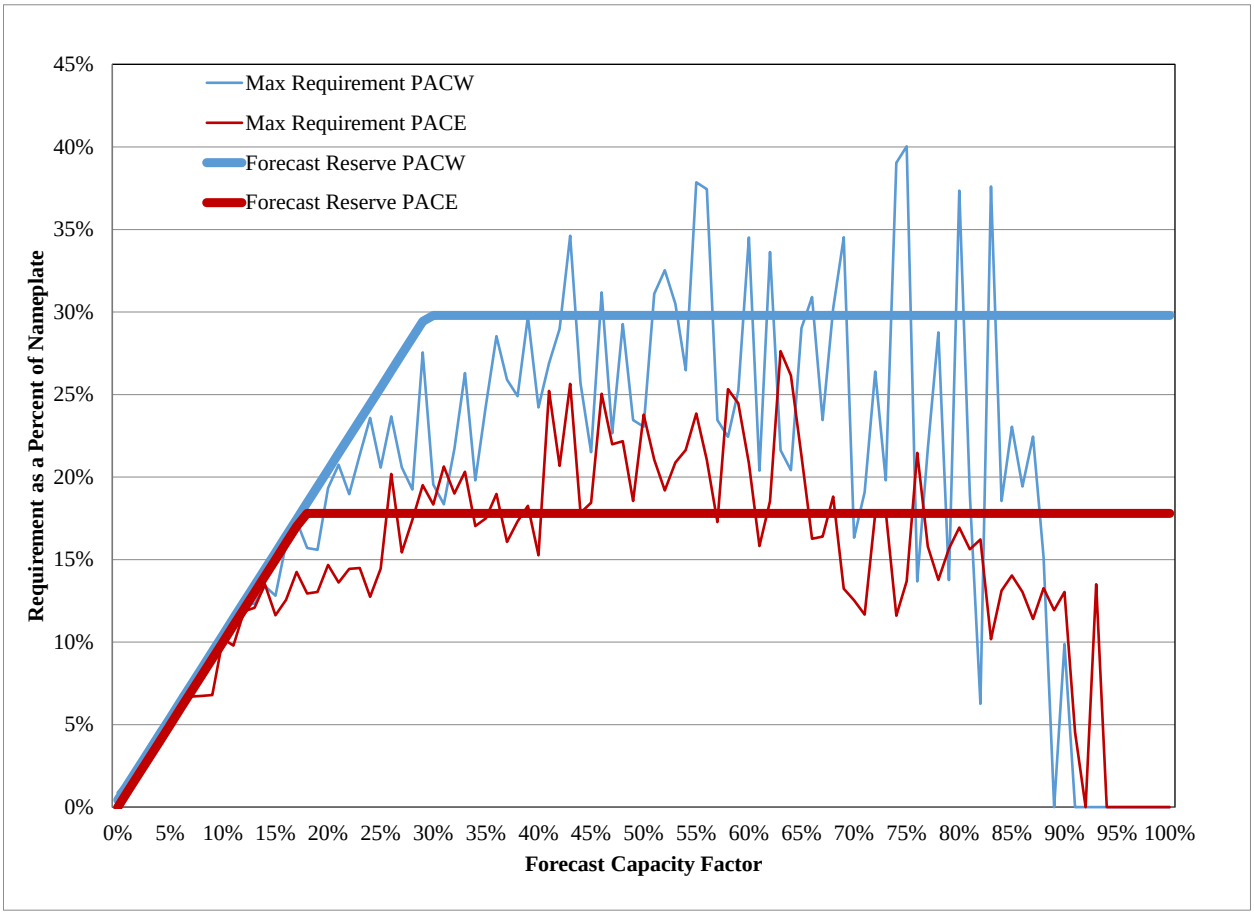
Figure F.10 below presents the regulation reserve forecast for PACE and PACW wind, incorporating the two trends described above: (1) the linear increase in requirements at low capacity factors (*i.e.*, below 20 percent); and (2) a uniform requirement at higher capacity factors (*i.e.*, from 20 percent to 100 percent). As illustrated in Figure 10, PACW had 888 hours with forecasted capacity factors between 41 percent and 55 percent, while PACE had 1,115 hours in

that range. PACW only had 64 hours with forecasted capacity factors of 85 percent or more, while PACE only had 109 hours in that range.

The wind regulation reserve forecast is a fixed percentage of the wind nameplate capacity, but never more than the difference between minimum actual output and the base schedule. The fixed percentage of nameplate capacity is set at the minimum level that achieves the reliability target of 0.88 loss of load hours per year. The forecast resulted in the possibility of reliability violations in roughly one percent of the hours. While the forecast does not result in any potential reliability violations at high capacity factors, this is likely due to the small number of observations in this range, as described above.

Using a forecast based on the hour-ahead base schedule results in a 2015 stand-alone regulation reserve requirement for wind of 384 MW, or approximately 14.8 percent of nameplate capacity. This forecast does not account for any diversity benefit from combining the reserve requirements for wind with the requirements of other classes. Diversity benefits are discussed later on in the study.

Figure F.10 - Stand-alone Wind Regulation Reserve Forecast



Non-VERs

Figure F.11 below illustrates the observed regulation reserve requirements for Non-VERs during 2015 as a function of the forecasted level of output, stated as a capacity factor (*i.e.*, a percentage of the nameplate Non-VERs capacity). For Non-VERs, the forecasted capacity factors during 2015 fall within limited ranges and do not approach either zero or 100 percent. Since the distribution of errors appears to be essentially random, the base schedule provides limited forecasting value for Non-VERs, resulting in a single reserve value applied in all hours.

Figure F.11 - Non-VER Regulation Reserve Requirements by Forecast Capacity Factor



Figure F.12 below illustrates the observed regulation reserve requirements for Non-VERs during 2015 as a function of hour of the day. The average and standard deviation are very low compared to the maximum events, indicating the relative rarity of large deviation events. However, the maximum, average, and standard deviation all exhibit comparable trends, indicating that the characteristics of the maximum are also reflected in the rest of the data for those periods. While an overall diurnal pattern is noticeable, significant volatility in the observed maximum requirements is apparent from hour to hour. For example, consider the significant drop in the observed maximum requirement for PACW in hour 19 relative to hours 18 and 20. The average and standard deviation do not indicate that hour 19 is significantly different from hours 18 and 20. As a result, this drop is more likely to be from randomness in the sample, rather than a specific characteristic of hour 19 itself.

Figure F.12 - Non-VER Regulation Reserve Requirements by Hour of the Day

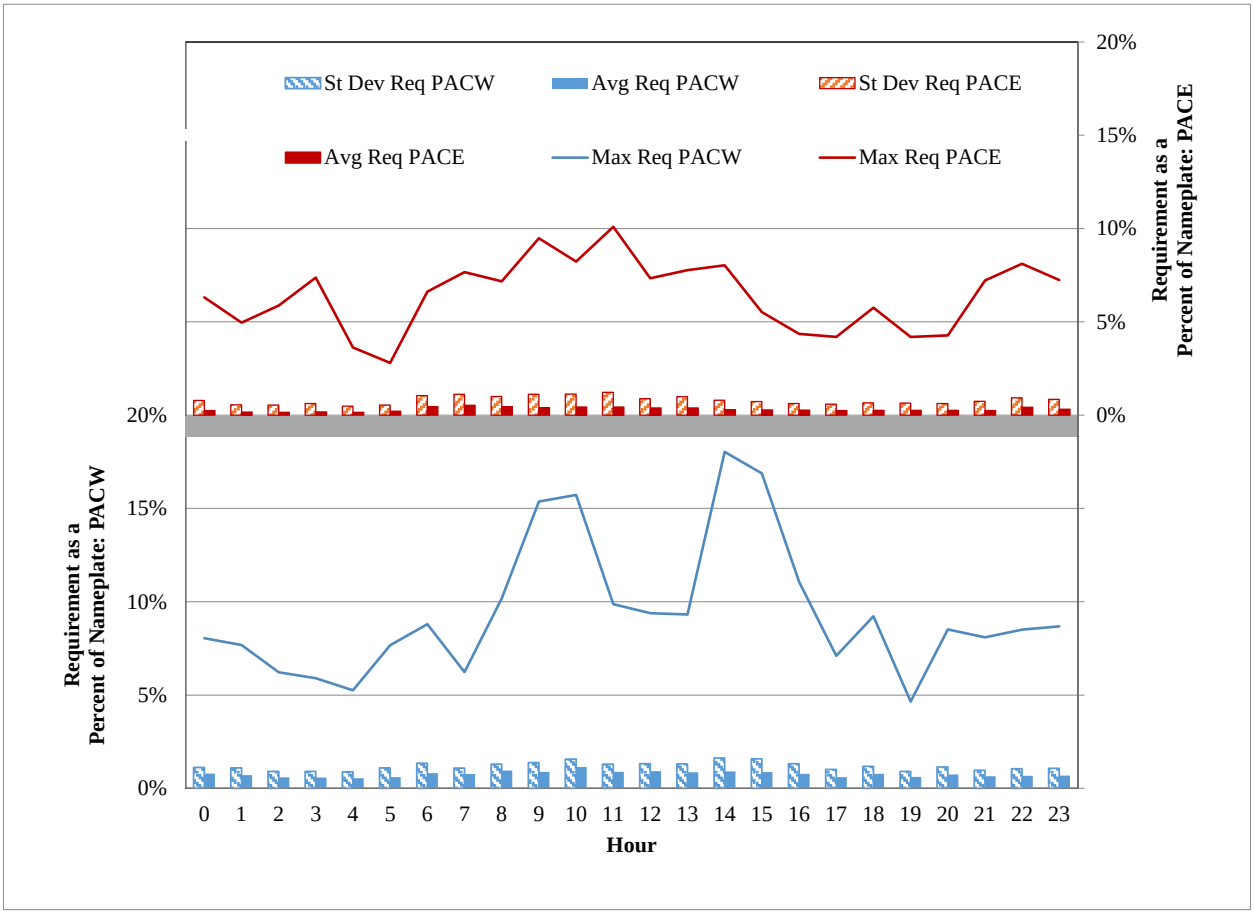
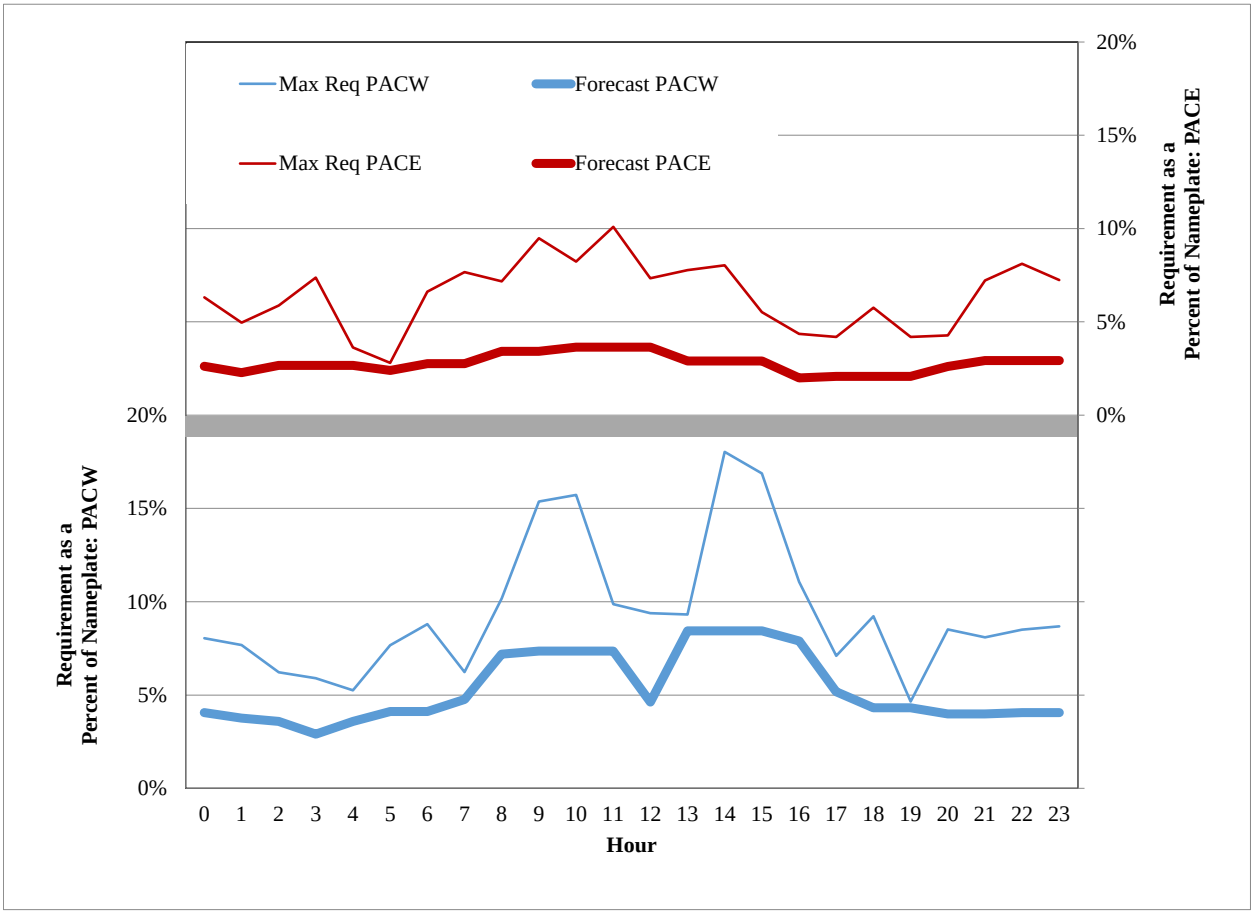


Figure F.13 below presents the regulation reserve forecast for each hour of the day for PACE and PACW Non-VERs. The forecast is based on the rolling three-hour maximum of regulation reserve requirements from 2015. This produces a smoother forecast, reflecting realistic hourly variation rather than just aligning with the large events in the sampled data for 2015. The forecasted requirement is then reduced by a fixed percentage until it reaches the minimum level necessary to achieve the reliability target of 0.88 loss of load hours per year. This forecast resulted in the possibility of reliability violations roughly 1.1 percent of the time on PACW, and 2.6 percent of the time on PACE. Due to the lower probability of a reliability violation in each hour for PACE Non-VERs, more hours of potential violations are aggregated to reach the reliability target of 0.88 loss of load hours per year. Using a forecast based on the hour of the day results in a 2015 stand-alone regulation reserve requirement for Non-VERs of 83 MW, or approximately 3.7 percent of nameplate capacity. This forecast does not account for any diversity benefit from combining the regulation reserve requirements for Non-VERs with the requirements of other classes.

Figure F.13 - Stand-alone Non-VER Regulation Reserve Forecast



Load

Figure F.14 below illustrates the relationship between the observed regulation reserve requirements for load during 2015 and hour of the day. Similar to the results for Non-VERs, the average and standard deviation are very low compared to the maximum events, indicating the relative rarity of large deviation events. However, the maximum, average, and standard deviation all exhibit comparable trends, indicating that the characteristics of the maximum are also reflected in the rest of the data for those periods.

Figure F.14 - Stand-alone Load Regulation Reserve Requirements by Hour of the Day

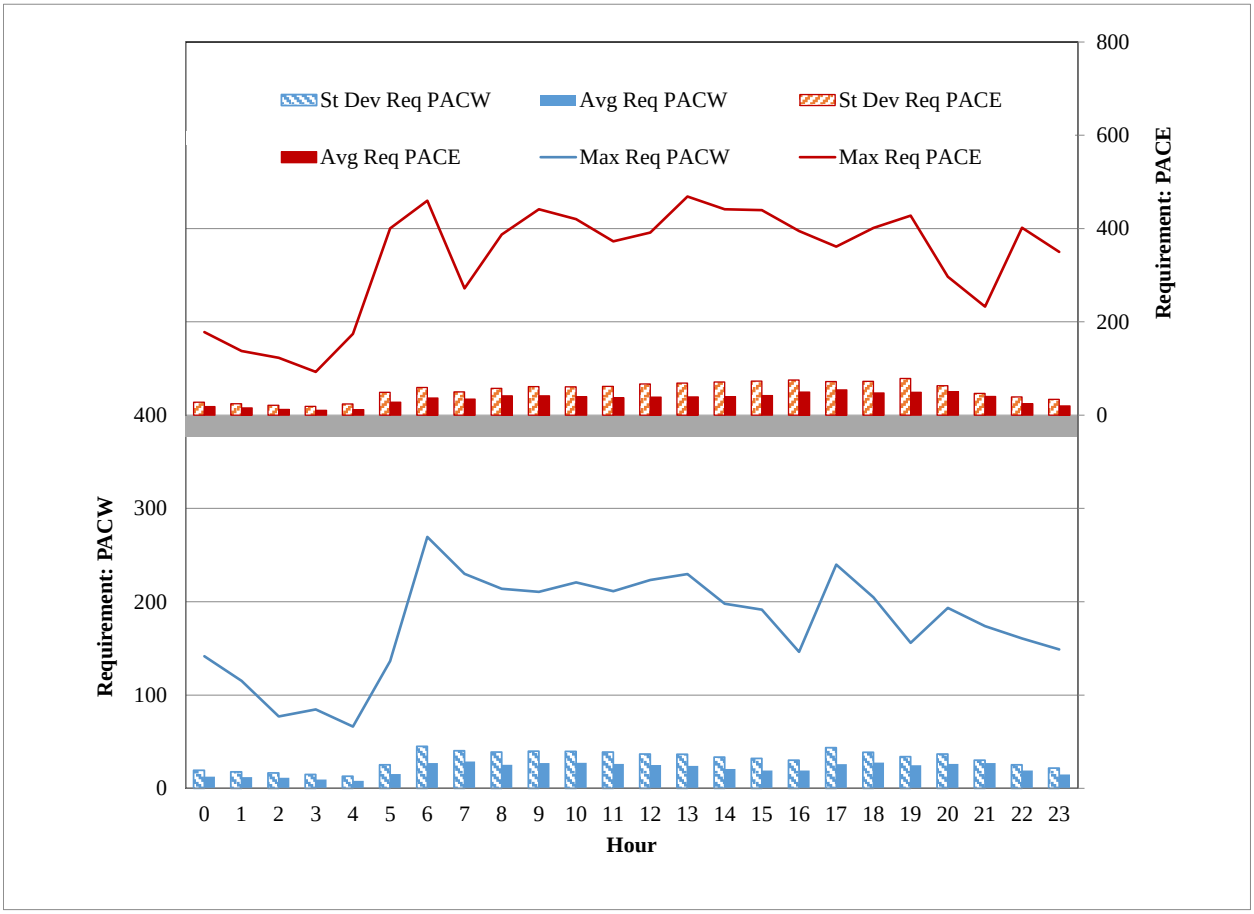
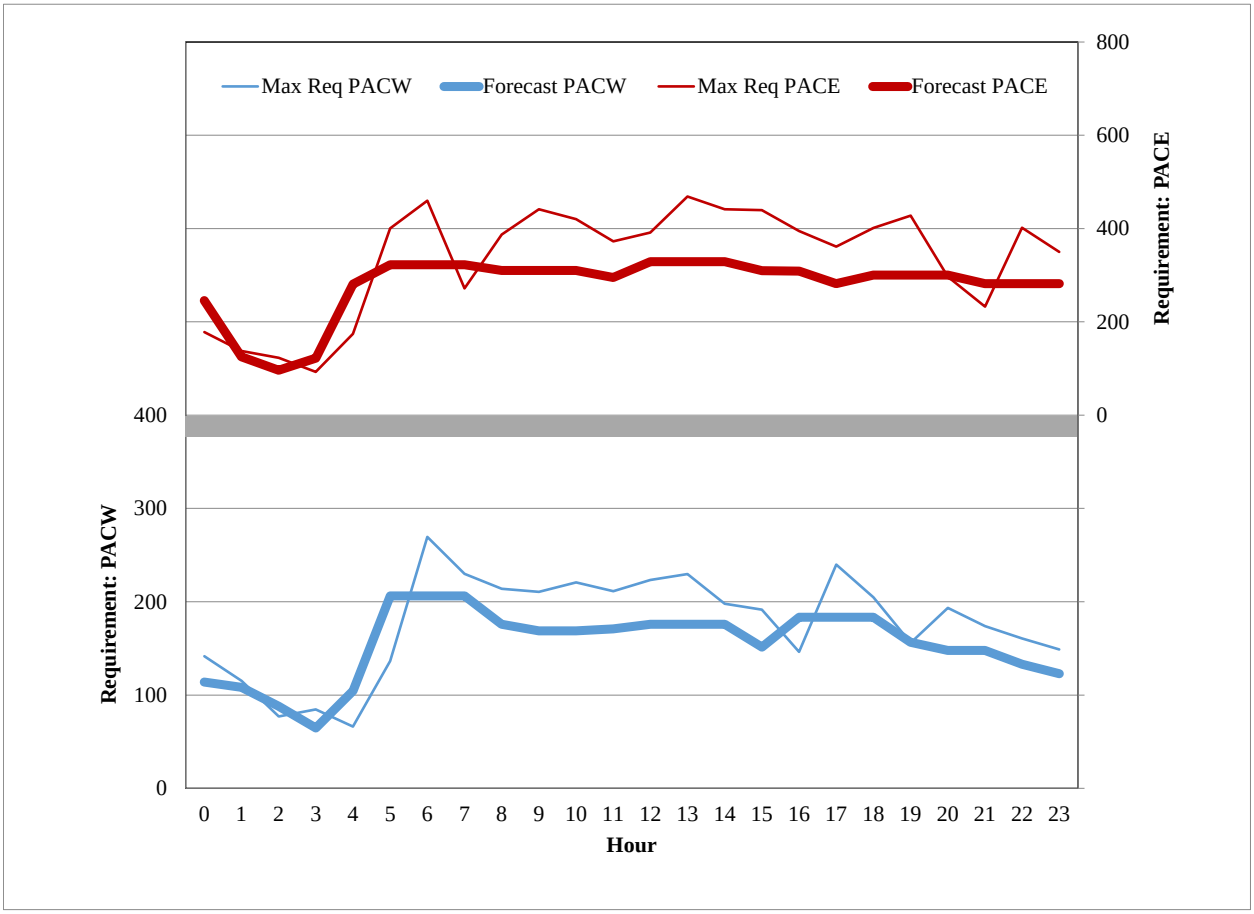


Figure F.15 below presents the regulation reserve forecast for each hour of the day for PACE and PACW load. The forecast is based on the rolling three-hour maximum of regulation reserve requirements from 2015. This produces a smoother forecast, reflecting realistic hourly variation rather than just aligning with the large events in the sampled data for 2015. The forecasted requirement is then reduced by a fixed percentage until it reaches the minimum level necessary to achieve the reliability target of 0.88 loss of load hours per year. This forecast resulted in the possibility of reliability violations roughly 0.7 percent of the time in both PACW and PACE. Using a forecast based on the hour of the day results in a 2015 stand-alone regulation reserve requirement for load of 433 MW, or approximately 4.5 percent of the 12CP. This forecast does not account for any diversity benefit from combining the reserve requirements for load with the requirements of other classes.

Figure F.15 - Stand-alone Load Regulation Reserve Forecast



2015 PacifiCorp System Diversity and EIM Diversity Benefits

PacifiCorp System-Wide Portfolio Diversity Benefit

The EIM is a voluntary energy imbalance market service through the CAISO where market systems automatically balance supply and demand for electricity every fifteen minutes, dispatching the least-cost resources every five minutes.

PacifiCorp began full EIM operation on November 1, 2014. NV Energy began full operation in EIM on December 1, 2015. Puget Sound Energy and Arizona Public Service Company commenced EIM participation on October 1, 2016. Additionally, several other entities have announced their intention to begin participating over the next few years. PacifiCorp's participation in the EIM results in improved power production forecasting and optimized intra-hour resource dispatch. This brings important benefits including reduced energy dispatch costs through automatic dispatch, enhanced reliability with improved situational awareness, better integration of renewable energy resources, and reduced curtailment of renewable energy resources

EIM also direct effects related to regulation reserve requirements. First, as a result of EIM participation, PacifiCorp has improved granularity for data used in the analysis contained in this FRS. The data and control provided EIM allow PacifiCorp to achieve the portfolio diversity benefits described in this section. Second, the EIM's intra-hour capabilities across the broader EIM

footprint provide the opportunity to reduce the amount of regulation reserve necessary for PacifiCorp to hold, as further explained in the next section.

The regulation reserve forecasts described above (384 MW for Wind, 83 MW for Non-VERs, and 433 MW for Load) independently ensure that the probability of a reliability violation for each class remains within the reliability target; however, the largest deviations in each class tend not to occur simultaneously, and in some cases deviations will occur in offsetting directions. Because the deviations are not occurring at the same time, the regulation reserve held can cover the expected deviations for multiple classes at once and a reduced total quantity of reserve is sufficient to maintain the desired level of reliability. This reduction in the reserve requirement is the diversity benefit from holding a single pool of reserve to cover deviations in Wind, Non-VERs, and Load. As a result, the regulation reserve forecast for the portfolio can be reduced while still meeting the reliability target.

As shown in Table F.5 below, the sum of the stand-alone forecasts for each class results in a cumulative LOLP of 0.03 hours per year. This is significantly less than the target of 0.88 hours per year as a result of the diversity among the different classes. PacifiCorp then calculated the proportional reduction to the standalone requirement—the diversity benefit shown in the second column of values in Table 3—that could be applied such that the PacifiCorp system just achieves the reliability target for the Study Term. A total portfolio requirement of 654 MW is sufficient to achieve the reliability target, resulting in diversity benefits equal to 118 MW for Load, 105 MW for Wind, and 23 MW for Non-VERs. The last column of Table 3 shows the regulation requirements for each class that incorporates the proportional allocation of portfolio diversity benefits. The diversity benefits result in a 27 percent reduction from the total standalone requirement of 900 MW.

Table F.5 - Results with PacifiCorp Portfolio Diversity

Scenario	Stand-alone Regulation Forecast (aMW)	Diversity Benefit (aMW)	Portfolio Regulation Forecast (aMW)
Non-VER	83	(23)	60
Load	433	(118)	315
VER - Wind	384	(105)	279
Total	900	(246)	654
Portfolio LOLP (hours/year)	0.03		0.88

EIM Intra-Hour Benefit

In addition to the direct benefits from EIM's increased system visibility and improved intra-hour operational performance described above, the participation of other entities in the broader EIM footprint—such as NV Energy, Puget Sound Energy, and Arizona Public Service Company—provides the opportunity to further reduce the amount of regulation reserve PacifiCorp must hold.

By pooling variability in load, wind, and solar output, EIM entities reduce the quantity of reserve required to meet flexibility needs. The EIM also facilitates procurement of flexible ramping

capacity in the fifteen-minute market to address variability that may occur in the five-minute market. Because variability across different BAAs may happen in opposite directions, the flexible ramping requirement for the entire EIM footprint can be less than the sum of individual BAAs' requirements. This difference is known as the "flexible ramping procurement diversity savings" in the EIM. This intra-hour benefit reflects offsetting variability and lower combined uncertainty. This flexibility reserve is in addition to the spinning and supplemental reserve carried against generation or transmission system contingencies under the NERC standards.

The CAISO calculates the EIM intra-hour benefit by first calculating a flexible reserve requirement for each individual EIM BAA and then by comparing the sum of those requirements to the flexible reserve requirement for the entire EIM area. The latter amount is expected to be less than the sum of the flexible reserve requirements from the individual BAAs due to the portfolio diversification effect of forecasting a larger pool of load and resources using intra-hour scheduling and increased system visibility in the hypothetical, single-BAA EIM. Each EIM BAA is then credited with a share of the intra-hour benefit calculated by CAISO based on its share of the stand-alone requirement relative to the total stand-alone requirement.

The EIM does not relieve participants of their reliability responsibilities. EIM entities are required to have sufficient resources to serve their load on a standalone basis each hour before participating in the EIM. Thus, each EIM participant remains responsible for all reliability obligations. Despite these limitations, EIM imports from other participating BAAs can help balance PacifiCorp's loads and resources within an hour, reducing the size of reserve shortfalls and the likelihood of a Balancing Authority ACE Limit violation. While substantial EIM imports do occur in some hours, it is only appropriate to rely on PacifiCorp's share of the intra-hour benefits associated with EIM, as these are derived from the structure of the EIM rather than resources contributed by other participants.

Under the current EIM operational structure, the calculated EIM intra-hour benefit is not known to PacifiCorp prior to its base schedule submission at T-55. The CAISO does not finalize the intra-hour benefit until T-40, therefore making it too late to incorporate any of the benefit into PacifiCorp's base schedule.

Table F.6 below provides a numeric example of flexible reserve requirements for each EIM participating BAA and application of the calculated intra-hour benefit.

Table F.6 - EIM Flexible Reserve Diversity Benefit Application Example

Interval	CAISO req't. before benefit (MW)	NEVP req't. before benefit (MW)	PACE req't. before benefit (MW)	PACW req't. before benefit (MW)	Total req't. before benefit (MW)	Total req't. after benefit (MW)	Total diversity benefit (MW)	PACE share (%)	PACE benefit (MW)	PACE req't. after benefit (MW)
15-minute Interval 1	550	110	165	100	925	583	342	17.8%	61	104
15-minute Interval 2	600	110	165	100	975	636	339	16.9%	57	108
15-minute Interval 3	650	110	165	110	1,035	689	346	15.9%	55	110
15-minute Interval 4	667	120	180	113	1,080	742	338	16.7%	56	124

While the intra-hour benefit is uncertain, that uncertainty is not significantly different from the uncertainty in the Balancing Authority ACE Limit described above. PacifiCorp proposes crediting its regulation reserve forecast with a probability distribution of calculated EIM intra-hour benefits

based on historical results. When a potential regulation shortfall occurs, the probability that the EIM intra-hour benefit would have exceeded that level can be calculated, and the LOLP associated with that event goes down. As a result, PacifiCorp's regulation reserve requirements can be reduced until the reliability target is again just achieved. While this FRS considers regulation reserve requirements in 2015, the participation of NV Energy in the EIM starting in December 2015 has resulted in increased intra-hour benefits. To capture these additional benefits for this analysis, PacifiCorp has applied the probability distribution of EIM intra-hour benefits from January 2016 through June 2016 because it is a more reasonable representation of actual operations going forward than the 2015 results. Relatively small incremental EIM diversity benefits are expected going forward as additional entities participate in EIM; however, operational data on new participants was not available at the time the study was prepared.

The inclusion of EIM intra-hour benefits in the 2015 regulation reserve analysis reduces the probability of reserve shortfalls and, in doing so, reduces the overall regulation reserve requirement. This allows PacifiCorp's forecasted requirements to be reduced until the PacifiCorp system just achieves the reliability target for the 2015 Study Term. As shown in Table F.7 below, the resulting regulation reserve requirement is 562 MW, a 38 percent reduction (including the portfolio diversity benefit) compared to the stand-alone requirement for each class. The average regulation reserve requirement is reduced by 92 MW relative to the PacifiCorp portfolio reserve requirement without the EIM intra-hour benefit.

Table F.7 - 2015 Results with PacifiCorp Portfolio Diversity and EIM Intra-Hour Benefit

Scenario	Stand-alone Regulation Forecast (aMW)	Stand-alone Rate (%)	Portfolio Regulation Forecast with EIM (aMW)	Portfolio Rate with EIM (%)	2015 Capacity (MW)	Rate Determinant
Non-VER	83	3.7%	52	2.3%	2,228	Nameplate
Load	433	4.4%	271	2.7%	9,852	12 CP
VER - Wind	384	14.8%	240	9.2%	2,588	Nameplate
Total	**900**		**562**			
Portfolio LOLP (hours/year)	0.03		0.88			
Diversity Savings (%)			38%			

Incremental Wind Regulation Reserve Requirements

Since 2015, 153 MW of wind resources have been added to PacifiCorp's system. Furthermore, the IRP portfolio optimization process contemplates the addition of new wind capacity as part of its selection of future resources. As PacifiCorp's portfolio of resources grows, the diversity of that portfolio is also expected to increase. As a result, incremental regulation reserve requirements are expected to be lower than the average requirement for a given portfolio.

The need to develop realistic deviation data for a period during which resources did not exist makes measuring an incremental diversity effect a difficult proposition. Instead, PacifiCorp's FRS evaluated the decremental diversity associated with reducing the size of PacifiCorp's wind portfolio. Removing specific resources produces a similar change in the size of PacifiCorp's

portfolio without requiring the creation of any data points. Specifically, the PacifiCorp system-wide results described above were recalculated using only 90 percent of the available wind resources, by removing approximately 10 percent of the wind capacity from each geographic location.

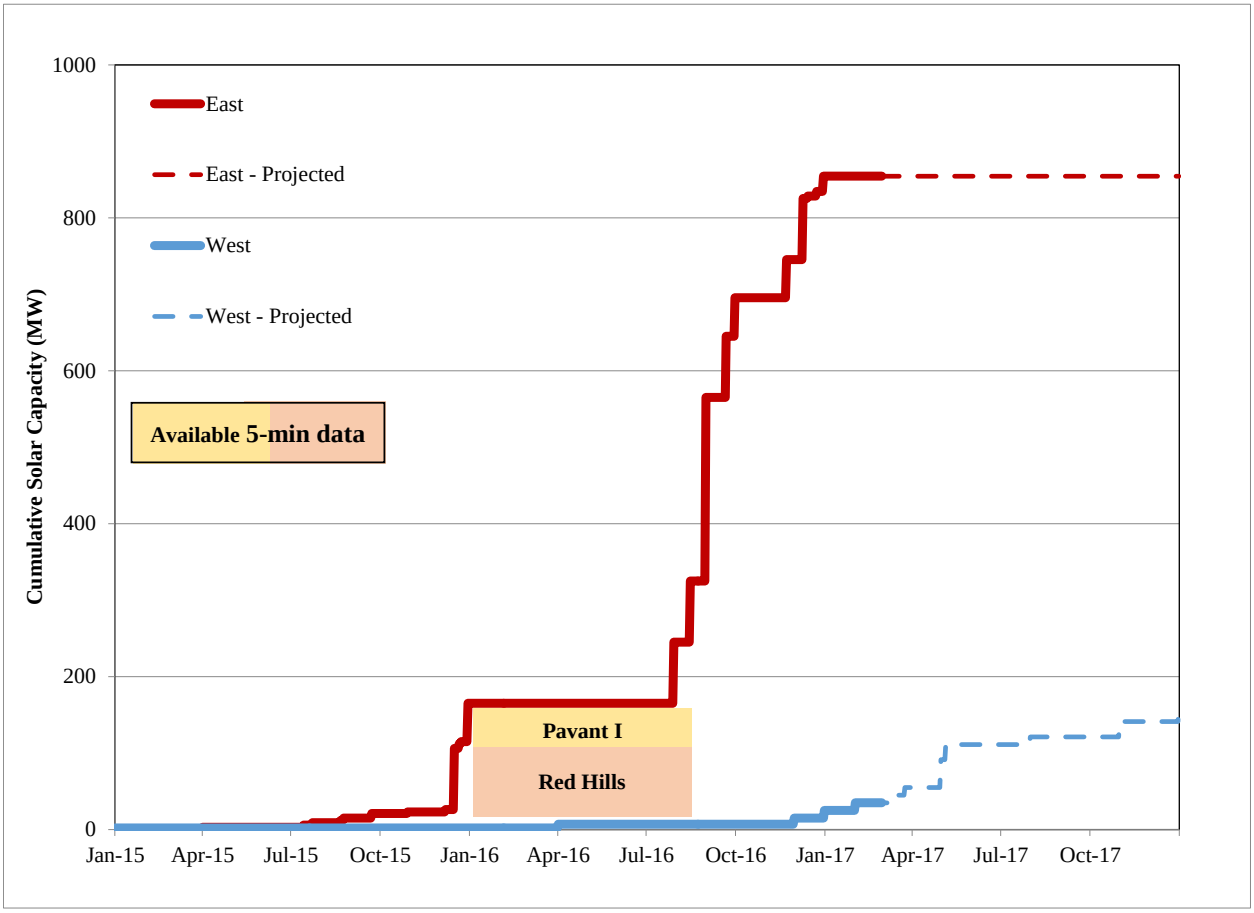
Regulation reserve requirements for PacifiCorp's system-wide portfolio dropped by 6.1percent of the wind capacity removed. This is lower than the average requirement of 9.2 percent in the 2015 portfolio results shown in Table F.7 above. This indicates that diversity is increasing as the pool of requirements increases, as expected. These incremental wind regulation requirement results are incorporated in the forecasted portfolio regulation results discussed later on in the study.

Solar Regulation Reserve Requirements

Overview

At the start of 2015, PacifiCorp had less than three megawatts of utility-scale solar generating capacity on its system. Over the course of 2015, an additional 165 MW was added but the majority was from two large resources which only came online in the second half of December. As shown in Figure F.16, solar capacity has increased rapidly in both PACE and PACW and by the end of 2017 is expected to total over 1,000 MW. Reference Table F.25 on page 64 contains the list of solar resources included in the study. Because solar resources have only recently been added to PacifiCorp's system, the 2015 study period used for the regulation reserve requirements for load, wind, and Non-VERs does not have data suitable predict current and future solar regulation reserve requirements.

Figure F.16 - Solar Capacity Additions



Five-minute solar data was collected from PacifiCorp's Ranger PI system for Jan. 1, 2016 through Aug. 23rd, 2016 for two large solar resources in southern Utah totaling 130 MW.[26] PacifiCorp's solar forecast service provider, DNV GL, provided generation forecasts for these resources during this timeframe, which were submitted to EIM. While EIM deviation data is available for a portion of this period, certain meteorological monitoring equipment was not in place for the entire timeframe, and the limited availability of historical results are expected to make the forecasts for these resources less accurate than what will be possible going forward. Instead, proxy solar base schedules were developed for these two resources, as described in the next section. To make the results easier to compare and apply elsewhere, the actual output of the resources was normalized by their capacity. The calculations described below were all carried out on a capacity factor basis.

Proxy Solar Base Schedule Development

Solar resource output is primarily a function of two attributes: the position of the sun, and the amount of cloud cover. The position of the sun is comparable from day to day at a given time, though over the course of weeks it changes by meaningful amounts. To estimate the maximum possible output for a particular date and time, the maximum output at that time from two weeks prior to two weeks following is calculated. The four week span helps ensure that at least one data point is likely to have very little cloud cover and maximum output, while limiting the effect of

[26] Pavant I, 50 MW and Utah Red Hills, 80 MW.

seasonal changes in the position of the sun. Identifying the maximum possible output for each interval allows the forecast to account for changes in output as the sun rises and sets. The following calculations were carried out independently for the two solar resources.

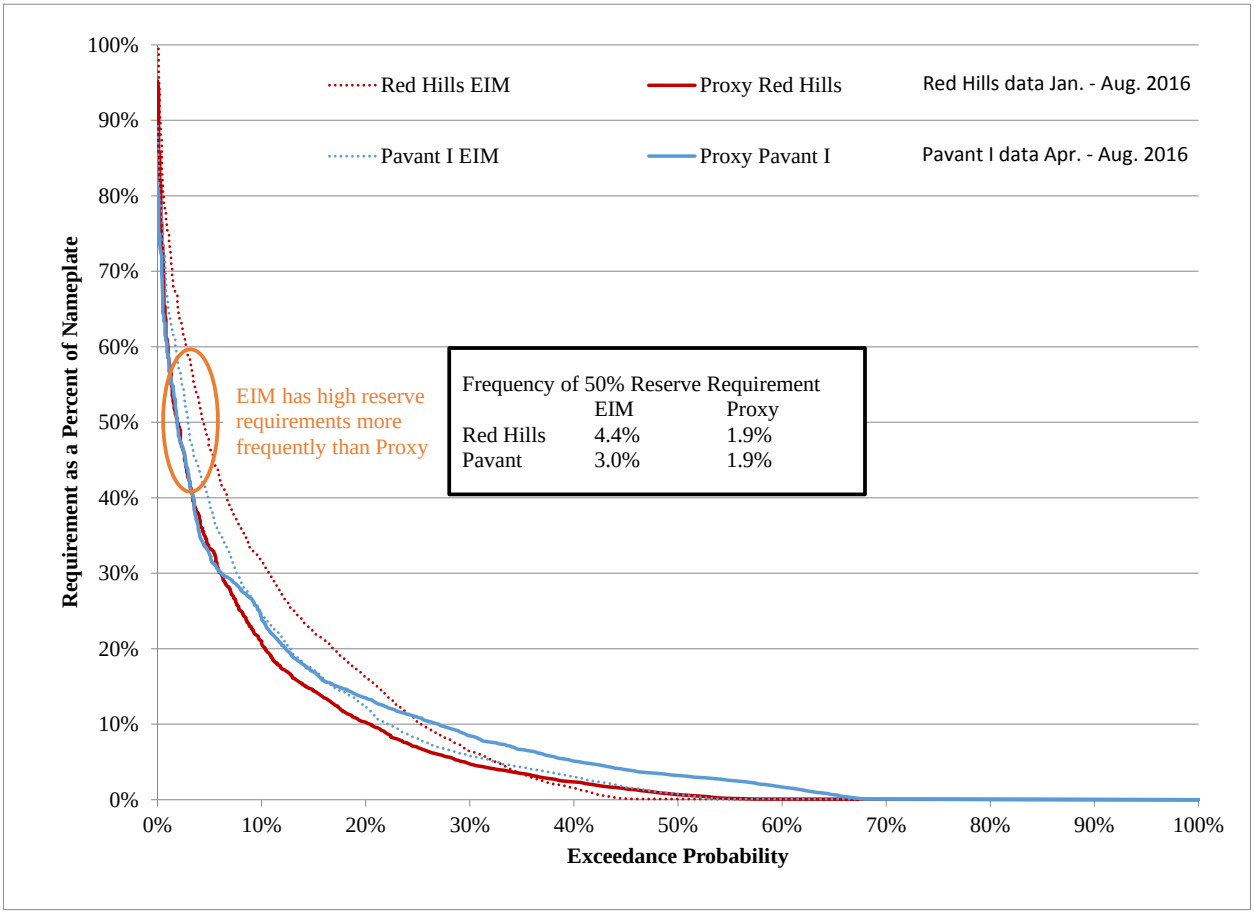
To estimate the amount of cloud cover, the solar availability is calculated by dividing the actual output in each five-minute interval by the maximum output for that interval, as identified above. This removes the effect of the position of the sun, and the changes that remain should primarily be primarily associated with cloud cover. From day to day, cloud cover is expected to vary widely, but from T-55 when the solar resource forecast is submitted as an hourly base schedule to EIM through the course of that upcoming hour, it is reasonable to assume the prevailing cloud conditions will continue. To improve further upon the cloud cover forecast using the available data, the trend in cloud conditions leading up to the time of forecast submission was also accounted for. If it is less cloudy at T-55 than it was twenty minutes earlier, that trend is also extrapolated forward to the forecast period. The weighting of the trend versus the final measurement before the forecast is submitted was set to maximize the correlation between the actual solar output and the forecasted hourly base schedule, i.e. to produce the best achievable forecast. Due to the absence of generation output, cloud cover can't be estimated from intervals prior to sunrise, so the forecasted output during the first hours after sunrise is set at the monthly average for those intervals.

The proxy solar base schedules incorporate cloud cover data and solar position data as follows. The cloud cover measurement is the primary component in the forecast for the upcoming hour. The cloud cover trend over the preceding intervals, and the cloud cover in the last interval are locked in at the values measured just prior to base schedule submission. On the other hand the position of the sun, embedded in the maximum output for each interval, is assumed to be fixed and known in advance. The base schedule submission looks forward in time to the forecast hour and incorporate the expected solar position changes over each five-minute interval in the hour.

While the forecast is created with a five-minute granularity, the base schedule submission to EIM at T-55 reflects an hourly average value in accordance with EIM operating procedures. The difference between this hourly average and the five-minute actual resource output (i.e. the original source data) is the deviation of the solar resource. Once base schedule and deviation data were prepared for the two solar resources, those deviations were applied in the same template used to calculate hourly regulation reserve requirements for load, wind, and Non-VERs, including the base schedule ramping adjustment described previously. This identifies the minimum hourly regulation reserve needed to guarantee compliance with BAL-001-2 with the resource in question viewed in isolation.

As shown in Figure F.17, the proxy solar forecasts have less frequent large deviations, and thus produce fewer instances of large regulation reserve requirements than the available EIM deviation data from the same period. Note that while Pavant I become operational in 2015, EIM deviations only became available starting April 1, 2016. For comparability, the proxy and EIM results for each generator are shown for the overlapping time period only. Regulation reserve requirements in excess of approximately 15 percent of nameplate capacity occurred more frequently in the EIM data than the proxy data. Because the largest errors are most likely to cause a BAAL violation, they drive the majority of the reserve requirement. Future results will show whether the forecast accuracy that can be achieved in actual practice is higher or lower than that in the proxy data used in this analysis.

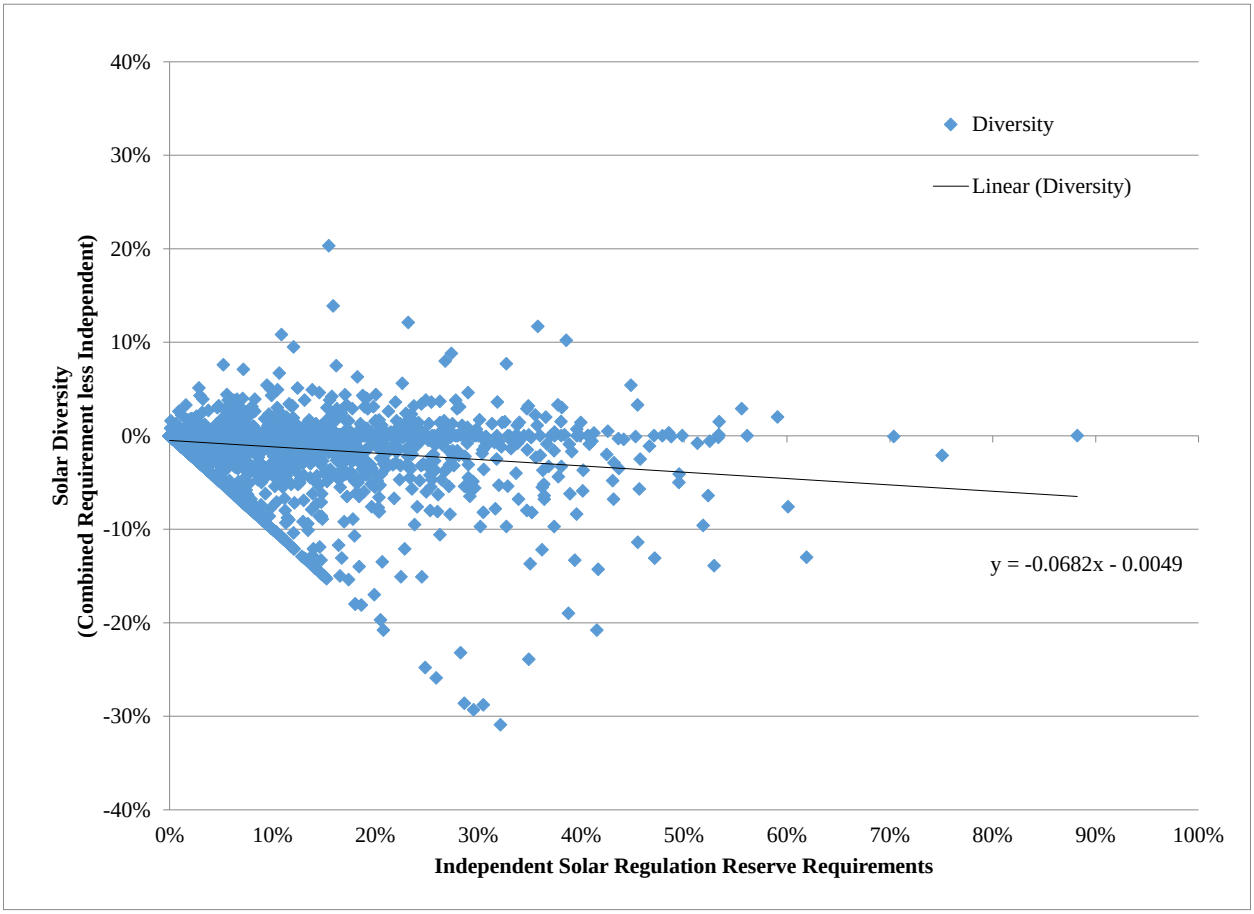
Figure F.17 - Solar Regulation Reserve Requirements: Proxy vs EIM



Solar Diversity

When the hourly regulation reserve requirements of the two solar resources are measured independently, as described above, the results do not capture any of the potential for diversity in the intra-hour requirements. To identify the potential diversity between the two solar resources, the average of their base schedules and actual output was used in the hourly regulation reserve calculation. The difference between the requirements when measured independently and the requirements when measured in aggregate is the result of diversity. The results of this diversity measurement are shown in Figure F.18.

Figure F.18 - Solar Diversity



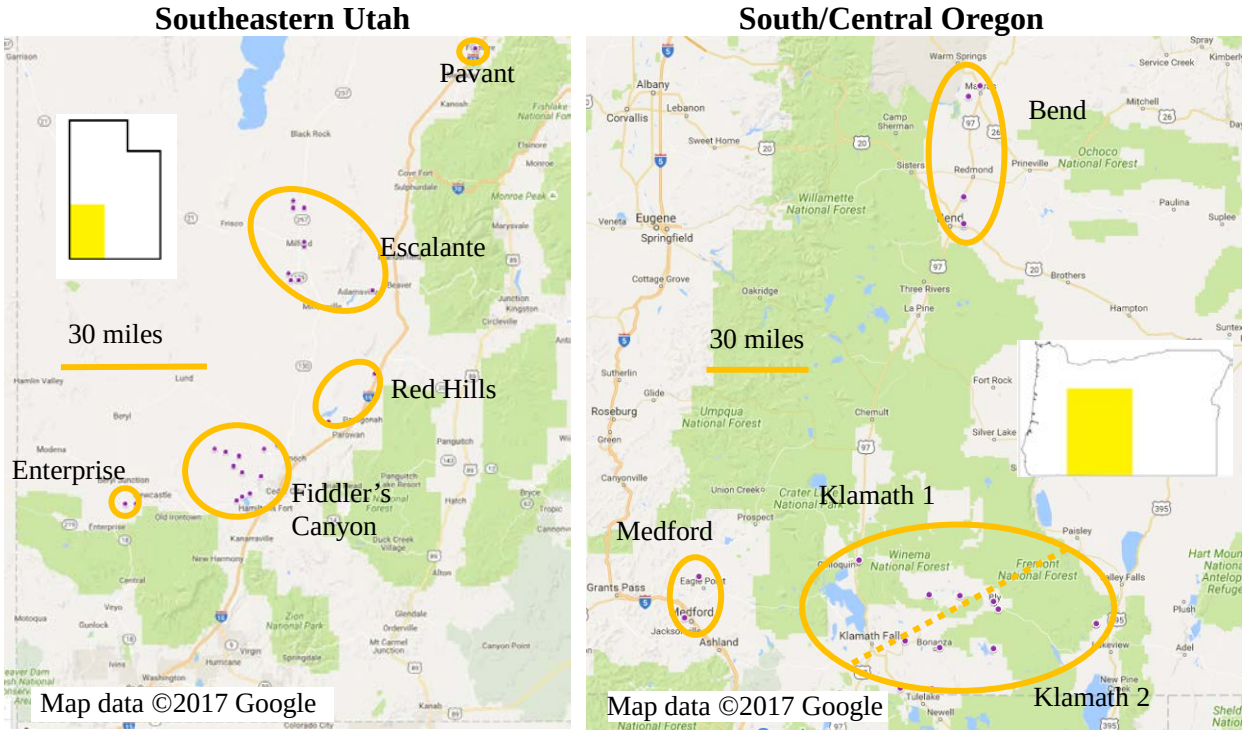
As shown in Figure F.18, diversity is not guaranteed to reduce hourly regulation reserve requirements. While this is not intuitive, it is a direct result of the 30 minute maximum time limit for deviations under BAL-001-2. If two resources each have deviations that are only 20 minutes long, the regulation reserve requirement is zero. If the deviations both started at the same time, then viewed together they will overlap perfectly, and the length of the deviation remains just 20 minutes with a regulation reserve requirement of zero. However, if one resource's deviation starts 15 minutes earlier than the other, the length of the aggregate deviation will be 35 minutes, and the regulation reserve requirement will be greater than zero to ensure compliance with BAL-001-2.

Despite the potential for increased aggregate requirements in some instances, on average the aggregate requirements are lower as a result of diversity. Because the regulation requirements are bounded by zero, the diversity benefit is limited to the size of the independent requirement. As a result, the diversity benefits increase as the independent requirements increase.

Solar Locations

The solar facilities on PacifiCorp's system are concentrated in southeastern Utah and southern and central Oregon. As shown in Figure F.19, within these areas multiple facilities are also clustered within relatively close proximity. Five clusters were identified in Utah, while three were identified in Oregon. Because one of the Oregon clusters is relatively dispersed, it is treated as two independent clusters.

Figure F.19 - Solar Resource Locations



While all of the clusters identified are in close enough proximity to experience most of the same passing weather systems, different clusters experience different cloud cover at the time of forecast submission, and different cloud cover over the course of the operating hour. These differences are in turn reflected in their actual output and deviations. On the other hand, due to their proximity, facilities within a given cluster are expected to reflect more closely-related weather conditions in their forecasts and deviations. As a result, the aggregate capacity within a given cluster is not expected to experience offsetting deviations, i.e. diversity benefits, whereas the effect of capacity spread among multiple clusters should create opportunities for offsetting deviations.

The IRP is focused not just on regulation reserve requirements for existing solar resources, but also on the requirements associated with incremental solar resources added in the future. Tables F.8 and F.9 present the solar capacity on PacifiCorp's system in three scenarios. The base scenario reflects the contracted solar resources scheduled to be online in 2017, while two incremental scenarios reflect the addition of 500 MW and 1000 MW of new solar resources. The incremental solar capacity is split between the PACE and PACW BAAs, and among existing and new clusters.

Table F.8 - East Solar Clusters by Scenario

East Cluster	Base	Incr. Solar 1	Incr. Solar 2
Enterprise	83	+17	+17
Fiddler's Canyon	311	+62	+62
Escalante	257	+51	+51
Red Hills	83	+17	+17
Pavant	120	+24	+24
New Cluster 1		+229	
New Cluster 2			+229
Total	**855**	**1,255**	**1,655**
% Change vs Base		47%	94%

Table F.9 - West Solar Clusters by Scenario

West Cluster	Base	Incr. Solar 1	Incr. Solar 2
Bend	50	+31	+6
Medford	20	+12	+2
Klamath 1	47	+29	+6
Klamath 2	47	+29	+6
New Cluster 1			+80
Total	**163**	**263**	**363**
% Change vs Base		61%	123%

Solar Portfolio Data

Red Hills and Pavant have proxy base schedules, hourly regulation reserve requirements, and diversity based on actual generation. It is reasonable to assume other solar resources within those two clusters would experience comparable conditions and results. Therefore, the Red Hills and Pavant results are scaled up to reflect any additional capacity within the cluster.

At the time the study was prepared, actual data for the other clusters in PACE and all of the clusters in PACW was unavailable. While the varying geographic locations of these clusters impact the timing of weather conditions, they are all relatively sunny locations, and it is reasonable to assume that the likelihood of over-forecasting resource output, resulting in a regulation reserve requirement, is similar in all of the clusters. With this in mind, all of the hourly regulation reserve requirements for Red Hills and Pavant (measured independently) were taken as a single data set and hourly regulation reserve requirements for the other clusters were assigned randomly from this distribution. While the resulting hourly regulation reserve requirements vary from 0 percent to 95 percent of the solar nameplate capacity, 18.7 percent of the regulation reserve requirements are zero, and half of the regulation reserve requirements are less than 2 percent of the solar nameplate. Despite being predominantly random, there is a relatively small positive correlation (+0.2638) between the hourly regulation reserve requirements for Red Hills and Pavant. This may reflect weather conditions that occur at the same time over a broad area, such as afternoon thundercloud formation, rather than as a result of passing weather fronts. This relationship is assumed to be real effect and is reflected in each of the calculated clusters by blending a random regulation requirement and the simultaneous requirement for one of the two source clusters. The weighting

of the blend was set such that the average correlation between the new clusters and the existing clusters matches the correlation measured between the existing clusters.

Because the hourly regulation reserve requirements described above reflect the independent regulation reserve requirements for Red Hills and Pavant, they do not capture the diversity between different clusters of solar resources. As discussed above, diversity is partly a linear function of the independent hourly regulation reserve requirements – the greater the requirement, the greater the diversity credit. However, much of the variation in diversity values appears to be unpredictable, i.e. largely random. In a similar manner to the regulation reserve requirements described above, the diversity results for Red Hills and Pavant were taken as a single data set and assigned randomly to each of the clusters. A weighted average diversity value was then calculated that takes into account the number of clusters since diversity requires two or more. In addition, because diversity benefits are bounded by a zero regulation reserve requirement, they may be truncated in manner that under-represents the potential diversity available. Instances when diversity leads to higher requirements are not bounded in this manner in the sample. With more than two clusters, it may be possible to utilize additional diversity benefits before hitting the zero bound. To help reflect this, whenever the sampled diversity components indicated an increase in requirements, the increase was reduced by half.

The random assignment of regulation reserve requirements described above disregards the hour of the day, and can overstate requirements when little output is expected such as during the morning ramp. To compensate, the aggregate regulation reserve requirements are reduced during the morning ramp to align with the requirements seen for Pavant and Red Hills.

Solar Regulation Reserve Forecast

The solar regulation reserve forecast is comparable to that developed for wind, representing a fixed percentage of the solar nameplate capacity, but never more than the maximum output in that hour, including a portion of the ramp up across the hour in the morning and down across the hour in the afternoon. The fixed percentage of nameplate capacity is set at the minimum level that achieves the reliability target of 0.88 loss of load hours per year. The reserve requirement necessary to achieve the reliability target varies in PACE and PACW, and with changes in total solar capacity.

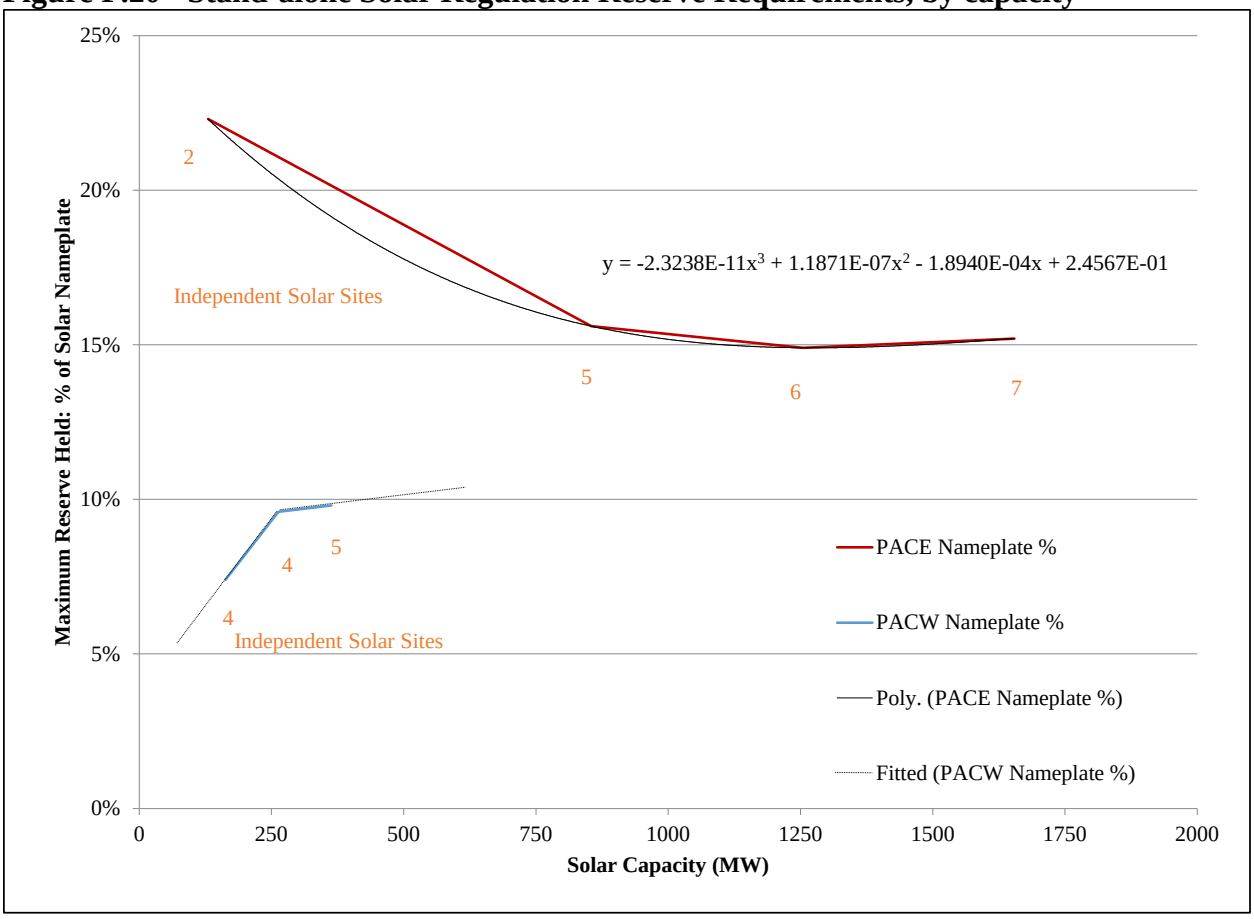
The results of the solar regulation requirements in the various scenarios is shown in Table F.10 below, with the wind results shown for comparison. Note that while the fixed percentage of nameplate capacity (i.e. the maximum reserve held) for solar and wind in PACE is similar, ranging from 14.9 percent to 18.6 percent of nameplate capacity, the average requirement for solar is significantly lower than that for wind. This is because solar output is zero for half of the hours in the year, whereas PACE wind output drops below the maximum reserve held infrequently. PACW wind output is more strongly correlated and drops to zero more frequently than PACE wind.

Table F.10 - Solar and Wind Stand-alone Regulation Requirements, as Percentage of Nameplate Capacity

Scenario	Average Reserve Held		Max Reserve Held	
	East	West	East	West
No Solar	12.3%	n/a	22.3%	n/a
Base Solar	8.8%	4.2%	15.6%	7.4%
Incr. Solar 1	8.5%	5.3%	14.9%	9.6%
Incr. Solar 2	8.6%	5.4%	15.2%	9.8%
90% Wind	15.1%	15.8%	18.6%	32.3%
Base Wind	14.6%	15.2%	17.8%	29.8%

For solar, the fixed percentage of nameplate in the reserve requirement calculation varies with the size of the solar capacity. There are two offsetting trends related to increasing solar capacity. First, more diverse solar resources (i.e. more clusters) have lower requirements, but the incremental benefit declines as more diversity is added. Second, spreading the fixed allowable BAAL variation across more capacity increases requirements, and the incremental impact increases as capacity increases. Figure F.20 shows these relationships as well as fitted curves used to project the solar regulation reserve requirements as a function of capacity for PACE and PACW. The solar regulation reserve requirement in PACE is assumed to be related to capacity using a third-order polynomial. The solar regulation reserve requirement in PACW is assumed to be related to capacity using two linear extrapolations.

Figure F.20 - Stand-alone Solar Regulation Reserve Requirements, by capacity



Portfolio Regulation Reserve Requirements

Overview

A single pool of regulation reserve is held to cover deviations by load, wind, solar, and non-dispatchable generation. Simultaneous large deviations by all classes are unlikely – as a result, this pool of regulation reserve can be smaller than what these classes would require on their own. The reduction in regulation reserve is a result of the diversity of the portfolio of requirements. While the diversity of load, wind, and Non-VER generation was measured using 2015 data, the solar deviations are from 2016 and are extrapolated from a very limited sample. As such, it is not currently possible to measure the diversity of the PacifiCorp system, inclusive of requirements for solar. Instead, several characteristics of the diversity of PacifiCorp's system were used to produce an estimate of the relationship between the amount of diversity and the portfolio of regulation requirements. These characteristics are discussed below.

Methodology

The most important element in PacifiCorp's portfolio diversity estimate is the system diversity, including EIM benefits, associated with load, wind, and Non-VERs during 2015. The diversity in the 2015 portfolio reduced reserve requirements by 37.51 percent. This captures the vast majority of the regulation reserve requirements both today and in likely future scenarios over the near term. For example, approximately 1000 MW of solar capacity is expected to be on the PacifiCorp system in 2017, and no solar was included in the 2015 results. However, this additional solar increases the stand-alone regulation reserve requirement (before accounting for diversity) by less than 10 percent. Since diversity only occurs in intervals when two or more regulation reserve requirements exist, changes in diversity in 10 percent of the intervals will have relatively limited effects.

In a portfolio without solar capacity, incremental wind generation was calculated to have reserve requirements of 6.1 percent of nameplate, after accounting for portfolio diversity, compared to an average requirement of 9.2 percent for the entire wind fleet. Much of the benefits are captured within the wind class – its stand-alone requirements increase by a limited amount; however, the diversity of the entire portfolio increases slightly when the reserve requirements for the incremental wind are added. This relationship between stand-alone reserve requirements and portfolio diversity is assumed to be linear - a small increase in diversity as the reserve requirements of the existing classes grows.

As a starting point, solar regulation reserve requirements are assumed to create equivalent amounts of diversity as the components of the pre-solar portfolio, including the linear increase as requirements grow. In addition, incremental diversity as a result of solar is assumed to occur in relation to the size of the stand-alone solar regulation requirements. When the solar requirements are equivalent in size to the requirements for load, wind, and Non-VERs, the incremental diversity benefits are assumed to be maximized at 20 percent of the solar requirement. At lower levels of solar requirements (i.e. for less solar capacity), the incremental diversity benefits are smaller and are assumed to proportional to the size of the solar requirements relative to the other regulation requirements. With four categories of requirements (load, wind, solar, Non-VER), solar requirements would need to be 25 percent of the total to achieve the maximum level of diversity. In the base scenario, solar requirements are 81 MW out of 998 MW total, and result in incremental

diversity benefits of 5.3 MW, on top of approximately 30 MW of benefits based on the diversity in the pre-solar portfolio.[27]

Based on the above, hourly regulation requirements for PACE and PACW are calculated as a function of: wind and solar nameplate capacity, forecasted wind output and month/hour as a proxy for expected solar output, and static hourly regulation reserve requirements for load and non-VER generation. Diversity is a function of the total requirements and is calculated dynamically as described above.

Results

Table F.11 presents the portfolio regulation requirement results from the various scenarios described above. As the wind and solar capacity on PacifiCorp's system increases, regulation requirements increase, but those requirements are partially offset by the increasing diversity of the portfolio. The 2017 Base Case regulation reserve requirements are 617 MW. By comparison, PacifiCorp's 2014 Wind Integration Study identified requirements of 626 MW for a smaller amount of wind, and without any requirements for solar or Non-VERs.

Table F.11 - Portfolio Regulation Requirement Results, by Scenario

Scenario	Wind capacity (MW)	Solar capacity (MW)	Stand-alone regulation requirement (MW)	Portfolio diversity credit (%)	Regulation requirement with diversity (MW)
2014 WIS	2,543	n/a	n/a	n/a	626
2015 (No Solar)	2,588	0	900	37.5%	562
2017 Base Case	2,757	1,050	998	38.2%	617
Incremental Wind	3,007	1,050	1,023	38.3%	631
Incremental Solar 1	2,757	1,550	1,033	38.6%	635
Incremental Solar 2	2,757	2,050	1,074	39.2%	653

There are a significant number of changes between the PacifiCorp's 2014 Wind Integration Study and the current study. First, the specific requirements of the BAL-001-2 standard are being applied, as previously discussed. Second, the updated requirements are based on an expanded portfolio of resources, including solar, Non-VERs, and additional wind capacity. Finally, diversity benefits are now shared among all requirements, rather than being allocated solely to wind resources as was done in the 2014 Study. Table F.12 presents a comparison of the regulation reserve requirement results in the current study and prior studies.

[27] 81 MW solar requirement / (998 MW total requirement / 4 classes) * 20% incremental diversity = 5.3 MW.

81 MW solar requirement * 37.6% pre-solar portfolio diversity = ~30 MW

Table F.12 - Portfolio Regulation Requirement Results, Percent of Nameplate Capacity

Study	Load	Wind	Non-VER	Solar	Method
2012 WIS: 2011	4.0%	8.7%	n/a	n/a	Load -> Incr Wind
2014 WIS: 2012	4.1%	8.1%	n/a	n/a	Load -> Incr Wind
2014 WIS: 2013	4.5%	7.3%	n/a	n/a	Load -> Incr Wind
2016 FRS	2.8%	8.9%	2.4%	4.6%	Portfolio Diversity (Base)
2016 FRS	n/a	5.8%	n/a	n/a	Base -> Incr Wind
2016 FRS	n/a	n/a	n/a	3.6%	Base -> Incr Solar 1
2016 FRS	n/a	n/a	n/a	3.8%	Incr Solar 1 -> Incr Solar 2

The 2012 and 2014 Wind Integration Studies calculated the regulation reserve requirement for load only, then the incremental requirement for the entire wind fleet, allocating all diversity to wind. The FRS calculates the regulation reserve requirement for the 2017 resource mix, allocating the diversity among all components. As compared to prior studies, the diversity allocation decreases the load requirement and increases the wind requirement, the changes in standards and methodology notwithstanding. In an additional step, the FRS also calculates incremental requirements for wind and solar which are more closely aligned with the obligations resulting from new resource additions contemplated in the IRP. While these requirements are lower than the average requirements in the base case, they will call on higher cost resources, as the least-cost regulation reserve resources are dispatched first. The cost of the regulation reserve obligation is discussed in more detail in the next section.

Regulation Reserve Cost

A series of PaR scenarios were prepared to isolate the regulation reserve cost associated with wind and solar generation. The scenarios are shown in Table F.13. These scenarios were based on 2017 and included the existing resources in the 2015 IRP Update. In the 2014 Wind Integration Study reserve requirements were modeled on both an hourly and monthly basis to reflect the timing differences of reserve requirements. While the requirements are calculated on an hourly basis, due to difficulties incorporating those requirements in the PaR model at that granularity, monthly requirements were used to calculate regulation reserve costs discussed herein. Where possible, it is recommended that hourly regulation requirements be modeled that are consistent with the resource capacity and generation profiles of the specific portfolio under evaluation.

Table F.13 - Regulation Reserve PaR Scenarios

#	Scenario	Resources	Regulation requirement
B.1	Base No Reserve	1/1/17 wind and solar	None
B.2	Base With Reserve	1/1/17 wind and solar	1/1/17 wind and solar
W.1	Incr. Wind, Base Reserve	Study B.2 + 250MW wind	1/1/17 wind and solar
W.2	Incr. Wind + Reserve	Study B.2 + 250MW wind	1/1/17 wind and solar + 250MW wind
S1.1	Incr. Solar 1, Base Reserve	Study B.2 + 500MW solar	1/1/17 wind and solar
S1.2	Incr. Solar 1 + Reserve	Study B.2 + 500MW solar	1/1/17 wind and solar + 500MW solar
S2.1	Incr. Solar 2, Base Reserve	Study B.2 + 1000MW solar	1/1/17 wind and solar
S2.2	Incr. Solar 2 + Reserve	Study B.2 + 1000MW solar	1/1/17 wind and solar + 1000MW solar

The regulation reserve cost results are shown in Table F.14. The 2014 Wind Integration Study identified regulation reserve costs for wind generation of $2.35/MWh. This value measured the incremental cost when regulation reserve for the existing wind fleet were added to the regulation reserve for load. The most comparable wind reserve cost from the FRS is $0.30/MWh. This represents the cost of the regulation reserve for existing wind, load, solar, and Non-VERs, relative to a scenario with no regulation reserve. The result is adjusted to account for the wind regulation reserve requirement relative to the total regulation reserve requirement.

Table F.14 - Regulation Reserve Cost Calculations

#	Value	Calculation	Units	Results
a	Base regulation reserve cost	[Study B.2] - [Study B.1]	$	5,936,990
b	Wind reserve requirement	[Wind req.] / [Total req.]	%	40%
c	Wind generation	[Study B.1]	MWh	7,802,061
	Base wind reserve rate	**[a] x [b] / [c]**	**$/MWh**	**$0.30**
a'	Incremental regulation reserve cost	[Study W.2] - [Study W.1]	$	$389,890
b'	Incremental wind generation	[Study W.1] - [Study B.1]	MWh	909,050
	Incremental wind reserve rate	**[a'] / [b']**	**$/MWh**	**$0.43**
a''	Incremental regulation reserve cost	[Study S2.2] - [Study S2.1]	$	$1,221,610
b''	Incremental solar generation	[Study S2.1] - [Study B.1]	MWh	2,667,200
	Incremental solar reserve rate	**[a''] / [b'']**	**$/MWh**	**$0.46**

The change in regulation reserve costs is primarily attributable to the following factors: lower market prices, transmission congestion, and 30-minute regulation reserve capability. Assuming sufficient regulating capability is available within PacifiCorp's portfolio, the cost of regulation reserve reflects the lost margin on resources that can provide the service, i.e. the difference between the market price or alternative generation cost and their fuel cost. Since the prior study, market prices have declined, which reduces this margin, and a 10 percent drop in market price can reduce the margin by more than 10 percent. In addition, transmission congestion has increased, primarily as a result of substantial additions of solar, which has reduced the ability of resources to get to market. If regulation-capable resources are already backed down due to transmission congestion there is no additional cost to count that capacity as regulation reserve. Finally, in the prior study the entire regulation reserve requirement was included in the spinning reserve category, which is limited to capacity available within 10 minutes. The FRS assumes that dispatchable capacity available within 30-minutes can be counted toward the regulation reserve requirement. This increases the supply of regulation resources and reduces costs when 30-minute capacity from the unit with the lowest-cost reserve can be used instead of being limited to only the 10-minute capacity of that unit.

While the Base wind reserve rate is helpful for comparison with the 2014 Wind Integration Study, it is not representative of the incremental cost of regulation reserve for new wind resources. Instead, PacifiCorp's FRS calculates regulation reserve requirements specific to the incremental resource additions contemplated in the IRP. As shown in Table F.14 above, the addition of 250 MW of wind capacity results in incremental regulation reserve costs of $0.43/MWh, while the addition of 1000 MW of solar capacity results in incremental regulation reserve costs of $0.46/MWh. It should be noted that the difference in reserve costs for wind and solar reflects timing differences. Per MWh of generation, the wind reserve obligation is 16 percent higher than

the solar obligation; however, the solar obligation is higher during the summer and during the day, when market prices and marginal reserve costs are higher.

While incremental reserve costs generally increase with volume, the 500 MW solar scenario had a slightly higher cost than the 1000 MW scenario, likely due to lower transmission congestion. For simplicity, the 1000 MW result was used where a specific dollar value was required in the IRP. The 2017 FRS results are applied in the 2017 IRP portfolio development process as a cost for wind and solar generation resources. Once candidate resource portfolios are developed using the SO model, the PaR model is used to evaluate portfolio risks. The PaR model inputs include regulation reserve requirements specific to the resource portfolio developed using the SO model. As a result, the IRP risk analysis using PaR includes the impact of differences in regulation reserve requirements between portfolios. Ideally, the hourly regulation reserve requirements should be used to determine costs specific to the requirements of the resource and portfolio under consideration. This ensures regulation reserve costs reflect changes in market prices and fuel costs, transmission congestion, and regulation reserve capability relative to the IRP analysis. The corollary of a more accurate estimate of incremental regulation reserve cost is a more accurate estimate of the value of resources that supply regulation reserve, including energy storage and direct load control.

Day-ahead System Balancing Costs

In addition to using PaR for evaluating operating reserve cost, the PaR model is also used to estimate the costs associated with daily system balancing activities. These system balancing costs result from the unpredictable nature of load and wind generation on a day-ahead basis and can be characterized as system costs borne from committing generation resources against a forecast of load and wind generation and then dispatching generation resources under actual load and wind conditions as they occur in real time. The methodology is comparable to that used in the 2014 Wind Integration Study, with modifications to account for solar and the allocation of costs between load, wind, and solar.

The PaR model simulates production costs of a system by committing and dispatching resources to meet system load. For this study, PacifiCorp developed nine different PaR simulations as summarized in Table F.15. These simulations isolate the system balancing costs of load, wind, and solar, plus the system balancing costs of the overall portfolio. These simulations were run assuming operation in the 2017 calendar year, applying 2015 load, wind, and solar data collected from PacifiCorp's wind forecast service provider, DNV GL. This calculation method combines the benefits of using actual system data with current forward price curves pertinent to calculating the costs for wind integration service on a forward basis, as well as the current resource portfolio.[28] PacifiCorp resources used in the simulations are based upon its existing resource portfolio.

[28] The Study uses the October 12, 2016 official forward price curve (OFPC).

Table F.15 - System Balancing Cost Simulations in PaR

#	Load	Wind profile	Solar profile	Commitment	Day-ahead forecast error
1	Day-ahead	Day-ahead	Day-ahead	Study 1	n/a
2	Actual	Actual	Actual	Study 2	None
3	Actual	Actual	Actual	***Study 1***	For Load/Wind/Solar
4	Day-ahead	Actual	Actual	Study 4	n/a
5	Actual	Day-ahead	Actual	Study 5	n/a
6	Actual	Actual	Day-ahead	Study 6	n/a
7	Actual	Actual	Actual	***Study 4***	For Load
8	Actual	Actual	Actual	***Study 5***	For Wind
9	Actual	Actual	Actual	***Study 6***	For Solar

Simulation 1 identifies the unit commitment using day-ahead forecasts of load, wind, and solar. Simulation 2 identifies the unit commitment using actual load, wind, and solar, and represents the optimal dispatch of the system. Simulation 3 uses the unit commitment from Simulation 1, along with the actual load, wind, and solar from Simulation 2. Since Simulation 2 and 3 both have identical load, wind, and solar, differences between them are solely due to unit commitment and Simulation 3 represents the achievable optimization of unit commitment using the information available on a day-ahead basis when unit commitment occurs. The difference in cost between Simulation 3 and Simulation 2 is the system balancing cost associated with changes between day-ahead load, wind, and solar forecasts and actual output.

Simulations 4-9 isolate the total day-ahead forecast cost of the individual components. Simulations 4-6 each calculate unit commitment using one day-ahead forecast and two actual results. Simulations 7-9 calculate the costs of those day-ahead unit commitment decisions under actual output. The relative costs of Simulations 7-9 are used to determine the relative allocation of the portfolio among the individual components. The simulation results and day-ahead balancing cost for each category is shown in Table F.16.

Table F.16 - Day-ahead Forecast System Balancing Cost Results

#	Value	Cost calculation	Cost ($)	Diversity calculation	Rate w/ diversity ($/MWh)
a	Total Combined	[Study 3] - [Study 2]	$6,208,760		
b	Load Only	[Study 7] - [Study 2]	$6,132,860	[b] * ([a] / [e]) / [Actual Load MWh]	**$0.09**
c	Wind Only	[Study 8] - [Study 2]	$1,053,530	[c] * ([a] / [e]) / [Actual Wind MWh]	**$0.14**
d	Solar Only	[Adjusted]	$31,111	[Set equal to wind result]	**$0.14**
e	Total One-off	[b] + [c] + [d]	$7,217,501		

As indicated in the Regulation Reserve section above, the actual solar on PacifiCorp's system in 2015 was very limited, and the available solar generation averages just 21 megawatts, or roughly 3 percent of the available wind generation. Because unit commitment changes have low granularity (a unit is either on or off), small differences can sometimes have a large effect, and this appears to be the case for the solar results, which were far out of proportion with the measured volumes. In light of the limited solar data set, it is unlikely those results would scale up to the current level of solar on PacifiCorp's system. In light of this, the day-ahead forecast cost for solar

generation has been reduced to the level calculated for wind generation.[29]

Table F.16 above has been modified from what was presented in the 2014 Wind Integration Study. In that study, day-ahead system balancing costs associated with load were calculated first, and incremental day-ahead system balancing costs associated with wind were calculated second. In this analysis, the total day-ahead system balancing costs are calculated for the portfolio and are allocated among the components based on their individual contributions. This attributes diversity in the requirements to all of the components and avoids differences related to the order the studies are conducted. A comparison of the day-ahead system balancing costs in the FRS and 2014 Wind Integration Study is shown in Table F.17.

Table F.17 - Day-Ahead System Balancing Cost Comparison

	2014 WIS (2014$/MWh)	2017 FRS (2016$/MWh)
Load	$0.01	$0.09
Wind	$0.71	$0.14
Solar	n/a	$0.14

The increase in the day-ahead system balancing costs associated with load do not appear to be a result of the portfolio allocation methodology, as load was previously calculated on a stand-alone basis, and the portfolio adjustment reduces the stand-alone day-ahead system balancing costs by 14 percent. Instead the difference appears to be related to market prices and the composition of the PacifiCorp's system. Market prices influence the relative costs of PacifiCorp's gas resources and determine how close they are to being economic or uneconomic. Resources generally only are faced with commitment changes when they have low margins. Because falling market prices have reduced margins, this occurs more frequently. In addition, transmission congestion has reduced the ability of resources to get to market. When resources are committed in anticipation of high load or low resources, there may not be sufficient transmission to get them to market if load is lower than expected or resources are higher. The costs of backing down economic resources due to transmission constraints is higher than the cost of forgone market sales, and thus contributes to higher day-ahead system balancing costs.

Technical Review Committee

As was done for its prior Wind Integration Studies, PacifiCorp engaged a Technical Review Committee (TRC) to review the study results from the FRS. PacifiCorp thanks each of the TRC members, identified below, for their participation and professional feedback. The members of the TRC are:

- **Andrea Coon** - Director, Western Renewable Energy Generation Information System (WREGIS) for the Western Electricity Coordinating Council (WECC)
- **Michael Milligan** - Principal Analyst at the National Renewable Energy Laboratory (NREL)
- **J. Charles Smith** - Executive Director, Utility Variable-Generation Integration Group (UVIG)

[29] The calculated Solar Only Day-Ahead Forecast Cost, [Study 9] – [Study 2], was $805k, or over $4/MWh.

- **Robert Zavadil** - Executive Vice President, EnerNex LLC

In its technical review[30] of PacifiCorp's FRS, the TRC provided comments and questions on specific aspects of the analysis.

Table F.18 - FRS TRC Recommendations

2016 FRS TRC Recommendations	Response to TRC Recommendations
The TRC feels that it might be useful to state the role of key assumptions generally - but specifically how key requirements of the EIM may have an impact on reserves (don't study it, just point out key issues).	EIM operating processes underlie PacifiCorp's regulation reserve requirements and the calculations in the FRS. Specific details on the EIM market process are available in the FRS, specifically in footnote 11.
On Slide page 8 of the presentation provided to the TRC, below the table: should that be 70 MW instead of 40 MW?	This references Figure F.6 in the FRS. The presentation stated: 40 MW is the maximum five-minute imbalance in any thirty-minute period in this hour. This is more accurately stated as: When the minimum imbalances in every rolling thirty-minute period are compared, 40 MW is the maximum five-minute imbalance in any thirty-minute period in this hour.
Would be helpful to include a few sentences about the ACE cap of 4L10?	This is addressed in the FRS in the section entitled "Balancing Authority ACE Limit: Allowed Deviations."
The use of what has traditionally been a resource adequacy metric – LOLH – use in long term capacity planning as a key criterion for estimating regulation reserve requirements is both interesting and a departure from previous studies – by Pacificorp as well as the general wind integration community in the U.S. This approach has been employed in a few recent integration analyses, but given the uniqueness, it would be good if it were more clearly called out/highlighted in the description of the analytical methodology. The discussion of 0.88 LOLH was helpful on the call. It would be useful to have a similar explanation in the report - something along the lines that the RA target resulted in 0.88 LOLH/year and that was judged to be an acceptable reliability level. Using the same target for operations, there are different drivers, but assuming resource adequacy is not the constraint, the 0.88 LOLH may instead result from UC errors that result in too little regulation being available when needed.	This is addressed in the FRS in the section entitled "Planning Reliability Target: Loss of Load Probability." The FRS identifies the "up" regulation reserve needed to maintain compliance with BAL-001-2. The 0.88 LOLH in the FRS assumes that resources are available to provide the identified hourly regulation requirements. To the extent resources are not available to meet the identified requirements, LOLH would increase. PacifiCorp's Flexible Resource Needs Assessment in the FRS assesses the availability of resources to meet its reserve requirements over the long term. In addition, over the short term, maintaining adequate reserve can be dependent on the availability of hourly market balancing opportunities. While a single unit can provide reserve in each hour of for a multi-hour ramp, it can only do so to the extent alternate resources can be procured so that it can ramp back to its starting point. Potential market balancing constraints are an area for future work.

[30] PacifiCorp 2016 Wind Integration Study Technical Review, Dec. 12, 2016. Available at: http://www.pacificorp.com/es/irp/irpsupport.html

2016 FRS TRC Recommendations	Response to TRC Recommendations
Would be useful to have discussion of how wind (and solar) are treated in the study - do they respond to AGC or dispatch or both? Impact of lost RECs vs. operational flexibility etc.	The FRS identifies the "up" regulation reserve needed to maintain compliance with BAL-001-2. The ability of wind or solar to provide "up" regulation reserve would impact the cost of meeting that need. Generally, the opportunity cost of foregone renewable resource output is higher than the variable cost of PacifiCorp's regulation reserve resources. When considered relative to the cost of adding flexible resource capacity, in some circumstances providing regulation reserve with wind or solar resources may be economic.
Is there a reference to the method used by the CAISO to allocate the diversity benefits for each EIM participant?	This is addressed in the FRS in the section entitled "EIM Intra-hour Benefit."
There is some remaining confusion on the part of the TRC regarding the assumptions and utilization of forecasting into the production simulations for calculating integration cost. Specifically, the forecast lead time is nearly one hour prior to the operating hour. The disconnect on the part of the TRC is likely driven by current operation in some larger RTOs, where very short term persistence forecasts (5 minutes ahead) are used to dispatch generators participating in the sub-hourly energy markets, which substantially reduces the remaining requirement for generators providing regulation.	While the EIM uses forecasts up to 7.5 minutes prior to the start of an interval, it can only dispatch the resources made available by participants. Because of EIM operating timelines, balanced load and resource schedules with regulation reserve capacity identified have to be submitted by 55 minutes prior to the hour. Once a resource is deployed, for instance to cover increasing load or decreasing wind, PacifiCorp cannot restore that regulating capacity to its original levels without buying additional resources from a third party. Bilateral hourly markets in the West have historically been liquid enough for this purpose, whereas sub-hourly markets, other than EIM, have not. Because EIM is an *Energy* Imbalance Market, each participant is independently responsible for meeting its reliability obligations and it is inappropriate to rely upon the availability of resources from other participants, though they will be deployed in the EIM if it is economic to do so. As discussed in the section entitled "EIM Intra-hour Benefit", the FRS incorporates benefits associated with the diversity of the EIM as whole, rather than the resources of other participants.
The use of actual high temporal resolution operating data, especially for wind generation (rather than synthesized data from numerical weather simulations) has been a key feature of the Pacificorp integration studies dating back to 2012. Going forward, the TRC feels that future Pacificorp integration studies could benefit greatly by a thorough comparison of "study results vs. real world", especially since a current year baseline is part of the analysis. This would provide perhaps the strongest validation of the analytical methodology or otherwise give strong clues to adjustments that may be needed.	PacifiCorp agrees that the performance of the regulation reserve forecast developed in the FRS against future regulation reserve requirements would provide valuable feedback. This is an area for future work.

Flexible Resource Needs Assessment

Overview

In its Order No. 12013 issued on January 19, 2012 in Docket No. UM 1461 on "Investigation of matters related to Electric Vehicle Charging", the Oregon Public Utility Commission (OPUC) adopted the OPUC staff's proposed IRP guideline:

1. Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period;

2. Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period; and

3. Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options including the use of electric vehicles (EVs), on a consistent and comparable basis.

In this section, PacifiCorp first identifies its flexible resource needs for the IRP study period of 2017 through 2036, and the calculation method used to estimate those requirements. PacifiCorp then identifies its supply of flexible capacity from its generation resources, in accordance with the Western Electricity Coordinating Council (WECC) operating reserve guidelines, demonstrating that PacifiCorp has sufficient flexible resources to meet its requirements.

Forecasted Reserve Requirements

Since contingency reserve and regulation reserve are separate and distinct components, PacifiCorp estimates the forward requirements for each separately. The contingency reserve requirements are derived from stochastic simulations run using the Planning and Risk (PaR) model. The regulating reserve requirements are part of the inputs to the PaR model, and are calculated by applying the methods developed in the Portfolio Regulation Reserve Requirements section. The contingency and regulation reserve requirements include three distinct components and are modeled separately in the 2017 IRP: 10-minute spinning reserve requirements, 10-minute non-spinning reserve requirements, and 30-minute regulation reserve requirements. The reserve requirements for PacifiCorp's two balancing authority areas are shown in Table F.19 below.

Table F.19 - Reserve Requirements (MW)

Year	East Requirement			West Requirement		
	Spin (10-minute)	Non-spin (10-minute)	Regulation (30-minute)	Spin (10-minute)	Non-spin (10-minute)	Regulation (30-minute)
2017	195	195	387	88	88	229
2018	197	197	387	89	89	229
2019	198	198	390	91	91	231
2020	200	200	390	91	91	231
2021	203	203	454	92	92	230
2022	205	205	454	92	92	230
2023	207	207	454	93	93	230
2024	209	209	454	93	93	230
2025	212	212	454	94	94	230
2026	211	211	454	95	95	230
2027	213	213	454	95	95	230
2028	215	215	390	96	96	232
2029	218	218	390	96	96	235
2030	219	219	390	97	97	235
2031	222	222	398	97	97	233
2032	225	225	396	98	98	234
2033	227	227	398	98	98	232
2034	228	228	392	98	98	231
2035	231	231	401	99	99	231
2036	235	235	436	99	99	230

Flexible Resource Supply Forecast

Requirements by NERC and the WECC dictate the types of resources that can be used to serve the reserve requirements.

- **10-minute spinning reserve** can only be provided by resources currently online and synchronized to the transmission grid;

- **10-minute non-spinning reserve** may be served by fast-start resources that are capable of being online and synchronized to the transmission grid within ten minutes. Interruptible load can only provide non-spinning reserve. Non-spinning reserve may be provided by resources that are capable of providing spinning reserve.

- **30-minute regulation reserve** can be provided by unused spinning or non-spinning reserve. Incremental 30-minute ramping capability beyond the 10-minute capability captured in the categories above also counts toward this requirement.

The resources that PacifiCorp employs to serve its reserve requirements include owned hydro resources that have storage, owned thermal resources, and purchased power contracts that provide reserve capability.
Hydro resources are generally deployed first to meet the spinning reserve requirements because of their flexibility and their ability to respond quickly. The amount of reserve that these resources can provide depends upon the difference between their expected capacities and their generation level at the time. The hydro resources that PacifiCorp may use to cover reserve requirements in the PacifiCorp West balancing authority area include its facilities on the Lewis River and the Klamath River as well as contracted generation from the Mid-Columbia projects. In the PacifiCorp East balancing authority area, PacifiCorp may use facilities on the Bear River to provide spinning reserve.

Thermal resources are also used to meet the spinning reserve requirements when they are online. The amount of reserve provided by these resources is determined by their ability to ramp up within a 10-minute interval. For natural gas-fired thermal resources, the amount of reserve can be close to the differences between their nameplate capacities and their minimum generation levels. In the current IRP, PacifiCorp's reserve are served not only from existing coal- and gas-fired resources, but also from new gas-fired resources selected in the preferred portfolio.

Table F.20 lists the annual reserve capability from resources in PacifiCorp's East and West balancing authority areas. All the resources included in the calculation are capable of providing all types of reserve. The non-spinning reserve resources under third party contracts are excluded in the calculations. The changes in the flexible resource supply reflect retirement of existing resources, addition of new preferred portfolio resources, and variation in hydro capability due to forecasted streamflow conditions, and expiration of contracts from the Mid-Columbia projects that are reflected in the preferred portfolio.

Table F.20 - Flexible Resource Supply Forecast (MW)

Year	East Supply (10-minute)	West Supply (10-minute)	East Supply (30-minute)	West Supply (30-minute)
2017	1,340	745	1,975	1,009
2018	1,340	751	1,975	1,015
2019	1,290	700	1,875	964
2020	1,290	743	1,875	1,007
2021	1,250	724	1,755	988
2022	1,250	684	1,755	948
2023	1,250	725	1,755	989
2024	1,250	725	1,755	989
2025	1,250	725	1,755	989
2026	1,250	724	1,755	988
2027	1,250	725	1,755	989
2028	1,169	726	1,675	990
2029	1,281	692	1,786	890
2030	1,231	968	1,656	1,166
2031	1,231	969	1,656	1,167
2032	1,231	970	1,657	1,168
2033	1,469	936	1,832	1,068
2034	1,469	935	1,832	1,067
2035	1,469	936	1,832	1,068
2036	1,469	937	1,833	1,069

Figure F.21 and Figure F.22 graphically display the balances of reserve requirements and capability of spinning reserve resources in PacifiCorp's East and West balancing authority areas respectively. The graphs demonstrate that PacifiCorp's system has sufficient resources to serve its reserve requirements throughout the IRP planning period.

Figure F.21 - Comparison of Reserve Requirements and Resources, East Balancing Authority Area (MW)

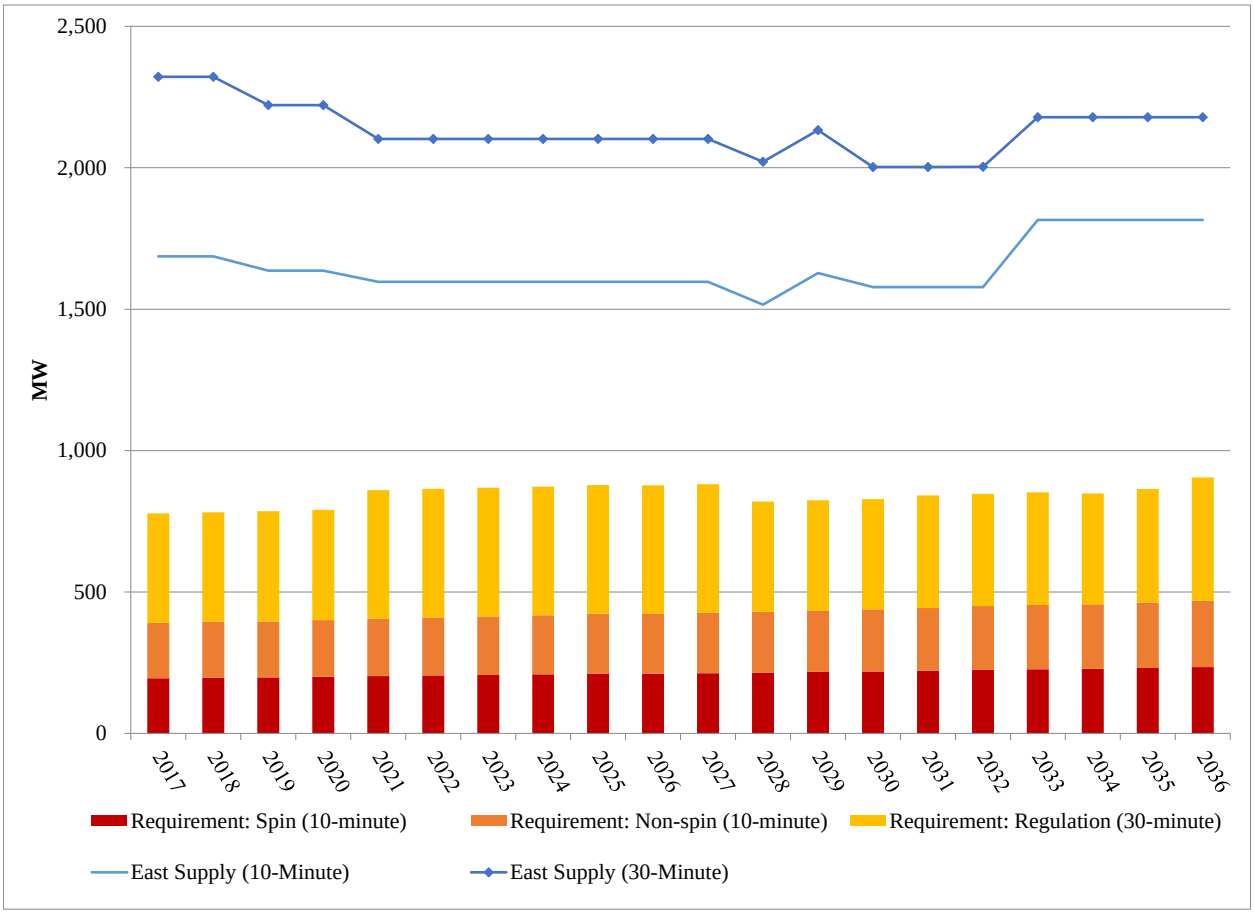
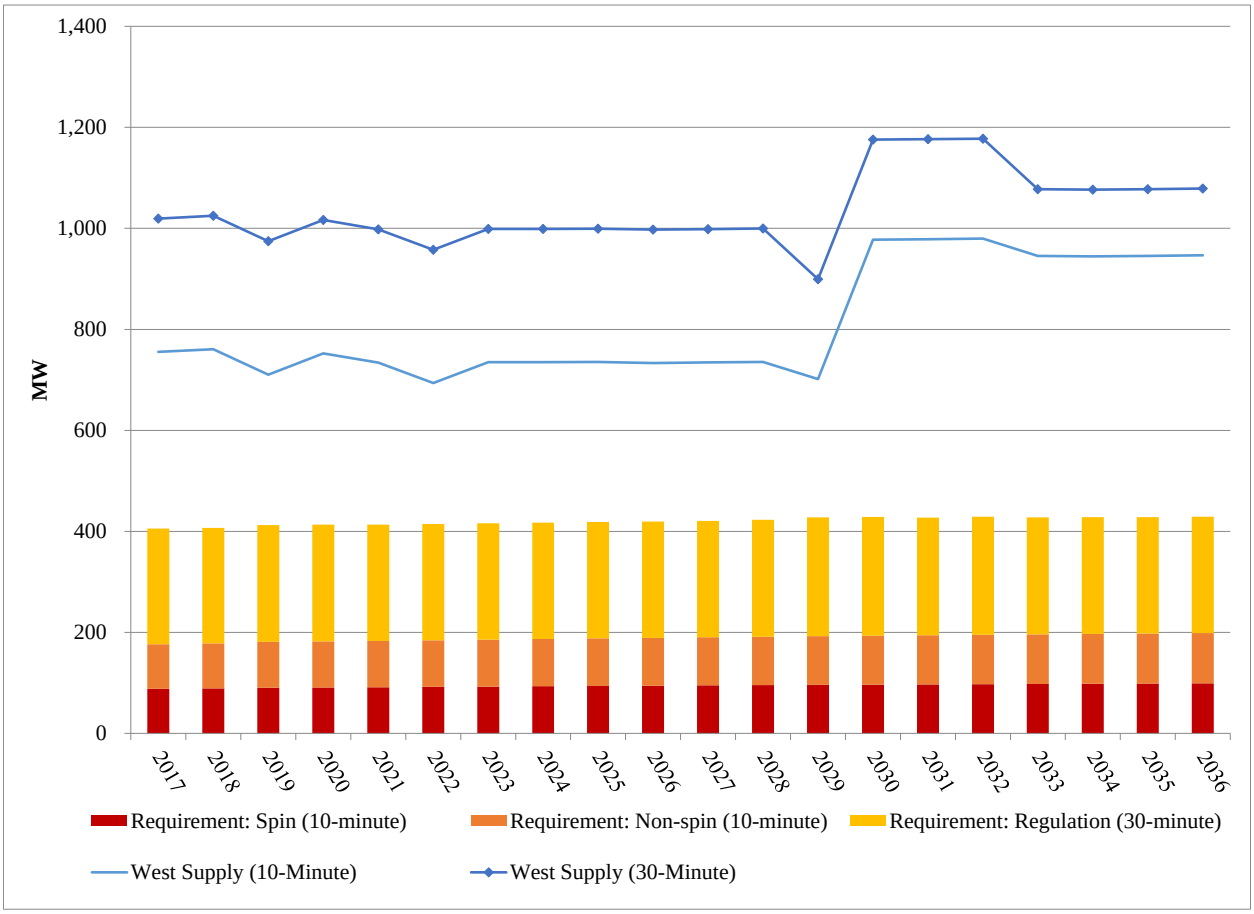


Figure F.22 - Comparison of Reserve Requirements and Resources, West Balancing Authority Area (MW)



Flexible Resource Supply Planning

In actual operations, PacifiCorp has been able to serve its reserve requirements and has not experienced any incidents where it was short of reserve. PacifiCorp manages its resources to meet its reserve obligation in the same manner as meeting its load obligation – through long term planning, market transactions, utilization of the transmission capability between the two balancing authority areas, and operational activities that are performed on an economic basis.

PacifiCorp and the California Independent System Operator Corporation implemented the energy imbalance market (EIM) on November 1, 2014, and participation has since expanded to include NV Energy, Arizona Public Service, and Puget Sound Energy, with several additional participants scheduled for entry between 2017 and 2019. By pooling variability in load and resource output, EIM entities reduce the quantity of reserve required to meet flexibility needs. Because variability across different BAAs may happen in opposite directions, the flexible ramping requirement for the entire EIM footprint can be less than the sum of individual BAAs' requirements. This difference is known as the "flexible ramping procurement diversity savings" in the EIM. This intra-hour benefit reflects offsetting variability and lower combined uncertainty. PacifiCorp's regulation reserve forecast includes a credit to account for the diversity benefits associated with its participation in EIM.

As indicated in the OPUC order, electric vehicle technologies may be able to meet flexible resource needs at some point in the future. However, the electric vehicle technology and market have not developed sufficiently to provide data for the current study. Since this analysis shows no gap between forecasted demand and supply of flexible resources over the IRP planning horizon, this IRP does not include whether electric vehicles could be used to meet future flexible resource needs.

Summary

The FRS first estimates the regulation reserve necessary to maintain compliance with NERC Standard BAL-001-2 given a specified portfolio of wind and solar resources. The FRS next calculates the cost of holding regulation reserve for incremental wind and solar resources and the cost of using day-ahead load, wind, and solar forecasts to commit gas units. Finally, the FRS compares PacifiCorp's overall operating reserve requirements over the IRP study period, including both regulation reserve and contingency reserve, to its flexible resource supply.

PacifiCorp incorporated a revised methodology in the FRS compared to its 2014 Wind Integration Study. The FRS now estimates regulation reserve based on the specific requirements of NERC Standard BAL-001-2. It also incorporates the current timeline for EIM market processes, as well as EIM resource deviations and flexibility reserve benefits based on actual results. The FRS also includes adjustments to regulation reserve requirements to account for the changing portfolio of solar and wind resources on PacifiCorp's system and accounts for the diversity of using a single portfolio of regulation reserve resources to cover variations in load, wind, solar, and Non-VERs. The regulation reserve requirements for the various portfolios considered in the analysis and in the 2014 Wind Integration Study are shown in Table F.21.

Table F.21 – Portfolio Regulation Reserve Requirements, by Scenario

Case	Wind Capacity (MW)	Solar Capacity (MW)	Stand-alone Regulation Requirement (MW)	Portfolio Diversity Credit (%)	Regulation Requirement with Diversity (MW)
2014 WIS	2,543	n/a	n/a	n/a	626
2015 (No Solar)	2,588	0	900	37.5%	562
2017 Base Case	2,757	1,050	998	38.2%	617
Incremental Wind	3,007	1,050	1,023	38.3%	631
Incremental Solar 1	2,757	1,550	1,033	38.6%	635
Incremental Solar 2	2,757	2,050	1,074	39.2%	653

Two categories of flexible resource costs are estimated using the Planning and Risk (PaR) model: one for meeting intra-hour regulation reserve requirements, and one for inter-hour system balancing costs associated with committing gas plants using day-ahead forecasts of load, wind, and solar. Table F.22 provides the wind and solar costs on a dollar per megawatt-hour ($/MWh) of generation basis. The results of the 2014 Wind Integration Study are also included for comparison.

Table F.22 – 2017 FRS Flexible Resource Costs as Compared to 2014 WIS Costs, $/MWh

	Wind 2014 WIS (2015$)	**Wind 2017 FRS** (2017$)	**Solar 2017 FRS** (2017$)
Intra-hour Reserve	$2.35	$0.43	$0.46
Inter-hour/System Balancing	$0.71	$0.14	$0.14
Total Flexible Resource Cost	**$3.06**	**$0.57**	**$0.60**

The 2017 FRS results are applied in the 2017 IRP portfolio development process as a cost for wind and solar generation resources. Once candidate resource portfolios are developed using the SO model, the PaR model is used to evaluate portfolio risks. The PaR model inputs include regulation reserve requirements specific to the resource portfolio developed using the SO model. As a result, the IRP risk analysis using PaR includes the impact of differences in regulation reserve requirements between portfolios.

Reference Tables

Table F.23 - Wind

Resource ID	Nameplate Capacity (MW)	BAA	Grouping
DUNLAP_6_UNIT	111	PACE	Wind
FOOTECRE_7_UNITS	133.6	PACE	Wind
FREEZOUT_6_UNIT	118.5	PACE	Wind
GLENROCW_6_UNIT	138	PACE	Wind
HINSHAW_7_UNITS	144	PACE	Wind
HIPLAINS_7_UNITS	127.5	PACE	Wind
HORSEBU_7_UNIT	57.6	PACE	Wind
JOLLYHIL_1_GOSHEN	124.5	PACE	Wind
LATIGO_6_UNIT	99	PACE	Wind
MEADOWCR_6_UNIT	119.7	PACE	Wind
MOONSHIN_7_UNITS	45	PACE	Wind
MTWNDCOL_7_UNITS	140.7	PACE	Wind
RAWHIDE_6_UNIT	16.5	PACE	Wind
ROLLHILL_6_UNIT	99	PACE	Wind
SPNFKWND_7_UNIT	18.9	PACE	Wind
TOPWORLD_7_UNITS	200.2	PACE	Wind
WOLVERIN_7_UNITS	64.5	PACE	Wind
CAMPCOL_6_UNIT	98.9	PACW	Wind
COMBINEH_6_UNIT	41	PACW	Wind
DALREED_7_WIND	9.9	PACW	Wind
GOODNOEH_7_UNIT	94	PACW	Wind
HINKLE_6_UNIT	64.55	PACW	Wind
LEANJNPR_7_UNIT	100.5	PACW	Wind
MARENGO_6_UNITS	210.6	PACW	Wind
NINEMIL_7_UNIT 1	210	PACW	Wind
Total	**2587.65**		

Table F.24 – Non-VERs

Resource ID	Nameplate Capacity (MW)	BAA	Class
BONANZA_7_UNIT	458	PACE	Non-VER
DALTONU_7_UNIT	4.6	PACE	Non-VER
EXXON_7_UNITS	107.4	PACE	Non-VER
GEMSTATE_1_UNIT	23.4	PACE	Non-VER
MILLCRK_7_UNIT 1	40	PACE	Non-VER

MILLCRK_7_UNIT 2	40	PACE	Non-VER
NEBOPS_7_UNITS	140	PACE	Non-VER
PALISADI_7_UNIT 1	44	PACE	Non-VER
PALISADI_7_UNIT 2	44	PACE	Non-VER
PALISADI_7_UNIT 3	44	PACE	Non-VER
PALISADI_7_UNIT 4	44	PACE	Non-VER
SLENERGY_7_UNIT	3.2	PACE	Non-VER
SUNNYSIU_6_UNIT	53	PACE	Non-VER
TESORO_7_UNITS	25	PACE	Non-VER
USBRGATE_7_UNIT	4.5	PACE	Non-VER
WESTVALL_7_UNIT 1	40	PACE	Non-VER
WESTVALL_7_UNIT 2	40	PACE	Non-VER
WESTVALL_7_UNIT 3	40	PACE	Non-VER
WESTVALL_7_UNIT 4	40	PACE	Non-VER
WESTVALL_7_UNIT 5	40	PACE	Non-VER
BIOMAS_7_PACW	32.5	PACW	Non-VER
CAMASMI_7_UNIT	61.5	PACW	Non-VER
CLEARWA1_7_UNIT	17.9	PACW	Non-VER
CLEARWA2_7_UNIT	31	PACW	Non-VER
COID_7_UNITS	6	PACW	Non-VER
COLSTR_5_PACE	74	PACW	Non-VER
COLSTR_5_PACW	74	PACW	Non-VER
COPCO1_7_UNIT 1	14	PACW	Non-VER
COPCO1_7_UNIT 2	14	PACW	Non-VER
COPCO2_7_UNIT 1	17	PACW	Non-VER
COPCO2_7_UNIT 2	17	PACW	Non-VER
DALREED_7_BIO	4.8	PACW	Non-VER
EVERGBIO_6_BIO	10	PACW	Non-VER
FALLCREE_7_UNIT	2	PACW	Non-VER
FARMERS_6_UNIT	4.15	PACW	Non-VER
FISHCREO_7_UNIT	10.4	PACW	Non-VER
GRACE_7_UNIT 3	11	PACW	Non-VER
GRACE_7_UNIT 4	11	PACW	Non-VER
GRACE_7_UNIT 5	11	PACW	Non-VER
IRONGATE_7_UNIT	18.8	PACW	Non-VER
JCBOYLE_7_UNIT 1	40	PACW	Non-VER
JCBOYLE_7_UNIT 2	43	PACW	Non-VER
LEMOLO1_7_UNIT	32	PACW	Non-VER
LEMOLO2_7_UNIT	38.5	PACW	Non-VER
MERWIN_7_UNITS	150	PACW	Non-VER
OPALSPRI_7_UNIT	4.3	PACW	Non-VER

PELTONRE_7_UNIT	19.6	PACW	Non-VER
PENSTOCK_6_UNIT	5	PACW	Non-VER
PROSPEC2_7_UNIT 1	18	PACW	Non-VER
PROSPEC2_7_UNIT 2	18	PACW	Non-VER
PROSPEC3_7_UNIT	7.7	PACW	Non-VER
RFP_6_UNIT	10	PACW	Non-VER
ROSEBURL_7_LUMB	20	PACW	Non-VER
SLIDECRE_7_UNIT	18	PACW	Non-VER
SODA_7_UNIT 1	7	PACW	Non-VER
SODA_7_UNIT 2	7	PACW	Non-VER
SODASPRI_7_UNIT	11.6	PACW	Non-VER
TIETONHY_6_UNIT	13.8	PACW	Non-VER
TOKETEE_7_UNIT 1	15	PACW	Non-VER
TOKETEE_7_UNIT 2	15	PACW	Non-VER
TOKETEE_7_UNIT 3	15	PACW	Non-VER
WEBER_7_UNIT	2	PACW	Non-VER
Total	**2227.65**		

Table F.25 - Solar

Resource	Nameplate Capacity (MW)	BAA	Class
Beryl Solar	3	PACE	Solar
Buckhorn	3	PACE	Solar
Cedar Valley	3	PACE	Solar
Enterprise Solar I QF	80	PACE	Solar
Escalante Solar I QF	80	PACE	Solar
Escalante Solar II QF	80	PACE	Solar
Escalante Solar III QF	80	PACE	Solar
Fiddler's Canyon 1	3	PACE	Solar
Fiddler's Canyon 2	3	PACE	Solar
Fiddler's Canyon 3	3	PACE	Solar
Granite Mountain East Solar QF	80	PACE	Solar
Granite Mountain West Solar QF	50.4	PACE	Solar
Granite Peak	3	PACE	Solar
Greenville	2.2	PACE	Solar
Iron Springs Solar QF	80	PACE	Solar
Laho #1	3	PACE	Solar
Milford 2	2.97	PACE	Solar
Milford Flat	3	PACE	Solar

Pavant II Solar QF	50	PACE	Solar
Pavant III Solar	20	PACE	Solar
Quichapa 1	3	PACE	Solar
Quichapa 2	3	PACE	Solar
Quichapa 3	3	PACE	Solar
South Milford	2.93	PACE	Solar
Three Peaks Solar QF	80	PACE	Solar
Utah Pavant Solar QF	50	PACE	Solar
Utah Red Hills Solar QF	80	PACE	Solar
Adams Solar Center LLC	10	PACW	Solar
Beatty Solar	5	PACW	Solar
Black Cap	2	PACW	Solar
Black Cap II LLC	8	PACW	Solar
Bly Solar Center LLC	8.5	PACW	Solar
Chiloquin Solar	9.9	PACW	Solar
Collier Solar	9.9	PACW	Solar
Elbe Solar Center LLC	10	PACW	Solar
Ivory Pine Solar	10	PACW	Solar
Norwest Energy 2 LLC (Neff)	10	PACW	Solar
Old Mill Solar	5	PACW	Solar
OR Solar 2 (Agate Bay Solar)	10	PACW	Solar
OR Solar 3 (Turkey Hill Solar)	10	PACW	Solar
OR Solar 5 (Merrill)	8	PACW	Solar
OR Solar 6 (Lakeview)	10	PACW	Solar
OR Solar 7 (Jacksonville)	10	PACW	Solar
OR Solar 8 (Dairy)	10	PACW	Solar
Sprague River Solar	7	PACW	Solar
Tumbleweed Solar	9.9	PACW	Solar
Total	**1017.7**		

APPENDIX G – PLANT WATER CONSUMPTION

The information provide in this appendix is for PacifiCorp owned plants. Total water consumption and generation includes all owners for jointly-owned facilities

Table G.1 – Plant Water Consumption with Acre-Feet Per Year

			Acre-Feet Per Year					MWhs Per Year				4-year Average	
Plant Name	Zero Discharge	Cooling Media	2012	2013	2014 *	2015 *	4-year Average	2012	2013	2014	2015	Gals/ MWH	GPM/ MW
Chehalis		Air	55	86	150	93	96	849,938	1,674,194	2,543,785	1,095,433	20	0.3
Currant Creek	Yes	Air	90	84	92	78	86	2,132,523	2,359,924	2,498,058	2,257,106	12	0.2
Dave Johnston		Water	7,721	8,941	9,474	9,736	8,968	4,906,422	5,295,081	5,183,347	5,140,970	569	9.5
Gadsby		Water	1,059	610	367	1,022	764	214,739	339,592	325,677	123,795	993	16.5
Hunter	Yes	Water	18,266	17,001	16,662	16,386	17,079	9,118,876	9,546,313	9,098,918	9,630,419	595	9.9
Huntington	Yes	Water	10,423	10,643	10,240	9,888	10,299	6,744,160	6,768,625	6,300,558	5,988,318	520	8.7
Jim Bridger	Yes	Water	23,977	25,059	23,936	22,493	23,866	13,625,135	14,817,041	14,016,315	13,439,341	557	9.3
Lake Side ***		Water	1,693	1,361	2,960	4,533	3,746	2,890,938	2,508,960	4,351,182	4,550,871	274	4.6
Naughton ****	Yes	Water	8,745	9,622	7,484	9,160	8,753	5,056,959	5,533,895	4,958,589	4,899,321	558	9.3
Wyodak	Yes	Air	322	319	332	228	300	2,526,307	2,518,120	2,625,183	2,563,421	38	0.6
TOTAL			**72,351**	**73,726**	**71,695**	**73,616**	**72,591**	**48,065,997**	**51,361,745**	**51,901,612**	**49,688,995**	**472**	**7.9**

* Beginning in 2014, net water consumed reflects "Raw Water Consumed" instead of "Raw Water Diversion."
** Gadsby includes a mix of both Rankine steam units and peaking gas turbines.
*** Lake Side 2 went commercial in May 30, 2014. The averages for Lake Side 2 are based only on 2014 and 2015 numbers.
**** Naughton Unit 3 was rerated in September 2015 from 330 MW to 280 MW. The averages remain as 4-year averages.

1 acre-foot of water is equivalent to 325,851 Gallons or 43,560 Cubic Feet

Table G.2 – Plant Water Consumption by State (acre-feet)

UTAH PLANTS						
Plant Name	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Currant Creek	82	78	90	84	92	78
Gadsby	893	864	1,059	610	367	1,022
Hunter	18,941	16,961	18,266	17,001	16,662	16,386
Huntington	9,549	9,069	10,423	10,643	10,240	9,888
Lake Side	1,533	1,154	1,693	1,361	2,960	4,533
TOTAL	**30,998**	**28,125**	**31,531**	**29,699**	**30,320**	**31,906**

Percent of total water consumption = 41.9%

WYOMING PLANTS						
Plant Name	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Dave Johnston	6,604	7,233	7,721	8,941	9,474	9,736
Jim Bridger	20,757	22,282	23,977	25,059	23,936	22,493
Naughton	13,354	14,157	8,745	9,622	7,484	9,160
Wyodak	396	367	322	319	332	228
TOTAL	**41111**	**44039**	**40765**	**43941**	**41225**	**41617**

Percent of total water consumption = 58.1%

Table G.3 – Plant Water Consumption by Fuel Type (acre-feet)

COAL FIRED PLANTS						
Plant Name	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Dave Johnston	6,604	7,233	7,721	8,941	9,474	9,736
Hunter	18,941	16,961	18,266	17,001	16,662	16,386
Huntington	9,549	9,069	10,423	10,643	10,240	9,888
Jim Bridger	20,757	22,282	23,977	25,059	23,936	22,493
Naughton	13,354	14,157	8,745	9,622	7,484	9,160
Wyodak	396	367	322	319	332	228
TOTAL	**69,601**	**70,069**	**69,454**	**71,585**	**68,127**	**67,891**

Percent of total water consumption = 95.7%

NATURAL GAS FIRED PLANTS						
Plant Name	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Currant Creek	82	78	90	84	92	78
Chehalis	24	43	55	86	150	93
Gadsby	893	864	1,059	610	367	1,022
Lake side	1,533	1,154	1,693	1,361	2,960	4,533
Total	**2,532**	**2,139**	**2,897**	**2,141**	**3,569**	**5,726**

Percent of total water consumption = 4.4%

Table G.4 – Plant Water Consumption for Plants Located in the Upper Colorado River Basin (acre-feet)

Plant Name	2010	2011	2012	2013	2014	2015
Hunter	18,941	16,961	18,266	17,001	16,662	16,386
Huntington	9,549	9,069	10,423	10,643	10,240	9,888
Naughton	13,354	14,157	8,745	9,622	7,484	9,160
Jim Bridger	20,757	22,282	23,977	25,059	23,936	22,493
TOTAL	**62,601**	**62,469**	**61,411**	**62,325**	**58,322**	**57,927**

Percent of total water consumption = 83.9%

APPENDIX H – STOCHASTIC PARAMETERS

For this IRP, PacifiCorp updated and re-estimated the stochastic parameters provided in the 2015 IRP for use in the Planning and Risk (PaR) model runs.

PaR, as used by PacifiCorp, develops portfolio cost scenarios via computational finance in concert with production simulation. The model stochastically shocks the case-specific underlying electricity price forecast as well as the corresponding case-specific key drivers (e.g., natural gas, loads, and hydro) and dispatches accordingly. Using exogenously calculated parameters (i.e., volatilities, mean reversions, and correlations), PaR develops scenarios that bracket the uncertainty surrounding a driver; statistical sampling techniques are then employed to limit the number of representative scenarios to 50. The stochastic model used in PaR is a two-factor (short- and long-run) short run mean reverting model.

PacifiCorp used short-run stochastic parameters for this IRP; long-run parameters were set to zero since PaR cannot re-optimize its capacity expansion plan. This inability to re-optimize or add capacity can create a problem when dispatching to meet extreme load and/or fuel price excursions, as often seen in long-term stochastic modeling. Such extreme out-year price and load excursions can influence portfolio costs disproportionately while not reflecting plausible outcome. Thus, since long-term volatility is the year-on-year growth rate, only the expected yearly price and/or load growth is simulated over the forecast horizon[1].

Key drivers that significantly affect the determination of prices tend to fall into two categories: loads and fuels. Targeting only key variables from each category simplifies the analysis while effectively capturing sensitivities on a larger number of individual variables. For instance, load uncertainty can encompass the sensitivities of weather, transmission availability, unit outages, and evolving end-uses. Depending on the region, fuel price uncertainty (especially that of natural gas) can encompass the sensitivities of weather, load growth, emissions, and hydro availability. The following sections summarize the development of stochastic process parameters and describe how these uncertain variables evolve over time.

[1]Mean reversion is assumed to be zero in the long run.

Introduction

Long-term planning demands specification of how important variables behave over time. For the case of PacifiCorp's long-term planning, important variables include natural gas and electricity prices, regional loads, and regional hydro generation. Modeling these variables involves not only a description of their expected value over time as with a traditional forecast, but also a description of the spread of possible future values. The following sections summarize the development of stochastic process parameters to describe how these uncertain variables evolve over time[2].

Volatility

The standard measure of uncertainty for a stochastic variable is volatility:

$$Volatility = \frac{Standard\ Deviation}{\sqrt{Time}}$$

The standard deviation[3] is a measure of how widely values are dispersed from the average value:

$$Standard\ Deviation = \sqrt{\frac{\sum_{i=1}^{n}(x_i - average)^2}{(n-1)}}$$

Volatility incorporates a time component so a variable with constant volatility has a larger spread of possible outcomes two years in the future than one year in the future. Volatilities are typically quoted on an annual basis but can be specified for any desired time period. Suppose the annual volatility of load in Idaho is two percent. This implies that the standard deviation of the range of possible loads in Idaho a year from now is two percent, while the standard deviation four years from now is four percent.

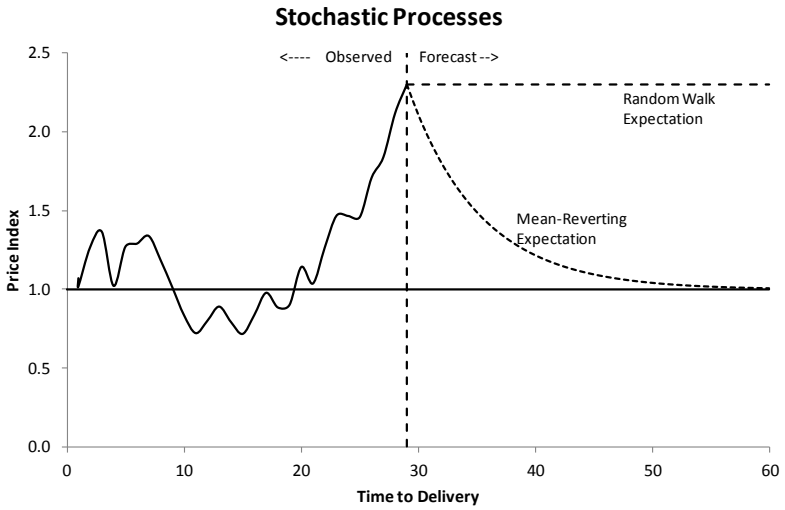
Mean Reversion

If volatility were constant over the forecast period, then the standard deviation would increase linearly with the square root of time. This is described as a "Random Walk" process and often provides a reasonable assumption for long-term uncertainty. However, for energy commodities as well as many other variables in the short-term, this is not typically the case. Excepting seasonal effects, the standard deviation increases less quickly with longer forecast time. This is called a mean reverting process - variable outcomes tend to revert back towards a long-term mean after experiencing a shock:

[2] A stochastic or random process is the counterpart to a deterministic process. Instead of dealing with only one possible reality of how the variables might evolve over time, there is some indeterminacy in the future evolution described by probability distributions.

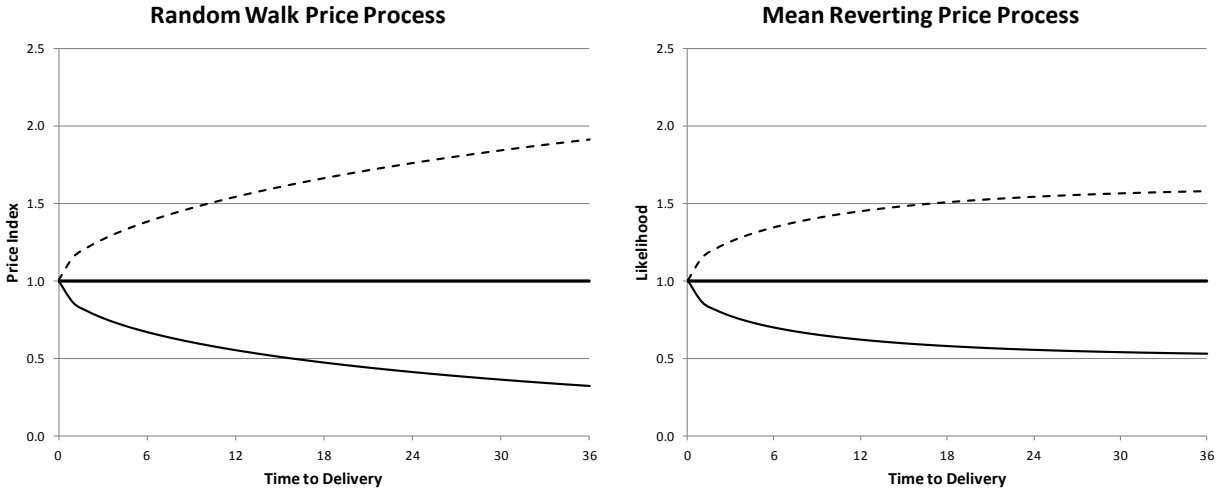
[3] "Standard Deviation" and "Variance" are standard statistical terms describing the spread of possible outcomes. The Variance equals the Standard Deviation squared.

Figure H.1 – Stochastic Processes



For a random walk process, the distribution of possible future outcomes continues to increase indefinitely. While for a mean reverting process, the distribution of possible outcomes reaches a steady-state. Actual observed outcomes will continue to vary within the distribution, but the distribution across all possible outcomes does not increase:

Figure H.2 – Random Walk Price Process and Mean Reverting Process



The volatility and mean reversion rate parameters combine to provide a compact description of the distribution of possible variable outcomes over time. The volatility describes the size of a typical shock or deviation for a particular variable and the mean reversion rate describes how quickly the variable moves back towards the long-run mean after experiencing a shock.

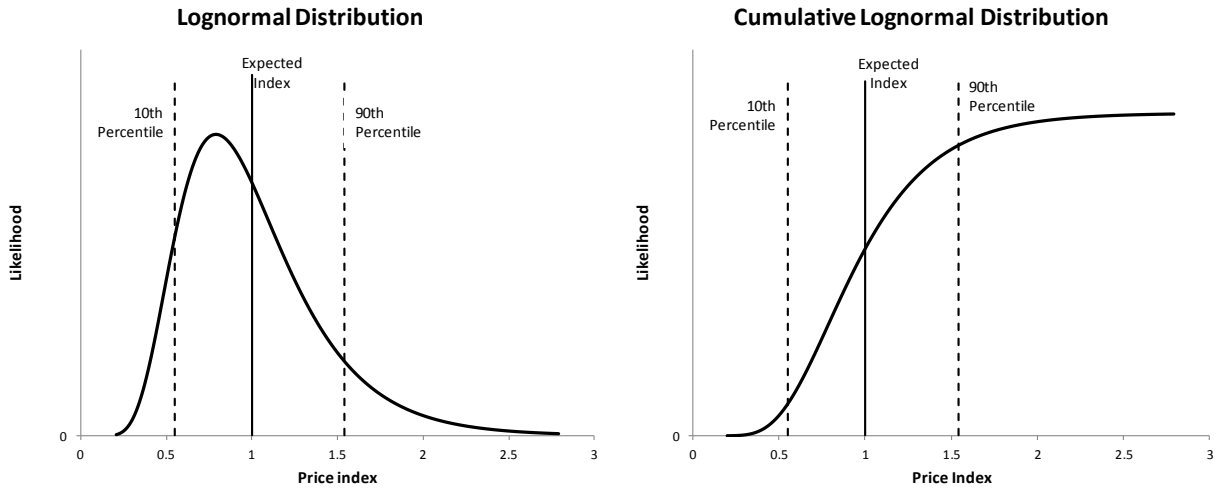
Estimating Short-term Process Parameters

Short-term uncertainty can best be described as a mean reverting process. The factors that drive uncertainty in the short-term are generally short-lived, decaying back to long-run average levels. Short-term uncertainty is mainly driven by weather (temperature, windiness, rainfall) but can also be driven by short-term economic factors, congestion, outages, etc. The process for estimating short-term uncertainty parameters is similar for most variables of interest. However, each of PacifiCorp's variables have characteristics that make their processes slightly different. The process for estimating short-term uncertainty parameters is described in detail below for the most straightforward variable -- natural gas prices. Each of the other variables is then discussed in terms of how they differ from the standard natural gas price parameter estimation process.

Stochastic Process Description

The first step in developing process parameter estimates for any uncertain variable is to determine the form of the distribution and time step for uncertainty. In the case of natural gas, and prices in general, the lognormal distribution is a good representation of possible future outcomes. A lognormal distribution is a continuous probability distribution of a random variable whose logarithm is normally distributed[4]. The lognormal distribution is often used to describe prices because it is bounded on the bottom by zero and has a long, asymmetric "tail" reflecting the possibility that prices could be significantly higher than the average:

Figure H.3 – Lognormal Distribution and Cumulative Lognormal Distribution



The time step for calculating uncertainty parameters depends on how quickly a variable can experience a significant change. Natural gas prices can change substantially from day to day and are reported on a daily basis, so the time step for analysis will be one day.

[4] A normal distribution is the most common continuous distribution represented by a bell-shaped curve that is symmetrical about the mean, or average, value.

All short-term parameters were calculated on a seasonal basis to reflect the different dynamics present during different seasons of the year. For instance, the volatility of gas prices is higher in the winter and lower in the spring and summer. Seasons were defined as follows:

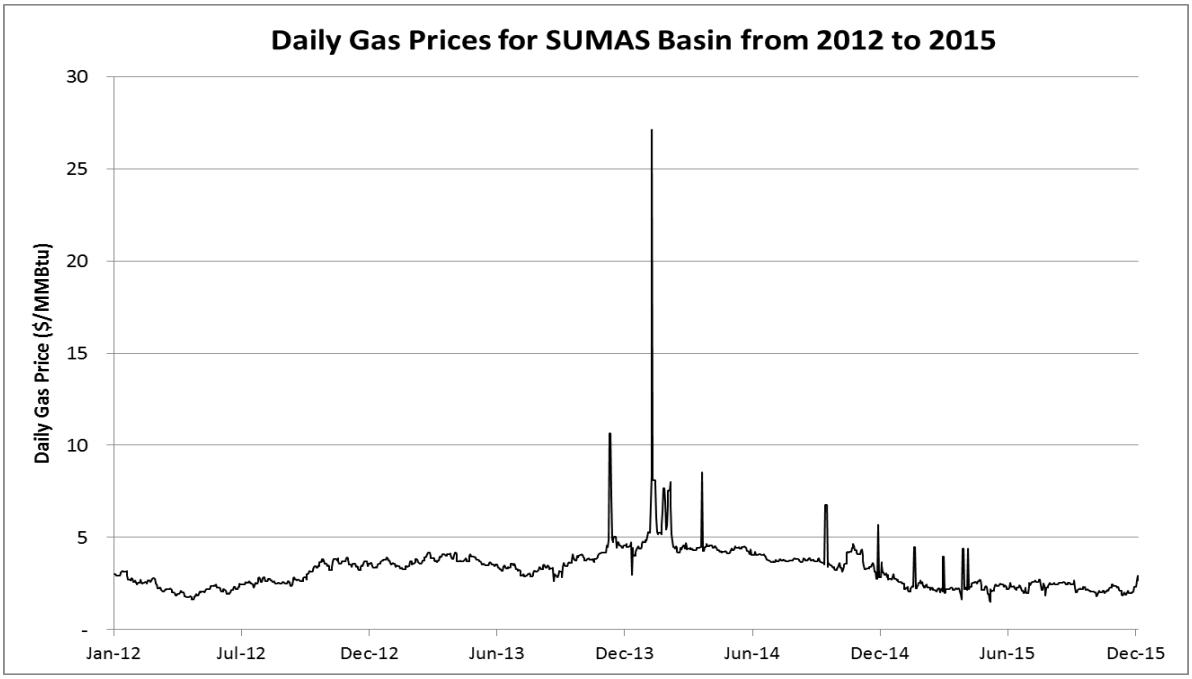
Table H.1 - Seasonal Definition

Winter	December, January, and February
Spring	March, April, and May
Summer	June, July, and August

Data Development

Basic Data Set:
The natural gas price data were organized into a consistent dataset with one natural gas price for each gas delivery point reported for each delivery day. The data were checked to make sure that there were no missing or duplicate dates. If no price is reported for a particular date, the date is included but left blank to maintain a consistent 24 hour time step between all observed prices. Four years of daily data from 2012 to 2015 was used for this short-term parameter analysis. The following chart shows the resulting data set for the Sumas gas basin:

Figure H.4 – Daily Gas Prices for SUMAS Basin



Development of Price Index:
Uncertainty parameters are estimated by looking at the movement, or deviation, in prices from one day to the next. However, some of this movement is due to expected factors, not uncertainty. For instance, gas prices are expected to be higher during winter or as we move towards winter. This expectation is already included in the gas price forecast and should not be considered a shock, or random event. In order to capture only the random or uncertain portion of price

movements, a price index is developed that takes into account the expected portion of price movements. There are three categories of price expectations that are calculated:

Seasonal Average: The level of gas prices may be different from one year to the next. While this can be attributed to random movements or shocks in the gas markets, it is not a short-term event and should not be included in the short-term uncertainty process. In order to account for this possible difference in the level of gas prices, the average gas price for each season and year is calculated. For example, Sumas prices in the winter of 2012 average $3.02/MMBtu.

Monthly Average: Within a season, there are different expected prices by month. For instance, within the fall season, November gas prices are expected to be much higher than September and October prices as winter is just around the corner. A monthly factor representing the ratio of monthly prices to the seasonal average price is calculated. For example, February prices in Sumas are 108 percent of the winter average price.

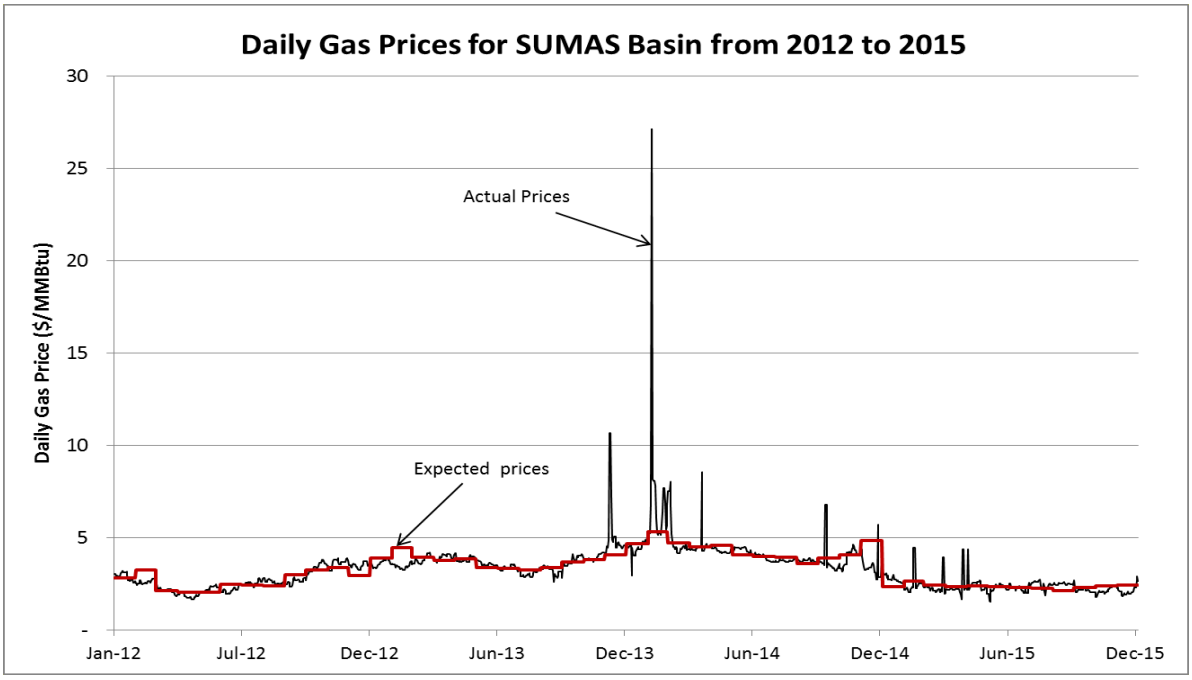
Weekly Shape: Many variables exhibit a distinct shape across the week. For instance, loads and electricity prices are higher during the middle of the week and lower on the weekends. The expected shape of gas prices across the week was calculated but found to be insignificant (expected variation by weekday did not exceed two percent of the weekly average).

These three components: seasonal average, monthly shape, and weekly shape, combine to form an expected price for each day. For example, the expected price of gas in Sumas in January of 2012 was $2.84/MMBtu, the product of the seasonal average and the monthly shape factor

$$Expected\ Gas\ Price\ = Seasonal\ Avg.Price * Monthly\ Shape\ within\ the\ Season$$

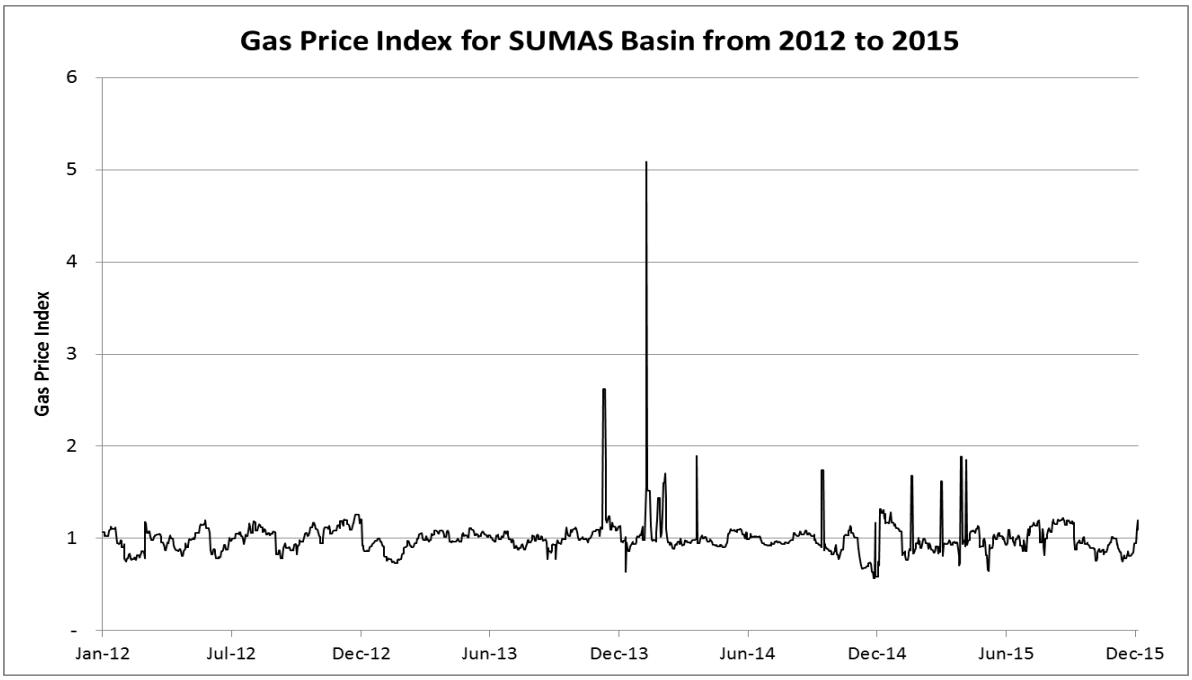
The chart below shows the comparison of the actual Sumas prices with the "expected" prices:

Figure H.5 – Daily Gas Prices for SUMAS Basin with "expected" prices



Dividing the actual gas prices by the expected prices forms a price index that averages one. This index captures only the random component of price movements—the portion not explained by expected seasonal, monthly, and weekly shape.

Figure H.6 – Gas Price Index for SUMAS Basin



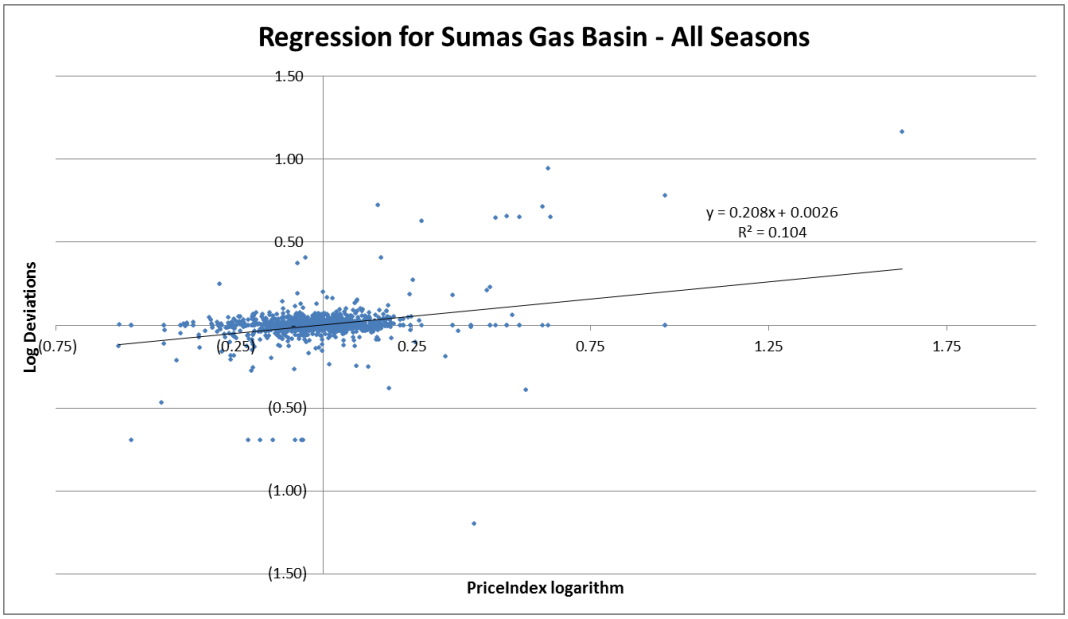
Parameter Estimation – Autoregressive Model

Uncertainty parameters are calculated for each variable by regressing the movement of each regions price index compared to the previous day's index.

Step 1 - Calculate Log Deviation of Price Index
Since gas prices are log normally distributed, the regression analysis is performed on the natural log of prices and their log deviations. The log deviations are simply the differences between the natural log of one day's price index and the natural log of the previous day's price index.

Step 2 - Perform Regression
The log deviations of price index are regressed against the previous day's logarithm of price index for each season as well as for the entire data set. The following chart shows the log of the price index versus the log deviations for Sumas gas for all seasons and the resulting regression equation:

Figure H.7 – Regression for SUMAS Gas Basin



Step 3 - Interpret the Results
The INTERCEPT of the regression represents the log of the long-run mean. So in this case, the intercept is approximately zero, implying that the long-run mean is equal to one. This is consistent with the way in which the price index is formulated.

The *SLOPE* of the regression is related to the auto correlation and mean reversion rate:

$$auto\ correlation = \emptyset = 1 + slope$$
$$Mean\ Reversion\ Rate\ \ \alpha = -\ln(\emptyset)$$

The autocorrelation measures how much of the price shock from the previous time period remains in the next time period. For instance, if the autocorrelation is 0.4 and gas prices

yesterday experienced a 10 percent jump over the norm, today's expected price would be four percent higher than normal. In addition, today's gas price will experience a shock today that may result in prices higher or lower than this expectation. The mean reversion rate expresses the same thing in a different manner. The higher the mean reversion rate, the faster prices revert to the long-run mean.

The last component of the regression analysis is the *STANDARD ERROR* or *STEYX*. This measures the portion of the price movements not explained by mean reversion and is the estimate of the variable's volatility.
Both the mean reversion rate and volatility calculated with this process are daily parameters and can be applied directly to daily movements in gas prices.

Step 4 - Results
The natural gas price parameters derived through this process are reported in the table below.

Table H.2 - Uncertainty Parameters for Natural Gas

	Winter	Spring	Summer	Fall
KERN OPAL				
Daily Volatility	13.2%	10.4%	2.7%	2.8%
Daily Mean Reversion Rate	0.219	0.652	0.068	0.060
SUMAS				
Daily Volatility	14.0%	10.0%	4.2%	6.0%
Daily Mean Reversion Rate	0.197	0.537	0.125	0.157

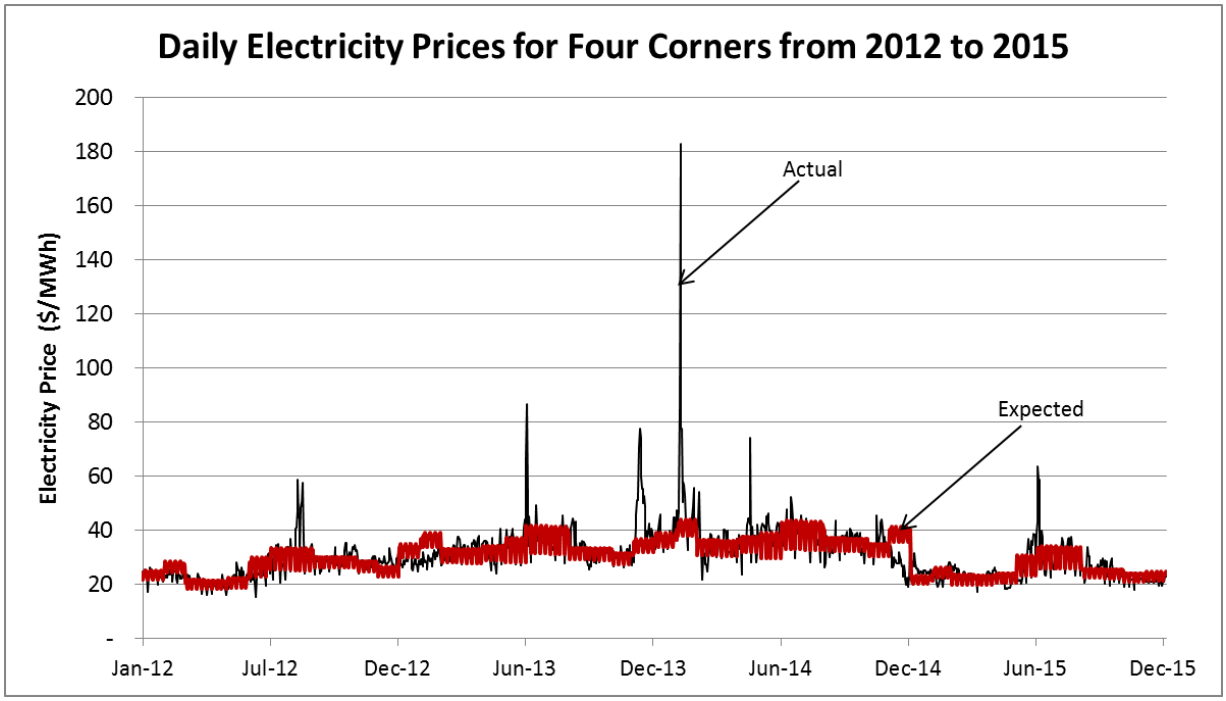
Electricity Price Process

For the most part, electricity prices behave very similar to natural gas prices. The lognormal distribution is generally a good assumption for electricity. While electricity prices do occasionally go below zero, this is not common enough to be worth using the Normal distribution assumption. And the distribution of electricity prices is often skewed upwards. In fact, even the lognormal assumption is sometimes inadequate for capturing the tail of the electricity price distribution. Similar to gas prices, electricity price can experience substantial change from one day to the next so a daily time step should be used.

Basic Data Set:
The electricity price data were organized into a consistent dataset with one price for each region reported for each delivery day similar to gas prices. Data covers the 2012 through 2015 time period. However, electricity prices are reported for "High Load Level" periods (16 hours for six days a week) and "Low Load Level" periods (eight hours for six days a week and 24 hours on Sunday & NERC holidays). In order to have a consistent price definition, a composite price calculated based on 16 hours of peak and eight hours of off-peak prices is used for Monday through Saturday. The Low Load Level price was used for Sundays since that already reflects the 24 hour price. Missing and duplicate data is handled in a fashion similar to gas prices. Illiquid delivery point prices are filled using liquid hub prices as reference. Mid-C is the most liquid market in PACW, so missing prices for COB are filled using latest available spread between COB and Mid-C markets. Similarly, Four Corner prices are filled using Palo Verde prices.

Development of Price Index:
As with gas prices, an electricity price index was developed which accounts for the expected components of price movements. The "expected" electricity price incorporates all three possible adjustments: seasonal average, monthly shape and weekly shape. For instance, the expected price for January 2, 2012 in the Four Corners region was $24.28/MWh. This price incorporates the 2012 winter average price of $25.26/MWh times the monthly shape factor for January of 94 percent and the weekday index for Monday of 102 percent. The following chart shows the Four Corners actual and expected electricity prices over the analysis time period.

Figure H.8 – Daily Electricity Prices for Four Corners



Electricity Price Uncertainty Parameters
Uncertainty parameters are calculated for each electric region similar to the process for gas prices. The electricity price parameters derived through this process are reported in the table below.

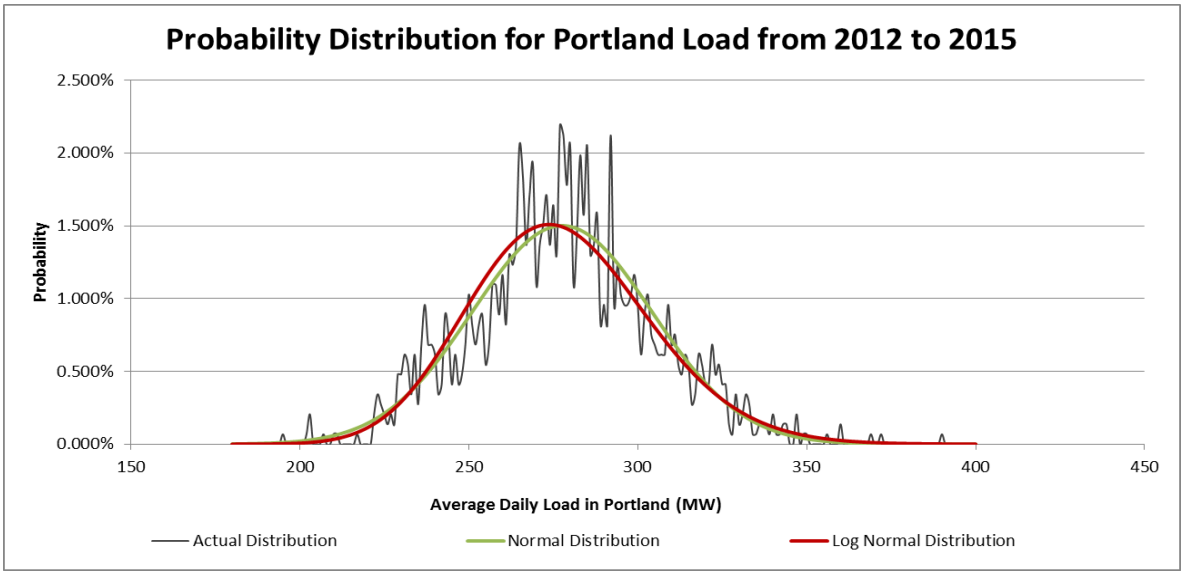
Table H.3 - Uncertainty Parameters for Electricity Regions

	Winter	Spring	Summer	Fall
Four Corners				
Daily Volatility	10.57%	8.68%	10.51%	6.55%
Daily Mean Reversion Rate	0.129	0.466	0.270	0.372
CA-OR Border				
Daily Volatility	13.61%	22.88%	23.51%	7.35%
Daily Mean Reversion Rate	0.135	0.435	0.390	0.227
Mid-Columbia				
Daily Volatility	16.18%	41.99%	38.34%	7.93%
Daily Mean Reversion Rate	0.138	0.510	0.910	0.188
Palo Verde				
Daily Volatility	10.59%	5.82%	8.78%	5.01%
Daily Mean Reversion Rate	0.160	0.308	0.252	0.247

Regional Load Process

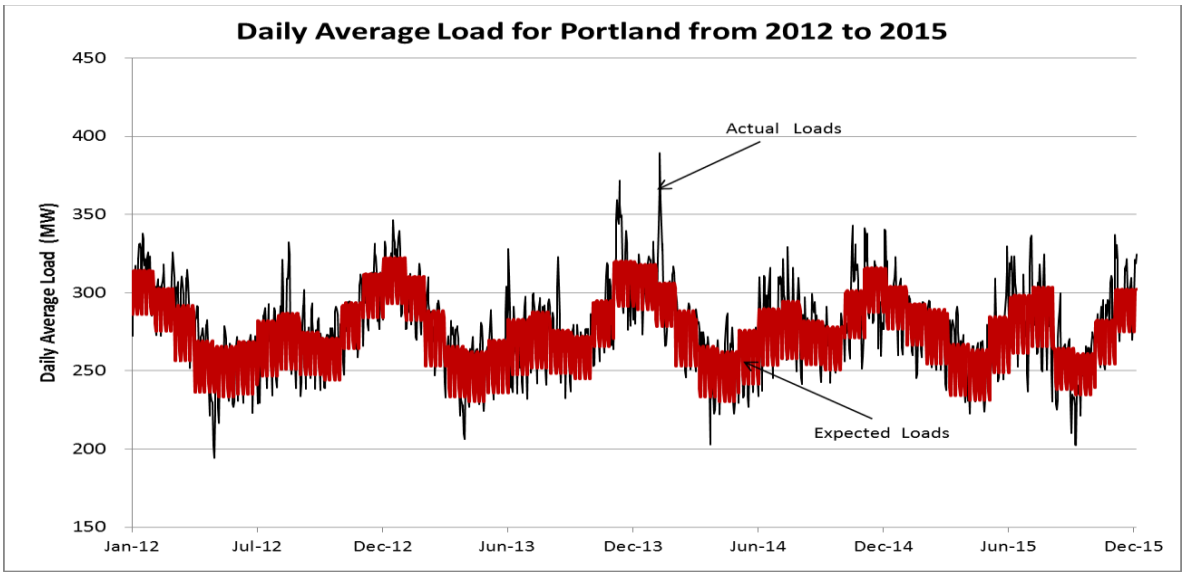
There are only two significant differences between the uncertainty analysis for regional loads and natural gas prices. The distribution of daily loads is somewhat better represented by a normal distribution rather than a lognormal distribution. And, similar to electricity prices, loads have a significant expected shape across the week. The chart below shows the distribution of historical load outcomes for the Portland area as well as normal and lognormal distribution functions representing load possibilities. Both distributions do a reasonable job of representing the spread of possible load outcomes but the tail of the lognormal distribution implies the possibility of higher loads than is supported by the historical data.

Figure H.9 – Probability Distribution for Portland Load



Development of Load Index:
As with electricity prices, a load index was developed which accounts for the expected components of load movements incorporating all three possible adjustments. For instance, the expected load for January 2, 2012 in Portland was 314 MW. This load incorporates the 2012 winter average load of 302 MW times the monthly shape factor for January of 101 percent and the weekday index for Monday of 102 percent. The following chart shows the Portland actual and expected loads over the analysis time period.

Figure H.10 – Daily Average Load for Portland



Load Uncertainty Parameters
Uncertainty parameters are calculated for each load region similar to the process for gas and electricity prices. Since loads are modeled as normally, rather than log-normally distributed, deviations are simply calculated as the difference between the load index and the previous day's index.

The uncertainty parameters for regional loads derived through this process are reported in the table below.

Table H.4 - Uncertainty Parameters for Load Regions

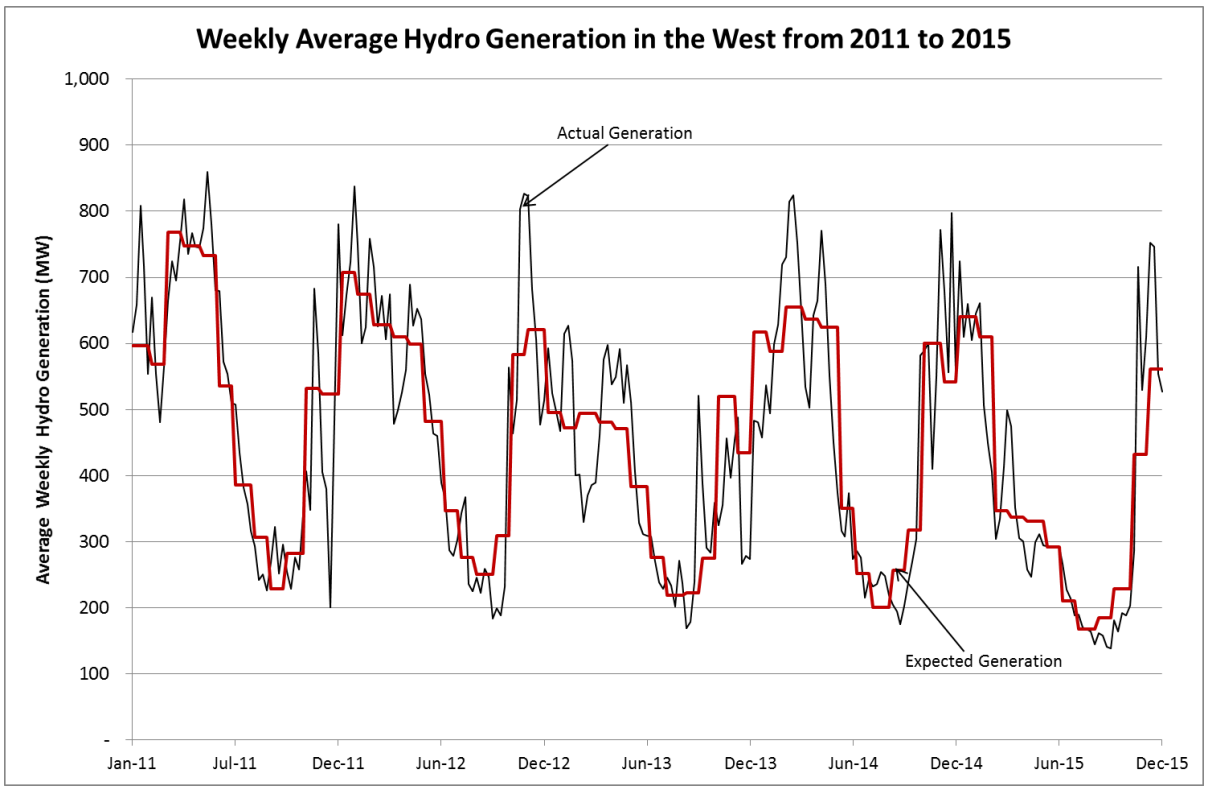
	Winter	Spring	Summer	Fall
California				
Daily Volatility	4.5%	4.1%	3.6%	4.8%
Daily Mean Reversion Rate	0.268	0.263	0.156	0.296
Idaho				
Daily Volatility	3.1%	5.2%	4.8%	4.9%
Daily Mean Reversion Rate	0.175	0.097	0.101	0.210
Portland				
Daily Volatility	3.3%	2.9%	3.9%	3.4%
Daily Mean Reversion Rate	0.237	0.204	0.294	0.268
Oregon Other				
Daily Volatility	4.4%	3.4%	3.8%	4.1%
Daily Mean Reversion Rate	0.206	0.279	0.200	0.212
Utah				
Daily Volatility	2.2%	2.9%	4.5%	3.3%
Daily Mean Reversion Rate	0.400	0.398	0.211	0.287
Washington				
Daily Volatility	4.9%	3.8%	4.8%	4.4%
Daily Mean Reversion Rate	0.202	0.250	0.184	0.184
Wyoming				
Daily Volatility	1.7%	1.6%	1.6%	1.7%
Daily Mean Reversion Rate	0.263	0.271	0.316	0.192

Hydro Generation Process

There are two differences between the uncertainty analysis for hydro generation and natural gas prices. Hydro generation varies on a slower time frame than other variables analyzed. As such, average hydro generation is calculated and analyzed on a weekly, rather than daily, basis. Generation is calculated as the average hourly generation across the 168 hour in a week. In addition, an extra year of data was analyzed for hydro generation. The hydro analysis covers the 2011 through 2015 time period.

Development of Hydro Index:
A hydro generation index was developed which accounts for the expected components of hydro movements incorporating seasonal and monthly adjustments. For instance, the expected hydro generation for the week of January 1, 2011 through January 7, 2011 in the Western Region was 596 MW. This generation incorporates the 2011 winter average generation of 562 MW times the monthly shape factor for January of 106 percent. The following chart shows the western hydro actual and expected generation over the analysis time period.

Figure H.11 – Weekly Average Hydro Generation in the West



Hydro Generation Uncertainty Parameters

Uncertainty parameters are calculated for each hydro region similar to the process for gas and electricity prices. The uncertainty parameters for hydro generation derived through this process are reported in the table below.

Table H.5 - Uncertainty Parameters for Hydro Generation

	Winter	Spring	Summer	Fall
Daily Volatility	20.83%	13.38%	14.89%	27.98%
Daily Mean Reversion Rate	0.81	0.37	1.44	1.06

Short-term Correlation Estimation

Correlation is a measure of how much the random component of variables tend to move together. After the uncertainty analysis has been performed, the process for estimating correlations is relatively straight-forward.

Step 1 - Calculate Residual Errors

Calculate the residual errors of the regression analysis for all of the variables. The residual error represents the random portion of the deviation not explained by mean reversion. It is calculated for each time period as the difference between the actual value and the value predicted by the linear regression equation:

$$Error = Actual\ Deviation - (Slope * Previous\ Deviation + Intercept)$$

All of the residual errors are compiled by delivery date.

Step 2 - Calculate Correlations

Correlate the residual errors of each pair of variables:

$$Correlation(X,Y) = \frac{\sum_i^n [(x_i - x_{avg.}) * (y_i - y_{avg.})]}{\sqrt{\sum_i^n (x_i - x_{avg.})^2 * \sum_i^n (y_i - y_{avg.})^2}}$$

There are a few things to note about the correlation calculations. First, correlation data must always be organized so that the same time period is being compared for both variables. So for instance, weekly hydro deviations cannot be compared to daily gas price deviations. Thus, a daily regression analysis was performed for the hydro variables.

Also note that what is being correlated is the residual errors of the regression—only the uncertain portion of the variable movements. Variables may exhibit similar expected shapes—both loads and electricity prices are higher during the week than on the weekend. This coincidence is captured in the expected weekly shapes input into the planning model. The correlation calculated here captures the extent to which the shocks experienced by two different variables tend to have similar direction and magnitude. The resulting short-term correlations by season are reported below:

Table H.6 - Short-term Correlations by Season

SHORT-TERM WINTER CORRELATIONS

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	92%	53%	27%	27%	52%	-4%	7%	14%	6%	2%	13%	6%	1%
SUMAS	92%	100%	46%	28%	28%	45%	-2%	9%	17%	10%	3%	16%	9%	-1%
4C	53%	46%	100%	54%	53%	78%	11%	21%	35%	27%	25%	34%	22%	6%
COB	27%	28%	54%	100%	96%	71%	14%	17%	35%	37%	18%	45%	22%	7%
Mid-C	27%	28%	53%	96%	100%	68%	14%	18%	36%	37%	18%	46%	23%	5%
PV	52%	45%	78%	71%	68%	100%	10%	16%	30%	25%	22%	31%	16%	9%
CA	-4%	-2%	11%	14%	14%	10%	100%	27%	40%	73%	32%	37%	18%	6%
ID	7%	9%	21%	17%	18%	16%	27%	100%	31%	33%	34%	37%	31%	-6%
Portland	14%	17%	35%	35%	36%	30%	40%	31%	100%	70%	51%	66%	35%	6%
OR Other	6%	10%	27%	37%	37%	25%	73%	33%	70%	100%	43%	65%	33%	8%
UT	2%	3%	25%	18%	18%	22%	32%	34%	51%	43%	100%	44%	48%	0%
WA	13%	16%	34%	45%	46%	31%	37%	37%	66%	65%	44%	100%	33%	15%
WY	6%	9%	22%	22%	23%	16%	18%	31%	35%	33%	48%	33%	100%	5%
Hydro	1%	-1%	6%	7%	5%	9%	6%	-6%	6%	8%	0%	15%	5%	100%

SHORT-TERM SPRING CORRELATIONS

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	87%	13%	9%	6%	18%	-1%	-1%	-2%	0%	-3%	-6%	3%	-2%
SUMAS	87%	100%	12%	9%	6%	14%	-2%	-2%	2%	1%	-3%	-1%	6%	-3%
4C	13%	12%	100%	42%	35%	64%	9%	9%	12%	10%	20%	11%	5%	-2%
COB	9%	9%	42%	100%	86%	46%	14%	2%	30%	28%	15%	33%	13%	3%
Mid-C	6%	6%	35%	86%	100%	33%	16%	7%	28%	26%	22%	30%	9%	0%
PV	18%	14%	64%	46%	33%	100%	12%	13%	24%	19%	30%	19%	9%	1%
CA	-1%	-2%	9%	14%	16%	12%	100%	23%	25%	45%	16%	31%	4%	3%
ID	-1%	-2%	9%	2%	7%	13%	23%	100%	9%	16%	47%	14%	12%	-11%
Portland	-2%	2%	12%	30%	28%	24%	25%	9%	100%	73%	29%	63%	24%	10%
OR Other	0%	1%	10%	28%	26%	19%	45%	16%	73%	100%	33%	69%	19%	11%
UT	-3%	-3%	20%	15%	22%	30%	16%	47%	29%	33%	100%	27%	35%	-11%
WA	-6%	-1%	11%	33%	30%	19%	31%	14%	63%	69%	27%	100%	19%	22%
WY	3%	6%	5%	13%	9%	9%	4%	12%	24%	19%	35%	19%	100%	2%
Hydro	-2%	-3%	-2%	3%	0%	1%	3%	-11%	10%	11%	-11%	22%	2%	100%

SHORT-TERM SUMMER CORRELATIONS

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	56%	7%	10%	5%	11%	-4%	8%	12%	12%	4%	11%	-1%	0%
SUMAS	56%	100%	10%	13%	5%	13%	-1%	3%	16%	12%	-8%	11%	-6%	3%
4C	7%	10%	100%	45%	34%	84%	21%	8%	19%	20%	25%	12%	10%	5%
COB	10%	13%	45%	100%	66%	53%	16%	15%	35%	34%	12%	27%	-1%	24%
Mid-C	5%	5%	34%	66%	100%	37%	19%	9%	35%	34%	16%	30%	2%	8%
PV	11%	13%	84%	53%	37%	100%	16%	6%	19%	21%	20%	10%	11%	12%
CA	-4%	-1%	21%	16%	19%	16%	100%	30%	26%	49%	24%	37%	9%	4%
ID	8%	3%	8%	15%	9%	6%	30%	100%	14%	19%	38%	21%	20%	9%
Portland	12%	16%	19%	35%	35%	19%	26%	14%	100%	78%	18%	63%	-4%	22%
OR Other	12%	12%	20%	34%	34%	21%	49%	19%	78%	100%	27%	75%	-2%	19%
UT	4%	-8%	25%	12%	16%	20%	24%	38%	18%	27%	100%	26%	43%	2%
WA	11%	11%	12%	27%	30%	10%	37%	21%	63%	75%	26%	100%	-1%	15%
WY	-1%	-6%	10%	-1%	2%	11%	9%	20%	-4%	-2%	43%	-1%	100%	-3%
Hydro	0%	3%	5%	24%	8%	12%	4%	9%	22%	19%	2%	15%	-3%	100%

SHORT-TERM FALL CORRELATIONS

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	35%	14%	7%	4%	17%	9%	11%	8%	14%	8%	10%	8%	12%
SUMAS	35%	100%	6%	3%	4%	1%	7%	7%	9%	16%	6%	11%	17%	7%
4C	14%	6%	100%	45%	38%	73%	16%	13%	22%	24%	28%	23%	10%	-18%
COB	7%	3%	45%	100%	85%	50%	7%	6%	21%	22%	20%	24%	1%	-12%
Mid-C	4%	4%	38%	85%	100%	37%	9%	9%	24%	25%	13%	26%	0%	-10%
PV	17%	1%	73%	50%	37%	100%	12%	14%	20%	20%	26%	19%	8%	-16%
CA	9%	7%	16%	7%	9%	12%	100%	26%	43%	66%	27%	54%	19%	5%
ID	11%	7%	13%	6%	9%	14%	26%	100%	22%	27%	35%	24%	7%	-11%
Portland	8%	9%	22%	21%	24%	20%	43%	22%	100%	77%	40%	71%	32%	9%
OR Other	14%	16%	24%	22%	25%	20%	66%	27%	77%	100%	37%	82%	31%	8%
UT	8%	6%	28%	20%	13%	26%	27%	35%	40%	37%	100%	36%	37%	-2%
WA	10%	11%	23%	24%	26%	19%	54%	24%	71%	82%	36%	100%	31%	9%
WY	8%	17%	10%	1%	0%	8%	19%	7%	32%	31%	37%	31%	100%	13%
Hydro	12%	7%	-18%	-12%	-10%	-16%	5%	-11%	9%	8%	-2%	9%	13%	100%

Conclusion

For the continuous, stochastic variables that drive PacifiCorp's electricity environment short-term volatility and mean reversion, complete with corresponding correlations, provide a robust picture of the spread of future outcome. The standard parameters developed here can be used within the PaR model to develop PacifiCorp's Integrated Resource Plan.

APPENDIX I - PLANNING RESERVE MARGIN STUDY

Introduction

The planning reserve margin (PRM), measured as a percentage of coincident system peak load, is a parameter used in resource planning to ensure there are adequate resources to meet forecasted load over time. PacifiCorp selects a PRM for use in its resource planning by studying the relationship between cost and reliability among ten different PRM levels, accounting for variability and uncertainty in load and generation resources.[1] Costs include capital and run-rate fixed costs for new resources required to achieve ten different PRM levels, ranging from 11 percent to 20 percent, along with system production costs (fuel and non-fuel variable operating costs, contract costs, and market purchases). In analyzing reliability, PacifiCorp performed a stochastic loss of load study using the Planning and Risk (PaR) production cost simulation model to calculate the following reliability metrics for each PRM level:

- Expected Unserved Energy (EUE): Measured in gigawatt-hours (GWh), EUE reports the expected (mean) amount of load that exceeds available resources over the course of a given year. EUE measures the magnitude of reliability events, but does not measure frequency or duration.
- Loss of Load Hours (LOLH): LOLH is a count of the expected (mean) number of hours in which load exceeds available resources over the course of a given year. A LOLH of 2.4 hours per year equates to one day in 10 years, a common reliability target in the industry. LOLH measurs the duration of reliability events, but does not measure frequency or magnitude.
- Loss of Load Events (LOLE): LOLE is a count of the expected (mean) number of reliability events over the course of a given year. A LOLE of 0.1 events per year equates to one event in 10 years, a common reliability target in the industry. LOLE measures the frequency of reliability events, but does not measure magnitude or duration.

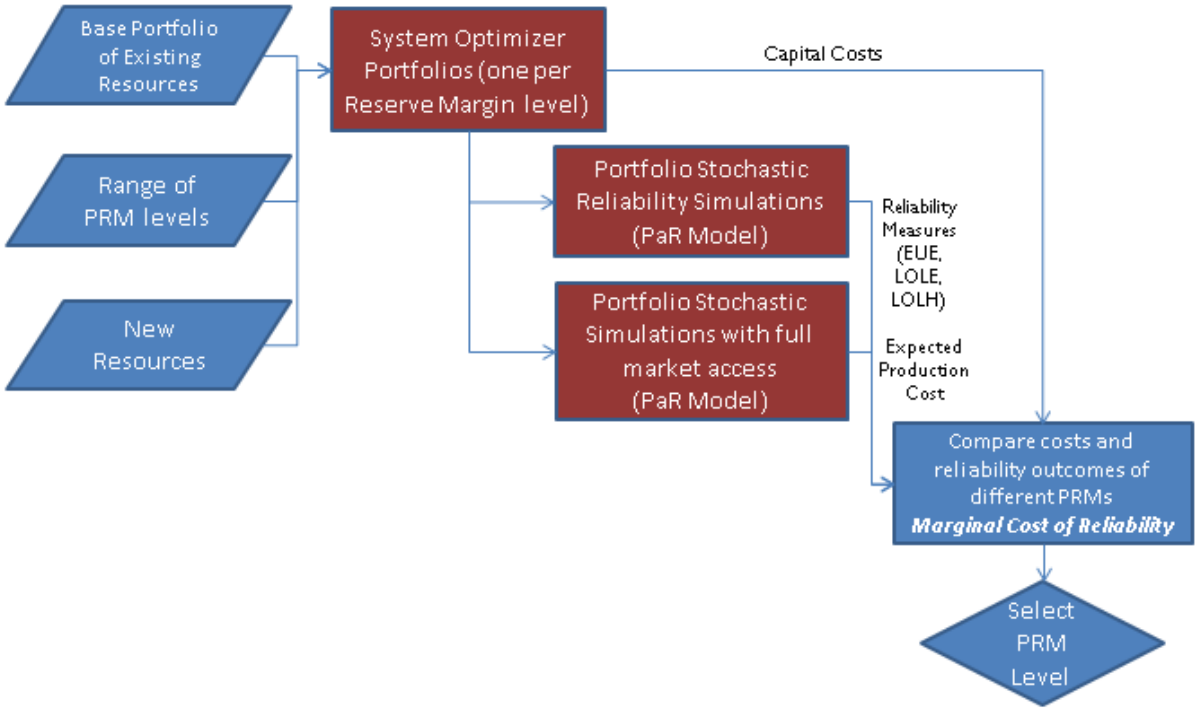
PacifiCorp's loss of load study results reflect its participation in the Northwest Power Pool (NWPP) reserve sharing agreement. This agreement allows a participant to receive energy from other participants within the first hour of a contingency event, defined as an event when there is an unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. PacifiCorp's participation in the NWPP reserve sharing agreement improves reliability at a given PRM level. Upon evaluating the relationship between cost and reliability in its PRM study, PacifiCorp will continue to use a 13 percent target PRM in its resource planning.

[1] Costs and reliability metrics are calculated for eleven different PRM levels, ranging from 10 percent to 20 percent. Comparative analysis among each PRM is performed for 10 different PRM levels by comparing the cost and reliability results from PRM levels ranging between 11 percent and 20 percent to those from the 10 percent PRM.

Methodology

Figure I.1 shows the workflow used in PacifiCorp's PRM study. The four basic modeling steps in the workflow include: (1) using the System Optimizer (SO) model, produce resource portfolios among eleven different PRM levels ranging between 10 percent and 20 percent; (2) using the Planning and Risk model (PaR), produce reliability metrics for each resource portfolio; (3) using PaR, produce system stochastic variable production costs with full market access for each resource portfolio; (4) produce the marginal cost of reliabability using outcomes of different PRM levels, (5) select PRM level.

Figure I.1 - Workflow for Planning Reserve Margin Study



Development of Resource Portfolios

The SO model is used to produce resource portoflios assuming PRM levels ranging between 10 percent and 20 percent. The SO model optimizes expansion resources over a 20-year planning horizon to meet peak load inclusive of the PRM applicable to each case. An improvement was made in the study to meet the PRM in both summer and winter. As the PRM level is increased from 10 percent to 20 percent, additional resources are added to the portfolio. Resource options used in this step of the workflow include demand side management (DSM), gas-fired combined cycle combustion turbines (CCCT), gas-fired simple cycle combustion turbines (SCCT), renewable resources and front office transactions (FOTs).

FOTs are considered as a resource expansion option in this phase of the workflow. FOTs are proxy resources used in the IRP portfolio development process that represent firm forward short-term market purchases for summer and winter on-peak delivery, which coincides with the time

of year and time of day in which PacifiCorp observes its coincident system peak load. These proxy resources are a reasonable representation of firm market purchases when performing comparative analysis of different resource portfolios to arrive at a preferred portfolio in the IRP.

Upfront capital and run-rate fixed costs from each portfolio are recorded and used later in the workflow where the relationship between cost and reliability is analyzed. Resources from each portfolio are used in the subsequent workflow steps where reliability metrics and production costs are produced in PaR.

Development of Reliability Metrics

PaR is used to produce reliability metrics for each of the resource portfolios developed assuming PRM levels ranging between 10 percent and 20 percent. PaR is a production cost simulation model, configured to represent PacifiCorp's integrated system, that uses Monte Carlo random sampling of stochastic variables to produce a distribution of system operation. For this step in the workflow, reliability metrics are produced from a 500-iteration PaR simulation with Monte Carlo draws of stochastic variables that affect system reliability—load, hydro generation, and thermal unit outages. As discussed above, system balancing hourly purchases are enabled to capture the contribution of firm market purchases to system reliability. The PaR reliability studies are used to report instances where load exceeds available resources, including system balancing hourly purchases. Reported EUE measures the stochastic mean volume of instances where load exceeds available resources, and is mesasured in GWh. EUE measures the magnitude of reliability events. Reported LOLH is a count of the stochastic mean hours in which load exceeds available resources. LOLH measures the duration of reliability events. Reported LOLE is a count of the stochastic mean events in which load exceeds available resources. LOLE is a measure of the frequency of reliability events.

Each of the reliability metrics described above is adjusted to account for PacifiCorp's participation in the NWPP reserve sharing agreement, which allows a participant to receive energy from other participants within the first hour of a contingency event. The NWPP adjustments are made to EUE by reducing the stochastic mean volume of instances where load exceeds available resources for the first hour of a reliability event. For example, if the stochastic mean volume of EUE for a reliability event is 120 MWh, equal to 40 MWh in three consecutive hours, then the adjusted EUE is 80 MWh after removing the first hour of the event. Using this same example, LOLH would be adjusted from three to two hours, and LOLE would not be adjusted. The LOLE is only adjusted inasmuch as a given reliability event has a one hour duration.

For PaR, the contribution of firm market purchases are removed and instead include system balancing hourly purchases that cover the firm market purchases, limited by transmission and market depth limits, for the reliability metrics.

Development of System Variable Production Costs

In addition to using PaR to develop reliability metrics, PaR is also used to produce system variable production operating costs for each of the resource portfolios developed assuming PRM levels ranging between 10 percent and 20 percent. For PaR's system variable production cost runs, its Monte Carlo sampling of stochastic variables is expanded to include natural gas and

wholesale market prices in addition to load, hydro generation, and thermal unit outages. At this step, the stochastic treatment of market prices is key given its influence on the economic dispatch of system resources, cost of system balancing purchases, and revenues from system balancing sales. In this step, full market access is included for the simulation. The stochastic mean of system variable costs is added to the upfront capital and run-rate fixed costs from each portfolio so that total portfolio costs are captured for each PRM level.

Marginal Cost of Reliability The marginal cost of reliability compares costs and reliabability outcomes across different PRM levels for 2020 through 2030. The use of a 10-year test period was an improvement to that of earlier IRPs which used a one-year test period. The marginal cost of reliability for each PRM, vis-a-vis that of the 10-percent PRM, is calculated as the difference in total production costs divided by the change in EUE. Correspondingly, for a 10 year period, the average marginal cost of reliability is the 10-year nominal levelized cost of yearly marginal reliability costs. The average ten-year marginal cost of reliability is calculated for all PRM levels ranging between 11 percent and 20 percent.

Selection of PRM Level

Using the marginal cost of reliability analysis, the PRM level is selected for use in the 2017 IRP.

Results

Resource Portfolios

Table I.1 shows new resources added to the portfolio for the summer at PRM levels ranging between 10 and 20 percent. Each portfolio includes high load hour (HLH) front office transactions (FOTs) ranging from 550 to 1,136 MWs and flat FOTs of 176 MW in all PRMs. A 454 MW CCCT is added for the 19 percent and 20 percent PRM studies. DSM resource additions range between 374 MW and 431 MW. An improvement, to prior IRPs, was the inclusion of DSM Class 1 to the resource selection. As the PRM increases, system capacity is largely met with FOTs. Because new CCCT resources are added in blocks indicative of a typical plant size (i.e. the model cannot add a 2 MW CCCT plant), the addition of new DSM resources does not always follow an increase in the PRM.

Table I.1 - Expansion Resource Additions by PRM for Summer

PRM (%)	Summer						
	DSM Capacity at System Peak	DSM Class 1	FOT	FOT Flat	SCCT	CCCT	Total
10	380	0	550	176	0	0	1,107
11	374	0	651	176	0	0	1,201
12	380	0	738	176	0	0	1,294
13	384	0	828	176	0	0	1,388
14	394	0	912	175	0	0	1,481
15	400	0	1,000	175	0	0	1,575
16	382	0	1,112	176	0	0	1,670
17	425	25	1,134	174	0	0	1,759
18	431	113	1,136	172	0	0	1,852
19	396	0	982	175	0	454	2,007
20	380	0	1,093	176	0	454	2,103

Table I.2 shows new resources added to the portfolio for the winter at PRM levels ranging between 10 percent and 20 percent. The winter resource rating are difference from summer due to temperative variations and contribution to system peak.

Table I.2 - Expansion Resource Additions by PRM for Winter

PRM (%)	Winter						
	DSM Capacity at System Peak	DSM Class 1	FOT	FOT Flat	SCCT	CCCT	Total
10	240	0	26	176	0	0	442
11	237	0	34	176	0	0	447
12	240	0	41	176	0	0	456
13	243	0	48	176	0	0	467
14	250	0	55	175	0	0	480
15	253	0	70	175	0	0	497
16	241	0	86	176	0	0	502
17	259	25	101	174	0	0	559
18	266	113	93	172	0	0	643
19	248	0	133	175	0	454	1,010
20	239	0	149	176	0	454	1,018

Reliability Metrics

Table I.3 shows EUE, LOLH, and LOLE reliability results before and after adjusting these reliability metrics for PacifiCorp's participation in the NWPP reserve sharing agreement. Each of the reliability metrics generally improve as the PRM increases and after accounting for benefits associated with PacifiCorp's participation in the NWPP reserve sharing agreement. After accounting for its participation in the NWPP reserve sharing agreement, all PRM levels meet a one day in ten year planning criteria (LOLH at or below 2.4), and PRM levels of between 19 and 20 percent meet a one event in ten year planning criteria (LOLE at or above 0.1).

Table I.3 - Expected Reliability Metrics by PRM

PRM (%)	Before NWPP Adjustment			After NWPP Adjustment		
	Simulated Energy Not Served (GWh)	LOLH (<2.4 target year) (Hour)	Loss of Load Episodes	EUE (GWh)	LOLH (Hour)	Modeled Loss of Load Episodes
10	79	0.94	0.69	21	0.25	0.15
11	80	0.93	0.68	21	0.25	0.15
12	79	0.94	0.69	21	0.25	0.15
13	78	0.92	0.68	20	0.24	0.15
14	76	0.90	0.66	20	0.24	0.15
15	75	0.90	0.66	20	0.24	0.15
16	78	0.94	0.69	21	0.25	0.15
17	72	0.92	0.68	19	0.24	0.15
18	71	0.91	0.68	18	0.23	0.14
19	33	0.78	0.60	8	0.18	0.10
20	34	0.76	0.58	8	0.19	0.10

The reliability metrics do not montonically improve with each incremental increase in the PRM. This is influenced by the physical location of new resources within PacifiCorp's system at varying PRM levels and the ability of these resources to serve load in all load pockets when Monte Carlo sampling is applied to load, hydro generation, and thermal unit outages. Considering that the reliability metrics are measuring very small magnitudes of change among the different PRM levels, the PaR outputs are fit to a logarithmic function to report the overall trend in reliability improvements as the PRM level increases. Table I.4 shows the fitted EUE LOLH, and LOLE results. Figure I.2, Figure I.3 and Figure I.4 show a plot of the fitted trend for EUE, LOLH, and LOLE, respectively, after accounting for PacifiCorp's participation in the NWPP reserve sharing agreement.

Table I.4 - Fitted Reliability Metrics by PRM

PRM (%)	Before NWPP Adjustment			After NWPP Adjustment		
	EUE (GWh)	LOLH (<2.4 target year) (Hour)	Modeled Loss of Load Episodes	EUE (GWh)	LOLH (Hour)	Modeled Loss of Load Episodes
10	91	0.97	0.71	24	0.26	0.16
11	81	0.94	0.69	22	0.25	0.15
12	76	0.92	0.68	20	0.24	0.15
13	72	0.90	0.67	19	0.23	0.14
14	68	0.89	0.66	18	0.23	0.14
15	66	0.88	0.66	17	0.23	0.14
16	64	0.87	0.65	16	0.22	0.14
17	62	0.87	0.65	16	0.22	0.13
18	60	0.86	0.65	15	0.22	0.13
19	58	0.86	0.64	15	0.22	0.13
20	57	0.85	0.64	14	0.21	0.13

Figure I.2 - Expected and Fitted Relationship of EUE to PRM

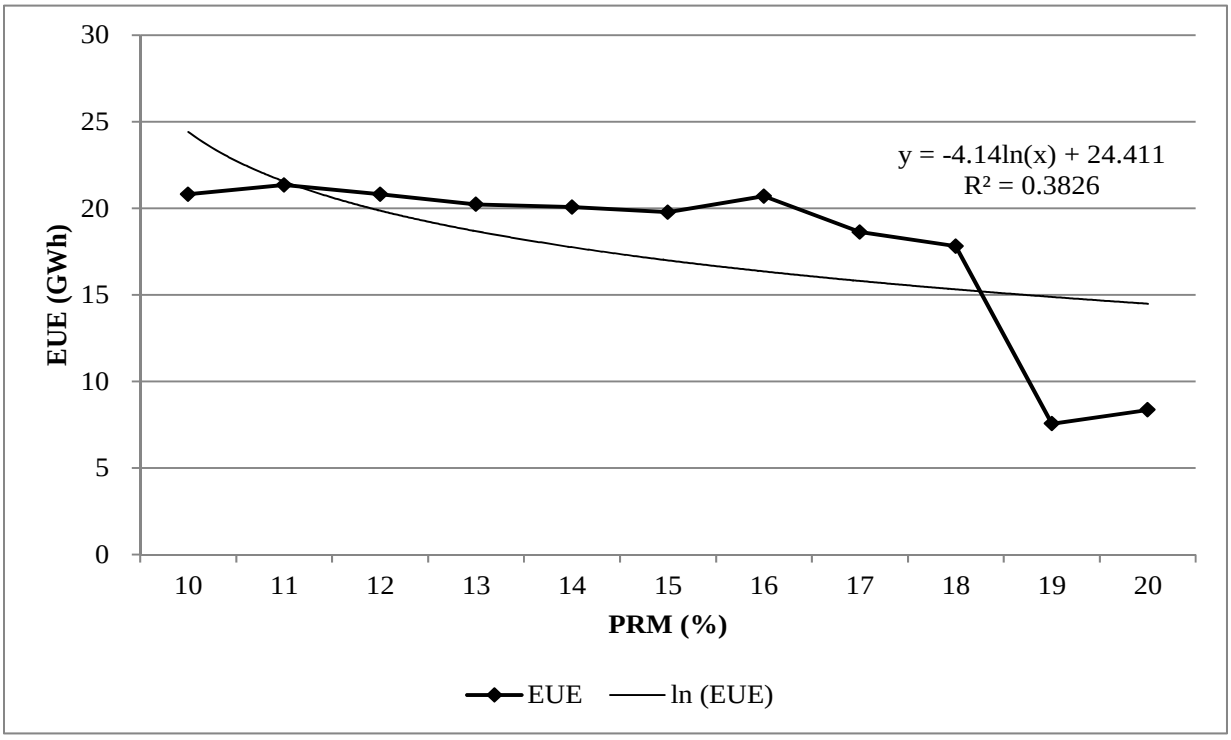


Figure I.3 - Expected and Fitted Relationship of LOLH to PRM

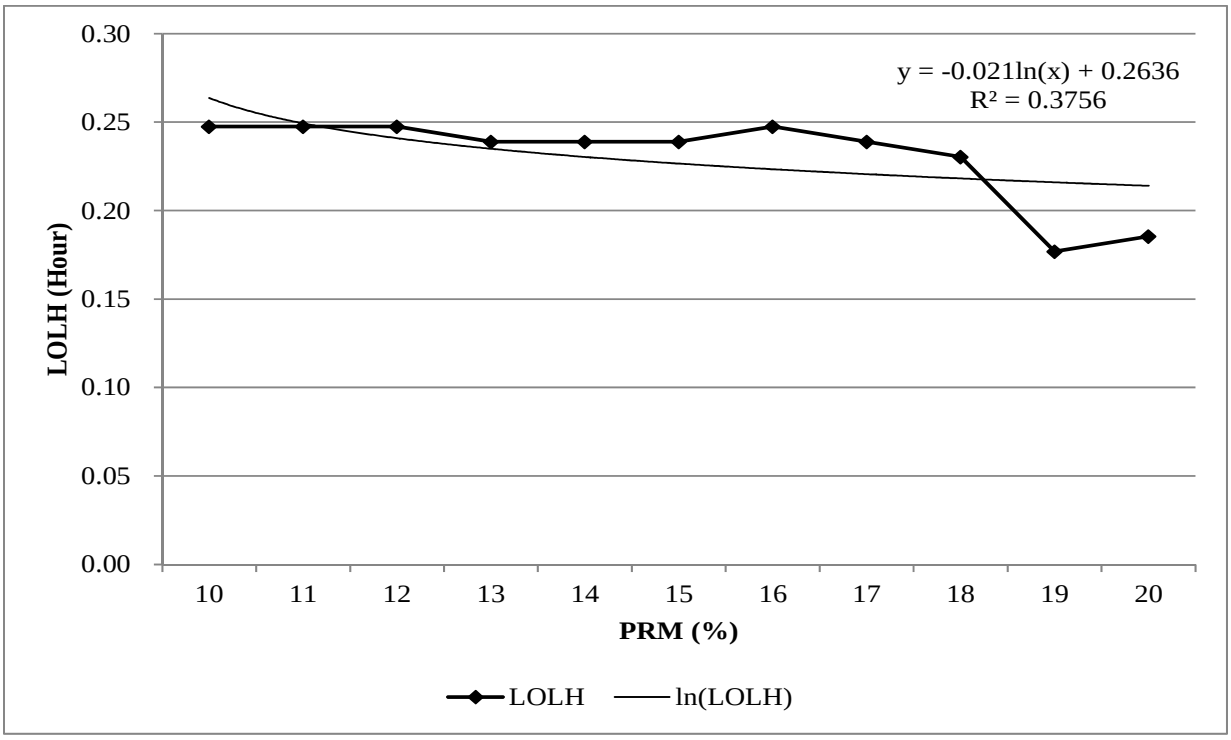
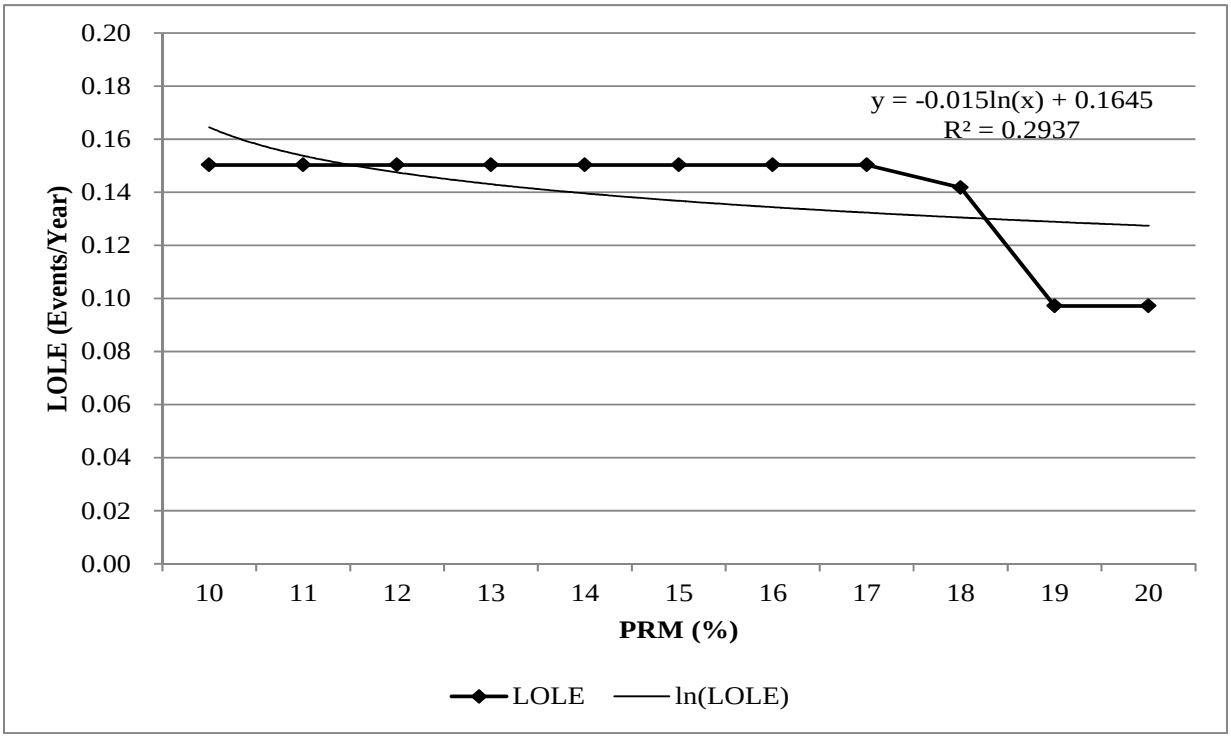


Figure I.4 - Simulated Relationship of Loss of Load Episode to PRM



System Costs

For the 2020 reference year, Table I.5 shows the stochastic mean of system variable production costs and the upfront capital and run-rate fixed costs, including the cost of new DSM resources, for each portfolio developed at PRM levels ranging between 10 percent and 20 percent. The fixed costs associated with these new resource additions drive total costs higher as PRM levels increase. DSM run-rate costs vary depending on resource additions for DSM Class 1 and new resources where a CCCT was added in 19 percent and 20 percent.

Table I.5 – System Variable, Up-front Capital, and Run-rate Fixed Costs by PRM

PRM (%)	System Production Costs ($m)	Class 2 DSM ($m)	Class 1 DSM ($m)	Existing Resource Fixed Costs ($m)	New Resource Fixed Cost ($m)	Total Costs ($m)
10	10,969	437	0	6,093	183	$17,681
11	11,003	404	0	6,093	197	$17,698
12	10,966	437	2	6,093	203	$17,701
13	10,958	463	9	6,093	193	$17,715
14	10,906	514	12	6,093	198	$17,723
15	10,892	553	28	6,093	181	$17,747
16	10,923	440	2	6,093	382	$17,840
17	10,882	522	18	6,093	354	$17,869
18	10,865	535	63	6,093	371	$17,927
19	10,835	527	26	6,093	581	$18,061
20	10,870	429	7	6,093	745	$18,144

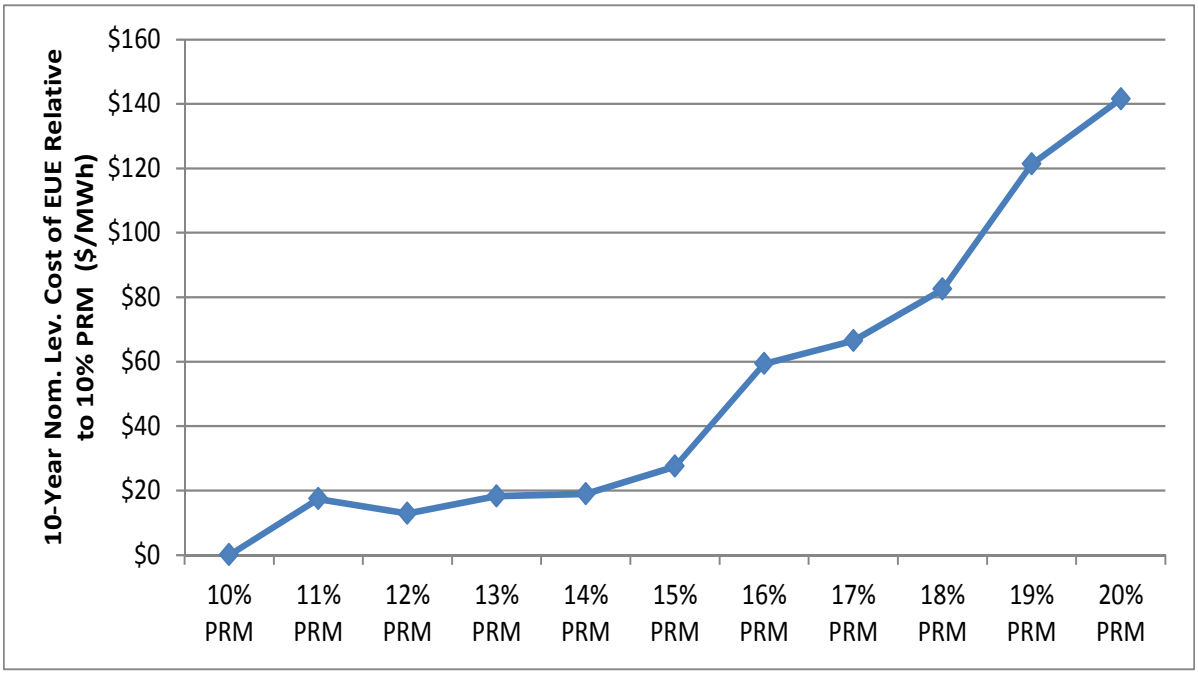
Incremental Cost of Reliability

Table I.6 shows the incremental cost of reliability, stated as the 10-year nominal levelized cost of EUE relative to 10 percent PRM, at PRM levels ranging between 11 percent and 20 percent. Figure I.5 depicts this same information graphically. The incremental cost of reliability rises modestly at the 14 percent to 15 percent PRM, then rises dramatically as PRM levels increase from 16 percent to 20 percent.

Table I.6 - 10-year nominal levelized cost of EUE relative to 10 percent PRM

PRM	Reduction in EUE Reliability from 10% PRM (GWh)	Reduction in Total Cost from 10% PRM ($ Million)	$/MWh
10	-	-	$0
11	930	16	$17
12	1,475	19	$13
13	1,861	34	$18
14	2,160	41	$19
15	2,405	66	$27
16	2,612	155	$59
17	2,791	185	$66
18	2,949	243	$82
19	3,091	375	$121
20	3,219	455	$141

Figure I.5 - Incremental Cost of Reliability by PRM



Conclusion

PacifiCorp will continue to use a 13 percent target PRM in its resource planning after evaluating the relationship between cost and reliability in the PRM study. A PRM below 13 percent would not sufficiently cover the need to carry short-term operating reserve needs (contingency and regulating margin) and longer-term uncertainties such as extended outages and changes in customer load.[2] A PRM above 15 percent improves reliability above a one event in ten year planning level, though with a 300 percent to 700 percent increase in the incremental cost per megawatt-hour of reduced EUE when compared to a 13 percent PRM. With these considerations, the selected 13 percent PRM level ensures PacifiCorp can reliably meet customer loads while maintaining operating reserves, with a planning criteria that meets one day in 10 year planning targets, at the lowest reasonable cost.

[2] PacifiCorp must hold approximately six percent of its resources in reserve to meet contingency reserve requirements and an estimated additional 4.5 percent to 5.5 percent of its resources in reserve, depending upon system conditions at the time of peak load, as regulating margin. This sums to 10.5 percent to 11.5 percent of operating reserves before even considering longer-term uncertainties such as extended outages (transmission or generation) and customer load growth.

APPENDIX J – WESTERN RESOURCE ADEQUACY EVALUATION

Introduction

The Public Service Commission of Utah, in its 2008 IRP Order, directed the Company to conduct two analyses pertaining to the Company's ability to support reliance on market purchases:

> *Additionally, we direct the Company to include an analysis of the adequacy of the western power market to support the volumes of purchases on which the Company expects to rely. We concur with the Office [of Consumer Services], the WECC is a reasonable source for this evaluation. We direct the Company to identify whether customers or shareholders will be expected to bear the risks associated with its reliance on the wholesale market. Finally, we direct the Company to discuss methods to augment the Company's stochastic analysis of this issue in an IRP public input meeting for inclusion in the next IRP or IRP update.*[1]

To fulfill the first requirement, PacifiCorp evaluated the Western Electricity Coordinating Council (WECC) Power Supply Assessment (PSA) reports to glean trends and conclusions from the supporting analysis. This evaluation, along with a discussion on risk allocation associated with reliance on market purchases, is provided below. As part of this evaluation, the Company also reviewed the status of resource adequacy assessments prepared for the Pacific Northwest by the Pacific Northwest Resource Adequacy Forum.

Western Electricity Coordinating Council Resource Adequacy Assessment

The WECC 2016 PSA, issued in December 2016, shows a planning reserve margin (PRM) calculated as a percentage of resources (generation and transfers) and load, and is the percentage of capacity greater than demand. The PRM indicates that there are sufficient resources when the PRM is equal to or greater than the target planning reserve margin. The 2016 PSA shows WECC in total not needing additional resources throughout the entire period of the study, which ends in 2026 (see Figure J.1).

In WECC's PSAs, the region and sub-region target planning reserve margins are calculated using a building block methodology established by WECC. As such, they do not reflect a criteria-based margin determination process and do not reflect any balancing authority area or load serving entity level requirements that may have been established through other processes (e.g., state regulatory authorities). They are not intended to supplant any of those requirements.

[1] Public Service Commission of Utah, PacifiCorp 2008 Integrated Resource Plan, Report and Order, Docket No. 09-2035-01, p. 30.

The WECC building block methodology is comprised of four elements[2]:

1. Contingency Reserves – An amount of operating reserves sufficient to reduce area control error to zero in ten minutes following loss of generating capacity, which would result from the most severe single contingency.

2. Regulating Reserves – The amount of spinning reserves responsive to automatic generation control that is sufficient to provide the normal regulating margin. The regulating component of this guideline was calculated using data provided in WECC's annual loads and resources data request responses.

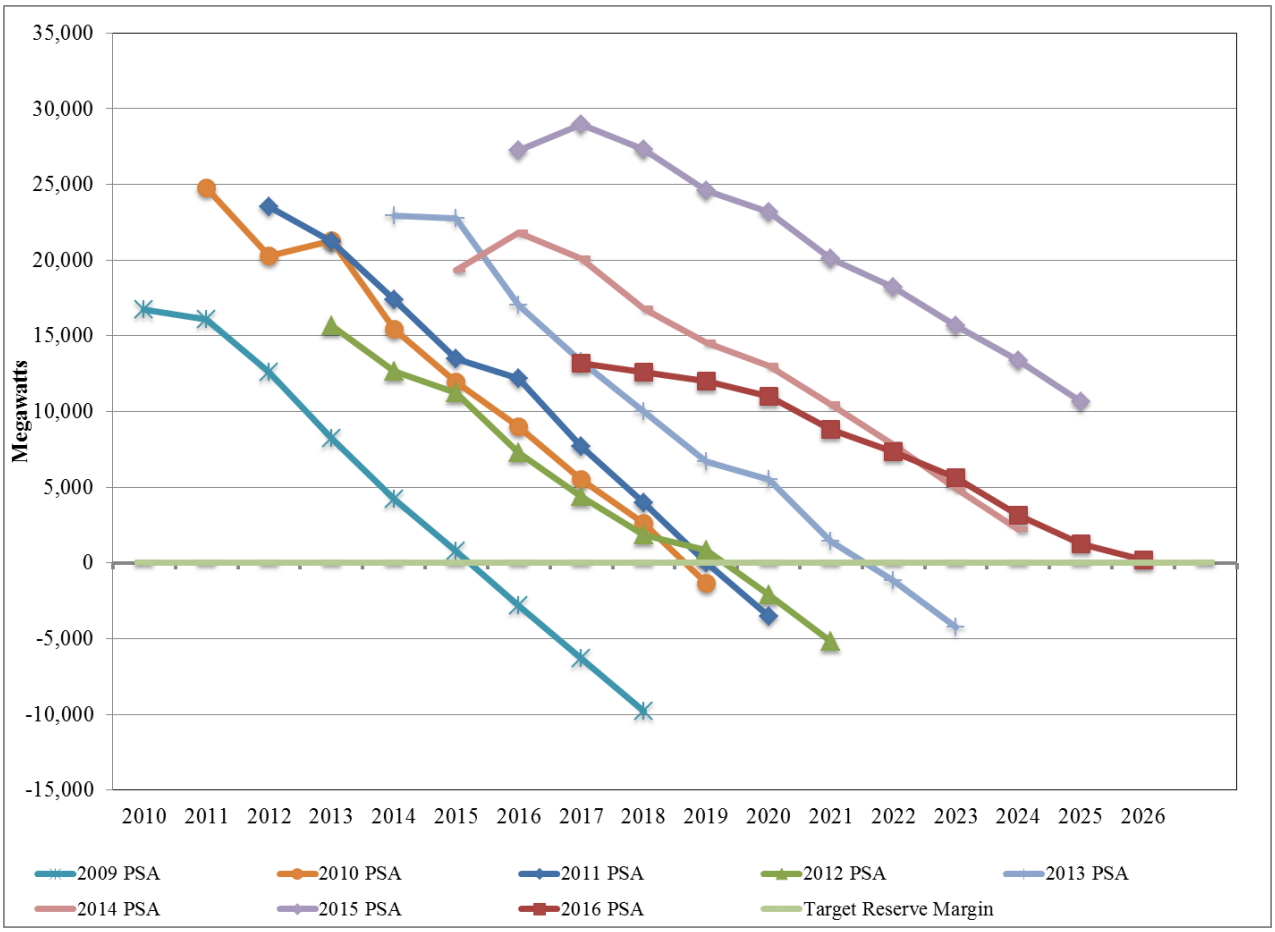
3. Reserves for Generation Forced Outages – The capacity lost to forced outages for both the summer (July) and winter (December) is added by sub-region and divided by the total capacity reported for each sub-region. The seasonal forced out rates are then averaged across five years to give the forced outage portion of the reserve margin.

4. Temperature Adders – a MW/degree Celsius coefficient is determined by WECC staff based on five years of daily peak demand regressed on daily maximum temperature for every weekday in the season. Fifty years of seasonal extremes in daily peak temperature are used to estimate the difference between a 1-in-2 and 1-in-10 observation. The MW/degree Celsius number is multiplied by the 1-in-10 temperature to yield a 90/10 extreme weather demand forecast.

As seen in Figure J.1, the 2016 PSA shows the WECC as having a positive summer power supply margin (PSM) in all years. The PSM is a measure of a region's ability to meet total load requirements, including its target reserve margin. As such, a PSM of zero or more indicates that demand plus the target reserve margin was met.

[2] Further details of building block elements can be found on the WECC website at the following location: https://www.wecc.biz/Reliability/2016LAR_MethodsAssumptions%20(002).pdf

Figure J.1 - WECC Forecasted Power Supply Margins, Issued 2009 to 2016 (Summer)



Note: WECC Power Supply Assessments include Class 1 Planned Resources Only

The 2016 PSA shows no deficit for the study period. Figure J.2 shows the difference between the 2016 and 2014 PSA studies. For all years the load forecasts (net internal demand) and capacity resources decreased. The target reserve margins change from year to year, though for the most part are not a major contributor to the PSA deviations between the 2016 and 2014 PSAs.

Figure J.2 - 2016 less 2014 WECC PSA (for Summer Periods)



Tables J.1 and J.2 show both the target summer and winter planning reserve margins calculated in the 2016 WECC PSA report, along with the forecasted yearly results. These results are based on the following elements:

- Monthly and annual peak demand and energy forecasts:
- Expected generation availability;
- Annual energy for energy limited resources;
- Coincident hourly-shaping data for loads and energy-limited resources; and
- A simplified transmission configuration that reflects nominal power transfer capability limits.

Table J.1 - 2016 WECC Forecasted Planning Reserve Margins (Summer)

Planning Reserve Margin											
Subregion	Target Reserve Margin	2017 (S)	2018 (S)	2019 (S)	2020 (S)	2021 (S)	2022 (S)	2023 (S)	2024 (S)	2025 (S)	2026 (S)
NWPP	**15.20%**	27.7%	26.5%	28.3%	27.9%	26.6%	25.4%	24.7%	22.8%	20.0%	18.9%
RMRG	**14.14%**	27.0%	24.3%	22.1%	20.1%	19.7%	19.7%	19.6%	16.7%	16.5%	16.5%
SRSG	**15.82%**	23.4%	21.2%	21.1%	17.6%	17.5%	17.5%	17.4%	17.4%	17.4%	17.3%
CA/MX	**16.16%**	19.1%	20.3%	20.1%	21.3%	19.7%	18.8%	17.4%	16.0%	16.0%	15.6%
WECC Total	**15.37%**	24.1%	23.6%	23.2%	22.5%	21.0%	20.0%	18.9%	17.3%	16.1%	15.5%

Table J.2 – 2016 WECC Forecasted Planning Reserve Margins (Winter)

Planning Reserve Margin											
Subregion	Target Reserve Margin	2017-18 (W)	2018-19 (W)	2019-20 (W)	2020-21 (W)	2021-22 (W)	2022-23 (W)	2023-24 (W)	2024-25 (W)	2025-26 (W)	2026-27 (W)
NWPP	**16.70%**	24.9%	24.9%	24.1%	23.1%	22.4%	21.3%	20.8%	19.9%	17.7%	17.1%
RMRG	**11.65%**	59.5%	51.8%	48.4%	44.6%	41.6%	39.5%	37.4%	35.1%	33.3%	31.2%
SRSG	**12.11%**	101.6%	101.0%	96.5%	94.2%	89.8%	85.0%	80.9%	77.1%	73.3%	69.7%
CA/MX	**13.50%**	19.3%	19.9%	20.8%	22.2%	18.8%	20.3%	19.6%	17.9%	18.2%	18.6%
WECC Total	**14.27%**	35.3%	34.9%	34.2%	33.5%	31.7%	29.9%	28.8%	27.5%	26.2%	25.3%

The 2016 WECC planning reserve margin results show that there is no resource need through 2026 on a WECC total basis. However, the planning reserve margin for the CA/MX sub-region falls below the target reserve margin beginning in summer period 2024.

Northwest Power Pool (NWPP) is a winter peaking WECC sub-region comprised of Washington, Oregon, Idaho, Montana, Nevada, Utah, western Wyoming, Alberta, British Columbia and the Balancing Authority of Northern California. The target summer reserve margin for this region is 15.2 percent, which is slightly below the WECC Total forecasted planning reserve margin for 2017-2026 (15.37 percent). The target winter reserve margin for this region is 16.70 percent, which is above the WECC Total forecasted planning reserve margin for 2017-2026 (14.27 percent).

Market depth refers to a market's ability to accept individual transactions without a perceptible change in market price. While different from market liquidity[3] the two are linked in that a deep market tends to be a liquid market. Electricity market depth is a function of the number of economic agents, market period, generating capacity, transmission capability, transparency, and institutional and/or physical constraints. Based on the 2016 PSA, WECC maintains a positive power supply margin (PSM) through 2026. All of the WECC's sub-regions also are forecasted to maintain sufficient PSM through 2026, with the exception of the CA/MX sub-region. In total, known market transactions, generation resources, load requirements, and the optimization of transfers within WECC show adequate market depth to maintain target reserve margins for several years.

Pacific Northwest Resource Adequacy Forum's Adequacy Assessment

The Pacific Northwest Resource Adequacy Forum (later replaced by the Resource Adequacy Advisory Committee) issued resource adequacy standards in April 2008, which were

[3] Market liquidity refers to having ready and willing buyers and sellers for large transactions.

subsequently adopted by the Northwest Power and Conservation Council. The standard calls for assessments three and five years out, conducted every year, and including only existing resources and planned resources that are already sited and licensed. The Resource Adequacy Advisory Committee issued a Pacific Northwest Power Supply Adequacy Assessment for 2021 on August 10, 2016. [4] This assessment concluded that power supply is expected to be adequate through 2020. However, with the planned retirements of four Northwest coal plants by July of 2022, 1,400 megawatts of new capacity will be needed to maintain the Council's adequacy standard. [5] In 2021, with the loss of 1,330 megawatts of capacity from the retirements of the Boardman and Centralia 1 coal plants, the likelihood of a power supply shortfall (also referred to as the loss of load probability) rises to 10 percent. In this scenario, the region will need more than 1,000 megawatts of new capacity to maintain adequacy. Northwest utilities show about 550 megawatts of planned generating capacity for 2021, yet this capacity was not included in the August 10, 2016 assessment because it was not yet sited and licensed.

Customer versus Shareholder Risk Allocation

Market purchase costs are reflected in rates. Consequently, customers bear the price risk of the Company's reliance on a given level of market purchases. However, customers also bear the cost impact of the Company's decision to build or acquire resources if those resources exceed market alternatives and result in an increase in rates. These offsetting risks stress the need for robust IRP analysis, efficient RFPs and ability to capture opportunistic procurement opportunities when they arise.

Market Purchases

As described in Volume I, Chapter 6 (Resource Options), PacifiCorp, other utilities, and power marketers who own and operate generation engage in market 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 models 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.

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.

[4] Pacific Northwest Power Supply Adequacy Assessment for 2021, at https://www.nwcouncil.org/media/7150504/2021-adequacy-assessment-final-aug_9_2016.pdf

[5] The standard deems the power supply to be inadequate if the likelihood of a power supply shortfall is higher than 5 percent.

In developing FOT limits for the 2017 IRP, PacifiCorp reviewed the studies described in the sections above as part of its assessment of western resource adequacy in addition to consideration of its active participation in wholesale power markets, its view of physical delivery constraints, and market liquidity and market depth. For the 2017 IRP, PacifiCorp held its FOT limits consistent with the prior IRP as shown in Table J.3.

Table J.3 – Maximum Available Front Office Transactions by Market Hub

Market Hub/Proxy FOT Product Type	Megawatt Limit and Availability
Mid-Columbia Flat Annual ("7x24") and July, Heavy Load Hour ("6x16") or December, Heavy Load Hour ("6x16")	400 MW, 2017 - 2036
July, Heavy Load Hour ("6x16"), December, Heavy Load Hour ("6x16")	375 MW, 2017 - 2036
California Oregon Border (COB) Flat Annual ("7x24") and July, Heavy Load Hour ("6x16") or December, Heavy Load Hour ("6x16")	400 MW, 2017- 2036
Southern Oregon / Northern California (NOB) July, Heavy Load Hour ("6x16"), December, Heavy Load Hour ("6x16")	100 MW, 2017- 2036
Mona July, Heavy Load Hour (6x16) December, Heavy Load Hour ("6x16")	300 MW, 2017-2036

In determining FOT limits for the 2017 IRP planning cycle, PacifiCorp reviewed historical market purchases from 2009 to 2015 in both the summer peak and winter peak periods. As shown in Figures J.3 and J.4 below, PacifiCorp reviewed its hourly purchases during peak load times in the summer and in the winter when market purchases may be more likely to be constrained by market depth or physical delivery constraints. The review showed that in 34 percent of summer hours and 17 percent of winter hours, PacifiCorp purchased more than its IRP FOT limit of 1,575 MW.

Figure J.3 - PacifiCorp Summer Peak Market Purchases 2009-2015

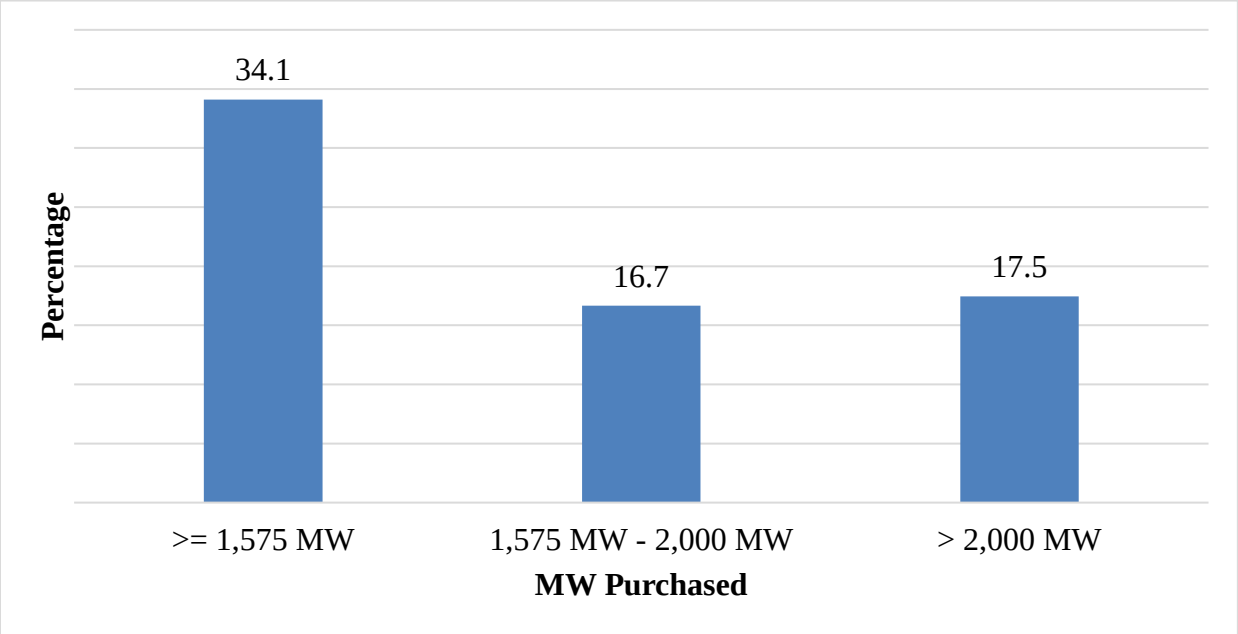
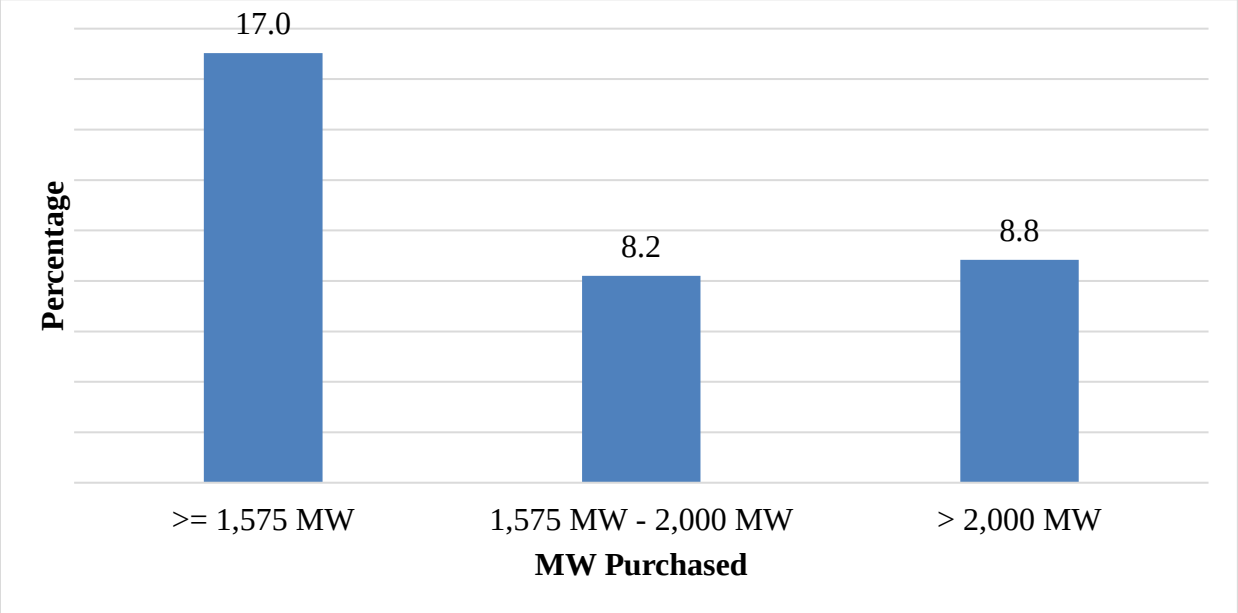


Figure J.4 - PacifiCorp Winter Peak Market Purchases 2009-2015



PacifiCorp believes based on its historical market transactions and review of western resource adequacy discussed above that its FOT limits for the 2017 IRP, unchanged from the 2015 IRP, continue to be a reasonable assumption.

APPENDIX K – CAPACITY EXPANSION RESULTS DETAIL

Portfolio Case Build Tables

This section provides the System Optimizer portfolio build tables for each of the case scenarios as described in the portfolio development section of Chapter 7. There are seven Regional Haze cases, eleven core cases, twenty sensitivity cases, and four final cases.

Table K.1 – Regional Haze Study Reference Guide

Case	Description	Benchmark	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal	SO PVRR. ($m)
Ref.	Reference Case	-	Base	Base	Mass Cap B	Base	None	2032	$24,219
RH-1	Regional Haze 1	-	Base	Base	Mass Cap B	Base	None	2030	$23,159
RH-2	Regional Haze 2	-	Base	Base	Mass Cap B	Base	None	2029	$23,482
RH-3	Regional Haze 3	-	Base	Base	Mass Cap B	Base	None	2029	$23,398
RH-4	Regional Haze 4	-	Base	Base	Mass Cap B	Base	None	2030	$23,663
RH-5	Regional Haze 5	-	Base	Base	Mass Cap B	Base	None	2029	$23,177
RH-6	Regional Haze 6	-	Base	Base	Mass Cap B	Base	None	2028	$23,986

Table K.2 – Core Case Study Reference Guide

Case	Description	Benchmark	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal	SO PVRR ($m)
OP-1	Optimized Portfolio	RH5	Base	Base	Mass Cap B	Base	None	2029	$23,177
OP-NT3	Optimized Naughton 3	OP-1	Base	Base	Mass Cap B	Base	None	2029	$23,052
OP-REP	Wind Repower	OP-NT3	Base	Base	Mass Cap B	Base	None	2029	$22,984
OP-GW4	Energy Gateway + Repower	OP-REP	Base	Base	Mass Cap B	Base	Segment D2	2029	$23,123
FR-1	Flexible Resource	OP-NT3	Base	Base	Mass Cap B	Base	None	2021	$23,585
FR-2	Flexible Resource	OP-NT3	Base	Base	Mass Cap B	Base	None	2021	$24,319
RE-1a	OR RPS Just in Time	OP-NT3	Base	Base	Mass Cap B	Base	None	2029	$23,082
RE-1b	WA RPS Just in Time	OP-NT3	Base	Base	Mass Cap B	Base	None	2029	$23,091
RE-1c	OR & WA RPS Just in Time	OP-NT3	Base	Base	Mass Cap B	Base	None	2029	$23,154
RE-2	OR RPS Early	OP-NT3	Base	Base	Mass Cap B	Base	None	2029	$23,098
DLC1	Direct Load Control	OP-NT3	Base	Base	Mass Cap B	Base	None	2030	$23,103

Table K.3 – Sensitivity Case Study Reference Guide

Case	Description	Benchmark	Load	Private Gen	CO2 Policy	FOTs	Gateway	1st Year of New Thermal	SO PVRR w/ Trans. ($m)
RH2a	Regional Haze	OP-1	Base	Base	Mass Cap B	Base	None	2029	$23,404
LD-1	1 in 20 Loads	OP-1	1 in 20	Base	Mass Cap B	Base	None	2029	$23,364
LD-2	Low Load	OP-1	Low	Base	Mass Cap B	Base	None	2030	$21,567
LD-3	High Load	OP-1	High	Base	Mass Cap B	Base	None	2028	$24,818
PG-1	Low Private Gen	OP-1	Base	Low	Mass Cap B	Base	None	2029	$23,304
PG-2	High Private Gen	OP-1	Base	High	Mass Cap B	Base	None	2030	$22,899
CPP-C	CPP Mass Cap C	OP-1	Base	Base	Mass Cap C	Base	None	2029	$23,268
CPP-D	CPP Mass Cap D	OP-1	Base	Base	Mass Cap D	Base	None	2029	$23,102
FOT-1	Limited FOT	OP-1	Base	Base	Mass Cap B	Restricted	None	2029	$23,347
CO2-1	CO_2 Price	OP-1	Base	Base	Tax, No CPP	Base	None	2030	$26,401
NO-CO2	No CO_2	OP-NT3	Base	Base	No Tax, No CPP	Base	None	2028	$22,891
BP	Business Plan	OP-NT3	Base	Base	Mass Cap D	Base	None	2030	$23,198
GW1	Gateway 1	OP-NT3	Base	Base	Mass Cap B	Base	Segment D	2029	$23,593
GW2	Gateway 2	OP-NT3	Base	Base	Mass Cap B	Base	Segment F	2029	$24,054
GW3	Gateway 3	OP-NT3	Base	Base	Mass Cap B	Base	Segment D&F	2029	$24,627
GW4	Gateway 4	OP-NT3	Base	Base	Mass Cap B	Base	Segment D2	2029	$23,159
Battery	Battery Storage	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2	2029	$23,162
CAES	CAES Storage	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2	2029	$23,121
WCA	WCA	FS-REP	Base	Base	Mass Cap B	Base	None	3033	$7,542
WCA-RPS	WCA RPS	FS-REP	Base	Base	Mass Cap B	Base	None	3033	$7,557

Table K.4 – Final Case Study Reference Guide

	Description	Benchmark	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal	SO PVRR ($m)
FS-REP	Wind Repower	OP-NT3	Base	Base	Mass Cap B	Base	Segment D2	2029	$23,042
FS-GW4	Gateway 4	FS-REP	Base	Base	Mass Cap B	Base	Segment D2	2029	$22,990
FS-1c	OR & WA RPS Just in Time	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2	2029	$23,006
FS-2	OR RPS Early	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2	2029	$22,995

Table K.5 – East Side Resource Name and Description

Resource List	Detailed Description
CCCT - DJohns - J 1x1	Combine Cycle Combustion Turbine J-Machine 1x1 with Duct Firing - Dave Johnston Brownfield
CCCT - Utah-S - J 1x1	Combine Cycle Combustion Turbine J-Machine 1x1 with Duct Firing - Utah South
CCCT - Utah-S - G 1x1	Combine Cycle Combustion Turbine G-Machine 1x1 with Duct Firing - Utah South
IC Aero UN	Inter-cooled Simple Cycle Combustion Turbine Aero - Utah North
SCCT Aero UN	Simple Cycle Combustion Turbine Aero - Utah North
SCCT Frame DJ	Simple Cycle Combustion Turbine Frame - Dave Johnston Brownfield
SCCT Frame UTN	Simple Cycle Combustion Turbine Frame - Utah North
SCCT Frame UTS	Simple Cycle Combustion Turbine Frame - Utah North
Battery Storage - East	Battery Storage – East
CAES - East	Compressed Air Energy Storage
Wind, DJohnston	Wind, Wyoming After DJ Retirement
Wind, GO	Wind, Goshen Idaho
Wind, UT	Wind, Utah
Wind, WYAE	Wind, Wyoming Aeolus
Utility Solar - PV - Utah-S	Utility Solar - Photovoltaic - Utah South
DSM, Class 1, ID-Cool/WH	Direct Load Control-Cooling & Water Heating-Residential, Commercial & Industrial - Idaho
DSM, Class 1, ID-Curtail	Curtailment - Idaho
DSM, Class 1, ID-Irrigate	Direct Load Control-Irrigation -Idaho
DSM, Class 1, UT-Cool/WH	Direct Load Control-Cooling & Water Heating-Residential, Commercial & Industrial - Utah
DSM, Class 1, UT-Curtail	Curtailment - Utah
DSM, Class 1, UT-ICE storage	Ice Energy Storage - Utah
DSM, Class 1, UT-Irrigate	Direct Load Control-Irrigation -Utah
DSM, Class 1, UT-Smart APPl	Direct Load Control-Smart Appliance-Residential - Utah
DSM, Class 1, UT-Thermostat	Direct Load Control-Smart Thermostat-Residential - Utah
DSM, Class 1, WY-Cool/WH	Direct Load Control-Cooling & Water Heating-Residential, Commercial & Industrial - Wyoming
DSM, Class 1, WY-Curtail	Curtailment - Wyoming
DSM, Class 1, WY-Irrigate	Direct Load Control-Irrigation -Wyoming
DSM, Class 2, ID	DSM, Class 2 - Idaho
DSM, Class 2, UT	DSM, Class 2 - Utah
DSM, Class 2, WY	DSM, Class 2 - Wyoming
FOT Mona - SMR	Front Office Transaction - Summer HLH Product - Mona

Table K.6 – West-Side Resource Name and Description

Resource List	Detailed Description
CCCT - SOregonCal - J 1x1	Combine Cycle Combustion Turbine J-Machine 1x1 with Duct Firing - Southern Oregon
CCCT - WillamValcc - G 1x1	Combine Cycle Combustion Turbine G-Machine 1x1 with Duct Firing - Willamette Valley, Oregon
CCCT - WillamValcc - J 1x1	Combine Cycle Combustion Turbine J-Machine 1x1 with Duct Firing - Willamette Valley, Oregon
CCCT - Yakima - G 1x1	Combine Cycle Combustion Turbine G-Machine 1x1 with Duct Firing - Yakima, Washington
IC Aero PO	Inter-cooled Simple Cycle Combustion Turbine Aero - Portland-North Coast, Oregon
IC Aero SO	Inter-cooled Simple Cycle Combustion Turbine Aero - Southern Oregon
IC Aero WV	Inter-cooled Simple Cycle Combustion Turbine Aero - Willamette Valley, Oregon
IC Aero WW	Inter-cooled Simple Cycle Combustion Turbine Aero - Walla Walla, Washington
SCCT Frame SO	Simple Cycle Combustion Turbine Frame - Southern Oregon
Battery Storage - West	Battery Storage – West
Wind, SO	Wind, Southern Oregon
Wind, YK	Wind, Yakima, Washington
Utility Solar - PV - S-Oregon	Utility Solar - Photovoltaic - Southern Oregon
Utility Solar - PV - Yakima	Utility Solar - Photovoltaic - Yakima, Washington
Geothermal, Greenfield - West	Geothermal, Greenfield - West
DSM, Class 1, CA-Cool/WH	Direct Load Control-Cooling & Water Heating-Residential, Commercial & Industrial - California
DSM, Class 1, CA-Curtail	Curtailment - California
DSM, Class 1, CA-Irrigate	Direct Load Control-Irrigation -California
DSM, Class 1, OR-Cool/WH	Direct Load Control-Cooling & Water Heating-Residential, Commercial & Industrial - Oregon
DSM, Class 1, OR-Curtail	Curtailment - Oregon
DSM, Class 1, OR-Irrigate	Direct Load Control-Irrigation -Oregon
DSM, Class 1, OR-Thermostat	Direct Load Control-Smart Thermostat-Residential - Oregon
DSM, Class 1, WA-Cool/WH	Direct Load Control-Cooling & Water Heating-Residential, Commercial & Industrial - Washington
DSM, Class 1, WA-Curtail	Curtailment - Washington
DSM, Class 1, WA-Irrigate	Direct Load Control-Irrigation -Washington
DSM, Class 1, WA-Thermostat	Direct Load Control-Smart Thermostat-Residential - Washington
DSM, Class 2, CA	DSM, Class 2 - California

Table K.6 – West-Side Resource Name and Description (Continued)

Resource List	Detailed Description
DSM, Class 2, OR	DSM, Class 2 - Oregon
DSM, Class 2, WA	DSM, Class 2 - Washington
FOT COB - SMR	Front Office Transaction - Summer HLH Product - California Oregon Border
FOT COB - WTR	Front Office Transaction - Winter HLH Product - California Oregon Border
FOT MidColumbia - SMR	Front Office Transaction - Summer HLH Product - Mid Columbia
FOT MidColumbia - SMR - 2	Front Office Transaction - Summer HLH Product - Mid Columbia
FOT MidColumbia - WTR	Front Office Transaction - Winter HLH Product - Mid Columbia
FOT MidColumbia - WTR2	Front Office Transaction - Winter HLH Product - Mid Columbia
FOT NOB - SMR	Front Office Transaction - Summer HLH Product - Nevada Oregon Border
FOT NOB - WTR	Front Office Transaction - Winter HLH Product - Nevada Oregon Border

Table K.7 – Regional Haze Cases, Detailed Capacity Expansion Portfolios

REF		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_AZ - Gas RePower	-	-	-	-	-	-	-	-	387	-	-	-	-	-	-	-	-	-	-	-	387	387
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	617	145	-	-	-	-	-	-	762
	Wind, WYAE	-	-	-	-	299	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	299	300
	Total Wind	-	-	-	-	299	-	-	-	-	-	-	-	-	617	145	-	1	-	-	-	299	1,062
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	226	155	-	381
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	80.0	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	219.0	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	5	7	6	6	5	5	5	5	5	5	5	5	4	4	4	3	3	2	2	54	92
	DSM, Class 2, UT	84	58	56	59	62	58	57	66	63	65	61	57	57	57	56	47	42	35	33	33	627	1,106
	DSM, Class 2, WY	8	10	11	10	11	13	14	14	14	14	12	11	10	10	10	9	8	7	7	7	119	210
	DSM, Class 2 Total	97	73	74	75	78	77	76	85	82	84	78	73	72	72	71	60	53	45	42	42	801	1,409
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	29	98	300	300	248	300	300	300	300	-	109
West	**Expansion Resources**																						
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	110	-	295	-	-	-	-	405
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	344	55	73	-	-	471
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	36.1	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	118.1	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	6	5	4	3	3	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	33	33	29	27	26	24	23	23	22	22	20	19	19	19	409	626
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	-	-	-	400	400	400	400	400	400	400	400	400	-	180
	FOT MidColumbia - SMR	399	400	400	400	378	400	360	341	400	400	400	400	400	400	400	400	400	400	400	400	388	394
	FOT MidColumbia - SMR - 2	-	276	112	46	-	23	-	-	64	-	65	375	375	375	375	375	375	375	375	375	52	198
	FOT NOB - SMR	100	100	100	100	-	9	7	67	100	100	100	100	100	100	100	100	100	100	100	100	68	84
	FOT MidColumbia - WTR	281	-	275	-	323	311	309	-	-	300	-	292	-	400	46	-	395	400	62	384	180	189
	FOT MidColumbia - WTR2	-	331	-	310	-	-	-	290	298	-	292	-	301	57	375	319	-	35	375	375	123	168
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	10	15	100	100	97	100	100	100	100	11	42
	Existing Plant Retirements/Conversions	-	-	5	-	-	-	-	-	-	(82)	-	(762)	-	(642)	(78)	-	(358)	-	(82)	-		
	Annual Additions, Long Term Resources	154	126	126	122	418	114	109	117	112	111	105	97	95	1,080	350	284	716	122	364	228		
	Annual Additions, Short Term Resources	779	1,107	887	856	701	743	676	698	915	854	865	1,606	1,689	2,132	2,096	1,939	2,070	2,110	2,112	2,434		
	Total Annual Additions	933	1,234	1,013	978	1,119	857	784	815	1,027	965	970	1,703	1,784	3,212	2,447	2,224	2,786	2,232	2,476	2,662		

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

RH-1		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	477	-	953
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	35	-	-	165	86	-	-	-	-	285
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	300	-	-	-	-	-	-	-	35	-	-	165	86	-	-	-	300	585
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	321	41	291	46	-	699
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	205.0	9.2	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	6	6	5	5	5	5	4	4	3	3	3	3	57	96
	DSM, Class 2, UT	84	58	62	59	62	68	66	66	68	65	65	61	57	57	58	49	44	37	34	35	656	1,152
	DSM, Class 2, WY	8	10	11	10	13	13	14	15	14	14	12	13	11	11	11	9	8	7	7	7	122	218
	DSM, Class 2 Total	97	74	79	75	81	86	85	86	89	84	82	78	73	73	73	62	55	47	43	44	835	1,465
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	300	108	195	300	300	300	300	300	3	123
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	-	15
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	217	7	-	-	-	224
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	11.4	24.7	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	93.5	24.7	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	22
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	9	9	8	10	9	9	9	8	8	7	7	6	6	5	4	3	3	2	2	89	134
	DSM, Class 2 Total	57	54	52	46	42	37	34	33	29	27	27	25	24	23	22	22	20	19	19	18	412	630
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	279	188	249	400	400	400	400	400	400	400	400	364	47	214
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	275	375	310	56	167	95	135	375	375	375	375	375	375	375	375	375	375	375	375	216	296
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	-	-	310	-	289	297	-	-	400	91	249	290	352	-	16	394	400	178	199
	FOT MidColumbia - WTR2	-	-	-	310	322	-	308	-	-	299	290	21	375	-	-	-	351	375	-	251	124	145
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	86	97	100	100	100	100	100	11	50
	Existing Plant Retirements/Conversions	-	(280)	-	-	-	-	-	-	(387)	(82)	-	(762)	-	(357)	(78)	-	(712)	-	(82)	(359)		
	Annual Additions, Long Term Resources	154	128	131	122	423	123	118	119	118	112	109	417	195	737	98	252	1,178	117	356	597		
	Annual Additions, Short Term Resources	779	1,106	1,150	1,119	877	976	903	924	1,503	1,442	1,449	2,096	2,141	1,717	1,857	2,027	2,026	2,066	2,069	2,290		
	Total Annual Additions	933	1,234	1,281	1,241	1,300	1,100	1,021	1,042	1,621	1,554	1,558	2,513	2,336	2,454	1,955	2,278	3,204	2,184	2,425	2,887		

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

RH-2		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Hunter 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	-	-	-	-	-	(418)
	Hunter 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	(269)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_CO - Gas RePower	-	-	-	-	-	-	82	-	-	-	-	-	-	-	-	-	-	-	(82)	-	82	-
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	CCCT - Utah-S - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	389	-	-	-	-	389
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	477	389	-	-	-	-	1,342
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	593	-	593
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	300	-	-	-	-	-	-	-	-	-	85	-	-	-	-	593	300	979
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	383	48	315	54	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	75.3	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	68.4	140.6	10.0	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	6	6	5	5	5	4	4	4	3	3	3	3	57	96
	DSM, Class 2, UT	84	58	62	59	62	64	66	66	68	65	65	61	57	57	58	47	44	37	34	35	653	1,146
	DSM, Class 2, WY	8	10	11	10	13	13	14	15	14	14	12	13	10	10	11	8	8	7	7	7	122	215
	DSM, Class 2 Total	97	74	79	75	81	83	85	86	89	84	82	78	72	72	73	59	55	47	43	44	832	1,457
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	300	71	272	300	279	300	300	300	300	-	121
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	-	(354)	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	54	-	-	-	-	-	-	54
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	244	-	-	-	-	244
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	11.4	17.7	3.3	-	-	-	-	-	-	32.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	93.5	17.7	3.3	-	-	-	-	-	-	114.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	20
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	87	131
	DSM, Class 2 Total	57	53	52	46	41	37	34	33	29	27	26	25	23	23	22	21	20	19	19	18	410	625
	FOT COB - SMR	-	-	-	-	-	-	-	-	347	283	344	400	400	400	400	400	400	400	400	367	63	227
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	276	107	41	153	266	194	234	375	375	375	375	375	375	375	375	375	375	375	375	202	288
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	-	275	-	-	-	-	290	298	-	-	-	300	375	368	-	-	317	319	400	114	161
	FOT MidColumbia - WTR2	-	331	-	310	323	311	309	-	-	300	292	291	-	-	-	306	276	-	-	210	188	163
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	10	-	100	100	45	100	100	100	100	11	38
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	(354)	-	-	(432)	(359)	(642)	(78)	(687)	(688)	-	(164)	-		
	Annual Additions, Long Term Resources	154	128	131	122	421	120	118	119	118	111	109	171	765	599	237	960	1,094	117	381	721		
	Annual Additions, Short Term Resources	779	1,106	882	851	975	1,077	1,003	1,024	1,572	1,512	1,520	1,876	1,647	2,022	2,043	1,904	1,951	1,992	1,994	2,252		
	Total Annual Additions	933	1,234	1,013	973	1,397	1,196	1,122	1,143	1,690	1,623	1,628	2,047	2,412	2,621	2,280	2,864	3,046	2,108	2,375	2,974		

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

RH-3		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame ID	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	800	-	-	800
	Wind, WYAE	-	-	-	-	235	-	-	-	-	-	-	-	-	-	-	-	65	-	-	-	235	300
	Total Wind	-	-	-	-	235	-	-	-	-	-	-	-	-	-	-	-	151	-	800	-	235	1,185
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	712	33	60	-	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	-	-	-	3.4
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	-	-	-	7.3	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	-	-	4.8	-	3.7	-	-	-	83.7
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	-	-	3.1
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	-	3.1	-	-	-	-	43.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	208.4	-	-	-	14.0	3.1	3.7	3.1	-	-	232.2
	DSM, Class 2, ID	5	7	7	6	6	6	6	6	6	6	5	5	5	5	5	4	4	3	3	2	58	98
	DSM, Class 2, UT	84	62	62	59	70	68	66	67	72	69	65	65	57	60	59	51	45	40	48	24	679	1,192
	DSM, Class 2, WY	8	10	11	12	13	13	15	15	14	14	13	13	12	11	11	10	9	8	9	5	125	227
	DSM, Class 2 Total	97	78	79	77	89	87	86	88	92	88	83	83	74	76	75	65	58	51	60	31	862	1,517
	Battery Storage - East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.0	-	-	-	8
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	127	91	188	300	300	300	300	272	3	112
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	286	13	19	-	-	318
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	36.1	-	-	-	3.3	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	3.8	-	-	-	9.2	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	108.9	-	-	-	12.6	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	9	9	8	9	9	9	9	8	8	7	6	5	5	5	4	3	3	2	2	88	130
	DSM, Class 2 Total	57	54	52	46	41	37	34	33	29	27	26	25	23	22	22	21	20	19	19	18	410	625
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	17	-	-	-	-	-	311	221	286	400	400	400	400	400	400	400	400	360	55	220
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	4	284	375	330	83	196	126	166	375	375	375	375	375	375	375	375	375	375	375	375	231	303
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	-	322	311	-	290	298	-	-	42	-	-	292	306	292	-	-	400	211	172
	FOT MidColumbia - WTR2	-	-	-	310	-	-	309	-	-	301	292	375	301	251	-	-	-	327	330	152	92	147
	FOT NOB - WTR	-	-	-	-	-	-	-	-	54	55	10	100	9	-	-	76	100	100	100	100	11	35
	Existing Plant Retirements/Conversions	-	(280)	-	-	-	-	-	-	(387)	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	365	124	120	121	122	115	110	455	733	575	96	113	1,429	128	960	249		
	Annual Additions, Short Term Resources	784	1,115	1,167	1,139	906	1,007	934	956	1,538	1,479	1,490	2,092	1,711	1,617	1,756	1,957	1,967	2,002	2,005	2,160		
	Total Annual Additions	938	1,247	1,299	1,263	1,271	1,131	1,054	1,077	1,659	1,594	1,599	2,547	2,443	2,192	1,852	2,070	3,396	2,130	2,966	2,409		

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

RH-4		Capacity (MW)																			Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	285	-	-	-	-	-	285
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	364	-	364
	Wind, WYAE	-	-	-	-	288	-	-	-	-	-	-	-	-	-	-	12	-	-	-	-	288	300
	Total Wind	-	-	-	-	288	-	-	-	-	-	-	-	-	-	-	297	-	-	-	364	288	950
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	347	41	291	121	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	61.9	6.4	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	80.0	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	61.9	31.0	126.0	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	68	65	63	61	57	57	58	49	44	37	34	35	647	1,141
	DSM, Class 2, WY	8	10	11	10	13	13	14	15	14	14	12	11	11	11	11	9	8	7	7	7	122	216
	DSM, Class 2 Total	97	74	79	75	81	77	85	86	88	84	80	77	73	73	73	62	55	47	43	44	826	1,453
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	24	298	300	140	228	300	300	300	300	300	-	124
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	(354)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	213	7	-	-	-	246
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	36.1	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	7.7	27.3	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	32.7	85.4	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	6	5	4	3	3	2	2	87	131
	DSM, Class 2 Total	57	53	52	46	41	37	34	33	29	27	26	25	24	23	22	22	20	19	19	18	410	626
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	25	-	-	400	400	400	400	400	400	400	400	364	2	179
	FOT MidColumbia - SMR	399	400	400	400	378	400	359	340	400	400	400	400	400	400	400	400	400	400	400	400	388	394
	FOT MidColumbia - SMR - 2	-	276	107	41	-	23	-	-	375	336	375	375	375	375	375	375	375	375	375	375	116	245
	FOT NOB - SMR	100	100	100	100	-	-	-	40	100	100	100	100	100	100	100	100	100	100	100	100	64	82
	FOT MidColumbia - WTR	281	-	275	-	-	311	-	290	-	-	-	291	300	264	-	349	-	388	15	400	116	158
	FOT MidColumbia - WTR2	-	331	-	310	323	-	309	-	298	300	292	-	-	-	316	-	348	-	375	277	187	174
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	10	54	100	100	100	100	100	100	100	11	44
	Existing Plant Retirements/Conversions	-	-	5	-	-	-	-	-	(387)	(82)	-	(762)	-	(642)	(78)	-	(712)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	410	114	118	119	117	111	107	163	160	973	98	409	1,115	117	356	560		
	Annual Additions, Short Term Resources	779	1,106	882	851	701	734	668	671	1,250	1,190	1,199	1,875	1,929	1,779	1,918	2,024	2,023	2,063	2,065	2,316		
	Total Annual Additions	933	1,234	1,013	973	1,110	848	787	789	1,368	1,301	1,306	2,038	2,090	2,752	2,016	2,433	3,137	2,180	2,422	2,876		

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

RH-5		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	-	182
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	485	-	485
	Wind, WYAE	-	-	-	-	229	-	-	-	-	-	-	-	-	-	-	51	20	-	-	-	229	300
	Total Wind	-	-	-	-	229	-	-	-	-	-	-	-	-	-	-	137	20	-	-	485	229	871
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	654	44	-	85	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	65.2	3.2	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	75.3	-	-	4.8	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	21.7	-	-	19.0	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	65.2	130.0	-	-	27.1	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	4	4	4	3	3	2	3	56	94
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	68	65	63	61	57	57	56	49	44	37	33	35	647	1,138
	DSM, Class 2, WY	8	10	11	10	13	13	14	15	14	14	12	11	11	9	10	9	8	7	6	7	122	213
	DSM, Class 2 Total	97	74	79	75	81	77	85	86	88	84	80	77	73	71	71	62	55	47	41	44	826	1,446
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	300	299	173	260	300	300	300	300	300	-	127
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	SCCT Frame SO	-	-	-	-	-	-	-	-	-	-	-	-	216	-	-	-	-	-	-	-	-	216
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	4.0	-	-	-	7.4	-	-	-	-	11.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	73.0	-	-	-	7.4	-	-	-	-	80.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	13	19
	DSM, Class 2, OR	46	40	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	306	470
	DSM, Class 2, WA	10	8	9	8	9	8	9	9	8	8	7	6	6	5	4	4	3	3	2	2	85	126
	DSM, Class 2 Total	57	50	52	46	41	35	33	33	29	27	26	24	23	22	21	21	19	18	18	18	404	616
	FOT COB - SMR	-	-	-	-	-	-	-	-	30	-	29	400	400	357	362	398	398	400	400	366	3	177
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	277	108	43	165	282	210	250	375	341	375	375	375	375	375	375	375	375	375	375	205	290
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	-	275	-	323	-	-	-	-	301	-	293	8	-	-	-	-	-	314	224	118	101
	FOT MidColumbia - WTR2	-	331	-	310	-	312	310	291	299	-	293	-	375	253	294	308	310	320	-	375	185	219
	FOT NOB - WTR	-	-	-	-	-	-	-	-	54	56	10	12	100	1	13	59	68	100	95	100	11	33
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	124	131	122	350	113	118	119	117	111	106	166	515	1,005	92	263	1,159	113	244	644		
	Annual Additions, Short Term Resources	779	1,108	884	853	988	1,094	1,021	1,042	1,258	1,198	1,207	1,880	2,057	1,658	1,804	1,941	1,951	1,995	1,984	2,239		
	Total Annual Additions	933	1,232	1,015	974	1,338	1,206	1,139	1,160	1,375	1,309	1,313	2,046	2,572	2,664	1,896	2,204	3,109	2,108	2,228	2,883		

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

RH-6		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	285	-	-	-	-	285
	Wind, CO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526	-	526
	Wind, WYAE	-	-	-	-	179	-	-	-	-	-	-	-	-	-	-	-	121	-	-	-	179	300
	Total Wind	-	-	-	-	179	-	-	-	-	-	-	-	-	-	-	-	407	-	-	526	179	1,111
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	391	41	291	78	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	-	-	-	4.8	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	164.3	46.6	-	-	3.4	11.2	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	4	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	63	65	62	61	57	56	56	49	44	37	34	35	642	1,132
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	11	11	9	10	9	8	7	7	7	121	213
	DSM, Class 2 Total	97	74	79	75	81	77	85	85	82	84	80	77	73	70	71	62	55	47	44	45	819	1,441
	FOT Mona - SMR	-	-	-	-	-	-	-	-	264	200	264	300	300	261	171	300	300	300	300	300	46	163
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	Expansion Resources																						
	CCCT - SOregonCal - J 1x1	-	-	-	-	-	-	-	-	-	-	-	509	-	-	-	-	-	-	-	-	-	509
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	509	-	-	-	-	-	-	-	-	-	509
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	110	7	-	-	-	117
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	7.4	-	-	-	32.0	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	20.4	-	-	-	32.0	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	20
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	33	33	29	27	26	25	23	22	22	21	20	19	19	18	409	624
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	173	101	142	400	400	400	400	400	400	400	400	400	400	400	364	122	259
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	276	375	310	90	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	293	334
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	-	323	311	309	290	298	-	-	321	399	-	-	319	-	9	11	298	242	189
	FOT MidColumbia - WTR2	-	-	-	310	-	-	-	-	-	300	292	-	-	327	341	-	343	375	375	375	61	152
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	-	55	100	100	100	100	11	43
	Existing Plant Retirements/Conversions	-	(280)	-	-	-	(356)	-	-	(387)	(82)	-	(762)	-	(357)	(78)	-	(358)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	300	114	118	118	112	111	106	843	163	569	292	87	1,055	117	356	678		
	Annual Additions, Short Term Resources	779	1,106	1,150	1,120	913	1,359	1,286	1,307	1,890	1,830	1,839	1,996	2,074	1,963	1,787	1,949	2,018	2,059	2,061	2,312		
	Total Annual Additions	933	1,234	1,281	1,242	1,213	1,473	1,404	1,425	2,002	1,941	1,945	2,839	2,237	2,532	2,079	2,036	3,073	2,176	2,418	2,990		

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

Table K.8 – Core Cases, Detailed Capacity Expansion Portfolio

OP-1		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	-	182
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	485	-	485
	Wind, WYAE	-	-	-	-	229	-	-	-	-	-	-	-	-	-	-	51	20	-	-	-	229	300
	Total Wind	-	-	-	-	229	-	-	-	-	-	-	-	-	-	-	137	20	-	-	485	229	871
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	654	44	-	85	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	65.2	3.2	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	75.3	-	-	4.8	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	21.7	-	-	19.0	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	65.2	130.0	-	-	27.1	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	4	4	4	3	3	2	3	56	94
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	68	65	63	61	57	57	56	49	44	37	33	35	647	1,138
	DSM, Class 2, WY	8	10	11	10	13	13	14	15	14	14	12	11	11	9	10	9	8	7	6	7	122	213
	DSM, Class 2 Total	97	74	79	75	81	77	85	86	88	84	80	77	73	71	71	62	55	47	41	44	826	1,446
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	300	299	173	260	300	300	300	300	300	-	127
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	SCCT Frame SO	-	-	-	-	-	-	-	-	-	-	-	-	216	-	-	-	-	-	-	-	-	216
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	4.0	-	-	-	7.4	-	-	-	-	11.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	73.0	-	-	-	7.4	-	-	-	-	80.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	13	19
	DSM, Class 2, OR	46	40	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	306	470
	DSM, Class 2, WA	10	8	9	8	9	8	9	9	8	8	7	6	6	5	4	4	3	3	2	2	85	126
	DSM, Class 2 Total	57	50	52	46	41	35	33	33	29	27	26	24	23	22	21	21	19	18	18	18	404	616
	FOT COB - SMR	-	-	-	-	-	-	-	-	30	-	29	400	400	357	362	398	398	400	400	366	3	177
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	277	108	43	165	282	210	250	375	341	375	375	375	375	375	375	375	375	375	375	205	290
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	-	275	-	323	-	-	-	-	301	-	293	8	-	-	-	-	-	314	224	118	101
	FOT MidColumbia - WTR2	-	331	-	310	-	312	310	291	299	-	293	-	375	253	294	308	310	320	-	375	185	219
	FOT NOB - WTR	-	-	-	-	-	-	-	-	54	56	10	12	100	1	13	59	68	100	95	100	11	33
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	124	131	122	350	113	118	119	117	111	106	166	515	1,005	92	263	1,159	113	244	644		
	Annual Additions, Short Term Resources	779	1,108	884	853	988	1,094	1,021	1,042	1,258	1,198	1,207	1,880	2,057	1,658	1,804	1,941	1,951	1,995	1,984	2,239		
	Total Annual Additions	933	1,232	1,015	974	1,338	1,206	1,139	1,160	1,375	1,309	1,313	2,046	2,572	2,664	1,896	2,204	3,109	2,108	2,228	2,883		

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

OP-NT3		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	407	393	150	950
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	460	-	460
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	450	-	-	-	-	-	-	-	-	85	-	-	-	-	407	853	450	1,796
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	58	151	-	380	41	171	5	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	-	3.9	-	-	3.4	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	205.0	-	14.0	-	-	6.5	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	5	4	3	3	3	3	57	97
	DSM, Class 2, UT	84	62	62	59	62	68	66	71	68	69	65	61	57	60	59	47	44	37	34	35	670	1,168
	DSM, Class 2, WY	8	10	11	12	13	13	14	15	14	14	12	13	12	11	11	9	8	7	7	7	124	221
	DSM, Class 2 Total	97	78	79	77	81	87	85	91	89	88	82	79	74	76	74	60	55	47	44	44	851	1,486
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	299	236	300	300	252	300	300	300	300	3	132
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - SOregonCal - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	509	-	-	-	-	-	-	-	-	509
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	509	-	-	-	-	-	-	-	-	509
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	76	3	-	31	7	13	-	-	130
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.0	-	32.1	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	73.0	-	45.1	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	20
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	34	33	29	27	26	25	23	23	22	21	20	19	19	18	410	625
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	19	130	58	95	249	156	217	400	400	400	400	400	400	400	400	357	71	224
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	8	372	305	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	294	334
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	310	-	311	-	290	298	-	-	27	317	400	17	-	-	378	380	286	210	195
	FOT MidColumbia - WTR2	-	-	-	-	323	-	309	-	-	300	292	375	-	27	375	287	337	-	-	375	93	150
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	572	123	119	124	118	115	109	382	605	577	253	280	998	117	657	933		
	Annual Additions, Short Term Resources	779	839	1,148	1,115	1,217	1,316	1,242	1,260	1,475	1,412	1,420	2,075	1,928	2,102	2,067	1,914	2,012	2,053	2,055	2,293		
	Total Annual Additions	933	971	1,279	1,239	1,789	1,440	1,361	1,385	1,593	1,527	1,528	2,457	2,533	2,679	2,320	2,195	3,010	2,170	2,712	3,226		

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

OP-REP		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	477	-	953
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	85
	Wind, GO	-	-	-	-	128	-	-	-	-	-	-	-	-	-	-	-	-	-	516	-	128	644
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	428	-	-	-	-	-	-	-	-	-	-	-	85	-	516	-	428	1,030
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	617	40	142	-	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	-	-	3.4
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	-	-	83.7
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	-	-	3.1
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	-	3.1	-	-	-	-	43.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	205.0	9.2	4.8	-	3.4	3.1	3.7	3.1	-	-	232.2
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	4	4	3	3	3	2	57	95
	DSM, Class 2, UT	84	58	62	59	62	68	66	66	68	67	65	61	57	57	58	49	44	37	34	24	658	1,144
	DSM, Class 2, WY	8	10	11	10	13	13	14	15	14	14	12	13	10	10	11	9	8	7	7	5	122	214
	DSM, Class 2 Total	97	74	79	75	81	87	85	86	89	86	82	78	72	72	73	62	55	47	44	31	838	1,453
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	282	236	300	300	300	300	300	29	3	120
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	53	247	37	8	13	-	-	357
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	11.4	-	-	-	3.3	-	-	-	-	-	14.7
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	80.5	13.0	-	-	3.3	-	-	-	-	-	96.8
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	10	9	9	9	8	8	7	7	6	5	5	4	3	3	2	2	88	132
	DSM, Class 2 Total	57	53	52	46	42	37	33	33	29	27	27	25	23	23	22	22	20	19	19	18	410	627
	FOT COB - SMR	-	-	-	-	24	135	64	103	258	165	227	400	400	400	400	400	400	400	400	342	75	226
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	11	375	307	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	294	335
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	273	307	-	308	-	287	295	-	-	35	397	-	348	312	314	-	357	-	208	192
	FOT MidColumbia - WTR2	-	-	-	-	319	-	306	-	-	297	289	375	-	323	-	-	-	355	-	308	92	129
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	550	123	118	119	118	113	109	388	553	576	148	337	1,217	117	737	526		
	Annual Additions, Short Term Resources	779	842	1,148	1,115	1,219	1,318	1,245	1,266	1,480	1,418	1,425	2,085	2,053	1,934	2,023	1,987	1,989	2,030	2,032	1,654		
	Total Annual Additions	933	970	1,279	1,236	1,769	1,441	1,363	1,384	1,598	1,532	1,535	2,473	2,607	2,510	2,171	2,325	3,206	2,147	2,770	2,180		

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

OP-GW4		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	182
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	-	9	5	-	-	-	85
	Wind, WYAE	-	-	-	-	1,200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,200	1,200
	Total Wind	-	-	-	-	1,200	-	-	-	-	-	-	-	-	-	72	-	9	5	-	-	1,200	1,285
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	59	167	208	40	279	-	-	752
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	34.8	40.5	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	123.8	90.5	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	63	65	65	61	57	57	59	49	44	37	34	35	642	1,139
	DSM, Class 2, WY	8	10	11	10	11	13	14	14	14	14	12	11	11	11	11	9	8	7	7	7	119	214
	DSM, Class 2 Total	97	74	79	75	78	77	85	85	82	84	82	77	73	73	74	62	55	47	44	44	817	1,448
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	293	300	291	300	300	300	300	300	263	3	135
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	82	-	64	70	16	8	13	-	-	253
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	49.1	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	10	9	9	9	8	8	7	7	6	5	5	4	3	3	2	2	88	132
	DSM, Class 2 Total	57	53	52	46	42	37	33	33	29	27	27	25	23	23	22	21	20	19	19	18	410	627
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	27	-	-	154	63	124	400	400	400	400	400	400	400	400	357	24	196
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	11	375	307	286	375	331	372	375	375	375	375	375	375	375	375	375	375	375	375	281	328
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	273	307	-	-	-	287	295	-	-	-	400	41	390	351	-	377	4	236	177	179
	FOT MidColumbia - WTR2	-	-	-	-	319	308	306	-	-	297	289	305	51	375	-	-	337	-	375	375	123	167
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	1,321	114	118	118	112	111	109	295	548	536	296	323	986	121	358	256		
	Annual Additions, Short Term Resources	779	842	1,148	1,115	1,105	1,210	1,137	1,159	1,376	1,316	1,323	1,973	2,126	2,081	2,065	2,026	2,012	2,052	2,054	2,206		
	Total Annual Additions	933	970	1,279	1,236	2,426	1,324	1,255	1,276	1,488	1,427	1,432	2,267	2,674	2,618	2,361	2,349	2,998	2,173	2,412	2,462		

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

FR-1		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	IC Aero UN	-	-	-	-	182	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	182
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	52	234	-	-	-	-	-	-	285
	Wind, CO	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	401	399	150	950
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	455	-	455
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	450	-	-	-	-	-	-	-	-	52	234	-	-	-	-	401	853	450	1,990
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	52	534	41	173	5	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	15.0	65.0	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	103.2	115.7	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	5	4	3	3	3	3	56	96
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	68	65	65	61	57	60	59	49	44	37	34	35	647	1,148
	DSM, Class 2, WY	8	10	11	10	13	13	14	15	14	14	12	13	12	11	11	9	8	7	7	7	122	218
	DSM, Class 2 Total	97	74	79	75	81	77	85	86	88	84	82	78	74	76	74	62	55	47	44	44	826	1,462
	Battery Storage - East	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	67	296	300	300	300	300	300	300	300	-	123
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	IC Aero SO	-	-	-	-	393	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	393	393
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	84	163	-	-	-	-	-	247
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16	8	13	-	-	36
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	24.7	11.4	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	27.3	7.7	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.8	9.1	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	4.7	4.4	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	66.5	51.6	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	22
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	6	5	4	3	3	2	2	87	131
	DSM, Class 2 Total	57	53	52	46	41	37	34	33	29	27	26	25	24	23	22	22	20	19	19	18	410	627
	Battery Storage - West	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	-	-	-	400	400	400	400	400	400	400	400	357	-	178
	FOT MidColumbia - SMR	399	400	400	400	378	400	359	355	400	400	400	400	400	400	400	400	400	400	400	400	389	395
	FOT MidColumbia - SMR - 2	-	11	375	310	-	23	-	-	109	45	106	375	375	375	375	375	375	375	375	375	87	218
	FOT NOB - SMR	100	100	100	100	-	63	56	100	100	100	100	100	100	100	100	100	100	100	100	100	82	91
	FOT MidColumbia - WTR	281	331	275	310	-	-	309	290	298	300	-	291	300	400	5	-	339	5	382	400	239	226
	FOT MidColumbia - WTR2	-	-	-	-	323	311	-	-	-	-	292	-	-	15	375	340	-	375	-	263	63	115
	FOT NOB - WTR	-	-	-	-	-	-	-	-	-	-	-	-	57	100	100	100	100	100	100	100	-	38
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	1,150	114	118	119	117	112	109	103	267	548	417	303	1,105	117	653	933		
	Annual Additions, Short Term Resources	779	842	1,150	1,120	701	798	724	745	907	845	898	1,633	1,928	2,090	2,055	2,015	2,014	2,055	2,057	2,295		
	Total Annual Additions	933	970	1,281	1,242	1,851	912	842	863	1,024	957	1,007	1,735	2,195	2,637	2,472	2,318	3,119	2,172	2,710	3,228		

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

FR-2		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	IC Aero UN	-	-	-	-	182	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	182
	SCCT Aero UN	-	-	-	-	121	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	121	121
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	39	-	-	247	-	-	-	-	285
	Wind, GO	-	-	-	-	46	-	-	-	-	-	-	-	-	-	-	-	-	-	-	800	46	846
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	346	-	-	-	-	-	-	-	-	39	-	-	247	-	-	800	346	1,432
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	466	41	279	19	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	80.0	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	217.1	-	3.4	5.0	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	5	7	6	6	5	5	5	5	5	5	5	5	5	4	4	3	3	3	3	54	93
	DSM, Class 2, UT	84	58	56	59	62	58	57	66	63	65	61	57	57	57	56	47	44	37	34	35	627	1,112
	DSM, Class 2, WY	8	10	11	10	11	13	14	14	14	14	12	11	10	10	10	9	8	7	7	7	119	211
	DSM, Class 2 Total	97	73	74	75	78	77	76	85	82	84	78	73	72	72	71	60	55	47	43	44	801	1,415
	Battery Storage - East	-	-	-	-	7.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	7
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	-	140	300	204	300	300	300	300	300	-	107
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	IC Aero PO	-	-	-	-	221	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	221
	IC Aero SO	-	-	-	-	196	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	196	196
	IC Aero WV	-	-	-	-	208	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	208	208
	IC Aero WW	-	-	-	-	221	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	221
	DSM, Class 2, CA	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	12	18
	DSM, Class 2, OR	46	40	39	34	29	26	23	23	20	18	18	17	16	16	16	17	15	15	16	16	297	461
	DSM, Class 2, WA	10	7	7	8	8	8	7	7	7	7	6	6	5	5	4	3	3	2	2	2	76	114
	DSM, Class 2 Total	57	48	47	43	38	35	32	31	27	27	25	23	22	22	21	21	19	18	18	18	384	592
	Battery Storage - West	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	2
	FOT COB - SMR	-	-	11	-	-	-	-	-	-	-	-	-	251	261	270	303	311	316	322	279	1	116
	FOT MidColumbia - SMR	399	400	400	400	138	117	116	97	97	97	97	400	400	400	400	400	400	400	400	400	226	298
	FOT MidColumbia - SMR - 2	-	15	375	322	-	-	-	-	-	-	-	363	375	375	372	375	375	375	375	375	71	204
	FOT NOB - SMR	100	100	100	100	-	-	-	-	25	-	26	100	100	100	100	100	100	100	100	100	43	68
	FOT MidColumbia - WTR	281	332	278	313	108	98	97	79	70	68	83	83	92	124	-	-	100	127	-	400	172	137
	FOT MidColumbia - WTR2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	84	98	-	-	136	16	-	17
	FOT NOB - WTR	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	74	82	100	100	100	-	28
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	121	120	118	1,620	113	107	115	110	110	104	96	94	349	292	83	1,268	109	344	894		
	Annual Additions, Short Term Resources	779	847	1,164	1,135	246	215	213	176	192	165	206	945	1,358	1,660	1,431	1,650	1,669	1,718	1,733	1,971		
	Total Annual Additions	933	968	1,284	1,253	1,867	327	320	292	302	275	310	1,042	1,452	2,010	1,722	1,734	2,936	1,826	2,078	2,864		

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

RE-1a		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	-	477
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	-	-	-	182
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	85	200	-	-	-	-	-	-	285
	Wind, CO	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	407	393	150	950
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	460	-	460
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	450	-	-	-	-	-	-	-	-	85	200	-	-	-	407	853	450	1,996
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	58	151	-	380	41	171	5	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	-	3.9	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	205.0	-	14.0	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	5	4	3	3	3	3	57	97
	DSM, Class 2, UT	84	62	62	59	62	68	66	71	68	69	65	61	57	60	59	47	44	37	34	35	670	1,168
	DSM, Class 2, WY	8	10	11	12	13	13	14	15	14	14	12	13	12	11	11	9	8	7	7	7	124	221
	DSM, Class 2 Total	97	78	79	77	81	87	85	91	89	88	82	79	74	76	74	60	55	47	44	44	851	1,486
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	299	265	300	257	300	300	300	300	287	3	133
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	Wind, YK	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	Wind, SO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	153	-	-	-	-	-	-	153
	Total Wind	-	-	-	-	1	-	-	-	-	-	-	-	-	-	153	-	-	-	-	-	1	154
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	305	-	-	56	-	-	-	-	361
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	126	3	166	235	7	13	-	-	550
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.0	-	32.1	-	3.3	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	73.0	-	45.1	-	3.3	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	20
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	34	33	29	27	26	25	23	23	22	21	20	19	19	18	410	625
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	19	130	58	95	249	156	217	400	400	400	400	400	400	400	400	370	71	225
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	8	372	305	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	294	334
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	310	-	-	-	290	-	-	292	400	-	67	361	-	370	400	400	318	149	205
	FOT MidColumbia - WTR2	-	-	-	-	323	311	309	-	298	300	-	-	348	375	-	367	-	10	13	375	154	151
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	573	123	119	124	118	115	109	382	573	732	602	253	1,160	117	657	933		
	Annual Additions, Short Term Resources	779	839	1,148	1,115	1,217	1,316	1,242	1,260	1,475	1,412	1,419	2,074	1,988	2,117	1,993	2,042	2,045	2,085	2,088	2,325		
	Total Annual Additions	933	971	1,279	1,239	1,789	1,439	1,361	1,384	1,592	1,527	1,528	2,455	2,561	2,849	2,595	2,295	3,205	2,203	2,744	3,258		

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

RE-1b		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	407	393	150	950
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	460	-	460
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	450	-	-	-	-	-	-	-	-	85	-	-	-	-	407	853	450	1,796
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	58	151	-	380	41	171	5	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	37.6	3.1	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	201.9	12.3	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	5	4	3	3	3	3	57	97
	DSM, Class 2, UT	84	62	62	59	62	68	66	71	68	69	65	61	57	60	59	47	44	37	34	35	670	1,168
	DSM, Class 2, WY	8	10	11	12	13	13	14	15	14	14	12	13	12	11	11	9	8	7	7	7	124	221
	DSM, Class 2 Total	97	78	79	77	81	87	85	91	89	88	82	79	74	76	74	60	55	47	44	44	851	1,486
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	299	289	156	160	105	300	300	300	300	3	113
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Wind, YK	-	-	-	-	80	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	80
	Total Wind	-	-	-	-	80	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	80
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	76	3	-	245	7	13	-	-	344
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.3	-	-	-	-	-	3.3
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	67.8	-	-	-	3.3	-	-	-	-	-	71.2
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	20
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	34	33	29	27	26	25	23	23	22	21	20	19	19	18	410	625
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	10	121	50	86	241	147	208	400	400	400	400	400	400	400	400	357	66	221
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	8	372	305	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	294	334
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	310	-	-	-	281	-	-	283	393	3	-	-	257	290	-	333	238	148	164
	FOT MidColumbia - WTR2	-	-	-	-	314	302	300	-	289	291	-	-	375	219	242	-	-	330	-	375	150	152
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	42	-	100	100	100	100	11	43
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	651	123	119	124	118	115	109	373	545	799	250	287	932	117	657	933		
	Annual Additions, Short Term Resources	779	839	1,148	1,115	1,199	1,299	1,225	1,243	1,457	1,394	1,402	2,066	2,042	1,751	1,720	1,636	1,965	2,005	2,008	2,245		
	Total Annual Additions	933	971	1,279	1,239	1,851	1,422	1,343	1,367	1,575	1,509	1,510	2,440	2,588	2,550	1,969	1,923	2,897	2,123	2,664	3,178		

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

RE-1c		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	-	477
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	-	-	-	182
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	279	6	-	-	-	-	-	-	285
	Wind, GO	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	407	393	150	950
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	460	-	460
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	450	-	-	-	-	-	-	-	-	279	6	-	-	-	407	853	450	1,996
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	58	151	-	380	41	171	5	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	-	3.9	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	37.6	-	3.1	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	201.9	-	15.1	-	5.3	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	5	4	3	3	3	3	57	97
	DSM, Class 2, UT	84	62	62	59	62	68	66	71	68	69	65	61	57	60	59	47	44	37	34	35	670	1,168
	DSM, Class 2, WY	8	10	11	12	13	13	14	15	14	14	12	13	12	11	11	9	8	7	7	7	124	221
	DSM, Class 2 Total	97	78	79	77	81	87	85	91	89	88	82	79	74	76	74	60	55	47	44	44	851	1,486
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	297	263	300	258	300	287	287	287	287	3	131
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	436
	Wind, YK	-	-	-	-	81	-	-	-	-	-	-	-	-	-	186	-	-	-	39	-	81	306
	Wind, SO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	212	-	-	-	-	-	-	212
	Total Wind	-	-	-	-	81	-	-	-	-	-	-	-	-	-	398	-	-	-	39	-	81	518
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	105	3	124	31	7	13	-	-	282
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	14.8	-	24.6	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	-	27.9	-	24.6	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	20
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	34	33	29	27	26	25	23	23	22	21	20	19	19	18	410	625
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	10	121	49	86	240	147	208	400	400	400	400	400	335	335	331	288	65	208
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	8	372	305	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	294	334
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	310	-	-	-	281	-	-	283	393	-	31	-	-	-	-	-	209	148	120
	FOT MidColumbia - WTR2	-	-	-	-	314	302	300	-	289	291	-	-	339	375	326	354	265	306	304	375	150	207
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	652	123	119	124	118	115	109	374	573	783	654	234	1,136	117	696	933		
	Annual Additions, Short Term Resources	779	839	1,148	1,115	1,199	1,298	1,224	1,242	1,457	1,394	1,402	2,065	1,978	2,081	1,959	2,029	1,863	1,903	1,897	2,134		
	Total Annual Additions	933	971	1,279	1,239	1,851	1,422	1,343	1,367	1,575	1,509	1,510	2,439	2,551	2,864	2,614	2,263	2,998	2,020	2,593	3,067		

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

RE-2		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	407	393	150	950
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	460	-	460
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	450	-	-	-	-	-	-	-	-	85	-	-	-	-	407	853	450	1,796
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	58	151	-	380	41	171	5	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	71.3	4.0	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	160.4	53.9	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	5	4	3	3	3	3	57	97
	DSM, Class 2, UT	84	62	62	59	62	68	66	71	68	69	65	61	57	60	59	47	44	37	34	35	670	1,168
	DSM, Class 2, WY	8	10	11	12	13	13	14	15	14	14	12	13	12	11	11	9	8	7	7	7	124	221
	DSM, Class 2 Total	97	78	79	77	81	87	85	91	89	88	82	79	74	76	74	60	55	47	44	44	851	1,486
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	198	300	300	-	300	300	300	300	3	118
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Wind, YK	-	-	-	-	296	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	296	296
	Total Wind	-	-	-	-	296	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	296	296
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	24	-	16	-	-	-	-	-	-	-	41
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	92	10	-	31	7	13	-	-	153
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	-	-	-	-	-	-	-	36.1
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	49.1	-	-	-	-	-	-	-	-	118.1
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	20
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	34	33	29	27	26	25	23	23	22	21	20	19	19	18	410	625
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	97	25	62	216	123	184	400	400	400	400	396	400	400	400	357	52	213
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	8	372	305	361	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	292	334
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	310	-	-	-	257	-	-	259	354	-	56	392	221	338	3	381	400	145	193
	FOT MidColumbia - WTR2	-	-	-	-	290	278	276	-	265	267	-	-	339	375	-	-	-	375	-	261	138	136
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	-	100	100	100	100	11	46
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	867	123	119	124	118	115	109	357	636	555	257	560	718	117	657	933		
	Annual Additions, Short Term Resources	779	839	1,148	1,115	1,151	1,250	1,177	1,195	1,409	1,346	1,354	2,029	1,912	2,106	2,067	1,491	2,013	2,053	2,056	2,293		
	Total Annual Additions	933	971	1,279	1,239	2,019	1,374	1,295	1,319	1,527	1,461	1,462	2,386	2,548	2,661	2,325	2,052	2,731	2,171	2,712	3,226		

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

DLC-1		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	121	-	-	-	-	-	121
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	285	-	-	-	-	-	-	-	285
	Wind, GO	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	407	393	150	950
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	-	-	460	-	473
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	450	-	-	-	-	-	-	-	-	285	-	-	13	-	407	853	450	2,008
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	58	151	-	380	41	171	5	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	3.4	-	-	-	-	-	-	-	11.5	-	-	3.4	-	-	3.1	-	3.4	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	45.8	-	-	-	-	-	-	-	22.5	-	-	-	-	-	-	-	45.8	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	71.3	-	-	-	-	-	-	-	4.0	4.8	-	-	-	3.7	-	2.2	71.3	85.9
	DSM, Class 1, UT-ICE storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.3	-	-	-	-	3.3
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, UT-Smart APPl	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.5	-	-	-	-	4.5
	DSM, Class 1, UT-Thermostat	-	-	-	-	23.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.4	23.4
	DSM, Class 1, WY-Cool/WH	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.9	4.8	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	37.6	-	-	-	-	-	-	-	3.1	-	-	-	3.1	-	-	2.0	37.6	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	186.4	-	-	-	-	-	-	-	51.3	4.8	-	3.4	10.8	3.7	3.1	11.6	186.4	274.9
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	5	4	3	3	3	3	57	97
	DSM, Class 2, UT	84	62	62	59	62	68	66	71	68	69	65	61	57	60	59	47	44	37	34	35	670	1,168
	DSM, Class 2, WY	8	10	11	12	13	13	14	15	14	14	12	13	12	11	11	9	8	7	7	7	124	221
	DSM, Class 2 Total	97	78	79	77	81	87	85	91	89	88	82	79	74	76	74	60	55	47	44	44	851	1,486
	Battery Storage - East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.0	-	-	-	-	10
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	281	300	300	300	300	300	300	300	300	-	134
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	Wind, YK	-	-	-	-	81	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	81	81
	Total Wind	-	-	-	-	81	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	81	81
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	405	-	-	-	-	-	-	-	-	405
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	101	254	3	41	94	7	13	-	-	514
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.7	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	24.7	-	-	-	-	-	-	-	11.4	-	3.3	-	-	-	-	-	24.7	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.0	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	9.1	-	-	-	-	-	-	-	3.8	-	-	-	-	-	-	-	9.1	12.8
	DSM, Class 1, OR-Thermostat	-	-	-	-	4.4	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	4.4	9.6
	DSM, Class 1, WA-Cool/WH	-	-	-	-	8.9	-	-	-	-	-	-	-	4.1	-	-	-	-	-	-	-	8.9	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.1	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	4.8
	DSM, Class 1, WA-Thermostat	-	-	-	-	3.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.5	3.5
	DSM, Class 1 Total	-	-	-	-	103.1	-	-	-	-	-	-	-	28.1	-	3.3	-	-	-	-	-	103.1	134.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	20
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	34	33	29	27	26	25	23	23	22	21	20	19	19	18	410	625
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	-	-	-	400	400	400	400	400	400	400	400	357	-	178
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	8	372	305	96	207	135	172	326	259	321	375	375	375	375	375	375	375	375	375	188	279
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	310	-	-	-	281	-	-	283	393	130	119	85	36	400	400	400	366	148	205
	FOT MidColumbia - WTR2	-	-	-	-	314	302	300	-	289	291	-	-	375	375	375	375	18	59	61	375	150	175
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	942	123	119	124	118	115	109	103	682	900	253	246	1,088	117	657	933		
	Annual Additions, Short Term Resources	779	839	1,148	1,115	910	1,009	935	953	1,168	1,105	1,112	2,048	2,180	2,169	2,135	2,086	2,093	2,134	2,136	2,373		
	Total Annual Additions	933	971	1,279	1,239	1,851	1,132	1,054	1,077	1,285	1,220	1,221	2,152	2,862	3,070	2,388	2,332	3,182	2,251	2,793	3,306		

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

Table K.9 – Sensitivity Cases, Detailed Capacity Expansion Portfolios

RH2a		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Hunter 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	-	-	-	-	-	(418)
	Hunter 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	(269)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	477
	CCCT - Utah-S - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	389	-	-	-	-	389
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	389	-	-	-	-	865
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	-	-	-	182
	SCCT Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	121	-	-	121
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	200
	SCCT Frame UTS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	88	152	314	-	-	555
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	300	-	-	-	-	-	-	-	-	85	-	-	88	152	314	-	300	940
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	122	150	219	309	-	-	-	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	-	-	-	3.4
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	-	-	83.7
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	-	-	3.1
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	-	-	3.1	-	-	-	43.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	208.4	3.9	6.7	-	3.4	3.1	3.7	3.1	-	-	232.2
	DSM, Class 2, ID	5	7	7	6	6	6	6	6	6	6	5	5	5	5	5	4	4	3	3	2	58	97
	DSM, Class 2, UT	84	62	62	59	70	68	66	71	70	69	65	64	60	60	59	49	44	37	34	24	681	1,178
	DSM, Class 2, WY	8	10	11	12	13	13	15	15	14	14	14	13	12	11	11	9	8	7	7	5	125	222
	DSM, Class 2 Total	97	78	79	77	89	87	86	92	91	88	84	82	77	76	75	62	55	47	43	31	864	1,497
	FOT Mona - SMR	-	-	-	-	-	-	-	-	197	130	191	300	300	300	300	300	300	300	300	267	33	159
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	-	-	-	(354)	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	1	121	2	58	8	-	-	-	-	190
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	7	13	-	-	26
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	21.8	-	14.2	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	8.9	-	4.1	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	99.8	-	18.3	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	22
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	9	9	8	10	9	9	9	8	8	7	7	6	6	5	4	3	3	2	2	89	134
	DSM, Class 2 Total	57	54	52	46	42	37	34	33	29	27	27	25	24	23	22	22	20	19	19	18	412	630
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	35	146	74	110	400	400	400	400	400	400	400	400	400	400	400	357	117	256
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	272	372	305	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	320	347
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	-	322	310	308	-	-	299	290	400	52	62	400	-	-	-	348	400	212	204
	FOT MidColumbia - WTR2	-	-	-	310	-	-	-	289	297	-	-	38	375	375	-	320	313	353	-	167	90	142
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	(280)	-	-	(387)	-	-	-	(354)	(82)	-	(432)	(359)	(357)	(78)	(687)	(688)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	432	124	120	125	120	116	110	415	542	683	253	1,041	1,060	229	513	249		
	Annual Additions, Short Term Resources	779	1,103	1,147	1,114	1,232	1,331	1,256	1,274	1,821	1,758	1,764	2,113	2,102	2,112	2,075	1,995	1,988	2,028	2,023	2,166		
	Total Annual Additions	933	1,235	1,278	1,238	1,664	1,455	1,376	1,399	1,941	1,873	1,874	2,529	2,644	2,794	2,328	3,036	3,048	2,258	2,536	2,416		

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

LD-1		Capacity (MW)																			Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	477	-	-	-	-	953
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	695	-	695
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	300	-	-	-	-	-	-	-	-	-	85	-	-	-	-	695	300	1,080
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	179	216	41	297	47	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	205.0	9.2	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	4	4	3	3	3	3	57	97
	DSM, Class 2, UT	84	62	62	59	62	68	66	71	68	69	65	61	57	60	59	49	44	37	34	35	670	1,170
	DSM, Class 2, WY	8	10	11	12	13	13	14	15	14	14	12	13	11	11	11	9	8	7	7	7	124	220
	DSM, Class 2 Total	97	78	79	77	81	87	85	92	89	88	82	79	73	76	74	62	55	47	44	44	852	1,488
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	84	300	300	300	300	300	300	300	3	127
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	151	-	16	130	70	16	8	-	-	-	391
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	11.4	24.7	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	7.9	5.1	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	88.3	29.8	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	9	9	8	10	9	9	9	8	8	7	7	6	6	5	4	3	3	2	2	89	134
	DSM, Class 2 Total	57	54	52	46	42	37	34	33	29	27	27	25	23	23	22	21	20	19	19	18	412	629
	FOT COB - SMR	-	209	44	-	96	210	138	177	334	244	311	400	400	400	400	400	400	400	400	364	145	266
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	306	375	375	354	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	366	371
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT COB - WTR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	-	1
	FOT MidColumbia - WTR	380	71	400	120	400	76	74	60	312	400	203	400	383	400	400	400	92	400	127	400	229	275
	FOT MidColumbia - WTR2	-	375	7	375	59	375	375	375	375	287	375	193	-	180	176	85	375	106	375	375	260	242
	FOT NOB - WTR	-	3	-	45	88	86	91	77	100	100	100	100	100	100	100	100	100	100	100	100	59	79
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	423	123	119	125	118	116	109	548	772	596	335	336	987	118	363	816		
	Annual Additions, Short Term Resources	1,186	1,532	1,325	1,394	1,518	1,623	1,553	1,564	1,996	1,933	1,891	2,268	1,842	2,255	2,251	2,160	2,142	2,181	2,177	2,425		
	Total Annual Additions	1,340	1,664	1,456	1,518	1,941	1,746	1,671	1,688	2,114	2,048	2,000	2,816	2,614	2,852	2,585	2,496	3,128	2,298	2,540	3,241		

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

LD-2		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	285	-	-	-	-	285
	Wind, WYAE	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	36	102	162	-	-	300
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	321	102	162	-	-	585
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	209	83	-	292
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	80.0	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	219.0	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	5	7	6	6	5	5	5	5	5	5	5	5	4	4	4	3	3	2	2	53	91
	DSM, Class 2, UT	84	58	56	53	62	58	57	57	63	60	61	57	57	57	56	47	43	36	33	34	607	1,088
	DSM, Class 2, WY	8	10	11	10	11	11	14	14	14	14	12	11	10	10	10	9	8	7	7	7	116	208
	DSM, Class 2 Total	97	73	74	69	78	75	76	76	81	79	78	73	72	72	71	60	54	46	42	43	777	1,387
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	27	276	144	194	298	300	300	300	300	-	107
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76	-	-	-	-	76
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	36.1	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	118.1	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	20
	DSM, Class 2, OR	46	40	42	37	31	26	23	23	20	18	18	17	17	16	16	17	15	15	16	16	306	470
	DSM, Class 2, WA	10	8	8	8	9	9	9	8	8	8	7	6	6	5	5	4	3	3	2	2	86	129
	DSM, Class 2 Total	57	50	52	46	41	37	33	32	29	27	26	24	23	23	22	21	20	19	19	18	404	619
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	-	-	-	276	400	400	400	400	400	400	400	400	-	174
	FOT MidColumbia - SMR	280	400	400	368	369	400	349	329	400	330	377	400	400	400	400	400	400	400	400	400	362	380
	FOT MidColumbia - SMR - 2	-	69	15	-	-	13	-	-	14	-	-	375	375	375	375	375	375	375	375	375	11	174
	FOT NOB - SMR	61	100	-	-	18	62	26	50	100	100	100	100	100	100	100	100	100	100	100	100	52	76
	FOT MidColumbia - WTR	280	-	274	-	321	-	-	-	-	291	-	289	-	290	-	-	377	393	400	353	116	163
	FOT MidColumbia - WTR2	-	329	-	308	-	309	307	288	289	-	289	-	334	-	310	372	-	-	2	375	183	176
	FOT NOB - WTR	-	-	-	-	-	-	-	-	42	42	-	-	100	100	100	100	100	100	100	100	8	44
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	123	126	115	119	112	109	108	110	105	104	97	95	898	96	84	1,151	170	436	156		
	Annual Additions, Short Term Resources	621	898	688	676	707	783	682	667	845	763	767	1,467	1,985	1,809	1,879	2,045	2,052	2,068	2,077	2,403		
	Total Annual Additions	774	1,021	814	791	827	895	790	775	956	868	870	1,564	2,079	2,707	1,975	2,129	3,202	2,238	2,513	2,559		

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

LD-3		Capacity (MW)																			Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	477	-	-	-	-	953
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	-	-	-	182
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	-	200
	SCCT Frame UTS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	630	-	-	630
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	300	-	-	-	-	-	-	85	-	-	-	-	-	-	630	-	300	1,015
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74	238	270	62	155	-	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	-	3.9	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	-	-	3.1	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	208.4	-	10.6	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	5	4	3	3	3	3	57	97
	DSM, Class 2, UT	84	62	62	59	66	68	66	71	68	69	65	61	57	60	59	49	44	37	34	35	674	1,174
	DSM, Class 2, WY	8	12	13	12	14	14	15	15	15	16	14	14	13	11	11	9	8	7	7	7	134	234
	DSM, Class 2 Total	97	80	81	77	85	87	86	92	89	90	84	79	74	76	74	62	55	47	44	45	865	1,506
	FOT Mona - SMR	-	-	-	-	-	-	-	-	22	-	52	300	252	300	300	300	300	300	300	265	2	135
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - SOregonCal - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	509	-	-	-	-	-	-	-	-	509
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	509	-	-	-	-	-	-	-	-	509
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	21	55	48	-	-	-	-	-	124
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	18	11	18	-	-	62
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	36.1	-	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	118.1	-	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	2	1	1	1	1	1	1	1	1	1	0	0	14	22
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	9	9	8	10	10	9	9	8	8	7	7	6	6	5	4	3	3	2	2	90	135
	DSM, Class 2 Total	57	54	52	46	42	37	34	33	30	27	27	25	23	23	22	22	20	19	19	18	413	631
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	30
	FOT COB - SMR	-	95	-	-	66	215	162	223	400	371	400	400	400	400	400	400	400	400	400	360	153	275
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	151	375	341	297	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	341	358
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	282	-	277	-	324	-	-	-	-	308	-	400	-	359	351	322	-	319	-	400	119	167
	FOT MidColumbia - WTR2	-	332	-	312	-	312	310	292	305	-	294	25	359	-	-	-	318	-	316	140	186	166
	FOT NOB - WTR	-	-	-	-	-	-	-	-	63	65	27	100	100	100	93	70	51	89	97	100	13	48
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	134	133	124	427	125	120	125	119	117	111	716	606	807	258	388	1,024	143	870	275		
	Annual Additions, Short Term Resources	932	1,302	1,118	1,109	1,264	1,402	1,347	1,390	1,666	1,620	1,648	2,100	1,986	2,034	2,019	1,967	1,944	1,983	1,988	2,140		
	Total Annual Additions	1,086	1,436	1,251	1,232	1,692	1,527	1,467	1,515	1,785	1,737	1,759	2,816	2,592	2,841	2,277	2,355	2,969	2,126	2,857	2,415		

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

PG-1		Capacity (MW)																			Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	-	182
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	83	3	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	62	212	-	526	-	800
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	347	-	347
	Wind, WYAE	-	-	-	-	211	-	-	-	-	-	-	-	-	-	-	-	89	-	-	-	211	300
	Total Wind	-	-	-	-	211	-	-	-	-	-	-	-	-	-	83	3	152	212	-	873	211	1,532
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	800	-	-	5	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	-	3.9	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.5	40.5	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40.7	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	82.4	-	10.6	39.5	88.0	5.0	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	68	65	63	61	57	57	56	49	44	37	34	35	647	1,140
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	11	10	10	11	9	8	7	7	7	121	214
	DSM, Class 2 Total	97	74	79	75	81	77	85	85	88	84	80	77	72	72	71	62	55	47	44	44	825	1,450
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	296	249	300	300	300	300	300	300	300	-	132
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - SOregonCal - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	509	-	-	-	-	-	-	-	-	509
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	509	-	-	-	-	-	-	-	-	509
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	141	14	16	-	-	186
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	23.7	-	1.2	44.1	52.4	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	33	33	29	27	26	25	23	23	22	21	20	19	19	18	409	625
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	54	-	64	400	400	400	400	400	400	400	400	365	5	184
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	281	115	50	178	298	228	270	375	372	375	375	375	375	375	375	375	375	375	375	217	296
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	-	275	-	323	-	-	-	-	301	-	292	-	-	334	313	259	291	-	180	118	142
	FOT MidColumbia - WTR2	-	331	-	310	-	311	309	291	298	-	293	-	301	269	-	-	-	-	274	375	185	168
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	9	11	-	-	-	38	100	100	100	100	11	28
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	332	114	118	118	117	111	107	208	603	783	275	227	1,403	295	264	952		
	Annual Additions, Short Term Resources	780	1,112	891	860	1,001	1,109	1,037	1,061	1,281	1,227	1,240	1,874	1,825	1,844	1,909	1,926	1,934	1,966	1,949	2,194		
	Total Annual Additions	934	1,240	1,022	982	1,333	1,223	1,155	1,178	1,398	1,338	1,347	2,082	2,428	2,627	2,185	2,153	3,337	2,262	2,213	3,146		

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

PG-2		Capacity (MW)																			Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	285	-	-	-	-	-	-	285
	Wind, CO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	503	297	-	800
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	463	-	463
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	300	-	-	-	-	-	-	-	-	-	285	-	-	-	503	760	300	1,849
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	33	150	502	-	115	5	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	75.3	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	209.0	10.0	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	68	65	63	61	57	57	58	49	44	37	34	35	647	1,141
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	11	11	11	11	9	8	7	7	7	121	216
	DSM, Class 2 Total	97	74	79	75	81	77	85	85	88	84	80	77	73	73	73	62	55	47	44	44	825	1,452
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	249	300	300	300	300	300	299	300	300	-	132
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	12	-	-	-	-	-	-	-	-	12
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	28	5	17	33	-	-	-	-	-	82
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	11.4	24.7	-	3.3	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	93.5	24.7	-	3.3	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	2	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	33	33	29	27	26	25	23	23	22	21	20	18	19	18	409	624
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	-	-	-	400	400	400	400	400	400	400	400	353	-	178
	FOT MidColumbia - SMR	395	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	268	97	27	133	245	172	207	354	281	320	375	375	375	375	375	375	375	375	375	178	274
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT COB - WTR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	86	-	4
	FOT MidColumbia - WTR	281	-	275	-	323	-	-	-	-	300	-	291	144	400	121	400	400	400	198	400	118	197
	FOT MidColumbia - WTR2	-	331	-	310	-	311	309	290	298	-	292	-	375	121	375	78	95	154	375	375	185	204
	FOT NOB - WTR	-	-	-	-	-	-	-	-	52	53	4	5	100	100	100	100	100	100	100	100	10	46
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	422	114	118	118	117	111	107	101	439	801	431	272	1,056	68	684	839		
	Annual Additions, Short Term Resources	776	1,099	873	837	955	1,056	981	997	1,204	1,133	1,116	1,820	2,194	2,196	2,171	2,153	2,170	2,228	2,248	2,489		
	Total Annual Additions	930	1,227	1,004	959	1,377	1,170	1,099	1,115	1,321	1,245	1,223	1,921	2,632	2,997	2,602	2,425	3,226	2,296	2,932	3,328		

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

CPP-C		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	477	-	-	-	-	953
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	285	-	-	-	-	-	-	285
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	300	-	-	-	-	-	-	-	-	-	285	-	-	-	-	-	300	585
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	196	49	293	212	-	750
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	80.0	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	37.6	3.1	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	68.4	-	142.3	6.4	5.3	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	2	2	56	94
	DSM, Class 2, UT	84	58	56	59	62	58	57	66	63	65	61	61	57	57	56	48	43	36	33	34	627	1,114
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	11	10	10	11	9	8	7	7	7	121	213
	DSM, Class 2 Total	97	74	74	75	81	77	76	85	82	84	78	77	72	72	71	61	54	46	42	43	805	1,421
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	299	284	298	300	300	300	300	300	300	-	134
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - Yakima - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	458	-	-	-	-	-	-	-	-	458
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	458	-	-	-	-	-	-	-	-	458
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	124	27	-	-	-	-	171
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14.7	24.7	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	69.1	27.8	24.7	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	8	8	8	8	8	7	6	5	5	5	4	3	2	2	2	83	123
	DSM, Class 2 Total	57	53	52	46	41	35	32	31	29	27	26	24	23	22	22	21	19	18	19	18	406	617
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	31	-	32	400	400	400	400	400	400	400	400	368	3	182
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	276	111	45	157	274	208	249	375	342	375	375	375	375	375	375	375	375	375	375	204	289
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	-	275	-	323	-	-	-	-	303	-	294	-	343	341	-	-	-	-	271	118	122
	FOT MidColumbia - WTR2	-	331	-	310	-	312	311	293	301	-	295	-	147	-	-	328	313	354	356	375	186	201
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	10	100	100	100	100	100	100	100	100	11	46
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	126	122	422	113	108	116	112	111	105	169	552	782	432	265	976	117	357	285		
	Annual Additions, Short Term Resources	779	1,106	886	855	979	1,085	1,019	1,042	1,259	1,199	1,209	1,879	1,806	2,016	2,016	2,003	1,988	2,029	2,031	2,289		
	Total Annual Additions	933	1,234	1,012	977	1,401	1,198	1,127	1,158	1,371	1,310	1,314	2,048	2,359	2,798	2,448	2,268	2,965	2,145	2,387	2,574		

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

CPP-D		Capacity (MW)																			Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	-	477
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	182
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	768	-	-	768
	Wind, WYAE	-	-	-	-	9	-	-	-	-	-	-	-	-	-	-	-	291	-	-	-	9	300
	Total Wind	-	-	-	-	9	-	-	-	-	-	-	-	-	-	-	-	377	-	768	-	9	1,154
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	684	40	75	-	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	-	3.9	-	-	3.4	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	80.0	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	18.6	22.1	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	82.4	-	109.3	27.4	-	6.5	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	56	59	62	58	66	66	63	65	63	61	57	57	58	47	44	37	34	35	637	1,128
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	11	10	10	11	9	8	7	7	7	121	215
	DSM, Class 2 Total	97	74	74	75	81	77	85	85	82	84	80	77	72	72	73	60	55	47	44	44	814	1,438
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	4	27	300	267	300	281	233	300	300	300	263	0	129
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - SOregonCal - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	509	-	-	-	-	-	-	-	509
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	509	-	-	-	-	-	-	-	509
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	12	-	-	98	8	13	-	-	130
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	18.9	-	50.1	52.4	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	87	130
	DSM, Class 2 Total	57	53	52	46	41	37	33	33	29	27	26	25	23	23	22	21	20	19	19	18	409	625
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	68	-	40	400	400	400	400	400	400	400	400	357	7	183
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	276	111	45	200	316	245	286	375	375	375	375	375	375	375	375	375	375	375	375	223	299
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	-	275	-	323	-	-	-	-	300	-	292	-	325	-	313	329	370	-	228	118	152
	FOT MidColumbia - WTR2	-	331	-	310	-	311	309	290	298	-	292	-	301	-	349	-	-	-	372	375	185	177
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	28	15	100	100	31	100	100	100	100	11	39
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	126	122	130	114	118	118	112	111	107	203	571	775	204	281	1,440	117	923	256		
	Annual Additions, Short Term Resources	779	1,106	886	855	1,023	1,127	1,054	1,076	1,294	1,233	1,243	1,894	1,858	2,000	2,005	1,852	2,004	2,045	2,047	2,198		
	Total Annual Additions	933	1,234	1,012	977	1,153	1,241	1,172	1,194	1,405	1,345	1,349	2,097	2,429	2,775	2,210	2,133	3,444	2,162	2,970	2,454		

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

FOT-1		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	477	-	-	-	-	953
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	-	182
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	285	-	-	-	-	-	-	285
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	387	-	387
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	300	-	-	-	-	-	-	-	-	-	285	-	-	-	-	387	300	973
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	115	535	40	-	111	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	210.3	3.9	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	5	4	3	3	3	3	57	97
	DSM, Class 2, UT	84	62	62	59	62	68	66	71	68	69	65	61	60	60	59	49	44	37	34	35	670	1,174
	DSM, Class 2, WY	8	10	11	12	13	13	15	15	14	14	12	13	12	11	11	9	8	7	7	7	125	222
	DSM, Class 2 Total	97	78	79	77	81	87	86	92	89	88	82	79	77	76	74	62	55	47	44	44	853	1,493
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	SCCT Frame SO	-	-	-	-	-	-	-	-	-	-	-	-	216	-	-	-	-	-	-	-	-	216
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	115	24	173	-	-	-	-	-	-	-	311
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	225	86	127	16	7	-	-	-	462
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	36.1	-	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	118.1	-	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	9	9	8	10	9	9	9	8	8	7	7	6	6	5	4	3	3	2	2	89	134
	DSM, Class 2 Total	57	54	52	46	42	37	34	33	29	27	27	25	24	23	22	21	20	19	19	18	412	629
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	101	34	96	400	400	400	400	400	400	400	398	364	14	190
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	272	103	36	247	358	285	322	375	375	375	375	375	375	375	375	375	375	375	375	237	306
	FOT NOB - SMR	100	100	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	20
	FOT MidColumbia - WTR	281	-	275	-	322	310	-	289	349	-	298	289	298	-	180	-	91	-	98	-	182	154
	FOT MidColumbia - WTR2	-	331	-	310	-	-	308	-	-	353	-	-	-	151	-	94	-	93	-	358	130	100
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	423	123	120	125	118	116	109	577	544	978	471	329	1,105	117	247	572		
	Annual Additions, Short Term Resources	779	1,103	878	846	968	1,068	993	1,011	1,225	1,162	1,169	1,464	1,473	1,326	1,355	1,269	1,266	1,268	1,270	1,497		
	Total Annual Additions	933	1,235	1,009	969	1,391	1,191	1,113	1,135	1,343	1,277	1,278	2,041	2,017	2,304	1,826	1,598	2,371	1,385	1,518	2,069		

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

CO_2-1		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - Utah-S - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	389	-	-	-	-	389
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	389	-	477	-	-	865
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	366	396	-	-	-	-	-	-	-	762
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	673	57	-	-	-	-	800
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	300	-	-	-	-	-	-	-	366	396	70	673	57	-	-	-	300	1,862
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	50	-	-	628	40	-	-	-	717
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	3.3	65.0	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	75.3	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	8.1	206.1	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	5	4	3	3	3	3	57	98
	DSM, Class 2, UT	84	62	62	59	70	68	66	71	70	69	65	61	60	60	59	49	44	37	34	37	681	1,187
	DSM, Class 2, WY	8	10	11	12	13	13	15	15	14	15	14	13	12	11	11	9	8	8	7	8	126	226
	DSM, Class 2 Total	97	78	79	77	89	87	86	92	90	89	84	80	77	76	74	62	56	47	43	48	865	1,511
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	300	300	300	300	300	300	300	86	149	-	117
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	Wind, YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	33	-	-	-	33
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	259	241	33	-	-	-	533
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	405	-	-	-	-	-	-	-	405
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	272	149	-	-	-	-	-	-	421
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	7.7	27.3	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	4.7	4.4	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	12.4	105.7	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	2	1	1	1	1	1	1	1	1	1	0	0	14	22
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	19	16	21	310	483
	DSM, Class 2, WA	10	9	9	8	10	10	9	9	8	8	7	7	6	6	5	4	3	3	2	2	90	135
	DSM, Class 2 Total	57	54	52	46	42	37	34	33	30	27	27	25	24	23	22	22	20	22	19	24	413	640
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	-	-	-	400	400	400	400	400	400	400	342	363	-	175
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	272	103	36	142	252	180	216	369	301	362	375	375	375	375	375	375	375	375	375	187	280
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	-	275	-	322	-	-	-	-	352	-	289	98	187	400	400	118	156	386	263	123	176
	FOT MidColumbia - WTR2	-	331	-	310	-	309	307	288	348	-	290	-	375	375	127	88	375	375	-	375	189	214
	FOT NOB - WTR	-	-	-	-	-	-	-	-	-	-	7	9	100	-	-	-	-	-	-	-	-	6
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	132	131	124	432	124	120	125	120	117	110	126	809	1,426	319	1,020	1,393	146	541	83		
	Annual Additions, Short Term Resources	779	1,103	878	846	963	1,062	987	1,005	1,217	1,153	1,159	1,873	2,148	2,137	2,102	2,063	2,068	2,106	1,690	2,025		
	Total Annual Additions	933	1,235	1,009	969	1,395	1,186	1,107	1,130	1,337	1,270	1,269	1,999	2,957	3,563	2,421	3,083	3,460	2,253	2,231	2,108		

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

NO-C0$_2$		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	SCCT Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	121	-	121
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	682	112	-	795
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	85	-	-	682	112	300	1,180
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	658	40	95	-	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	209.0	-	8.1	5.3	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	5	4	3	3	3	3	56	96
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	63	65	64	61	57	57	59	49	44	37	36	37	642	1,143
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	13	12	11	11	9	8	7	7	7	121	219
	DSM, Class 2 Total	97	74	79	75	81	77	85	85	82	84	82	78	74	73	74	62	55	47	46	47	819	1,458
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	208	300	259	300	300	300	300	300	300	3	131
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - Yakima - G 1x1	-	-	-	-	-	-	-	-	-	-	-	458	-	-	-	-	-	-	-	-	-	458
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	458	-	-	-	-	-	-	-	-	-	458
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	159	13	6	11	-	-	192
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	14.8	-	10.3	14.2	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	96.9	-	10.3	14.2	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	40	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	306	471
	DSM, Class 2, WA	10	7	9	8	9	8	7	8	8	8	7	6	5	5	5	4	3	2	2	2	81	121
	DSM, Class 2 Total	57	49	52	46	41	35	32	31	29	27	26	24	23	22	22	21	19	18	19	18	400	613
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	3	-	49	166	95	136	293	202	264	400	400	400	400	400	400	400	400	357	94	238
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	14	375	312	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	295	335
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	332	276	311	-	-	-	294	302	-	-	-	36	337	-	336	338	3	382	280	180	175
	FOT MidColumbia - WTR2	-	-	-	-	324	313	312	-	-	304	296	-	375	-	359	-	-	375	-	375	125	152
	FOT NOB - WTR	-	-	-	-	-	-	-	-	54	56	10	99	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	123	131	122	422	113	116	116	112	111	108	560	403	571	147	353	1,149	116	857	310		
	Annual Additions, Short Term Resources	779	846	1,154	1,123	1,247	1,354	1,282	1,305	1,525	1,464	1,472	1,582	2,086	1,971	2,034	2,011	2,013	2,053	2,057	2,287		
	Total Annual Additions	933	969	1,285	1,245	1,669	1,466	1,399	1,422	1,636	1,575	1,580	2,142	2,488	2,542	2,181	2,364	3,162	2,169	2,913	2,597		

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

BP		Capacity (MW)																			Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Coal Ret_WY - Gas RePower	-	-	285	-	-	-	-	-	-	-	-	-	-	(285)	-	-	-	-	-	-	285	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	477	-	953
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	269	-	150	419
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	450	-	-	-	-	-	-	-	-	85	-	-	-	-	269	-	450	804
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	23	153	167	210	40	208	-	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	14.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	3.3	65.0	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	75.3	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	3.3	209.0	6.7	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	5	5	6	6	5	5	6	6	6	5	5	5	5	4	4	3	3	3	3	54	93
	DSM, Class 2, UT	84	86	80	59	62	58	66	66	68	65	65	61	57	58	58	49	44	37	34	35	694	1,191
	DSM, Class 2, WY	8	8	8	10	13	13	14	15	14	14	12	13	11	11	11	9	8	7	7	7	118	213
	DSM, Class 2 Total	97	99	94	75	81	77	85	86	89	84	82	78	73	73	73	62	55	47	44	44	865	1,497
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	275	300	300	300	300	300	300	300	29	-	120
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	87	22	-	-	-	-	-	-	-	109
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	70	16	7	13	-	-	109
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	29.1	7.0	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	111.1	7.0	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	14	22
	DSM, Class 2, OR	50	46	41	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	315	479
	DSM, Class 2, WA	10	10	11	8	9	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	92	135
	DSM, Class 2 Total	62	58	55	46	41	37	33	33	29	27	26	25	23	23	22	21	20	19	19	18	421	637
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	-	-	-	-	-	-	400	400	400	400	400	400	400	400	321	-	176
	FOT MidColumbia - SMR	400	400	400	393	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	399	400
	FOT MidColumbia - SMR - 2	10	274	117	-	82	198	127	166	321	257	318	375	375	375	375	375	375	375	375	375	155	262
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	-	270	-	318	-	-	-	-	296	-	287	103	400	400	374	360	25	400	-	116	176
	FOT MidColumbia - WTR2	-	329	-	305	-	306	304	285	293	-	287	-	375	49	13	-	-	375	3	347	182	164
	FOT NOB - WTR	-	-	-	-	-	-	-	-	51	52	6	9	100	100	100	100	100	100	100	100	10	46
	Existing Plant Retirements/Conversions	-	-	5	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(642)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	158	157	148	122	572	114	118	119	118	111	109	106	503	906	254	323	980	117	555	551		
	Annual Additions, Short Term Resources	791	1,103	887	798	899	1,004	931	952	1,165	1,104	1,112	1,845	2,153	2,124	2,088	2,049	2,035	2,075	2,078	1,673		
	Total Annual Additions	949	1,260	1,036	919	1,471	1,118	1,049	1,071	1,282	1,216	1,221	1,951	2,657	3,030	2,342	2,372	3,015	2,192	2,633	2,224		

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

GW-1		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	46	152	-	602	150	950
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	91
	Wind, WYAE	-	-	-	-	300	440	-	-	-	-	-	-	-	-	-	-	-	-	-	-	740	740
	Total Wind	-	-	-	-	450	440	-	-	-	-	-	-	-	-	85	-	46	152	-	693	890	1,867
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	2	-	112	166	524	-	-	-	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	6.9	33.9	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	171.2	43.1	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	6	6	5	5	5	5	4	4	3	3	3	3	57	96
	DSM, Class 2, UT	84	58	62	59	62	68	66	66	68	65	65	61	57	58	59	49	44	37	34	35	656	1,155
	DSM, Class 2, WY	8	10	11	10	13	13	14	15	14	14	12	13	12	11	11	9	8	7	7	7	122	219
	DSM, Class 2 Total	97	74	79	75	81	87	85	86	89	84	82	78	74	74	74	62	55	47	44	44	835	1,470
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	281	300	291	300	300	300	300	281	300	3	135
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	150	-	-	70	16	7	-	-	-	244
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	49.1	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	9	9	8	10	9	9	9	8	8	7	7	6	5	5	4	3	3	2	2	89	134
	DSM, Class 2 Total	57	54	52	46	42	37	34	33	29	27	27	25	23	23	22	21	20	19	19	18	411	629
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	23	69	-	37	191	100	161	400	400	399	400	400	400	400	400	364	42	207
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	11	375	310	375	375	372	375	375	375	375	375	375	375	375	375	375	375	375	375	294	335
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	310	322	310	-	-	297	-	290	-	78	400	18	-	-	393	363	294	212	198
	FOT MidColumbia - WTR2	-	-	-	-	-	-	308	289	-	299	-	343	375	17	375	353	352	-	-	375	90	154
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	573	563	118	119	118	111	109	343	572	538	298	323	1,140	229	266	768		
	Annual Additions, Short Term Resources	779	842	1,150	1,119	1,220	1,253	1,180	1,201	1,415	1,355	1,362	2,000	2,128	2,082	2,068	2,028	2,027	2,068	2,019	2,307		
	Total Annual Additions	933	970	1,281	1,241	1,792	1,817	1,298	1,319	1,533	1,466	1,471	2,343	2,699	2,620	2,365	2,351	3,167	2,297	2,284	3,075		

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

GW-2		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	46	152	-	602	150	950
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	91	-	91
	Wind, WYAE	-	-	-	-	300	-	440	-	-	-	-	-	-	-	-	-	-	-	-	-	740	740
	Total Wind	-	-	-	-	450	-	440	-	-	-	-	-	-	-	85	-	46	152	-	693	890	1,867
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	2	-	112	166	524	-	-	-	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	6.9	33.9	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	171.2	43.1	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	6	6	5	5	5	5	4	4	3	3	3	3	57	96
	DSM, Class 2, UT	84	58	62	59	62	68	66	66	68	65	65	61	57	58	59	49	44	37	34	35	656	1,155
	DSM, Class 2, WY	8	10	11	10	13	13	14	15	14	14	12	13	12	11	11	9	8	7	7	7	122	219
	DSM, Class 2 Total	97	74	79	75	81	87	85	86	89	84	82	78	74	74	74	62	55	47	44	44	835	1,470
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	281	300	291	300	300	300	300	281	300	3	135
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	150	-	-	70	16	7	-	-	-	244
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	49.1	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	9	9	8	10	9	9	9	8	8	7	7	6	5	5	4	3	3	2	2	89	134
	DSM, Class 2 Total	57	54	52	46	42	37	34	33	29	27	27	25	23	23	22	21	20	19	19	18	411	629
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	23	134	-	37	191	100	161	400	400	399	400	400	400	400	400	364	49	210
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	11	375	310	375	375	372	375	375	375	375	375	375	375	375	375	375	375	375	375	294	335
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	310	322	310	-	-	297	-	290	-	78	42	18	353	352	18	-	294	212	178
	FOT MidColumbia - WTR2	-	-	-	-	-	-	308	289	-	299	-	343	375	375	375	-	-	375	363	375	90	174
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	573	123	558	119	118	111	109	343	572	538	298	323	1,140	229	266	768		
	Annual Additions, Short Term Resources	779	842	1,150	1,119	1,220	1,319	1,180	1,201	1,415	1,355	1,362	2,000	2,128	2,082	2,068	2,028	2,027	2,068	2,019	2,307		
	Total Annual Additions	933	970	1,281	1,241	1,792	1,442	1,738	1,319	1,533	1,466	1,471	2,343	2,699	2,620	2,365	2,351	3,167	2,297	2,284	3,075		

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

GW-3		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	376	-	376
	Wind, WYAE	-	-	-	-	300	440	760	-	-	-	-	-	-	-	-	-	-	-	-	-	1,500	1,500
	Total Wind	-	-	-	-	300	440	760	-	-	-	-	-	-	-	-	-	-	85	-	376	1,500	1,961
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	163	210	18	291	118	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	75.3	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	89.0	125.2	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	63	65	65	61	57	57	59	49	44	37	34	35	642	1,139
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	11	11	11	11	9	8	7	7	7	121	215
	DSM, Class 2 Total	97	74	79	75	81	77	85	85	82	84	82	77	73	73	74	62	55	47	43	44	819	1,450
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	295	286	300	300	300	300	300	300	3	137
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	5	-	-	142	74	16	7	-	-	-	244
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	24.7	10.3	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	49.7	68.4	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	10	9	9	9	8	8	7	7	6	6	5	4	3	3	2	2	89	134
	DSM, Class 2 Total	57	54	52	46	42	37	34	33	29	27	27	25	23	23	22	21	20	19	19	18	411	628
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	46	97	-	-	110	19	80	400	400	400	400	400	400	400	400	364	27	196
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	11	375	310	375	375	287	327	375	375	375	375	375	375	375	375	375	375	375	375	281	328
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	310	322	310	-	-	297	-	291	-	71	35	15	350	-	-	4	291	212	159
	FOT MidColumbia - WTR2	-	-	-	-	-	-	308	289	-	299	-	287	375	375	375	-	336	375	375	375	90	188
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	71	100	100	100	100	100	100	100	100	11	49
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	423	554	878	118	112	111	109	245	520	537	241	324	980	180	356	568		
	Annual Additions, Short Term Resources	779	842	1,150	1,120	1,243	1,282	1,095	1,116	1,334	1,274	1,281	1,933	2,116	2,071	2,065	2,025	2,011	2,050	2,054	2,305		
	Total Annual Additions	933	970	1,281	1,241	1,665	1,836	1,973	1,234	1,446	1,385	1,390	2,179	2,636	2,608	2,306	2,349	2,991	2,230	2,410	2,873		

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

GW-4		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	182
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
	Wind, WYAE	-	-	-	-	1,200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,200	1,200
	Total Wind	-	-	-	-	1,200	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	1,200	1,285
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	53	167	210	41	279	-	-	749
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	34.8	40.5	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	123.8	90.5	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	63	65	65	61	57	57	59	49	44	37	34	35	642	1,139
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	11	11	11	11	9	8	7	7	7	121	216
	DSM, Class 2 Total	97	74	79	75	81	77	85	85	82	84	82	77	73	73	74	62	55	47	44	44	819	1,450
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	293	300	291	300	300	300	300	300	263	3	135
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	83	-	68	70	16	7	13	-	-	257
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	49.1	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	10	9	9	9	8	8	7	7	6	6	5	4	3	3	2	2	89	134
	DSM, Class 2 Total	57	54	52	46	42	37	34	33	29	27	27	25	23	23	22	21	20	19	19	18	411	628
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	-	-	-	28	-	-	154	63	125	400	400	400	400	400	400	400	400	357	25	196
	FOT MidColumbia - SMR	399	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	11	375	310	287	375	332	372	375	375	375	375	375	375	375	375	375	375	375	375	281	328
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	331	275	310	-	310	-	289	297	-	-	-	400	40	390	350	-	377	4	235	209	194
	FOT MidColumbia - WTR2	-	-	-	-	322	-	308	-	-	299	291	305	50	375	-	-	336	-	375	375	93	152
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	1,323	114	118	118	112	111	109	295	549	537	306	323	980	117	358	256		
	Annual Additions, Short Term Resources	779	842	1,150	1,120	1,108	1,213	1,139	1,161	1,379	1,319	1,326	1,974	2,125	2,081	2,065	2,025	2,011	2,052	2,054	2,205		
	Total Annual Additions	933	970	1,281	1,241	2,431	1,327	1,258	1,279	1,491	1,430	1,435	2,268	2,675	2,617	2,371	2,349	2,991	2,169	2,412	2,461		

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

Battery		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	182
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	113	25	147	-	-	-	285
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	448	-	-	448
	Wind, WYAE	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,100	1,100
	Total Wind	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	-	113	25	147	448	-	1,100	1,833
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	110	528	2	161	-	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	75.3	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	89.0	125.2	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	63	65	65	61	57	57	58	49	44	37	34	35	642	1,137
	DSM, Class 2, WY	8	10	11	10	11	13	14	14	14	14	12	11	11	11	11	9	8	7	7	7	119	214
	DSM, Class 2 Total	97	74	79	75	78	77	85	85	82	84	82	77	73	73	73	62	55	47	44	44	817	1,446
	Battery Storage - East	-	-	-	-	80.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80	80
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	278	269	300	300	300	300	300	263	3	133
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	6	-	-	111	100	16	8	13	-	-	253
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	7.7	27.3	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	32.7	85.4	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	10	9	9	9	8	8	7	7	6	5	5	4	3	3	2	2	88	132
	DSM, Class 2 Total	57	53	52	46	42	37	33	33	29	27	27	25	23	23	22	21	20	19	19	18	410	627
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	3	-	-	-	-	-	93	2	64	400	400	400	400	400	400	400	400	357	10	186
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	21	375	307	225	342	270	311	375	375	375	375	375	375	375	375	375	375	375	375	260	318
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	332	273	307	-	-	-	287	295	-	-	284	400	19	390	350	-	15	392	248	178	194
	FOT MidColumbia - WTR2	-	-	-	-	319	308	306	-	-	297	289	-	29	375	-	-	349	375	-	375	123	151
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	57	100	100	100	100	100	100	100	100	11	49
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	1,301	114	118	118	112	111	109	230	537	536	209	410	1,123	225	687	256		
	Annual Additions, Short Term Resources	781	853	1,151	1,115	1,045	1,149	1,076	1,098	1,316	1,256	1,263	1,916	2,082	2,038	2,065	2,025	2,024	2,065	2,067	2,218		
	Total Annual Additions	935	981	1,282	1,236	2,345	1,264	1,194	1,216	1,428	1,367	1,372	2,146	2,619	2,574	2,273	2,435	3,147	2,290	2,754	2,474		

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

CAES		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	IC Aero UN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	182	-	182
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	151	28	107	-	-	-	285
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	447	-	-	447
	Wind, WYAE	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,100	1,100
	Total Wind	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	-	151	28	107	447	-	1,100	1,833
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	527	12	161	-	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	75.3	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	89.0	125.2	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	63	65	65	61	57	57	58	49	44	37	34	35	642	1,137
	DSM, Class 2, WY	8	10	11	10	11	13	14	14	14	14	12	11	11	11	11	9	8	7	7	7	119	214
	DSM, Class 2 Total	97	74	79	75	78	77	85	85	82	84	82	77	73	73	73	62	55	47	44	44	817	1,446
	CAES - East	-	-	-	-	80.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	80.0	80.0
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	278	269	300	300	300	300	300	263	3	133
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	6	-	-	111	100	16	8	13	-	-	253
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	7.7	27.3	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	32.7	85.4	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	10	9	9	9	8	8	7	7	6	5	5	4	3	3	2	2	88	132
	DSM, Class 2 Total	57	53	52	46	42	37	33	33	29	27	27	25	23	23	22	21	20	19	19	18	410	627
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	3	-	-	-	-	-	93	2	64	400	400	400	400	400	400	400	400	357	10	186
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	21	375	307	225	342	270	311	375	375	375	375	375	375	375	375	375	375	375	375	260	318
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	332	273	307	319	308	-	-	295	-	-	-	400	19	390	350	349	390	17	400	211	221
	FOT MidColumbia - WTR2	-	-	-	-	-	-	306	287	-	297	289	284	29	375	-	-	-	-	375	223	89	123
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	57	100	100	100	100	100	100	100	100	11	49
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	1,301	114	118	118	112	111	109	230	537	536	209	437	1,125	196	687	256		
	Annual Additions, Short Term Resources	781	853	1,151	1,115	1,045	1,149	1,076	1,098	1,316	1,256	1,263	1,916	2,082	2,038	2,065	2,025	2,024	2,065	2,067	2,218		
	Total Annual Additions	935	981	1,282	1,236	2,345	1,264	1,194	1,216	1,427	1,367	1,372	2,146	2,619	2,574	2,273	2,462	3,149	2,261	2,754	2,474		

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

WCA		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Expansion Resources**																						
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	436
	Wind, SO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	-	500
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	-	500
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	13	19
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	7	7	8	9	8	7	7	7	8	7	6	5	5	4	3	3	2	2	2	77	116
	DSM, Class 2 Total	57	52	50	46	41	35	32	31	27	27	26	24	22	22	21	21	19	18	18	18	399	609
	FOT COB - SMR	-	-	-	-	-	58	180	193	182	188	207	206	400	400	400	400	333	340	348	250	80	204
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	162	160	306	204	368	375	170	164	198	182	177	187	338	345	352	359	375	375	375	375	229	277
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT COB - WTR	-	-	-	-	-	-	241	-	238	390	305	267	400	400	400	400	400	400	242	189	87	214
	FOT MidColumbia - WTR	400	246	400	400	400	320	400	332	94	400	400	400	400	296	400	306	227	236	400	400	339	343
	FOT MidColumbia - WTR2	146	375	177	164	301	375	55	375	375	20	24	58	269	375	276	375	375	375	375	375	236	262
	FOT NOB - WTR	100	100	100	100	100	100	100	100	100	-	86	100	100	100	100	100	100	100	100	100	90	94
	Existing Plant Retirements/Conversions	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	(359)	-	-	-		
	Annual Additions, Long Term Resources	57	52	50	46	41	35	32	31	27	27	26	24	22	22	21	21	455	18	18	518		
	Annual Additions, Short Term Resources	1,308	1,382	1,483	1,368	1,670	1,729	1,646	1,664	1,687	1,681	1,700	1,717	2,406	2,416	2,428	2,439	2,310	2,326	2,340	2,189		
	Total Annual Additions	1,365	1,434	1,533	1,414	1,711	1,764	1,678	1,695	1,714	1,708	1,725	1,741	2,429	2,438	2,449	2,460	2,765	2,343	2,359	2,708		

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

WCA-RPS		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	436
	Wind, YK	-	-	-	-	11	59	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
	Wind, SO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	-	500
	Total Wind	-	-	-	-	11	59	-	-	-	-	-	-	-	-	-	-	-	-	-	500	70	570
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	13	19
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	7	7	8	9	8	7	7	7	7	7	6	5	5	4	3	3	2	2	2	77	116
	DSM, Class 2 Total	57	52	50	46	41	35	32	31	27	27	26	24	22	22	21	21	19	18	18	18	399	608
	FOT COB - SMR	-	-	-	-	-	51	180	193	182	188	207	206	400	400	400	400	325	332	341	242	79	202
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	162	160	306	204	367	375	162	156	190	175	169	179	330	338	345	351	375	375	375	375	226	273
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT COB - WTR	-	-	-	-	-	-	241	-	238	390	291	267	400	400	400	400	400	400	235	182	87	212
	FOT MidColumbia - WTR	171	246	202	400	400	313	72	324	400	38	42	75	400	400	400	400	400	228	400	400	257	286
	FOT MidColumbia - WTR2	375	375	375	164	300	375	375	375	61	375	375	375	261	264	268	273	195	375	375	375	315	314
	FOT NOB - WTR	100	100	100	100	100	100	100	100	100	-	100	100	100	100	100	100	100	100	100	100	90	95
	Existing Plant Retirements/Conversions	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	(359)	-	-	-		
	Annual Additions, Long Term Resources	57	52	50	46	52	94	32	31	27	27	26	24	22	22	21	21	455	18	18	518		
	Annual Additions, Short Term Resources	1,308	1,382	1,483	1,368	1,667	1,713	1,631	1,648	1,671	1,666	1,685	1,702	2,391	2,401	2,413	2,424	2,295	2,311	2,325	2,174		
	Total Annual Additions	1,365	1,434	1,533	1,414	1,719	1,807	1,662	1,679	1,699	1,692	1,710	1,726	2,414	2,423	2,434	2,445	2,750	2,328	2,344	2,693		

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

Table K.10 – Final Screening Cases, Detailed Capacity Expansion Portfolios

FS-REP		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	CCCT - Utah-S - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	477	-	953
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	103	-	-	-	-	-	-	-	-	-	-	-	-	-	512	-	103	615
	Wind, WYAE	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Wind	-	-	-	-	403	-	-	-	-	-	-	-	-	85	-	-	-	-	512	-	403	1,001
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	88	153	167	209	40	143	-	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	-	-	3.4
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	75.3	-	4.8	-	-	-	3.7	-	-	-	83.7
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	-	-	3.1
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	-	3.1	-	-	-	-	43.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	205.0	9.2	4.8	-	3.4	3.1	3.7	3.1	-	-	232.2
	DSM, Class 2, ID	5	7	7	6	6	5	6	6	6	6	5	5	5	5	4	4	3	3	3	2	57	96
	DSM, Class 2, UT	84	58	62	59	62	68	66	66	68	67	65	61	57	60	58	49	44	37	34	24	658	1,147
	DSM, Class 2, WY	8	10	11	10	13	13	14	15	14	14	12	13	12	11	11	9	8	7	7	5	122	217
	DSM, Class 2 Total	97	74	79	75	81	87	85	86	89	86	82	78	74	76	73	62	55	47	44	31	838	1,459
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	231	300	300	300	300	300	300	29	3	121
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Wind - Repower Existing resource	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	West Wind-Repower	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	-	436
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	36	-	-	-	-	-	-	-	36
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	101	10	62	16	8	13	-	-	210
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	11.4	24.7	-	-	3.3	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	3.8	9.2	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	84.2	33.9	-	-	3.3	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	10	9	9	9	8	8	7	6	6	5	5	4	3	3	2	2	88	132
	DSM, Class 2 Total	57	53	52	46	42	37	33	33	29	27	27	25	23	23	22	22	20	19	19	18	410	627
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	3	-	28	139	67	107	261	169	230	400	400	400	400	400	400	400	400	342	77	227
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	21	375	307	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	295	335
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	332	273	307	-	308	-	287	295	-	-	38	-	54	15	-	340	381	383	334	208	181
	FOT MidColumbia - WTR2	-	-	-	-	319	-	306	-	-	297	289	375	371	375	375	354	-	-	-	-	92	153
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	526	123	118	119	118	113	109	392	606	613	258	319	980	117	734	526		
	Annual Additions, Short Term Resources	781	853	1,151	1,115	1,222	1,322	1,248	1,269	1,484	1,422	1,429	2,088	1,977	2,104	2,065	2,029	2,015	2,056	2,058	1,680		
	Total Annual Additions	935	981	1,282	1,236	1,748	1,445	1,367	1,388	1,601	1,535	1,538	2,480	2,583	2,717	2,323	2,349	2,995	2,173	2,792	2,206		

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

	FS-GW4	Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	774	-	774
	Wind, WYAE	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,100	1,100
	Total Wind	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	85	-	-	-	-	774	1,100	1,959
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	79	167	210	41	291	13	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	34.8	40.5	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	123.8	90.5	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	63	65	65	61	57	57	59	49	44	37	34	35	642	1,139
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	11	11	11	11	9	8	7	7	7	121	216
	DSM, Class 2 Total	97	74	79	75	81	77	85	85	82	84	82	77	73	73	74	62	55	47	44	44	819	1,450
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	300	291	300	300	300	300	300	300	3	137
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	11	97	-	38	70	16	8	-	-	-	240
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	49.1	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	10	9	9	9	8	8	7	7	6	5	5	4	3	3	2	2	88	132
	DSM, Class 2 Total	57	53	52	46	42	37	33	33	29	27	27	25	23	23	22	21	20	19	19	18	410	627
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	3	-	-	41	-	10	167	76	137	400	400	400	400	400	400	400	400	364	30	200
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	21	375	307	299	375	344	375	375	375	375	375	375	375	375	375	375	375	375	375	285	330
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	332	273	307	-	308	-	287	295	-	-	-	400	41	390	351	-	377	4	291	208	197
	FOT MidColumbia - WTR2	-	-	-	-	319	-	306	-	-	297	289	312	51	375	-	-	337	-	375	375	92	152
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	1,223	114	118	118	112	111	109	306	563	536	303	323	980	117	356	861		
	Annual Additions, Short Term Resources	781	853	1,151	1,115	1,118	1,223	1,150	1,172	1,390	1,329	1,336	1,987	2,126	2,081	2,065	2,026	2,012	2,052	2,054	2,305		
	Total Annual Additions	935	981	1,282	1,236	2,341	1,337	1,268	1,289	1,501	1,440	1,445	2,293	2,688	2,618	2,368	2,349	2,992	2,169	2,411	3,166		

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

FS-R1c		Capacity (MW)																				Resource Totals 1/	
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	774	-	774
	Wind, WYAE	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,100	1,100
	Total Wind	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	85	-	-	-	-	774	1,100	1,959
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	79	167	210	41	291	13	-	800
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	10.9	3.9	-	-	3.4	-	-	-	3.1	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	34.8	40.5	4.8	-	-	-	3.7	-	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	-	-	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	40.7	-	-	-	3.1	-	-	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	123.8	90.5	4.8	-	3.4	3.1	3.7	-	14.7	-	243.8
	DSM, Class 2, ID	5	7	7	6	6	5	5	6	5	6	5	5	5	5	4	4	3	3	3	3	56	95
	DSM, Class 2, UT	84	58	62	59	62	58	66	66	63	65	65	61	57	57	59	49	44	37	34	35	642	1,139
	DSM, Class 2, WY	8	10	11	10	13	13	14	14	14	14	12	11	11	11	11	9	8	7	7	7	121	216
	DSM, Class 2 Total	97	74	79	75	81	77	85	85	82	84	82	77	73	73	74	62	55	47	44	44	819	1,450
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	294	294	284	300	300	300	300	297	300	3	136
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Wind, YK	-	-	-	-	57	-	-	-	-	-	-	-	-	-	-	-	-	-	239	128	57	423
	Wind, SO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	193	-	238
	Total Wind	-	-	-	-	57	-	-	-	-	-	-	-	-	-	-	-	-	-	284	322	57	662
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	11	97	-	38	70	16	8	-	-	-	240
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	2.4
	DSM, Class 1, CA-Curtail	-	-	-	-	-	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-	-	-	1.2
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	-	-	-	-	-	3.7
	DSM, Class 1, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	36.1	-	3.3	-	-	-	-	-	-	39.4
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	35.0	-	-	-	-	-	-	-	-	-	35.0
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	-	-	-	-	-	12.8
	DSM, Class 1, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	13.0	-	-	-	-	-	-	-	-	13.0
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	9.1	-	-	-	-	-	-	-	-	-	9.1
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	49.1	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2, CA	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	13	21
	DSM, Class 2, OR	46	44	42	37	31	26	23	23	20	19	18	17	17	16	16	17	15	15	16	16	310	474
	DSM, Class 2, WA	10	8	9	8	10	9	9	9	8	8	7	7	6	5	5	4	3	3	2	2	88	132
	DSM, Class 2 Total	57	53	52	46	42	37	33	33	29	27	27	25	23	23	22	21	20	19	19	18	410	627
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	3	-	-	34	-	3	161	70	131	400	400	400	394	394	394	394	369	290	27	192
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	21	375	307	293	375	338	375	375	375	375	375	375	375	375	375	375	375	375	375	283	329
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	332	273	307	313	301	-	-	288	-	282	306	69	34	9	-	330	371	342	218	210	203
	FOT MidColumbia - WTR2	-	-	-	-	-	-	300	281	-	291	-	-	375	375	375	344	-	-	-	375	87	136
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	1,280	114	118	118	112	111	109	306	563	536	303	323	980	117	637	1,186		
	Annual Additions, Short Term Resources	781	853	1,151	1,115	1,106	1,211	1,137	1,159	1,377	1,317	1,324	1,975	2,113	2,069	2,053	2,013	1,999	2,039	1,982	2,158		
	Total Annual Additions	935	981	1,282	1,236	2,385	1,325	1,255	1,277	1,489	1,428	1,433	2,281	2,676	2,605	2,355	2,336	2,979	2,157	2,619	3,343		

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

APPENDIX L – STOCHASTIC PRODUCTION COST SIMULATION RESULTS

Introduction

This appendix reports additional results for the Monte Carlo production cost simulations conducted with the Planning and Risk (PaR) model for the core, sensitivity and final screening cases. These results supplement the data presented in Volume I, Chapter 8 (Modeling and Portfolio Selection Results) of the IRP document. The results presented include the following:

- Statistics of the stochastic simulation results
- Components of portfolios' present value revenue requirements (PVRR)
- Energy-not-served
- Customer rate impact of portfolios in the final screen as compared with the preferred portfolio
- Loss of load probability of the preferred portfolio

There are seven Regional Haze cases, eleven core cases, twenty sensitivity cases, and four final screening cases.

Table L.1 – Stochastic Mean PVRR by Price Scenario, Regional Haze Cases

PVRR ($m)	Low Gas, MC A	Med Gas, MC A	High Gas, MC A	Low Gas, MC B	Med Gas, MC B	High Gas, MC B
Ref.	23,979	24,553	26,760	24,048	24,559	26,833
RH-1	22,840	23,453	25,654	22,931	23,477	25,827
RH-2	22,934	23,671	26,346	22,898	23,655	26,366
RH-3	22,953	23,593	25,956	22,981	23,593	26,046
RH-4	23,342	23,949	26,126	23,429	23,970	26,274
RH-5	22,762	23,446	26,088	22,730	23,430	26,059
RH-6	23,624	24,278	26,642	23,626	24,266	26,670

Table L.2 – Stochastic Mean PVRR by Price Scenario, Core Cases

PVRR ($m)	Low Gas, MC A	Med Gas, MC A	High Gas, MC A	Low Gas, MC B	Med Gas, MC B	High Gas, MC B
OP-1	22,763	23,444	25,988	22,730	23,430	26,020
OP-NT3	22,761	23,407	25,716	22,724	23,388	25,722
OP-REP	22,719	23,350	25,573	22,686	23,333	25,590
OP-GW4	23,069	23,608	25,400	23,035	23,584	25,413
FR-1	23,257	23,892	26,251	23,220	23,873	26,239
FR-2	23,820	24,485	27,003	23,783	24,467	26,995
RE-1a	22,819	23,431	25,651	22,783	23,449	25,656
RE-1b	22,772	23,395	25,632	22,737	23,413	25,650
RE-1c	22,868	23,462	25,613	22,832	23,444	25,627
RE-2	22,828	23,422	25,567	22,795	23,410	25,588
DLC-1	22,878	23,475	25,673	22,842	23,458	25,667

Table L.3 – Stochastic Mean PVRR by Price Scenario, Sensitivity Cases

PVRR ($m)	Low Gas, MC A	Med Gas, MC A	High Gas, MC A	Low Gas, MC B	Med Gas, MC B	High Gas, MC B
RH2a	22,842	23,558	26,149	22,806	23,542	26,167
CPP-C	22,813	23,513	26,274	22,777	23,505	26,490
CPP-D	22,699	23,364	25,667	22,661	23,330	25,663
FOT-1	23,048	23,681	26,061	23,011	23,663	26,067
CO2-1	23,791	24,306	25,620	23,748	24,261	25,667
GW1	23,321	23,890	25,841	23,283	23,867	25,846
GW2	23,667	24,236	26,194	23,629	24,212	26,199
GW3	24,214	24,723	26,440	24,176	24,696	26,449
GW4	23,055	23,611	25,480	23,020	23,587	25,489
WCA	6,767	7,090	8,261	6,739	7,066	8,225
WCA-RPS	6,789	7,102	8,241	6,762	7,079	8,207

Table L.4 – Stochastic Mean PVRR by Price Scenario, Final Screening Cases

PVRR ($m)	Low Gas, MC A	Med Gas, MC A	High Gas, MC A	Low Gas, MC B	Med Gas, MC B	High Gas, MC B
Ref.	23,979	24,553	26,760	24,048	24,559	26,833
RH-1	22,840	23,453	25,654	22,931	23,477	25,827
RH-2	22,934	23,671	26,346	22,898	23,655	26,366
RH-3	22,953	23,593	25,956	22,981	23,593	26,046
RH-4	23,342	23,949	26,126	23,429	23,970	26,274
RH-5	22,762	23,446	26,088	22,730	23,430	26,059
RH-6	23,624	24,278	26,642	23,626	24,266	26,670

Table L.5 – Stochastic Risk Results, Regional Haze Cases – Low Gas, MC A

PVRR ($m)	Low Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
Ref.	123	23,818	24,097	24,272	15,464
RH-1	118	22,688	22,959	23,134	15,584
RH-2	128	22,771	23,052	23,225	15,638
RH-3	119	22,809	23,107	23,244	15,646
RH-4	121	23,199	23,467	23,629	15,598
RH-5	119	22,614	22,882	23,051	15,681
RH-6	123	23,460	23,738	23,902	15,659

Table L.6 – Stochastic Risk Results, Regional Haze Cases – Medium Gas, MC A

PVRR ($m)	Medium Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
Ref.	138	24,375	24,682	24,869	16,086
RH-1	134	23,282	23,606	23,770	16,246
RH-2	145	23,482	23,804	23,987	16,421
RH-3	135	23,444	23,751	23,922	16,335
RH-4	136	23,784	24,086	24,262	16,253
RH-5	136	23,272	23,596	23,758	16,412
RH-6	140	24,119	24,425	24,605	16,386

Table L.7 – Stochastic Risk Results, Regional Haze Cases – High Gas, MC A

PVRR ($m)	High Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
Ref.	205	26,438	26,990	27,130	18,376
RH-1	197	25,383	25,882	26,036	18,562
RH-2	210	26,014	26,568	26,730	19,199
RH-3	201	25,703	26,193	26,380	18,822
RH-4	199	25,860	26,437	26,500	18,551
RH-5	199	25,790	26,259	26,478	19,161
RH-6	206	26,390	27,019	27,059	18,890

Table L.8 – Stochastic Risk Results, Regional Haze Cases – Low Gas, MC B

PVRR ($m)	Low Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
Ref.	123	23,893	24,174	24,347	15,525
RH-1	121	22,776	23,064	23,220	15,687
RH-2	127	22,737	23,007	23,188	15,598
RH-3	118	22,845	23,135	23,275	15,673
RH-4	123	23,287	23,576	23,721	15,697
RH-5	118	22,585	22,854	23,018	15,643
RH-6	121	23,487	23,755	23,921	15,675

Table L.9 – Stochastic Risk Results, Regional Haze Cases – Medium Gas, MC B

PVRR ($m)	Medium Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
Ref.	137	24,384	24,698	24,878	16,078
RH-1	132	23,315	23,622	23,818	16,260
RH-2	144	23,469	23,790	23,969	16,399
RH-3	134	23,432	23,758	23,936	16,329
RH-4	133	23,795	24,104	24,289	16,258
RH-5	135	23,259	23,571	23,743	16,393
RH-6	139	24,108	24,412	24,593	16,366

Table L.10 – Stochastic Risk Results, Regional Haze Cases – High Gas, MC B

PVRR ($m)	High Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
Ref.	195	26,517	27,168	27,220	18,424
RH-1	189	25,531	26,175	26,240	18,724
RH-2	208	26,094	26,577	26,751	19,219
RH-3	195	25,806	26,251	26,481	18,893
RH-4	190	26,002	26,597	26,674	18,676
RH-5	198	25,743	26,239	26,449	19,127
RH-6	202	26,435	26,929	27,091	18,912

Table L.11 – Stochastic Risk Results, Core Cases – Low Gas, MC A

PVRR ($m)	Low Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
OP-1	119	22,615	22,883	23,051	15,681
OP-NT3	121	22,606	22,885	23,054	15,557
OP-REP	118	22,573	22,843	23,002	15,395
OP-GW4	120	22,924	23,196	23,363	14,891
FR-1	119	23,107	23,391	23,547	15,528
FR-2	97	23,668	23,930	23,978	15,459
RE-1a	118	22,671	22,948	23,103	15,318
RE-1b	116	22,628	22,892	23,051	15,360
RE-1c	117	22,716	22,996	23,154	15,254
RE-2	117	22,680	22,955	23,108	15,246
DLC-1	122	22,715	23,014	23,169	15,318

Table L.12 – Stochastic Risk Results, Core Cases – Medium Gas, MC A

PVRR ($m)	Medium Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
OP-1	136	23,270	23,593	23,756	16,414
OP-NT3	137	23,234	23,558	23,730	16,255
OP-REP	133	23,185	23,500	23,659	16,074
OP-GW4	135	23,440	23,753	23,919	15,473
FR-1	135	23,721	24,037	24,203	16,211
FR-2	114	24,300	24,624	24,669	16,167
RE-1a	133	23,269	23,581	23,741	15,978
RE-1b	131	23,239	23,547	23,701	16,031
RE-1c	132	23,293	23,620	23,772	15,894
RE-2	132	23,255	23,577	23,728	15,888
DLC-1	138	23,292	23,624	23,787	15,964

Table L.13 – Stochastic Risk Results, Core Cases – High Gas, MC A

PVRR ($m)	High Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
OP-1	201	25,695	26,191	26,370	19,067
OP-NT3	201	25,419	25,933	26,104	18,678
OP-REP	195	25,266	25,776	25,943	18,414
OP-GW4	198	25,146	25,660	25,778	17,373
FR-1	198	25,971	26,474	26,627	18,677
FR-2	189	26,704	27,209	27,361	18,833
RE-1a	196	25,379	25,861	26,030	18,306
RE-1b	196	25,346	25,858	25,999	18,375
RE-1c	195	25,313	25,820	25,992	18,154
RE-2	195	25,294	25,776	25,938	18,144
DLC-1	203	25,388	25,880	26,059	18,273

Table L.14 – Stochastic Risk Results, Core Cases – Low Gas, MC B

PVRR ($m)	Low Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
OP-1	118	22,585	22,854	23,018	15,643
OP-NT3	119	22,575	22,842	23,016	15,516
OP-REP	116	22,535	22,810	22,967	15,357
OP-GW4	119	22,894	23,161	23,327	14,854
FR-1	118	23,068	23,346	23,507	15,487
FR-2	96	23,632	23,885	23,938	15,418
RE-1a	116	22,643	22,920	23,066	15,276
RE-1b	115	22,600	22,856	23,015	15,321
RE-1c	115	22,691	22,953	23,117	15,212
RE-2	115	22,655	22,927	23,072	15,207
DLC-1	121	22,684	22,977	23,131	15,278

Table L.15 – Stochastic Risk Results, Core Cases – Medium Gas, MC B

PVRR ($m)	Medium Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
OP-1	135	23,259	23,571	23,743	16,393
OP-NT3	136	23,219	23,538	23,709	16,226
OP-REP	132	23,164	23,470	23,641	16,053
OP-GW4	134	23,424	23,722	23,898	15,448
FR-1	134	23,696	24,017	24,188	16,187
FR-2	113	24,296	24,600	24,649	16,146
RE-1a	133	23,289	23,595	23,760	15,989
RE-1b	131	23,260	23,551	23,719	16,041
RE-1c	131	23,280	23,598	23,755	15,869
RE-2	131	23,248	23,557	23,714	15,868
DLC-1	138	23,283	23,606	23,773	15,943

Table L.16 – Stochastic Risk Results, Core Cases – High Gas, MC B

PVRR ($m)	High Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
OP-1	199	25,708	26,224	26,399	19,093
OP-NT3	197	25,410	25,934	26,104	18,666
OP-REP	191	25,329	25,790	25,957	18,408
OP-GW4	197	25,155	25,669	25,787	17,378
FR-1	196	25,952	26,447	26,608	18,663
FR-2	187	26,705	27,232	27,360	18,819
RE-1a	192	25,396	25,858	26,024	18,296
RE-1b	191	25,363	25,868	26,010	18,375
RE-1c	192	25,356	25,831	25,996	18,155
RE-2	192	25,306	25,793	25,959	18,149
DLC-1	201	25,389	25,874	26,044	18,265

Table L.17 – Stochastic Risk Results, Sensitivity Cases – Low Gas, MC A

PVRR ($m)	Low Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
RH2a	119	22,982	23,284	23,420	15,854
CPP-C	121	22,661	22,956	23,082	15,585
CPP-D	122	22,532	22,832	22,992	15,739
FOT-1	117	22,894	23,185	23,322	15,496
CO2-1	134	23,637	23,968	24,075	15,913
GW1	118	23,165	23,449	23,611	15,091
GW2	124	23,513	23,815	23,963	15,150
GW3	116	24,065	24,342	24,493	14,719
GW4	119	22,906	23,182	23,344	14,993
WCA	82	6,678	6,871	6,972	4,970
WCA-RPS	81	6,700	6,899	6,991	4,910

Table L.18 – Stochastic Risk Results, Sensitivity Cases – Medium Gas, MC A

PVRR ($m)	Medium Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
RH2a	136	24,015	24,352	24,499	16,954
CPP-C	139	23,332	23,652	23,808	16,333
CPP-D	138	23,186	23,505	23,679	16,449
FOT-1	133	23,502	23,844	23,990	16,177
CO2-1	138	24,167	24,472	24,584	16,422
GW1	133	23,721	24,050	24,202	15,689
GW2	140	24,058	24,400	24,561	15,737
GW3	130	24,554	24,878	25,022	15,258
GW4	134	23,439	23,766	23,928	15,523
WCA	95	6,981	7,220	7,300	5,312
WCA-RPS	94	6,996	7,231	7,309	5,241

Table L.19 – Stochastic Risk Results, Sensitivity Cases – High Gas, MC A

PVRR ($m)	High Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
RH2a	200	28,092	28,631	28,768	21,249
CPP-C	207	26,025	26,458	26,630	19,197
CPP-D	209	25,358	25,991	26,074	18,868
FOT-1	199	25,780	26,271	26,450	18,670
CO2-1	193	25,348	25,847	25,996	17,802
GW1	196	25,565	26,079	26,235	17,767
GW2	202	25,912	26,504	26,578	17,824
GW3	191	26,179	26,667	26,804	17,090
GW4	197	25,224	25,764	25,893	17,581
WCA	119	8,118	8,431	8,458	6,495
WCA-RPS	117	8,113	8,403	8,433	6,391

Table L.20 – Stochastic Risk Results, Sensitivity Cases – Low Gas, MC B

PVRR ($m)	Low Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
RH2a	118	22,985	23,275	23,415	15,847
CPP-C	120	22,584	22,872	22,992	15,489
CPP-D	120	22,496	22,789	22,951	15,698
FOT-1	116	22,858	23,141	23,283	15,455
CO2-1	134	23,526	23,848	23,960	15,796
GW1	117	23,134	23,413	23,571	15,051
GW2	123	23,481	23,769	23,921	15,108
GW3	115	24,034	24,309	24,453	14,679
GW4	118	22,876	23,148	23,307	14,956
WCA	82	6,644	6,841	6,944	4,941
WCA-RPS	81	6,688	6,870	6,965	4,882

Table L.21 – Stochastic Risk Results, Sensitivity Cases – Medium Gas, MC B

PVRR ($m)	Medium Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
RH2a	135	23,360	23,701	23,856	16,296
LD-1	133	23,534	23,827	23,997	16,270
LD-2	124	21,490	21,801	21,940	15,210
LD-3	146	25,016	25,382	25,559	17,690
PG-1	136	23,417	23,745	23,919	16,416
PG-2	133	22,985	23,300	23,458	16,042
CPP-C	138	23,276	23,576	23,739	16,253
CPP-D	137	23,146	23,476	23,654	16,418
FOT-1	132	23,489	23,822	23,972	16,155
CO2-1	138	24,046	24,344	24,472	16,309
NO-CO2	143	23,010	23,333	23,510	16,164
BP	140	23,316	23,643	23,816	16,407
GW1	132	23,696	24,021	24,182	15,677
GW2	139	24,041	24,376	24,540	15,730
GW3	129	24,532	24,850	24,995	15,244
GW4	133	23,422	23,740	23,911	15,567
Battery	132	23,322	23,629	23,795	15,344
CAES	131	23,274	23,598	23,749	15,334
WCA	93	6,961	7,178	7,279	5,285
WCA-RPS	92	6,997	7,197	7,289	5,215

Table L.22 – Stochastic Risk Results, Sensitivity Cases – High Gas, MC B

PVRR ($m)	High Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
RH2a	199	28,368	28,904	29,036	21,521
CPP-C	200	26,161	26,589	26,774	19,256
CPP-D	207	25,349	25,982	26,071	18,855
FOT-1	196	25,799	26,272	26,441	18,668
CO2-1	191	25,307	25,906	25,971	17,774
GW1	195	25,557	26,083	26,238	17,771
GW2	201	25,929	26,511	26,583	17,825
GW3	189	26,189	26,676	26,808	17,093
GW4	196	25,213	25,745	25,876	17,568
WCA	117	8,083	8,397	8,420	6,456
WCA-RPS	116	8,080	8,373	8,398	6,353

Table L.23 – Stochastic Risk Results, Final Screening Cases, Low Gas, MC A

PVRR ($m)	Low Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
FS-REP	121	22,586	22,868	23,026	15,424
FS-GW4	121	22,671	22,964	23,107	14,852
FS-R1c	118	22,697	22,971	23,141	14,754
FS-R2	121	22,675	22,958	23,107	14,793

Table L.24 – Stochastic Risk Results, Final Screening Cases, Medium Gas, MC A

PVRR ($m)	Medium Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
FS-REP	136	23,198	23,514	23,682	16,105
FS-GW4	136	23,182	23,510	23,660	15,433
FS-R1c	134	23,190	23,511	23,677	15,318
FS-R2	136	23,184	23,500	23,652	15,364

Table L.25 – Stochastic Risk Results, Final Screening Cases, High Gas, MC A

PVRR ($m)	High Gas, MC A				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
FS-REP	201	25,337	25,832	25,975	18,460
FS-GW4	199	24,865	25,388	25,524	17,323
FS-R1c	197	24,830	25,435	25,476	17,153
FS-R2	199	24,822	25,346	25,478	17,221

Table L.26 – Stochastic Risk Results, Final Screening Cases, Low Gas, MC B

PVRR ($m)	Low Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
FS-REP	119	22,556	22,831	22,987	15,385
FS-GW4	120	22,642	22,919	23,070	14,816
FS-R1c	117	22,668	22,941	23,105	14,718
FS-R2	120	22,645	22,926	23,070	14,756

Table L.27 – Stochastic Risk Results, Final Screening Cases, Medium Gas, MC B

PVRR ($m)	Medium Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
FS-REP	135	23,184	23,484	23,662	16,081
FS-GW4	136	23,164	23,486	23,639	15,409
FS-R1c	133	23,172	23,483	23,657	15,300
FS-R2	136	23,163	23,472	23,631	15,341

Table L.28 – Stochastic Risk Results, Final Screening Cases, High Gas, MC B

PVRR ($m)	High Gas, MC B				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
FS-REP	197	25,361	25,837	25,988	18,450
FS-GW4	198	24,876	25,391	25,532	17,326
FS-R1c	196	24,842	25,442	25,487	17,163
FS-R2	198	24,831	25,350	25,484	17,222

Table L.29 – Stochastic Risk Adjusted PVRR by Price Scenario, Regional Haze Cases

PVRR ($m)	Low Gas MC A	Med Gas MC A	High Gas MC A	Low Gas MC B	Med Gas MC B	High Gas MC B
Ref.	25,192	25,797	28,117	25,265	25,803	28,194
RH-1	23,997	24,642	26,956	24,092	24,668	27,139
RH-2	24,095	24,871	27,683	24,058	24,853	27,703
RH-3	24,116	24,789	27,275	24,145	24,789	27,370
RH-4	24,523	25,162	27,451	24,615	25,185	27,607
RH-5	23,915	24,634	27,412	23,881	24,618	27,382
RH-6	24,819	25,508	27,995	24,822	25,496	28,025

Table L.30 – Stochastic Risk Adjusted PVRR by Price Scenario, Core Cases

PVRR ($m)	Low Gas MC A	Med Gas MC A	High Gas MC A	Low Gas MC B	Med Gas MC B	High Gas MC B
OP-1	23,915	24,632	27,306	23,881	24,618	27,339
OP-NT3	23,913	24,593	27,021	23,875	24,573	27,028
OP-REP	23,870	24,533	26,870	23,834	24,515	26,888
OP-GW4	24,238	24,804	26,689	24,201	24,779	26,702
FR-1	24,434	25,103	27,582	24,395	25,083	27,570
FR-2	25,019	25,718	28,371	24,980	25,699	28,363
RE-1a	23,974	24,618	26,953	23,937	24,637	26,958
RE-1b	23,924	24,580	26,932	23,887	24,599	26,950
RE-1c	24,026	24,650	26,913	23,988	24,632	26,927
RE-2	23,984	24,609	26,864	23,948	24,595	26,886
DLC-1	24,036	24,664	26,976	23,998	24,647	26,969

Table L.31 – Stochastic Risk Adjusted PVRR by Price Scenario, Sensitivity Cases

PVRR ($m)	Low Gas MC A	Med Gas MC A	High Gas MC A	Low Gas MC B	Med Gas MC B	High Gas MC B
RH2a	24,013	24,783	27,588	23,976	24,735	27,619
LD-1					24,896	
LD-2					22,757	
LD-3					26,507	
PG-1					24,794	
PG-2					24,330	
CPP-C	23,967	24,703	27,605	23,926	24,691	27,829
CPP-D	23,848	24,548	26,971	23,809	24,513	26,966
FOT-1	24,215	24,881	27,384	24,176	24,862	27,389
CO2-1	24,994	25,535	26,919	24,946	25,484	26,966
NO-CO2					24,369	
BP					24,686	
GW1	24,501	25,100	27,153	24,462	25,076	27,158
GW2	24,865	25,464	27,523	24,825	25,439	27,528
GW3	25,439	25,974	27,780	25,399	25,946	27,789
GW4	24,223	24,808	26,775	24,185	24,783	26,782
Battery					24,672	
CAES					24,628	
WCA	7,116	7,456	8,684	7,087	7,430	8,646
WCA-RPS	7,139	7,468	8,662	7,110	7,443	8,627

Table L.32 – Stochastic Risk Adjusted PVRR by Price Scenario, Final Screening Cases

PVRR ($m)	Low Gas MC A	Med Gas MC A	High Gas MC A	Low Gas MC B	Med Gas MC B	High Gas MC B
FS-REP	23,892	24,556	26,915	23,854	24,536	26,928
FS-GW4	23,976	24,538	26,418	23,939	24,513	26,428
FS-R1c	24,005	24,549	26,369	23,969	24,525	26,383
FS-R2	23,977	24,531	26,372	23,940	24,506	26,383

Table L.33 – Carbon Dioxide Emissions by Price Scenario, Regional Haze Cases

Thousand tons	Low Gas MC A	Med Gas MC A	High Gas MC A	Low Gas MC B	Med Gas MC B	High Gas MC B
Ref.	777,629	792,139	822,316	746,112	771,917	807,893
RH-1	778,296	796,129	832,155	747,953	770,068	810,428
RH-2	740,349	760,516	789,876	731,639	746,202	782,057
RH-3	765,552	784,124	815,564	741,886	765,080	800,197
RH-4	778,761	797,502	833,982	748,802	772,180	814,146
RH-5	761,055	778,905	794,102	750,003	763,392	791,235
RH-6	769,111	790,454	823,815	750,212	774,962	815,909

Table L.34 – Carbon Dioxide Emissions by Price Scenario, Core Cases

Thousand tons	Low Gas MC A	Med Gas MC A	High Gas MC A	Low Gas MC B	Med Gas MC B	High Gas MC B
OP-1	761,704	779,805	807,022	750,003	763,392	797,073
OP-NT3	752,088	770,091	805,130	742,449	755,898	798,248
OP-REP	751,414	770,912	808,128	740,165	756,131	800,948
OP-GW4	729,100	754,628	799,689	720,898	742,897	796,752
FR-1	748,949	767,334	797,491	740,031	752,705	791,557
FR-2	758,938	776,901	803,494	749,934	761,926	796,269
RE-1a	744,406	762,430	795,949	734,788	748,177	789,525
RE-1b	752,346	771,202	806,636	742,328	756,734	799,467
RE-1c	747,267	766,006	800,317	737,728	751,818	793,791
RE-2	751,162	769,348	804,314	741,245	755,066	797,294
DLC-1	743,323	761,665	792,462	734,533	747,387	787,203

Table L.35 – Carbon Dioxide Emissions by Price Scenario, Sensitivity Cases

Thousand tons	Low Gas MC A	Med Gas MC A	High Gas MC A	Low Gas MC B	Med Gas MC B	High Gas MC B
RH2a	736,327	755,384	784,856	727,604	740,985	776,869
LD-1					761,575	
LD-2					753,141	
LD-3					768,550	
PG-1					760,451	
PG-2					756,276	
CPP-C	762,993	772,981	791,975	750,783	753,561	770,192
CPP-D	772,053	793,785	832,451	763,993	783,373	829,399
FOT-1	754,305	772,805	800,512	745,459	758,254	793,920
CO2-1	611,462	669,010	797,827	604,190	660,142	791,631
NO-CO2					790,322	
BP					767,893	
GW1	741,560	764,748	806,382	733,200	752,041	802,801
GW2	742,726	765,925	807,538	734,339	752,954	803,467
GW3	728,679	754,860	801,057	720,557	743,122	798,561
GW4	732,726	757,439	801,200	724,538	745,567	798,313
Battery					744,571	
CAES					744,830	
WCA	186,112	201,116	220,945	183,590	198,186	220,099
WCA-RPS	185,814	200,791	220,609	183,288	197,860	219,764

Table L.36 – Carbon Dioxide Emissions by Price Scenario, Final Screening Cases

Thousand tons	Low Gas MC A	Med Gas MC A	High Gas MC A	Low Gas MC B	Med Gas MC B	High Gas MC B
FS-REP	751,656	770,177	806,095	742,090	756,079	799,221
FS-GW4	731,108	756,103	800,457	722,965	744,328	797,681
FS-R1c	730,427	755,499	799,914	722,284	743,734	797,140
FS-R2	729,953	755,491	800,937	721,857	743,727	798,200

Table L.37 – Energy Not Served, Regional Haze Cases, Low Gas

GWh	Low Gas, MC A		Low Gas, MC B	
	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036
Ref.	13.7	33.4	14.2	33.4
RH-1	11.5	31.2	12.4	32.4
RH-2	11.9	34.4	12.2	34.5
RH-3	11.2	30.5	11.4	30.3
RH-4	11.5	30.4	12.3	31.1
RH-5	11.5	30.2	11.7	30.3
RH-6	12.0	30.9	12.3	30.9

Table L.38 – Energy Not Served, Regional Haze Cases, Medium Gas

GWh	Medium Gas, MC A		Medium Gas, MC B	
	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036
Ref.	13.3	33.4	13.9	33.8
RH-1	11.1	31.0	11.6	31.3
RH-2	11.5	34.0	12.0	34.3
RH-3	10.8	30.2	11.3	30.6
RH-4	11.1	30.2	11.6	30.5
RH-5	11.1	30.1	11.6	30.5
RH-6	11.7	30.7	12.3	31.1

Table L.39 – Energy Not Served, Regional Haze Cases, High Gas

GWh	High Gas, MC A		High Gas, MC B	
	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036
Ref.	14.5	33.8	14.9	34.4
RH-1	12.3	31.6	12.5	31.8
RH-2	12.6	35.1	12.9	35.8
RH-3	11.9	30.8	12.1	30.9
RH-4	12.2	30.6	12.5	30.9
RH-5	12.2	30.7	12.4	30.8
RH-6	12.9	31.3	13.3	31.8

Table L.40 – Energy Not Served, Core Cases, Low Gas

GWh	Low Gas MC A		Low Gas, MC B	
	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036
OP-1	11.5	30.2	11.7	30.3
OP-NT3	12.1	31.4	12.4	31.3
OP-REP	11.0	30.9	11.3	30.9
OP-GW4	11.0	30.3	11.3	30.5
FR-1	12.4	31.4	12.7	31.5
FR-2	2.8	8.2	3.0	8.3
RE-1a	12.1	31.2	12.4	31.4
RE-1b	10.9	29.8	11.2	29.9
RE-1c	11.2	30.6	11.5	30.5
RE-2	11.2	30.2	11.5	30.2
DLC-1	12.8	32.1	13.1	32.1

Table L.41 – Energy Not Served, Core Cases, Medium Gas

GWh	Medium Gas, MC A		Medium Gas, MC B	
	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036
OP-1	11.1	30.1	11.6	30.5
OP-NT3	11.8	31.0	12.3	31.4
OP-REP	10.7	30.7	11.2	31.0
OP-GW4	10.8	30.0	11.3	30.5
FR-1	12.0	31.1	12.6	31.5
FR-2	2.8	8.1	3.1	8.2
RE-1a	11.7	31.0	12.3	31.4
RE-1b	10.6	29.7	11.1	30.1
RE-1c	10.8	30.2	11.4	30.5
RE-2	10.8	29.9	11.4	30.3
DLC-1	12.5	31.7	13.0	32.1

Table L.42 – Energy Not Served, Core Cases, High Gas

GWh	High Gas, MC A		High Gas, MC B	
	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036
OP-1	12.2	30.7	12.4	30.8
OP-NT3	13.0	31.5	13.2	31.6
OP-REP	11.8	31.3	12.1	31.4
OP-GW4	12.0	30.7	12.2	30.8
FR-1	13.1	31.8	13.2	31.7
FR-2	3.1	8.4	3.1	8.5
RE-1a	12.9	31.7	13.1	32.0
RE-1b	11.7	30.1	12.0	30.3
RE-1c	12.0	30.7	12.2	30.8
RE-2	12.0	30.4	12.2	30.6
DLC-1	13.7	32.3	13.8	32.5

Table L.43 – Energy Not Served, Sensitivity Cases, Low Gas

GWh	Low Gas, MC A		Low Gas, MC B	
	Average Annual Energy Not Served 2017 - 2036	Upper Tail Mean Energy Not Served Cumulative Total 2017 - 2036	Average Annual Energy Not Served 2017 - 2036	Upper Tail Mean Energy Not Served Cumulative Total 2017 - 2036
RH2a	11.2	30.5	11.5	30.5
CPP-C	13.3	32.0	13.4	32.0
CPP-D	12.3	31.9	12.6	31.9
FOT-1	11.9	30.9	12.2	31.0
CO2-1	14.8	38.4	14.8	38.4
GW1	11.2	30.4	11.5	30.5
GW2	11.7	30.6	11.9	30.9
GW3	10.9	30.3	11.2	30.6
GW4	11.0	31.0	11.3	31.3
WCA	15.6	39.2	15.9	39.4
WCA-RPS	15.6	39.2	15.9	39.4

Table L.44 – Energy Not Served, Sensitivity Cases, Medium Gas

GWh	Medium Gas, MC A		Medium Gas, MC B	
	Average Annual Energy Not Served 2017 - 2036	Upper Tail Mean Energy Not Served Cumulative Total 2017 - 2036	Average Annual Energy Not Served 2017 - 2036	Upper Tail Mean Energy Not Served Cumulative Total 2017 - 2036
RH2a	10.8	30.1	11.4	30.5
LD-1			11.8	31.4
LD-2			9.9	27.5
LD-3			16.1	36.6
PG-1			13.3	32.9
PG-2			10.5	28.3
CPP-C	12.8	31.8	13.1	32.0
CPP-D	12.1	31.5	12.6	31.9
FOT-1	11.5	30.6	12.1	31.0
CO2-1	13.1	34.1	13.2	34.0
NO-CO2			9.9	29.2
BP			12.1	31.4
GW1	11.0	30.1	11.5	30.5
GW2	11.4	30.3	11.9	30.7
GW3	10.7	30.1	11.3	30.6
GW4	10.8	30.7	11.3	31.3
Battery			11.6	31.7
CAES			11.5	31.2
WCA	14.8	38.9	15.8	39.6
WCA-RPS	14.8	38.8	15.8	39.6

Table L.45 – Energy Not Served, Sensitivity Cases, High Gas

GWh	High Gas, MC A		High Gas, MC B	
	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036	Average Annual Energy Not Served 2017 - 2036	Upper Tail Mean Energy Not Served Cumulative Total 2017 - 2036
RH2a	12.1	30.9	12.2	31.1
CPP-C	13.9	32.1	14.1	32.7
CPP-D	13.2	32.1	13.3	32.3
FOT-1	12.7	31.2	12.8	31.3
CO2-1	14.2	34.1	14.8	34.2
GW1	12.1	30.8	12.3	30.9
GW2	12.5	31.3	12.7	31.8
GW3	11.9	30.7	12.1	30.8
GW4	11.9	31.4	12.2	31.7
WCA	15.3	39.1	15.3	39.0
WCA-RPS	15.3	39.1	15.3	39.0

Table L.46 – Energy Not Served, Final Screening Cases, Low Gas

GWh	Low Gas MC A		Low Gas, MC B	
	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036
FS-REP	11.5	30.5	11.7	30.6
FS-GW4	11.3	30.0	11.6	30.3
FS-R1c	11.0	30.2	11.3	30.3
FS-R2	11.2	30.0	11.5	30.4

Table L.47 – Energy Not Served, Final Screening Cases, Medium Gas

GWh	Medium Gas, MC A		Medium Gas, MC B	
	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036
FS-REP	11.1	30.3	11.6	30.5
FS-GW4	11.1	29.7	11.6	30.3
FS-R1c	10.7	29.8	11.3	30.3
FS-R2	11.0	29.7	11.5	30.3

Table L.48 – Energy Not Served, Final Screening Cases, High Gas

GWh	High Gas, MC A		High Gas, MC B	
	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036	Average Annual Energy Not Served, 2017-2036	Upper Tail Mean Energy Not Served Cumulative Total, 2017-2036
FS-REP	12.3	30.8	12.5	30.9
FS-GW4	12.2	30.5	12.4	30.7
FS-R1c	11.9	30.5	12.1	30.6
FS-R2	12.2	31.0	12.4	31.2

Table L.49 – PVRR Cost Components by Price Scenario, Regional Haze Cases, MC A

Low Gas MC A	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
Ref.	11,256	479	428	2,510	857	(2,202)	1,804	8,847	23,979
RH-1	11,430	525	427	2,502	915	(2,096)	1,562	7,575	22,840
RH-2	11,193	505	428	2,486	904	(1,877)	1,631	7,665	22,934
RH-3	11,380	561	427	2,501	961	(2,094)	1,582	7,634	22,953
RH-4	11,435	517	427	2,500	899	(2,086)	1,574	8,076	23,342
RH-5	11,269	524	428	2,482	888	(1,892)	1,660	7,404	22,762
RH-6	11,408	578	428	2,489	886	(2,079)	1,625	8,289	23,624

Medium Gas MC A	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
Ref.	11,862	524	434	2,510	857	(2,573)	2,093	8,847	24,553
RH-1	12,097	575	434	2,502	915	(2,448)	1,804	7,575	23,453
RH-2	11,995	553	435	2,486	904	(2,205)	1,840	7,665	23,671
RH-3	12,085	608	434	2,501	961	(2,449)	1,818	7,634	23,593
RH-4	12,105	563	434	2,500	899	(2,437)	1,809	8,076	23,949
RH-5	11,970	571	434	2,482	888	(2,195)	1,892	7,404	23,446
RH-6	12,151	631	435	2,489	886	(2,443)	1,840	8,289	24,278

High Gas MC A	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
Ref.	13,626	587	457	2,510	857	(3,874)	3,750	8,847	26,760
RH-1	14,029	651	457	2,502	915	(3,606)	3,132	7,575	25,654
RH-2	14,222	627	455	2,486	904	(3,242)	3,230	7,665	26,346
RH-3	14,058	679	457	2,502	961	(3,573)	3,237	7,634	25,956
RH-4	14,017	631	457	2,500	899	(3,596)	3,141	8,076	26,126
RH-5	13,687	638	459	2,482	888	(3,107)	3,637	7,404	26,088
RH-6	14,215	716	458	2,489	886	(3,594)	3,183	8,289	26,642

Table L.50 – PVRR Cost Components by Price Scenario, Regional Haze Cases, MC B

Low Gas MC B	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
Ref.	10,891	478	424	2,510	857	(2,055)	2,096	8,847	24,048
RH-1	11,080	526	424	2,502	915	(1,946)	1,857	7,575	22,931
RH-2	11,016	504	425	2,486	904	(1,801)	1,701	7,665	22,898
RH-3	11,077	558	423	2,501	961	(1,967)	1,792	7,634	22,981
RH-4	11,088	515	424	2,500	899	(1,937)	1,864	8,076	23,429
RH-5	11,074	522	424	2,482	888	(1,813)	1,749	7,404	22,730
RH-6	11,144	577	424	2,489	886	(1,968)	1,784	8,289	23,626

Medium Gas MC B	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
Ref.	11,468	518	429	2,510	857	(2,388)	2,318	8,847	24,559
RH-1	11,649	568	429	2,502	915	(2,237)	2,077	7,575	23,477
RH-2	11,692	548	430	2,486	904	(2,059)	1,989	7,665	23,655
RH-3	11,711	603	429	2,501	961	(2,262)	2,014	7,634	23,593
RH-4	11,667	556	429	2,500	899	(2,229)	2,073	8,076	23,970
RH-5	11,654	564	429	2,482	888	(2,052)	2,061	7,404	23,430
RH-6	11,823	626	430	2,489	886	(2,276)	2,000	8,289	24,266

High Gas MC B	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
Ref.	13,104	571	459	2,510	857	(3,639)	4,124	8,847	26,833
RH-1	13,445	634	458	2,502	915	(3,361)	3,659	7,575	25,827
RH-2	13,927	615	457	2,486	904	(3,112)	3,425	7,665	26,366
RH-3	13,581	664	458	2,502	961	(3,360)	3,605	7,634	26,046
RH-4	13,456	614	459	2,500	899	(3,367)	3,637	8,076	26,274
RH-5	13,475	626	459	2,482	888	(3,018)	3,743	7,404	26,059
RH-6	13,882	701	459	2,489	886	(3,451)	3,415	8,289	26,670

Table L.51 – PVRR Cost Components by Price Scenario, Core Cases, MC A

Low Gas MC A	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
OP-1	11,277	524	427	2,482	888	(1,893)	1,654	7,404	22,763
OP-NT3	11,103	545	427	2,497	937	(1,918)	1,636	7,534	22,761
OP-REP	11,145	544	426	2,489	911	(1,974)	1,535	7,643	22,719
OP-GW4	10,695	518	425	2,543	890	(1,991)	1,486	8,503	23,069
FR-1	10,974	492	427	2,506	906	(1,869)	1,777	8,045	23,257
FR-2	11,168	452	427	2,488	829	(1,909)	1,775	8,590	23,820
RE-1a	10,944	534	427	2,502	937	(1,946)	1,607	7,814	22,819
RE-1b	11,141	536	427	2,499	937	(1,990)	1,499	7,722	22,772
RE-1c	11,021	532	427	2,503	937	(2,020)	1,544	7,923	22,868
RE-2	11,088	530	427	2,503	937	(2,080)	1,525	7,898	22,828
DLC-1	10,867	505	427	2,506	937	(1,959)	1,709	7,886	22,878

Medium Gas MC A	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
OP-1	11,984	571	434	2,482	888	(2,199)	1,881	7,404	23,444
OP-NT3	11,772	598	433	2,497	937	(2,228)	1,864	7,534	23,407
OP-REP	11,837	594	433	2,489	911	(2,297)	1,741	7,643	23,350
OP-GW4	11,386	569	431	2,543	890	(2,342)	1,628	8,503	23,608
FR-1	11,647	541	433	2,506	906	(2,176)	1,991	8,045	23,892
FR-2	11,908	489	434	2,488	829	(2,234)	1,982	8,590	24,485
RE-1a	11,588	588	433	2,502	937	(2,260)	1,829	7,814	23,431
RE-1b	11,823	585	433	2,499	937	(2,315)	1,710	7,722	23,395
RE-1c	11,682	584	433	2,503	937	(2,349)	1,749	7,923	23,462
RE-2	11,755	580	433	2,503	937	(2,418)	1,734	7,898	23,422
DLC-1	11,510	557	433	2,506	937	(2,277)	1,923	7,886	23,475

High Gas MC A	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
OP-1	13,936	641	455	2,482	888	(3,196)	3,377	7,404	25,988
OP-NT3	13,725	677	454	2,497	937	(3,290)	3,181	7,534	25,716
OP-REP	13,852	672	454	2,489	911	(3,407)	2,960	7,643	25,573
OP-GW4	13,354	648	452	2,543	890	(3,556)	2,567	8,503	25,400
FR-1	13,493	611	454	2,506	906	(3,200)	3,436	8,045	26,251
FR-2	13,817	529	454	2,488	829	(3,267)	3,562	8,590	27,003
RE-1a	13,456	670	454	2,503	937	(3,339)	3,155	7,814	25,651
RE-1b	13,804	661	454	2,499	937	(3,414)	2,969	7,722	25,632
RE-1c	13,598	662	454	2,504	937	(3,466)	3,002	7,923	25,613
RE-2	13,698	657	454	2,503	937	(3,551)	2,971	7,898	25,567
DLC-1	13,288	633	454	2,506	937	(3,345)	3,314	7,886	25,673

Table L.52 – PVRR Cost Components by Price Scenario, Core Cases, MC B

Low Gas MC B	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
OP-1	11,074	522	424	2,482	888	(1,813)	1,749	7,404	22,730
OP-NT3	10,918	543	423	2,497	937	(1,841)	1,714	7,534	22,724
OP-REP	10,947	542	423	2,489	911	(1,893)	1,624	7,643	22,686
OP-GW4	10,528	516	421	2,543	890	(1,919)	1,552	8,503	23,035
FR-1	10,795	490	423	2,506	906	(1,796)	1,849	8,045	23,220
FR-2	10,988	451	424	2,488	829	(1,836)	1,849	8,590	23,783
RE-1a	10,758	532	423	2,502	937	(1,870)	1,685	7,814	22,783
RE-1b	10,952	534	423	2,499	937	(1,912)	1,581	7,722	22,737
RE-1c	10,837	531	423	2,503	937	(1,943)	1,621	7,923	22,832
RE-2	10,900	528	423	2,503	937	(1,999)	1,605	7,898	22,795
DLC-1	10,690	503	423	2,506	937	(1,885)	1,781	7,886	22,842

Medium Gas MC B	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
OP-1	11,654	564	429	2,482	888	(2,052)	2,061	7,404	23,430
OP-NT3	11,476	591	428	2,497	937	(2,090)	2,014	7,534	23,388
OP-REP	11,533	587	428	2,489	911	(2,155)	1,898	7,643	23,333
OP-GW4	11,130	562	426	2,543	890	(2,216)	1,745	8,503	23,584
FR-1	11,347	536	429	2,506	906	(2,039)	2,143	8,045	23,873
FR-2	11,604	486	429	2,488	829	(2,097)	2,138	8,590	24,467
RE-1a	11,290	581	428	2,502	937	(2,121)	2,016	7,814	23,449
RE-1b	11,522	579	428	2,499	937	(2,173)	1,898	7,722	23,413
RE-1c	11,386	577	428	2,503	937	(2,208)	1,898	7,923	23,444
RE-2	11,458	574	428	2,503	937	(2,271)	1,882	7,898	23,410
DLC-1	11,212	550	428	2,506	937	(2,137)	2,074	7,886	23,458

High Gas MC B	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
OP-1	13,590	627	457	2,482	888	(3,057)	3,629	7,404	26,020
OP-NT3	13,437	663	456	2,497	937	(3,174)	3,372	7,534	25,722
OP-REP	13,546	657	456	2,489	911	(3,283)	3,171	7,643	25,590
OP-GW4	13,194	637	452	2,543	890	(3,463)	2,657	8,503	25,413
FR-1	13,230	595	456	2,506	906	(3,095)	3,596	8,045	26,239
FR-2	13,507	512	457	2,488	829	(3,137)	3,749	8,590	26,995
RE-1a	13,171	656	456	2,503	937	(3,222)	3,341	7,814	25,656
RE-1b	13,503	647	456	2,499	937	(3,288)	3,174	7,722	25,650
RE-1c	13,309	648	456	2,504	937	(3,341)	3,192	7,923	25,627
RE-2	13,404	643	456	2,503	937	(3,416)	3,163	7,898	25,588
DLC-1	13,055	620	456	2,506	937	(3,239)	3,446	7,886	25,667

Table L.53 – PVRR Cost Components by Price Scenario, Sensitivity Cases, MC A

Low Gas MC A	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
RH2a	11,004	514	427	2,501	964	(1,888)	1,710	7,610	22,842
CPP-C	11,337	535	427	2,496	864	(2,032)	1,626	7,560	22,813
CPP-D	11,432	542	427	2,486	878	(1,926)	1,575	7,287	22,699
FOT-1	11,138	478	427	2,509	948	(1,928)	1,617	7,861	23,048
CO2-1	9,890	508	426	2,520	966	(1,555)	2,759	8,276	23,791
GW1	10,864	525	426	2,524	916	(1,969)	1,472	8,546	23,305
GW2	10,894	527	426	2,523	916	(1,967)	1,479	8,850	23,648
GW3	10,632	515	425	2,549	896	(1,986)	1,372	9,799	24,202
GW4	10,746	519	426	2,543	896	(1,971)	1,448	8,380	22,986
WCA	2,989	353	(44)	70	225	(373)	1,514	2,034	6,767
WCA-RPS	2,983	351	(44)	71	225	(398)	1,489	2,112	6,789

Medium Gas MC A	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
RH2a	11,758	570	433	2,501	964	(2,204)	1,925	7,610	23,558
CPP-C	11,975	583	434	2,496	864	(2,319)	1,921	7,560	23,513
CPP-D	12,183	589	433	2,486	878	(2,250)	1,760	7,287	23,364
FOT-1	11,827	513	433	2,509	948	(2,233)	1,823	7,861	23,681
CO2-1	10,879	555	431	2,520	966	(1,970)	2,649	8,276	24,306
GW1	11,549	578	431	2,524	916	(2,308)	1,637	8,546	23,874
GW2	11,582	579	432	2,523	916	(2,306)	1,640	8,850	24,217
GW3	11,311	565	430	2,549	896	(2,339)	1,499	9,799	24,710
GW4	11,438	570	431	2,543	896	(2,316)	1,599	8,380	23,542
WCA	3,359	436	(44)	70	225	(505)	1,515	2,034	7,090
WCA-RPS	3,352	433	(44)	71	225	(536)	1,488	2,112	7,102

High Gas MC A	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
RH2a	13,856	659	454	2,502	964	(3,235)	3,341	7,610	26,149
CPP-C	13,962	656	455	2,496	864	(3,308)	3,590	7,560	26,274
CPP-D	14,377	663	455	2,486	878	(3,375)	2,898	7,287	25,667
FOT-1	13,737	566	455	2,510	948	(3,271)	3,257	7,861	26,061
CO2-1	13,326	621	453	2,521	966	(3,447)	2,903	8,276	25,620
GW1	13,507	659	452	2,525	916	(3,476)	2,698	8,546	25,826
GW2	13,539	660	452	2,523	916	(3,470)	2,704	8,850	26,176
GW3	13,270	645	451	2,549	896	(3,557)	2,376	9,799	26,429
GW4	13,405	650	452	2,544	896	(3,508)	2,594	8,380	25,412
WCA	4,095	584	(44)	70	225	(755)	2,053	2,034	8,261
WCA-RPS	4,086	580	(44)	71	225	(800)	2,010	2,112	8,240

Table L.54 – PVRR Cost Components by Price Scenario, Sensitivity Cases, MC B

Low Gas MC B	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
RH2a	10,829	514	423	2,501	964	(1,815)	1,779	7,610	22,806
CPP-C	11,127	533	424	2,496	864	(1,945)	1,719	7,560	22,777
CPP-D	11,263	540	423	2,486	878	(1,855)	1,640	7,287	22,661
FOT-1	10,960	476	423	2,509	948	(1,855)	1,688	7,861	23,011
CO2-1	9,735	507	422	2,520	966	(1,487)	2,809	8,276	23,748
GW1	10,694	524	422	2,524	916	(1,898)	1,539	8,546	23,268
GW2	10,723	525	422	2,523	916	(1,895)	1,546	8,850	23,610
GW3	10,465	513	421	2,549	896	(1,915)	1,437	9,799	24,165
GW4	10,579	517	422	2,543	896	(1,900)	1,514	8,380	22,951
WCA	2,930	351	(44)	70	225	(364)	1,537	2,034	6,739
WCA-RPS	2,924	349	(44)	71	225	(389)	1,513	2,112	6,762

Medium Gas MC B	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
RH2a	11,456	566	429	2,501	964	(2,063)	2,080	7,610	23,542
LD-1	11,681	667	429	2,487	943	(2,185)	1,889	7,787	23,696
LD-2	11,262	504	426	2,485	824	(2,189)	1,567	6,782	21,660
LD-3	11,994	641	432	2,498	973	(1,875)	2,648	7,917	25,229
PG-1	11,636	574	429	2,490	894	(2,047)	2,081	7,542	23,598
PG-2	11,459	564	429	2,503	896	(2,103)	1,931	7,478	23,157
CPP-C	11,623	577	430	2,496	864	(2,160)	2,115	7,560	23,505
CPP-D	11,931	583	427	2,486	878	(2,130)	1,869	7,287	23,330
FOT-1	11,527	506	429	2,509	948	(2,094)	1,978	7,861	23,663
CO2-1	10,663	550	425	2,520	966	(1,860)	2,720	8,276	24,261
NO-CO2	12,108	605	425	2,497	884	(2,395)	1,612	7,423	23,160
BP	11,690	556	429	2,502	1,003	(2,035)	1,842	7,476	23,464
GW1	11,278	571	427	2,524	916	(2,178)	1,766	8,546	23,850
GW2	11,305	573	428	2,523	916	(2,175)	1,773	8,850	24,193
GW3	11,054	559	426	2,549	896	(2,214)	1,614	9,799	24,683
GW4	11,178	564	427	2,543	896	(2,189)	1,719	8,380	23,517
Battery	11,154	558	426	2,541	889	(2,221)	1,618	8,499	23,464
CAES	11,156	558	427	2,541	889	(2,222)	1,613	8,461	23,423
WCA	3,262	432	(44)	70	225	(486)	1,573	2,034	7,066
WCA-RPS	3,255	429	(44)	71	225	(515)	1,545	2,112	7,078

High Gas MC B	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
RH2a	13,572	646	457	2,502	964	(3,115)	3,532	7,610	26,167
CPP-C	13,473	642	457	2,496	864	(3,057)	4,056	7,560	26,490
CPP-D	14,194	651	455	2,486	878	(3,285)	2,997	7,287	25,663
FOT-1	13,464	554	457	2,509	948	(3,158)	3,432	7,861	26,067
CO2-1	13,077	609	453	2,521	966	(3,324)	3,090	8,276	25,667
GW1	13,322	646	455	2,525	916	(3,381)	2,803	8,546	25,831
GW2	13,343	648	456	2,523	916	(3,374)	2,819	8,850	26,181
GW3	13,120	634	451	2,549	896	(3,469)	2,458	9,799	26,438
GW4	13,244	638	452	2,544	896	(3,417)	2,684	8,380	25,420
WCA	4,065	575	(44)	70	225	(740)	2,041	2,034	8,225
WCA-RPS	4,056	571	(44)	71	225	(783)	1,998	2,112	8,206

Table L.55 – PVRR Cost Components by Price Scenario, Final Screening Cases, MC A

Low Gas MC A	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
FS-REP	11,102	536	427	2,504	916	(1,947)	1,560	7,643	22,741
FS-GW4	10,714	520	426	2,539	895	(1,989)	1,421	8,292	22,817
FS-R1c	10,703	517	426	2,541	895	(2,036)	1,390	8,410	22,844
FS-R2	10,698	519	425	2,540	878	(1,995)	1,400	8,352	22,818

Medium Gas MC A	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
FS-REP	11,777	589	433	2,504	916	(2,263)	1,774	7,643	23,372
FS-GW4	11,400	571	431	2,539	895	(2,338)	1,566	8,292	23,356
FS-R1c	11,387	567	431	2,541	895	(2,394)	1,528	8,410	23,366
FS-R2	11,387	571	431	2,540	878	(2,347)	1,538	8,352	23,349

High Gas MC A	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
FS-REP	13,739	668	454	2,505	916	(3,350)	3,042	7,643	25,616
FS-GW4	13,361	652	452	2,539	895	(3,544)	2,518	8,292	25,165
FS-R1c	13,342	646	452	2,541	895	(3,626)	2,458	8,410	25,119
FS-R2	13,351	651	451	2,541	878	(3,562)	2,459	8,352	25,122

Table L.56 – PVRR Cost Components by Price Scenario, Final Screening Cases, MC B

Low Gas MC B	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
FS-REP	10,917	535	423	2,504	916	(1,871)	1,637	7,643	22,705
FS-GW4	10,547	518	422	2,539	895	(1,918)	1,487	8,292	22,782
FS-R1c	10,537	515	422	2,541	895	(1,965)	1,456	8,410	22,810
FS-R2	10,533	518	421	2,540	878	(1,924)	1,465	8,352	22,783

Medium Gas MC B	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
FS-REP	11,482	582	428	2,504	916	(2,125)	1,922	7,643	23,353
FS-GW4	11,143	565	427	2,539	895	(2,212)	1,684	8,292	23,333
FS-R1c	11,130	561	427	2,541	895	(2,266)	1,646	8,410	23,343
FS-R2	11,130	564	426	2,540	878	(2,221)	1,655	8,352	23,326

High Gas MC B	Stochastic PVRR ($ millions)								
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
FS-REP	13,453	654	456	2,505	916	(3,231)	3,233	7,643	25,629
FS-GW4	13,203	640	452	2,539	895	(3,452)	2,606	8,292	25,175
FS-R1c	13,185	635	452	2,541	895	(3,529)	2,545	8,410	25,133
FS-R2	13,194	639	451	2,541	878	(3,470)	2,547	8,352	25,133

Table L.57 – 10-year Average Incremental Customer Rate Impact, Final Screening Cases

	10-year Average Incremental Customer Rate Impact (2017 - 2026)							
	Low Gas, MC B		Medium Gas, MC B		High Gas, MC B		Average	
$ Millions	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank
FS-GW4	0.0	3	0.0	3	0.0	3	0.0	3
FS-REP	4.3	4	12.6	4	43.6	4	20.2	4
FS-R1c	(0.1)	2	(0.3)	2	(0.7)	2	(0.4)	2
FS-R2	(0.4)	1	(0.6)	1	(1.2)	1	(0.7)	1

	10-year Average Incremental Customer Rate Impact (2017 - 2036)							
	Low Gas, MC B		Medium Gas, MC B		High Gas, MC B		Average	
$ Millions	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank
FS-GW4	0.0	3	0.0	3	0.0	3	0.0	3
FS-REP	3.8	4	12.1	4	46.7	4	20.9	4
FS-R1c	(0.1)	2	(0.3)	2	(0.8)	2	(0.4)	2
FS-R2	(0.4)	1	(0.5)	1	(1.3)	1	(0.7)	1

Table L.58 – Loss of Load Probability, Major (> 25,000 MWh) July Event, Final Screening Cases, Medium Gas, MC B

Year	FS-REP	Preferred Portfolio FS-GW4	FS-R1c	FS-R2
2017	0%	0%	0%	0%
2018	8%	8%	8%	8%
2019	0%	0%	0%	0%
2020	0%	0%	0%	0%
2021	2%	2%	2%	2%
2022	4%	4%	4%	4%
2023	0%	0%	0%	0%
2024	6%	6%	6%	6%
2025	4%	4%	4%	4%
2026	6%	6%	6%	6%
2027	4%	4%	4%	4%
2028	2%	2%	2%	2%
2029	4%	4%	4%	4%
2030	8%	6%	6%	8%
2031	2%	2%	2%	2%
2032	8%	8%	8%	8%
2033	14%	12%	12%	14%
2034	8%	10%	10%	8%
2035	4%	2%	2%	2%
2036	8%	8%	8%	8%

Table L.59 – Summer Peak, Average Loss of Load Probability, Final Screening Cases, Medium Gas, MC B

Event Size (MWh)	Average for operating years 2017 through 2026 (10 Year)			
	FS-REP	Preferred Portfolio FS-GW4	FS-R1c	FS-R2
> 0	94%	94%	94%	94%
> 1,000	78%	78%	78%	78%
> 10,000	10%	10%	10%	10%
> 25,000	3%	3%	3%	3%
> 50,000	0%	0%	0%	0%
> 100,000	0%	0%	0%	0%
> 500,000	0%	0%	0%	0%

Event Size (MWh)	Average for operating years 2017 through 2036 (20 Year)			
	FS-REP	Preferred Portfolio FS-GW4	FS-R1c	FS-R2
> 0	96%	96%	96%	96%
> 1,000	82%	81%	81%	81%
> 10,000	12%	12%	12%	12%
> 25,000	5%	4%	4%	5%
> 50,000	1%	1%	1%	1%
> 100,000	0%	0%	0%	0%
> 500,000	0%	0%	0%	0%
> 1,000,000	0%	0%	0%	0%

APPENDIX M – CASE STUDY FACT SHEETS

Case Fact Sheet Overview

This appendix documents the 2017 Integrated Resource Plan modeling assumptions used for the regional haze, core case, sensitivity and final screening studies.

Case Fact Sheets - Overview

Regional Haze Case Fact Sheets

The following Regional Haze Case Fact Sheets summarize key assumptions and portfolio results for each portfolio being developed for the 2017 IRP. All cases produce resource portfolios capable of meeting state renewable portfolio standard requirements. Similarly, in addition to the Regional Haze compliance requirements specified for each case, all cases include costs to meet known and assumed compliance obligations for Mercury and Air Toxics (MATS), coal combustion residuals (CCR) under subtitle D of the Resource Conservation and Recovery Act (RCRA), cooling water intake structures under §316(b) of the Clean Water Act, and effluent guidelines.

Quick Reference Guide

Case	Description	Benchmark	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal	SO PVRR w/o Trans. ($m)	SO PVRR w/ Trans. ($m)
Ref.	Reference Case	-	Base	Base	Mass Cap B	Base	None	2032	$24,156	$24,219
RH-1	Regional Haze 1	-	Base	Base	Mass Cap B	Base	None	2030	$23,066	$23,159
RH-2	Regional Haze 2	-	Base	Base	Mass Cap B	Base	None	2029	$23,313	$23,482
RH-3	Regional Haze 3	-	Base	Base	Mass Cap B	Base	None	2029	$23,315	$23,398
RH-4	Regional Haze 4	-	Base	Base	Mass Cap B	Base	None	2030	$23,582	$23,663
RH-5	Regional Haze 5	-	Base	Base	Mass Cap B	Base	None	2029	$23,081	$23,177
RH-6	Regional Haze 6	-	Base	Base	Mass Cap B	Base	None	2028	$23,891	$23,986

Core Case Fact Sheets

The following Core Case Fact Sheets summarize key assumptions and portfolio results for each portfolio being developed for the 2017 IRP. All cases produce resource portfolios capable of meeting state renewable portfolio standard requirements. As with the regional haze cases, all core cases comply with the environmental obligations.

Quick Reference Guide

Case	Description	Benchmark	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal	SO PVRR w/o Trans. ($m)	SO PVRR w/ Trans. ($m)
OP-1	Optimized Portfolio	RH5	Base	Base	Mass Cap B	Base	None	2029	$23,081	$23,177
OP-NT3	Optimized Naughton 3	OP-1	Base	Base	Mass Cap B	Base	None	2029	$22,913	$23,052
OP-REP	Wind Repower	OP-NT3	Base	Base	Mass Cap B	Base	None	2029	$22,890	$22,984
OP-GW4	Energy Gateway + Repower	OP-REP	Base	Base	Mass Cap B	Base	Segment D2	2029	$22,612	$23,123
FR-1	Flexible Resource	OP-NT3	Base	Base	Mass Cap B	Base	None	2021	$23,463	$23,585
FR-2	Flexible Resource	OP-NT3	Base	Base	Mass Cap B	Base	None	2021	$24,136	$24,319
RE-1a	OR RPS Just in Time	OP-NT3	Base	Base	Mass Cap B	Base	None	2029	$22,945	$23,082
RE-1b	WA RPS Just in Time	OP-NT3	Base	Base	Mass Cap B	Base	None	2029	$22,962	$23,091
RE-1c	OR & WA RPS Just in Time	OP-NT3	Base	Base	Mass Cap B	Base	None	2029	$23,016	$23,154
RE-2	OR RPS Early	OP-NT3	Base	Base	Mass Cap B	Base	None	2029	$22,967	$23,098
DLC-1	Direct Load Control	OP-NT3	Base	Base	Mass Cap B	Base	None	2030	$22,942	$23,103

Sensitivity Fact Sheets

The following Sensitivity Fact Sheets summarize key assumptions and portfolio results for each sensitivity being developed for the 2017 IRP. All sensitivities produce resource portfolios capable of meeting state

renewable portfolio standard requirements. As with the regional haze cases, all sensitivities comply with the environmental obligations.

Quick Reference Guide

Case	Description	Benchmark	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal	SO PVRR w/o Trans. ($m)	SO PVRR w/ Trans. ($m)
RH2a	Regional Haze	OP-1	Base	Base	Mass Cap B	Base	None	2029	$23,237	$23,404
LD-1	1 in 20 Loads	OP-1	1 in 20	Base	Mass Cap B	Base	None	2029	$23,207	$23,364
LD-2	Low Load	OP-1	Low	Base	Mass Cap B	Base	None	2030	$21,512	$21,567
LD-3	High Load	OP-1	High	Base	Mass Cap B	Base	None	2028	$24,629	$24,818
PG-1	Low Private Gen	OP-1	Base	Low	Mass Cap B	Base	None	2029	$23,203	$23,304
PG-2	High Private Gen	OP-1	Base	High	Mass Cap B	Base	None	2030	$22,782	$22,899
CPP-C	CPP Mass Cap C	OP-1	Base	Base	Mass Cap C	Base	None	2029	$23,129	$23,268
CPP-D	CPP Mass Cap D	OP-1	Base	Base	Mass Cap D	Base	None	2029	$23,010	$23,102
FOT-1	Limited FOT	OP-1	Base	Base	Mass Cap B	Restricted	None	2029	$23,189	$23,347
CO2-1	CO_2 Price	OP-1	Base	Base	Tax, No CPP	Base	None	2030	$26,222	$26,401
NO-CO2	No CO_2	OP-NT3	Base	Base	No Tax, No CPP	Base	None	2028	$22,787	$22,891
BP	Business Plan	OP-NT3	Base	Base	Mass Cap D	Base	None	2030	$23,053	$23,198
GW1	Gateway 1	OP-NT3	Base	Base	Mass Cap B	Base	Segment D	2029	$22,803	$23,593
GW2	Gateway 2	OP-NT3	Base	Base	Mass Cap B	Base	Segment F	2029	$22,841	$24,054
GW3	Gateway 3	OP-NT3	Base	Base	Mass Cap B	Base	Segment D&F	2029	$22,706	$24,627
GW4	Gateway 4	OP-NT3	Base	Base	Mass Cap B	Base	Segment D2	2029	$22,648	$23,159
Battery	Battery Storage	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2	2029	$22,735	$23,162
CAES	CAES Storage	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2	2029	$22,659	$23,121
WCA	WCA	FS-REP	Base	Base	Mass Cap B	Base	None	3033	$7,539	$7,542
WCA-RPS	WCA RPS	FS-REP	Base	Base	Mass Cap B	Base	None	3033	$7,554	$7,557

Case Fact Sheets - Overview

Final Case Fact Sheets

The following Final Case Fact Sheets summarize key assumptions and portfolio results for each portfolio being developed for the 2017 IRP. All cases produce resource portfolios capable of meeting state renewable portfolio standard requirements. As with the regional haze cases, all final cases comply with the environmental obligations.

Quick Reference Guide

Case	Description	Benchmark	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal	SO PVRR w/o Trans. ($m)	SO PVRR w/ Trans. ($m)
FS-REP	Wind Repower	OP-NT3	Base	Base	Mass Cap B	Base	Segment D2	2029	$22,907	$23,042
FS-GW4	Gateway 4	FS-REP	Base	Base	Mass Cap B	Base	Segment D2	2029	$22,549	$22,990
FS-R1c	OR & WA RPS Just in Time	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2	2029	$22,561	$23,006
FS-R2	OR RPS Early	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2	2029	$22,554	$22,995

Master Fact Sheet

CASE ASSUMPTIONS - MASTER

Description

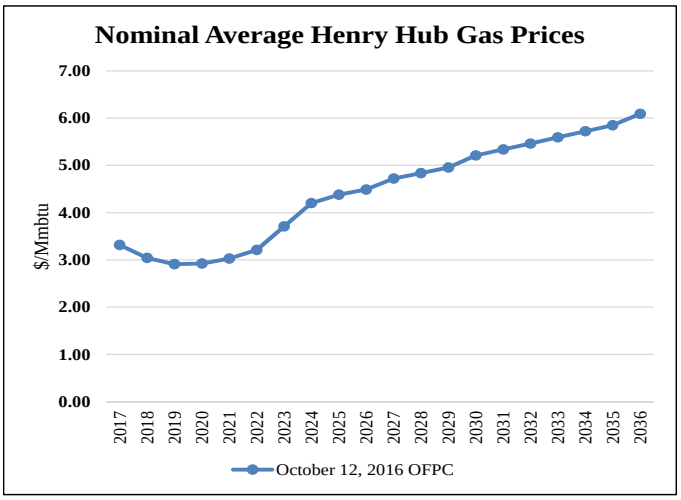
The following assumptions are applicable to all cases, except where otherwise specified.

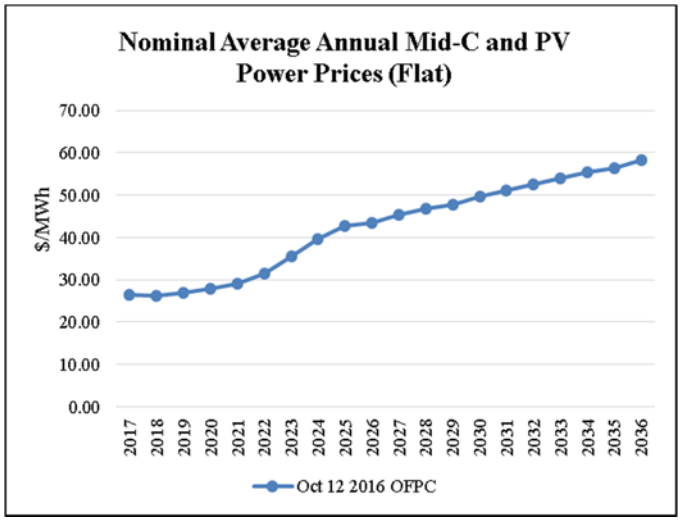
Federal CO_2 Policy/Price Signal

The Clean Power Plan is reflected in all Regional Haze, core cases, final selections and sensitivities, with the exception of the CO_2 Price and No CO_2 sensitivities.

Forward Price Curve

Gas and power prices utilize medium natural gas price assumptions consistent with the Company's October 12, 2016 OFPC through October 2022. After October 2022, prices are followed by a 12-month blend that segues into a pure fundamentals forecast. Prices reflect Mass Cap B total allocation cap.



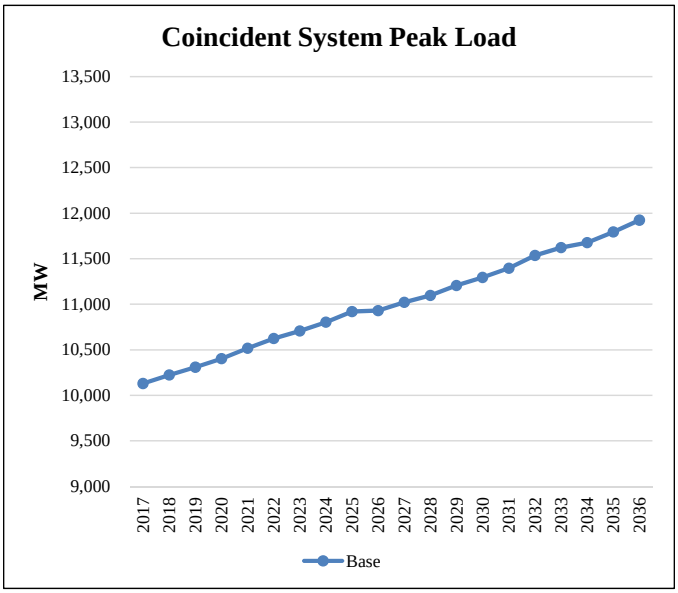


Federal Tax Incentives

- PTCs phase out beginning in 2017 and expire entirely end of 2019. To achieve the PTC, projects must be under construction by the end of 2019.
- ITC of 30 percent steps down to 26 percent in 2020 and 22 percent for 2021 through 2023, thereafter it continues in perpetuity at 10 percent.

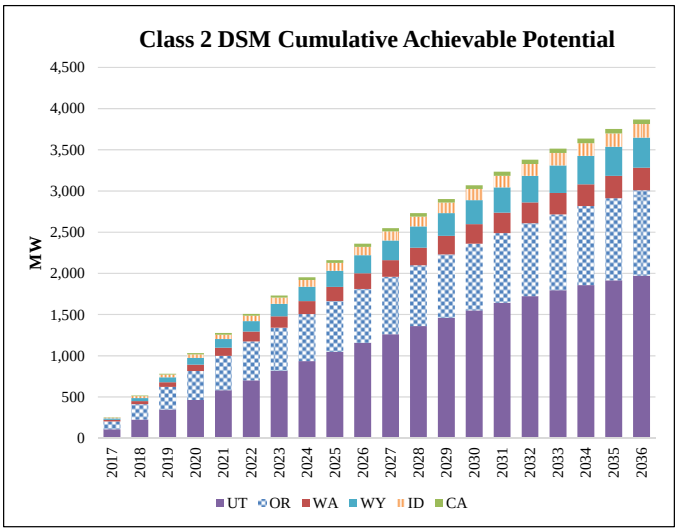
Load Forecast

The figure below shows the base system coincident peak load forecast applicable to core cases before accounting for any potential contribution from DSM. Loads include private generation resources.



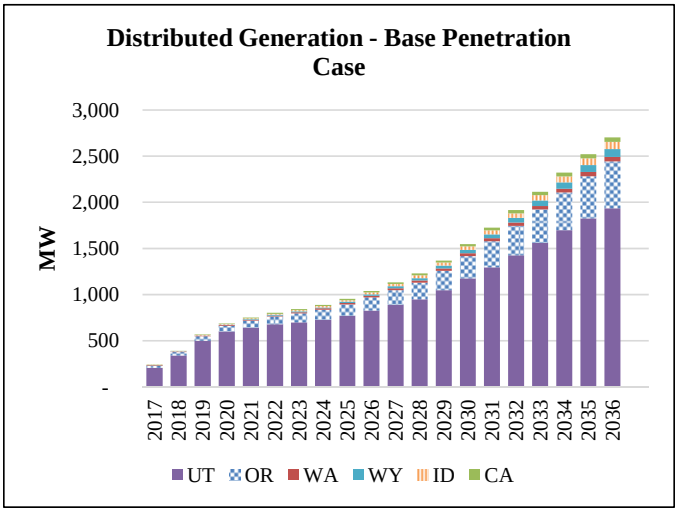
Energy Efficiency (Class 2 DSM)

Core case studies uses base supply curves with economic resource selections up to the achievable potential. Class 2 resources that are not selected in any given year are not available for selection in future years. Achievable potential by state and year are summarized below.



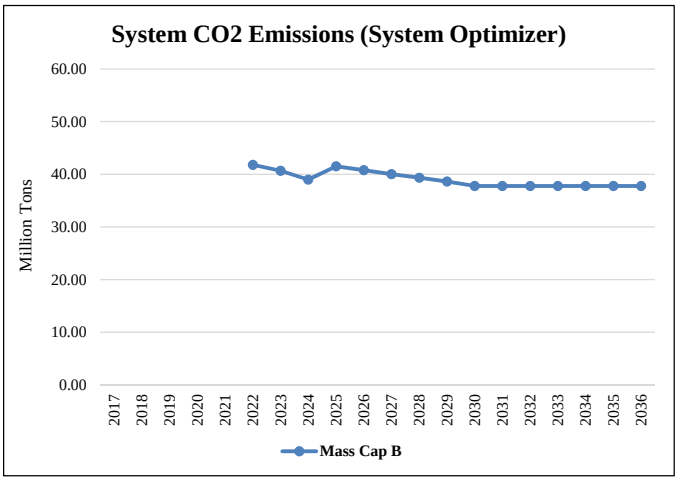
Private Generation

Base case private generation penetration by state and year are summarized in the following figure, which is included in the load forecast.



System CO_2 Emissions (System Optimizer)

System CO_2 emissions from System Optimizer are shown in the figure below. Emissions reflect Mass Cap B total allocation cap.



Regional Haze Case Fact Sheets

CASE ASSUMPTIONS

Description

Refer to Volume I, Chapter 7 (Regional Haze Case Definitions).

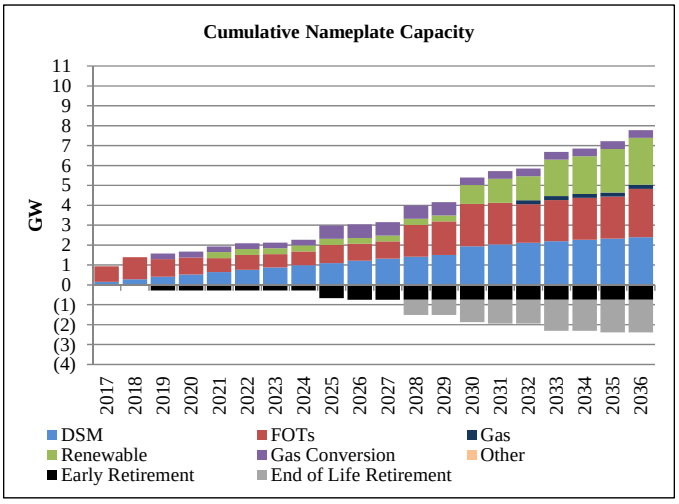
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$24,156
Transmission Integration	$51
Transmission Reinforcement	$12
Total Cost	$24,219

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Regional Haze

Regional Haze assumptions are summarized in the following table.

Coal Unit	Description
Cholla 4	Gas Conversion by Dec 2025, Retire Dec 2042
Colstrip 3	Retire Dec 2046
Colstrip 4	Retire Dec 2046
Craig 1	Retire Dec 2025
Craig 2	SCR by Dec 2017, Retire Dec 2034
Dave Johnston 1	Retire Dec 2027
Dave Johnston 2	Retire Dec 2027
Dave Johnston 3	Retire Dec 2027
Dave Johnston 4	Retire Dec 2027
Hayden 1	Retire Dec 2030
Hayden 2	SCR by Dec 2016, Retire Dec 2030
Hunter 1	SCR by 2021, Retire Dec 2042
Hunter 2	SCR by 2021, Retire Dec 2042
Hunter 3	Retire Dec 2042
Huntington 1	SCR by 2021, Retire Dec 2036
Huntington 2	SCR by 2021, Retire Dec 2036
Jim Bridger 1	SCR by 2022, Retire Dec 2037
Jim Bridger 2	SCR by 2021, Retire Dec 2037
Jim Bridger 3	Retire Dec 2037
Jim Bridger 4	SCR by Dec 2016, Retire Dec 2037
Naughton 1	Retire Dec 2029
Naughton 2	Retire Dec 2029
Naughton 3	Gas Conversion by Dec 2019, Retire Dec 2029
Wyodak	Retire Dec 2039

SCR = selective catalytic reduction

Regional Haze Case Fact Sheets

CASE ASSUMPTIONS

Description

Refer to Volume I, Chapter 7 (Regional Haze Case Definitions).

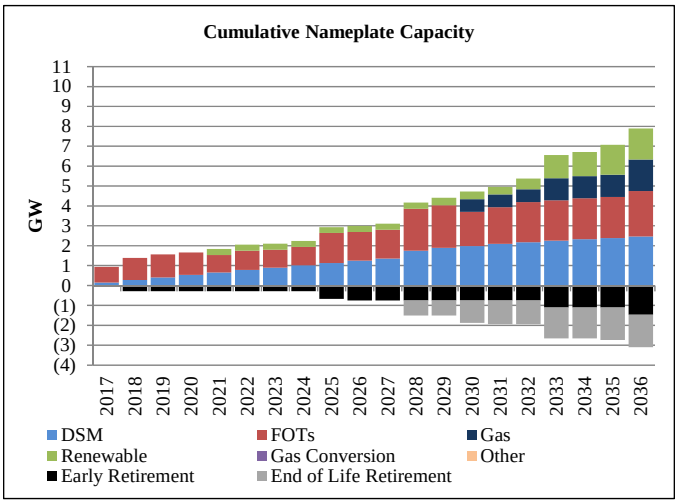
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,066
Transmission Integration	$81
Transmission Reinforcement	$12
Total Cost	$23,159

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Regional Haze

Regional Haze assumptions are summarized in the following table.

Coal Unit	Description
Cholla 4	Retire Apr 2025
Colstrip 3	Retire Dec 2046
Colstrip 4	Retire Dec 2046
Craig 1	Retire Dec 2025
Craig 2	SCR by Dec 2017, Retire Dec 2034
Dave Johnston 1	Retire Dec 2027
Dave Johnston 2	Retire Dec 2027
Dave Johnston 3	Retire Dec 2027
Dave Johnston 4	Retire Dec 2027
Hayden 1	Retire Dec 2030
Hayden 2	SCR by Dec 2016, Retire Dec 2030
Hunter 1	NOx by 2021, Retire Dec 2042
Hunter 2	NOx by 2021, Retire Dec 2042
Hunter 3	Retire Dec 2042
Huntington 1	Retire Dec 2036
Huntington 2	Retire Dec 2036
Jim Bridger 1	Retire Dec 2032
Jim Bridger 2	Retire Dec 2035
Jim Bridger 3	Retire Dec 2037
Jim Bridger 4	SCR by Dec 2016, Retire Dec 2037
Naughton 1	Retire Dec 2029
Naughton 2	Retire Dec 2029
Naughton 3	Retire Dec 2017
Wyodak	Retire Dec 2039

SCR = selective catalytic reduction
NOx = Low NOx burner

Regional Haze Case Fact Sheets

CASE ASSUMPTIONS

Description

Refer to Volume I, Chapter 7 (Regional Haze Case Definitions).

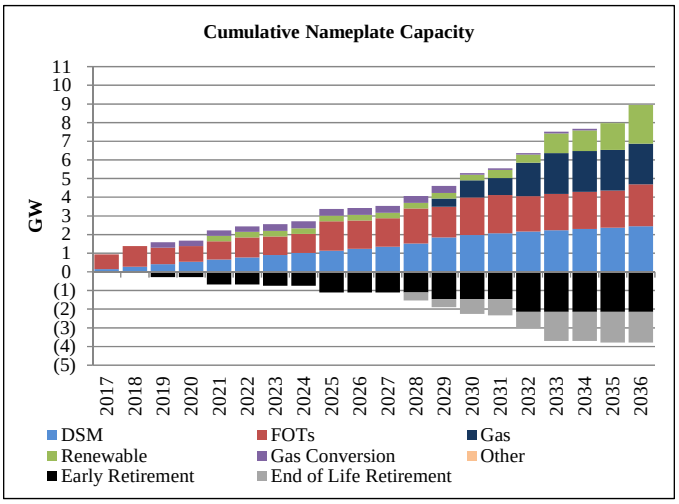
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,313
Transmission Integration	$157
Transmission Reinforcement	$12
Total Cost	$23,482

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Regional Haze

Regional Haze assumptions are summarized in the following table.

Coal Unit	Description
Cholla 4	Retire Dec 2020
Colstrip 3	Retire Dec 2046
Colstrip 4	Retire Dec 2046
Craig 1	Gas Conversion by Dec 2023, Retire Dec 2034
Craig 2	SCR by Dec 2017, Retire Dec 2034
Dave Johnston 1	Retire Dec 2027
Dave Johnston 2	Retire Dec 2027
Dave Johnston 3	Retire Dec 2027
Dave Johnston 4	Retire Dec 2032
Hayden 1	Retire Dec 2030
Hayden 2	SCR by Dec 2016, Retire Dec 2030
Hunter 1	Retire Dec 2031
Hunter 2	Retire Dec 2031
Hunter 3	Retire Dec 2042
Huntington 1	Retire Dec 2036
Huntington 2	Retire Dec 2036
Jim Bridger 1	Retire Dec 2024
Jim Bridger 2	Retire Dec 2028
Jim Bridger 3	Retire Dec 2037
Jim Bridger 4	SCR by Dec 2016, Retire Dec 2037
Naughton 1	Retire Dec 2029
Naughton 2	Retire Dec 2029
Naughton 3	Gas Conversion by Dec 2019, Retire Dec 2029
Wyodak	Retire Dec 2039

SCR = selective catalytic reduction

Regional Haze Case Fact Sheets

CASE ASSUMPTIONS

Description

Refer to Volume I, Chapter 7 (Regional Haze Case Definitions).

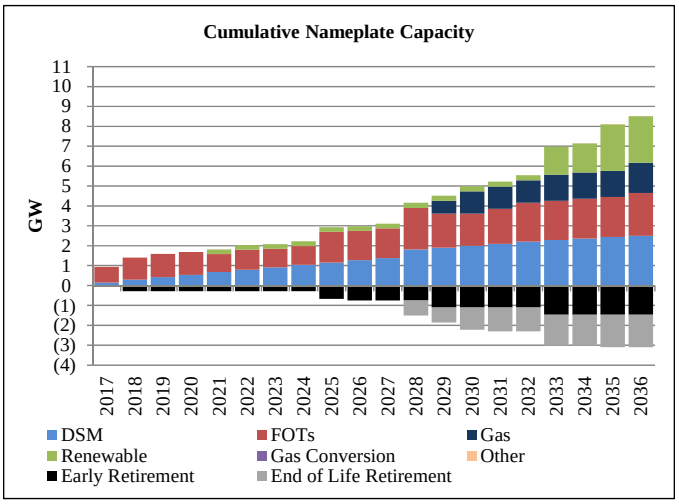
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,315
Transmission Integration	$70
Transmission Reinforcement	$12
Total Cost	$23,398

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Regional Haze

Regional Haze assumptions are summarized in the following table.

Coal Unit	Description
Cholla 4	Retire Apr 2025
Colstrip 3	Retire Dec 2046
Colstrip 4	Retire Dec 2046
Craig 1	Retire Dec 2025
Craig 2	SCR by Dec 2017, Retire Dec 2034
Dave Johnston 1	Retire Dec 2027
Dave Johnston 2	Retire Dec 2027
Dave Johnston 3	Retire Dec 2027
Dave Johnston 4	Retire Dec 2027
Hayden 1	Retire Dec 2030
Hayden 2	SCR by Dec 2016, Retire Dec 2030
Hunter 1	NOx by Dec 2026, Retire Dec 2042
Hunter 2	NOx by Dec 2027, Retire Dec 2042
Hunter 3	Retire Dec 2042
Huntington 1	NOx by Dec 2026, Retire Dec 2036
Huntington 2	NOx by Dec 2027, Retire Dec 2036
Jim Bridger 1	Retire Dec 2028
Jim Bridger 2	Retire Dec 2032
Jim Bridger 3	Retire Dec 2037
Jim Bridger 4	SCR by Dec 2016, Retire Dec 2037
Naughton 1	Retire Dec 2029
Naughton 2	Retire Dec 2029
Naughton 3	Retire Dec 2017
Wyodak	Retire Dec 2039

SCR = selective catalytic reduction
NOx = Low NOx burner

Regional Haze Case Fact Sheets

CASE ASSUMPTIONS

Description

Refer to Volume I, Chapter 7 (Regional Haze Case Definitions).

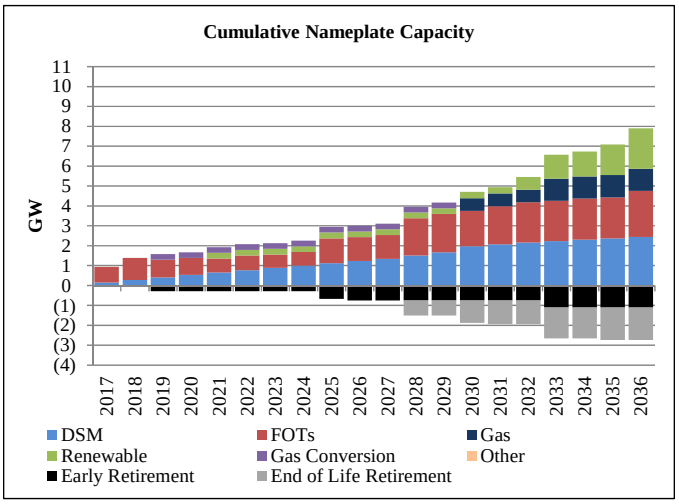
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,582
Transmission Integration	$69
Transmission Reinforcement	$12
Total Cost	$23,663

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Regional Haze

Regional Haze assumptions are summarized in the following table.

Coal Unit	Description
Cholla 4	Retire Apr 2025
Colstrip 3	Retire Dec 2046
Colstrip 4	Retire Dec 2046
Craig 1	Retire Dec 2025
Craig 2	SCR by Dec 2017, Retire Dec 2034
Dave Johnston 1	Retire Dec 2027
Dave Johnston 2	Retire Dec 2027
Dave Johnston 3	Retire Dec 2027
Dave Johnston 4	Retire Dec 2027
Hayden 1	Retire Dec 2030
Hayden 2	SCR by Dec 2016, Retire Dec 2030
Hunter 1	SCR by Dec 2021, Retire Dec 2042
Hunter 2	NOx by Dec 2027, Retire Dec 2042
Hunter 3	Retire Dec 2042
Huntington 1	SCR by Dec 2021, Retire Dec 2036
Huntington 2	NOx by Dec 2027, Retire Dec 2036
Jim Bridger 1	NOx by Dec 2022, Retire Dec 2032
Jim Bridger 2	SCR by Dec 2021, Retire Dec 2037
Jim Bridger 3	Retire Dec 2037
Jim Bridger 4	SCR by Dec 2016, Retire Dec 2037
Naughton 1	Retire Dec 2029
Naughton 2	Retire Dec 2029
Naughton 3	Gas Conversion by Dec 2019, Retire Dec 2029
Wyodak	Retire Dec 2039

SCR = selective catalytic reduction

NOx = Low NOx burner

Regional Haze Case Fact Sheets

CASE ASSUMPTIONS

Description

Refer to Volume I, Chapter 7 (Regional Haze Case Definitions). This Regional Haze case became core case OP-1.

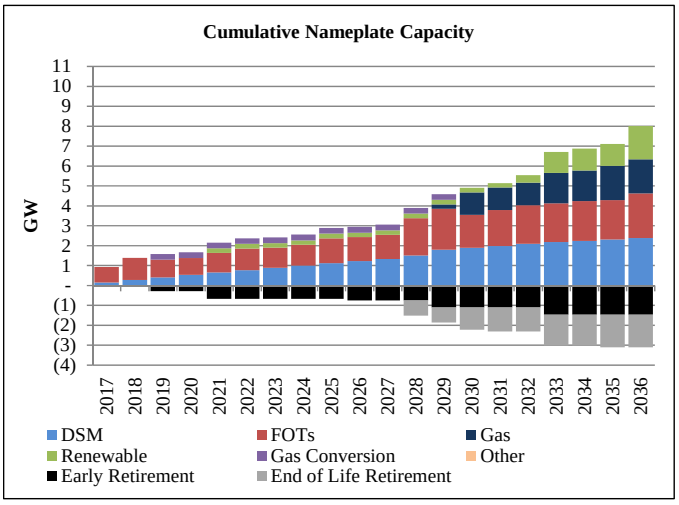
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,081
Transmission Integration	$84
Transmission Reinforcement	$12
Total Cost	$23,177

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Regional Haze

Core case OP-1 Regional Haze assumptions are summarized in the following table.

Coal Unit	Description
Cholla 4	Retire Dec 2020
Colstrip 3	Retire Dec 2046
Colstrip 4	Retire Dec 2046
Craig 1	Retire Dec 2025
Craig 2	SCR by Dec 2017, Retire Dec 2034
Dave Johnston 1	Retire Dec 2027
Dave Johnston 2	Retire Dec 2027
Dave Johnston 3	Retire Dec 2027
Dave Johnston 4	Retire Dec 2027
Hayden 1	Retire Dec 2030
Hayden 2	SCR by Dec 2016, Retire Dec 2030
Hunter 1	NOx by Dec 2021, Retire Dec 2042
Hunter 2	NOx by Dec 2021, Retire Dec 2042
Hunter 3	Retire Dec 2042
Huntington 1	Retire Dec 2036
Huntington 2	Retire Dec 2036
Jim Bridger 1	Retire Dec 2028
Jim Bridger 2	Retire Dec 2032
Jim Bridger 3	Retire Dec 2037
Jim Bridger 4	SCR by Dec 2016, Retire Dec 2037
Naughton 1	Retire Dec 2029
Naughton 2	Retire Dec 2029
Naughton 3	Gas Conversion by Dec 2019, Retire Dec 2029
Wyodak	Retire Dec 2039

SCR = selective catalytic reduction

NOx = Low NOx burner

Regional Haze Case Fact Sheets

CASE ASSUMPTIONS

Description

Refer to Volume I, Chapter 7 (Regional Haze Case Definitions).

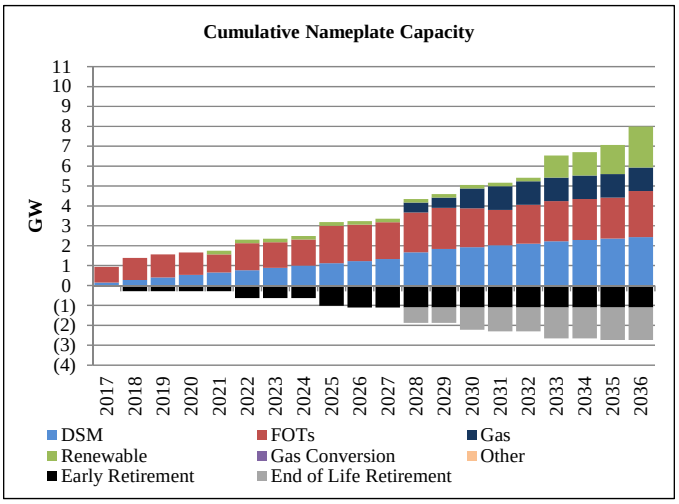
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,891
Transmission Integration	$83
Transmission Reinforcement	$12
Total Cost	$23,986

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Regional Haze

Regional Haze assumptions are summarized in the following table.

Coal Unit	Description
Cholla 4	Retire Apr 2025
Colstrip 3	Retire Dec 2046
Colstrip 4	Retire Dec 2046
Craig 1	Retire Dec 2025
Craig 2	SCR by Dec 2017, Retire Dec 2034
Dave Johnston 1	Retire Dec 2027
Dave Johnston 2	Retire Dec 2027
Dave Johnston 3	Retire Dec 2027
Dave Johnston 4	Retire Dec 2027
Hayden 1	Retire Dec 2030
Hayden 2	SCR by Dec 2016, Retire Dec 2030
Hunter 1	SCR by 8/4/2021 or Retire by 7/31/2021
Hunter 2	SCR by 8/4/2021 or Retire by 7/31/2021
Hunter 3	Retire Dec 2042
Huntington 1	SCR by 8/4/2021 or Retire by 7/31/2021
Huntington 2	SCR by 8/4/2021 or Retire by 7/31/2021
Jim Bridger 1	SCR by 12/31/2022 or Retire by 12/30/2022
Jim Bridger 2	SCR by 12/31/2022 or Retire by 12/30/2022
Jim Bridger 3	Retire Dec 2037
Jim Bridger 4	SCR by Dec 2016, Retire Dec 2037
Naughton 1	Retire Dec 2029
Naughton 2	Retire Dec 2029
Naughton 3	Retire Dec 2017
Wyodak	Retire Dec 2039

SCR = selective catalytic reduction

Core Case Fact Sheets

CASE ASSUMPTIONS

Description

This case is the least-cost-least-risk Regional Haze case emerging from screening stage 1 (RH-5). The Regional Haze case with the best cost-risk metrics is promoted to become core case 1, and serves as the basis for further studies, including the remaining core cases and sensitivities. Therefore, as with the underlying Regional Haze case, all resources have been optimized (selected endogenously by System Optimizer), and valued in the Planning and Risk model.

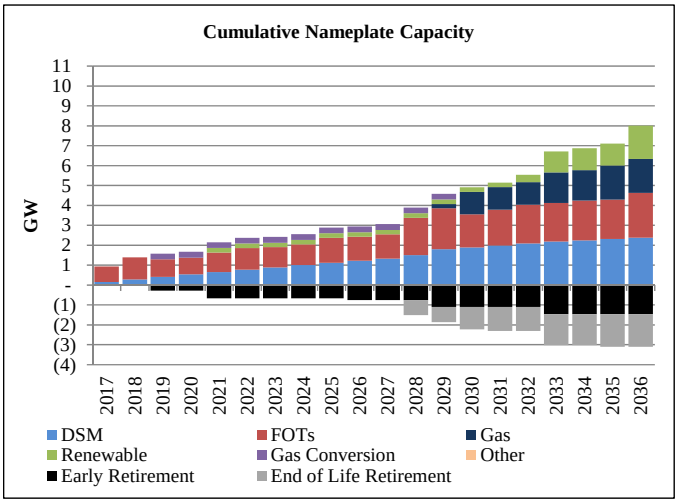
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,081
Transmission Integration	$84
Transmission Reinforcement	$12
Total Cost	$23,177

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Regional Haze

Core case OP-1 Regional Haze assumptions are summarized in the following table.

Coal Unit	Description
Cholla 4	Retire Dec 2020
Colstrip 3	Retire Dec 2046
Colstrip 4	Retire Dec 2046
Craig 1	Retire Dec 2025
Craig 2	SCR by Dec 2017, Retire Dec 2034
Dave Johnston 1	Retire Dec 2027
Dave Johnston 2	Retire Dec 2027
Dave Johnston 3	Retire Dec 2027
Dave Johnston 4	Retire Dec 2027
Hayden 1	Retire Dec 2030
Hayden 2	SCR by Dec 2016, Retire Dec 2030
Hunter 1	NOx by Dec 2021, Retire Dec 2042
Hunter 2	NOx by Dec 2021, Retire Dec 2042
Hunter 3	Retire Dec 2042
Huntington 1	Retire Dec 2036
Huntington 2	Retire Dec 2036
Jim Bridger 1	Retire Dec 2028
Jim Bridger 2	Retire Dec 2032
Jim Bridger 3	Retire Dec 2037
Jim Bridger 4	SCR by Dec 2016, Retire Dec 2037
Naughton 1	Retire Dec 2029
Naughton 2	Retire Dec 2029
Naughton 3	Gas Conversion by Dec 2019, Retire Dec 2029
Wyodak	Retire Dec 2039

SCR = selective catalytic reduction

NOx = Low NOx burner

Core Case Fact Sheets

CASE ASSUMPTIONS

Description

Case OP-NT3 is the optimal Regional Haze case selected as core case 1 and includes enhancements of full PTC value and Naughton 3 retirement by December 31, 2018. All resources optimized (selected endogenously by System Optimizer), and valued in the Planning and Risk model. This case is a variant of core case OP-1.

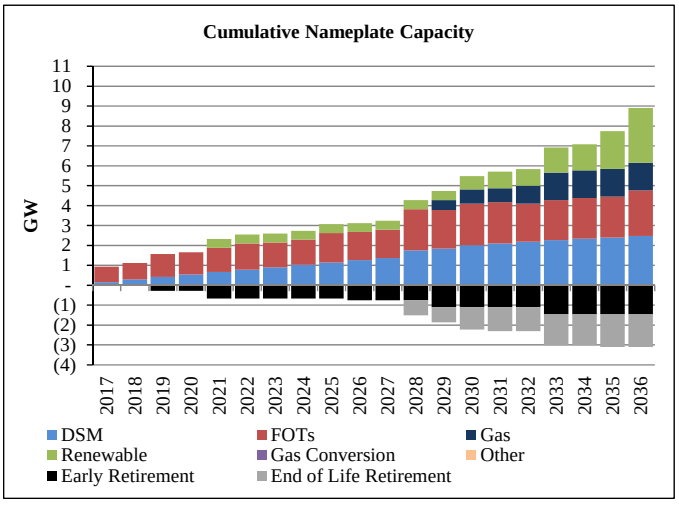
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,913
Transmission Integration	$127
Transmission Reinforcement	$12
Total Cost	$23,052

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Regional Haze

Core case OP-NT3 Regional Haze assumptions are summarized in the following table.

Coal Unit	Description
Cholla 4	Retire Dec 2020
Colstrip 3	Retire Dec 2046
Colstrip 4	Retire Dec 2046
Craig 1	Retire Dec 2025
Craig 2	SCR by Dec 2017, Retire Dec 2034
Dave Johnston 1	Retire Dec 2027
Dave Johnston 2	Retire Dec 2027
Dave Johnston 3	Retire Dec 2027
Dave Johnston 4	Retire Dec 2027
Hayden 1	Retire Dec 2030
Hayden 2	SCR by Dec 2016, Retire Dec 2030
Hunter 1	NOx by Dec 2021, Shut Down Dec 2042
Hunter 2	NOx by Dec 2021, Shut Down Dec 2042
Hunter 3	Retire Dec 2042
Huntington 1	Retire Dec 2036
Huntington 2	Retire Dec 2036
Jim Bridger 1	Retire Dec 2028
Jim Bridger 2	Retire Dec 2032
Jim Bridger 3	Retire Dec 2037
Jim Bridger 4	SCR by Dec 2016, Retire Dec 2037
Naughton 1	Retire Dec 2029
Naughton 2	Retire Dec 2029
Naughton 3	Retire Dec 2018
Wyodak	Retire Dec 2039

SCR = selective catalytic reduction

NOx = Low NOx burner

Core Case Fact Sheets

CASE ASSUMPTIONS

Description

Core case OP-REP assumes 905 MW of existing wind resources are repowered by the end of 2020 (Glenrock, Rolling Hills, Seven Mile Hill, High Plains, McFadden Ridge, Dunlap, Marengo and Leaning Juniper). The repower projects provide significant customer benefits among all market price and Clean Power Plan scenarios. The 20-year planning horizon used for the IRP is insufficient to capture the incremental wind generation associated with the extended life of the repowered wind facilities: incremental annual energy production is in excess of 500 GWh over the existing life of the wind projects and incremental annual energy production beyond the current existing life exceeds 3,100 GWh. This case is a variant of core case OP-NT3.

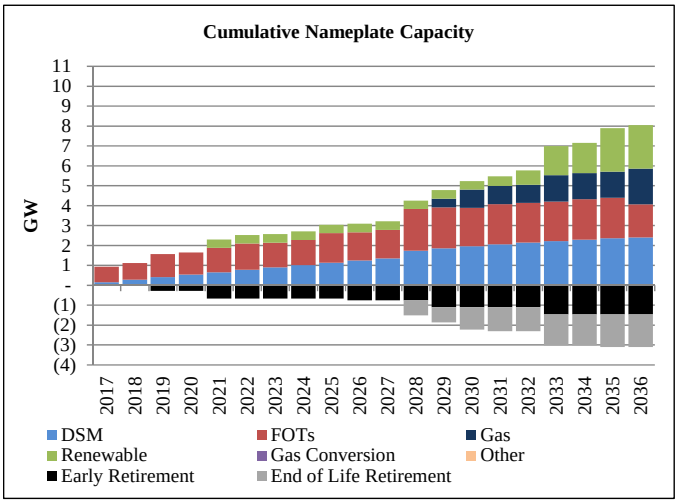
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,890
Transmission Integration	$81
Transmission Reinforcement	$12
Total Cost	$22,984
Total Cost thru 2050	$22,638

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Core Case Fact Sheets

CASE ASSUMPTIONS

Description

Core case OP-GW4 assumes 905 MW of existing wind resources are repowered by the end of 2020 and Gateway segment D2 – Aeolus to Anticline (assumed in-service year-end 2020). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 900 MW of Wyoming wind additions in 2021 (proxy for year-end 2020). This case is a variant of core case OP-REP.

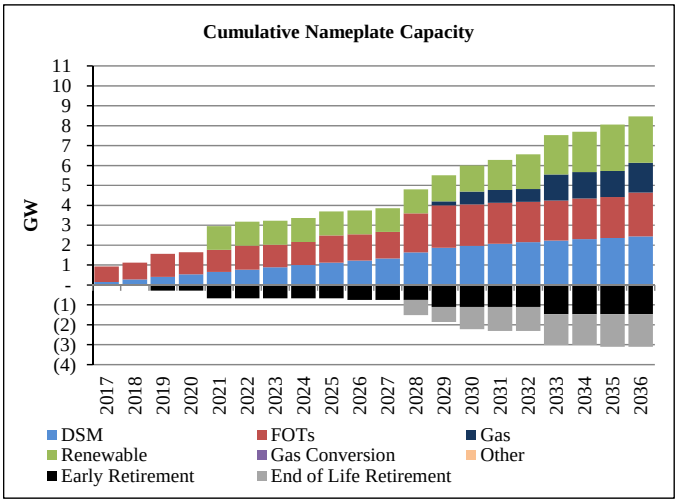
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

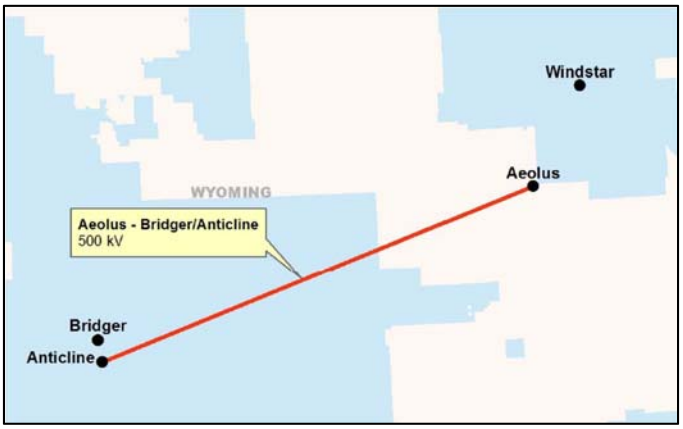
System Cost without Transmission Upgrades	$22,612
Transmission Integration	$94
Transmission Reinforcement	$12
Gateway Transmission	$405
Total Cost	$23,123
Total Cost thru 2050	$22,777

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Transmission Path



Core Case Fact Sheets

CASE ASSUMPTIONS

Description

In core case FR-1, fast ramp resources are added with a capacity of at least 10 percent of the system L&R need. Fast-ramp resources available for selection include: SCCT Aero (i.e., LM6000); Intercooled SCCT Aero (i.e., LMS100); IC Reciprocating Engines; pumped storage, compressed air energy storage, and battery storage. This case is a variant of core case OP-NT3.

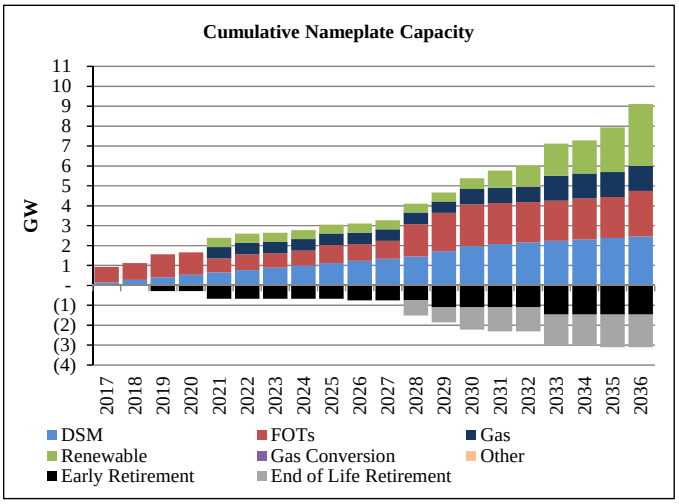
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,463
Transmission Integration	$110
Transmission Reinforcement	$12
Total Cost	$23,585

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Core Case Fact Sheets

CASE ASSUMPTIONS

Description

In core case FR-2 fast ramp resources are added with a capacity of at least 20 percent of the system L&R need. Fast-ramp resources available for selection include: SCCT Aero (i.e., LM6000); Intercooled SCCT Aero (i.e., LMS100); IC Reciprocating Engines; pumped storage, compressed air energy storage, and battery storage. This case is a variant of core case OP-NT3.

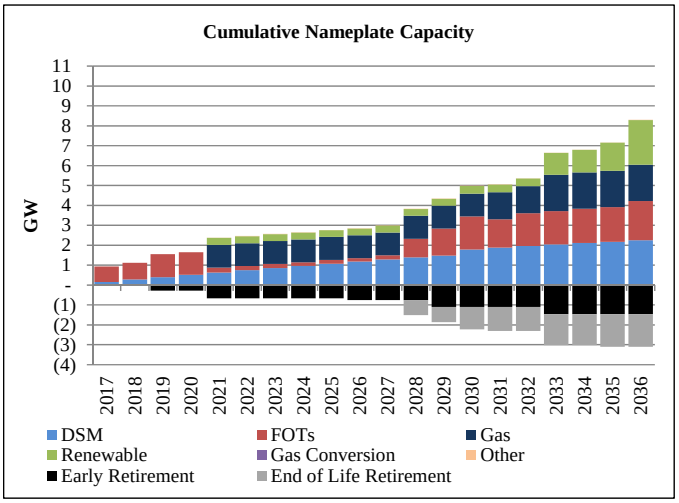
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$24,136
Transmission Integration	$170
Transmission Reinforcement	$12
Total Cost	$24,319

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Core Case Fact Sheets

CASE ASSUMPTIONS

Description

Case RE-1a retains endogenous renewables from core case 1 (OP-1) and includes additional renewables added to physically comply with Oregon RPS. Additions are made beginning the first year in which there is a projected compliance shortfall (just-in-time compliance). This case is a variant of core case OP-NT3.

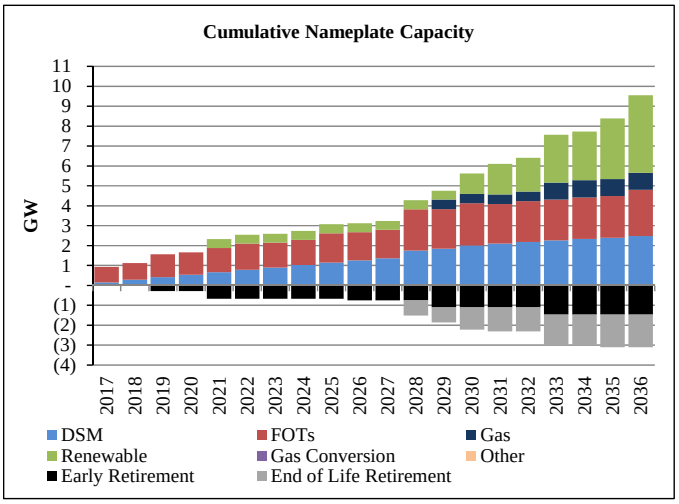
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,945
Transmission Integration	$126
Transmission Reinforcement	$12
Total Cost	$23,082

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Core Case Fact Sheets

CASE ASSUMPTIONS

Description

Case RE-1b retains endogenous renewables from core case 1 (OP-1) and includes additional renewables added to physically comply with Washington RPS. West Control Area renewable resource additions only. Additions are made beginning the first year in which there is a projected compliance shortfall (just-in-time compliance). This case is a variant of core case OP-NT3.

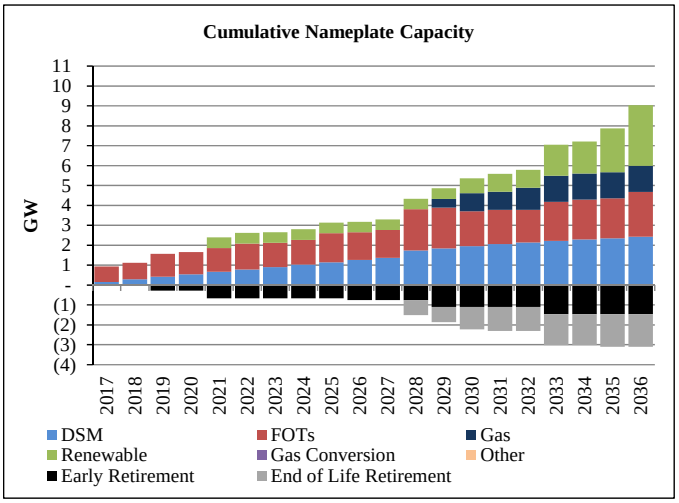
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,962
Transmission Integration	$116
Transmission Reinforcement	$12
Total Cost	$23,091

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Core Case Fact Sheets

CASE ASSUMPTIONS

Description

Case RE-1c retains endogenous renewables from core case 1 (OP-1) and includes additional renewables added to physically comply with Oregon and Washington RPS. Additions are made beginning the first year in which there is a projected compliance shortfall (just-in-time compliance). This case is a variant of core case OP-NT3.

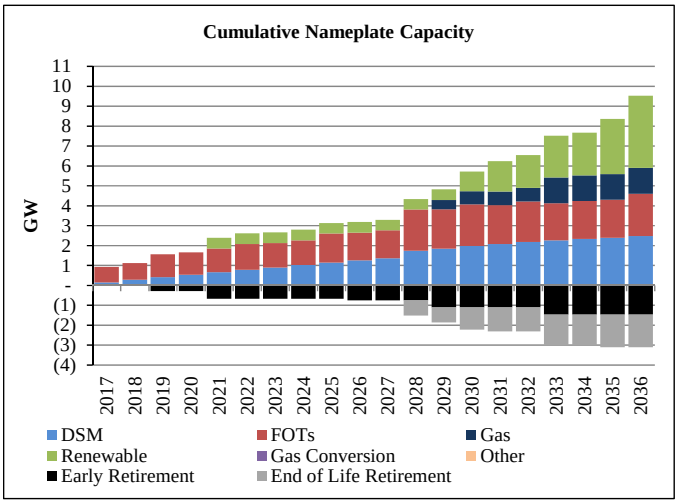
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,016
Transmission Integration	$126
Transmission Reinforcement	$12
Total Cost	$23,154

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Core Case Fact Sheets

CASE ASSUMPTIONS

Description

Case RE-2 retains endogenous renewables from core case 1 and includes additional renewables to physically comply with projected Oregon RPS requirements. Additions are also made in 2021 (proxy for year-end 2020) to meet requirements throughout the planning period (early compliance). This case is a variant of core case OP-NT3.

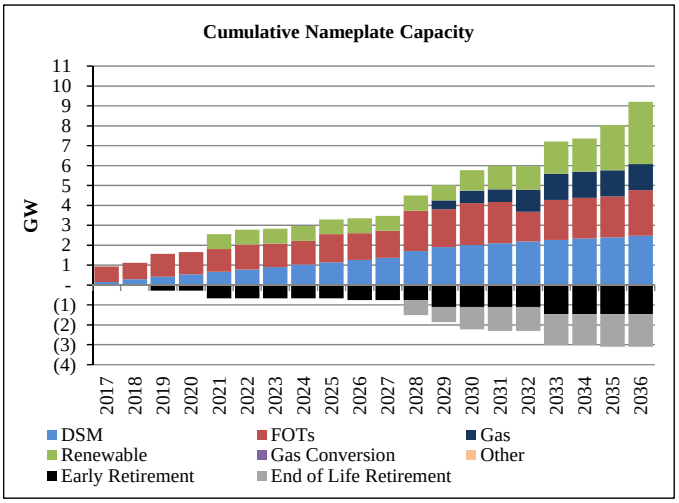
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,967
Transmission Integration	$119
Transmission Reinforcement	$12
Total Cost	$23,098

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Core Case Fact Sheets

CASE ASSUMPTIONS

Description

Case DLC-1 is a reference case with additional Direct Load Control (DLC) added to core case 1 in the first year (2021). Added DLC capacity is at least five percent of the system L&R need. Renewable resource assumptions are consistent with Case 4 (RE-1c), assuming Oregon and Washington physical RPS just-in-time compliance. This case is a variant of core case OP-NT3.

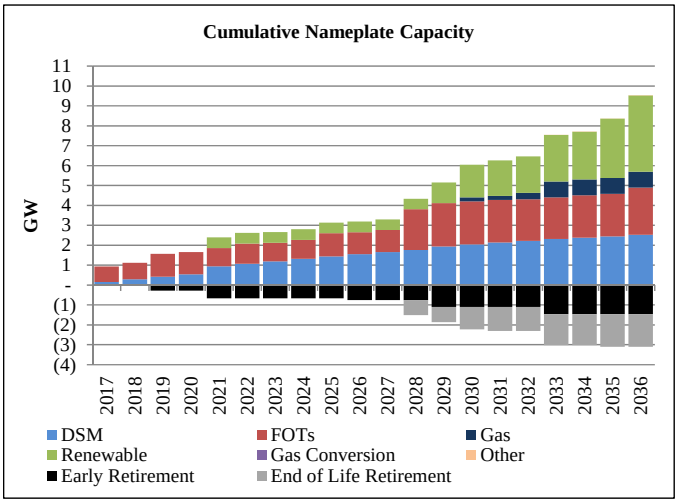
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,942
Transmission Integration	$149
Transmission Reinforcement	$12
Total Cost	$23,103

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

In response to stakeholder feedback, Case RH-2a examines the impact of a Naughton 3 retirement year-end 2017 and a Craig 1 retirement year-end 2025 as an alternative to Case RH-2. This sensitivity is a variant of core case RH2.

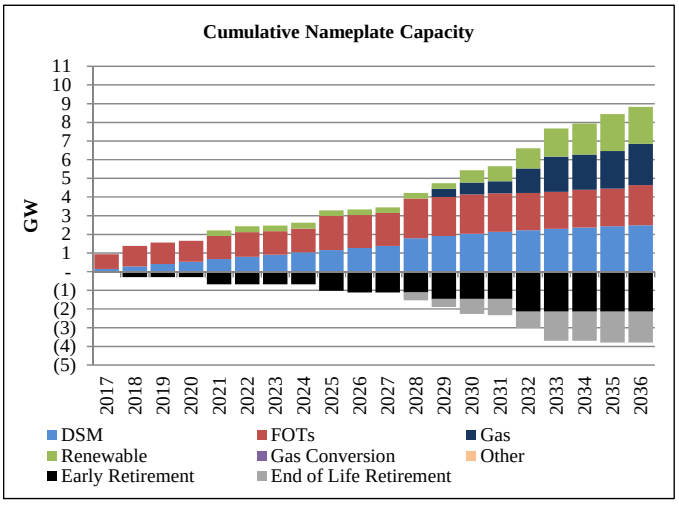
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,237
Transmission Integration	$154
Transmission Reinforcement	$12
Total Cost	$23,404

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Regional Haze

Sensitivity RH-2a Regional Haze assumptions are summarized in the following table.

Coal Unit	Description
Cholla 4	Retire Dec 2020
Colstrip 3	Retire Dec 2046
Colstrip 4	Retire Dec 2046
Craig 1	Retire Dec 2025
Craig 2	SCR by Dec 2017, Retire Dec 2034
Dave Johnston 1	Retire Dec 2027
Dave Johnston 2	Retire Dec 2027
Dave Johnston 3	Retire Dec 2027
Dave Johnston 4	Retire Dec 2032
Hayden 1	Retire Dec 2030
Hayden 2	SCR by Dec 2016, Retire Dec 2030
Hunter 1	Retire Dec 2031
Hunter 2	Retire Dec 2031
Hunter 3	Retire Dec 2042
Huntington 1	Retire Dec 2036
Huntington 2	Retire Dec 2036
Jim Bridger 1	Retire Dec 2024
Jim Bridger 2	Retire Dec 2028
Jim Bridger 3	Retire Dec 2037
Jim Bridger 4	SCR by Dec 2016, Retire Dec 2037
Naughton 1	Retire Dec 2029
Naughton 2	Retire Dec 2029
Naughton 3	Retire Dec 2017
Wyodak	Retire Dec 2039

SCR = selective catalytic reduction

Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The 1-in-20 peak load sensitivity is a five percent 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. This sensitivity is a variant of core case OP-1.

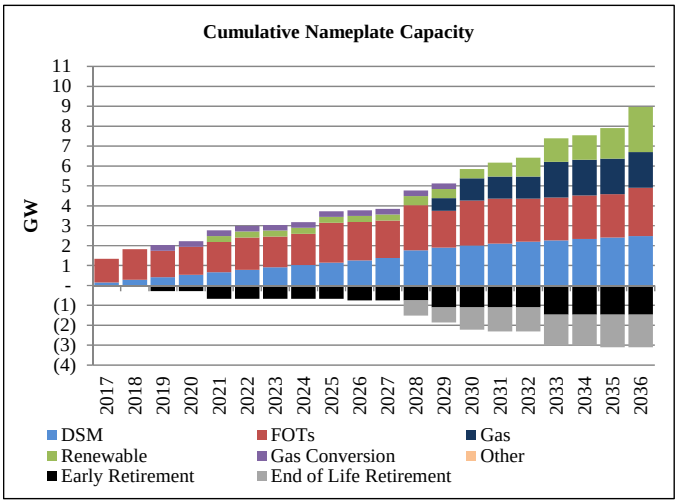
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,207
Transmission Integration	$144
Transmission Reinforcement	$12
Total Cost	$23,364

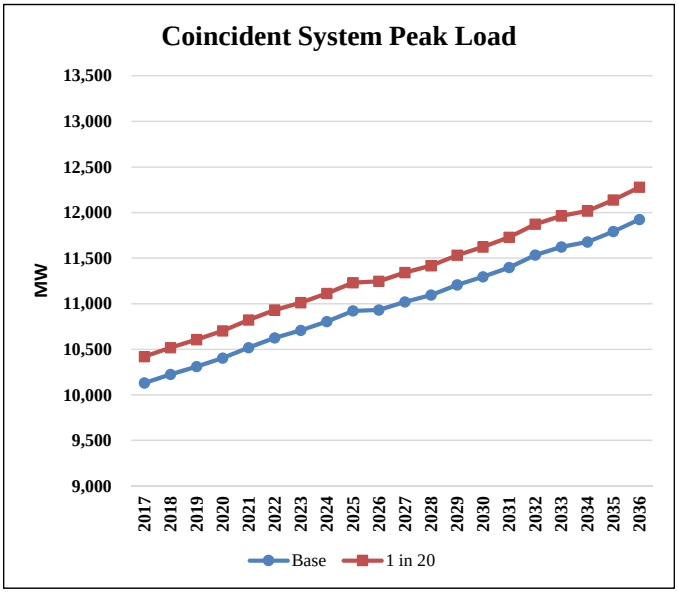
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Load Forecast

The figure below shows the base system coincident peak load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources. Energy load forecast is identical to Base Case.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The low load forecast sensitivity reflects pessimistic economic growth assumptions from IHS Global Insight and low 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 industrial load forecast is taken from 5th percentile. This sensitivity is a variant of core case OP-1.

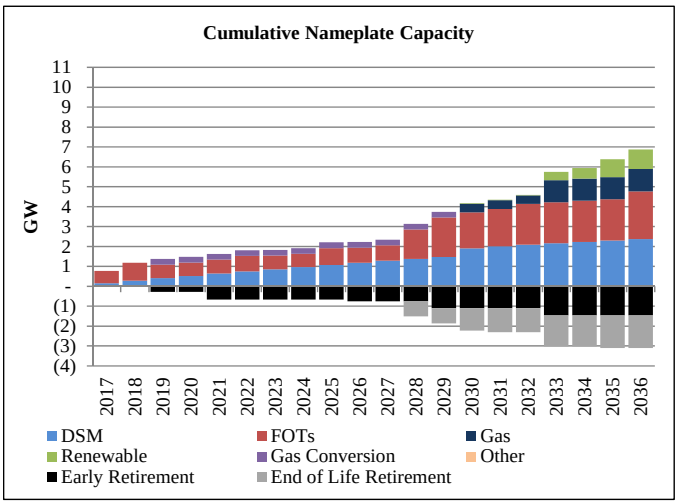
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$21,512
Transmission Integration	$42
Transmission Reinforcement	$12
Total Cost	$21,567

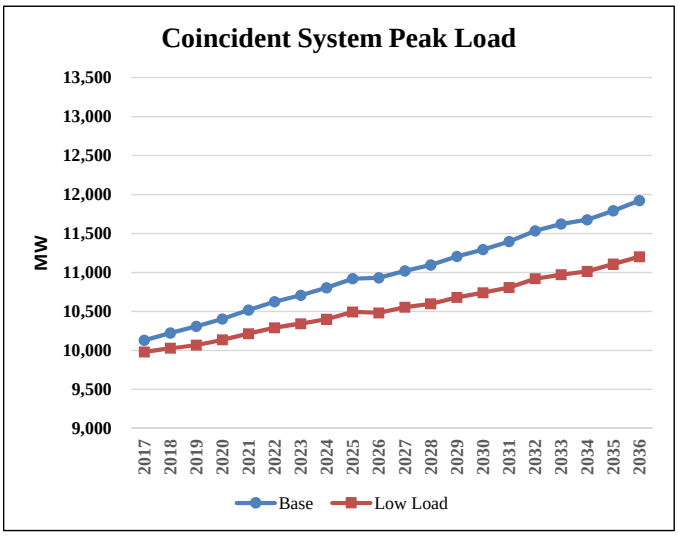
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.

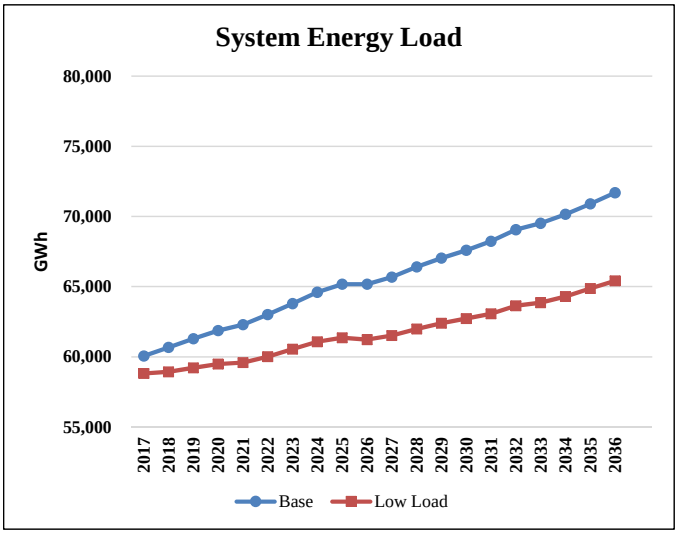


Load Forecast

The figure below shows the base system coincident peak load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



The figure below shows the base energy load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The high load forecast sensitivity reflects optimistic economic growth assumptions from IHS Global Insight and low 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 high industrial load forecast is taken from 95th percentile. This sensitivity is a variant of core case OP-1.

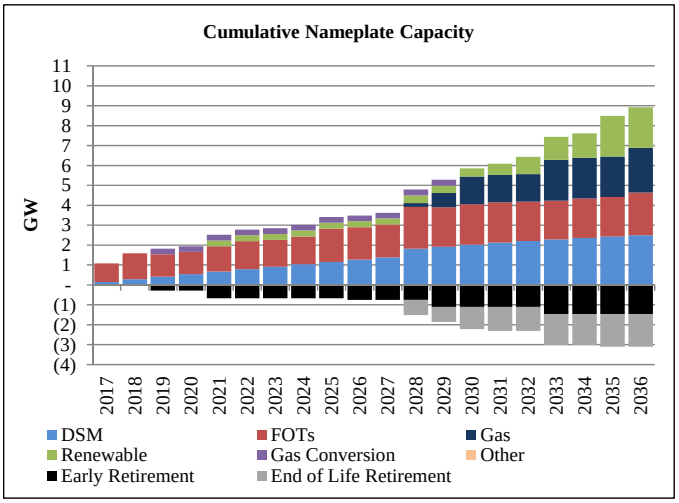
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$24,629
Transmission Integration	$177
Transmission Reinforcement	$12
Total Cost	$24,818

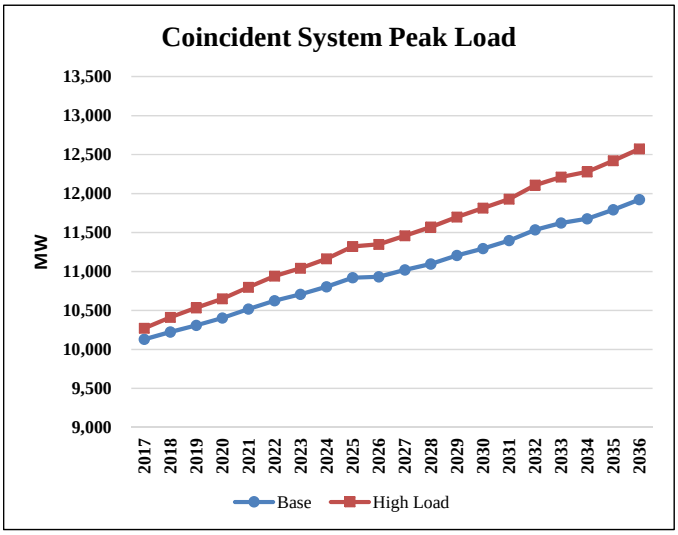
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.

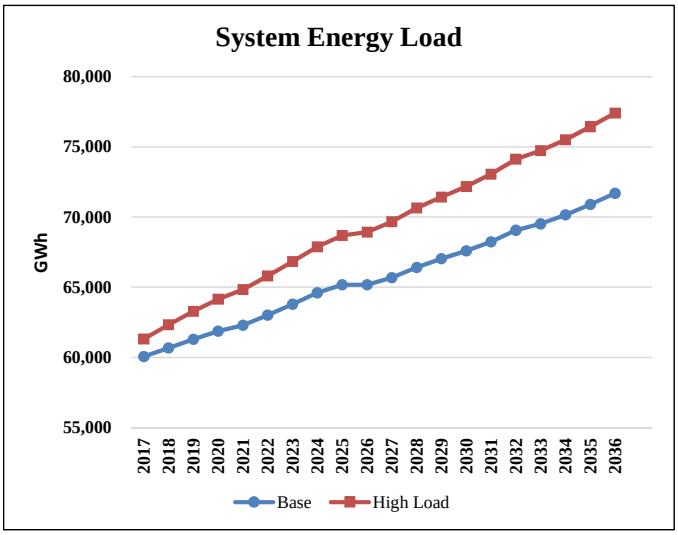


Load Forecast

The figure below shows the base system coincident peak load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



The figure below shows the base energy load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The low private generation sensitivity reflects reductions in technology costs, reduced technology performance levels, and lower retail electricity rates, compared to base penetration levels incorporating annual reductions in technology costs. This sensitivity is a variant of core case OP-1.

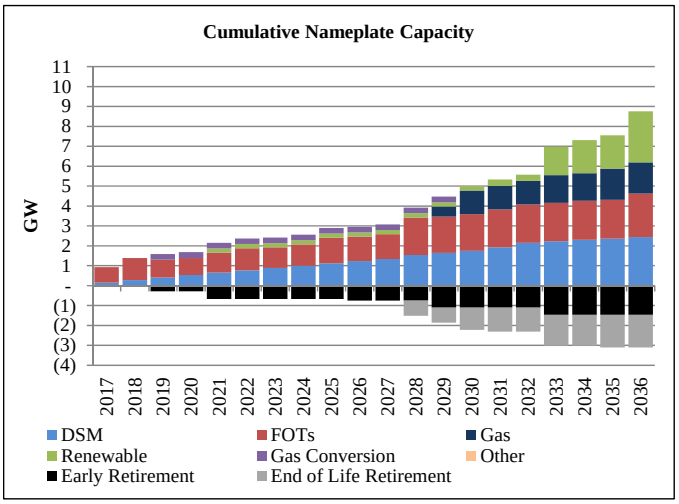
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,203
Transmission Integration	$89
Transmission Reinforcement	$12
Total Cost	$23,304

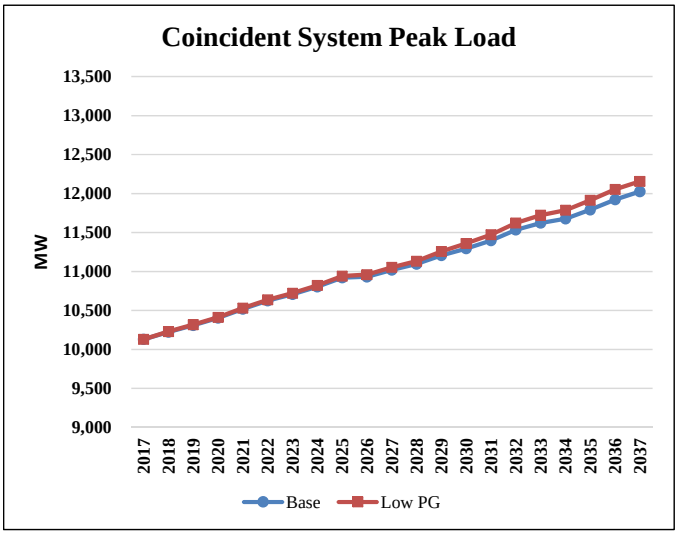
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.

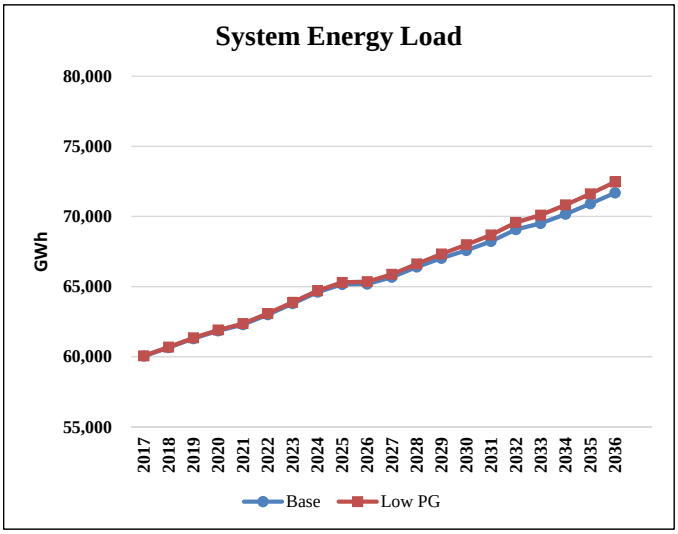


Load Forecast

The figure below shows the base system coincident peak load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



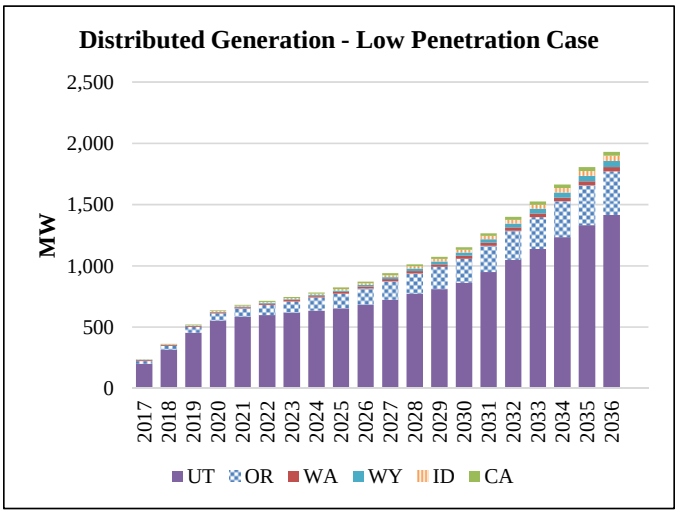
The figure below shows the base energy load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



Sensitivity: Low Private Gen (PG-1)

Private Generation

Scenario private generation penetration by state and year are summarized in the following figure.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The high private generation sensitivity reflects more aggressive technology cost reduction assumptions, higher technology performance levels, and higher retail electricity rates, compared to base penetration levels incorporating annual reductions in technology costs. This sensitivity is a variant of core case OP-1.

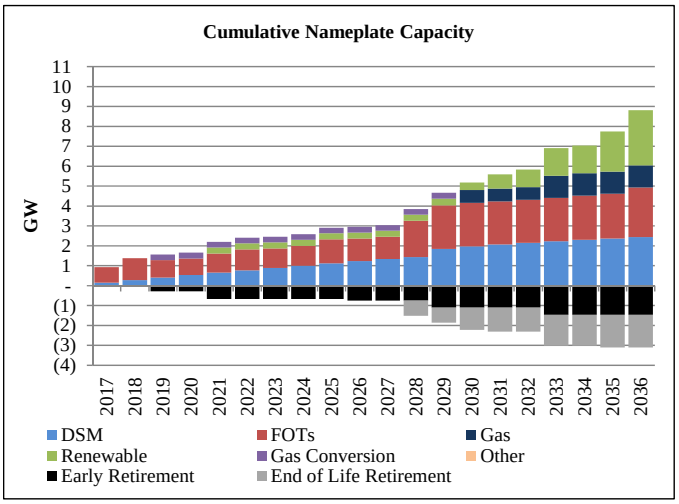
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,782
Transmission Integration	$105
Transmission Reinforcement	$12
Total Cost	$22,899

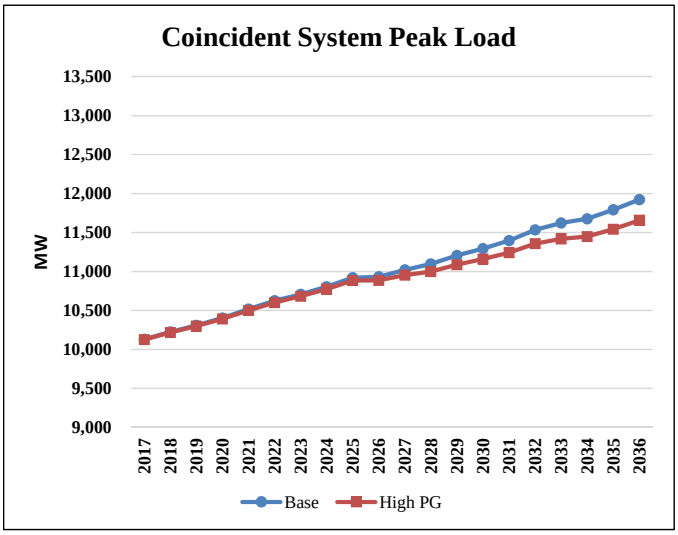
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.

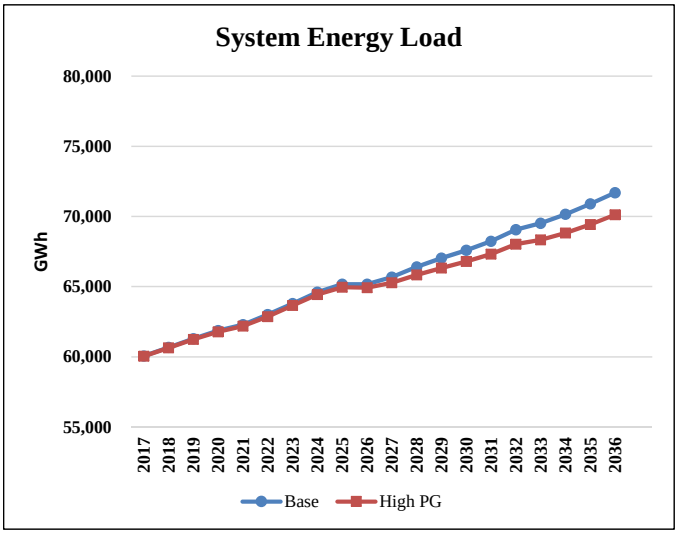


Load Forecast

The figure below shows the base system coincident peak load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



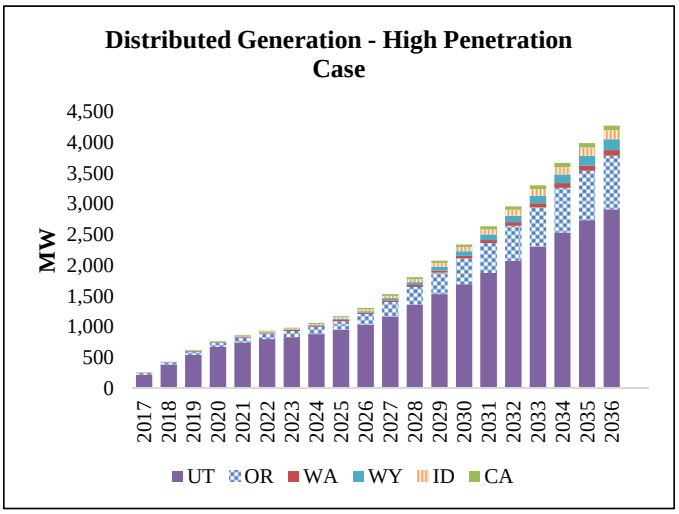
The figure below shows the base energy load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



Sensitivity: High Private Gen (PG-2)

Private Generation

Scenario private generation penetration by state and year are summarized in the following figure.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The CPP Mass Cap C scenario reflects the mass based compliance approach with pro-rata allowance allocation based on historical generation with no new source complement less the CEIP (Clean Energy Incentive Program), renewable and output-based set-asides. PacifiCorp does not receive any allocation of set-asides. New resources are not restricted by the CPP cap. (the CEIP is an optional "matching fund" program that states may choose to use to incentivize wind or solar power generation in all communities and energy efficiency measures in low-income communities.) This sensitivity is a variant of core case OP-1.

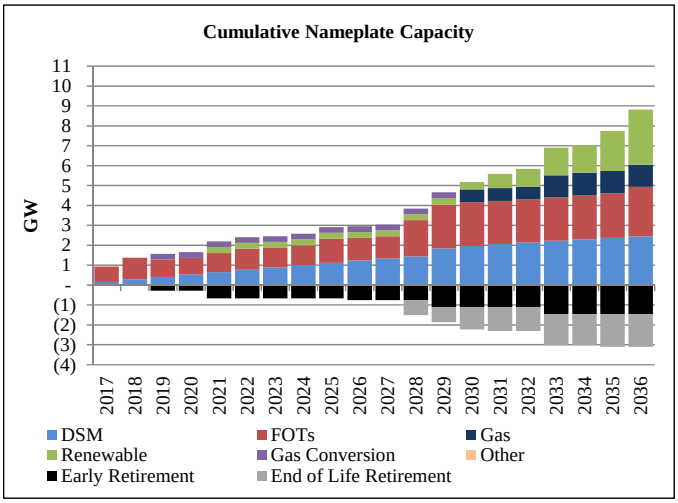
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,129
Transmission Integration	$126
Transmission Reinforcement	$12
Total Cost	$23,268

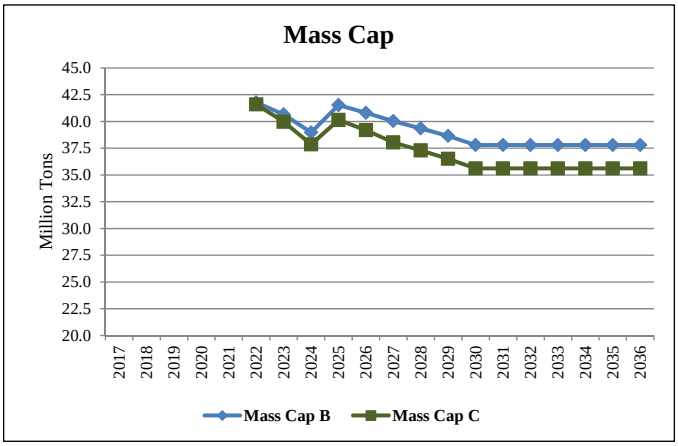
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



System CO_2 Emissions (System Optimizer)

System CO_2 Emissions from System Optimizer are shown alongside those from Base Case in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The CPP Mass Cap D scenario reflects the mass based compliance approach with no set-aside program, but does benefit from the new source complement, which assumes that the mass-based limit grows to accommodate new resources needed to meet load growth. This sensitivity is a variant of core case OP-1.

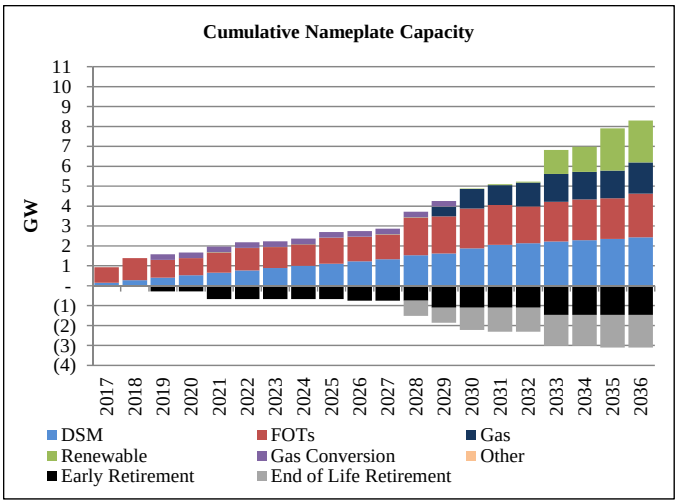
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,010
Transmission Integration	$79
Transmission Reinforcement	$12
Total Cost	$23,102

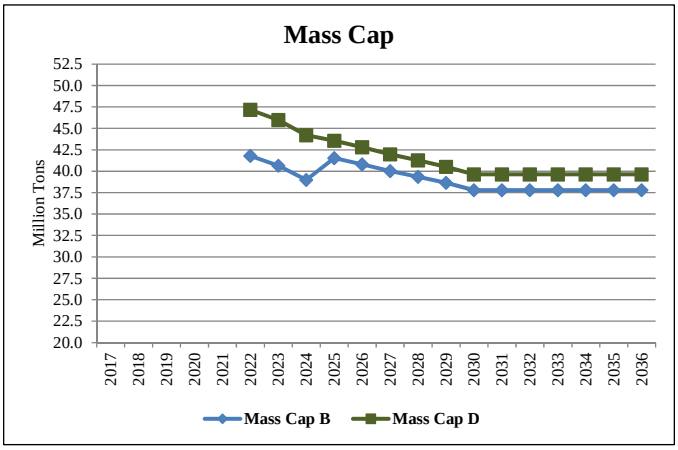
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



System CO_2 Emissions (System Optimizer)

System CO_2 Emissions from System Optimizer are shown alongside those from Base Case in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

PacifiCorp develops FOT limits based on its active participation in wholesale power markets; its view of physical delivery constraints, market liquidity, and market depth; and with consideration of regional resource supply. Alternative FOT limit assumptions applied during the portfolio development process eliminates the availability of FOTs at the NOB (100 MW) and Mona (300 MW) market hubs in summer and winter beginning 2021. This sensitivity is a variant of core case OP-1.

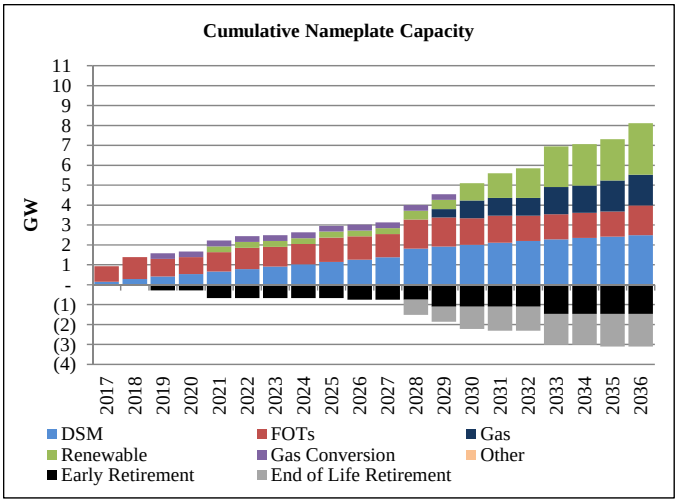
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,189
Transmission Integration	$145
Transmission Reinforcement	$12
Total Cost	$23,347

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The CO_2 Price sensitivity examines the impact of replacing the Clean Power Plan (currently stayed by the U.S. Supreme Court) with an CO_2 proxy price beginning in the year 2025, based on the assumption that even if the CPP is not in effect, there will be some carbon-based policy in place by this time. CO_2 prices applied to each ton of CO_2 emissions from new and existing resources, beginning in 2025 at $4.75/ton and reaching $38.02/ton by 2036. This sensitivity is a variant of core case OP-1.

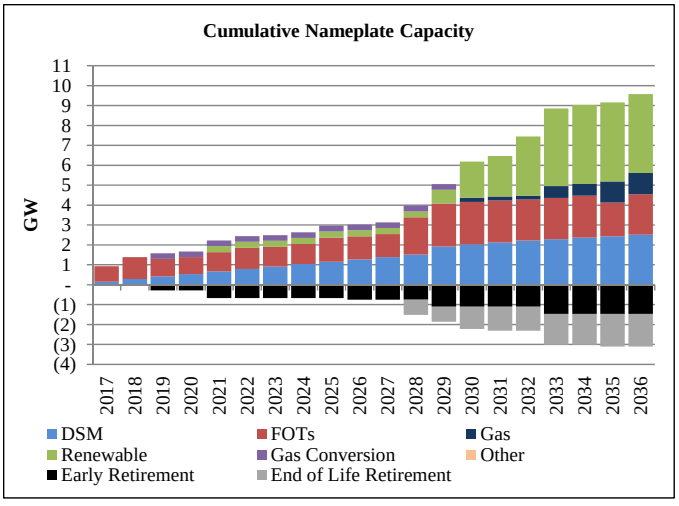
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$26,222
Transmission Integration	$166
Transmission Reinforcement	$12
Total Cost	$26,401

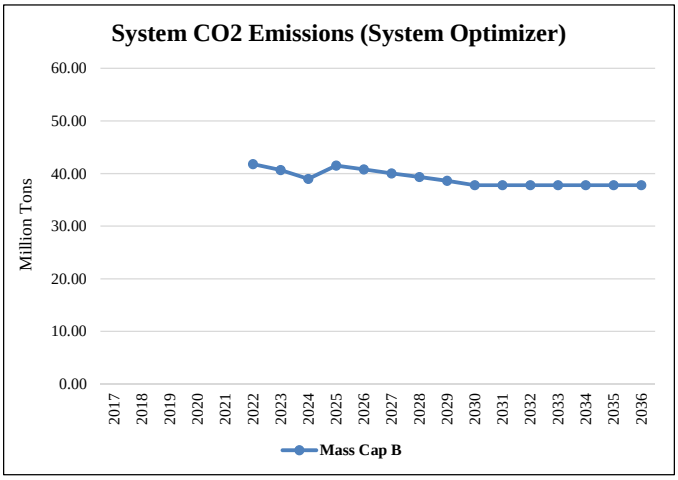
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



System CO_2 Emissions (System Optimizer)

System CO_2 Emissions from System Optimizer are shown in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The No CO_2 sensitivity is a response to a stakeholder request and examines the impact of having no incremental state or federal CO_2 emissions policy in place through the 2017 – 2036 study period. This sensitivity is a variant of core case OP-NT3.

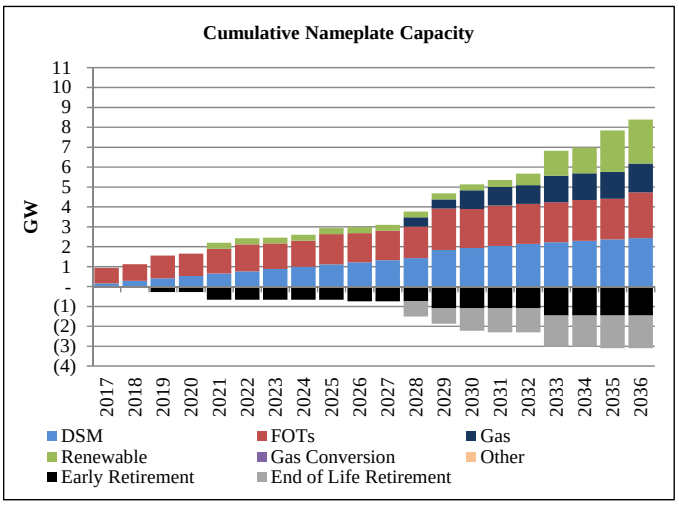
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,787
Transmission Integration	$91
Transmission Reinforcement	$12
Total Cost	$22,891

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The Business Plan sensitivity complies with the Utah requirement to perform a business plan sensitivity consistent with the commission's order in Docket No. 15-035-04. Over the first three years, resources align with those assumed in PacifiCorp's Fall 2016 Business Plan. Beyond the first three years of the study period, unit retirement assumptions are aligned with the draft preferred portfolio selected from the second screening stage. All other resources are optimized. Note that initially, these assumptions were expected to align with core case 1. Due to the timing of this sensitivity, the study was modeled based on the outcome of a later screening stage. This serves to make the business plan sensitivity closer to the eventual preferred portfolio selection, and therefore a more indicative comparison. This sensitivity is a variant of core case OP-NT3.

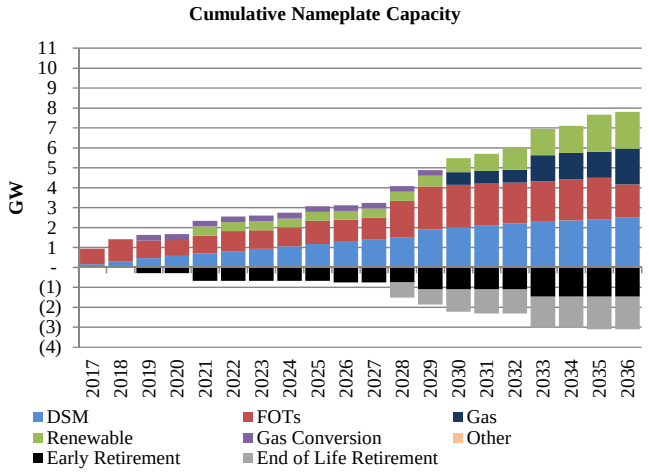
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$23,053
Transmission Integration	$133
Transmission Reinforcement	$12
Total Cost	$23,198

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

Sensitivity GW1 includes segment D – Windstar to Anticline (assumed in-service 2022). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 440 MW of Wyoming wind additions. This sensitivity is a variant of core case OP-NT3.

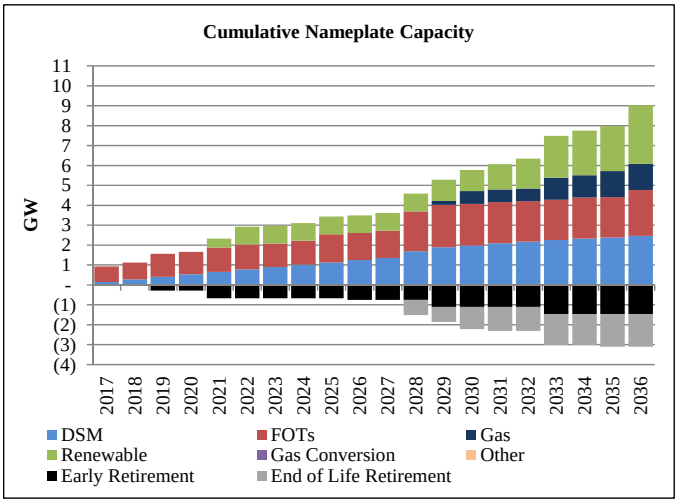
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,803
Transmission Integration	$125
Transmission Reinforcement	$12
	$652
Total Cost	$23,593

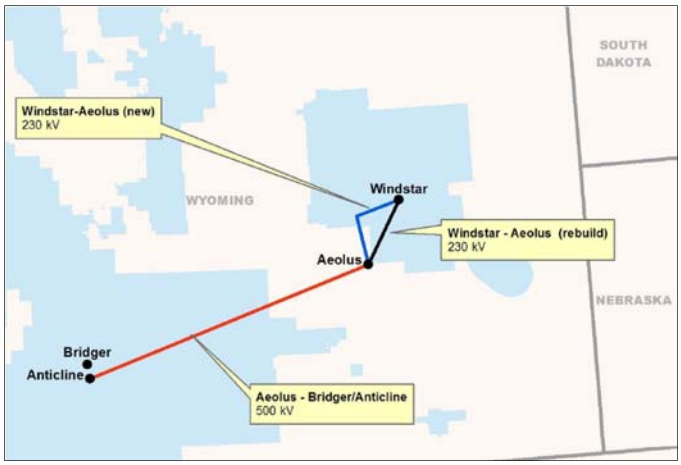
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Transmission

Transmission path is shown in the map below



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

Sensitivity GW2 includes Segment F – Windstar to Mona/Clover (assumed in-service 2023). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 440 MW of Wyoming wind additions. This sensitivity is a variant of core case OP-NT3.

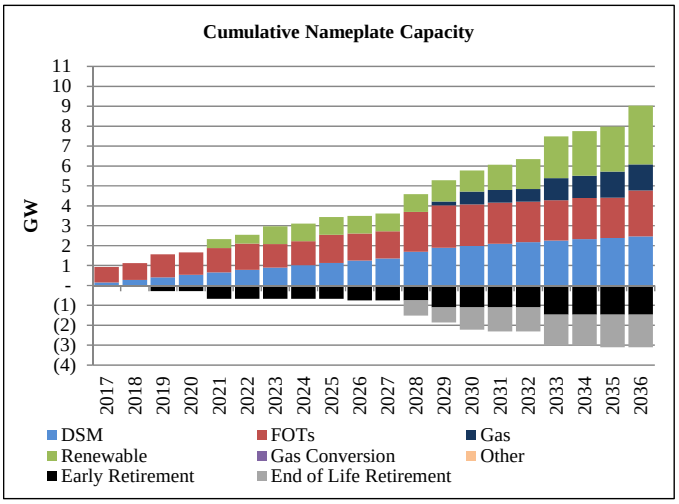
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,841
Transmission Integration	$132
Transmission Reinforcement	$12
Gateway Transmission	$1,068
Total Cost	$24,054

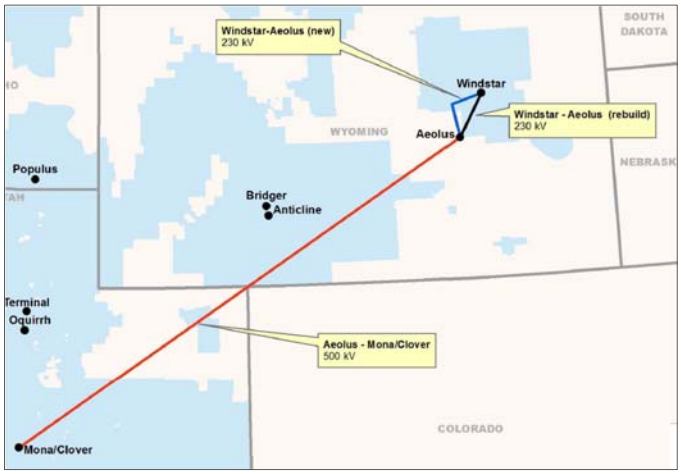
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Transmission

Transmission path is shown in the map below



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

Sensitivity GW3 includes segments D & F – Windstar to Anticline and Aeolus to Mona/Clover (assumed in-service 2022 and 2023, respectively). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 1,200 MW of Wyoming wind additions. This sensitivity is a variant of core case OP-NT3.

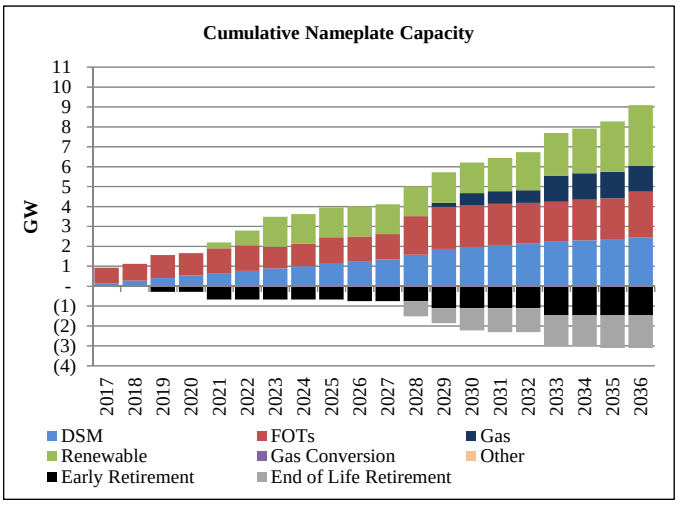
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,706
Transmission Integration	$96
Transmission Reinforcement	$12
	$1,813
Total Cost	$24,627

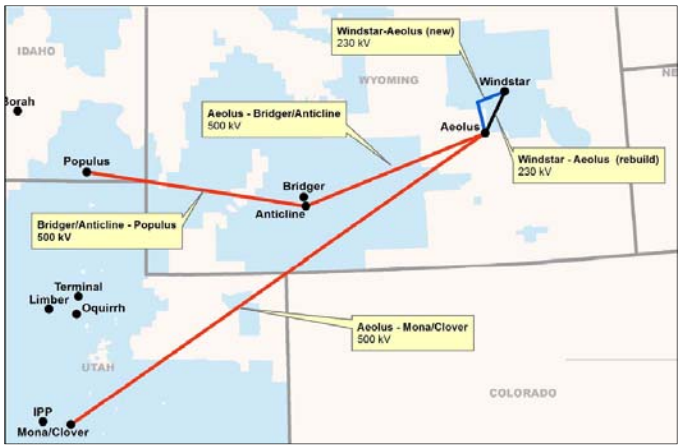
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Transmission

Transmission path is shown in the map below



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

Sensitivity GW4 includes segment D2 – Aeolus to Anticline (assumed in-service year-end 2020). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 900 MW of Wyoming wind additions in 2021 (proxy for year-end 2020). This sensitivity is a variant of core case OP-NT3.

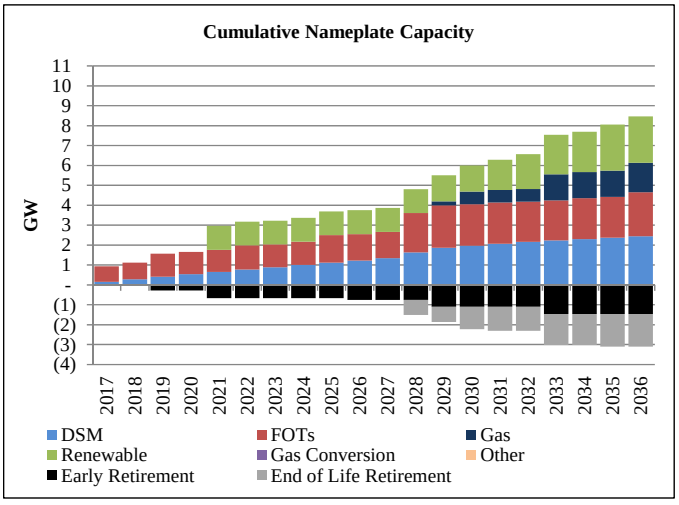
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,648
Transmission Integration	$94
Transmission Reinforcement	$12
Gateway Transmission	$405
Total Cost	$23,159

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Transmission

Transmission path is shown in the map below



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The battery storage sensitivity is the first of two storage sensitivities that force large scale energy storage resources into the resource portfolio, but allow the models to optimize their usage. This sensitivity forces 80 MW of battery storage capacity also in PacifiCorp's east BAA (Wyoming). The site was based on a qualitative assessment of locations best suited for storage to provide support for added renewables, in the expectation that storage plants have the ability to mitigate the non-dispatchable nature of wind and solar energy production. Study includes Gateway segment D2 – Aeolus to Anticline (assumed in-service year-end 2020). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 800 MW of Wyoming wind additions in 2021 (proxy for year-end 2020), reflecting a refinement of the initial Gateway 4 analysis (OP-GW4). This sensitivity is a variant of core case FS-GW4.

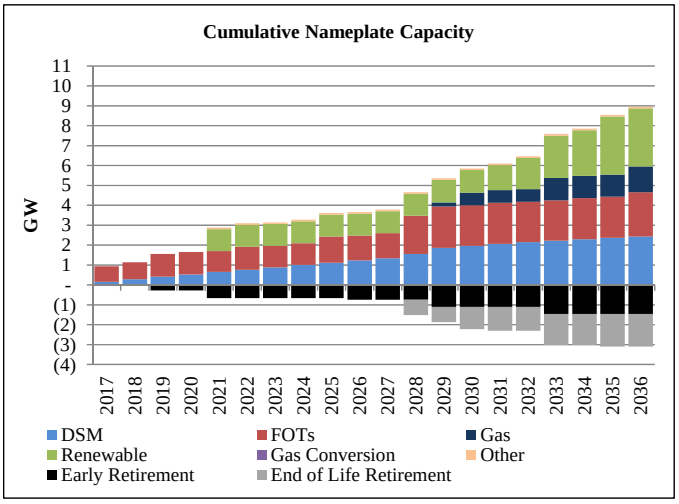
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,735
Transmission Integration	$81
Transmission Reinforcement	$12
Gateway Transmission	$334
Total Cost	$23,162
Total Cost thru 2050	$22,901

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The CAES storage sensitivity is the second of two storage sensitivities that force large scale energy storage resources into the resource portfolio, but allow the models to optimize their usage. This sensitivity forces an 80 MW compressed air storage plant (CAES) sited in PacifiCorp's east BAA (Utah South). The site was based on a qualitative assessment of locations best suited for storage to provide support for added renewables, in the expectation that storage plants have the ability to mitigate the non-dispatchable nature of wind and solar energy production. Study includes Gateway segment D2 – Aeolus to Anticline (assumed in-service year-end 2020). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 800 MW of Wyoming wind additions in 2021 (proxy for year-end 2020), reflecting a refinement of the initial Gateway 4 analysis (OP-GW4). This sensitivity is a variant of core case FS-GW4.

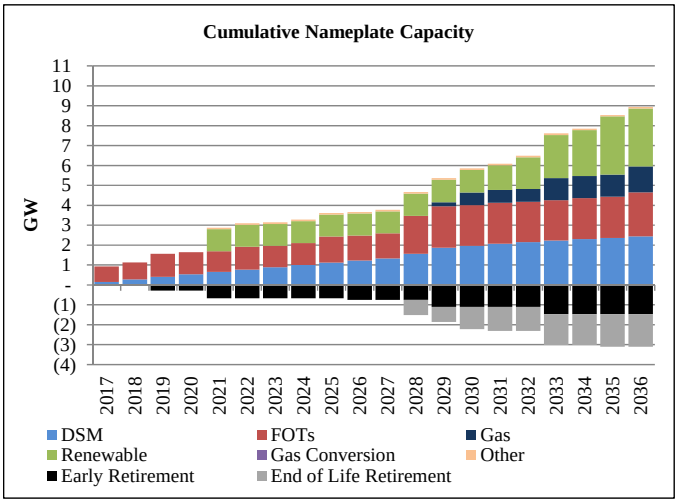
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,659
Transmission Integration	$116
Transmission Reinforcement	$12
Gateway Transmission	$334
Total Cost	$23,121
Total Cost thru 2050	$22,860

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The WCA sensitivity assumes separate balancing authority areas (BAA) for the Company's East and West territory and produces standalone resource portfolios for the WCA, as required by the Washington Utilities and Transportation Commission. Key assumptions include maintaining a 13 percent reserve margin applicable to summer and winter peak; allowing on-peak FOT's with limits at Mid-C (775 MW), COB (400 MW) and NOB (100 MW); including all of Jim Bridger in the west BAA; including Colstrip in the west BAA up to transmission limits; and applying Mass Cap B and CAR emission limits. This sensitivity is a variant of core case FS-REP.

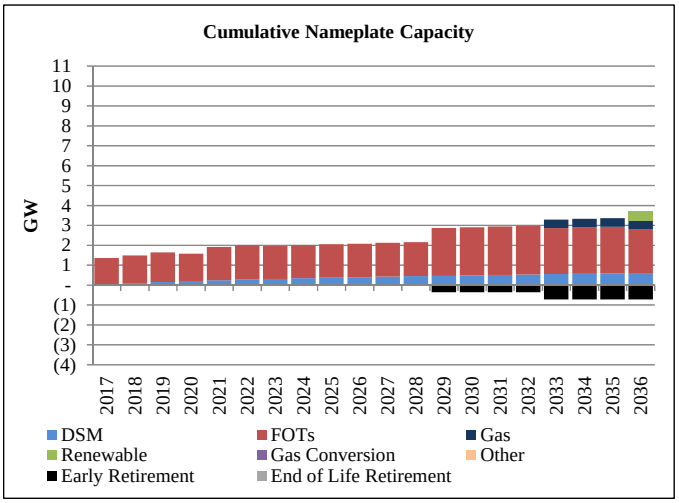
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$7,539
Transmission Integration	$4
Transmission Reinforcement	$0
Total Cost	$7,542

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The WCA RPS sensitivity assumes separate balancing authority areas (BAA) for the Company's East and West territory and produces standalone resource portfolios for the WCA, as required by the Washington Utilities and Transportation Commission. In addition, the sensitivity assumes compliance with Washington RPS requirements. Key assumptions include maintaining a 13 percent reserve margin applicable to summer and winter peak; allowing on-peak FOT's with limits at Mid-C (775 MW), COB (400 MW) and NOB (100 MW); including all of Jim Bridger in the west BAA; including Colstrip in the west BAA up to transmission limits; and applying Mass Cap B and CAR emission limits. This sensitivity is a variant of core case FS-REP.

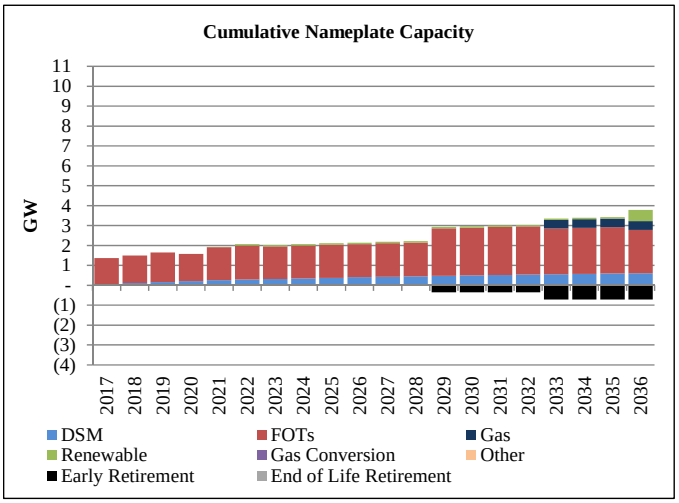
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$7,554
Transmission Integration	$4
Transmission Reinforcement	$0
Total Cost	$7,557

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Final Selection Fact Sheets

CASE ASSUMPTIONS

Description

Final screening case FS-REP assumes 905 MW of existing wind resources are repowered by the end of 2020 (Glenrock, Rolling Hills, Seven Mile Hill, High Plains, McFadden Ridge, Dunlap, Marengo and Leaning Juniper) and was updated with more current wind shape information. This case is a variant of core case OP-NT3.

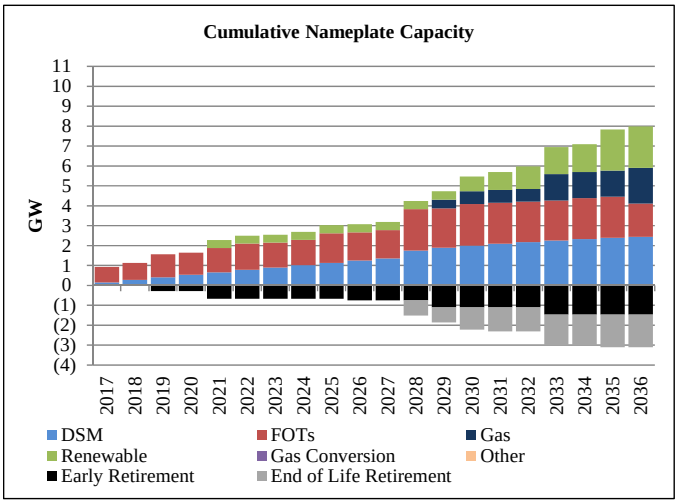
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,907
Transmission Integration	$123
Transmission Reinforcement	$12
Total Cost	$23,042
Total Cost thru 2050	$22,781

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Final Selection Fact Sheets

CASE ASSUMPTIONS

Description

Final screening case FS-GW4 assumes 905 MW of existing wind resources are repowered by the end of 2020. Study includes Gateway segment D2 – Aeolus to Anticline (assumed in-service year-end 2020). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 800 MW of Wyoming wind additions in 2021 (proxy for year-end 2020), reflecting a refinement of the initial Gateway 4 analysis (OP-GW4). This case is a variant of final selection FS-REP.

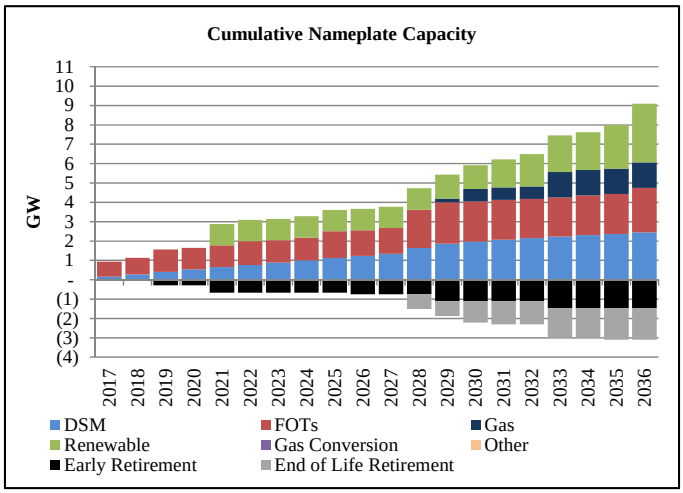
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

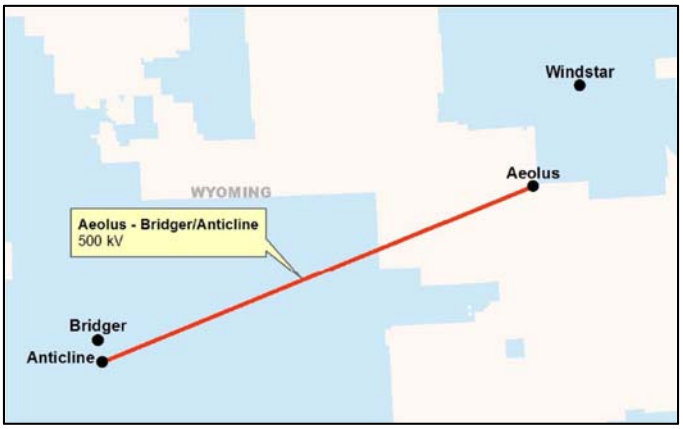
System Cost without Transmission Upgrades	$22,549
Transmission Integration	$95
Transmission Reinforcement	$12
Gateway Transmission	$334
Total Cost	$22,990
Total Cost thru 2050	$22,729

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Transmission Path



Final Selection Fact Sheets

CASE ASSUMPTIONS

Description

Final screening case FS-R1c assumes 905 MW of existing wind resources are repowered by the end of 2020. Study includes Gateway segment D2 – Aeolus to Anticline (assumed in-service year-end 2020). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 800 MW of Wyoming wind additions in 2021 (proxy for year-end 2020), reflecting a refinement of the initial Gateway 4 analysis (OP-GW4). This study also includes additional renewables added to physically comply with Oregon and Washington RPS. Renewable additions are made beginning the first year in which there is a projected compliance shortfall (just-in-time compliance). This case is a variant of final selection FS-GW4.

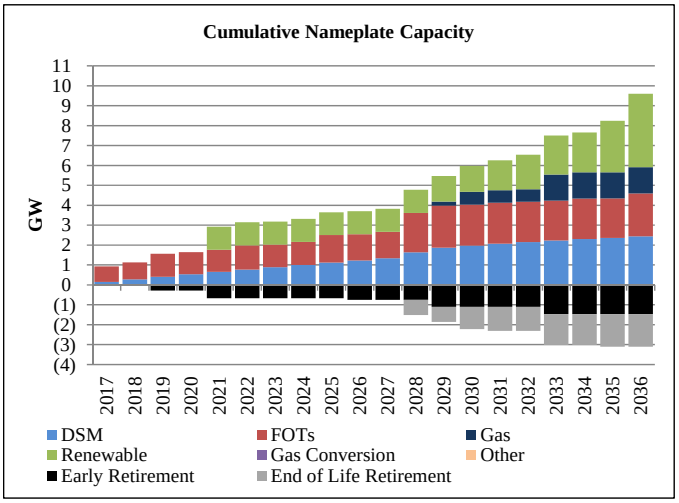
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,561
Transmission Integration	$99
Transmission Reinforcement	$12
Gateway Transmission	$334
Total Cost	$23,006
Total Cost thru 2050	$22,745

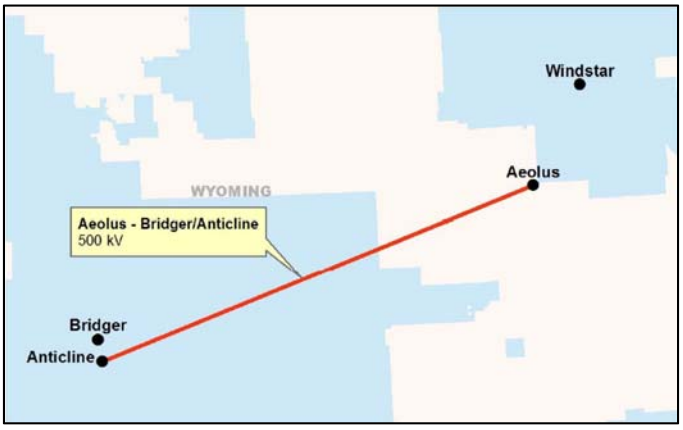
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Transmission

Transmission path is shown in the map below



Final Selection Fact Sheets

CASE ASSUMPTIONS

Description

Final screening case FS-R2 assumes 905 MW of existing wind resources are repowered by the end of 2020. Study includes Gateway segment D2 – Aeolus to Anticline (assumed in-service year-end 2020). In addition to the 300 MW of Wyoming wind in case OP-NT3, the additional transmission enables 800 MW of Wyoming wind additions in 2021 (proxy for year-end 2020), reflecting a refinement of the initial Gateway 4 analysis (OP-GW4). This study includes additional renewables added to physically comply with projected Oregon RPS requirements. Renewable additions are made in 2021 (proxy for year-end 2020) to meet requirements throughout the planning period (early compliance). This case is a variant of final selection FS-GW4.

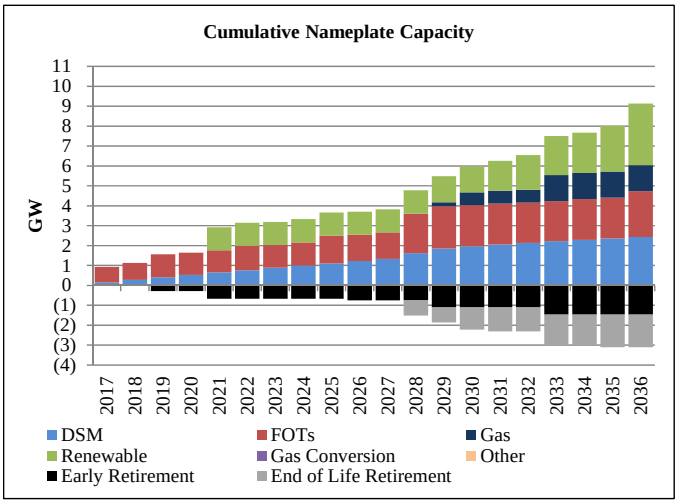
PORTFOLIO SUMMARY

System Optimizer PVRR ($m)

System Cost without Transmission Upgrades	$22,554
Transmission Integration	$95
Transmission Reinforcement	$12
Gateway Transmission	$334
Total Cost	$22,995
Total Cost thru 2050	$22,734

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Transmission

Transmission path is shown in the map below



APPENDIX N – WIND AND SOLAR CAPACITY CONTRIBUTION STUDY

Introduction

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 this report, 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 calculated peak capacity contribution values for wind and solar resources using the capacity factor approximation method (CF Method) as outlined in a 2012 report produced by the National Renewable Energy Laboratory (NREL Report)[1].

The capacity contribution of wind and solar resources affects PacifiCorp's resource planning activities. PacifiCorp conducts its resource planning to ensure there is sufficient capacity on its system to meet its load obligation at the time of system coincident peak inclusive of a planning reserve margin. To ensure resource adequacy is maintained over time, all resource portfolios evaluated in the integrated resource plan (IRP) have sufficient capacity to meet PacifiCorp's net coincident peak load obligation inclusive of a planning reserve margin throughout a 20-year planning horizon. Consequently, planning for the coincident peak drives the amount and timing of new resources, while resource cost and performance metrics among a wide range of different resource alternatives drive the types of resources that can be chosen to minimize portfolio costs and risks.

PacifiCorp derives its planning reserve margin from a LOLP study. The study evaluates the relationship between reliability across all hours in a given year, accounting for variability and uncertainty in load and generation resources, and the cost of planning for system resources at varying levels of planning reserve margin. In this way, PacifiCorp's planning reserve margin LOLP study is the mechanism used to transform hourly reliability metrics into a resource adequacy target at the time of system coincident peak. This same LOLP study was utilized for calculating the peak capacity contribution using the CF Method. **Error! Reference source not found.**, summarizes the peak capacity contribution results for PacifiCorp's East and West balancing authority areas (BAAs).

The CF Method ignores transmission constraints that can prevent resource output in a location from reaching an area location where loss of load events occur. If transmission constraints prevent resources from reaching areas with loss of load events, additional capacity in those areas may not provide an adequate planning reserve margin or contribute to reliability. At the January 26-27, 2017 public input meeting PacifiCorp identified the potential for transmission constraints to impact

[1] Madaeni, S. H.; Sioshansi, R.; and Denholm, P. "Comparison of Capacity Value Methods for Photovoltaics in the Western United States." NREL/TP-6A20-54704, Denver, CO: National Renewable Energy Laboratory, July 2012 (NREL Report). http://www.nrel.gov/docs/fy12osti/54704.pdf

the effective capacity contribution from resources in Wyoming Northeast, Oregon, and Utah South.[2]

In light of the inclusion of Energy Gateway transmission segment D2 described in Volume I, Chapter 4 (Transmission) in the 2017 IRP preferred portfolio, the Wyoming Northeast transmission area is less constrained. This is particularly evident during summer months when LOLP is highest, as wind output in that area is relatively low in the summer. The 2017 IRP preferred portfolio also includes significant expansion resources in the 2030 timeframe in Oregon and Utah South. By the time additional capacity is required and new resources are added, transmission congestion in these areas is reduced, relative to the 2020 sample year used in the capacity contribution analysis, as a result of load growth, expiring contracts, and retiring resources.

Methodology

The NREL Report summarizes several methods for estimating the capacity value of renewable resources that are broadly categorized into two classes: 1) reliability-based methods that are computationally intensive; and 2) approximation methods that use simplified calculations to approximate reliability-based results. The NREL Report references a study from Milligan and Parsons that evaluated capacity factor approximation methods, which use capacity factor data among varying sets of hours, relative to the more computationally intensive reliability-based effective load carrying capability (ELCC) metric. As discussed in the NREL Report, the CF Method was found to be the most dependable technique in deriving capacity contribution values that approximate those developed using the ELCC Method.

As described in the NREL Report, the CF Method "considers the capacity factor of a generator over a subset of periods during which the system faces a high risk of an outage event." When using the CF Method, hourly LOLP is calculated and then weighting factors are obtained by dividing each hour's LOLP by the total LOLP over the period. These weighting factors are then applied to the contemporaneous hourly capacity factors for a wind or solar resource to produce a weighted average capacity contribution value.

The weighting factors based on LOLP are defined as:

$$w_i = \frac{LOLP_i}{\sum_{j=1}^{T} LOLP_j}$$

where w_i is the weight in hour i, $LOLP_i$ is the LOLP in hour i, and T is the number of hours in the study period, which is 8,760 hours for the current study. These weights are then used to calculate the weighted average capacity factor as an approximation of the capacity contribution as:

$$CV = \sum_{i=1}^{T} w_i C_i,$$

[2] 2017 IRP: Public Input Meeting 7. January 26-27, 2017. Presentation available at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/PacifiCorp_2017_IRP_PIM07_1-26-17_Presentation.pdf

where C_i is the capacity factor of the resource in hour *i*, and *CV* is the weighted capacity value of the resource.

To determine the capacity contribution using the CF method, PacifiCorp implemented the following two steps:

1. A 500-iteration hourly Monte Carlo simulation of PacifiCorp's system was produced using the Planning and Risk (PaR) model to simulate the dispatch of the Company's system for a sample year (calendar year 2020). This PaR study is based on the Company's 2017 IRP planning reserve margin study using a 13 percent target planning reserve margin level. The LOLP for each hour in the year is calculated by counting the number of iterations in which system load could not be met with available resources and dividing by 500 (the total number iterations). For example, if in hour 9 on January 12th there are two iterations with Energy Not Served (ENS) out of a total of 500 iterations, then the LOLP for that hour would be 0.4 percent.[3]

2. Weighting factors were determined based upon the LOLP in each hour divided by the sum of LOLP among all hours. In the example noted above, the sum of LOLP among all hours is 143 percent.[4] The weighting factor for hour 9 on January 12th would be 0.2797 percent.[5] The hourly weighting factors are then applied to the capacity factors of wind and solar resources in the corresponding hours to determine the weighted capacity contribution value in those hours. Extending the example noted, if a resource has a capacity factor of 41.0 percent in hour 9 on January 12th, its weighted annual capacity contribution for that hour would be 0.1146 percent.[6]

Results

Table N.1 summarizes the resulting annual capacity contribution using the CF Method described above as compared to capacity contribution values assumed in the 2015 IRP. In implementing the CF Method, PacifiCorp used actual wind project data from wind resources operating in its system to derive hourly wind capacity factor inputs. For solar resources, PacifiCorp used solar profiles from signed solar projects to apply to the 2017 IRP, differentiated between single axis tracking and fixed tilt projects. Separate solar and wind capacity contribution values were calculated using profiles corresponding to the East and West BAAs.

[3] 0.4 percent = 2 / 500.
[4] For each hour, the hourly LOLP is calculated as the number of iterations with ENS divided by the total of 500 iterations. There are 715 ENS iteration-hours out of total of 8,760 hours. As a result, the sum of LOLP is 715 / 500 = 143 percent.
[5] 0.2797 percent = 0.4 percent / 143 percent, or simply 0.2797 percent = 2 / 715.
[6] 0.1146 percent = 0.2797 percent x 41.0 percent.

Table N.1 – 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
2017 IRP Results	15.8%	37.9%	59.7.8%	11.8%	53.9%	64.8%
2015 IRP Results	14.5%	34.1%	39.1%	25.4%	32.2%	36.7%

Figure N.1 presents daily average LOLP results from the PaR simulation, which shows that loss of load events are most likely to occur during the summer when load peaks in July.

Figure N.1 – Daily LOLP

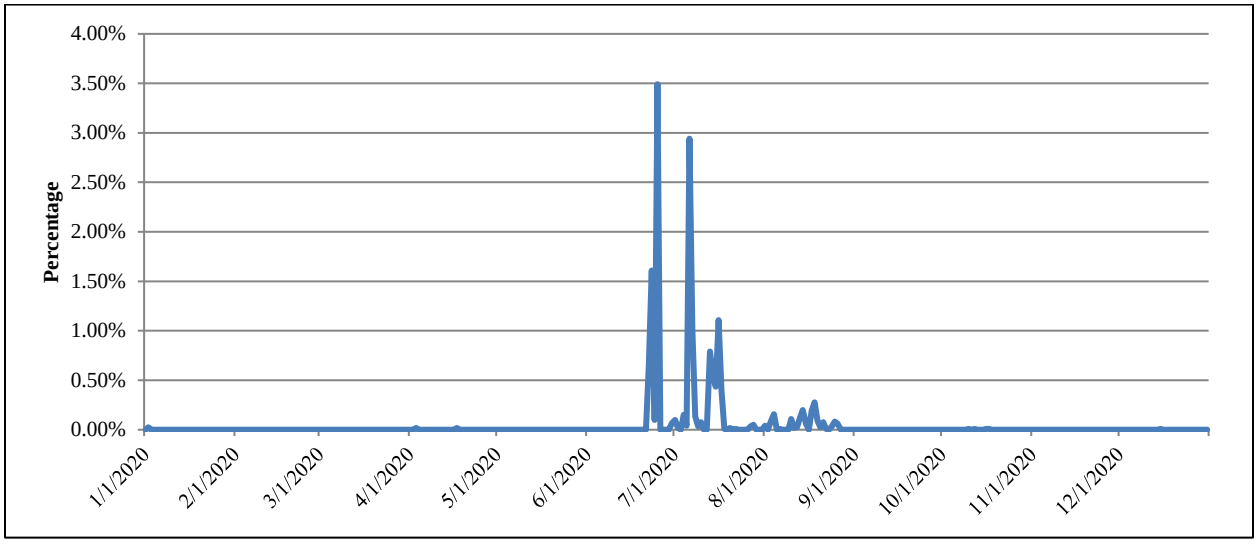


Figure N.2 presents the relationship between monthly capacity factors among wind and solar resources (primary y-axis) and average monthly LOLP from the PaR simulation (secondary y-axis) in PacifiCorp's CF Method analysis. As noted above, the average monthly LOLP is most prominent in summer (July peak loads).

Figure N.2 – Monthly Resource Capacity Factors as Compared to LOLP

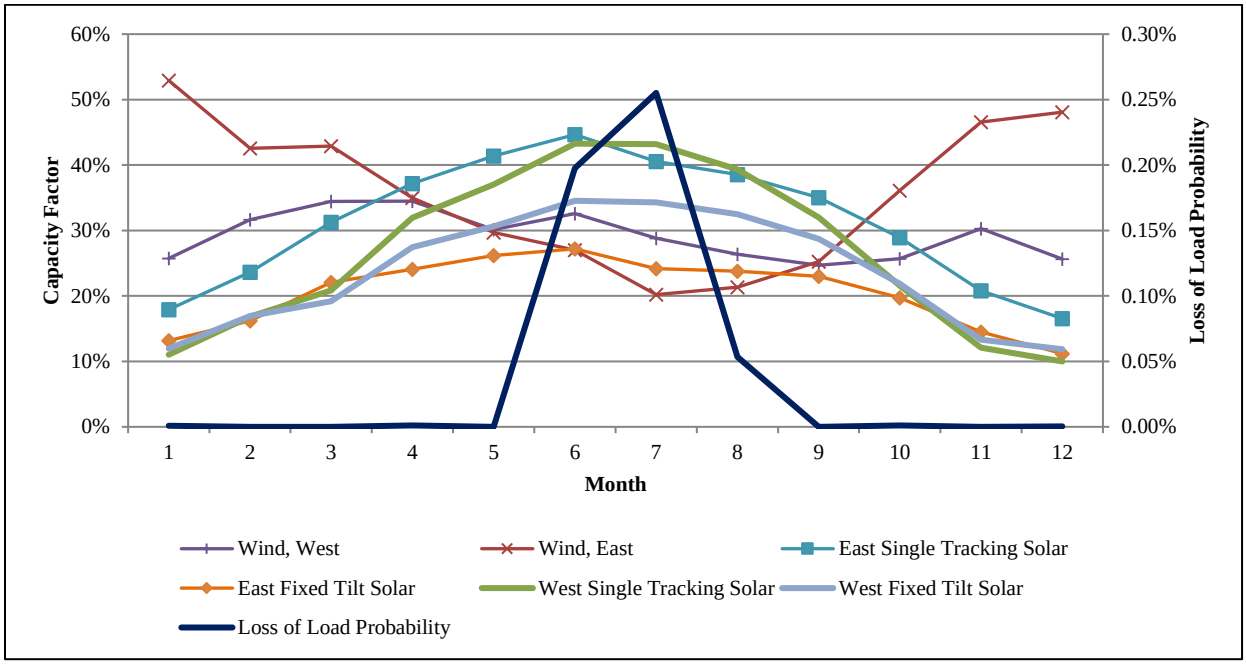
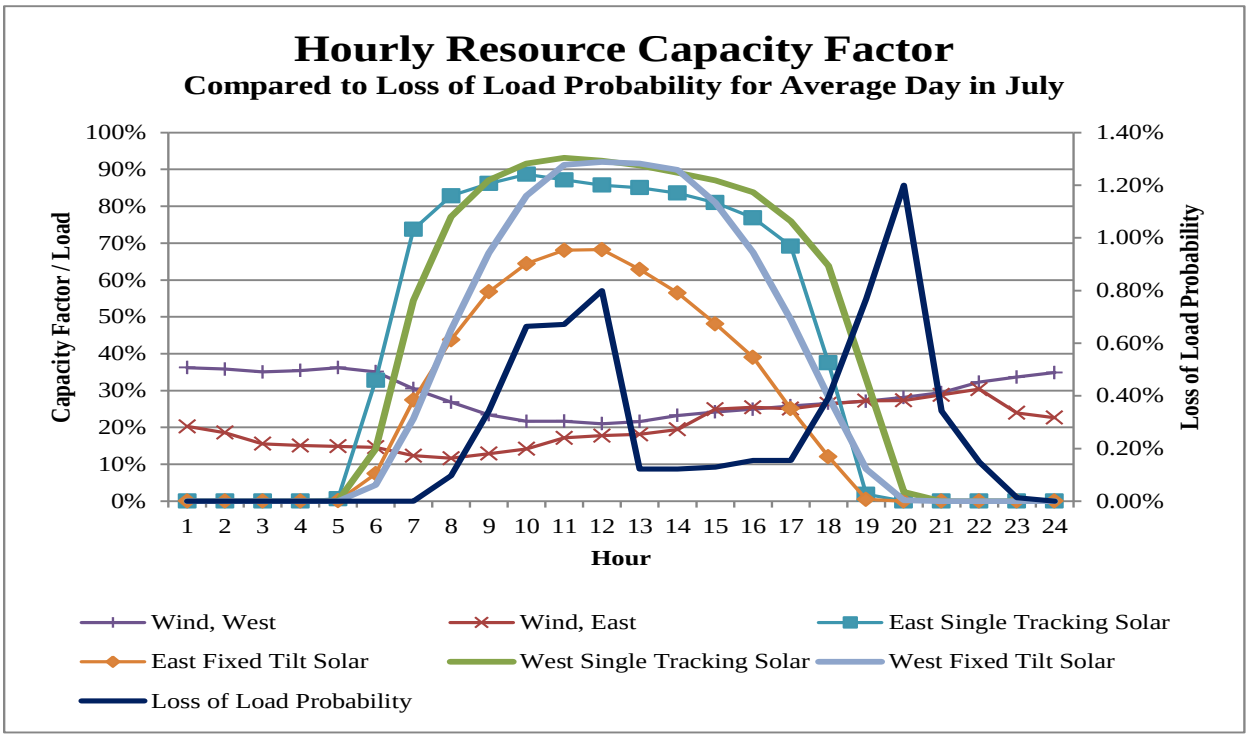


Figure N.3 presents the average hourly capacity factors for wind and solar resources (primary y-axis) as compared to the average hourly LOLP (secondary y-axis) for the month of July. In July, LOLP events peak during higher load hours and during the evening ramp.

Figure N.3 – Hourly Resource Capacity Factors as Compared to LOLP for an Average Day in July



Conclusion

PacifiCorp conducts its resource planning by ensuring there is sufficient capacity on its system to meet its net load obligation at the time of system coincident peak inclusive of a planning reserve margin. The peak capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is the weighted average capacity factor of these resources during periods when load cannot be met with available resources. The peak capacity contribution values developed using the CF Method are based on a LOLP study that aligns with PacifiCorp's 13 percent planning reserve margin, and therefore represent the expected contribution that wind and solar resources make toward achieving PacifiCorp's target resource planning criteria.

APPENDIX O – PRIVATE GENERATION STUDY

Introduction

Navigant Consulting, Inc. prepared the Private Generation Long-Term Resource Assessment (2017-2036) for PacifiCorp. A key objective of this research is to assist PacifiCorp in developing private generation resource penetration forecasts to support its 2017 Integrated Resource Plan. The purpose of this study is to project the level of private generation resources PacifiCorp's customers might install over the next twenty years.

NAVIGANT

Private Generation Long-Term Resource Assessment (2017-2036)

Prepared for:

PacifiCorp



Prepared by:
Karin Corfee
Shalom Goffri
Andrea Romano

July 29th, 2016
Corrected: December 22nd, 2016

Navigant Consulting, Inc.
One Market Street
Spear Street Tower, Suite 1200
San Francisco, CA 94105

415.356.7100
navigant.com

Reference No.: 184060

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July 29th, 2016

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EXECUTIVE SUMMARY

Navigant Consulting, Inc. (Navigant) prepared this Long-term Private Generation Resource Assessment on behalf of PacifiCorp. Private generation sources provide customer-sited energy generation and are generally of relatively small size, generating less than the amount of energy used at a particular location. The purpose of this study is to support PacifiCorp's 2017 Integrated Resource Plan (IRP) by projecting the level of private generation resources PacifiCorp's customers might install over the next twenty years under base, low, and high penetration scenarios.

This study builds on Navigant's previous assessment [1] which supported PacifiCorp's 2015 IRP, incorporating updated load forecasts, market data, technology cost and performance projections. Navigant evaluated five private generation resources in detail in this report:

1. Photovoltaic (Solar) Systems
2. Small Scale Wind
3. Small Scale Hydro
4. Combined Heat and Power Reciprocating Engines
5. Combined Heat and Power Micro-turbines

Project sizes were determined based on average customer load across four customer classes including commercial, irrigation, industrial and residential.

Navigant also evaluated the future potential of energy storage, evaluating the drivers, challenges and applications of energy storage today. Summary findings are detailed in APPENDIX C.

Private generation technical potential[2] and expected market penetration[3] for each technology was estimated for each major customer class in each state in PacifiCorp's service territory. Shown in Figure 1, PacifiCorp serves customers in California, Idaho, Oregon, Utah, Washington, and Wyoming.

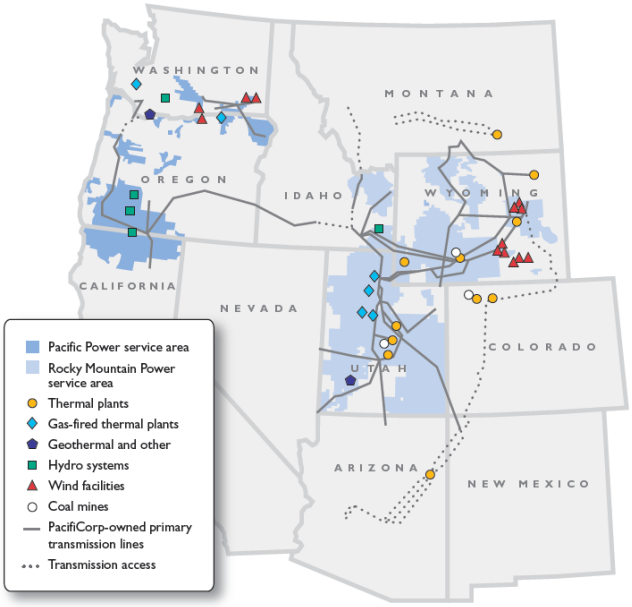
[1] Navigant, Distributed Generation Resource Assessment for Long-Term Planning Study, http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/2015IRPStudy/Navigant_Distributed-Generation-Resource-Study_06-09-2014.pdf.

[2] Total resource potential factoring out resources that cannot be accessed due to non-economic reasons (i.e. land use restrictions, siting constraints and regulatory prohibitions), including those specific to each technology. Technical potential does not vary by scenario.

[3] Based on economic potential (technical potential that can be developed because it's not more expensive than competing options), estimates the timeline associated with the diffusion of the technology into the marketplace, considering the technology's relative economics, maturity, and development timeline.

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Figure 1 PacifiCorp Service Territory[4]



Key Findings

Using PacifiCorp-specific information on customer size and retail rates in each state and public data sources for technology costs and performance, Navigant conducted a Fisher-Pry[5] payback analysis to determine likely market penetration for private generation technologies from 2017 to 2036. This analysis was performed for typical commercial, irrigation, industrial and residential PacifiCorp customers in each state.

In the base case scenario, Navigant estimates approximately 1.4 GW AC[6] of private generation capacity will be installed in PacifiCorp's territory from 2017-2036.[7] As shown in Figure 2, the low and high scenarios project a cumulative installed capacity of 1.0 GW AC and 2.1 GW AC, respectively. The main drivers between the different scenarios include variation in technology costs, system performance, and electricity rate escalation assumptions. These assumptions are provided in Table 7.

Figure 3 indicates that Utah and Oregon will drive the majority of private generation installations over the next two decades, largely because these two states are PacifiCorp's largest markets in terms of customers and sales. Reference APPENDIX A for detailed state-specific customer data. In both of these

[4] http://www.pacificorp.com/content/dam/pacificorp/doc/About_Us/Company_Overview/Service_Area_Map.pdf.

[5] Fisher-Pry are researchers who studied the economics of "S-curves", which describe how quickly products penetrate the market. They codified their findings based on payback period, which measures how long it takes to recoup initial high first costs with energy savings over time.

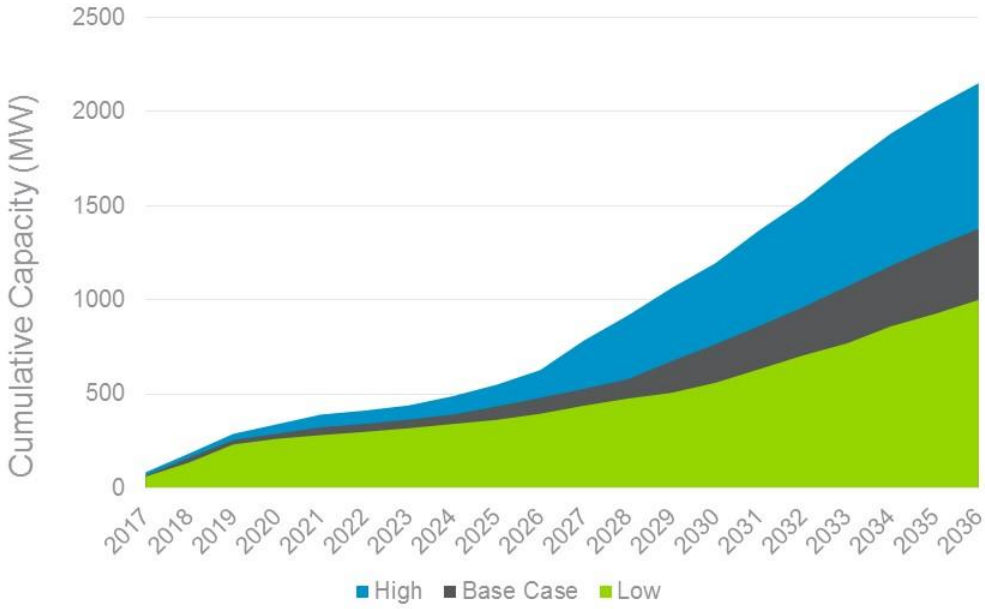
[6] Alternating current (AC) is an electric current in which the flow of electric charge periodically reverses direction, whereas in direct current (DC) the flow of electric charge is only in one direction. AC is the form in which electric power is transmitted on the grid.

[7] All capacity numbers across all five resources are projected in MW AC. Figures throughout the report are all in MW AC.

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states private generation installations are also driven by local tax credits and incentives. As displayed in Figure 4, solar represents the highest market penetration potential across the five technologies examined, with residential solar development leading the way, followed by non-residential solar (commercial, industrial, and irrigation). The Results section of the report contains results by state and technology for the high, base, and low scenarios.

Figure 2 Cumulative Market Penetration Results (MW AC), 2017 – 2036



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Figure 3 Cumulative Market Penetration Results by State (MW AC), 2017 – 2036, Base Case

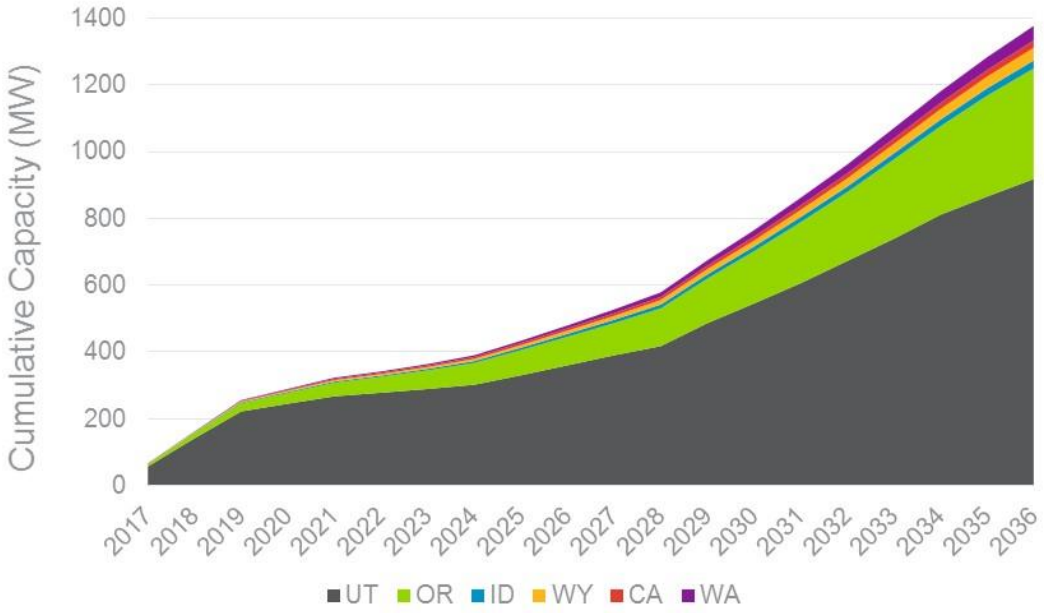
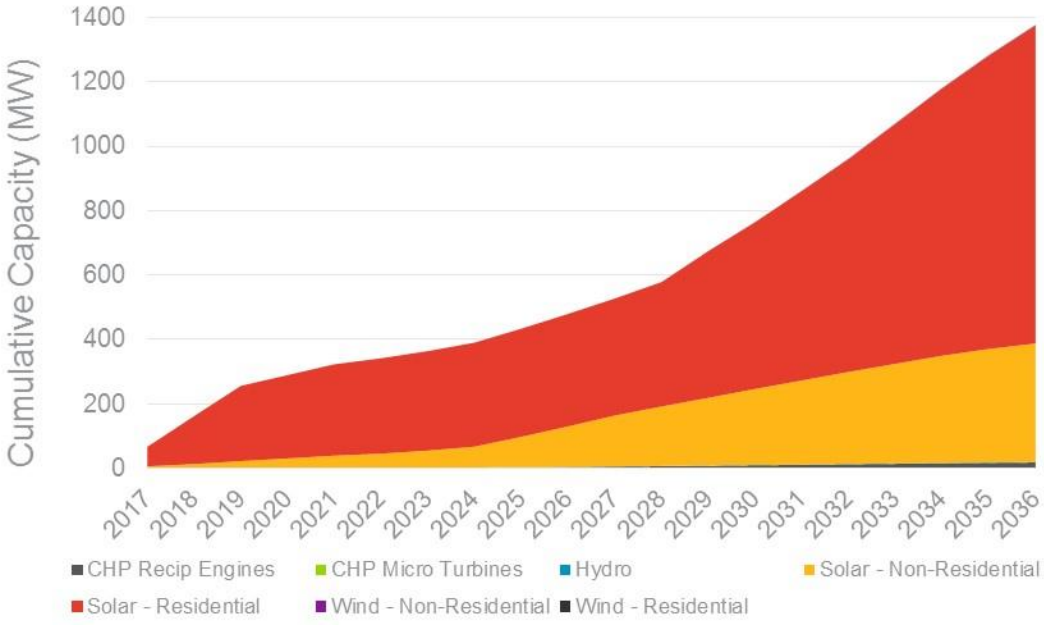


Figure 4 Cumulative Market Penetration Results by Technology (MW AC), 2017 – 2036, Base Case



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Report Organization

The report is organized as follows:

- Private Generation Market Penetration Methodology
- Results
- APPENDIX A: Customer Data
- APPENDIX B: System Capacity Assumptions
- APPENDIX C: Storage Evaluation
- APPENDIX D: Detailed Numeric Results
- APPENDIX E: Washington Levelized Costs
- APPENDIX F: Comparison of 2016 and 2014 Study

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PRIVATE GENERATION MARKET PENETRATION METHODOLOGY

This section provides a high-level overview of the study methodology.

1.1 Methodology

In assessing the technical and market potential of each private generation resource and opportunity in PacifiCorp's service area, the study considered a number of key factors, including:

- Technology maturity, costs, and future cost projections
- Industry practices, current and expected
- Net metering
- Federal and state tax incentives
- Utility or third-party incentives
- O&M costs
- Historical performance, and expected performance projections
- Hourly private generation
- Consumer behavior and market penetration

1.2 Market Penetration Approach

The following five-step process was used to estimate the market penetration of private generation resources in each scenario:

1. **Assess a Technology's Technical Potential:** Technical potential is the amount of a technology that can be physically installed without considering economics or other barriers to customer adoption. For example, technical potential assumes that photovoltaic systems are installed on all suitable residential roofs.
2. **Calculate Simple Payback Period for Each Year of Analysis:** From past work in projecting the penetration of new technologies, Navigant has found that Simple Payback Period is a key indicator of customer uptake. Navigant used all relevant federal, state, and utility incentives in its calculation of paybacks, incorporating their projected reduction and/or discontinuation over time, where appropriate.
3. **Project Ultimate Adoption Using Payback Acceptance Curves:** Payback Acceptance Curves estimate the percentage of a market that will ultimately adopt a technology, but do not factor in how long adoption will take.
4. **Project Market Penetration Using Market Penetration Curves:** Market penetration curves factor in market and technology characteristics, projecting the adoption timeline.
5. **Project Market Penetration under Different Scenarios.** In addition to the base case scenario, high and low case scenarios were created by varying cost, performance, and retail rate projections.

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These five steps are explained in detail in the following sections.

1.3 Assess Technical Potential

Each technology considered has its own characteristics and data sources that influence the technical potential assessment; the amount of a technology that can be physically installed within PacifiCorp's service territory without considering economics or other barriers to customer adoption. Navigant escalated technical potentials at the same rate PacifiCorp projects its sales will change over time.

1.4 Simple Payback

For each customer class (i.e., residential, commercial, irrigation and industrial), technology, and state, Navigant calculated the simple payback period using the following formula:

Simple Payback Period *= (Net Initial Costs) / (Net Annual Savings)*

Net Initial Costs *= Installed Cost – Federal Incentives – Capacity-Based Incentives*(1 – Tax Rate)*

Net Annual Savings *= Annual Energy Bills Savings + (Performance Based Incentives – O&M Costs – Fuel Costs)*(1 – Tax Rate)*

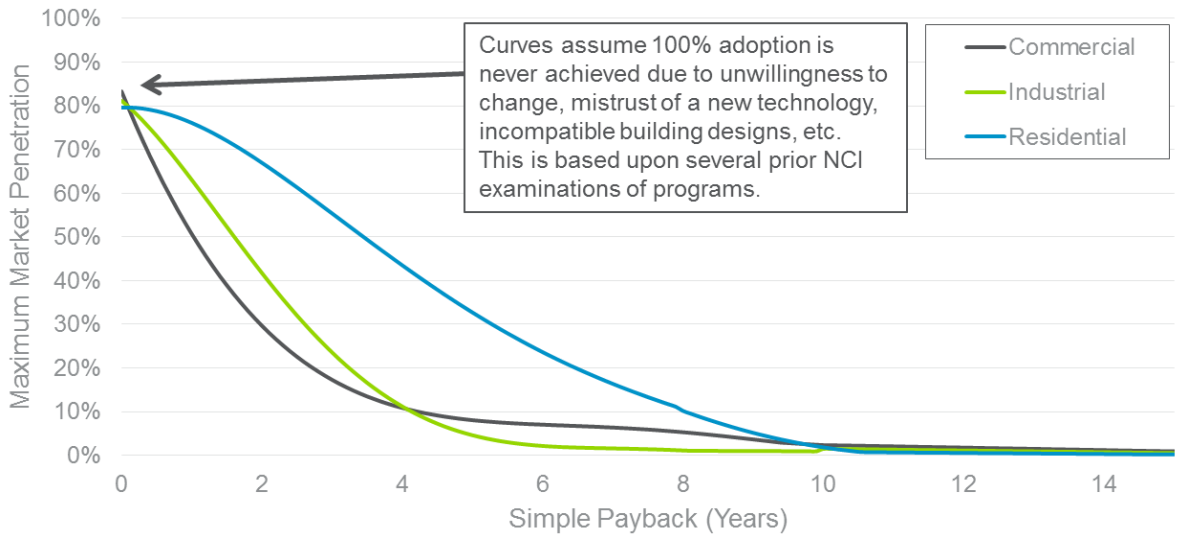
- *Federal tax credits can be taken against a system's full value if other (i.e. utility or state supplied) capacity-based or performance-based incentives are considered taxable.*
- *Navigant's Market Penetration model calculates first year simple payback assuming new installations for each year of analysis.*
- *For electric bills savings, Navigant conducted an 8,760 hourly analysis to take into account actual rate schedules, actual output profiles, and demand charges. System performance assumptions are listed in Section 1.3 above. Solar performance and wind performance profiles were calculated for representative locations within each state based on the National Renewable Energy Laboratory (NREL) Solar Advisory Model (SAM), which now also models wind. Building load profiles were provided by PacifiCorp, and were scaled to match the average electricity usage for each customer class based on billing data.*

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1.5 Payback Acceptance Curves

For private resources, Navigant used the following payback acceptance curves to model market penetration of private generation sources from the retail customer's perspective.

Figure 5 Payback Acceptance Curves



Source: Navigant Consulting based upon work for various utilities, federal government organizations, and state/local organizations. The curves were developed from customer surveys, mining of historical program data, and industry interviews.

These payback curves are based upon work for various utilities, federal government organizations, and state local organizations. They were developed from customer surveys, mining of historical program data, and industry interviews.[8] Given a calculated payback period, the curve predicts the level of maximum market penetration. For example, if the technical potential is 100 MW, the 3-year commercial payback predicts that 15% of this technical potential, or 15 MW, will ultimately be achieved over the long term.

1.6 Market Penetration Curves

To determine the future private generation market penetration within PacifiCorp's territory, the team modeled the growth of private generation technologies from 2017 thru 2036. The model is a Fisher-Pry based technology adoption model that calculates the market growth of private generation technologies. It uses a lowest-cost approach to consumers to develop expected market growth curves based on maximum achievable market penetration and market saturation time, as defined below.[9]

[8] Payback acceptance curves are based on a broad set of data from across the United States and may not predict customer behavior in a specific market (e.g. Utah customers may install solar at a faster rate than the rate indicated by the payback acceptance curves due to market specific reasons).

[9] Michelfelder and Morrin, "Overview of New Product Diffusion Sales Forecasting Models" provides a summary of product diffusion models, including Fisher-Pry. Available: law.unh.edu/assets/images/uploads/pages/ipmanagement-new-product-diffusion-sales-forecasting-models.pdf

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- **Market Penetration** – The percentage of a market that purchases or adopts a specific product or technology. The Fisher-Pry model estimates the achievable market penetration based on the simple payback period of the technology. Market penetration curves (sometimes called S-curves) are well established tools for estimating diffusion or penetration of technologies into the market. Navigant applies the market penetration curve to the payback acceptance curve shown in Figure 5 Payback Acceptance Curves.
- **Market Saturation Time** – The duration in years for a technology to increase market penetration from around 10% to 80%.

The Fisher-Pry model estimates market saturation time based on 12 different market input factors; those with the most substantial impact include:

- **Payback Period** – Years required for the cumulative cost savings to equal or surpass the incremental first cost of equipment.
- **Market Risk** – Risk associated with uncertainty and instability in the marketplace, which can be due to uncertainty regarding cost, industry viability, or even customer awareness, confidence, or brand reputation. An example of a high market risk environment is a jurisdiction lacking long-term, stable guarantees for incentives.
- **Technology Risk** – Measures how well-proven and the availability of the technology. For example, technologies that are completely new to the industry have a higher risk, whereas technologies that are only new to a specific market (or application) and have been proven elsewhere have lower risk.
- **Government Regulation** – Measure of government involvement in the market. A government-stated goal is an example of low government involvement, whereas a government mandated minimum efficiency requirement is an example of high involvement, having a significant impact on the market.

The model uses these factors to determine market growth instead of relying on individual assumptions about annual market growth for each technology or various supply and/or demand curves that may sometimes be used in market penetration modeling. With this approach, the model does not account for other more qualitative limiting market factors, such as the ability to train quality installers or manufacture equipment at a sufficient rate to meet the growth rates. Corporate sustainability, and other non-economic growth factors, are also not modeled.

The Fisher-Pry market growth curves have been developed and refined over time based on empirical adoption data for a wide range of technologies.[10] The model is an imitative model that uses equations developed from historical penetration rates of real products for over two decades. It has been validated in this industry via comparison to historical data for solar photovoltaics, a key focus of this study.

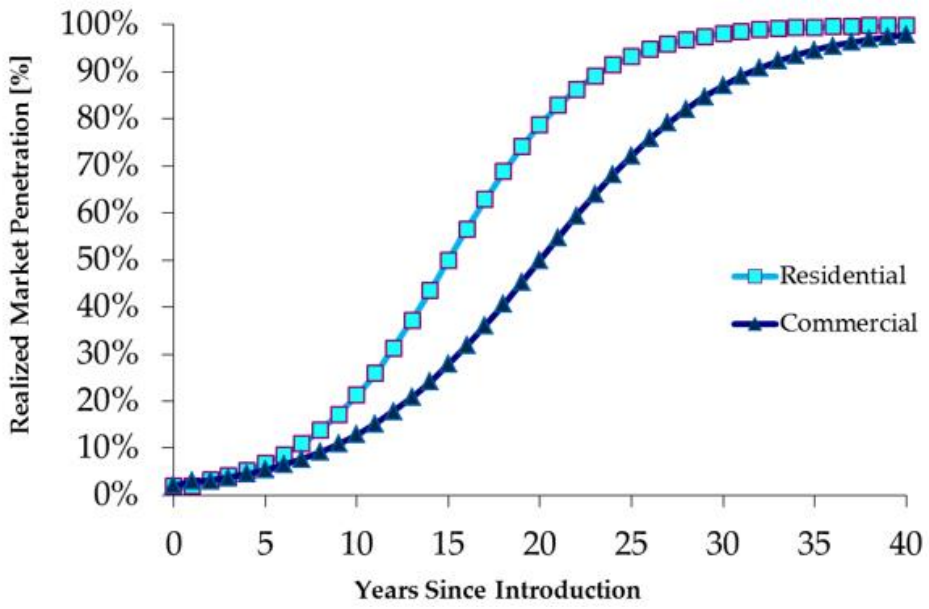
Navigant Consulting has used gathered market data on the adoption of technologies over the past 120 years and fit the data using Fisher-Pry curves. A key parameter when using market penetration curves is the assumed year of introduction. For the market penetration curves used in this study, Navigant assumed that the first year introduction occurred when the simple payback period was less than 25 years (per the pay-back acceptance curves used, this is the highest pay-back period that has any adoption).

[10] Fisher, J. C. and R. H. Pry, "A Simple Substitution Model of Technological Change", Technological Forecasting and Social Change, 3 (March 1971), 75-88.

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When the above payback period, market risk, technology risk, and government regulation factors above are analyzed, our general Fisher-Pry based method gives rise to the following market penetration curves used in this study:

Figure 6 Market Penetration Curves [11]



Source: Navigant Consulting, November 2008 as taken from Fisher, J.C. and R.H. Pry, A Simple Substitution Model of Technological Change, *Technological Forecasting and Social Change*, Vol 3, Pages 75 – 99, 1971.

The model is designed to analyze the adoption of a single technology entering a market, and assumes that the private generation market penetration analyzed for each technology is additive because the underlying resources limiting installations (sun, wind, water, high thermal loads) are generally mutually exclusive, and because current levels of market penetration are relatively low (plenty of customers exist for each technology).

1.7 Key Assumptions

The following section details the key technology-specific and base, low and high scenario assumptions.

1.7.1 Technology Assumptions

Assumptions including costs and performance were decided for each technology evaluated.

[11] Realized market penetration is applied to the maximum market penetration (Figure 6) for each technology, customer payback, and point in time. For example a residential customer with a five-year payback would have a maximum market penetration of around 35 percent, as indicated by the residential payback acceptance curve (Figure 5). A technology that was introduced 10 years ago will have realized about 20 percent of its maximum market penetration (Figure 6), having a market penetration of about seven percent of the technical potential.

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1.7.1.1 CHP: Reciprocating Engines

A reciprocating engine uses one or more reciprocating pistons to convert pressure into rotating motion. In a combined heat and power (CHP) application, a small CHP source will burn a fuel to produce both electricity and heat. In many applications, the heat is transferred to water, and this hot water is then used to heat a building.

Navigant sized the system to meet the minimum customer load, assuming the reciprocating engine system would function to meet the customer's base load. Based on system size, CHP reciprocating engines were assumed a reasonable technology for commercial and industrial customers. Assumptions on system capacity sizes in each state are detailed in APPENDIX B. Table 1 Reciprocating Engine Assumptions provides the cost and performance assumptions used in the analysis and the source for each.

Table 1 Reciprocating Engine Assumptions[12]

Private Generation Resource Costs	Units	2015 Baseline	Sources
Installed Cost – 100kW	$/kW	$2,900	EPA, Catalog of CHP Technologies, March 2015, pg. 2-15
Change in Annual Installed Cost	%	0.4%	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 92
Variable O&M	$/MWh	$20	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 92
Fuel Cost	$/MWh	PacifiCorp Gas Forecast	
Private Generation Performance Assumptions			
Electric Heat Rate (HHV)	Btu/kWh	12,637	EPA, Catalog of CHP Technologies, March 2015, pg. 2-10

1.7.1.2 CHP: Micro-turbines

Micro-turbine use natural gas to start a combustor, which drives a turbine. The turbine in turn drives an AC generator and compressor, and the waste heat is exhausted to the user. The device therefore produces electrical power from the generator, and waste heat to the user.

Navigant sized the system to meet the minimum customer load, assuming the reciprocating engine system would function to meet the customer's base load. Based on system size, CHP reciprocating engines were assumed a reasonable technology for commercial and industrial customers. Assumptions

[12] EPA, Catalog of CHP Technologies: www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf; ICF, Combined Heat and Power Policy Analysis, www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

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on system capacity sizes in each state are detailed in APPENDIX B. Table 2 Micro-turbines Assumptions provides the cost and performance assumptions used in the analysis and the source for each.

Table 2 Micro-turbines Assumptions[13]

Private Generation Resource Costs	Units	2015 Baseline	Sources
Installed Cost – 30kW	$/kW	$2,690	EPA, Catalog of CHP Technologies, March 2015, pg. 5-7
Change in Annual Installed Cost	%	-0.3%	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 97
Variable O&M	$/MWh	$23	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 97
Fuel Cost	$/MWh	PacifiCorp Gas Forecast	
Private Generation Performance Assumptions			
Electric Heat Rate (HHV)	Btu/kWh	15,535	EPA, Catalog of CHP Technologies, March 2015, pg. 5-6

1.7.1.3 Small Hydro

Small hydro is the development of hydroelectric power on a scale serving a small community or industrial plant. The detailed national small hydro studies conducted by the Department of Energy (DOE) from 2004 to 2013,[14] formed the basis of Navigant's small hydro technical potential estimate. In the Pacific Northwest Basin, which covers WA, OR, ID, and WY, a detailed stream-by-stream analysis was performed in 2013, and DOE provided these data to Navigant directly. For these states, Navigant combined detailed GIS PacifiCorp service territory data with detailed GIS data on each stream / water source. Using this method, Navigant was able to sum the technical potentials of only those streams located in PacifiCorp's service territory. For the other two states, Utah and California, Navigant relied on an older 2006 national analysis, and multiplied the given state figures by the area served by PacifiCorp within that state. Table 3 Small Hydro Assumptions provides the cost and performance assumptions used in the analysis and the source for each.

[13] EPA, Catalog of CHP Technologies: www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf; ICF, Combined Heat and Power Policy Analysis, www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

[14] Navigant used the same methodology and sources as in the 2014 study.

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Table 3 Small Hydro Assumptions[15]

Private Generation Resource Costs	Units	2017 Baseline	Sources
Installed Cost	$/kW	$4,000	Double average plant costs in "Quantifying the Value of Hydropower in the Electric Grid: Plant Cost Elements." Electric Power Research Institute, November 2011; this accounts for permitting/project costs
Change in Annual Installed Cost	%	0.00%	Mature technology, consistent with other mature technologies in the IRP.
Fixed O&M	$/kW-yr.	$52	Renewable Energy Technologies: Cost Analysis Series. "Hydropower." International Renewable Energy Agency, June 2012.
Private Generation Performance Assumptions			
Capacity Factor	%	50% ±5%	Average capacity factor variance will be reflected in the low and high penetration scenarios.

1.7.1.4 Solar Photovoltaics

Solar photovoltaic (solar) systems convert sunlight to electricity. Navigant applied a 20% discount factor to account for system sizing less than 100% of annual load and Direct Current (DC) to Alternating Current (AC) conversion. System size was then multiplied by the number of customers and the roof access factor. Assumptions on system capacity sizes in each state are detailed in APPENDIX B and access factors remained consistent with the 2014 study. Table 4 Solar Assumptions provides the cost and performance assumptions used in the analysis and the source for each.

[15] Note: No change from 2014 study.

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Table 4 Solar Assumptions

Private Generation Resource Costs	Units	2015 Baseline	Sources
Installed Cost – Res	$/kW DC	UT: $3,000 Other: $3,500	Navigant Forecast validated by NREL, U.S. Photovoltaic Prices and Cost Breakdowns: Q1 2015 Benchmarks for Residential, Commercial and Utility-Scale Systems
Installed Cost – Non-Res	$/kW DC	All Markets: $2,300	
Average Change in Annual Installed Cost (2015-2034)	%	-2.4% (Res) -2.2% (Non-Res)	
Fixed O&M – Res	$/kW-yr.	$25	National Renewable Energy Laboratory, U.S. Residential Photovoltaic (PV) System Prices, Q4 2013 Benchmarks: Cash Purchase, Fair Market Value, and Prepaid Lease Transaction Prices, Oct. 2014;National Renewable Energy Laboratory, Distributed Generation Renewable Energy Estimate of Costs, Accessed February 1, 2016
Fixed O&M – Non-Res	$/kW-yr.	$23	

As shown in Figure 7 and Figure 8, the rapid decline in solar costs over the past decade has driven private solar adoption across the country for all customer classes. In the past, these cost declines were primarily due to reduction in the cost of equipment (e.g. panels, inverters and balance of system components) driven by economies of scale and improvements in efficiency. Solar costs are expected to continue to decline over the next decade as system efficiencies continue to increase, although these declines are expected to occur at a slower rate than what occurred in recent years. In the long term, Navigant expects price reductions to decline as the industry matures and efficiency gains become harder to achieve.

Navigant's national solar cost forecast includes a low, base and high forecast. For this project, Navigant developed a PacifiCorp forecast which is the average between the national base and high forecast. Navigant decided to use for California, Idaho, Oregon, Washington and Wyoming, as all of those states currently have relatively small solar markets in PacifiCorp's territory, resulting in less competition and economies of scale to drive down local solar costs. For Utah, Navigant used the base cost forecast, as Utah has a larger and more mature private solar market.

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Figure 7. Non-Residential Solar System Costs, 2015-2036

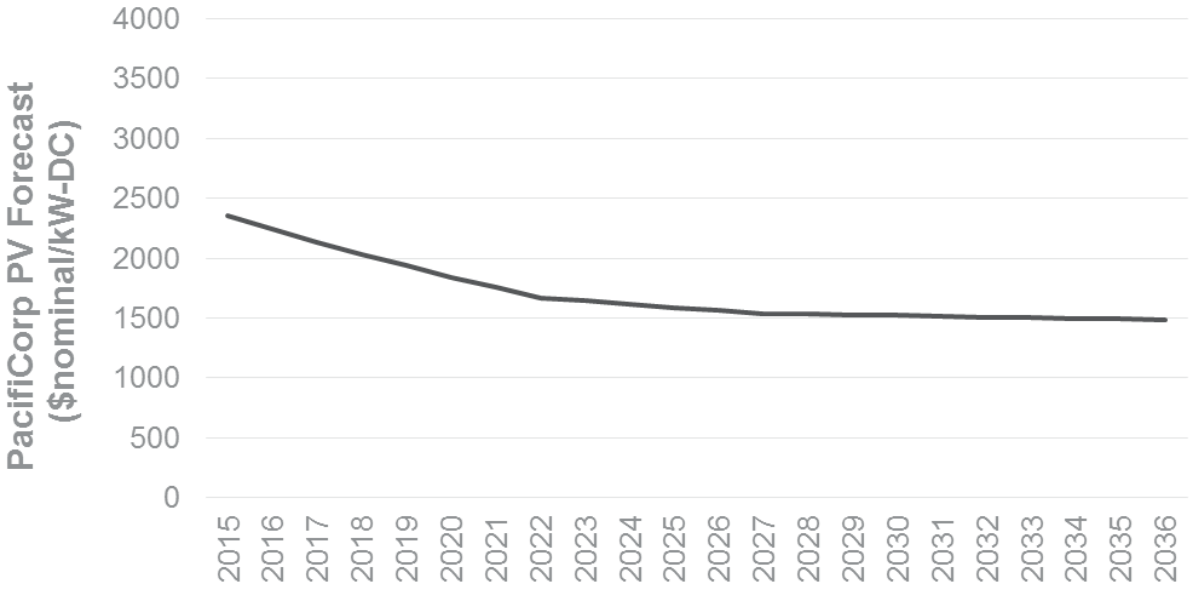
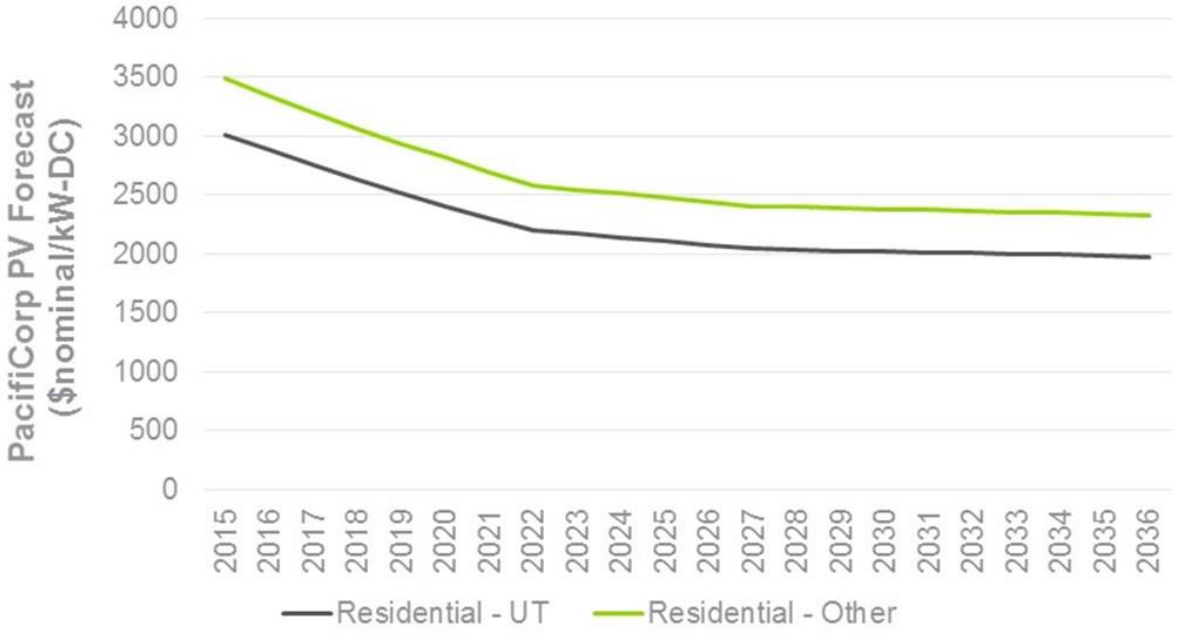


Figure 8 Residential Solar System Costs, 2015-2036



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The solar capacity factors (Table 5) were calculated using NREL's System Advisory Model for each state territory.

Table 5 Solar Capacity Factors[16]

Performance Assumptions			
		(kW-DC/kWh AC)	(kW-AC/kWh AC)
Capacity Factor	UT	16.3%	20.4%
	WY	16.8%	21.0%
	WA	14.0%	17.5%
	CA	16.6%	20.8%
	ID	16.0%	20.0%
	OR	12.4%	15.5%

1.7.1.5 Small Wind

Wind power is the use of air flow through wind turbines to mechanically power generators for electricity. Navigant sized the wind systems at 80% of customer load to reduce the chance that the wind system will produce more than the customer's electric load in a given year. System size was then multiplied by the number of customers and the access factor. The 2014 study access factors were used for this study.

The following cost and performance assumptions were used in the analysis.

[16] NREL, System Advisory Model (SAM) for specific state locations, consistent with 2014 study. Navigant used the default system configuration in SAM, which has a DC to AC derate factor of about 80%.

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Table 6 Wind Assumptions

Private Generation Resource Costs	Units	2014 Baseline	Sources
Installed Cost – Res (2.5-10kW)	$/kW	$7,200	Department of Energy, 2014 Distributed Wind Market Report, August 2015
Installed Cost – Com (11-100kW)	$/kW	$6,000	
Change in Annual Installed Cost	%	0.0%	Mature technology, consistent with other mature technologies in the IRP.
Fixed O&M	$/kW-yr.	$40	Department of Energy, 2014 Distributed Wind Market Report, August 2015
Change in Annual O&M Cost	%	-1.0%	
Private Generation Performance Assumptions			
Capacity Factor	%	20% (2013) - 25% (2034)	Small scale wind hub heights are lower, with shorter turbine blades, relative to 30% capacity factor large scale turbines.

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1.7.2 Scenario Assumptions

Navigant used the market penetration model to analyze three scenarios, capturing the impact of major changes that could affect market penetration. For the low and high penetration cases, Navigant varied technology costs, system performance, and electricity rate assumptions.

Table 7 Scenario Variable Modifications

Cases	Technology Costs	Performance	Electricity Rates
Base Case	See technology and cost section	As modeled	Increase at inflation rate, assumed at 1.9%
Low Penetration	PV: Same as Base Case Other: Mature technologies. Same as base case	PV: Same as Base Case Other: 5% worse	Increases at 1.4%, 0.5%/year lower than the Base Case
High Penetration	PV: 2X steeper cost reduction/year Other: Mature technologies. Same as base case	Reciprocating Engines: 0.5% better (mature) Micro-turbines: 2% better Hydro: 5% better (reflecting wide performance distribution uncertainty) PV/Wind: 1% better (relatively mature)	Increases at 2.4%, 0.5%/year higher than the Base Case

Technology cost reduction is the variable having the largest impact on market penetration over the next 20 years. Average technology performance assumptions are relatively constant across states and sites. Changes in electricity rates are modeled conservatively, reflecting the long-term stability of electricity rates in the United States. Navigant expects short-term volatility for all variables but when averaged over the 20-year IRP period, long-term trends show less variation.

1.7.3 Incentives

Federal and state incentives are a very important private generation market penetration driver, as they can reduce a customer's payback period significantly.

1.7.3.1 Federal

The Federal Business Energy Investment Tax Credit (ITC) allows the owner of the system to claim a tax credit for a certain percentage of the installed private generation system price.[17] The ITC, originally set to expire in 2016 for commercial solar systems and reduce to 10% for residential solar systems, was extended for solar PV systems in December 2015 through the end of 2021, with step downs occurring in

[17] Business Energy Investment Tax Credit, http://energy.gov/savings/business-energy-investment-tax-credit-itc.

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2020 through 2022. The 2014 Navigant Distributed Generation Resource Assessment for Long-Term Planning Study assumed that the ITC would expire for commercial solar PV systems at the end of 2016 and step down to 10% for residential PV systems, per the legislation in place at the time of the analysis. The table below details how the ITC applies to the technologies evaluated in this study, however, this schedule may change in the future.

Table 8 Federal Tax Incentives

Technology	2016	2017	2018	2019	2020	2021	>2021
Recip. Engines	**10%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Micro Turbines	**10%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Small Hydro	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
PV - Com	**30%**	**30%**	**30%**	**30%**	**26%**	**22%**	**10%**
PV - Res	**30%**	**30%**	**30%**	**30%**	**26%**	**22%**	**0%**
Wind - Com	**30%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Wind - Res	**30%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**

1.7.3.2 State

State incentives drive the local market and are an important aspect promoting private generation market penetration. Currently, all states evaluated have full retail rate net energy metering (NEM) in place for all customer classes considered in this analysis. The study assumes that NEM policy remains constant, although future uncertainty exists surrounding NEM policy. Longer-term uncertainty also exists regarding other state incentives. Idaho also has a local state residential personal tax deduction for solar and wind projects. Currently, state incentives do not exist in California[18] or Wyoming. The following tables detail the assumptions made regarding local state incentives.

[18] In 2007, California launched the California Solar Initiative, however, incentives no longer remain in most utility territories, http://csi-trigger.com/.

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Table 9 Oregon Incentives

Technology	2016	2017	2018	2019	2020	2021	>2021
Recip. Engines	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Micro Turbines	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Small Hydro	**0**	**0**	**0**	**0**	**0**	**0**	**0**
PV – Com ($/W)*	**0.81**	**0.78**	**0.75**	**0.72**	**0.69**	**0.66**	**0.63**
PV – Res ($/W)* & ($/system)**	**0.62 (6,000)**	**0.60 (6,000)**	**0.57 (6,000)**	**0.55 (6,000)**	**0.52 (6,000)**	**0.50 (6,000)**	**0.48 (6,000)**
Wind – Com ($/kWh)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Wind – Res ($)*	**6,000**	**6,000**	**6,000**	**6,000**	**6,000**	**6,000**	**6,000**

* Energy Trust of Oregon Solar Incentive (capped at $2M/year for residential and $1.6M/year for non-residential). Energy Trust of Oregon incentives after 2016 are estimated based on assumed system cost trends.
** Residential Energy Tax Credit - $6,000 over the life of the system, distributed $1,500/yr. http://programs.dsireusa.org/system/program/detail/638
***The Residential Energy Tax Credit (RETC), in its current legislative form, is set to expire at the end of 2017. It is not yet known whether the Oregon Legislature will extend the RETC beyond 2017. Similarly, should the RETC be extended beyond 2017, it is not known if it would have the same value or eligibility criteria. However, for purposes of this analysis, it was assumed that the RETC will be extended beyond 2017 with the same value and eligibility criteria as exists as of the date of this report.

Table 10 Utah Incentives

Technology	2016	2017	2018	2019	2020	2021	>2021
Recip. Engines (%)	**10**	**10**	**10**	**10**	**10**	**10**	**10**
Micro Turbines (%)	**10**	**10**	**10**	**10**	**10**	**10**	**10**
Small Hydro (%)	**10**	**10**	**10**	**10**	**10**	**10**	**10**
PV – Com (%)	**10**	**10**	**10**	**10**	**10**	**10**	**10**
PV – Res ($)*	**$2,000**	**$2,000**	**$2,000**	**$2,000**	**$2,000**	**$2,000**	**$2,000**
Wind – Com (%)	**10**	**10**	**10**	**10**	**10**	**10**	**10**
Wind – Res ($)*	**$2,000**	**$2,000**	**$2,000**	**$2,000**	**$2,000**	**$2,000**	**$2,000**

*Renewable Energy Systems Tax Credit, Program Cap: Residential cap = $2,000; commercial systems <660kW, no limit
**The Utah Renewable Energy Systems Tax Credit is assumed for the purpose of this report to continue at its current incentive level. The timing and value of any possible changes to the state tax credit remain unclear.

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Table 11 Washington Incentives

Technology	2016	2017	2018	2019	2020	2021	>2021
Recip. Engines	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Micro Turbines	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Small Hydro	**0**	**0**	**0**	**0**	**0**	**0**	**0**
PV - Com ($/kWh)*	**0.15**	**0.15**	**0.15**	**0.15**	**0.08**	**0**	**0**
PV - Res ($/kWh)*	**0.15**	**0.15**	**0.15**	**0.15**	**0.08**	**0**	**0**
Wind - Com ($/kWh)*	**0.12**	**0.12**	**0.12**	**0.12**	**0.06**	**0**	**0**
Wind - Res ($/kWh)*	**0.12**	**0.12**	**0.12**	**0.12**	**0.06**	**0**	**0**

* Feed-in Tariff: $/kWh for all kWh generated through mid-2020; annually capped at $5,000/year, http://programs.dsireusa.org/system/program/detail/5698

Table 12 Idaho Incentives

Technology	2016	2017	2018	2019	2020	2021	>2021
Recip. Engines	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Micro Turbines	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Small Hydro	**0**	**0**	**0**	**0**	**0**	**0**	**0**
PV - Com	**0**	**0**	**0**	**0**	**0**	**0**	**0**
PV – Res (%)*	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**
Wind – Com	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Wind – Res (%)*	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**

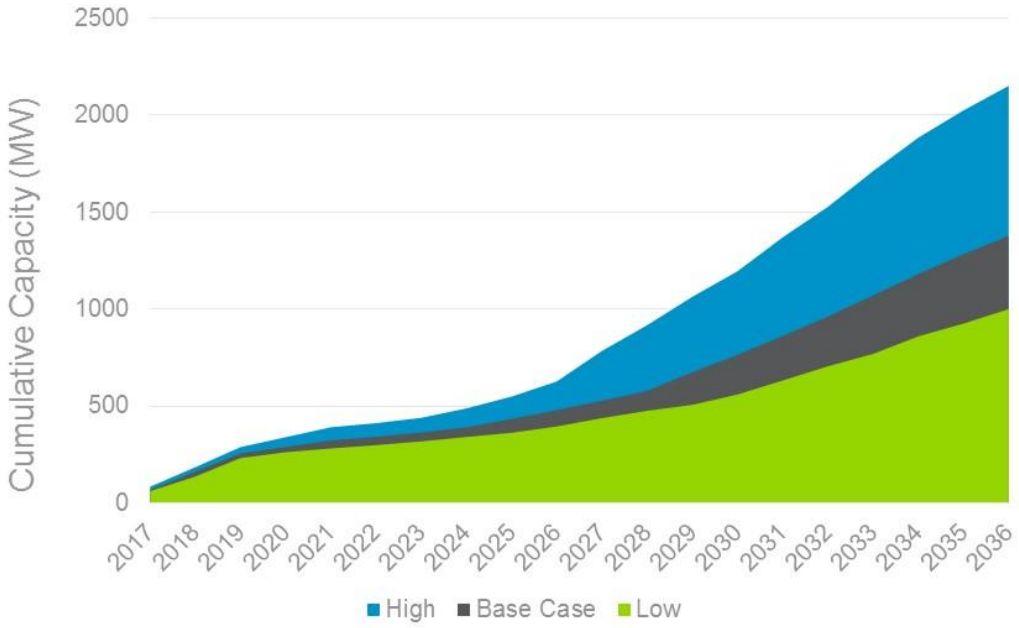
* Residential Alternative Energy Income Tax Deduction: 40% in the first year and 20% for the next three years, http://programs.dsireusa.org/system/program/detail/137.

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RESULTS

Navigant estimates approximately 1.4 GW of private generation capacity will be installed in PacifiCorp's territory from 2017-2036 in the base case scenario. [19] As shown in Figure 9, the low and high scenarios project a cumulative installed capacity of 1.00 GW and 2.10 GW by 2036, respectively. The main drivers between the different scenarios include variation in technology costs, system performance, and electricity rate assumptions.

Figure 9. Cumulative Market Penetration Results (MW AC), 2017 – 2036



1.8 PacifiCorp Territories

The following sections report the results by state, providing high, base and low scenario installation projections. Results for each scenario are also broken out by technology. The solar sector exhibits the highest adoption across all states. Generally non-residential solar adoption is less sensitive to high and low scenario adjustments when compared the residential sector. This is because the residential customer payback is more sensitive to scenario changes (e.g. technology costs, performance, electricity rates) when compared to non-residential sectors.

[19] Solar capacity is projected in DC, while the capacity for all other resources is projected in AC. Figures throughout the report that include all resources forecasted, reflect a combination of AC and DC.

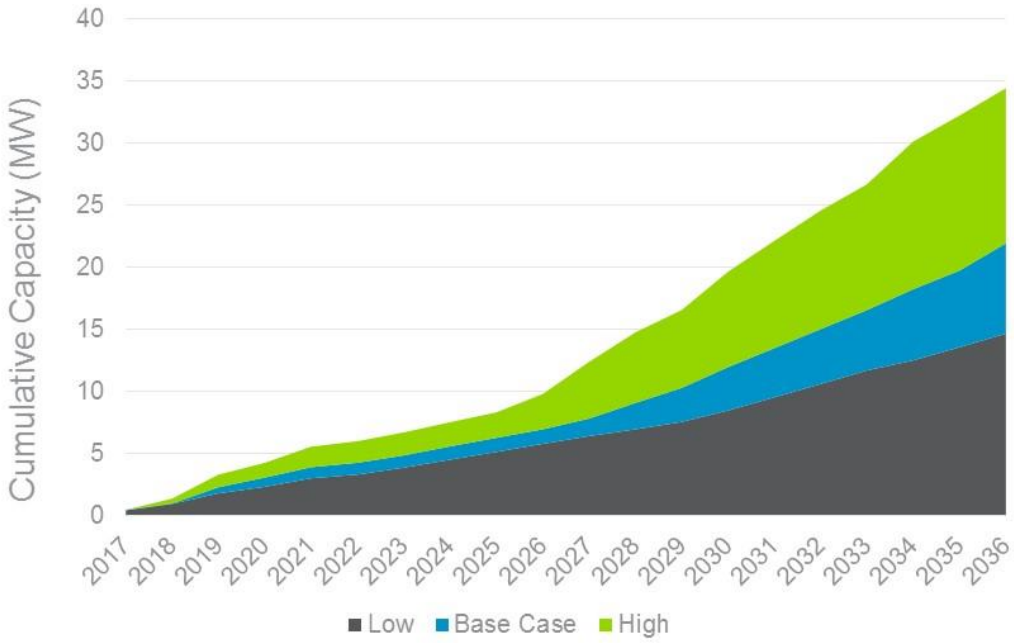
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1.8.1 California

PacifiCorp's customers in northern California are projected to install about 22 MW of capacity over the next two decades in the base case, averaging about 1.1 MW annually. California does not currently have any state incentives promoting the installation of private generation and the ratcheting down of the Federal ITC from 2020 to 2022 has a negative impact on annual capacity installations after 2020. The main driver of private generation in California is its high electricity rates relative to other states. Over time, the increase in private generation installation capacity is driven by escalating electricity rates and declining technology costs. Both residential and non-residential solar installations are responsible for the majority of private generation growth over the horizon of this study.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 10. The 22 MW from the base case decreases by 32% to 15 MW in the low case and increases by 55% to 34 MW in the high case.

Figure 10. Cumulative Capacity Installations by Scenario (MW AC), California



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Figure 11. Cumulative Capacity Installations by Technology (MW AC), California Base Case

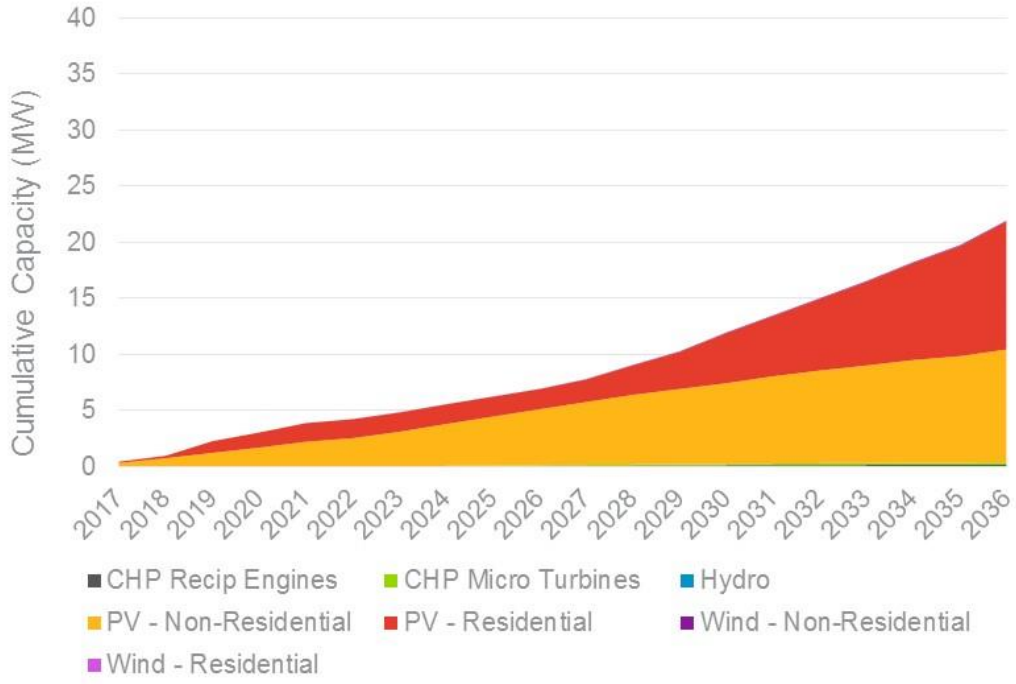
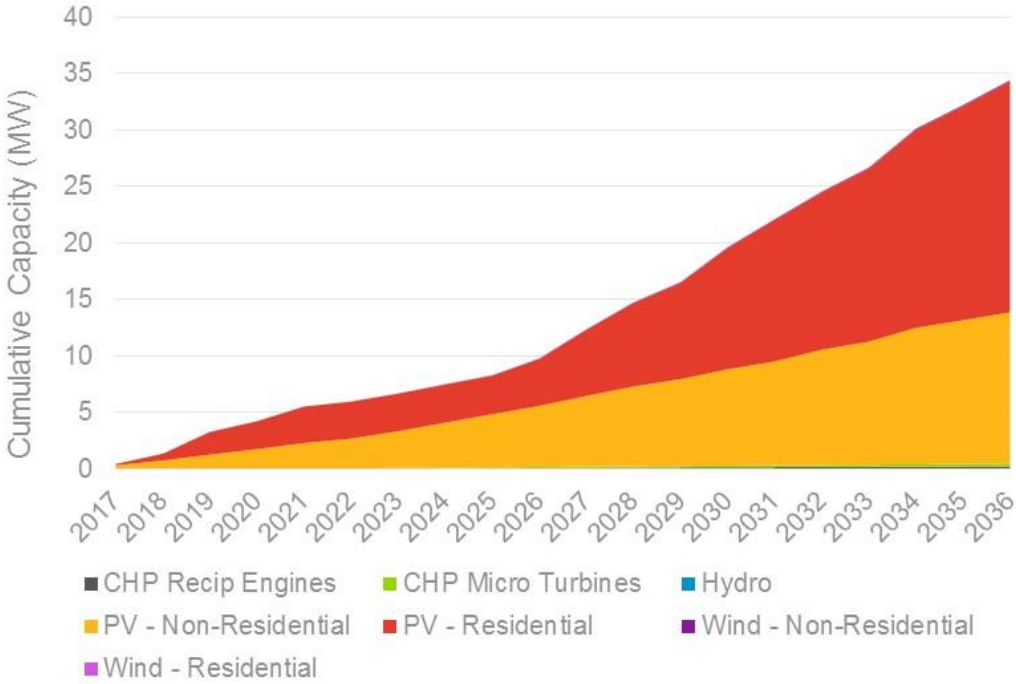
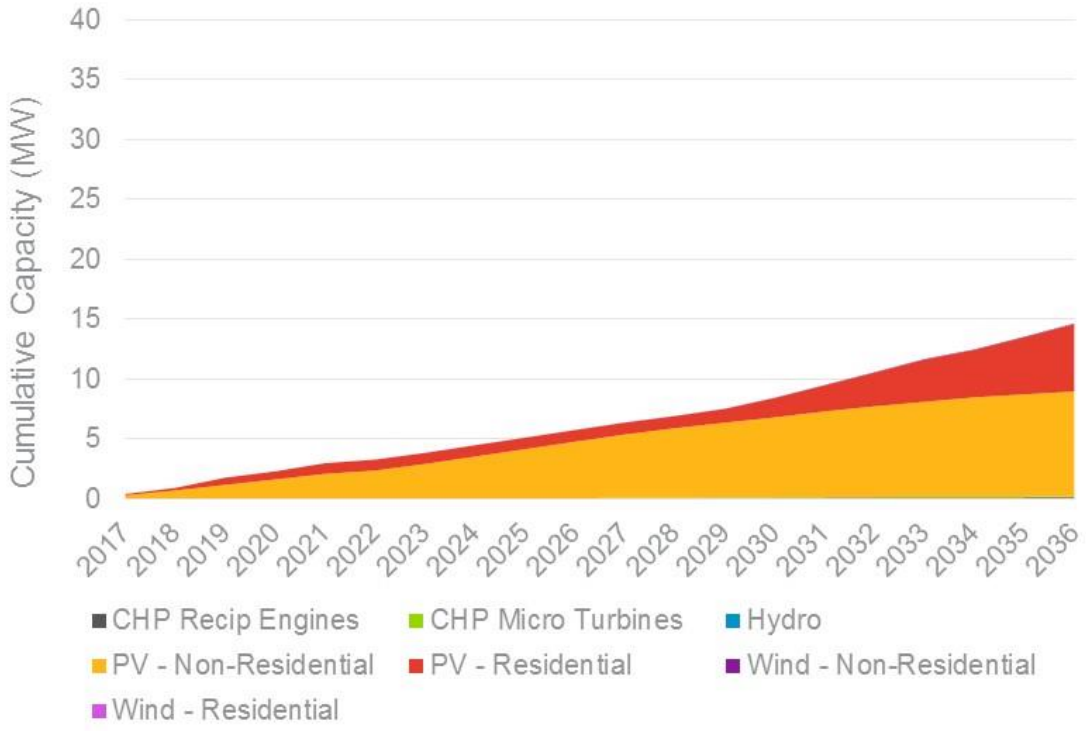


Figure 12. Cumulative Capacity Installations by Technology (MW AC), California High Case



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Figure 13. Cumulative Capacity Installations by Technology (MW AC), California Low Case



1.8.2 Idaho

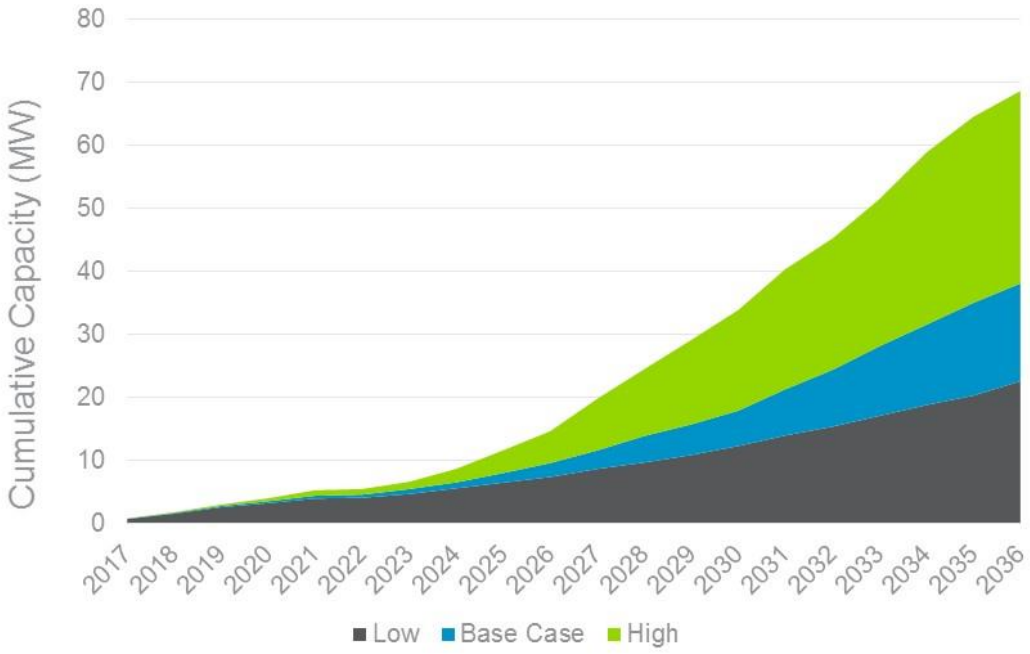
PacifiCorp's Idaho customers are projected to install about 39 MW of capacity over the next two decades in the base case, averaging about 1.9 MW annually. Idaho currently has a Residential Alternative Energy Income Tax Deduction for residential solar and wind installations[20], although this incentive seems to have minimal impact on the market, as non-residential solar installations are responsible for the majority of private generation growth in the early years due to a combination of technical potential and escalating electric rates. The ratcheting down of the Federal ITC from 2020 to 2022 has a negative impact on annual capacity installations in the short term and overtime the increase in private generation installation capacity is driven by escalating electricity rates and declining technology costs.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 14. The 38 MW from the base case decreases by 39% to 23 MW in the low case and increases by 82% to 69 MW in the high case.

[20] Residential Alternative Energy Income Tax Deduction: 40% in the first year and 20% for the next three years, http://programs.dsireusa.org/system/program/detail/137.

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Figure 14. Cumulative Capacity Installations by Scenario (MW AC), Idaho



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Figure 15. Cumulative Capacity Installations by Technology (MW AC), Idaho Base Case

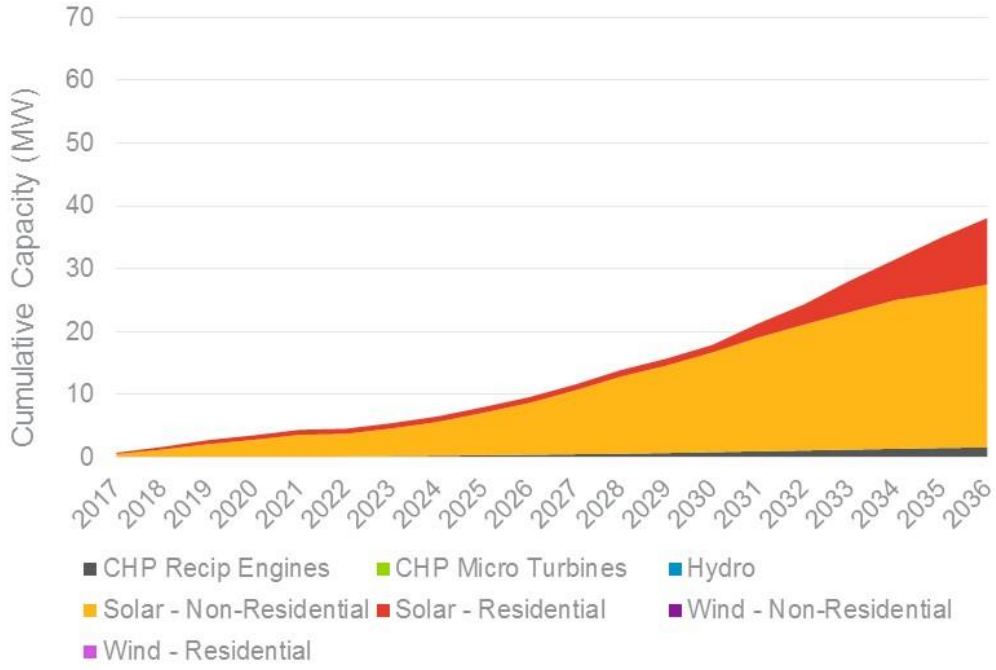
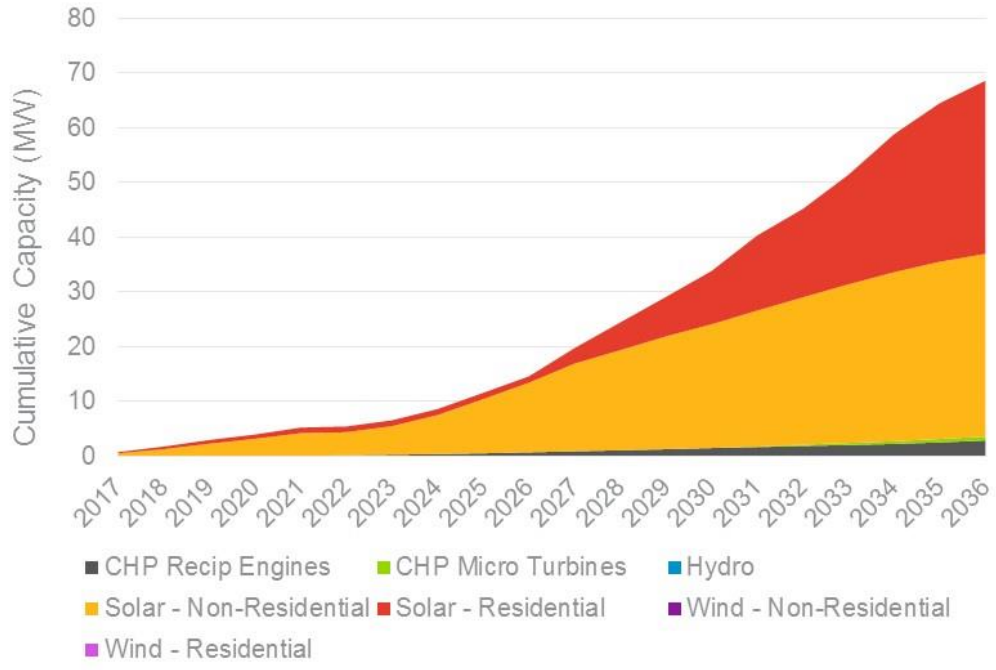
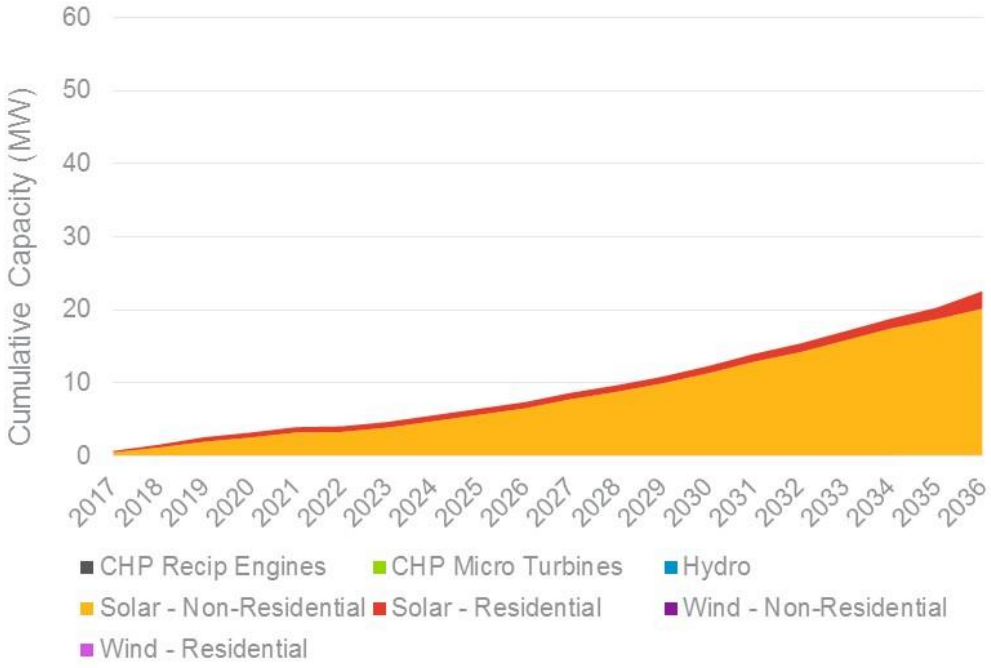


Figure 16. Cumulative Capacity Installations by Technology (MW AC), Idaho High Case



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Figure 17. Cumulative Capacity Installations by Technology (MW AC), Idaho Low Case



1.8.3 Oregon

PacifiCorp's Oregon customers are projected to install about 331 MW of private generation capacity over the next two decades in the base case, averaging about 16.6 MW annually. Solar is responsible for all of the private generation growth over the horizon of this study. Although the solar resource in Oregon is not as strong as the majority of other states in PacifiCorp's territory, the Energy Trust of Oregon's Solar Incentive and the state Residential Energy Tax Credit, assumed to extend through 2036, drive solar market adoption. The ratcheting down of the Federal ITC from 2020 to 2022 results in a relatively flat market in the short term but overtime the increase in solar capacity installation is driven by escalating electricity rates and declining technology costs.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 18. The 331 MW from the base case decreases by 30% to 232 MW in the low case and increases by 72% to 568 MW in the high case.

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Figure 18. Cumulative Capacity Installations by Scenario (MW AC), Oregon

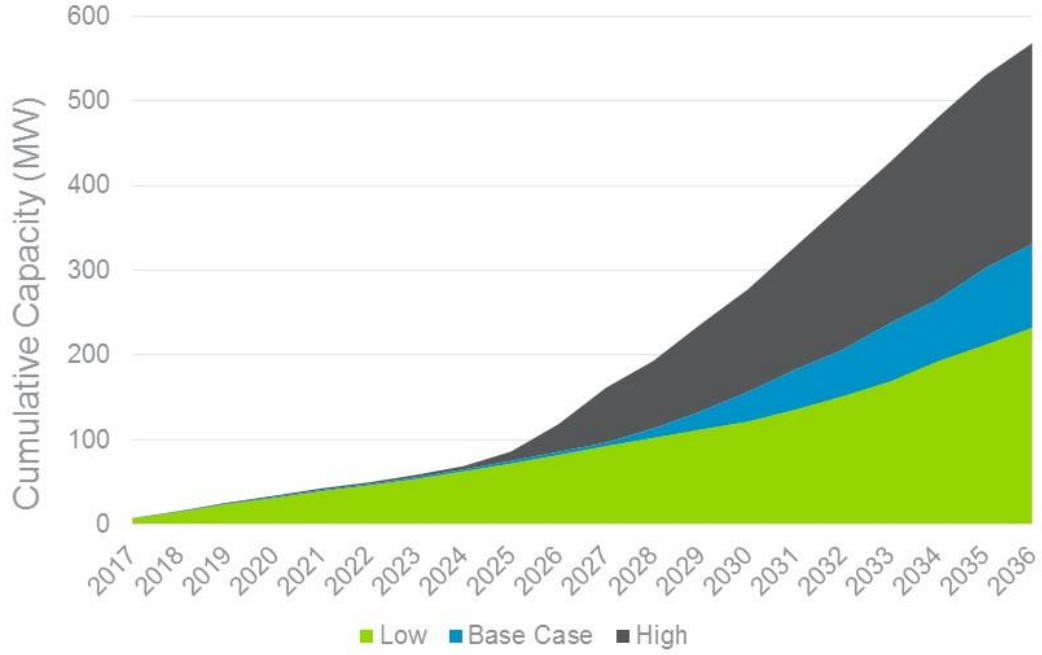
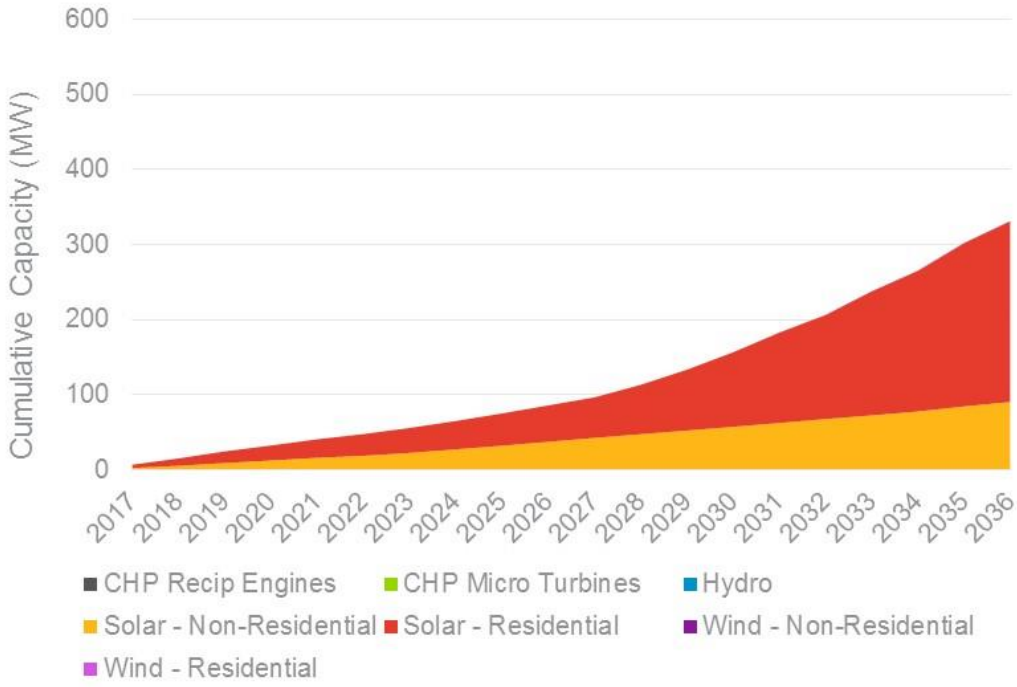


Figure 19. Cumulative Capacity Installations by Technology (MW AC), Oregon Base Case



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Figure 20. Cumulative Capacity Installations by Technology (MW AC), Oregon High Case

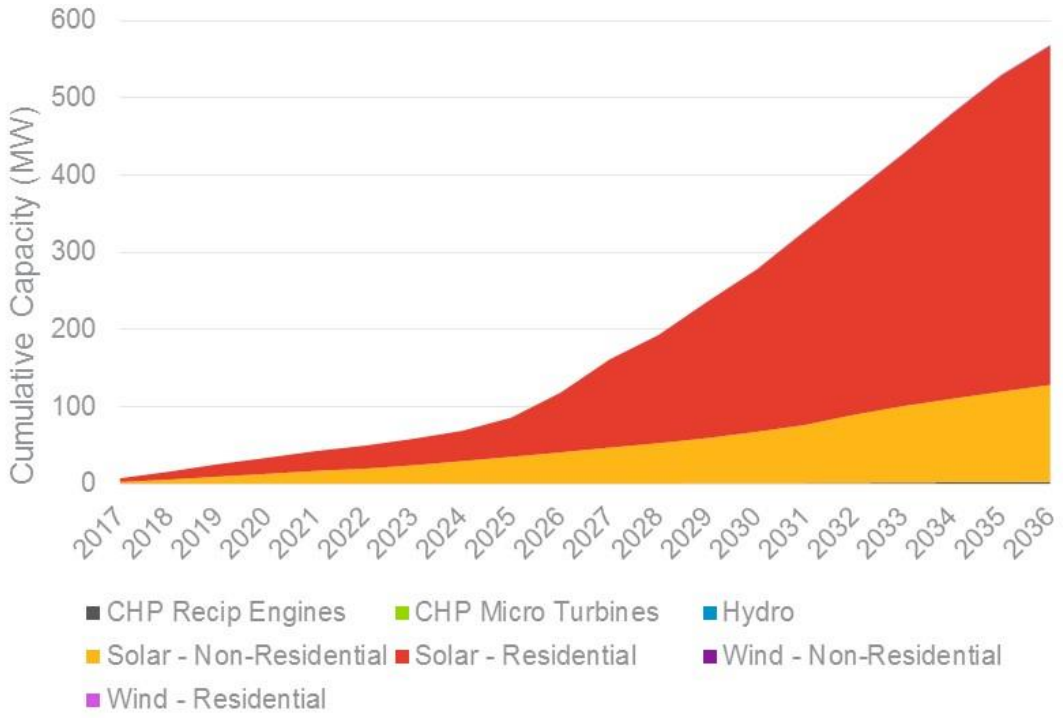
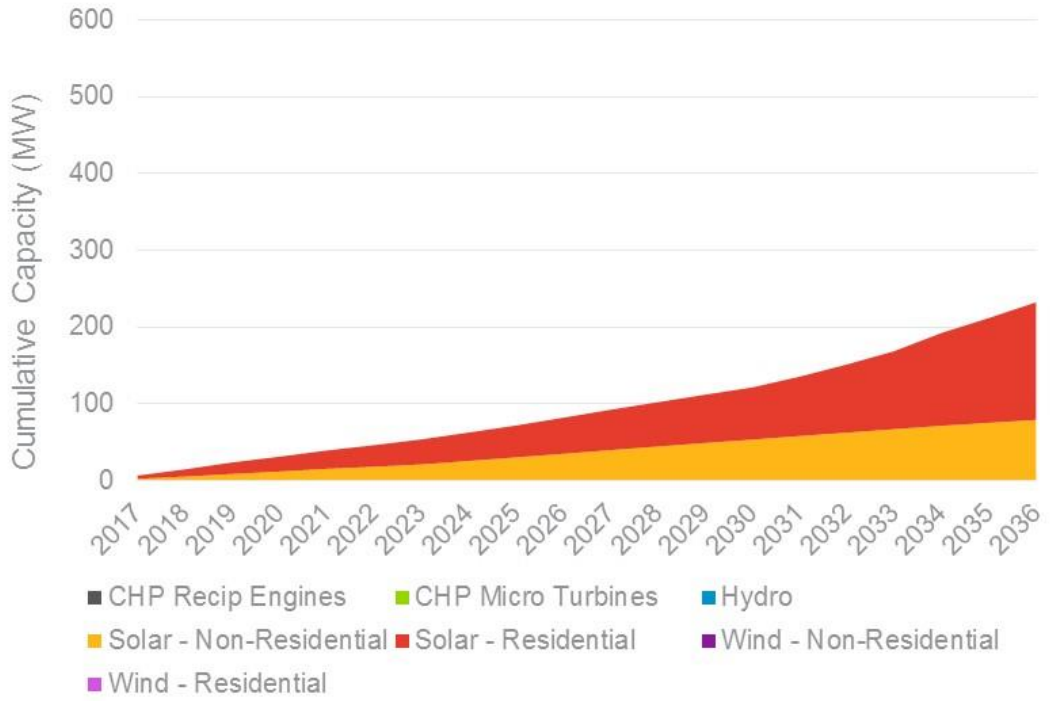


Figure 21 Cumulative Capacity Installations by Technology (MW AC), Oregon Low Case



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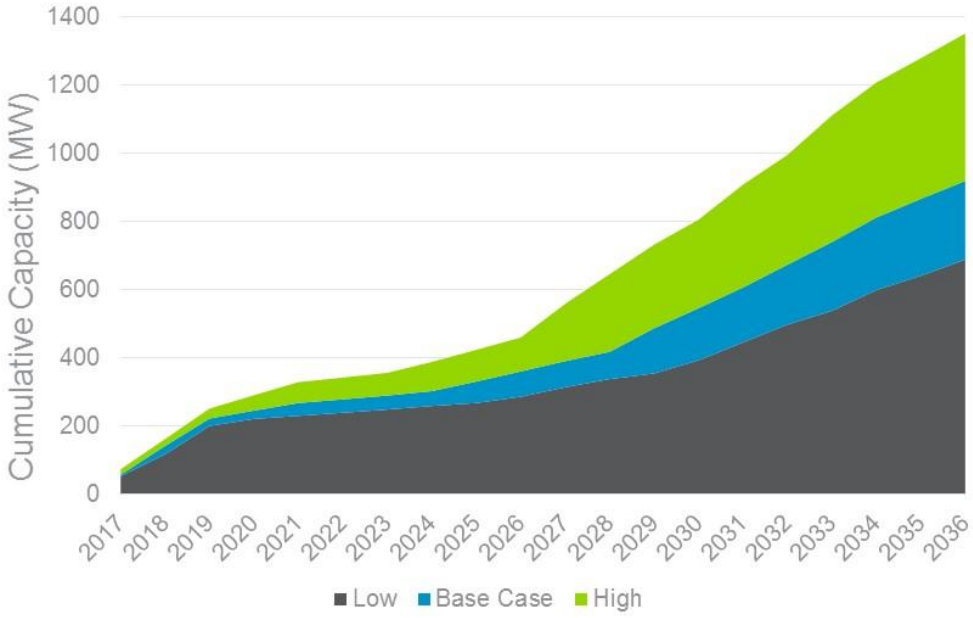
1.8.4 Utah

PacifiCorp's Utah customers are projected to install about 919 MW of private generation capacity over the next two decades in the base case, averaging around 45 MW annually. Solar is responsible for the majority of private generation installations over the horizon of this study, with CHP reciprocating engines being installed in small numbers in future years. Utah has the strongest solar resource in PacifiCorp's territory and system costs are lower than in other states due to Utah's larger and more mature market.

The projection in the early years is dominated by residential customers adopting solar. The state Renewable Energy Systems Tax Credit applies to all technologies evaluated and has an impact on solar adoption. Solar adoption declines dramatically in 2020 as the ITC ratchets down. In 2025 projected capacity installation increases as solar prices continue to decline and utility rates escalate.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 22. The 919 MW from the base case decreases by 25% to 688 MW in the low case and increases by 47% to 1351 MW in the high case.

Figure 22. Cumulative Capacity Installations by Scenario (MW AC), Utah



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Figure 23. Cumulative Capacity Installations by Technology (MW AC), Utah Base Case

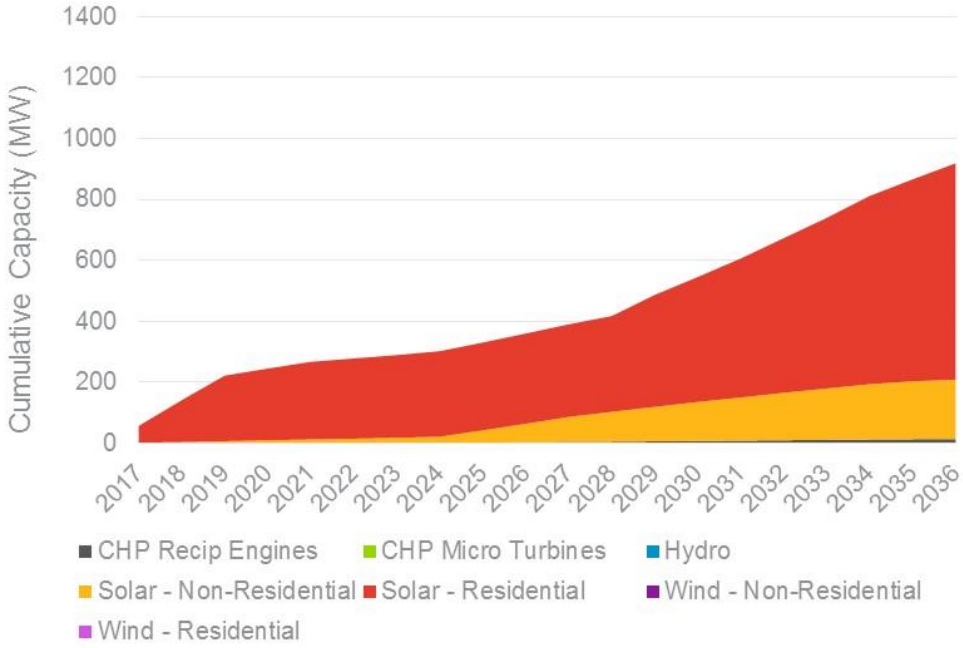
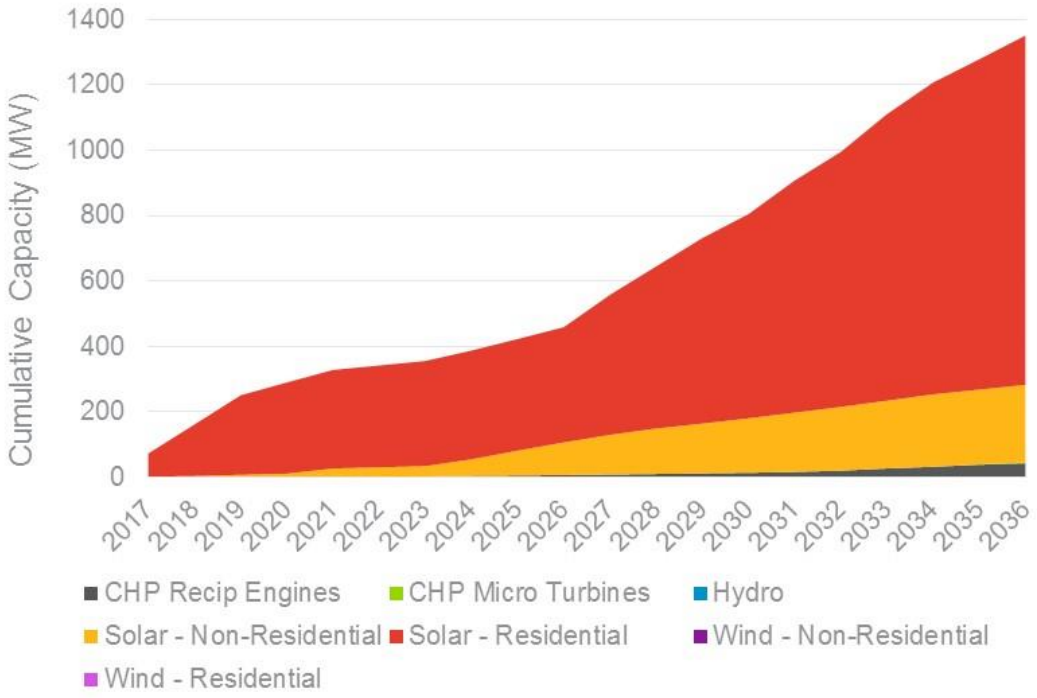
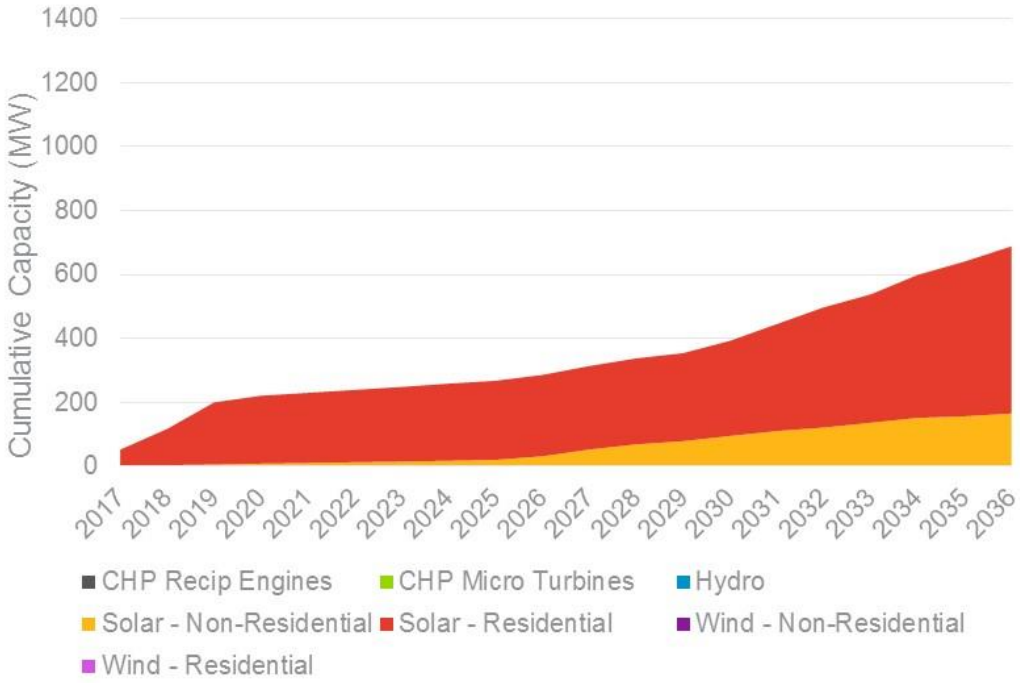


Figure 24. Cumulative Capacity Installations by Technology (MW AC), Utah High Case



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Figure 25. Cumulative Capacity Installations by Technology (MW AC), Utah Low Case



1.8.5 Washington

PacifiCorp's Washington customers are expected to install about 23.9 MW of private generation capacity over the next two decades in the base case, averaging 1.2 MW annually. Solar is responsible for the majority of private generation installations over the horizon of this study, with CHP reciprocating engines being installed in small numbers in future years. Washington does not have a very strong solar resource, yet the lucrative Feed-In-Tariff in Washington, which extends through 2020, props up the solar market in the near term. The solar market is driven by non-residential solar installations, most likely due to the lower cost of installing larger systems. Solar adoption declines dramatically in 2020 as the ITC ratchets down. In 2025, installation capacity increases as solar prices continue to decline and utility rates escalate.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 26. The 24 MW from the base case decreases by 29% to 17 MW in the low case and increases by 96% to 47 MW in the high case.

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Figure 26. Cumulative Capacity Installations by Scenario (MW AC), Washington

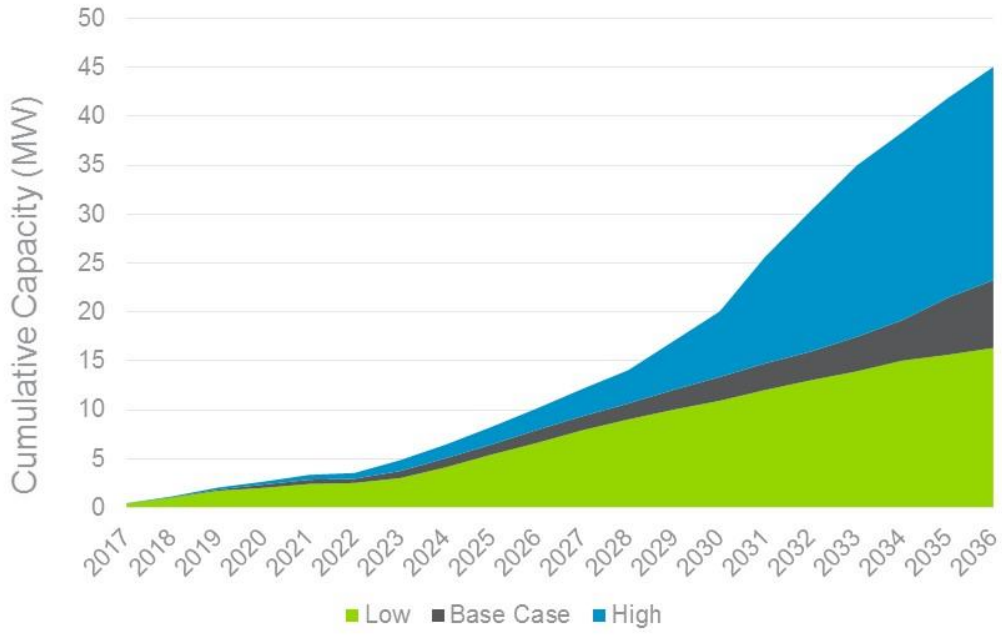
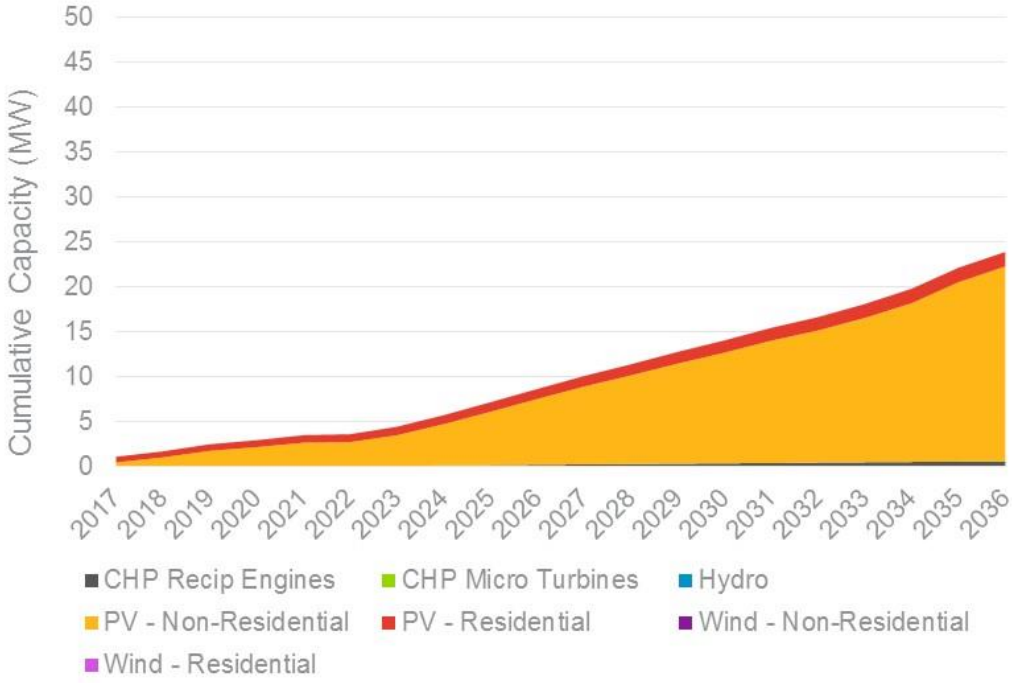


Figure 27. Cumulative Capacity Installations by Technology (MW AC), Washington Base Case



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Figure 28. Cumulative Capacity Installations by Technology (MW AC), Washington High Case

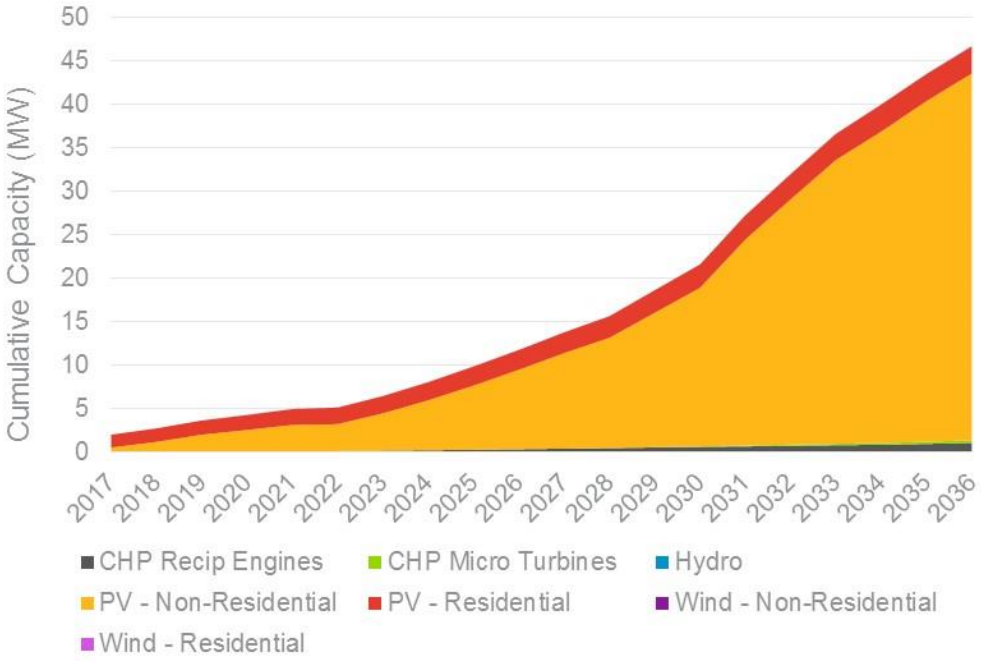
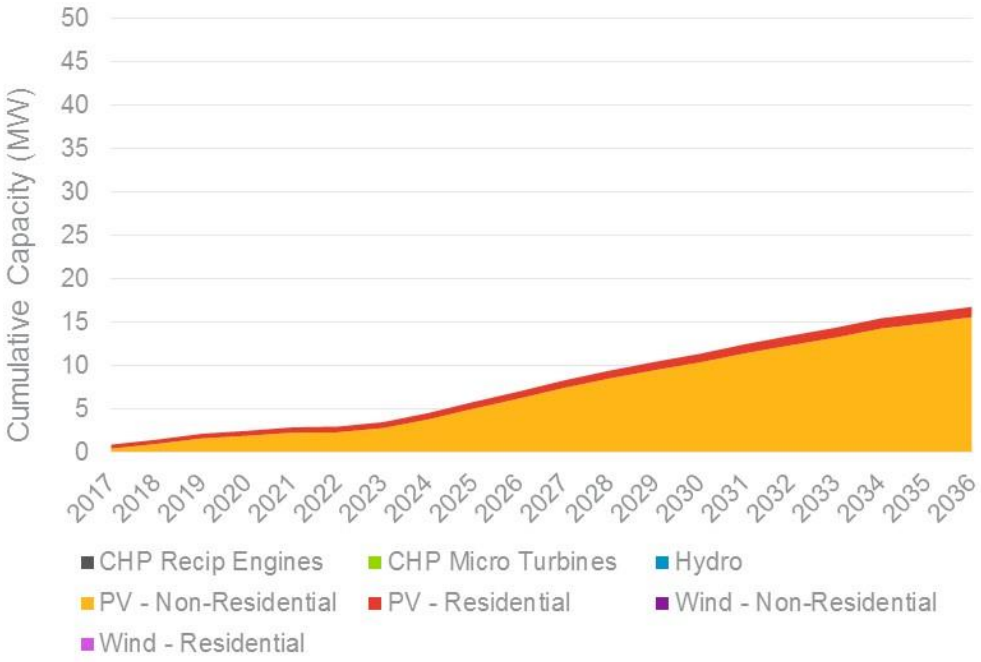


Figure 29. Cumulative Capacity Installations by Technology (MW AC), Washington Low Case



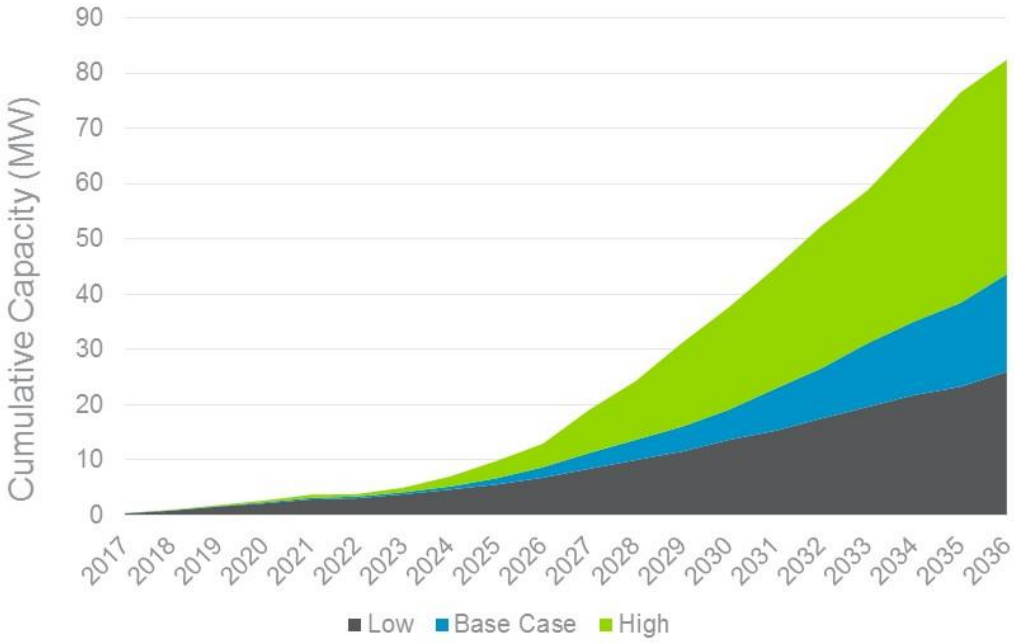
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1.8.6 Wyoming

PacifiCorp's Wyoming customers are projected to install about 44 MW of capacity over the next two decades in the base case, averaging about 2.2 MW annually. Solar is responsible for the majority of private generation installations over the horizon of this study, with CHP reciprocating engines, small hydro, and small wind being installed in small numbers in future years. Wyoming does not have any state incentives promoting the installation of private generation. Similar to other states, the ratcheting down of the Federal ITC from 2020 to 2022 has a negative impact on annual capacity installations but in 2023 the market begins to grow at a faster pace, driven by escalating electricity rates and declining technology costs. Both residential and non-residential solar installations are responsible for the majority of private generation growth over the horizon of this study.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 30. The 44 MW from the base case decreases by 48% to 26 MW in the low case and increases by 86% to 82 MW in the high case.

Figure 30. Cumulative Capacity Installations by Scenario, Wyoming



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Figure 31. Cumulative Capacity Installations by Technology (MW AC), Wyoming Base Case

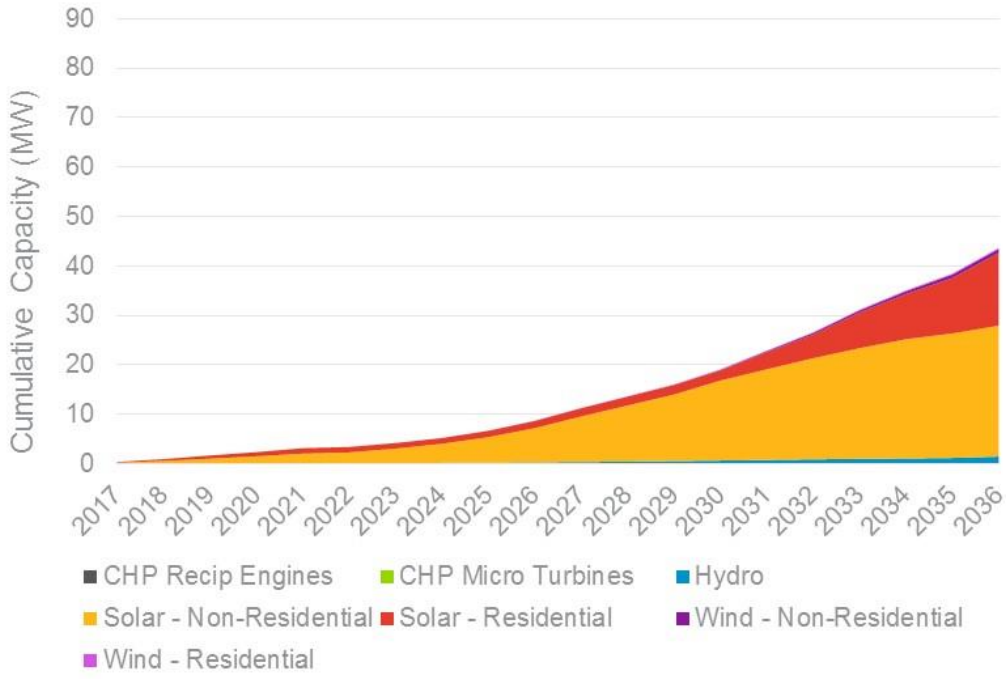
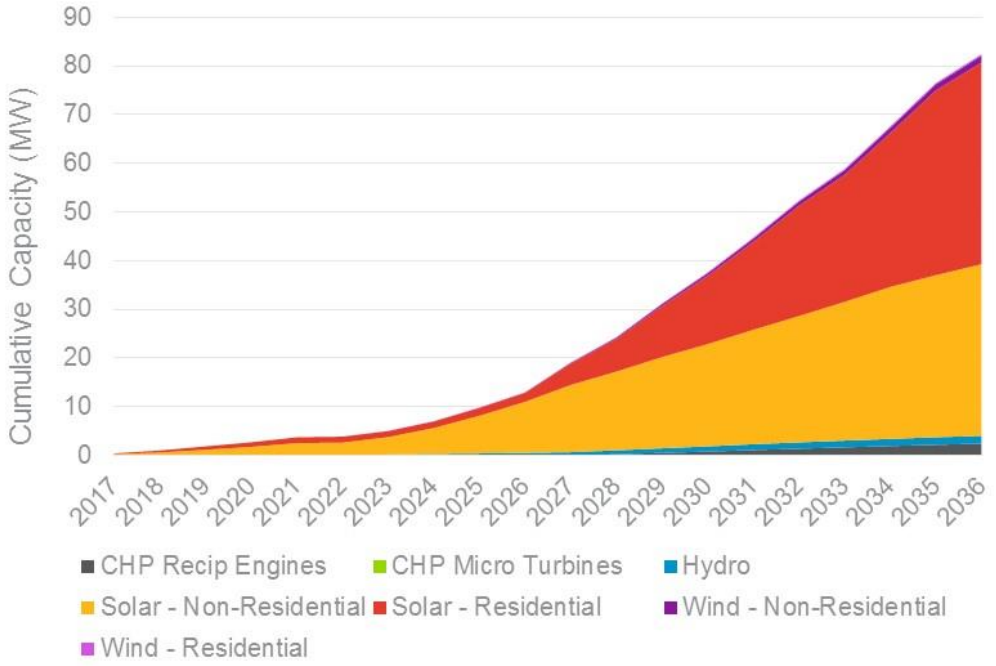
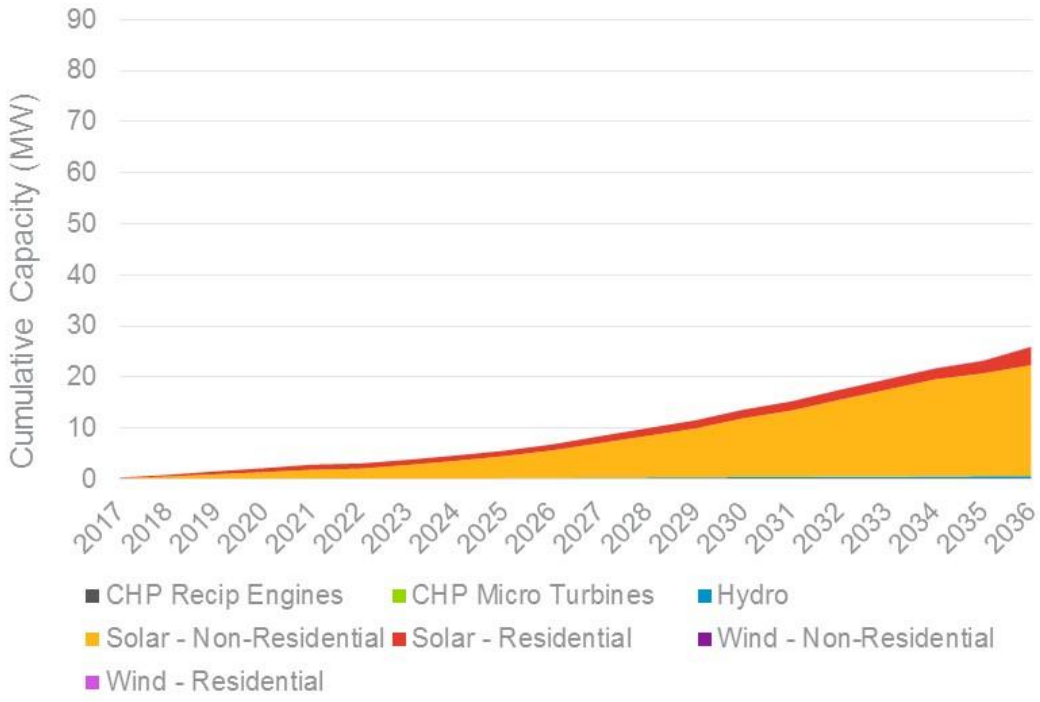


Figure 32. Cumulative Capacity Installations by Technology, Wyoming High Case



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Figure 33. Cumulative Capacity Installations by Technology (MW AC), Wyoming Low Case



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APPENDIX A. CUSTOMER DATA

Table 13 California

Rate Class	# Customers	2016 MWh Sales	Avg. Rates ($/kWh)
Residential	35,461	369,076	0.138
Commercial	7,179	235,760	0.132
Industrial	125	48,336	0.099
Irrigation	1,835	97,790	0.132

Table 14 Idaho

Rate Class	# Customers	2016 MWh Sales	Avg. Rates ($/kWh)
Residential	61,788	690,071	0.109
Commercial	8,478	468,291	0.083
Industrial	592	1,728,411	0.068
Irrigation	4,947	592,595	0.091

Table 15 Oregon

Rate Class	# Customers	2016 MWh Sales	Avg. Rates ($/kWh)
Residential	493,990	5,387,920	0.102
Commercial	65,287	5,104,499	0.090
Industrial	1,446	2,192,338	0.071
Irrigation	7,713	338,450	0.096

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Table 16 Utah

Rate Class	# Customers	2016 MWh Sales	Avg. Rates ($/kWh)
Residential	776,356	6,840,892	0.110
Commercial	82,889	8,581,242	0.085
Industrial	5,095	8,870,838	0.065
Irrigation	3,117	216,410	0.077

Table 17 Washington

Rate Class	# Customers	2016 MWh Sales	Avg. Rates ($/kWh)
Residential	107,382	1,585,732	0.100
Commercial	15,561	1,539,732	0.081
Industrial	500	798,140	0.065
Irrigation	5,091	162,150	0.087

Table 18 Wyoming

Rate Class	# Customers	2016 MWh Sales	Avg. Rates ($/kWh)
Residential	114,763	1,042,938	0.119
Commercial	22,856	1,510,255	0.086
Industrial	2,073	7,010,964	0.063
Irrigation	743	23,840	0.092

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APPENDIX B. SYSTEM CAPACITY ASSUMPTIONS

Table 19 Access Factors (%)

Technology	CA	ID	OR	UT	WA	WY
Recip. Engines	N/A	N/A	N/A	N/A	N/A	N/A
Micro Turbines	N/A	N/A	N/A	N/A	N/A	N/A
Small Hydro	N/A	N/A	N/A	N/A	N/A	N/A
PV - Com	42%	42%	42%	42%	42%	42%
PV - Res	35%	35%	35%	35%	35%	35%
Wind - Com	5%	5%	8%	16%	8%	51%
Wind - Res	5%	5%	8%	16%	8%	51%

Table 20 California (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	2	0	0	28
Micro Turbines	2	0	0	28
Small Hydro	500	0	0	500
PV - Com	18	29	0	212
PV - Res	0	0	6	0
Wind - Com	10	16	0	113
Wind - Res	0	0	3	0

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Table 21 Idaho (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	4	0	0	185
Micro Turbines	4	0	0	185
Small Hydro	500	0	0	500
PV - Com	31	68	0	250
PV - Res	0	0	6	0
Wind - Com	29	62	0	1515
Wind - Res	0	0	6	0

Table 22 Oregon (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	6	0	0	110
Micro Turbines	6	0	0	110
Small Hydro	500	0	0	500
PV - Com	25	32	0	100
PV - Res	0	0	6	0
Wind - Com	30	17	0	584
Wind - Res	0	0	4	0

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Table 23 Utah (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	7	0	0	150
Micro Turbines	7	0	0	150
Small Hydro	500	0	0	500
PV - Com	58	39	0	130
PV - Res	0	0	5	0
Wind - Com	56	0	0	938
Wind - Res	0	0	5	0

Table 24 Washington (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	6	0	0	88
Micro Turbines	6	0	0	88
Small Hydro	500	0	0	500
PV - Com	65	21	0	250
PV - Res	0	0	10	0
Wind - Com	41	13	0	655
Wind - Res	0	0	6	0

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Table 25 Wyoming (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	150	0	0	150
Micro Turbines	150	0	0	150
Small Hydro	500	0	0	500
PV - Com	25	17	0	150
PV - Res	0	0	5	0
Wind - Com	23	11	0	1192
Wind - Res	0	0	3	0

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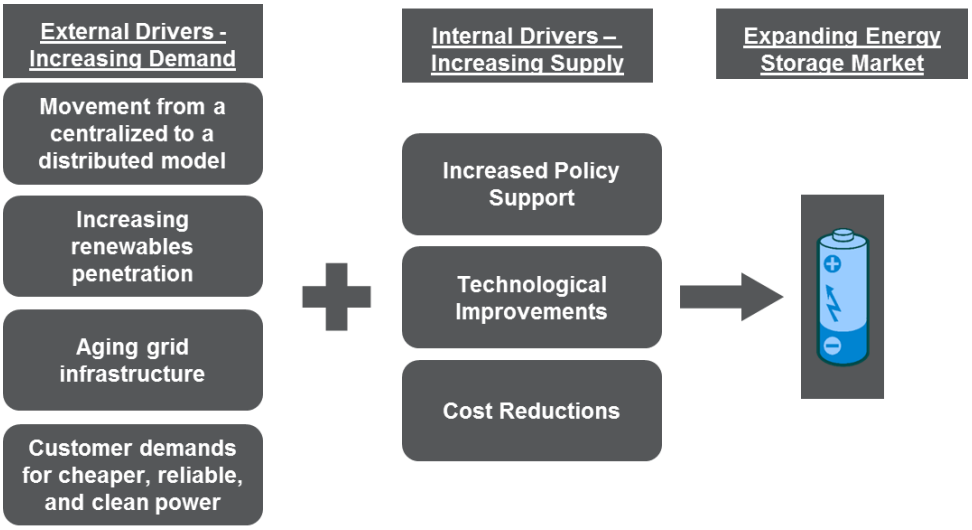
APPENDIX C. STORAGE EVALUATION

Navigant evaluated the future potential of energy storage, evaluating the drivers, challenges and applications of energy storage today.

C.1 Drivers

Changes in the electric sector are increasing the need for storage and changes in the storage sector are increasing the viability. Figure 17 details the external and internal drivers driving the expansion of the energy storage market.

Figure 34. Internal and External Storage Drivers



Sector specific drivers include:

- **Commercial and Industrial**
  - Most commercial customers face demand charges and/or time-of-use (TOU) pricing. This makes storage extremely useful for energy cost management.
  - Storage may also provide additional reliability by smoothing out short term power fluctuations (similar to a large uninterruptible power supply (UPS)), and can provide reactive power to help reduce reactive power charges.
  - Consistent and predictable loads for sub-sets of commercial sites (restaurants, retail, office), will allow for some standardization in terms of product offering.
  - Market may begin to focus on larger scale longer, duration Li-ion battery storage coupled with demand response technology to meet emerging capacity market drivers.

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- **Residential**
    - Residential market is currently very small and driven by the back-up power application. It is expected to remain that way in the near term since conventional backup power is still more cost effective.

C.2 Challenges

Storage requires high electricity prices, high demand charges and in many cases a subsidy to make economic sense (e.g. SGIP in California). Sector-specific challenges include:

- **Commercial and Industrial**
    - Limited short-term demand spike facilities with high demand charge
        - Given the current cost of batteries, power conversion technology, software and controls and system integrator services, most projects still require incentives, high demand charge tariffs and emerging financing structures.
    - Customer acquisition and project development costs are high
        - Each specific building load pattern must be analyzed to determine project viability, increasing the cost of customer acquisition.
    - Lack of project finance at scale
        - C&I storage projects, like solar PV, typically do not offer paybacks that meet conventional host return on investment criteria, thereby requiring financing.
        - Despite battery manufacturer's efforts to provide performance guarantees and warranties, financing capital is not available at scale and remains limited.
    - Dispatch algorithm
        - Difficult to design the algorithms correctly so storage discharges at the correct time.
- **Residential**
    - Most residential customers do not pay demand charges or TOU rates. As such, a standalone storage system only provides a reliability benefit.
    - Without regulatory changes, the business case for residential solar + storage will remain NPV negative in all but a few select geographies (e.g. Hawaii).

C.3 Policy

Federal and state policy promoting energy storage remains one of the most important market drivers.

Federal

The predominant federal energy storage policies include the Investment Tax Credit, MACRS, USEPA Clean Power Plan and FERC Rules 792, 755, and 784.

- **The Investment Tax Credit (ITC)** is a federal government established 30 percent tax credit for residences and businesses that invest in solar photovoltaics and other qualifying renewable energy technologies.
    - ITC is applicable for energy storage system coupled with renewable energy.

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  - PLR allows 10%-30% ITC depending on RE technology if 75% of energy to battery is renewable.
  - Recapture risk if renewable < 75% to battery in a single year.

- **Federal Modified Accelerated Cost Recovery System (MACRS)**, which classifies photovoltaics (and other technologies) as a five-year property for investment recovery through depreciation deductions. Energy storage systems coupled with RE eligible.
- **USEPA Clean Power Plan** released August 2015 which mandates that utilities reduce carbon emissions. Implementation will be on a state by state basis, with plans due by 2018. Storage may be co-located with fuel assets to improve carbon efficiency, or with renewables or as DR assets to reduce carbon during peak demand or grid stabilization events.
- **FERC Rules 792, 755, and 784** have created a pay for performance structure for frequency regulation which has enabled storage to compete in these markets.

State

The energy storage market is currently driven by a handful of states with high electricity prices, demand charges and supportive policy. Some of the most notable policies currently include the following:

- **California:**
  - **Self-Generation Incentive Program (SGIP)** allows up to $1620/kW for advanced energy storage technologies with a maximum eligible capacity of 3MW. It is budgeted for $83m/year through 2019.
  - **AB 2514** requires 1325MW of storage procurement by 2020 for the large IOUs, including a carve-out of 199MW for behind-the-meter storage.
- **New York REV** has suggested methods of reforming the electricity sector in order to facilitate energy storage installations and controls.
- **Oregon HB-2193-B** which defines the value of storage, and allows utilities to submit rate-recoverable energy storage procurements through to 2017.
- **Massachusetts state government** has allocated $10 million for demonstration projects.
- **Connecticut SB 1078** requires that resources solicited for the Integrated Resource Plan be done through an RFP, and storage may participate in those RFPs.

C.4 Storage Customer Applications

Current Applications

- Demand charge reduction
- Retail rate management
- Energy arbitrage - renewable energy shifting
- Power quality
- Backup power

Future Applications

- Operating Reserves
- Capacity (currently only in PJM and CAISO territories via IOUs)

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Non-Residential Solar + Storage

Current Applications

- **Demand charge reduction** – Reduce demand charges by eliminating spikes in demand. Solar coincides with peak but doesn't effectively reduce demand charges due to intermittent production profile.
- **Retail rate management -** Aid with tariff switching by eliminating consistent spikes in demand, minutes long that could be responsible for unfavorable tariff rates.
- **Energy arbitrage** – Storing energy when it is inexpensive and discharging when electricity is expensive. This requires a large price differential ($/kWh) between different periods of the day. Requires a smart inverter in NEM states.
- **Power quality** – Increasing power quality at the facility, ideal for protecting sensitive equipment.

Future Applications

- **Back-up power** – Provide backup power during grid failure. Currently, battery storage is cost prohibitive to serve this application and cannot compete with gas fired back-up generators for non-residential customers.
- **Load shifting** – With the potential future elimination of NEM, storage could allow customers to store excess electricity during daylight hours and discharge during times of high load.

Residential Solar + Storage

The bulk of the residential storage market will be storage tied to solar PV.

Current Applications

- **Back-up power** – Provide back-up power in an outage.

Future Applications

- **Demand response** - Reduce demand charges by eliminating spikes in power demand.
    - Most residential customers do not pay demand charges or TOU rates (AZ only state with demand charges). Many utilities are considering moving toward time of use pricing although only a few have made the move.
- **Energy arbitrage** – Storing energy when it is inexpensive and discharging when electricity is expensive. This requires a large price differential ($/kWh) between different periods of the day.
- **Load shifting** – With the potential future elimination of NEM, storage could allow customers to store excess electricity during daylight hours and discharge during times of high load.

Wind + Storage

Current Applications

- **Demand charge reduction** - Reduce demand charges by eliminating spikes in demand.
- **Retail rate management -** Aid with tariff switching by eliminating consistent spikes in demand, minutes long that could be responsible for unfavorable tariff rates.
- **Energy arbitrage** – Storing wind energy when it is inexpensive and discharging when electricity is expensive. This requires a large price differential ($/kWh) between different periods of the day.
- **Power quality** – Increasing power quality at the facility, ideal for protecting sensitive equipment.

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Future Applications

- **Back-up power**– Provide backup power during grid failure. Currently, battery storage is cost prohibitive to serve this application and cannot compete with gas fired back-up generators for non-residential customers.
- **Load shifting** – With the potential future reduction or elimination of NEM benefits, storage could allow customers to store excess electricity during times of high wind and discharge during times of high load.
- **Interconnection costs** – If utility plans to charge large interconnection costs to integrate the variable wind, energy storage could mitigate those impacts.

Hydro + Storage

- Small hydro should have an even electricity generation profile throughout a 24 hour period, so coupling storage with hydro has minimal impact compared with intermittent renewables (e.g. solar and wind).
- Did not make the short list of storage for renewables integration applications in recent Navigant Research report.
- To a lesser degree, storage can still provide the following benefits when coupled with hydro:
    - Demand charge reduction
    - Retail rate management
    - Power quality
    - Back-up power
    - Load shifting

CHP + Storage

- Availability of storage will likely not impact forecasts for CHP.
- Both reciprocating engines and micro-turbines are load following technologies for customers with high thermal loads.
- Load following technologies already help customers manage energy and demand charges.
- Customers with high thermal load will chose CHP over energy storage because CHP reduces thermal and electricity costs, simultaneously.

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APPENDIX D. WASHINGTON HIGH-EFFICIENCY COGENERATION LEVELIZED COSTS

Section 480.109.100 of the Washington Administrative Code[21] establishes high-efficiency cogeneration as a form of conservation that electric utilities must assess when identifying cost-effective, reliable, and feasible conservation for the purpose of establishing 10-year forecasts and biennial targets. To supplement the analysis in the main body of this report addressing reliability and feasibility, this appendix, analyzes the levelized cost of energy (LCOE) of these resources, for use in cost-effectiveness analysis.

Key assumptions for the analysis are presented in Table 26 and Table 27. It is worth noting that the LCOE calculation is for the electrical generation component only and the cost of the heat recapture and recovery was taken out of the total installed system cost. PacifiCorp provided the natural gas pricing and the weighted average cost of capital (WACC) assumptions.

D.1 Key Assumptions

Table 26 Reciprocating Engines LCOE – Key Assumptions[22]

private generation Resource Costs	Units	2017	2026	2036	Notes
Installed System Cost	$/W	$2.61/W	$2.71/W	$2.82/W	• EPA, Catalog of CHP Technologies, March 2015, pg. 2-15 • Assumed cost for electrical generation only, system cost was reduced by 10% to exclude heating generation costs.
Asset Life	Years	25	25	25	
Capacity Factor	%	85%	85%	85%	Navigant Assumption
Variable O&M	$/MWh	$20	$20	$20	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 92
Fuel Cost	$/MMBtu	PacifiCorp Gas Forecast	PacifiCorp Gas Forecast	PacifiCorp Gas Forecast	Provided by PacifiCorp
WACC	%	6.57%	6.57%	6.57%	Provided by PacifiCorp

[21] http://apps.leg.wa.gov/WAC/default.aspx?cite=480-109-100

[22] EPA, Catalog of CHP Technologies: www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf; ICF, Combined Heat and Power Policy Analysis, www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

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Table 27 Micro-turbines LOE – Key Assumptions[23]

private generation Resource Costs	Units	2017	2026	2036	Notes
Installed System Cost	$/W	$2.561/W	$2.55/W	$2.54/W	• EPA, Catalog of CHP Technologies, March 2015, pg. 2-15 • Assumed cost for electrical generation only, system cost was reduced by 5% to exclude heating generation costs.
Asset Life	Years	25	25	25	Assumption
Capacity Factor	%	85%	85%	85%	Assumption
Variable O&M	$/MWh	$20	$20	$20	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 92
Fuel Cost	$/MMBtu	PacifiCorp Gas Forecast	PacifiCorp Gas Forecast	PacifiCorp Gas Forecast	Provided by PacifiCorp
WACC	%	6.57%	6.57%	6.57%	Provided by PacifiCorp

D.2 Results

The results of the LCOE analysis are presented in Table 28, with levelized costs estimated to range from $88/MWh to $111/MWh over the forecast period, varying by year and technology.

Table 28 LCOE Results – Electric Component Only

Technology	Units	2017	2026	2036
Reciprocating Engines	$/MWh	98.0	99.7	108.7
Microturbines	$/MWh	87.5	99.6	110.9

[23] EPA, Catalog of CHP Technologies: www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf; ICF, Combined Heat and Power Policy Analysis, www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

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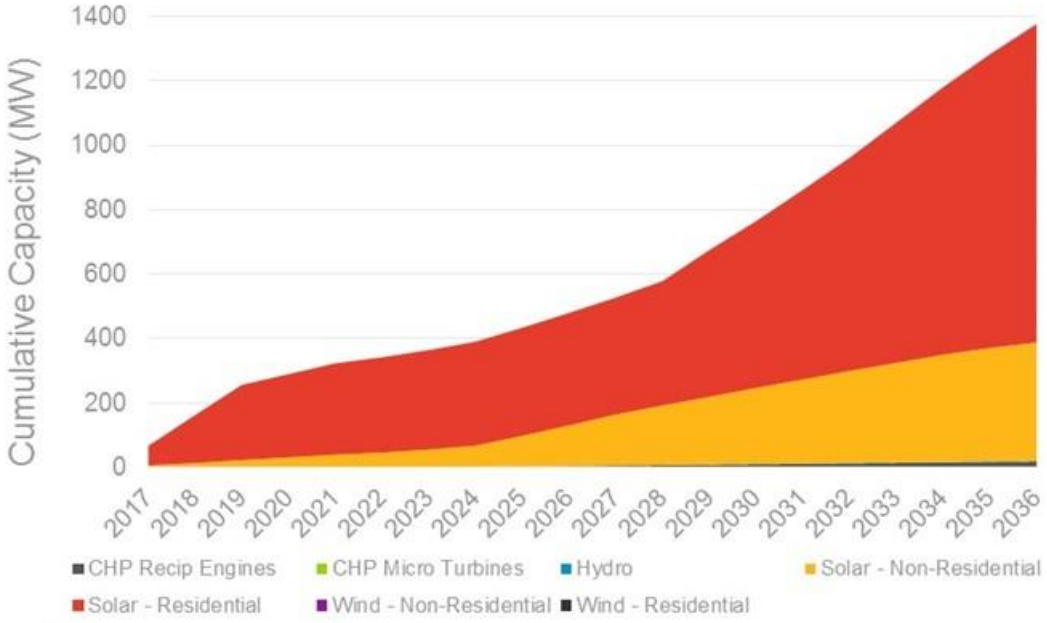
APPENDIX E. COMPARISON OF 2016 AND 2014 STUDY

The growth of the solar industry is the main driver in the difference between the 2014 and 2016 study results across PacifiCorp's territory. Cumulative solar market penetration for the combined residential and non-residential sectors is expected to increase at about six times the rate projected in 2014. This increase in penetration is driven by the ITC extension and the continued decline of solar installation costs. The ITC, originally set to expire in 2016 for commercial solar systems and reduce to 10 percent for residential solar systems, was extended for solar PV systems in December 2015 through the end of 2021, with step downs occurring from 2020 through 2022. The 2014 Study assumed that the ITC would expire for commercial solar PV systems at the end of 2016 and step down to 10 percent for residential PV systems, per the legislation in place at the time of the analysis. Additionally, solar costs have continued to rapidly decline at a faster rate than expected the last few years, with 2017 residential and non-residential solar costs declining by 15 and 25 percent, respectively between the 2014 and 2016 studies.

Another difference between the market penetration results is the adoption of CHP micro-turbines and reciprocating engines. Based on the latest references, the cost of installing a micro-turbine remained relatively constant to the assumptions made in 2014, yet CHP reciprocating engines increased by about 30 percent. Additionally, in the 2014 study, technology costs were expected to decline aggressively at 1.4 percent annually over the next 20 years, while the 2016 study expects the equipment costs of these fairly mature technologies to stay relatively flat.

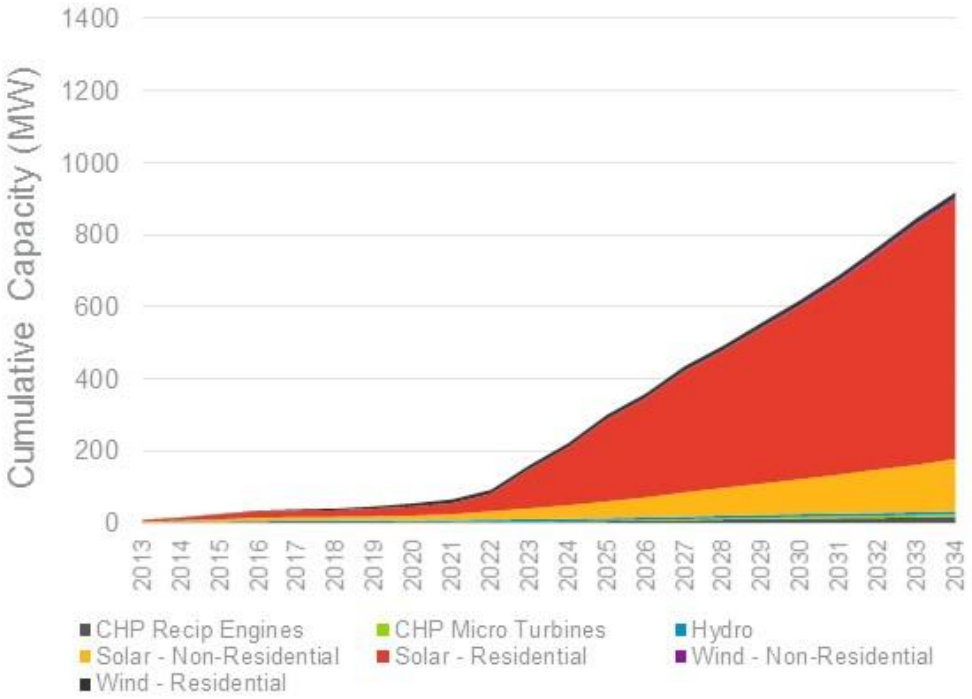
All other technologies evaluated had minimal cumulative market penetration in both the 2014 and 2016 studies.

Figure 35. Cumulative Market Penetration Results by Technology (MW AC), 2017 – 2036, Base Case (Current Study)



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Figure 36. Cumulative Market Penetration Results by Technology (MW AC), 2013 – 2034, Base Case (2014 Study)



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APPENDIX F. DETAILED NUMERIC RESULTS

F.1 Utah

Table 29. Utah – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.1	0.2	0.2	0.3	0.4	0.4	0.5	0.6	0.7	0.9	0.9	1.2	1.1	1.2	1.4	1.1	1.2	1.0	1.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	55.4	82.0	77.7	20.2	19.5	8.3	8.4	9.3	7.4	7.9	8.0	10.5	53.0	42.6	46.1	51.4	52.3	57.8	45.2	47.0
PV	Commercial	1.8	2.0	2.4	2.2	1.8	2.1	2.1	2.3	19.3	20.0	19.9	15.0	13.9	13.8	12.5	12.7	11.2	11.3	5.4	2.5
PV	Industrial	0.1	0.1	0.3	0.5	0.5	0.1	0.1	0.5	0.8	0.7	0.9	0.6	0.6	0.7	0.6	0.9	1.6	1.3	2.8	1.9
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.3	0.4	0.4	0.4	0.5	0.4	0.4	0.4	0.4	0.2	0.2
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Table 30. Utah – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	17	1090	1551	1767	2379	2657	3128	4076	4265	4987	7044	6664	9214	8485	8665	10487	8562	8652	7690	7411
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	99113	146737	139036	36123	34960	14844	15007	16617	13279	14202	14234	18753	94911	76192	82487	91991	93634	103402	80897	84212
PV	Commercial	3200	3651	4357	3879	3292	3734	3775	4180	34562	35862	35657	26883	24894	24753	22367	22737	19995	20245	9657	4460
PV	Industrial	177	202	448	865	971	250	253	939	1476	1325	1570	987	1150	1214	1163	1588	2954	2338	4981	3325
PV	Irrigation	53	60	72	64	78	62	63	260	264	532	773	676	677	966	671	690	637	641	395	352
Wind	Residential	0	1	1	1	0	1	1	1	0	0	0	1	0	1	1	1	0	1	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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Table 31. Utah – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	50.6	62.7	80.5	18.4	6.8	7.1	7.1	7.9	6.3	6.8	6.8	7.8	6.4	22.3	37.1	41.4	25.4	45.7	36.9	38.7
PV	Commercial	1.7	1.9	2.3	2.0	1.7	2.0	2.0	2.2	1.7	10.7	20.1	15.4	9.3	15.4	14.7	9.8	14.1	14.2	4.5	8.3
PV	Industrial	0.1	0.1	0.1	0.3	0.4	0.1	0.1	0.2	0.7	0.7	0.8	0.5	0.5	0.6	0.5	0.5	0.6	0.5	0.3	0.3
PV	Irrigation	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.4	0.4	0.4	0.2	0.3
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Table 32. Utah – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	7	12	19	13	7	11	11	15	6	8	8	13	5	10	11	16	8	12	0	0
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	90623	112341	144056	32940	12169	12653	12791	14164	11318	12105	12133	13974	11535	39933	66480	74086	45520	81816	66117	69300
PV	Commercial	2999	3422	4085	3637	3086	3500	3539	3918	3131	19117	35909	27611	16732	27625	26238	17557	25265	25404	8050	14804
PV	Industrial	172	196	234	528	750	224	227	413	1207	1254	1503	918	861	1147	864	949	1144	972	524	524
PV	Irrigation	47	54	64	81	156	58	59	203	218	261	224	289	375	396	535	709	708	739	288	555
Wind	Residential	0	0	1	1	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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Table 33. Utah – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.2	0.3	0.3	0.6	0.7	0.9	1.2	1.4	1.6	1.6	1.7	1.7	1.8	2.7	3.8	6.5	5.4	6.2	4.4
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.4
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	71.2	86.1	85.7	35.5	22.6	10.0	10.1	11.2	8.9	11.0	75.6	67.7	71.4	57.5	85.1	69.9	96.2	77.6	56.6	57.7
PV	Commercial	1.9	2.2	2.6	2.9	14.4	2.6	2.6	18.3	23.5	22.0	19.6	15.1	10.7	10.7	11.6	10.4	9.7	11.1	6.0	7.2
PV	Industrial	0.1	0.1	0.5	0.5	0.6	0.2	0.2	1.0	1.0	1.0	1.2	2.0	2.4	3.0	2.9	2.9	2.7	2.6	1.1	1.5
PV	Irrigation	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.3	0.6	0.6	0.7	0.5	0.3	0.4	0.3	0.4	0.2	0.3	0.2	0.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Table 34. Utah – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	263	1527	1979	2529	4623	5190	7009	8666	10053	11582	11847	12878	13006	13440	20087	28503	48346	39904	46391	33085
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7483	10723
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	127507	154195	153509	63551	40508	17892	18087	20029	16005	19661	135315	121192	127912	102994	152448	125061	172300	138896	101378	103387
PV	Commercial	3385	3862	4609	5224	25777	4575	4625	32747	42125	39369	35037	27103	19088	19151	20771	18628	17286	19877	10791	12971
PV	Industrial	184	210	970	944	1040	276	364	1770	1762	1834	2160	3602	4363	5314	5243	5276	4832	4623	2046	2640
PV	Irrigation	59	67	80	71	109	70	71	602	1097	1140	1333	853	588	736	502	635	440	462	304	211
Wind	Residential	0	1	1	1	0	1	1	1	0	0	0	1	0	1	1	1	1	1	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	113
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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F.2 Oregon

Table 35. Oregon – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	4.4	5.4	5.8	4.4	4.6	4.3	4.4	4.5	5.1	5.5	5.6	11.7	15.2	18.2	21.2	18.1	26.6	22.1	30.2	23.2
PV	Commercial	2.5	2.7	3.4	3.2	3.4	2.6	3.5	4.5	4.5	4.7	4.6	4.5	4.4	4.5	4.5	4.5	4.1	4.5	5.5	5.1
PV	Industrial	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
PV	Irrigation	0.1	0.2	0.2	0.1	0.2	0.0	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.3	0.5	0.4	0.5	1.0	0.7
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Table 36. Oregon – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	0	0	0	0	0	0	170	667	819	788	967	869	824	919	955	822	703
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	5946	7341	7853	6031	6273	5863	5961	6080	6991	7538	7663	15924	20755	24760	28945	24615	36228	30123	41169	31558
PV	Commercial	3388	3730	4630	4345	4659	3600	4787	6095	6132	6419	6324	6140	6053	6119	6137	6194	5641	6163	7430	6982
PV	Industrial	39	55	69	51	63	6	66	100	100	117	114	110	96	153	158	200	198	171	172	132
PV	Irrigation	92	215	287	195	263	26	278	397	384	454	430	399	378	329	381	665	593	639	1321	905
Wind	Residential	-1	0	0	0	0	0	0	0	0	0	0	20	30	31	31	32	31	32	25	25
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	127	152	163	168	172
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	1	8	9	10	11	12	10	12	10

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Table 37. Oregon – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	4.1	5.2	5.7	4.2	4.6	4.3	4.4	4.4	4.5	5.5	5.6	5.1	5.3	5.1	9.3	11.4	12.7	19.3	15.5	16.7
PV	Commercial	2.5	2.7	3.1	3.0	3.3	2.6	3.0	4.1	4.3	4.3	4.5	4.3	4.3	4.1	4.4	4.1	4.3	4.1	3.7	3.6
PV	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
PV	Irrigation	0.1	0.1	0.2	0.1	0.2	0.0	0.1	0.2	0.3	0.3	0.3	0.3	0.2	0.2	0.3	0.2	0.2	0.2	0.1	0.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Table 38. Oregon – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	5628	7113	7766	5771	6207	5843	5939	6054	6162	7487	7615	6945	7174	6992	12636	15583	17377	26370	21109	22733
PV	Commercial	3353	3679	4249	4109	4516	3583	4080	5639	5895	5902	6081	5907	5856	5561	5946	5609	5897	5582	4976	4941
PV	Industrial	35	50	65	40	53	5	35	90	91	99	105	92	78	90	79	92	74	90	128	127
PV	Irrigation	91	170	259	178	222	23	201	332	352	380	397	367	298	300	355	300	274	286	180	172
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	25
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1

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Table 39. Oregon – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	4.8	5.5	5.8	4.6	4.8	4.3	4.4	5.0	11.7	26.5	36.7	25.9	36.6	33.2	41.4	36.6	38.6	42.8	40.0	29.7
PV	Commercial	2.5	2.9	3.6	3.4	3.7	2.7	4.1	4.8	4.9	5.1	5.3	4.8	5.5	6.6	7.7	11.6	9.7	8.0	8.4	7.8
PV	Industrial	0.0	0.0	0.1	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1
PV	Irrigation	0.1	0.2	0.2	0.2	0.2	0.0	0.3	0.3	0.4	0.4	0.5	0.7	0.8	1.0	1.1	1.1	1.0	0.9	0.5	0.6
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Table 40. Oregon – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	0	0	350	566	726	772	996	1037	1173	1163	1235	1455	2279	2305	2401	2028	2011
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	6497	7468	7962	6308	6558	5892	5992	6759	15981	36114	50073	35265	49878	45265	56411	49921	52575	58317	54574	40466
PV	Commercial	3410	3956	4917	4603	4975	3624	5594	6607	6679	7012	7255	6490	7496	8975	10456	15821	13264	10884	11468	10593
PV	Industrial	43	56	79	57	74	7	99	125	127	163	293	206	237	250	224	232	224	236	181	177
PV	Irrigation	129	241	289	250	265	33	411	471	502	501	627	960	1155	1399	1437	1434	1321	1263	641	772
Wind	Residential	-1	0	0	0	0	0	0	0	28	37	38	38	38	38	32	45	47	48	47	37
Wind	Commercial	-1	0	0	0	0	0	0	0	0	0	0	97	173	174	191	207	213	192	189	189
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	8	9	11	12	14	13	15	11	14	13	13

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F.3 Washington

Table 41. Washington – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.6	0.0	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
PV	Commercial	0.4	0.5	0.7	0.4	0.4	0.0	0.6	1.0	1.1	1.2	1.1	1.0	1.0	1.0	1.0	0.8	1.0	1.2	1.9	1.4
PV	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.3	0.3
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Table 42. Washington – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	39	88	101	141	142	163	247	207	342	331	232	350	336	193	392	305	290	274	260
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	961	69	82	77	93	69	86	87	105	75	92	93	113	82	100	98	96	96	0	0
PV	Commercial	657	794	1012	550	647	69	976	1577	1758	1826	1742	1557	1602	1500	1529	1240	1471	1811	2996	2121
PV	Industrial	40	54	68	50	61	5	76	93	109	105	110	140	147	175	183	154	154	190	125	122
PV	Irrigation	18	10	11	11	13	10	94	170	204	189	198	177	182	143	291	269	458	462	412	401
Wind	Residential	0	0	0	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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Table 43. Washington – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Commercial	0.4	0.5	0.6	0.3	0.3	0.0	0.4	0.8	1.1	1.0	1.0	0.9	0.8	0.7	0.9	0.7	0.7	0.9	0.5	0.5
PV	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Table 44. Washington – Incremental Annual Adoption (MWh) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	26	45	41	63	38	42	59	45	94	48	0	25	8	0	10	30	0	0	0
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	707	51	60	57	68	51	63	64	77	55	68	68	83	61	74	72	71	71	0	0
PV	Commercial	628	761	901	405	462	61	637	1296	1615	1508	1603	1430	1247	1146	1413	1136	1106	1365	757	724
PV	Industrial	38	50	63	43	52	4	53	86	88	97	94	86	79	73	73	137	139	107	119	118
PV	Irrigation	12	9	11	10	12	9	23	157	173	176	185	142	144	157	133	129	124	122	82	214
Wind	Residential	0	0	0	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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Table 45. Washington – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	1.5	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
PV	Commercial	0.5	0.6	0.7	0.5	0.5	0.1	1.1	1.2	1.4	1.4	1.4	1.3	2.2	2.2	4.9	4.0	3.9	2.8	3.0	2.6
PV	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.2
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.1	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.3	0.2	0.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Table 46. Washington – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	-1	88	128	176	225	248	297	377	397	509	512	477	551	458	449	496	471	445	714	980
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	209	240	220	336	277	285	262	263
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	2272	114	135	128	153	114	142	145	173	124	153	154	187	136	165	163	160	160	0	0
PV	Commercial	696	898	1150	725	762	79	1623	1912	2129	2209	2147	1974	3387	3451	7525	6136	6029	4298	4640	4022
PV	Industrial	42	59	75	59	68	7	103	122	142	259	261	197	236	202	209	210	210	176	167	369
PV	Irrigation	67	28	13	12	15	11	107	204	241	228	435	442	622	628	634	607	563	399	376	230
Wind	Residential	0	0	0	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	51
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	3	6	6	6

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F.4 Idaho

Table 47. Idaho – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.2	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	1.0	1.0	1.8	1.5	2.3	1.8
PV	Commercial	0.2	0.3	0.3	0.2	0.3	0.0	0.3	0.3	0.3	0.4	0.4	0.6	0.5	0.8	1.1	0.8	0.8	0.8	0.6	0.5
PV	Industrial	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3
PV	Irrigation	0.3	0.4	0.4	0.3	0.4	0.1	0.4	0.5	0.9	0.9	1.3	1.4	1.0	1.0	1.0	1.0	0.9	0.9	0.3	0.4
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Table 48. Idaho – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	144	177	236	295	324	406	503	529	621	621	645	797	994	1013	1032	1000	1003	944	690
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	366	384	407	98	152	43	44	48	41	45	45	134	136	189	1774	1750	3143	2584	4121	3090
PV	Commercial	371	439	542	431	464	63	523	595	600	615	709	1071	849	1355	1944	1458	1417	1418	1064	894
PV	Industrial	99	123	219	157	196	22	108	279	295	313	325	255	248	251	250	208	246	256	126	505
PV	Irrigation	505	624	723	574	657	102	779	821	1540	1659	2297	2415	1805	1796	1738	1700	1558	1511	558	765
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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Table 49. Idaho – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.2	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.8
PV	Commercial	0.2	0.2	0.3	0.2	0.2	0.0	0.2	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.4	0.5	0.5	0.5	0.7	0.7
PV	Industrial	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
PV	Irrigation	0.3	0.3	0.4	0.3	0.4	0.0	0.3	0.4	0.4	0.4	0.8	0.6	0.8	1.0	1.0	0.7	1.0	1.0	0.4	0.7
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Table 50. Idaho – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	-1	0	0	0	0	0	0	30	35	116	92	2	153	49	43	172	176	182	106	103
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	356	344	397	90	109	39	40	43	38	41	41	44	38	125	138	194	143	153	428	1444
PV	Commercial	342	425	527	379	401	59	367	557	566	516	585	446	418	415	788	818	831	824	1239	1179
PV	Industrial	92	120	170	125	157	19	45	194	270	290	265	233	185	232	186	238	182	188	174	103
PV	Irrigation	469	607	704	509	629	86	606	780	704	711	1318	1075	1390	1749	1799	1163	1805	1816	761	1233
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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Table 51. Idaho – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.4
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.2	0.2	0.2	0.1	0.2	0.0	0.0	0.0	0.0	0.0	1.7	2.2	2.1	2.5	4.0	2.4	3.9	5.2	3.8	2.6
PV	Commercial	0.2	0.3	0.3	0.3	0.3	0.0	0.4	0.4	0.7	1.0	1.6	1.1	1.0	0.8	0.9	0.7	0.8	0.6	0.4	0.2
PV	Industrial	0.1	0.1	0.2	0.1	0.1	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.4	0.4	0.6	0.6	0.6	0.5	0.4
PV	Irrigation	0.3	0.4	0.5	0.5	0.6	0.1	0.5	1.3	1.8	1.6	1.5	1.0	1.1	0.9	1.0	0.8	0.7	0.7	0.5	0.3
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Table 52. Idaho – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	33	183	229	306	369	416	786	978	1055	1331	1358	1320	1498	1544	1355	1540	1257	1447	2125	2618
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	759	1044	1052	897	911	850
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	379	427	385	177	406	53	54	59	51	55	2919	3929	3740	4466	6959	4281	6768	9116	6608	4635
PV	Commercial	386	482	567	458	533	68	689	696	1275	1739	2727	1899	1810	1354	1622	1208	1346	1022	776	400
PV	Industrial	102	156	285	177	217	25	235	341	394	383	358	327	275	632	617	1081	1104	1111	903	761
PV	Irrigation	524	647	836	868	976	109	834	2281	3202	2818	2713	1766	1972	1508	1679	1326	1189	1202	928	575
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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F.5 California

Table 53. California – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.1	0.1	0.8	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.2	0.6	0.7	1.2	0.9	1.0	1.1	1.2	1.2	1.6
PV	Commercial	0.2	0.3	0.3	0.3	0.3	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.4	0.3	0.3	0.3	0.2	0.4
PV	Industrial	0.0	0.0	0.1	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0
PV	Irrigation	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.2
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Table 54. California – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	11	33	45	56	67	74	91	97	108	108	117	111	100	106	87	83	66	63	58	76
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	4	13	17	20	26	31	41	69	90	94	129	140	114	113	130	100	84	77	68	59
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	192	204	1489	565	577	49	46	57	39	49	388	1118	1240	2112	1639	1847	1956	2175	2102	2904
PV	Commercial	440	484	529	534	580	393	676	753	678	684	674	701	546	541	678	561	501	539	382	725
PV	Industrial	31	56	108	74	103	6	41	154	193	170	166	111	123	118	108	104	68	87	54	32
PV	Irrigation	183	201	220	222	241	163	280	313	281	284	280	291	226	224	281	233	208	223	158	301
Wind	Residential	-1	-1	-1	0	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	3	4	6	7	9	9	11	12	13	11	13	10	12	9	9	8	10
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1
Wind	Irrigation	0	0	0	1	1	2	3	4	4	4	5	5	4	5	4	5	4	4	4	3

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Table 55. California – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.1	0.1	0.4	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.5	0.6	0.6	0.7	0.4	0.8	0.9
PV	Commercial	0.2	0.3	0.3	0.3	0.3	0.2	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.1	0.1
PV	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.0	0.0	0.0
PV	Irrigation	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Table 56. California – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	-1	8	26	34	41	51	60	87	79	87	91	95	90	88	82	79	39	62	57	51
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	1	6	7	8	14	17	21	22	27	27	29	35	30	30	29	28	25	24	23	15
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	176	198	705	140	399	28	27	34	23	29	29	38	238	862	1008	1178	1307	778	1455	1584
PV	Commercial	414	489	530	527	537	345	673	700	666	661	636	569	490	476	542	463	394	417	262	260
PV	Industrial	30	41	84	65	75	5	14	113	153	168	173	106	132	95	123	88	105	74	71	38
PV	Irrigation	172	203	220	218	223	143	279	290	276	274	264	236	203	197	225	192	164	173	109	108
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	2	3	4	5	5	6	6	6	7	10	8	8	8	7	7	7	7
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	1	1	2	2	2	2	2	2	3	4	3	3	3	3	3	3	3

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Table 57. California – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.1	0.5	1.4	0.5	0.8	0.0	0.0	0.1	0.0	0.7	1.7	1.5	1.1	2.2	1.8	1.4	1.4	2.2	1.4	1.5
PV	Commercial	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.4	0.6	0.4	0.7	0.5	0.8	0.4	0.4
PV	Industrial	0.0	0.0	0.1	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1
PV	Irrigation	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.3	0.2	0.2
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Table 58. California – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	14	41	47	58	69	82	93	106	113	122	118	133	130	113	132	109	94	139	98	96
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	6	16	27	42	68	88	94	110	118	126	128	129	109	116	98	97	85	89	93	100
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	198	890	2563	850	1375	90	84	106	71	1334	3102	2796	2076	3990	3265	2533	2548	4036	2565	2689
PV	Commercial	435	479	553	548	596	460	731	787	806	787	963	939	715	1020	767	1233	821	1465	772	804
PV	Industrial	32	75	139	84	111	7	122	211	162	179	165	127	111	108	101	105	95	106	83	94
PV	Irrigation	180	199	229	227	247	191	303	326	334	326	399	389	297	423	318	512	341	608	320	334
Wind	Residential	-1	-1	-1	0	-1	0	0	0	-1	0	0	0	0	0	0	0	0	0	5	5
Wind	Commercial	0	0	0	4	5	7	8	11	11	12	13	14	14	14	14	14	10	12	9	26
Wind	Industrial	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1
Wind	Irrigation	0	0	0	2	2	3	3	4	5	5	5	6	6	6	6	6	4	5	4	11

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F.6 Wyoming

Table 59. Wyoming – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.1	0.2	0.3	0.2	0.2	0.0	0.0	0.0	0.1	0.2	0.2	0.2	0.1	0.1	1.4	1.4	2.4	1.9	2.1	3.5
PV	Commercial	0.2	0.3	0.3	0.3	0.4	0.2	0.6	0.7	1.0	1.4	1.9	1.7	1.8	2.3	1.8	1.7	1.6	1.5	0.8	1.0
PV	Industrial	0.0	0.1	0.1	0.1	0.1	0.0	0.1	0.2	0.3	0.3	0.3	0.4	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Table 60. Wyoming – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1410
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	44	55	74	85	103	132	145	170	180	226	286	308	375	467	472	471	440	267	418	384
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	258	381	531	397	427	38	36	47	240	336	340	278	253	203	2562	2486	4437	3558	3816	6454
PV	Commercial	357	481	628	629	715	360	1055	1257	1782	2506	3538	3193	3249	4281	3323	3221	2919	2737	1457	1922
PV	Industrial	86	114	161	172	237	16	250	440	513	643	607	658	584	612	596	592	555	449	456	435
PV	Irrigation	9	12	21	18	29	2	26	44	81	81	90	80	77	78	72	68	59	55	30	36
Wind	Residential	0	0	0	0	0	0	0	26	36	36	36	30	34	28	34	27	29	39	41	41
Wind	Commercial	1	1	1	0	0	0	0	0	0	0	0	0	-1	228	247	266	226	282	295	246
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	3	4	4	4	4	5	4	5	4	3

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Table 61. Wyoming – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.1	0.2	0.3	0.2	0.2	0.0	0.0	0.0	0.0	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3	1.1
PV	Commercial	0.2	0.3	0.3	0.3	0.4	0.1	0.5	0.6	0.7	0.8	1.0	1.1	1.1	1.6	1.2	1.7	1.7	1.7	0.9	1.4
PV	Industrial	0.0	0.1	0.1	0.1	0.1	0.0	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.3	0.2	0.2
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Table 62. Wyoming – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	36	47	60	73	89	107	125	147	143	165	175	180	146	167	152	117	121	146	241	144
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	232	362	480	367	357	34	32	43	27	216	324	264	177	192	183	257	176	183	610	2056
PV	Commercial	333	466	609	572	681	267	999	1117	1208	1401	1933	1982	2020	3035	2124	3200	3131	3104	1654	2550
PV	Industrial	81	110	146	132	165	59	232	277	352	523	536	517	516	464	533	535	413	504	330	311
PV	Irrigation	8	11	17	14	20	5	25	32	44	58	82	56	74	77	75	54	68	46	53	31
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	15	27	27	27	20	27	20
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	3	3	4

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Table 63. Wyoming – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.2	0.2	0.3	0.3	0.3	0.0	0.0	0.1	0.3	0.2	2.5	2.3	3.8	3.5	4.0	4.6	3.4	5.5	6.3	3.5
PV	Commercial	0.2	0.3	0.4	0.4	0.6	0.0	0.8	1.4	2.0	2.3	2.8	1.9	2.1	1.8	1.9	1.5	1.3	1.4	0.9	0.9
PV	Industrial	0.0	0.1	0.1	0.1	0.2	0.0	0.2	0.3	0.4	0.4	0.5	0.4	0.4	0.4	0.6	0.9	1.2	1.3	1.2	1.1
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Table 64. Wyoming – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	0	0	0	0	0	0	0	0	1821	2133	2097	2258	2026	2035	2063	1953	1743
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	49	64	83	101	116	203	219	378	397	449	601	531	510	511	468	428	360	316	303	197
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	277	428	567	469	467	43	40	191	493	421	4644	4271	6966	6501	7442	8499	6287	10160	11676	6473
PV	Commercial	373	501	681	825	1039	77	1491	2618	3661	4224	5164	3563	3880	3321	3473	2786	2408	2637	1683	1592
PV	Industrial	89	122	244	199	293	19	409	592	694	741	833	700	753	791	1082	1643	2217	2302	2118	1969
PV	Irrigation	9	13	30	29	31	2	52	79	90	96	99	80	82	73	66	62	64	55	32	44
Wind	Residential	1	1	1	0	0	21	49	47	47	39	45	31	52	53	51	51	48	38	41	51
Wind	Commercial	1	1	1	0	0	0	0	0	-1	47	252	266	298	332	305	364	314	316	328	326
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	1	4	4	5	5	6	5	5	6	5	5	5	5

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APPENDIX P – ENERGY STORAGE STUDIES

To support PacifiCorp's 2017 Integrated Resource Plan (IRP) two energy storage studies, initiated for previous IRPs, were updated including a battery energy storage study that focused on battery technologies and a bulk energy storage study that focused on pumped hydro and compressed air energy storage (CAES).

DNV-GL's Battery Energy Storage Study provided PacifiCorp with a catalog of commercially available and emerging battery energy storage technologies with forecasts and estimates for both performance and costs. To further support PacifiCorp's bi-annual IRP, DNV GL produced probabilistic cost graphs for each of the proposed technologies, broken out by technology, energy conversion system, controls, and the remaining balance of system.

The Bulk Energy Storage Study prepared by Black and Veatch (B&V) is an update to work HDR Navigant performed to support the 2015 IRP, incorporating updated information on three pumped hydro energy storage projects and a compressed air energy storage project within PacifiCorp's territory. The study provides an update to information on commercially available utility-scale energy storage technologies, as well as their applications, performance characteristics, and estimated capital and operating costs.

The estimates and information in the studies was used to inform the 2017 IRP and may be used to develop alternative applications to traditional utility transmission and distribution issues.

Battery Energy Storage Study for the 2017 IRP

PacifiCorp

Customer Reference: Battery Energy Storage Study for IRP 2016 SOW
Document No.: 128197#-P-01-A
Date of this Issue: 8/22/2016
Date of last Issue: 7/27/2016
Legal Entity: KEMA, Inc.



Customer Details

Customer Name:	Pacificorp
Customer Address:	1407 West North Temple Salt Lake City, UT 84106 Tel: +1 801 220 2017
Customer Reference:	Battery Energy Storage Study for IRP 2016 SOW
Contact Person:	Ian Hoag

DNV GL Company Details

DNV GL Legal Entity:	KEMA, Inc.
DNV GL Organization Unit:	Advisory Americas
DNV GL Address:	4377 County Line Road, Chalfont, PA 18914
DNV GL Telephone. No.:	215-997-4500
DNV GL doc. No.:	128197

About this document

Report Title:	Energy Storage Technology Review
Date of this issue:	2016-08-22
Date of last revision:	2016-07-27
Validity of Report:	30 days from date of issue
Document Classification (see key below):	Customer's Discretion

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For KEMA, Inc.

Prepared by:
Michael Kleinberg
Senior Consultant

Approved by:
John David Erickson
Head of Section, Distributed Energy Resources

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1 INTRODUCTION

1.1 Objective and Scope of Work

At the behest of PacifiCorp, DNV GL has provided a status report and assessment of future potential applications for battery energy storage. DNV GL understands that PacifiCorp's objective is to compile and maintain a catalog of engineering estimates of costs and performance metrics for utility scale battery energy storage technology, both demonstrated for currently commercially available technology as well as forecasted for emerging technology. The 2017 PacifiCorp Integrated Resource Plan (IRP) will include a portfolio of generating resources and energy storage options for evaluation. The provided estimates and information is intended for PacifiCorp's use when preparing their upcoming and future IRPs and assessing energy storage applications for traditional utility transmission and distribution planning issues.

The scope of work is divided between cataloging technology updates and cost trends. The technology updates are broken down by current stage of commercialization, utility applications with associated value streams, and a detailed list of technology performance metrics. The cost analysis includes current system costs for the battery, PCS, controls, installation and O&M, as well as 10-year cost trends for each listed technology. PacifiCorp has specifically requested the scope to include NCM, $LiFePO_4$, and LTO Lithium-Ion (Li-Ion) batteries, Sodium Sulfur (NaS) batteries, Vanadium Redox (VRB) and Zinc Redox (ZnBr) flow batteries, as well as Zinc Hybrid Cathode (also known as Zinc-air) batteries. The report scope does not include application modeling or costs related to a specific vendor, but instead aims to cover the broader energy storage industry as it applies to applications being pursued by PacifiCorp.

The final report provides PacifiCorp with a catalog of commercially available and emerging battery energy storage technologies with forecasts and estimates for both performance and costs. DNV GL has compiled this catalog through the proposed scope of work. To further support PacifiCorp's bi-annual IRP, DNV GL has produced probabilistic cost graphs for each of the proposed technologies, broken out by technology, energy conversion system, controls, and the remaining balance of system.

1.2 Background and Materials

In 2013, PacifiCorp hired HDR Engineering to prepare an energy storage screening study, examining utility-scale storage potential, which was updated by HDR for PacifiCorp's 2015 IRP. This study covered operating and cost data for various energy storage technologies, with a section dedicated to batteries, including details on system size and lifecycle, comparing them to other storage options. The HDR study considers specific manufacturer's products and reference cases under standard operating conditions. PacifiCorp utilized the information from the HDR research to contribute to the modeling of future energy consumption, and how various technologies impact load profiles, costs, and CO2 emissions. This and other previous energy storage studies performed for PacifiCorp are available at www.pacificorp.com/es/irp.html. Energy storage continues to be of interest to stakeholders – and options for advanced large batteries (one megawatt or larger) are detailed in the IRP as quoted from the HDR study, including the battery types DNV GL has been requested to explore. To the extent possible, DNV GL has built upon and utilized existing studies and reports, to expand and update a battery catalog to include a deeper dive into battery technologies, costs, and applications for PacifiCorp's use in their 2017 IRP.

As a global advisory, classification, certification, and technical assurance company, DNV GL has served the energy sector as well as maritime and oil & gas industries for over 150 years. DNV GL is a leading authority on consulting, implementation, research, testing, and certification of solutions for the energy sector. Recognized as a global leader in the area of energy storage, DNV GL provides strategic advisory services, innovative modeling tools, and independent testing and certification of energy storage products to clients across various sectors. DNV GL operates as an independent entity without ties to any vendor, with no investments, affiliations, or financial interest with any equipment or service providers.

Most notably related to this effort, DNV GL has been actively involved in supporting multiple energy storage procurement efforts in the US. Our models for energy storage cost-effectiveness have been employed by state energy commissions, system operators, electric utilities, and project developers to assess the application value of energy operating the grid for a variety of current and future applications. DNV GL has performed independent bid evaluation for utility wholesale and distribution connected energy storage RFOs. This work involved processing energy storage offers from project developers and providing a ranking and bid evaluation on the capital and O&M costs as well as an assessment of the proposed warranty and performance guarantees. Finally, DNV GL is the industry leader in providing independent engineering analysis and technical due diligence to support third-party financing of energy storage deployments. As part of this work, DNV GL has gained significant insight into the costs, technical characteristics, and life-time performance guarantees of energy storage projects being developed in the US. For this report, DNV GL leveraged their experience with battery technology and the broader energy industry to develop reasonable average values for technology parameters, as well as how these parameters affect the cost and feasibility of a particular technology for an application.

Additionally, this study draws on a recommended practice (RP) document called GRIDSTOR (DNVGL-RP-0043), which was developed by DNV GL in partnership with members of the energy storage industry, including technology vendors, grid service providers, energy consultants, and universities. The GRIDSTOR RP provides a breadth of actionable information for deploying safe and reliable grid-connected energy storage systems, offering a blueprint for an independent quality guarantee of the safe implementation and operation of energy storage systems. This guideline draws on DNV GL experience, credible industry insight, and globally accepted regulations and best practices (such as IEC, ISO, and IEE standards), and was utilized as a reference for this report. GRIDSTOR is publicly available for free download at www.dnvgl.com/energy/brochures/download/gridstor.html.

Finally, under the scope of this effort, DNV GL also conducted current market research. This research included a review of published reports from consulting and energy-related clearinghouses, such as Navigant and IRENA, publicly available specification sheets and pricing for reviewed systems, and university and government sponsored research.

2 STAGE OF COMMERCIAL DEVELOPMENT

In this chapter, DNV GL provides an overview of the commercial development of each battery technology requested by PacifiCorp. DNV GL understands the importance of assessing the commercial viability of technologies which are intended to be procured as 10 to 20 year critical assets. With this consideration, DNV GL has provided definitions and basic information surrounding each considered technology and the associated system, followed by a sample of technology providers and sample products available on the market. This is followed by a summary of data available on current industry installation rates, including additional insight into some of the drivers behind the recent trends on installations.

2.1 Lithium-Ion Batteries

Lithium-Ion (Li-Ion) batteries utilize the exchange of Lithium ions between electrodes to charge and discharge the battery. Li-ion is a highly attractive material for batteries because it has high reduction potential, i.e., a tendency to acquire electrons (-3.04 Volt versus a standard hydrogen electrode), and it is lightweight. Li-Ion batteries are typically characterized as power devices capable of short durations (approximately 15 minutes to 1 hour) or stacked to form longer durations (but increasing costs). Rechargeable Li-ion batteries are commonly found in consumer electronic products, such as cell phones and laptops, and are the standard battery found in electric vehicles. In recent years this technology has developed and expanded its portfolio of applications considerably into utility-scale applications. Today, Li-Ion batteries have been implemented for applications relating to ancillary services in grid connected storage. Because of its characteristics, Li-Ion technology is well suited for fast-response applications like frequency regulation, frequency response, and short-term (30-minutes or less) spinning reserve applications.

Li-Ion batteries do carry some safety and environmental risk. Toxic or reactive gases may be released both during creation of the battery cells, as well as in case of thermal runaway within an operating system. However, this risk is being managed across the industry. During cell manufacture, effluent gases can be scrubbed and captured, to be disposed of safely.

Once fully constructed, Li-Ion battery systems come with various methods of cooling, not only to help prevent thermal runaway but also to provide the most beneficial operating temperatures for the battery cells. This risk is being managed from a broader perspective, too; local authorities are preparing to appropriately address any fire concerns. The New York Fire Department (FDNY) and their stakeholders in the National Fire Protection Association (NFPA) have worked with DNV GL to develop ventilation, extinguishing, and cooling requirements for battery fires. Similar types of precautions have been taken industry-wide, in coordination with local communities.

Figure 1 provides a schematic showing what is entailed in a general Li-Ion battery system. This includes monitoring, control, and management systems, power converter/inverter, and the batteries themselves.

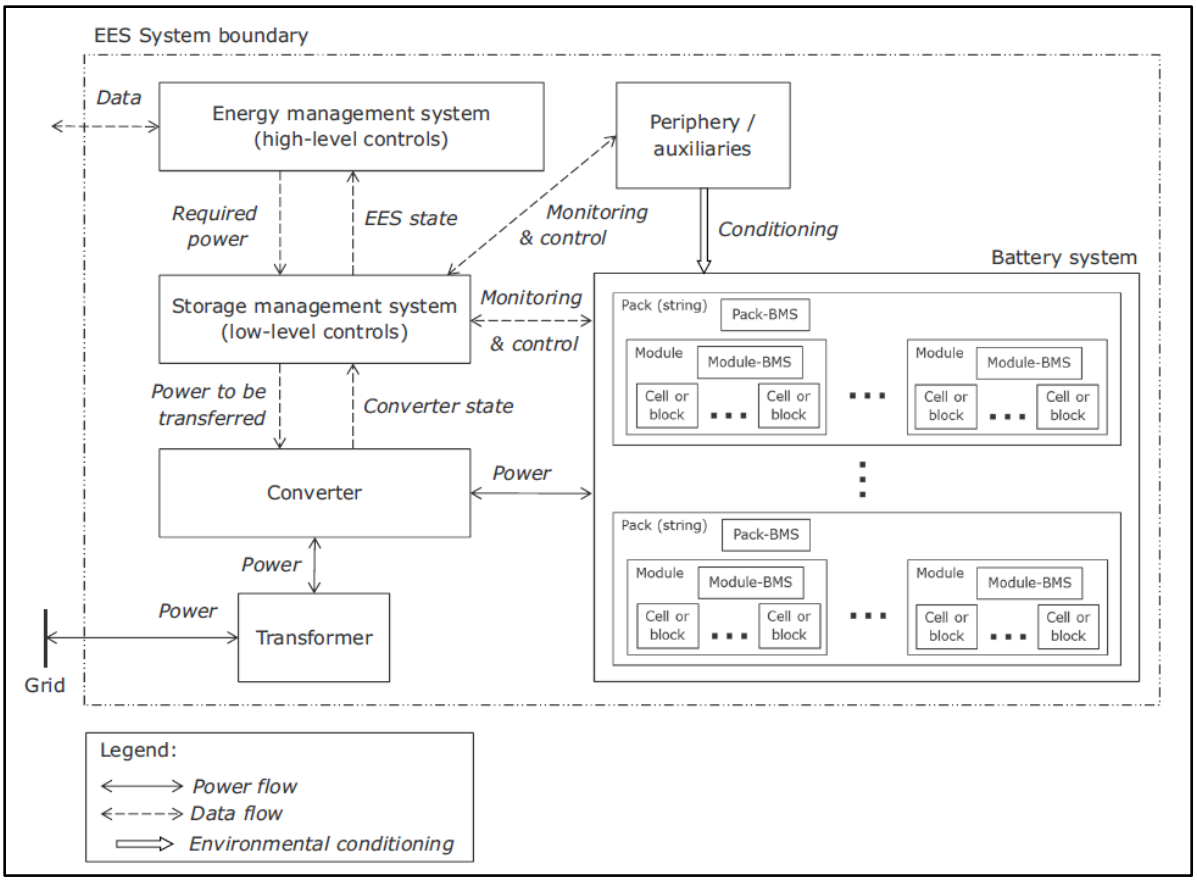


Figure 1 General Schematic and Components of a Cell-Based Battery Energy Storage System

Li-ion technology varies between chemistries. This report will focus on three of the most prominent and promising chemistries, Lithium Nickel Manganese Cobalt Oxide ($LiNiMnCoO_2$ or NCM), Lithium Iron Phosphate ($LiFePO_4$), and Lithium Titanate (Li_4Ti5O_{12} or LTO), and compare and contrast their attributes.

NCM is one of the most commonly used chemistries in grid-scale energy systems. This technology demonstrates balanced performance characteristics in terms of energy, power, cycle life, and cost. NCM chemistry is very common due to these features – it provides an engineering compromise.

$LiFePO_4$, on the other hand, can be purchased at a low cost for a high power density, and its chemistry is considered one of the safest available within Li-Ion batteries. Further, due to its very constant discharge voltage, the cell can deliver essentially full power to 100% DOD. However, LiFePO4 batteries are typically applicable to a more limited set of applications due to its low energy capacity and elevated self-discharge levels.

Finally, LTO offers a stable Li-Ion chemistry, one of the highest cycle lifetimes reported, and a high power density. Further, it is the fastest charging Li-Ion chemistry of those reviewed here. However, in balance, it has a much lower energy density and much higher average cost.

These systems are manufactured widely, but there is relatively high turn-over in manufacturers. Some of the more prominent or market-tested systems are included below, in Table 1.

Table 1 Li-Ion Battery Manufacturers

Technology	Manufacturer	Cell or System Product
NCM	Enerdel Hitachi LeClanche LG Chem Panasonic PBES Samsung XALT Electronova	CE175-360, 160-365 Moxie+ Graphite/NMC JH2 NCR18650A 25R 31,40, 53, 75Ah HE; 31, 40, 63, 75Ah HP; 31, 37Ah UHP
$LiFePO_4$	A123 BYD K2 Energy Microvast Saft Sony Thundersky XO Genesis	AMP20, AHP14, ANR26650, APR18650 LFP123A VL10Fe, VL25Fe IJ1001M WB-LYP, TS-LYP
LTO	Altainano LaClanche Microvast Toshiba XALT	nLTO LTO LpTO (Gen 1) SCiB 2.9, 20, 23Ah 60Ah LTO

2.2 Sodium Sulfur Batteries

Sodium-sulfur (NaS) batteries are a type of molten-salt battery. The systems have high energy density, fast response times, and long cycle lives. They also have some of the longest durations available on the market.

The inclusion of the term “molten” alludes to the battery operating temperature. NaS batteries store electricity through a chemical reaction which operates at 300 °C or above. At lower temperatures the chemicals become solid and reactions cannot occur. The high operating temperature makes the NaS batteries suitable for larger applications supporting the electric grid, but not personal electronic devices or vehicles. Further, due to the high temperature and natural reactivity of pure Sodium when exposed to water, the system can present a safety hazard if damaged.

Figure 1 above provides a schematic showing what is entailed in a general NaS battery system, which is parallel in its architecture to Li-Ion systems. This includes monitoring, control, and management systems, power converter/inverter, and the batteries themselves.

NaS batteries are a mature technology, and the system cost has generally leveled off. Although manufactured by more than one company, the market-share, and thus proven performance, of the company listed in Table 2 represents the majority of installations.

Table 2 NaS Battery Manufacturers

Technology	Manufacturer	Cell or System Product Description
NaS	NGK	NAS

2.3 Vanadium Redox Batteries

Vanadium Redox batteries (VRB), or Vanadium flow batteries, are based on the redox reaction between the two electrolytes in the system. “Redox” is the abbreviation for “reduction-oxidation” reaction. These reactions include all chemical processes in which atoms have their oxidation number changed. In a redox flow cell, the two electrolytes are separated by a semi-permeable membrane. This membrane permits ion flow but prevents mixing of the liquids. Electrical contact is made through inert conductors in the liquids. As the ions flow across the membrane, an electrical current is induced in the conductors to charge the battery. This process is reversed during the discharge cycle. Figure 2 below provides a schematic showing what is entailed in a general VRB system. This includes monitoring, control, and management systems, power converter/inverter, and the electrolyte tanks and stack of the batteries themselves.

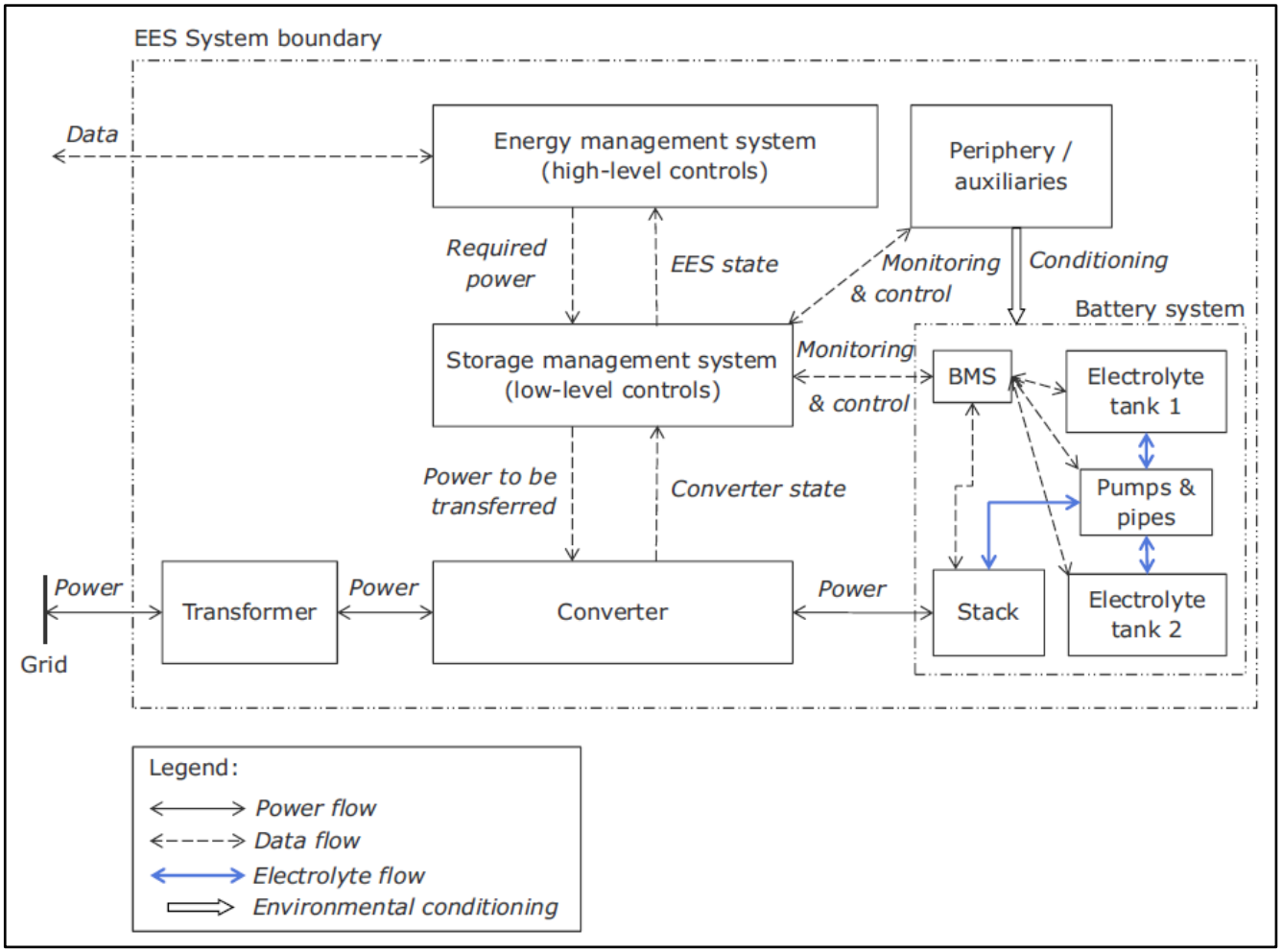


Figure 2 General Schematic and Components of a Redox Flow Battery Energy Storage System

In VRBs, the liquid electrolyte used for charge-discharge reactions is stored externally and pumped through the cell. This allows the energy capacity of the battery to be increased at a low cost. Energy and power are decoupled since energy content depends on the amount of electrolyte stored. VRB systems are unique in that they use one common electrolyte, which provides opportunities for increased cycle life. These large, liquid solution containers do however limit the VRB to stationary storage applications.

An important advantage of VRB technology is that it can be "stopped" without any concern about maintaining a minimum operating temperature or state of charge. This is a key point to most flow batteries in that the batteries can actually be "turned off." This technology can be left uncharged essentially indefinitely without significant capacity degradation.

These systems are relatively new to the battery industry but are solidifying their place in the market. Some of the more prominent or market-tested systems are included below, in Table 3.

Table 3 VRB Manufacturers

Technology	Manufacturer	Cell or System Product Description
VRB	American Vanadium Imergy UET/UniEnergy Vionx	CellCube ESP5, 50, 250 UniSystem, ReFlex

2.4 Zinc Redox Batteries

The Zinc Bromine (ZnBr) battery utilizes similar flow battery technology as the previously discussed VRB. Due to this, it shares many of the same advantages: little to no claimed degradation over time (both in use and in the fully-discharged state), high energy density, 100% DOD, and easily scalable. The ZnBr consists of a zinc-negative electrode and a bromine-positive electrode, separated by a micro-porous separation. Solutions of zinc and a bromine complex compound are circulated through the two compartments. In a ZnBr the electrodes (Zn- and Br+) serve as substrates for the reaction. During charging, the Zinc is electroplated at the anode and bromine is evolved at the cathode. When not cycled, there is a potential for the Zinc to form dendrites that can degrade capacity or damage the battery components. To prevent this, the battery must be regularly and fully discharged.

Figure 2 above provides a schematic showing what is entailed in a general ZnBr system, which is of similar physical structure to VRB, though differing completely in chemistry at the core of energy storage. This includes monitoring, control, and management systems, power converter/inverter, and the electrolyte tanks and stack of the batteries themselves.

The response time for this technology is thought to be inadequate for fast-response applications; this should be verified on a case by case basis as new system designs may be able to improve on this limitation. ZnBr is a promising technology for balancing low-frequency power generation and consumption. However, cycle life tends to be less than that of VRBs.

These systems are in the early stages of commercialization but are being produced by multiple manufacturers. Some of the more prominent or market-tested systems are included below, in Table 4.

Table 4 ZnBr Battery Manufacturers

Technology	Manufacturer	Cell or System Product Description
ZnBr	Enphase (Previously ZBB) Primus Power Flow RedFlow	Enerstor, Agile EnergyCell ZBM2, ZBM3

2.5 Zinc Hybrid Cathode Batteries

Zinc hybrid cathode (Zinc-air) batteries are a type of metal-air battery which uses an electropositive metal in an electrochemical couple with oxygen from the air to generate electricity. Zinc-air batteries take oxygen from the surrounding air to generate current. The oxygen serves as an electrode while the battery construction includes an electrolyte and a zinc electrode that channels air inside the battery.

Zinc-air batteries have power densities similar to Li-ion batteries, but lower energy density. On the other hand, Zinc-air batteries in comparison to flow batteries can have both higher power and energy densities. Unlike Li-Ion, however, Zinc-air batteries are generally claimed to be benign, though their electrolytes – like those of other battery technologies – contain acidic or alkaline compounds and could produce SO2 if burned. The main Zinc-air battery material, zinc-oxide, is theoretically fully recyclable, though this has yet to be demonstrated at scale. In addition, the metals used or proposed in most metal-air designs are low cost.

Zinc-air systems appear attractive for utility applications if their ability to charge and recharge can be improved. The challenge for researchers has been to devise a method where the air electrolyte is not deactivated in the recharging cycle to the point where the oxidation reaction is slowed or stopped. The cessation of the oxidation reaction reduces the number of times that a Zinc-air battery can be recharged. Some of the newest emerging technology, as created by Eos, claims to have addressed these issues by implementing a near-neutral, non-dendritic, and self-healing electrolyte solutions. This, Eos claims, prevents air electrode clogging, rupture of the membrane due to dendrites, and the drying out of the electrolyte, along with other innovations that have prepared the system for commercial launch.

Potential applications include integrating renewable assets, peak shifting and load balancing, and frequency regulation. Consolidated Edison (ConEd) is currently pursuing one of the first utility-scale systems for demonstration with Eos technology.

These systems are in the early stages of commercialization and, as such, manufacturing is limited. Although being researched by more than one company, the earliest product being actively used in demonstration projects is produced by the manufacturer listed in Table 5.

Table 5 Zinc-Hybrid Cathode Battery Manufacturer

Technology	Manufacturer	Product name (if available)
Zinc-air	Eos	Znyth cell in Aurora 1000, 4000

2.6 Commercialization Data

Commercialization and installation data are based on DNV GL's research and publicly available information. This data excludes projects that have been decommissioned for any reason, or construction has not yet started.

Table 6 Installation and Commercialization Data

System Attributes	Li-Ion NCM	Li-Ion $LiFePO_4$	Li-Ion LTO	NaS	VRB	ZnBr	Zinc-air[1]
Typical project size (kW)[2]	6,500	5,000	2,000	6,000	4,000	1,000	3,500
Typical project size (kWh)	15,000	3,100	1,300	40,000	14,000	2,000	13,000
Largest project size installed (kW)[3]	30,000	31,500	40,000	50,000	15,000	1,000	250
Largest project size installed (kWh)	60,000	12,000	40,000	300,000	60,000	2,000	1,000
Current total power capacity installed (MW)[4]	77	142	31	186	66	5	0.25
Current total energy capacity installed (MWh)	30	220	19	1,254	226	25	1

[1] Zinc-air is an emerging technology. Due to this, the majority of the projects DNV GL cited are publicly announced but not yet installed and operational. This clarification is provided to give context to the typical system size being larger than the largest installed system size.
[2] Typical project size, both kW and kWh, are based on averages of publicly known projects that are operational, under construction, contracted, and announced. Decommissioned projects have been excluded from these counts.
[3] Largest project size, both kW and kWh, is based on projects that are currently operational, under construction, or contracted. Announced and decommissioned projects have been excluded from these counts.
[4] Current total power and energy capacity installed are based on publicly known projects that are operational, under construction, or contracted. Announced and decommissioned projects have been excluded from these counts.

3 PERFORMANCE CHARACTERISTICS

This chapter of the report provides a summary of technical parameters for each of the proposed storage technologies in a number of requested fields identified by PacifiCorp as useful for consideration within their 2017 IRP. The specific technology parameters of interest, as identified by PacifiCorp, are as follows:

1. Power Capacity
2. Energy Capacity
3. Recharge Rates
4. Roundtrip Efficiency
5. Availability
6. Degradation
7. Expected Life
8. Environmental Impact upon disposal

Each of the specified parameters are first defined and discussed below followed by a summary of values for each technology. Further, these characteristics are utilized later in this report, in Chapter 5, in determining the appropriateness of a technology for a particular application.

3.1 Power Capability

In composing this analysis, a variety of values were available given DNV GL's experience in the field, depending on operating conditions as well as marketing versus as-built specs. In all cases, all technologies in the study were available down to at least the 1 MW power capacity level, with many having wide use at smaller sizes, for commercial and industrial, residential or non-stationary storage applications. The maximum values were based on the largest installed or proposed and contracted systems to date.

The minimum size of 1 MW was based on feedback from PacifiCorp based on their IRP planning needs. DNV GL notes that all of these technologies are available in sizes smaller than 1 MW and can be installed as customer-sited, behind-the-meter resources. Storage is emerging as a technology being considered to provide utility services from aggregated behind-the-meter resources. Most notably, in 2014 Southern California Edison awarded two (2) capacity contracts to aggregated behind-the-meter energy storage.

3.2 Energy Capacity

The energy capacity DNV GL has compiled is what has been quoted by manufacturing specs as the optimal charge pattern of the entire capacity of the battery as designed. However, in many cases, these units are sold and marketed at a capacity reduced from the system's true total capacity. As such, useable or nameplate system capacity values are provided specified so that the system operates at a usable 0-100% SOC range.

3.3 Recharge Rates

All batteries have certain tolerances with regard to the rate at which they are charged or discharged. The current rating determines the C-rate for the battery, i.e., the rate at which a battery is discharged relative to its maximum energy capacity. Some batteries are more tolerant than others to high discharge rates. On the manufacturer specification sheets that accompany batteries, C-rates that are less than 1 are typically conservative, and may be recommended by the manufacturer to attain longer cycle lifetimes. Typically, discharge rates are higher than charge rates.

3.4 Round Trip Efficiency

Efficiency data provided in this report is the full energy storage system round trip efficiency (RTE). Full system RTE includes the losses from the power conversion system, HVAC equipment loads, control system losses, and self-consumption. Often a manufacturer will provide battery efficiency rather than RTE when promoting their technology. However, there can be a 5-10% difference between these efficiency ratings, when conversion equipment, air conditioning, and other “parasitic” balance of plant devices from the full system are taken into consideration. Auxiliary losses like air conditioning or heating vary considerably according to the technology and the specific application it must perform. For example, the heating requirement for a NaS battery is about 3 percent of its rating but heating is not needed if the battery is discharged daily because heat released during discharge will keep it warm. In this case, typically RTE values are reported based on the system performed a minimum amount of cycling per day.

3.5 Availability

The availability that DNV GL notes is based on guarantees being offered by manufacturers and distributors. Aside from these availability guarantees, annual planned maintenance carve-outs are typically included which do not contribute to these availability figures. Data here is provided based on currently observed guarantees being offered along with utility-scale energy storage systems, however, it should be noted that longer term operation experience will be required before these values are fully verified in practice.

3.6 Degradation

Storage is a unique technology in that its performance characteristics are significantly influenced by degradation. Degradation is highly dependent on system operation. System operation is in turn affected by location, power and energy capacity, applications, and how frequently those applications are utilized. Typically, manufacturer packaging, control and management systems, and environmental considerations are in place to ensure these parameters stay within safe and non-destructive ranges. However, outside influences and one-time events resulting from environmental control failure, BMS failures, or dispatch control error can lead to significant degradation of the device.

The degradation ranges that DNV GL has provided are given at year 10 after installation, based upon the average system operation, segmented by application type. The most common energy applications include electric time shift, electric supply capacity, spinning and non-spinning reserves, and T&D congestion relief. The Power applications include regulations, voltage support, load following and ramping support, and frequency response.

As noted previously, battery performance deteriorates as a result of various degradation mechanisms. The complexity and interactions of these mechanisms are given in detail below.

- **Temperature**: All batteries have an ideal temperature operating range; most batteries control their operation to 30ºC or less. High temperatures (generally above 30-40ºC) tend to degrade capacity severely. Many battery chemistries will indicate operational temperature ranges between 0-60ºC, however operation at or near these limits can severely impact efficiency of the cell as well as lifetime.
- **Charge and Discharge Rates:** For many batteries, high charge/discharge rates lead to higher temperature, compounding the degradation effect.
- **High or Low Average State of Charge:** If a battery spends a significant amount of time at a high state of charge, it will degrade faster than if it is left and maintained at a mid-level state of charge. Some batteries are more sensitive to this than others, but generally it is known that the higher the average state of charge (SOC) over the battery life, the faster it will degrade. Similarly, if a battery is kept at very low average SOC, it will also degrade quickly. This phenomenon has been studied extensively and it has been shown that battery capacity and average SOC are inversely proportional.
- **Depth of Discharge:** Generally, the greater the average depth of discharge (DOD), the faster the battery capacity will fade. In most cases, battery spec sheets will list the lifetime of the battery as number of cycles until 80% of capacity is reached at 100% DOD at 25 C. These conditions are considered nominal and if cycle life of the battery is mentioned without these additional specifications, it is important to verify the DOD, final capacity, and temperature of the tests. Unfortunately, these conditions are often unlike what the battery may experience in an actual application. It is often not noted whether long rest times between charge and discharge were implemented (allowing the battery to cool). Longer rest times can inflate the total cycle life.
- **Calendar Life:** The calendar life of the battery can affect its capacity as much or more than the cycling effects, but it is largely dependent on temperature. Assessing the time the battery is left at rest as a function of temperature is relevant to assessing its state of health. For this reason, most state of health predictions includes both calendar and cycling components.
- **Maintenance:** It is assumed that batteries will not operate completely autonomously. This Maintenance ensures unit operate optimally, given product specific operating constraints. Some manufacturers will further offer capacity maintenance agreements wherein systems are provided with maintenance, supplemental units integrated into the system, or refreshed electrolyte solutions in order to ensure capacity does not degrade past agreed to trigger points.
- **Compounding and Consequential Effects:** It is not possible to list the degradation factors from greatest to least without caveat considerations for specific chemistries, environment and duty cycle, but within the conservative limits established on a battery specification sheet, it may generally be assumed that abuse factors from least to greatest are: Temperature > Depth of Discharge > C-Rates . All of these factors are linked, however, and therefore have compounding effects depending on the battery duty cycle.

3.7 Expected Life

Most systems have not been available at a commercially mature stage for long enough to provide meaningful field data on lifetime performance, so the expected life is currently based on vendor projections, accelerated life-testing (ALT) on cells or modules and limited field results. Cell life tests are typically a good representation of the maximum possible lifetime under ideal conditions, and validation of these results is recommended on a case-by-case basis. With these caveats in mind, the expected life based on standardized cycling and disregarding extenuating circumstances is at least 10 years in all cases. Many manufacturers claim longer calendar lives; these claims assume periodic maintenance, including integrating new modules or adding new electrolyte. The number of cycles that these claims cover varies from technology to technology, based on the applications expected for use. As with calendar life claims, vendors typically claim cycle life in excess of 3,000 cycles. These claims are tied to the same periodic maintenance as previously mentioned. Further, all of the mechanisms discussed above that cause degradation are related to expected life and the system's ability to continue to meet the needs of the customer.

3.8 Environmental Effect Upon Disposal

While batteries claim advantages over traditional energy sources, including the ability to provide energy and power essentially instantaneously and without emission, the components will eventually require disposal. Disposal or recycling, however, comes with consequences. The United States Environmental Protection Agency states that no rechargeable electrochemical cells may lawfully be disposed of to be taken to a landfill. Li-ion and nickel-based electrochemical cells are classified as toxic due to the presence of lead, as well as cobalt, copper, nickel, chromium, thorium, and silver.

The majority of energy storage technologies covered in this report have yet to see adoption rates, much less decommissioning rates, high enough that significant research has been conducted on opportunities and limitations to recycling. While the US Department of Energy has pursued research on the subject, even producing functional Li-Ion cells from recycled materials, the process is so far limited to small pilot operations. For this reason, when decommissioning, disposing of, or pursuing potential recycling of batteries, the manufacturer of the energy storage system should be consulted for guidance. As energy storage systems are deployed in greater numbers, decommissioning and recycling are rising as important facets to financing agreements, contributing to the total cost of ownership.

Lead-acid battery repurposing and recycling activities are a well-established and extremely successful system. The policy has not addressed lithium and nickel-based battery recycling the same way it has lead-acid, and this is due to a number of challenges. The construction materials used in these systems are similar to the advanced technologies covered in this report (alloy and mild steel, aluminum alloys, copper, titanium, HPDE, etc.) and thus the majority of the challenge faced has to do with disassembly, destruction, sorting and any potential contamination. These batteries are mechanically varied between manufacturers and technologies, and packs are very sophisticated relative to lead-acid. In addition, there is a much larger range of materials in each battery, as well as a wide range of chemistries between batteries. Mined Lithium itself is low cost so although recycling is feasible, at present it is not economical. Instead, the primary components of interest are nickel and cobalt (and copper), and not all Li-ion batteries contain them in sufficient quantities. In many cases, the metals involved may just be sent to slag, to be burned for process heat (with the appropriate emission scrubbing). Materials can be recovered from this slag, but they must be

in high enough quantity, quality, and demand to merit the additional effort. NCM batteries, for instance, contain a high enough percentage of valuable constituents (nickel and cobalt) to be recyclable.

Beyond the potential for emissions from burning slag, the chemicals have additional properties that affect disposal options. A universal issue for Li-Ion battery recycling is Lithium's high reactivity, creating a risk of fire if handled incorrectly. Otherwise, DNV GL's own research indicates that the materials within Li-Ion batteries are individually not exotic – for instance, Iron Phosphate is used as a non-toxic pesticide – but their destruction or combustion can create flammable gases such as ethylene, methane, and carbon monoxide. Toxic gases are also created, such as hydrogen fluoride, hydrogen chloride, and hydrogen cyanide. It should be noted that all of these gases are also created during the burning of plastics. To provide perspective as to Li-Ion battery toxicity, on a mass and volume equivalence, plastics are equally or more toxic than the by-products of Li-ion battery combustion.

As to redox flow batteries, electrolytes such as Zinc bromide and Vanadium solutions can typically be reused, sometimes for the life of the battery. However, contaminants or impurities may occur, requiring monitoring and removal. Additionally, upon decommissioning, the Vanadium and Zinc from these batteries may be recycled. It should be noted, however, that several materials commonly found in redox flow batteries are environmentally hazardous and regulated and thus should be disposed of according to regional government requirements. VRB electrolytes can dry or evaporate to form V_2O_5 dust as well as sulfate salts, while ZnBr electrolytes can evolve bromine at temperatures above 50°C.

Finally, Zinc-air batteries, upon decommissioning, have similar overall construction materials that can be recycled via standard processes. Further, the aqueous electrolyte is non-flammable and non-hazardous (both non-toxic to humans and the environment). This electrolyte solution contains salts that are mildly corrosive but are not uniquely different or more hazardous than competing chemistries. The main component of Zinc-air batteries is Zinc-oxide, which is theoretically fully recyclable, although this has not yet been demonstrated on a large scale.

Properties of potential byproducts of battery decomposition are shown in Table 7.

Table 7 Combustion Byproducts of Commercially Available Batteries

		Concentration (ppm unless otherwise noted)								
	Chemical Formula	**LEL (Lower Explosion Limit)**	**IDLH (Immediately Dangerous to Life and Health)**	**Solubility in Water (mg/L)**	**Autoignition Temp (degC)**	**Thermal Instability Threshold (deg C)**	**NFPA Flammability**	**NFPA Health**	**NFPA Reactivity**	**Ref.**
Methane	CH4	50,000	5,000	22.7	537	-	4	1	0	NJ DOH
Carbon Monoxide	CO	12,500	1,500	27.6	609	-	4	2	0	CDC.gov
Ethylene	C2H4	27,000	-	2.9	490	-	4	2	2	Matheson MSDS
H2S	H2S	4,000	300	4,000.0	260	-	4	4	0	CDC.gov
Hydrogen Fluoride	HF	-	30	miscible	-		0	4	0	CDC.gov
Hydrogen Chloride	HCl	-	100	720.0	-	1500	0	3	1	CDC.gov
Hydrogen Cyanide	HCN	-	50	miscible	-		4	4	2	CDC.gov
V2O5 Dust	V2O5	-	35 mg/m^3	0.8	-		0	3	0	CDC.gov
Pb Vapor, salts, dust	Pb	-	700 mg/m^3	10^-5 to 4400	-		0	2	0	CDC.gov
SO2	SO2	-	100	94,000.0	-		0	3	0	CDC.gov

3.9 Technical Parameters Data

System parameters and characteristics are based on DNV GL's industry experience, internal research, and publicly available data. They are subject to the assumptions detailed in the previous sections.

Table 8 Technical Parameters and Performance Characteristics Data, from Both Cell and Project-Scale Perspectives

Parameter/ Technology		Li-Ion NCM	Li-Ion $LiFePO_4$	Li-Ion LTO	NaS	VRB	ZnBr	Zinc-air
Power capability	**Available down to 1 MW[1]**	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Maximum[2] (MW)	35	35	40	50	20	20	15
Energy capacity[3]	**SOC upper limit**	90%	85%	98%	90%	95%	98%	98%
	SOC lower limit	10%	15%	10%	10%	5%	5%	10%
Recharge rates		1C	2C-1C	3C-1C	1C-0.5C	1C-0.25C	1C-0.25C	2C-1C
Round trip efficiency		77 - 85%	78 - 83%	77 - 85%	77 - 83%	65 - 78%	65 - 80%	72 - 75%
Availability	**Up-time**	97%	97%	96%	95%	95%	95%	96%
	Carve Outs	72 hr/yr	72 hr/yr	72 hr/yr	72 hr/yr	1 wk/yr	1 wk/yr	72 hr/yr
Energy Capacity Degradation[4]	**Energy Applications**	30-40%	20-40%	15-25%	15-30%	5-10%	5-10%	15-25%
	Power Applications	10-20%	15-25%	5-15%	5-15%	5-10%	5-10%	5-15%
Expected life[5]	**Years**	10	10	10	15	10	10	10
	Cycles	3,500	2,000	15,000	4,500	5,000	3,000	5,000
Environmental effect upon disposal?[6]		Yes	Yes	Yes	Yes	Yes	Yes	Yes

[1] The minimum size of 1 MW was based on feedback from PacifiCorp based on their IRP planning needs. DNV GL notes that all of these technologies are available in sizes smaller than 1 MW and can be installed as customer-sited, behind-the-meter resources.
[2] Maximum power capability based on largest publicly proposed project.
[3] For usable energy capacity, manufacturers will commonly advertise their battery as allowing 100% DOD based on nameplate capacity. SOC limits given here reflect limits with respect to actual installed energy capacity.
[4] Degradation value based on percent of installed nameplate capacity lost after 10 years of operation. These values assume maintenance is performed as a part of normal operation. Flow battery degradation (VRB and ZnBr) can be mitigated to an extant through normal maintenance and chemistry refresh.
[5] Expected life in calendar years is given for the energy storage component of an ESS and is based on operation at 100% DOD, 25°C, 1C for the number of cycles shown. These values assume maintenance is performed as a part of normal operation. Full system life, including PCS and balance of plant equipment have been observed in range of 15-25 years, implying full replacement of energy storage system components.
[6] Discussion of the severity and risk of these effects are discussed in detail in section 3.8.

4 COST ESTIMATES AND TRENDS

In addition to the commercial and technical review, PacifiCorp requested DNV GL utilize industry experience, in-house data, and market research to the prepare capital and O&M cost estimates for each technology, expressed in mid-2016 dollars. Costs estimates are broken down as follow:

1. Energy Storage Equipment
2. Power Conversion Equipment
3. Power Control System
4. Balance of System
5. Installation
6. Fixed Operation and Maintenance

Each of these costs components are provided as a range covering currently observed industry estimates. In addition to current cost estimates, cost trends over 10 years will be provided as graphs demonstrating a breakdown of system costs in the requested components.

The capital cost for an installed energy storage system is calculated for a system by adding the costs of the energy storage equipment, power conversion equipment, power control system, balance of system, and the installation costs. Each of these categories is accounted for separately because they provide different functions or cost components and are priced based on different system ratings. System component costs based on the power capacity ratings are priced in $/kW, while component costs based on the energy capacity ratings, such as the DC energy storage system, are priced in $/kWh. A description of the system and project development elements included in each cost component is provided below, followed by a summary table of all system costs and graphs depicting 10-year cost trends of relevant components.

4.1 Energy Storage Equipment Costs

Energy storage equipment costs are inclusive of the DC battery system which includes the costs of the energy storage medium, such as Li-Ion battery cells or flow battery electrolyte, along with associated costs of assembling these components into a DC battery system. For Li-Ion systems, battery cells are arranged and connected into strings, modules, and packs which are then packaged into a DC system meeting the required power and energy specifications of the project. The DC system will include internal wiring, temperature and voltage monitoring equipment, and an associated battery management system responsible for managing low-level safety and performance of the DC battery system. For flow batteries, the DC system costs include electrolyte storage tanks, membrane power stacks and container costs for the system along with associated cycling pumps and battery management controls. Energy storage equipment costs are provided on a $/kWh basis which is most appropriate for quantifying the cost of an energy capacity constrained resource. The DC system cost trends are shown in Figure 3.

4.2 Power Conversion System Equipment Costs

Power conversion system (PCS) costs are inclusive of the cost of the inverter, packaging, container, and controls. Inverters employed in energy storage systems are more expensive than the grid-tied inverters widely deployed for solar PV generation, and differentiated by their bi-directional, 4-quadrant operational

capabilities. The cost of the power conversion equipment is proportional to the power rating of the system and provided in $/kW. The PCS cost trends are shown in Figure 4.

4.3 Power Control System Costs

Unique to energy storage systems are the required high-level controllers being deployed to dispatch and operate the systems. With dispatch becoming an ever more important part of storage system design, controllers have to combine multiple functions – from forecasting the load, to understanding the tariff structure and factoring in the type of charge management required for a specific application and technology. The energy industry is currently seeing a number of software companies emerging which are focused solely on control and management of energy storage systems. This includes companies such as Geli, Greensmith, 1Energy Systems, and Intelligent Generation. System integrators and battery storage vendors themselves are also producing controls to operate their systems. These companies include storage and renewable energy companies such as Stem, Advanced Microgrid Systems, RES Americas and SolarCity, as well as established utility energy industry players such as General Electric, Schneider Electric, and ABB. For systems owned or operated by a utility, these controllers must additionally be integrated with utility monitoring and control systems such as Supervisory Control and Data Acquisition Systems (SCADA), Energy Management Systems (EMS), and Distribution Management Systems (DMS), among others. As more advanced applications are considered, such as the energy storage Virtual Power Plants (VPP) currently being considered at Duke Energy and Consolidated Edison, these control layers will become increasingly critical to the success of a given project. At present, the costs for the power control systems have been observed to vary widely and are provided here based on the power capacity of a plant as $/kW. The trend graphs show conservative reduction in costs over ten years; as controls grow more prevalent and efficiencies are found, the control requirements and designs will likely increase in intricacy. The controls cost trends are shown in Figure 5.

4.4 Balance of System

The equipment cost of the storage system will further depend on ancillary equipment necessary for the full storage system interconnection. The balance of system cost here includes wiring, interconnecting transformer, and additional ancillary equipment. For some technologies, this may include the cost of centralized HVAC systems which is required for maintaining acceptable environmental equipment. The balance of system cost is proportional to the power rating of the system and provided in $/kW. The balance of system cost trends are shown in Figure 6.

4.5 Installation

Installation cost accounts for associated Engineer-Procure-Construct (EPC) costs inclusive of installation parts and labor, permitting, site design, and procurement and transportation of all equipment.

4.6 Fixed O&M

Yearly operation and maintenance costs is currently a debated issue for storage projects employing the technologies discussed in this report, as the industry does not yet have longer term operating experience

with the technologies. O&M requirements for Li-Ion systems are generally assumed to be light and include maintenance of HVAC system, tightening of mechanical and electrical connections, cabinet touch up painting and cleaning, and landscaping maintenance. Further, the majority of projects being developed for utilities applications include some type of capacity maintenance agreement. This capacity maintenance agreement guarantees some fixed level of available energy capacity in the system over the term of the project. The cost of the capacity maintenance agreement can be accounted for in the Fixed O&M or as part of the upfront capital costs of the system. For flow battery systems, maintenance services include power stack and pump replacements, tightening of plumbing fixtures, tightening of mechanical and electrical connections, as well as semi-annual chemistry refresh and full discharge cycles to refresh capacity. Further, while many technologies are developing third party training and qualification programs for O&M services, at present many of vendors technology companies themselves are providing O&M services.

Variable O&M costs, while typical to conventional generation sources, are generally assumed negligible for most energy storage systems. It is noted that systems operators can use a variable O&M cost as one means of including the capacity degradation within an energy storage dispatch model. However, there is not currently a uniform or industry acceptable methodology for quantifying variable O&M in this manner. For the purposes of this report, energy storage variable O&M is considered to be negligible.

4.7 Total System Cost Estimates

System costs are based on DNV GL's industry experience, internal research, and publicly available data. These costs are provided in 2016 dollars. This information is given in further context in Section 4.9, which provides calculations for an example installation.

Table 9 Energy storage system cost estimates[1]

Cost Parameter/ Technology	Li-Ion NCM	Li-Ion $LiFePO_4$	Li-Ion LTO	NaS	VRB	ZnBr	Zinc-air
Energy storage equipment cost ($/kWh)[2]	$325-$450	$350-$525	$500-$850	$800-$1000	$500-$700	$525-$725	$200-$400
Power conversion system equipment cost ($/kW)[3]	$350-$500	$350-$500	$350-$500	$500-$750	$500-$750	$500-$750	$350-$500
Power control system cost ($/kW)[4]	$80-$120	$80-$120	$80-$120	$80-$120	$100-$140	$100-$140	$100-$140
Balance of system ($/kW)[5]	$80-$100	$80-$100	$80-$100	$100-$125	$100-$125	$100-$125	$80-$100
Installation ($/kWh)[6]	$120-$180	$120-$180	$120-$180	$140-$200	$140-$200	$140-$200	$120-$180
Fixed O&M cost ($/kW yr)[7]	$6-$11	$6-$11	$6-$11	$7-$12	$7-$12	$7-$12	$6 - $12

[1] All cost estimates provided in mid-2016 dollars
[2] Energy storage equipment includes the full DC battery system which includes the costs of the energy storage medium, such as Li-Ion battery cells or flow battery electrolyte, internal wiring and connections, packaging and containers, and battery management system (BMS).
[3] PCS equipment includes the inverter, packaging, container and inverter controls.
[4] Control system includes supervisory control software, along with the controller and communications hardware required to dispatch and operate energy storage systems.
[5] Balance of system includes site wiring, interconnecting transformer, and additional ancillary equipment.
[6] Installation includes Engineer-Procure-Construct (EPC) costs inclusive of installation parts and labor, permitting, site design, procurement and transportation of equipment.
[7] Fixed O&M costs are provided as real levelized dollars with assumed 20 year project life.

4.8 Example Installed Cost Calculation

Table 10 below shows an example calculation to estimate the installed cost of 10 MW, 20 MWh NCM Li-Ion energy storage system using the cost estimates provided in Table 9. The provided cost estimates result in a low side estimate of $14,000,000 and a high side estimate of $19,800,000 for the system, with component sub-total costs based on the power or energy rating of the system.

Table 10 Example Installed Capital Cost Calculation for 10 MW, 20 MWh NCM Li-Ion Energy Storage System

Cost Parameter	ESS Size	Component Unit Cost Low	Component Unit Cost High	Component Sub-Total Low	Component Sub-Total High
Energy storage equipment cost ($/kWh)	20,000 kWh	$325/kWh	$450/kWh	$6,500,000	$9,000,000
Power conversion equipment cost ($/kW)	10,000 kW	$350/kW	$500/kW	$3,500,000	$5,000,000
Power control system cost ($/kW)	10,000 kW	$80/kW	$120/kW	$800,000	$1,200,000
Balance of system ($/kW)	10,000 kW	$80/kW	$100/kW	$800,000	$1,000,000
Installation ($/kWh)	20,000 kWh	$120/kWh	$180/kWh	$2,400,000	$3,600,000
				Low Total	**High Total**
				$14,000,000	$19,800,000
				Average $16,900,000	

4.9 System 10-Year Cost Trends

As referenced in sections 4.1 to 4.4, graphs depicting 10-year future cost trends are shown below. Cost trends are based on currently available industry projections, as well as DNV GL's interaction with industry partners, and basic cost reduction assumptions, as well as the information discussed in the relevant section, 4.1 through 4.4. These trends are provided for the period from 2016 to 2026.

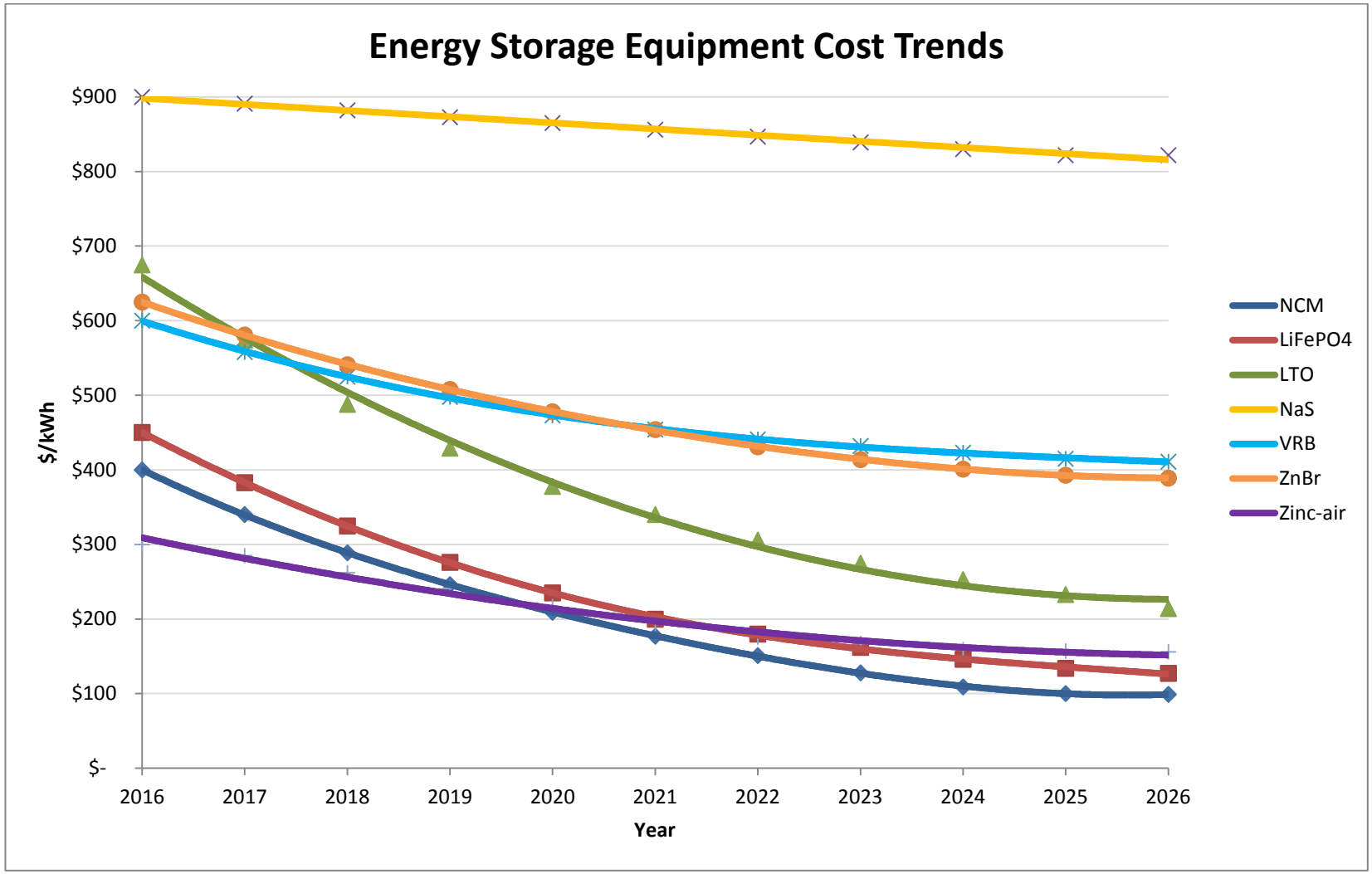


Figure 3 Projected Energy Storage Equipment Cost Trends for Various Technologies, From 2016 to 2026

PCS cost trends are shown in Figure 4. The PCS cost trends mirror each other across two technology groupings. The PCS costs for all Li-ion and Zinc-air technologies are expected to follow similar trends as they are pulling from the same manufacturers utilizing more mature PCS architectures. PCS costs for flow batteries, while currently offered at a higher price point, are expected to converge to similar costs as the Li-ion over time as these technologies mature and gain additional commercial adoption. While NAS is a more mature technology, current PCS costs are above those of Li-ion technologies with future cost reductions expected to benefit from increased adoption of flow battery PCS architectures.

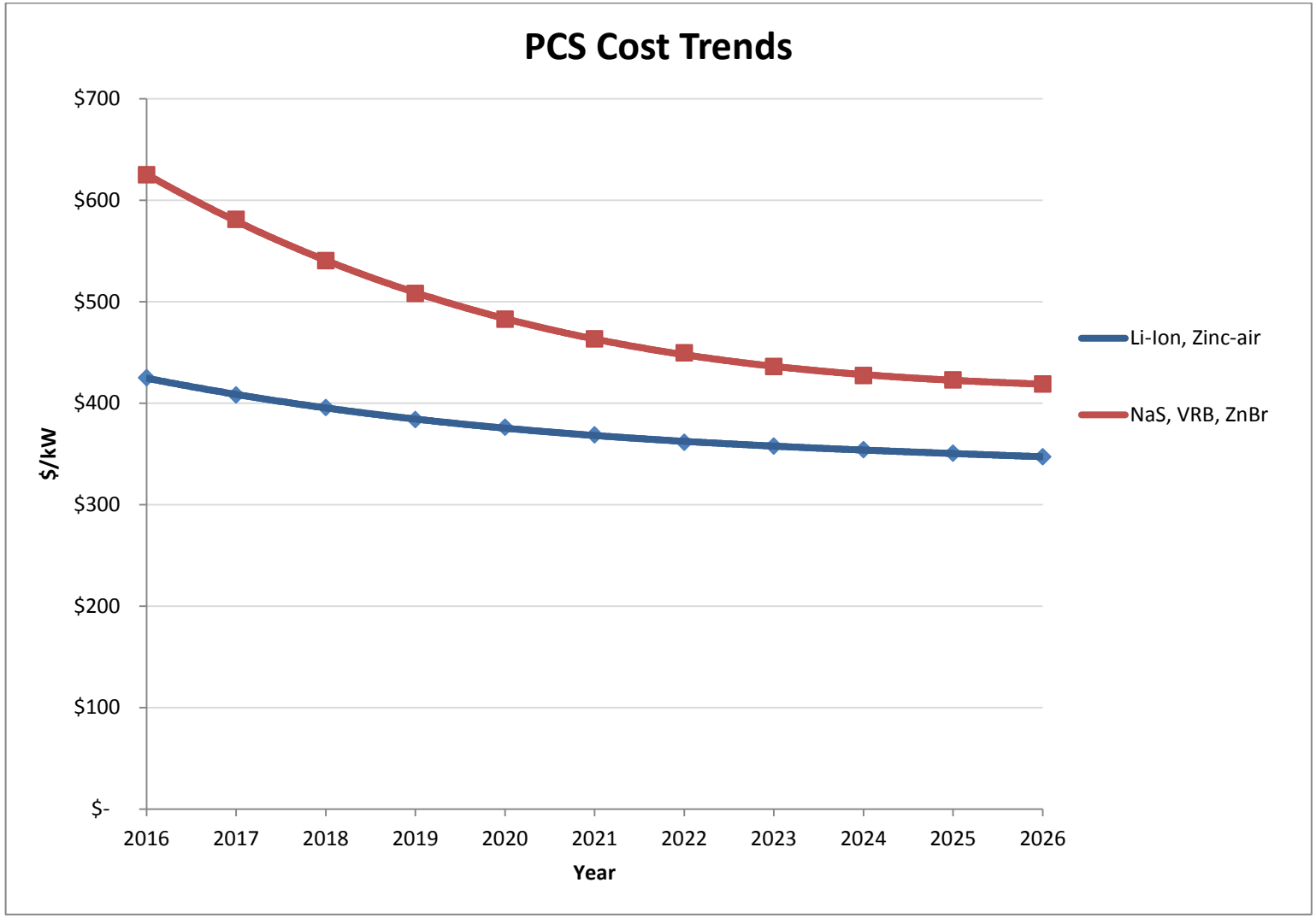


Figure 4 Projected PCS Cost Trends for Various Technologies, From 2016 to 2026

Controls cost reductions, shown in Figure 5, are expected to be relatively uniform across all technologies. While competition in the space is expected to continue, the need for increasingly sophisticated controllers which interact with both utility and distributed behind-the-meter storage assets are expected to result in modest cost reductions over time, converging to a relatively uniform price across technologies.

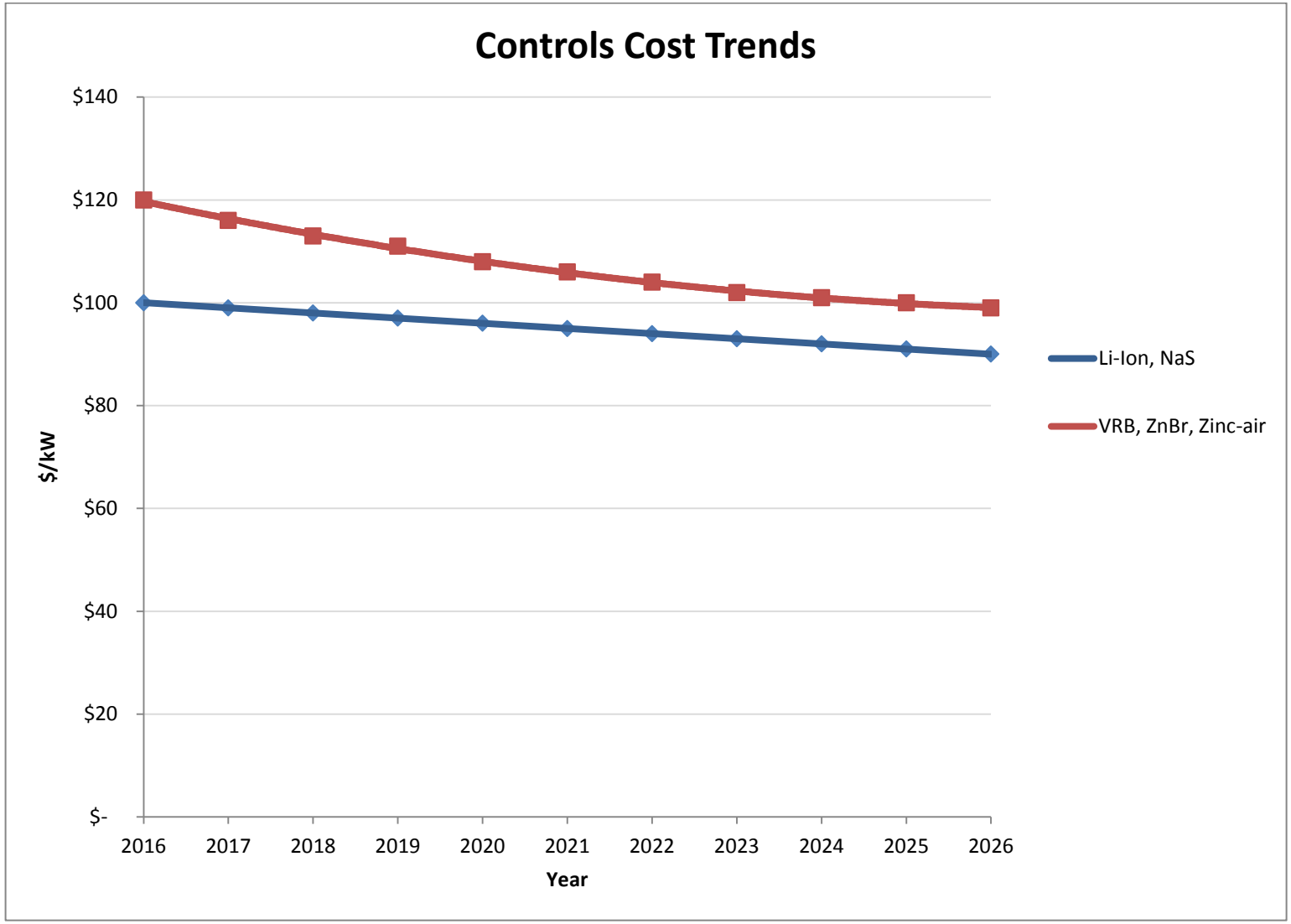


Figure 5 Projected Controls Cost Trends for Various Technologies, From 2016 to 2026

Balance of system costs, shown in Figure 6, is expected to fall dramatically over the next 5 years with continued modest gains through 2026. Cost reductions are expected as project developers gain experience deploying these technologies and system interconnection requirements become more uniform for storage technologies. Li-ion technologies and Zinc-air follow similar trends due to similarities in construction and balance of plant requirements, while reductions for flow batteries and NaS systems are expected to follow similar patterns.

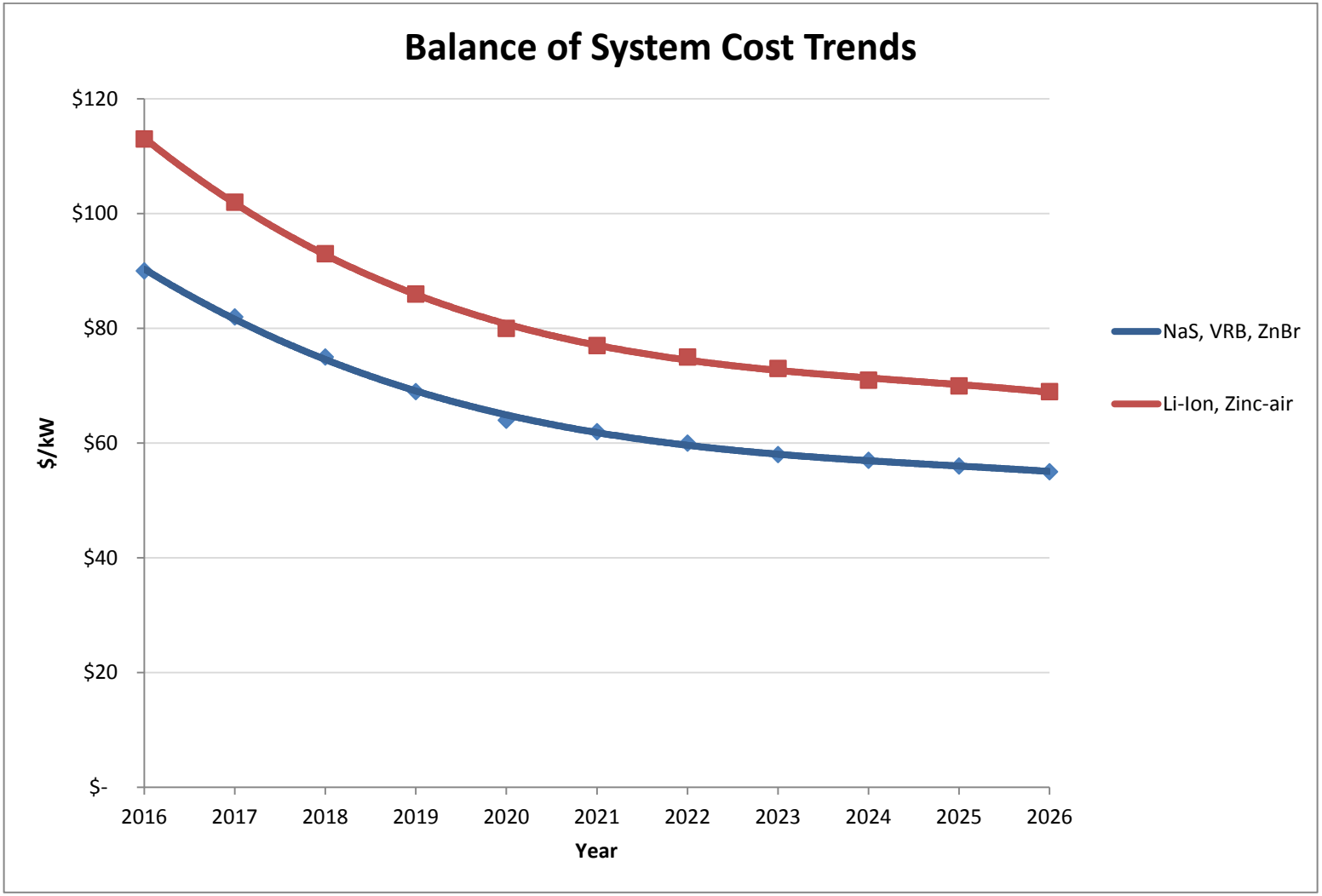


Figure 6 Projected Balance of System Cost Trends for Various Technologies, From 2016 to 2026

5 UTILITY APPLICATIONS AND VALUE STREAM

In this chapter, an application-technology ranking is provided which is intended to indicate the applicability of each technology and their relative potential for generating economic value for at least one of eight (8) benefit cases within PacifiCorp's service territory over the next 20 years. This assessment considers both the likelihood that a particular storage application is relevant to the current PacifiCorp market, as well as the appropriateness of a specific technology to serve the needs of that application. The eight applications identified by PacifiCorp for considerations are as follows:

1. Electric Energy Time Shift
2. Electric Supply Capacity
3. Regulation
4. Spinning, Non-Spinning, and Supplemental Reserves
5. Voltage Support
6. Load Following/Ramping Support for Renewables
7. Frequency Response
8. T&D Congestion Relief

In this chapter, definitions of each application will be provided, followed by an overview of regulatory concerns specific to PacifiCorp territory providing an assessment of both planned regulatory initiatives and local network and market conditions in the PacifiCorp region. These will be reviewed specifically as they relate to energy storage potential. Finally, results of the assessment are provided indicating the applicability of each technology and the relative potential for generating economic value for at least one of the benefit cases within PacifiCorp's service territory over the next 20 years. These rankings are provided on a 1 to 10 scale.

At PacifiCorp's request, this report additionally includes an assessment on applicability of each technology and the relative potential for generating economic value under an alternative market scenario with PacifiCorp operating under market rules similar to those implemented in California ISO (CAISO).

5.1 Considered Applications

DNV GL reviewed applications for energy storage systems based on the regulations and standards in place in PacifiCorp territories, including the availability of financial resources to support energy storage development, as well as the general expansion of demand. Descriptions of these applications are provided below, based on the Department of Energy's Energy Storage Handbook and DNV GL's recommended practice guide, GRIDSTOR.

- **Electric energy time shift –** Energy storage systems operating within an electrical energy time-shift application are charged with inexpensive electrical energy and discharged when prices for electricity are high. On a shorter timescale, energy storage systems can provide a similar time-shift duty by storing excess energy production from, for example, renewable energy sources with a variable energy production, as this might otherwise be curtailed. If the difference in energy prices is the main driver and energy is stored to compensate for (for example) diurnal energy consumption patterns, this application is often referred to as arbitrage.

Storing energy (i.e. in charge mode) at moments of peak power to prevent curtailment or overload is a form of peak shaving. Peak shaving can be applied for peak generation and also – in discharge mode – for peak demand (e.g. in cases of imminent overload). Peak shaving implicates that the energy charged or discharged is discharged or recharged, respectively, at a later stage. Therefore, peak shaving is a form of the energy time-shift application.

An energy storage system used for energy time-shift could be located at or near the energy generation site or in other parts of the grid, including at or near loads. When the energy storage system used for time-shift is located at or near loads, the low-value charging power is transmitted during off-peak times.

Important for an energy storage system operating in this application are the variable operating costs (non-energy related), the storage round-trip efficiency and the storage performance decline as it is being used (i.e. ageing effects).

- **Electric Supply Capacity -** An energy storage system could be used to defer or reduce the need to buy new central station generation capacity and/or purchase capacity in the wholesale electricity market. In this application, the energy storage system supplies part of the peak capacity when the demand is high, thus relieving the generator by limiting the required capacity peak. Following a (partial) discharge, the energy storage system is recharged when the demand is lower. The power supply capacity application is a form of generation peak shaving, therefore a form of electrical energy time-shift. An energy storage system participating in the electrical capacity market may be subject to restrictions/requirements of this market, for example required availability during some periods.
- **Regulation** - Regulation is used to reconcile momentary differences between demand and generation inside a control area or momentary deviations in interchange flows between control areas, caused by fluctuations in generation and loads. In other words, this is a power balancing application. Conventional power plants are often less suited for this application, where rapid changes in power output could incur significant wear and tear. Energy storage systems with a rapid-response characteristic are suitable for operation in a regulation application.

  Energy storage used in regulation applications should have access to and be able to respond to the area control error (ACE) signal (where applicable), which may require a response time of fewer than five seconds. Furthermore, energy storage used in regulation applications should be reliable with a high quality, stable (power) output characteristics.
- **Spinning, Non-spinning, and supplemental reserves** - A certain reserve capacity is usually available when operating an electrical power system. This reserve capacity can be called upon in case some generation capacity becomes unavailable unexpectedly, thus ensuring system operation and availability. A subdivision can be made based on how quickly a reserve capacity is available:
  - Spinning reserve is reserve capacity connected and synchronized with the grid and can respond to compensate for generation or transmission outages. In remote grids spinning reserve is mainly present to cover for volatile consumption. In case a reserve is used to maintain system frequency, the reserve should be able to respond quickly. Spinning reserves are the first type of backup that is used when a power shortage occurs.

- Non-spinning reserve is connected but not synchronized with the grid and usually available within 10 minutes. Examples are offline generation capacity or a block of interruptible loads.
- Supplemental reserve is available within one hour and is usually a backup for spinning and non-spinning reserves. Supplemental reserves are used after all spinning reserves are online.

Stored energy reserves are usually charged energy backups that have to be available for discharge when required to ensure grid stability. An example of a spinning reserve is an uninterruptible power supply (UPS) system, which can provide nearly instantaneous power in the event of a power interruption or a protection from a sudden power surge. Large UPS systems can sometimes maintain a whole local grid in case of a power outage; this application is called island operation.

- **Voltage support** - Grid operators are required to maintain the grid voltage within specified limits. This usually requires management of reactive power (but also active power, e.g. in the LV grid), therefore also referred to as Volt/VAr support. Voltage support is especially valuable during peak load hours when distribution lines and transformers are the most stressed. An application of an energy storage system could be to serve as a source or sink of the reactive power. These energy storage systems could be placed strategically at central or distributed locations.

  Voltage support typically is a local issue at low voltage (LV), medium voltage (MV) or high voltage (HV) level. The distributed placement of energy storage systems allows for voltage support near large loads within the grid. Voltage support can also be provided by operation of generators, loads, and other devices. A possible advantage of energy storage systems over these other systems is that energy storage systems are available to the grid even when not generating or demanding power.

  Note that no (or low) real power is required from an energy storage system operating within a voltage/VAr support application, so cycles per year are not applicable for this application and storage system size is indicated in MVAr rather than MW. The converter needs to be capable of operating at a non-unity power factor in order to source or sink reactive power. The nominal duration needed for voltage support is estimated to be 30 minutes, which allows the grid time to stabilize and/or begin orderly load shedding.

- **Load following / ramping support for renewables** - Load following is one of the ancillary services required to operate a stable electricity grid. Energy storage systems used in load following applications are used to supply (discharge) or absorb (charge) power to compensate for load variations. Therefore, this is a power balancing application. In general, the load variations should stay within certain limits for the rate of change, or ramp rate. Therefore, this application is a form of ramp rate control. The same holds for generation variations, which is very applicable to renewable energy sources. Due to the intermittency of renewables production, having a storage device with several hour durations can provide a large advantage to renewable efficiencies, easing of grid impacts, and renewable production. Conventional power generation can also operate with a load following (or RES compensating) application. Within these applications, the benefits of energy storage systems over conventional power generation are that:
  - most systems can operate at partial load with relatively modest performance penalties
  - most systems can respond quickly with respect to a varying load

- systems are suitable for both load following down (as the load decreases) and load following up (as the load increases) by either charging or discharging.

Note that an energy storage system operating with a load-following or ramp rate control application within a market area needs to purchase (when charging) or sell (when discharging) energy at the going wholesale price. As such the energy storage efficiency is important when determining the value of the load following application.

- **Frequency response -** Synthetic inertia behavior is the increase or decrease in power output proportional to the change of grid frequency; physical inertia is provided by conventional power generators, i.e. synchronous generators. If the total amount of physical inertia decreases in a power system, the amount of synthetic inertia should be increased to maintain a certain minimum amount of total inertia. Many grid-connected renewable energy sources do not provide additional synthetic inertia. Therefore, larger grid frequency deviations may occur as the total inertia in the power system decreases. Keeping track of the total system inertia could be a future task of ISOs.

  Some energy storage systems add synthetic inertia to the system and can thereby be used to compensate for fluctuations in the grid frequency. Causes of fluctuations could be the loss of a generation unit or a transmission line (causing a sudden power imbalance). Various generator response actions are needed to counteract a sudden frequency deviation, often within seconds.

  Energy storage within a frequency response application could support the grid operator and thereby assure a smoother transition from an upset period to normal operation. For a frequency response type of application, the energy storage is required to provide support within milliseconds. Storage helps to maintain the grid frequency and to comply with Control Performance Standards (CPSs) 1 and 2 of the North American Reliability Council (NERC). Aside from this quick response, the frequency response application is similar to load following and regulation, as described previously.

- **Transmission and distribution congestion relief** – During moments of peak demand, it may occur that the available transmission lines do not provide enough capacity to deliver the least-cost energy to some or all of the connected loads. This transmission congestion may increase the energy cost.

  Energy storage systems at strategic positions within the electricity grid help to avoid congestion-related costs and charges. The energy storage system can be charged when there is no congestion and discharged when congestion occurs. Energy storage can, in this way, additionally delay and sometimes avoid the need to upgrade a transmission or distribution system.

5.2 PacifiCorp Territory Regulatory Concerns and Application Drivers

Currently, the largest drivers of energy storage deployment nationally have been a direct result of state and federal level regulatory actions encouraging or mandating procurement and installation of energy storage technologies. Much of the regulatory action has come as follow-up initiatives to more aggressive renewable portfolio standards (RPS) with storage seen as an enabling technology which can mitigate issues associated with higher level of renewable penetration. To a lesser extent, regulatory action around energy security has additionally spurred some development opportunities for energy storage as a reliability resource.

Additionally, a small set of cost-effective applications in select markets, such as frequency regulation, supply capacity, and transmission and distribution deferral have been driving installations. Where market operators have permitted energy storage systems to obtain capacity credits, larger-scale energy storage systems have been justified financially based on the capacity payments over 10-20 year contracts. These structures have additionally supported storage applications for transmission and distribution (T&D) congestion relief. Finally, markets which have developed mechanisms to compensate fast regulation or pay-for-performance market products, have allowed for an opportunity for battery energy storage systems which can obtain high-performance scores in these markets.

Of note, the growth of commercial and industrial behind-the-meter storage installations has been driven in select markets where customers are exposed to high retail rates, and more importantly, high monthly peak demand charges. At the residential level, in select markets where net-metering rules are unfavorable to customers installing solar generation, and high retail energy rates exist, residential self-supply is also seen as a cost-effective energy storage application.

Based on these current trends, storage applications related to capacity such as supply capacity and T&D congestion relief, as well as applications supporting renewable integration, such as renewable time shifting, regulation, and load following, and to a lesser extent, frequency response and voltage support, are likely to be the more likely application for storage over the next 20 years. The relative ranking of these applications is more nuanced and requires a look at the policies in-place or planned for PacifiCorp's service territory.

The PacifiCorp territory is comprised of regions throughout California, Oregon, and Washington (under PacificPower), and Idaho, Utah, and Wyoming (under Rocky Mountain Power). Each state observes a variety of regulations relating to energy security, distribution, and storage. Further, the federal government provides additional regulation that must be observed. At both the state and federal level, incentives are additionally provided in some cases.

The PacificPower region, in particular, has a well-developed set of regulations and incentives already in place. Oregon, Washington, and California all have Renewable Portfolio Standards (RPS) as well as other legislation that encourages utility pursuit of clean energy and potentially energy storage systems.

Oregon's most influential energy storage-specific legislation that passed in 2015, HB 2193, directs the state's electric utility companies to procure one or more energy storage systems capable of storing a specified energy capacity by 2020, allowing them to recover all costs through electrical rates. Additionally, SB 1547 passed in 2016, requiring, among other things, an RPS which would amount to 50% renewables for PacifiCorp by 2040, and the elimination of coal-generated energy utilization by 2030. This legislation will put additional pressure for energy storage to support the growing renewables portfolio.

In the state of Washington, several bills have been passed that create a supportive infrastructure for energy storage. For example, HB 1897 established a program in support of R&D to develop next generation clean energy technology sustainably; HB 1296 legislated that an IRP is required to include energy storage; SB 5025 amended laws to support the meeting of renewable energy targets by utilities and minimum standards for energy efficient buildings; and HB 1895, a bill currently pending a hearing, if passed would promote the deployment of clean distributed energy, and prioritizes deployment of smart grids and microgrids. Further, the Energy Independence Act, or I-937, specifically requires a 15% RPS by 2020. The pursuit of these standards has recently been supported by HB 1115. This legislation sets aside $44 million in grants that are to be directed towards renewables advancement and technology, specifically including energy storage.

California has for many years been a leading state in the pursuit of clean energy. Many pieces of legislation support renewable technology infrastructure, especially focused on the causes of reducing emissions and improving energy resiliency. For instance, SB 1358 specifies emission performance standards and SB 350 requires an increase in the amount of electricity generated and sold from renewable energy resources in order to strengthen the diversity and resilience of the electrical system. California further passed SB 83, requiring public utilities to enact net metering tariffs to enhance diversification and reliability of the state's energy resources. Recently, AB 1530 states that clean distributed energy must be deployed by utilities, and prioritizes deployment of smart grids and microgrids. Specifically, California utilities must meet an RPS of 50% by 2030, with intermediate goals, as initiated by AB 327 and SB 350, noted previously.

In contrast, the Rocky Mountain Power region does not have as many or as specific regulation or support. While Utah provides a renewable energy target of 20% by 2025, but not an RPS, neither Idaho nor Wyoming has any RPS or voluntary renewable goals. There are, however, several pieces of legislation that support, directly or indirectly, energy storage, chiefly as a method to support reliability and resiliency.

Utah leads the way with SB 0115, called the Sustainable Transportation and Energy Plan (STEP) Act. This bill allows for the Public Service Commission to authorize the implementation of tariffs by utilities in order to establish electric efficiency technology programs, allows the utility to provide incentives for air quality improvement technology and electric vehicle infrastructure development, and provides support for clean energy programs implemented by utilities. PacifiCorp has already reacted to this legislation with their STEP initiative. This includes the STEP Pilot programs, 5-year programs providing funding to, among other projects, battery storage development. Additionally, PacifiCorp has applied to the Public Service Commission to offer large customers the option to participate in a Renewable Energy Tariff, paying directly to get part or all of their electricity from a specific renewable project. Further, Utah has passed SB 280, which promotes the development of diverse energy resources, including nonrenewable and renewable resources, nuclear, and alternative transportation fuels. This distributed generation policy's focus is to promote resiliency and reliability of the grid, and will likely naturally lead to an investigation of energy storage procurement and integration.

Idaho passed HB 189, which removed all property taxes on renewable generation sites, in favor of a 3-3.5% tax on generation. Otherwise, although Idaho has neither net metering law nor RPS, it does offer tax credits for renewable energy.

Wyoming, meanwhile, has no net metering law and provides no credits or exemptions for clean distributed energy resources. Further, Wyoming taxes wind generation and is currently considering further raising those taxes. As noted previously, Wyoming has no RPS.

Finally, the Federal Government has put in place regulations to encourage renewables and energy storage. Widely known and utilized is the Investment Tax Credit provided by the Federal government. This 30% direct tax credit was extended until 2019, reduced stepwise annually after that, to 26% in 2020, 22% in 2021, and 10% in 2022, before ending. As to standards, the Clean Power Plan, as regulated by the EPA, assigns each state an emissions reduction target by 2030, contributing to a 32% reduction nationwide. Specific to PacifiCorp, Wyoming, Utah, and Washington have aggressive reduction targets, above 31%, while California, Oregon, and Idaho have reduction targets below 20%, in comparison with 2012 levels. These targets are based on, among other things, generation activity, as well as actions already taken to reduce emissions. States are required to submit a plan for compliance by September 2016, or be subject to a

federally developed plan, both likely to directly affect utilities. Although there is some Congressional action to block these requirements, none has currently passed.

5.3 Application Ranking Methodology and Results

DNV GL developed a ranking system for the various applications that battery energy storage systems may be utilized for within PacifiCorp territory. Within this ranking system, information about each technology is used to ascertain its appropriateness for a particular application. The battery type's typical size, technology maturity level, market penetration, as well as technical parameters and various costs influenced these rankings.

First, each application was defined by its requirements for power, energy, cycling, and response time. These Application Requirements were scored on a comparative scale. For instance, in the case of the application of Electric Energy Time Shift, the energy capacity of the system is paramount and thus ranked highly. Alternatively, in the case of the application for Frequency Response, the energy capacity of the system is of lesser importance while response time and power capability are the prioritized requirements. Each technology was then defined by its capabilities to meet these requirements for power, energy, cycling, and response time. These technology capabilities were similarly scored on a comparative scale. For instance, Li-ion technology provides nearly instantaneous response time and was thus ranked highest in that parameter. Flow batteries, on the other hand, scored highest for cycling as they are capable of fully discharging daily with less impact on lifetime and degradation. A Technology Maturity score was then also assigned to technology each based on its current stage of commercialization and scale of field deployments.

The Application Requirements and Technology Capability scores were then compared, defining how well-matched a specific technology was for a given application. For instance, if an application required fast response time, the technologies that provide a fast response time would score highest. Scores across each property were then averaged to provide a Technology Application score for each technology providing each application.

A PacifiCorp Application Need score was then assigned to each application based on the high-level cost-effectiveness and regulatory analysis of the PacifiCorp territory. Based on current PacifiCorp market scenario, storage applications with high value that are not dependent on market-related rule changes, such as T&D congestion relief, are expected to be the most likely candidates for PacifiCorp to deploy energy storage. Additionally, as noted in the review, renewable portfolio standards across the PacifiCorp region will drive some renewable integration applications such as renewable time shifting, regulation, and load following. Faster regulation applications such frequency response and voltage support are likely to be lower value applications. A second set of Scores for PacifiCorp Application Need scores were provided for the alternative market scenario with PacifiCorp operating under market rules similar to those implemented in California ISO (CAISO). For this scenario, CAISO market rules which directly allow storage to qualify for supply capacity credit increased this application score. Also, further developed fast regulation and emerging ramping market products increased the PacifiCorp Application Need score for frequency regulation and applications tied to renewable integration.

Finally, PacifiCorp application rankings were computed for each application and technology under each market rules scenarios. The final rankings were computed by taking the average score over the Technology Application score, the Technology Maturity Score, and the PacifiCorp Need score. This methodology resulted in Table 11 and Table 12.

Table 11 Application Rankings in Current Market Rules Scenario

Application	Current Market Scenario						
	Li-Ion NCM	Li-Ion LiFePO4	Li-Ion LTO	NaS	VRB	ZnBr	Zinc-air
Electric Energy Time Shift	9	8	8	9	8	8	7
Electric Supply Capacity	9	9	9	9	8	8	7
Regulation	9	9	9	9	8	8	7
Spinning, Non-spin, Supplemental reserves	8	8	9	8	8	8	7
Voltage support	7	8	8	7	6	6	6
Load following / ramping support for renewables	8	8	9	8	8	8	7
Frequency response	7	7	8	7	6	6	5
Transmission and distribution congestion relief	9	9	9	9	9	9	8

Table 12 Application Rankings for CAISO Market Rules Scenario

Application	CAISO Market Scenario						
	Li-Ion NCM	Li-Ion LiFePO4	Li-Ion LTO	NaS	VRB	ZnBr	Zinc-air
Electric Energy Time Shift	9	9	9	9	9	9	7
Electric Supply Capacity	9	9	9	9	9	9	8
Regulation	9	9	9	9	8	8	7
Spinning, Non-spin, Supplemental reserves	9	9	9	9	8	8	7
Voltage support	7	8	8	7	6	6	6
Load following / ramping support for renewables	9	9	9	9	8	8	7
Frequency response	7	7	8	7	6	6	5
Transmission and distribution congestion relief	9	9	9	9	9	9	8

6 CONCLUSION

The data from this study is intended to support PacifiCorp in making decisions regarding energy storage procurement and grid integration to support their 2017 IRP, giving confidence in the current state of the industry while providing insight into what trends and regulations which will prevail in the future. Further, this study is intended to provide general guidance on the appropriateness of each presented technology for specific applications, as needs and requirements vary across each PacifiCorp region. The inclusion of battery energy storage, particularly when paired with other distributed energy resources, will allow PacifiCorp to comply with emerging energy regulations while also providing greater flexibility, resiliency, and efficiency in the allocation of resources.

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FINAL

BULK STORAGE STUDY FOR THE 2017 INTEGRATED RESOURCE PLAN

B&V PROJECT NO. 192472

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PREPARED FOR

PacifiCorp

19 AUGUST 2016

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1.0 Introduction

Black & Veatch Corporation (B&V) was retained by PacifiCorp to perform a Bulk Energy Storage Study (Study) to support PacifiCorp's 2017 Integrated Resource Plan (IRP). IRPs are developed by power utilities to evaluate a portfolio of generating resources and energy storage options for their system in order to balance increasing levels of variable energy resources and, as generation from variable energy resources and their relative percentage of load grow, the need for additional system flexibility to assure grid reliability. For PacifiCorp, generating resource options include fossil fuel options, such as coal and natural gas, as well as renewable options including wind, geothermal, hydro, biomass, and solar.

Energy storage technologies have been evaluated in the past by PacifiCorp.

- HDR Engineering (HDR) was retained by PacifiCorp to perform an energy storage study titled "Energy Storage Screening Study For Integrating Variable Energy Resources within the PacifiCorp System" dated December 9, 2011, to support PacifiCorp's 2013 IRP.
- To support PacifiCorp's 2015 IRP, HDR provided an updated version of their 2011 study titled "Update to Energy Storage Screening Study for Integrating Variable Energy Resources within the PacifiCorp System" dated July 9, 2014.

As requested by PacifiCorp to support their 2017 IRP, the scope of work for this Study is only an update of the estimates of costs, schedules, and operating/performance characteristics provided in the previous HDR energy storage studies with a focus on two primary energy storage technologies with specific projects of each in various stages of planning as follows.

- Pumped Storage Hydroelectric
  - Swan Lake North
  - JD Pool - Klikitat
  - Seminoe
- Compressed Air Energy Storage
  - Magnum Energy

The results of the Study are provided in the following report sections and appendices. The information presented has been gathered from and is based on public and private documentation, studies, reports, and project data of the specific projects associated with the two primary energy storage technologies of the scope of work. Although not included in the scope of work for this Study, a thorough and applicable discussion of considerations for integrating variable energy resources into power systems is provided in HDR's 2011 and 2014 reports for information purposes and will not be restated herein.

2.0 Pumped Storage Hydroelectric

The previous HDR 2011 and 2014 energy storage studies considered potential pumped storage hydroelectric projects within the PacifiCorp operating power system region as follows:

- HDR 2011 Study
  - Swan Lake North
  - Yale-Merwin
  - JD Pool
  - Parker Knoll
- HDR 2014 Study
  - Swan Lake North
  - JD Pool
  - Black Canyon[1]

For this Study, PacifiCorp has requested that only the estimated costs, schedules, and operating/performance characteristics from the HDR 2014 study be updated for the Swan Lake North, JD Pool, and Seminoe projects.

2.1 GENERAL

A pumped storage hydroelectric facility requires a lower and upper reservoir. During times of minimal load demand or when required to absorb energy, excess energy is used to pump water from a lower reservoir to an upper reservoir. When energy is required (during a high value or a peak electrical demand period), water in the upper reservoir is released through a turbine to produce electricity. The pumping and generating is typically accomplished by a reversible pump-turbine/motor-generator. In addition to providing electricity at times of peak power demand, applications for pumped storage hydroelectric projects include:

- Providing transmission system support through ancillary services, such as load shifting and following, frequency control, grid stabilization, and reserve generation, etc.
- Energy storage for less dependable renewable resources, such as wind and solar energy.

Pumped storage projects may be categorized as either open-loop or closed-loop pumped storage projects. The Federal Energy Regulatory Commission (FERC) defines these classifications as follows:

- Open-loop pumped storage projects are continuously connected to a naturally-flowing water feature.

[1] Black Canyon Pumped Storage Project is a precursor to the Seminoe Pumped Storage Project.

- Closed-loop pumped storage projects are not continuously connected to a naturally-flowing water feature.

For open-loop pumped storage systems, acquisition of environmental approvals has become increasingly challenging due to the need to develop a lower reservoir on an active river or existing lake. To mitigate this issue, many recent pumped storage developments have proposed closed-loop systems, which often utilize existing features such as abandoned quarries or underground mines as the lower reservoir of the pumped storage system. This allows the pumped storage project to be developed and operated off-stream, reducing environmental impacts and also reducing costs associated with development of the lower reservoir.

2.2 SWAN LAKE NORTH

2.2.1 Current Project Status

In HDR's 2014 study, it is noted that various preliminary Federal Energy Regulatory Commission (FERC) permits and a draft license application were filed for the Swan Lake North Pumped Storage Project (FERC No. 13318) (Project) between 2010 and 2012. Over this period, the proposed capacity of the project went from 1,000 megawatts (MW) to 600 MW due to the developer, Swan Lake North Hydro LLC, making a number of changes to the project layout, size of reservoirs, water conveyance arrangement, and consideration of surface penstocks. The 600 MW project capacity was the basis for HDR's 2014 study.

Since 2014, a Final License Application (FLA) was filed by Swan Lake North Hydro LLC on October 27, 2015, and is currently under consideration by the FERC. In this document, the proposed project capacity was further reduced to 400 MW due to further project optimization during the course of final license application development. Although drawings from the final license application are not publically available through the FERC website, it is assumed that the general project configuration will be similar to the site layout and profile provided in the HDR 2014 study, only at a lower capacity. The 400 MW project capacity and the description of the project facilities provided in the final license application exhibits that is publically available from the FERC website are the basis for this Study.

2.2.2 Project Description

The Project is a closed-loop pumped storage system with an installed capacity of 393.3 MW in generating mode. It will be located approximately 11 miles northwest of Klamath Falls, Oregon. A general summary of the proposed Project facilities is provided in Table 1 in Appendix A.

2.2.3 Schedule

The proposed construction schedule for the Project is described and presented in Exhibit C of the FLA. The schedule assumes approximately 24 months for final design with an expected completion date in 2017. Final review and approval of the design is anticipated to take 6 to 12 months after which construction will begin. Construction will take approximately 4 years to complete. The proposed commercial operation date is November 2022, assuming a FERC Notice-to-Proceed in January 2018.

2.3 JD POOL

2.3.1 Current Status

In HDR's 2014 study, it is noted that an original preliminary FERC permit and a successive application had been filed by the Public Utility District No. 1 of Klickitat County, Washington (KPUD) for the JD Pool Pumped Storage Project (FERC No. 13333) (Project) on November 29, 2008, and April 30, 2012, respectively. The information provided in the successive application was the basis of information for HDR's 2014 study. The proposed Project capacity at that time was 1,500 MW.

After the HDR 2014 study, a Pre-Application Document (PAD) was filed by KPUD in October 2014. The information in the PAD revised the project configuration and reduced the Project proposed capacity to 1,200 MW. Due to the effective date of the successive application, KPUD filed a second successive preliminary permit application on November 3, 2015, in order to extend the effective date of the application. At the same time, Clean Power Development LLC (Clean Power) filed a competing preliminary permit application for the proposed Columbia Gorge Renewable Energy Balancing Project (FERC No. 14729) (Columbia Gorge Project) at the same location.

The lower reservoir site for both applications is currently undergoing a cleanup process due to decades of contamination from the former operation of the Columbia Gorge Aluminum smelter. Given the uncertainty of the timeline for the site cleanup and its suitability for development, FERC found it not prudent to issue a preliminary permit for the site and dismissed both applications.

The above information concerning the Project status and dismissal of the preliminary permit applications filed by KUPD and Clean Power is summarized from FERC's "ORDER DISMISSING PRELIMINARY PERMIT APPLICATIONS" document dated December 23, 2015. FERC also notes in this document that they may consider development applications in the future for the site, but the applications must thoroughly address all concerns related to developing the Project at a previously contaminated site. Thus, permitting this site in the future may require special considerations, and its timeline is unknown at this time.

Based on the public information available from the FERC website, the 1,200 MW project capacity and the description of the project facilities provided in the PAD are the basis for this Study.

2.3.2 Project Description

The Project is a closed-loop pumped storage system with an installed capacity of 1,200 MW in generating mode. It will be located approximately 8 miles southwest of Goldendale, Washington. A general summary of the proposed Project facilities is provided in Table 2 in Appendix A.

Based on a review of the PAD information, there is a high likelihood that the Project can be further optimized to reduce costs, such as finalizing the total storage requirement of the reservoirs and the number and/or size of the water conveyance conduits.

2.3.3 Schedule

The proposed development and construction schedule for the Project is outlined in the PAD as follows:

- Pre-filing Schedule for Filing License Application: 1 year
- Pre-construction Development Activities after FERC Issuance of License, Including Design/Construction Drawings: 3 years
- Project Construction: 5 years
- Anticipated Commissioning of Project: 5th Year of Construction

2.4 SEMINOE

2.4.1 Current Status

The HDR 2014 study included the Black Canyon Pumped Storage Project (FERC No. P-14087). A preliminary FERC permit application for the project was prepared by Gridflex Energy, LLC and filed by Black Canyon Hydro, LLC on January 25, 2011. The application showed several possible alternatives for pumped storage development that included two new upper reservoirs that could be connected to one of two existing lower reservoirs, the Seminoe and Kortes Reservoirs. Both of the existing reservoirs are owned and operated by the U.S. Department of Interior's Bureau of Reclamation. The original preliminary permit for the project, along with Gridflex's response to HDR's Request for Information (RFI), was the basis of information for HDR's 2014 study. As noted by HDR, there was conflicting information relative to generating and pumping capacities between the original preliminary permit and the RFI response.

On July 1, 2014, Gridflex prepared and Black Canyon Hydro, LLC filed a successive preliminary permit application for the Black Canyon Pumped Storage Project (FERC No. P-14087). This filing occurred about the time HDR had concluded their 2014 study. The successive application identified and included an additional alternative for consideration. However, on November 26, 2014, FERC issued an order denying the successive preliminary permit on the general basis that very little progress toward the filing of a development application had been made during the course of the original three-year permit term and did not warrant a successive permit.

Gridflex prepared and Black Canyon Hydro, LLC filed a preliminary FERC permit application for the Seminoe Pumped Storage Project (FERC No. P-14787) (Project) on June 16, 2016. This Project is similar to and utilizes the concept of the Black Canyon Pumped Storage Project. Per FERC letter dated June 21, 2016, some deficiencies and the need for additional information were identified with regard to the application. Gridflex prepared and Black Canyon Hydro, LLC filed an amended preliminary FERC permit application on June 28, 2016, which was accepted by FERC on June 30, 2016. The proposed total Project capacity is 700 MW and consists of two developments (i.e. East and West) that utilize the existing Seminoe Reservoir as their lower reservoir.

2.4.2 Project Description

The Project is an open-loop pumped storage system with a total installed capacity of 700 MW in the generating mode. It will be located approximately 30 miles northeast of Rawlins, Wyoming. The Project utilizes the water resources of the North Platte River as stored and conveyed through the existing reservoir. The Project includes two new forebay reservoirs (i.e. East and West), two underground powerhouses, two power tunnels between the forebays and powerhouses, and two tailrace tunnels between the powerhouses and the existing Seminoe Reservoir. In the generating mode, the East and West powerhouses have installed capacities of 400 and 300 MW, respectively, for a total Project installed capacity of 700 MW. A general summary of the proposed Project facilities is provided in Table 3 in Appendix A.

2.4.3 Schedule

The preliminary permit includes a three-year duration schedule for studies to design the technical aspects of the Project and confirm its economic viability. No overall schedule for Project implementation was provided; however, it would be anticipated that the FERC final license application would be completed in 2019 with final engineering, construction, and commercial operation of the Project completed during the 2020 through 2025 timeframe.

2.5 OPERATING CHARACTERISTICS AND REGULATORY OVERVIEW

A relevant discussion of typical pumped storage hydroelectric project operating characteristics relating to the beneficial services that such projects can provide, and general considerations and important aspects concerning environmental and regulatory factors with regard to siting and developing a potential pumped storage project are provided in HDR's 2014 report for information purposes and will not be restated herein.

2.6 CAPITAL, OPERATING, AND MAINTENANCE COSTS

The following sections provide an update of the cost estimates from the HDR 2014 study with regard to expected capital and operation and maintenance (O&M) costs for the three potential pumped storage projects in the PacifiCorp region selected for this Study. Costs provided are expressed in mid-2016 dollars.

2.6.1 Capital Cost

The HDR 2014 study provided a general discussion of capital costs associated with pumped storage projects. As noted in the HDR 2014, which is particularly true, the direct cost to construct a pumped storage facility may vary greatly and is dependent upon a number of physical site factors. The HDR 2014 study also notes the direct and indirect cost items generally included for capital costs, which would also generally include Owner project contingency, development, and project team costs. In addition to those cost items, capital cost assumptions for this Study include an Engineer-Procure-Construct (EPC) type of project delivery methodology and estimates reflecting a +/- 30% order of accuracy, which would approach an Association for the Advancement of Cost Engineering (AACE) Class 4 cost estimate classification.

2.6.1.1 Swan Lake North

As reported in the HDR 2014 study, EDF provided an AACE Class 4 cost estimate of $2,300/kW for the envisioned 600 MW facility at that time, which apparently compared favorably to earlier cost opinions prepared by HDR for the Project. Escalating this cost to mid-2016 dollars using a rate of 3% per year results in a total project cost of approximately $2,500/kW. The 3% per year escalation rate was used in the HDR 2014 study and is considered appropriate for escalating HDR values to mid-2016 dollars for this Study.

No recent cost information was available from Swan Lake North Hydro LLC for the current Project capacity of 400 MW and description provided in their FLA dated October 27, 2015. Based on our review of the Project described in the FLA, a cost opinion on the order of $2,600/kW would be expected, which compares favorably to the developer's escalated unit cost of $2,500/kW.

2.6.1.2 JD Pool

As reported in the HDR 2014 study, HDR performed a reconnaissance level study and AACE Class 5 cost opinion in 2005 for the 1,500 MW Project envisioned at that time. Their study resulted in an escalated cost opinion of $2,500/kW in 2014 dollars. Escalating to 2016 using a rate of 3% per year, this cost opinion would be approximately $2,700/kW.

No recent cost information was available from KPUD for the current Project described in their PAD dated October 2014, having a capacity of 1,200 MW. However, as reported in the HDR 2014 report, KPUD did provide a cost opinion of $2 billion to $2.5 billion for a 1,000 to 1,200 MW project in their Preliminary Permit Application, which equated to unit costs of $1,700 to $2,500/kW. Escalating to 2016 using a rate of 3% per year, these cost opinions would be approximately $1,800 to $2,700/kW. Based on our review of the Project described in the PAD, a cost opinion on the order of $2,700/kW would be expected, which compares favorably to the developer's escalated unit cost for a 1,200 MW Project.

2.6.1.3 Seminoe

As reported in the HDR 2014 study, HDR noted that the Developer's estimated cost of $1,500/kW in 2014 dollars appeared too low to satisfactorily cover the direct and indirect costs (i.e. capital costs) of the original Black Canyon Pumped Storage Project, which has a different installed capacity than the Seminoe Pumped Storage Project. HDR's cost opinion for Black Canyon was on the order of $2,000 to $2,300/kW in 2014 dollars. Escalating to 2016 using a rate of 3% per year, these costs would be approximately $1,600/kW and $2,100 to $2,400/kW, respectively. Based on our review of the 700 MW Seminoe Project described in the preliminary permit, an average cost opinion for the combined East and West facilities on the order of $2,600/kW would be expected, which compares favorably to the upper range of HDR's escalated cost opinion for the Black Canyon Project.

2.6.1.4 Summary

A comparison of the cost opinions is provided in Table 4 in Appendix A. It would appear that the capital cost of a pumped storage hydroelectric project would be in the range of $1,800 to $2,700/kW.

2.6.2 Annual Operation and Maintenance (O&M) Costs

The "Pumped Storage Planning and Evaluation Guide" dated January 1990 by the Electric Power Research Institute (EPRI) is an appropriate resource for estimating annual costs for pumped storage hydroelectric projects and was used by HDR in their 2014 study. Based on this document, estimating the annual costs to operate and maintain a pumped storage hydroelectric project would include the following.

- Operation and Maintenance (O&M). O&M costs can be estimated by the following equation:

$$\text{O\&M Costs (1987\$/yr)} = 34{,}730 \times C^{0.32} \times E^{0.33}$$

where:

C = Plant Capacity, MW

E – Annual Energy, GWh

- General expenses. A 35% surcharge of the site specific O&M cost is suggested to cover administration expenditures.
- Insurance. To cover payments for insurance, a surcharge of 0.1% of the plant investment cost is suggested.

As noted in the HDR 2014 study, using the EPRI information, a 2.06 escalation factor had to be used to obtain the annual costs in 2014 dollars. Escalating to 2016, using 3% per year, this factor becomes 2.19. Table 5 in Appendix A summarizes the annual costs for the three Projects considered for this Study.

2.6.3 Bi-Annual Outage Costs

As noted in the HDR 2014 study, it is recommended within the hydro industry that bi-annual outages be conducted for inspections and possible repairs following the inspections. The frequency of inspections and possible repairs can vary greatly from project to project depending upon the usage (hours/year) and cycling of the units that may occur, along with site specific conditions that may impact the condition of the units over time. The assumption of taking two units out of service during a 3-week outage every two years for a 4 unit, 1,000 MW powerhouse at an estimated cost of $262,000 in 2014 dollars is reasonable. Escalating this cost using 3% per year would be approximately $280,000 in 2016 dollars and appropriate for budgeting purposes. Our review of the bi-annual outage cost compares favorably with the escalated value; assuming only nominal repairs are required.

2.6.4 Major Maintenance Costs

As noted in the HDR 2014 study, it is also recommended within the hydro industry that a pump-turbine overhaul (i.e. major unit rehabilitation) and generator rewind be scheduled at year 20, and the typical outage duration for this work is approximately 6 to 8 months. Because of the nature of this type of facility, pumped storage projects typically operate more hours per year than

conventional generating units. This results in increased cycling of the units, which impacts service life requiring major maintenance. These are reasonable assumptions and suggested for this Study.

Because the scope of this type of rehabilitation work can vary greatly, HDR in their 2014 study suggested an estimated cost of $6.28 million for reversible Francis units at year 20. Escalating this value using 3% per year would be approximately $6.7 million in 2016 dollars. This value appears to be slightly low. In using the "Hydropower Modernization Guide" date July 1989 by the EPRI, a range of major rehabilitation average costs for the size of units being considered at Swan Lake North, JD Pool, and Seminoe (i.e. 100 MW to 300 MW) would be approximately $3.7 to $8.0 million. We suggest using this range of costs for major maintenance costs during the plant life.

2.7 SUMMARY

A matrix of operating parameters and costs for the pumped storage bulk energy storage option is provided in Table 6 in Appendix A. An estimated EPC expenditure timeline for a pumped storage facility based on a 5-year EPC schedule is also provided in Table 7 and Figure 1 in Appendix A.

3.0 Compressed Air Energy Storage

3.1 CAES TECHNOLOGY DESCRIPTION

3.1.1 Current Project Status

The DOE maintains a Global Energy Storage Database.[2] Black & Veatch filtered and sorted the data as shown in Table 8 in Appendix A. The characteristics of the identified projects included in the DOE database for the Technology Categories of Compressed Air Energy Storage (CAES) and Liquid Air Energy Storage (LAES) as of June 14, 2016 are shown. Descriptions for these projects as given in the DOE database are provided in Table 8, Table 9 and Table 10 in Appendix A. While the information in the DOE database is informative, not all the data is current.

As noted in the HDR 2014 study, only two CAES plants are currently in operation; the Power South (formerly AEC) McIntosh plant rated at 110 MW in McIntosh, Alabama which began operation in June 1991 and the 290 MW Huntorf facility which began operation in December 1978 in Hannover, Germany. Both of these plants use a solution mined salt cavity and are diabatic type CAES plants.

Other large CAES plants have been proposed but, as of yet, have not moved forward beyond conceptual design or have been cancelled.

With respect to the larger CAES projects, several were identified in the HDR 2014 study and include the following;

- Western Energy Hub Project
- Norton Energy Storage (NES) Project
- PG&E Kern County CAES Plant
- ADELE CAES Plant in Stassfut, Germany

Updates for CAES plants are as follows:

3.1.1.1 Western Energy Hub Project

The Western Energy Hub is situated directly above a salt dome at a nominal depth of 3,000 feet. Three-dimensional seismic mapping of the formation indicates the salt dome measures at least one mile thick and is approximately three miles wide. The Western Energy Hub project is planned to include multiple phases and services to support the expansion and utilization of renewable energy technologies. The Western Energy Hub will feature solution-mined salt caverns capable of storing natural gas, compressed air, and liquid energy products (including refined products of aviation fuel, diesel, and motor gasoline) underground.

[2] http://www.energystorageexchange.org/projects

Magnum is currently developing the Magnum Refined Products phase and it is expected to be the first underground salt cavern storage facility for refined products in the Rocky Mountain Region. The Magnum Gas Storage Project would also include the first High-Deliverability Multi-Cycle (HDMC) storage facility in the Rocky Mountain Region. The facility will contain four solution mined storage caverns capable of storing 54 billion cubic feet of natural gas. It will be interconnected with the interstate natural gas pipeline system by a new 61-mile-long header pipeline.

In addition to these services, the Western Energy Hub project will include a CAES plant in conjunction with a combined-cycle power generation project. The CAES plant will include additional solution-mined caverns to store compressed air. Off-peak renewable generation will be used to compress air into the caverns. The compressed air will be released to produce power during periods of peak power demand. Magnum anticipates an in-service date for the CAES plant of around 2021. Additional information on the CAES plant as provided to PacifiCorp by Magnum is included in Table 11 in Appendix A.

3.1.1.2 Norton Energy Storage (NES)

As noted in the HDR 2014 study; "In December 2012, First Energy suspended construction on the project due to unfavorable economic conditions including low cost of power prices and insufficient demand. As of September 2013, the Ohio Power Siting Board invalidated the certificate at this site." No further activity has been noted.

3.1.1.3 PG&E Kern County CAES

PG&E continues to evaluate the potential development of a Compressed Air Energy Storage (CAES) project and issued a Request for Offers (RFO) on October 9, 2016. Offers were received on June 1, 2016 with potential negotiations with shortlisted bidders to commence in August 2016. PG&E anticipates the project would be between 100 and 350 MW and would be required to have a minimum storage duration of 4 hours.

The RFO is intended to potentially procure products and services related to the CAES project, and to determine the technical and economic feasibility of energy storage using compressed air in a depleted natural gas reservoir in a porous rock formation, approximately one half to one mile underground.

The depleted natural gas field in San Joaquin County, California was selected for the project site and was subjected to air injection/withdrawal testing. PG&E notes that specific findings on geology, preliminary engineering, environmental analysis, and other information was gathered through testing and analyses for the site.

3.1.1.4 ADELE CAES

No new information could be found for the adiabatic ADELE CAES plant. It does not appear that there has been any recent development activity.

3.1.1.5 APEX Bethel Energy Center

This 317 MW CAES plant with 96 hours of storage was announced in 2013. In 2014 the project was placed on hold. It does not appear that there has been any recent development activity.

3.1.2 Performance Characteristics

3.1.2.1 Site Elevation

Site elevation will impact the compression work required to charge the storage for any CAES technology. Given the compressor section is not directly connected to the expansion turbine for conventional CAES operation, the volume flow of compressed air made available to the expansion turbine is not affected by site atmospheric pressure, but is instead driven by storage pressure. There is only a minor impact for conventional CAES plant output due to variation in exhaust pressure due to site elevation. Other configurations which may include a combustion turbine would see a greater impact due to site elevation.

3.1.2.2 Reliability/Availability

In addition to the historic availability data given in the HDR 2014 study, the Huntorf CAES plant has reportedly operated with 99 percent starting reliability.

3.1.2.3 Start Times

In addition to the start times given in the HDR 2014 study, newer CAES plants can achieve start times and fast ramp rates as noted in Table 11 in Appendix A. This data was provided to PacifiCorp by APEX Magnum.

3.1.2.4 Emission Profiles/Rates

No updates.

3.1.2.5 Air Quality Control System Design

In addition to Dry-Low NO_x combustion technology, water injection may also be used to control NO_x. A selective catalytic reduction (SCR) system can be included in the recuperator design to further reduce NO_x emissions. CO catalysts can also be incorporated into the recuperator design to control CO emissions if required by the CAES plant design and air permit requirements.

3.1.3 Geological Considerations

In addition to the geological formations generally considered for storing compressed air: salt domes, aquifers, and rock caverns; depleted methane reservoirs, which are being considered for the PG&E Kern River CAES plant, can be used.

For the Huntorf and McIntosh plants, there were large vertical salt domes that were accessible for solution mining of single caverns for compressed air storage. In some parts of the country, the salt

is deposited between rock layers, creating shorter, squatter caverns with susceptibility to overhead shale spalling. These cavern costs can be higher.

In addition, underwater storage reservoirs, as offered by Hydrostor, are possible. Above ground storage can be considered for smaller plants or when geological conditions are not favorable for a site.

3.1.4 Capital, Operating, and Maintenance Cost Data

Regarding the HDR 2014 study's discussion of project schedule, it is noted the project durations can be driven by the storage system development. Based on a Front End Engineering Design (FEED) study prepared for the NYSEG Seneca CAES Project for a 136 MW to 210 MW utility-owned facility, it is noted that the development time required to complete the three cavern system required for the site was estimated at approximately six years. The CAES plant would have initially gone into service with only one third of the required storage capacity and would not achieve full capability until after approximately five years of commercial operation. The above emphasizes the point that the time required to develop storage can be very site dependent.

3.1.4.1 Capital Costs

The HDR 2014 study assumes project capital costs to include project direct costs associated with equipment procurement, installation labor, and commodity procurement as well as construction management, project management, engineering, and other project and owner indirect costs. The HDR estimate does not include storage cavern cost. Values were presented in 2014 dollars.

Table 11 in Appendix A shows a capital cost, including site development costs, of $1,740/kW as provided by APEX Magnum. No further cost breakdown or clarification for this cost was provided. Black & Veatch interprets this cost to be the installed cost including the solution-mined caverns. This cost is assumed to not include any Owners costs.

Site-specific factors can strongly influence the design of the CAES plant, the cavern and associated costs and ultimately the project economics.

3.1.4.2 Operating Costs

In addition to the operating costs given in the 2014 report, expected O&M costs for the Magnum CAES facility are given in Table 11 in Appendix A.

Appendix A. Data Tables

Table 1 Swan Lake North Pumped Storage Project Facilities Summary[3]

ITEM	DESCRIPTION
Project Type:	Closed-Loop Pumped Storage
Upper Reservoir:	
Storage:	
Total:	3,229 acre-feet (ac-ft)
Live:	2,562 ac-ft
Surface Area:	
Maximum Fill:	64.21 acres (ac)
Minimum Fill:	45.87 ac
Operating Levels:	
Maximum:	6,128 mean sea level (msl)
Minimum:	6,084 msl
Elevation Change During Operation:	44 feet
Overflow Spillway Capacity:	3,230 cubic feet/sec (cfs)
Reservoir Lining:	Asphaltic concrete with geomembrane liner and underdrain system
Lower Reservoir:	
Storage:	
Total:	3,206 ac-ft
Live:	2,581 ac-ft
Surface Area:	
Maximum Fill:	60.41 ac
Minimum Fill:	39.89 ac
Operating Levels:	
Maximum:	4,457 msl
Minimum:	4,408 msl
Elevation Change During Operation:	49 ft
Overflow Spillway Capacity:	3,230 cfs
Reservoir Lining:	Asphaltic concrete with geomembrane liner and underdrain system
Source of Initial Fill and Long-term Refill:	Local Groundwater Agriculture Pumping System (Three existing wells)
Water Conveyance:	
Headrace Penstock:	
Diameter:	13.8 ft (4.2 meter)(1 pipe)
Length:	9,655 ft

[3] The information in this table has been obtained from Exhibits A and B of the FLA filed by Swan Lake North Hydro LLC on October 27, 2015

ITEM	DESCRIPTION
Tailrace Penstock:	
Diameter:	9.8 ft (3.0 meter)(3 pipes)
Length:	1,430 ft
Anchor Blocks (number):	5
Powerhouse:	
Footprint:	
Substructure:	220 ft x 62.5 ft (Bottom 65 ft below ground level @ EL 4248.3 msl)
Superstructure:	305 ft x 176 ft
Crane Capacity:	190 ton
Pump-Turbine/Motor Generator:	
Type:	Variable Speed
Number of Units:	3
Generating Mode:	
Total Maximum Capacity:	393.3 MW
Total Maximum Flow:	3,072 cfs
Gross Turbine Head Range:	Between 1,627 and 1,720 ft
Time per Day:	9.5 hours
Pumping Mode:	
Total Maximum Capacity:	415.8 MW
Total Maximum Flow:	2,427 cfs
Time per Day:	11.5 hours
Annual Energy Production (Based on Operational Modeling for 8.3 hours per Day):	1,187 Gigawatt-hours (GWh)
Transmission Line:	
Voltage:	230 Kilovolts (kV)
Length:	32.8 miles (mi)
Structures:	
Height:	80 to 120 ft
Type:	Steel Monopole
Right-of-Way:	
Length:	32.8 mi
Width:	300 ft
Intertie:	BPA Malin Substation (existing) near Malin, Oregon
Project Boundary Area:	
Reservoirs and Associated Features:	857 ac
Transmission Right-of-Way:	1,637 ac
Total Project:	2,494 ac

Table 2 JD Pool Pumped Storage Project Facilities Summary[4]

ITEM	DESCRIPTION
Project Type:	Closed-Loop Pumped Storage
Upper Reservoirs:	
Configuration:	Two Reservoirs Connected By Tunnel
Total Active Storage:	11,800 ac-ft
Reservoir 1:	
Storage:	
Total:	5,000 ac-ft
Active:	4,700 ac-ft
Surface Area at Maximum Operating Level:	46 ac
Operating Levels:	
Maximum:	2,935 msl
Minimum:	2,785 msl
Elevation Change During Operation:	150 feet
Reservoir 2:	
Storage:	
Total:	7,700 ac-ft
Active:	7,100 ac-ft
Surface Area at Maximum Operating Level:	67 ac
Operating Levels:	
Maximum:	2,935 msl
Minimum:	2,785 msl
Elevation Change During Operation:	150 feet
Dams:	
Type:	Rockfill Embankment
Reservoir 1:	
Height:	165 ft
Length:	5,200 ft
Reservoir 2:	
Height:	165 ft
Length:	6,300 ft
Overflow Spillway:	None
Reservoir Linings:	Concrete
Lower Reservoir:	
Storage:	
Total:	12,100 ac-ft
Active:	11,800 ac-ft
Surface Area at Maximum Operating Level:	100 ac

[4] The information in this table has been obtained from the PAD filed by KPUD in October 2014

ITEM	DESCRIPTION
Operating Levels:	
Maximum:	580 msl
Minimum:	430 msl
Elevation Change During Operation Storage:	150 ft
Dam:	
Type:	Rockfill Embankment
Height:	165 ft
Length:	7,800 ft
Overflow Spillway:	None
Reservoir Linings:	Concrete
Initial Fill and Long-term Refill:	
Source:	Columbia River
Upgraded Existing Pump Station Capacity:	34.6 cfs
Pipeline Length to Lower Reservoir:	11,800 ft
Estimated Annual Net Water Loss Due to Evaporation:	746 ac-ft
Water Conveyance:	
Main Waterway Diameter:	21 ft
Waterway Segments Number/Length:	
Upper Reservoir Connection Tunnel:	1/2,010 ft
Low Pressure Tunnel:	2/1,140 and 1,290 ft, respectively
Vertical Power Shaft:	2/2,100 ft each
High Pressure Tunnel:	2/3,420 and 4,050 ft, respectively
Manifold:	2/270 ft each splitting into 4 penstocks
Penstocks:	4/190, 410, 610, and 820, respectively
Draft Tube Tunnel:	4/250, 350, 320, 420 ft, respectively
Tailrace Tunnel:	2/800 and 1,110 ft, respectively
Powerhouse:	
Type:	Pit Style
Footprint:	
Substructure Each Unit:	86 ft Diameter x 235 ft Deep
Superstructure:	710 ft Long x 96 ft Wide x 88 ft High
Pump-Turbine/Motor-Generator:	
Type:	Variable Speed
Number of Units:	4
Generating Mode:	
Total Capacity:	1,200 MW
Total Rated Flow:	7,000 cfs
Capacity per Unit:	300 MW
Rated Flow Per Unit	1,750 cfs
Rated Net Head:	2,200 ft (approximate)
Time per Day:	10.0 hours

ITEM	DESCRIPTION
Annual Energy Production (Based on Operating 10 Hours a Day, 50 Weeks of the Year):	4,200 GWh
Transmission Line:	
Voltage:	230 kV
Length:	3,000 ft
Intertie:	BPA Harvalum Substation (existing)
Project Area:	2,255 ac

Table 3 Seminoe Pumped Storage Project Facilities Summary[5]

ITEM	DESCRIPTION
Project Type:	Open-Loop Pumped Storage
Configuration:	Two new forebay reservoirs (i.e. East and West), two underground powerhouses, two power tunnels between the forebays and powerhouses, and two tailrace tunnels between the powerhouses and the existing Seminoe Reservoir
Upper Reservoirs:	
East Forebay:	
Storage:	4,800 ac-ft
Surface Area:	85 ac
Operating Level:	7,370 msl
Dam Embankment A:	
Type:	Concrete-Faced Rockfill (CFRD)
Height:	85 ft
Crest Length:	1,320 ft
Dam Embankment B:	
Type:	CFRD
Height:	Varies (5 ft at grade to 55 ft)
Crest Length:	5,890 ft
West Forebay:	
Storage:	3,740 ac-ft
Surface Area:	63 ac
Operating Level:	7,400 msl
Dam Embankment:	
Type:	CFRD
Height:	Varies (5 ft at grade to 60 ft)

[5] The information in this table has been obtained from the Preliminary FERC Permit filed by Black Canyon Hydro, LLC in June 2016.

ITEM	DESCRIPTION
Crest Length:	5,890 ft
Lower Reservoir:	Seminoe Reservoir (existing)
Storage:	1,016,717 ac-ft
Surface Area:	20,291 ac
Operating Level:	6,359 msl
Dam (Existing):	
Type:	Concrete Arch
Height:	295 ft
Crest Length:	530 ft
Source of Reservoir Filling:	North Platte River (existing Seminoe Reservoir)
Water Conveyance:	
East Headrace Tunnel:	
Diameter:	18.8 ft (Tunnel/Shaft)
Length:	3,000 ft (Tunnel) 1,250 ft (Shaft)
East Tailrace Tunnel:	
Diameter:	22.6 ft
Length:	1,300 ft
West Headrace Tunnel:	
Diameter:	16.1 ft (Tunnel/Shaft)
Length:	1,300 ft (Tunnel) 1,800 ft (Shaft)
West Tailrace Tunnel:	
Diameter:	19.3 ft
Length:	2,800 ft
East Powerhouse:	
Footprint:	250 ft long x 65 ft wide x 120 ft high
Pump-Turbine/Motor Generator:	
Type:	Variable Speed
Number of Units:	3
Generating Capacity:	400 MW
Maximum Static Head:	1,079 ft
West Powerhouse:	
Footprint:	220 ft long x 55 ft wide x 120 ft high
Pump-Turbine/Motor Generator:	
Type:	Variable Speed
Number of Units:	3
Generating Capacity:	300 MW
Maximum Static Head:	1,098 ft
Annual Energy Production (combined East and West powerhouses):	1,840 GWh
Transmission Line:	

ITEM	DESCRIPTION
Voltage:	230 kV
Length:	35 mi (approximate)
Intertie:	Either Aeolous Substation (PacifiCorp)(planned) near Medicine Bow, WY or TransWest Express Terminal Substation (planned) near Sinclair, WY

Table 4 Cost Opinion Comparison

ITEM (COSTS ARE EXPRESSED IN 2016$)	SWAN LAKE NORTH	JD POOL	SEMINOE (EAST AND WEST)
B&V Cost Opinion ($/kW)	$2,600	$2,700	$2,600
Developer Estimated Capital Cost ($/kW)	$2,500	$1,800 - $2,700	$2,100 - $2,400[b]

Table 5 Annual Cost Comparison

ITEM (COSTS ARE EXPRESSED IN 2016$)	SWAN LAKE NORTH	JD POOL	SEMINOE (EAST AND WEST)
Plant Capacity (MW)	400	1,200	700
Annual Energy (GWh)	1,187	4,200	1,840
O&M Cost ($/yr)	5,400,000	11,500,000	7,400,000
General Expense ($/yr)	1,900,000	4,000,000	2,600,000
Plant Investment Unit Cost ($/kW)	2,600	2,700	2,600
Insurance ($/yr)	1,000,000	3,200,000	1,800,000
Total Annual Cost Opinion ($/yr)	8,300,000	18,700,000	11,800,000

[6] As noted in HDR's 2014 study, developer's estimated capital cost was deemed too low. HDR's cost opinion is shown.

Table 6 Pumped Storage Technology Summary Matrix

ITEM	SWAN LAKE NORTH	JD POOL	SEMINOE (EAST AND WEST)
General Criteria			
Location	OR	WA	WY
FERC Licensing Status	Final License Application Filed	Preliminary Permits Dismissed	Preliminary Permit Filed
Project Type (Closed/Open Loop)	Closed Loop	Closed Loop	Open Loop
Upper Reservoir Maximum Operating Elevation (msl)	6,128	2,935	7,370 (East) 7,400 (West)
Lower Reservoir Maximum Operating Elevation (msl)	4,457	580	6,359
Static Head (maximum/minimum) (ft)	1,720/1,627	2,505/2,205	1,079 (East)(max.) 1,098 (West)(max.)
Upper Reservoir Usable Volume (ac-ft)	2,562	11,800	4,800 (East) 3,740 (West)
Lower Reservoir Usable Volume (ac-ft)	2,581	11,800	> 8,540
Distance to Electrical Transmission Interconnection (mi)	32.8	< 1	35 (approximate)
Interconnection Size (kV)	230	230	230
Performance Characteristics[7]			
Energy Storage/Day (MWh)	3,800	12,000	7,000
Assumed Hours of Storage/Day (hrs)	9.5	10.0	10.0
Installed Capacity (MW)	400	1,200	700
Estimated Annual Generation (GWh)	1,187	4,200	1,840
Annual Forced Outage Rate (% of time)	0 – 3%[8]		
Type of Pump-Turbine/Motor-Generator	Variable Speed		
Round Trip Efficiency (%)	77		
Expected Life of Generating Equipment (yrs)	20+		
Expected Life of Project (yrs)	50+		
Basis of Cost Opinions (Costs are expressed in 2016 dollars.)			
Range of Capital Costs ($/kW)	$1,800 - $2,700		
Range of O&M Costs ($/kW-yr)	$4.45 - $6.99		
Bi-annual Outage Costs ($)	$280,000		
Range of Major Maintenance Costs/Unit ($)	$3,700,000 - $8,000,000		
Replacement Frequency (yrs)	20		

[7] Other performance characteristics, such as ramp rate, minimum loads, and time to switch from pumping to generating modes and vice versa for variable speed units, are presented in Table 3 of HDR's 2014 study and are reasonable and appropriate for this Study.

[8] Range of annual forced outage rate aligns with values presented in HDR's 2014 study.

Table 7 Estimated 5-year EPC expenditure pattern for a pumped storage facility

YEAR	QUARTER	CUMULATIVE QUARTER	QUARTERLY EXPENDITURE (%)	CUMULATIVE EXPENDITURE (%)
		0	0%	0%
1	1	1	2%	2%
1	2	2	2%	4%
1	3	3	3%	7%
1	4	4	3%	10%
2	1	5	4%	14%
2	2	6	4%	18%
2	3	7	5%	23%
2	4	8	5%	28%
3	1	9	6%	34%
3	2	10	6%	40%
3	3	11	8%	48%
3	4	12	8%	56%
4	1	13	8%	64%
4	2	14	8%	72%
4	3	15	7%	79%
4	4	16	7%	86%
5	1	17	7%	93%
5	2	18	3%	96%
5	3	19	3%	99%
5	4	20	1%	100%

Figure 1 Estimated 5-year EPC expenditure pattern for a pumped storage facility

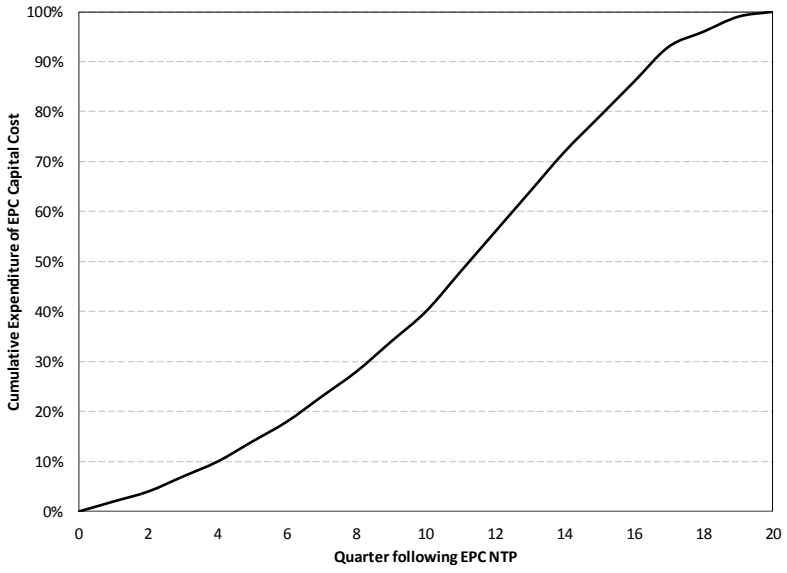


Table 8 Technology Categories of Compressed Air Energy Storage (CAES) and Liquid Air Energy Storage (LAES) as of June 14, 2016

Project Name	McIntosh CAES Plant	PG&E Advanced Underground Compressed Air Energy Storage (CAES)	Next Gen CAES using Steel Piping - NYPA	SustainX Inc Isothermal Compressed Air Energy Storage	Highview Pilot Plant	NYSEG Seneca/Watkins Glen CAES Project	Texas Dispatchable Wind	Apex Bethel Energy Center	Hydrostor UCAES Demonstration Facility	Hydrostor UCAES Aruba Project	Kraftwerk Huntorf	Pollegio-Loderio Tunnel ALACAES Demonstration Plant	Pre-Commercial Liquid Air Energy Storage Technology Demonstrator	ATK Launch Systems Microgrid CAES [1]	Hybrid Compressed Air Energy Storage and Thermal Energy Storage - UCLA - Southern California Edison [1]	Adele CAES Project [1]
Technology Type	In-ground Natural Gas Combustion Compressed Air	In-ground Compressed Air Storage	Modular Compressed Air Storage	Modular Iso-thermal Compressed Air	Modular Compressed Air Storage	In-ground Compressed Air Storage	In-ground Iso-thermal Compressed Air	In-ground Compressed Air Storage	Modular Compressed Air Storage	Modular Compressed Air Storage	In-ground Natural Gas Combustion Compressed Air	Adiabatic Compressed Air Storage	Liquid Air Energy Storage	Modular Compressed Air Storage	Compressed Air Storage	In-ground Iso-thermal Compressed Air
Record Created	6/28/2012	6/29/2012	6/29/2012	7/18/2012	10/31/2012	5/2/2013	5/21/2013	10/11/2013	10/25/2013	10/25/2013	1/30/2014	6/25/2014	5/25/2016	5/6/2013	9/10/2015	11/4/2013
Last Updated	5/23/2016	6/14/2016	5/24/2016	5/24/2016	5/26/2016	9/5/2014	5/18/2016	1/28/2015	5/10/2016	7/23/2014	4/18/2016	5/19/2016	5/26/2016	7/11/2014	9/28/2015	10/27/2014
Rated Power in kW	110,000	300,000	9,000	1,500	350	0	2,000	317,000	1,000	1,000	321,000	500	5,000	80	0	200,000
Duration at Rated Power HH:MM	26:0.00	10:0.00	4:30.00	1:0.00	7:0.00	0:0.00	250:0.00	96:0.00	4:0.00	8:0.00	2:0.00	4:0.00	3:0.00	0:45.00	0:0.00	5:0.00
Status	Operational	Announced	Announced	Operational	Operational	Announced	Operational	Announced	Under	Contracted	Operational	Under	Under	Under	Announced	Under
City	McIntosh	San Joaquin	Queens	Seabrook	Slough	Reading	Seminole	Tennessee	Toronto	San Nicolas	Große Hellmer 1E	Loderio	Bury	Promontory	Pomona	Staßfurt
State/Province	Alabama	California	New York	New Hampshire	Berkshire	New York	Texas	Texas	Ontario	Aruba	Elsfleth	Ticino	Lancashire	Utah	California	Sachsen-Anhalt
Country	United States	United States	United States	United States	United Kingdom	United States	United States	United States	Canada	Netherlands	Germany	Switzerland	United Kingdom	United States	United States	Germany
Announcement Date		01.01.2010	01.06.2012		01.03.2010	30.11.2010		01.07.2013		01.10.2013		01.01.2013	13.02.2014	06.05.2013	20.08.2015	
Construction Date					01.02.2011		01.01.2011		01.01.2013	01.02.2015		13.06.2014	26.02.2015			01.01.2013
Commissioning Date	01.01.1991	01.01.2020		11.09.2013	31.07.2011		19.12.2012		01.09.2014		12.01.1978	01.06.2016				
ISO/RTO	N/A	CAISO	NYISO	ISO-NE	N/A	NYISO	SPP	ERCOT	IESO	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Utility	PowerSouth	Pacific Gas and Electric Company	New York Power Authority (NYPA)		SSE (Scottish and Southern Energy)	New York State Electric & Gas (NYSEG)				WEB Aruba N.V.	E.ON		Electricity North West	Rocky Mountain Power	Southern California Edison	
Energy Storage Technology Provider	Dresser-Rand			SustainX	Highview Power Storage		General Compression, Inc.	Dresser-Rand	Hydrostor	Hydrostor	BBC, Alstom	ALACAES	Highview Power Storage			
Expected Use Cases:																
Black Start			X			X		X			X					
Electric Supply Reserve Capacity - Non-Spinning												X	X			
Electric Supply Reserve Capacity - Spinning	X	X	X		X	X	X				X					
Load Following (Tertiary Balancing)							X									
Ramping				X				X								
Voltage Support													X			
Electric Energy Time Shift	X	X	X		X	X					X				X	X
Electric Supply Capacity							X									X
Transmission Congestion Relief				X		X							X			
Transmission Support													X			
Renewables Capacity Firming		X	X	X	X				X	X						
Distribution upgrade due to solar																
Distribution upgrade due to wind																
Transmission upgrades due to solar																
Transmission upgrades due to wind																
Electric Bill Management					X							X		X		
Grid-Connected Commercial (Reliability & Quality)																
Grid-Connected Residential (Reliability)																
Frequency Regulation	X	X	X			X		X			X		X			
Transportable Transmission/Distribution Upgrade Deferral																
Stationary Transmission/Distribution Upgrade Deferral																
Onsite Renewable Generation Shifting							X									
Electric Bill Management with Renewables																
Renewables Energy Time Shift				X	X		X	X	X	X		X				
On-Site Power														X		
Transportation Services																
Microgrid Capability																
Resiliency																
Demand Response																
Note 1: DOE still verifying record entry.																
Source: DOE Global Energy Storage Database (http://www.energystorageexchange.org/projects)																

Table 9 CAES and LAES project descriptions

Project Name	Rated Power in kW	Duration at Rated Power HH:MM	Description
McIntosh CAES Plant	110,000	26:0.00	The 2nd commercial CAES plant, in operation since 1991. Like the Huntorf plant, the McIntosh Unit 1 facility stores compressed air in a solution-mined salt cavern. The cavern is 220 ft in diameter and 1,000 ft tall, for a total volume of 10 million cubic feet. At full charge, the cavern is pressurized to 1,100 psi, and it is discharged down to 650 psi. During discharge, 340 pounds of air flow out of the cavern each second. The cavern can discharge for 26 hours. The plant also utilizes nuclear-sourced night-time power for compression and then produces peak power during the day by releasing the compressed air into a 110-MW gas-fired combustion turbine built by Dresser Rand. The turbine unit also makes use of an air-to-air heat exchanger to preheat air from the cavern with waste heat from the turbine. The waste heat recovery system reduces fuel usage by roughly 25%. Compared to conventional combustion turbines, the CAES-fed system can start up in 15 minutes rather than 30 minutes, uses only 30% to 40% of the natural gas, and operates efficiently down to low loads (about 25% of full load). The key function of the facility is for peak shaving.
PG&E Advanced Underground Compressed Air Energy Storage (CAES)	300,000	10:0.00	A 300 MW A-CAES demo plant will use an underground storage container (depleted gas reservoir), and next-generation turbomachinery. The project has 3 phases: Phase 1 - preliminary engineering, geologic reservoir engineering, econmoic analyses, and regulatory permitting; Phase 2 - Construction and plant commissioning; Phase 3: Plant operation and plant performance monitoring. Ph 2 of the project will go ahead if the Ph1 results show PG&E and California regulatory management that the project is cost effective.
Next Gen CAES using Steel Piping - NYPA	9,000	4:30.00	9-MW plant will use steel piping to hold pressurized air instead of geologic based air store. Preliminary plant design complete; NYSERDA funding expected in July 2012; Vendors, utility sponsor, and site location determined. Groundbreaking slated for 2013 to 2014 time frame.
SustainX Inc Isothermal Compressed Air Energy Storage	1,500	1:0.00	SustainX is constructing a 1.5MW pilot system in Seabrook, New Hampshire to demonstrate their modular isothermal compressed air energy storage system (ICAES). This second generation ICAES system is scheduled for completion in 2013, with the third generation field-deployed ICAES system ready for operation by 2014. The current schedule would have SustainX's isothermal system ready for commercial production in 2015. SustainX's ICAES system captures the heat from compression in water and stores the captured heat until it is needed again for expansion. Storing the captured heat eliminates the need for a gas combustion turbine and improves efficiency. SustainX achieves isothermal cycling by combining patented innovations with a design control on mature industrial components and principles. The system is designed for a 20-year lifetime. It achieves full power output from start-up in less than one minute, and it does not use toxic chemicals.
Highview Pilot Plant	350	7:0.00	Highview's technology uses off-peak or 'wrong-time' power to liquefy air (710 litres of air becomes one litre of liquid air), which is then held in a tank until electricity is required. The liquid air is then returned to gaseous form, expanding 710 times, to drive a turbine. Extreme cold is recovered and stored to assist with subsequent liquefaction, thus greatly improving the overall efficiency of the system. If waste heat is available (e.g. from a neighbouring power plant or industrial process) then this can be introduced at the expansion phase, enhancing system efficiency.
NYSEG Seneca/Watkins Glen CAES Project	0	0:0.00	***09/2012: NYSEG has concluded that the economics of the project are not favorable for development in the current and forecast wholesale electric market in New York State, and further project development work is not warranted.*** Read the final project report here: http://goo.gl/HbiWQ9 New York State Electric & Gas (NYSEG) intended to build an advanced compressed air energy storage (CAES) plant with a rated capacity of 150 MW (2.4 GWh) using an existing 4.5 million cubic foot underground salt cavern in Reading, New York. The plant was to be sited between the bulk of U.S. wind resources and the heavy population centers of the East Coast. The plant will have the capacity to operate 16 hours a day and will provide energy arbitrage for approximately 2,300-2,500 hours each year. It will use off-peak electricity to compress air into the cavern. When electricity is needed the air will be withdrawn, heated, and passed through a turbine to drive an electric generator, burning one-third the amount of fuel compared to conventional combustion turbines. NYSEG's CAES plant will provide flexible generation capability to accommodate fluctuations in load. The plant will be tied to NYSEG's cross-state 230 kV/345 kV transmission system that feeds major metropolitan centers in Central New York. The 230 kV line is the recipient of a large proportion of wind power and is tied to the New York City load areas. It will provide redundancy in capacity, ensure against congestion and power fluctuations, and can provide improved power quality to the grid. Iberdrola USA, the parent of NYSEG, plans to conduct a feasibility study in the future to determine the ability to increase the plant's capacity to 360 MW or greater.
Texas Dispatchable Wind	2,000	250:0.00	The Gaines, Texas Dispatchable Wind Project is a 2.0MW wind generation project located in West Texas. It is owned and operated by Texas Dispatachable Wind 1, LLC, a subsidiary of General Compression. The project consists of a wind turbine, a General Compression Advanced Energy Storage (GCAES™) system, a storage cavern, and other electrical & ancillary facilities. The project has the capability to, during periods of low demand, store portions of the energy generated by the wind turbine and later, during periods of increased demand, release the stored energy. Construction of the project began in 2011 and the project was commissioned in late 2012.
Apex Bethel Energy Center	317,000	96:0.00	Development of the 317 MW compressed air energy storage facility with 96 hours of storage has been put on hold as of 10/2014. New information on development is anticipated in summer 2015.

Table 10 CAES and LAES project descriptions (continued)

Project Name	Rated Power in kW	Duration at Rated Power HH:MM	Description
Hydrostor UCAES Demonstration Facility	1,000	4:0.00	Construction is underway on a 1 MW/4 MWh demonstration facility to showcase Hydrostor's first-of-a-kind system. Located Approx. 5km from the shore of Toronto, the system will be situated in Lake Ontario at a depth of 80m.
Hydrostor UCAES Aruba Project	1,000	8:0.00	Hydrostor's proprietary technology is based on a simple idea: Anchor a low-cost air cavity to the bottom of a lake or ocean floor, and store energy in it by filling it with compressed air created using surplus renewable energy. The energy is discharged from the system by releasing the air stored underwater to drive a turbine recreating electricity when it is most needed - either to meet daily demand peaks or to cover periods of calm winds or cloud cover that prevent power from being harnessed.
Kraftwerk Huntorf	321,000	2:0.00	1st commercial CAES plant, operational since 1978. The 321-MW plant utilizes nuclear-sourced night-time power for compression and produces peak power during the day via a natural gas turbine. The facility stores the compressed air in two ""solution-mined"" salt caverns which comprise a total of 310,000 cubic meters. (Water was pumped into and out of a salt deposit to dissolve the salt and form the cavern.) The depth of the caverns is more than 600 m which ensures the stability of the air for several months' storage, and guarantees the specified maximum pressure of 100 bar. One cavern is cycled on a diurnal basis. The second cavern serves as a black start asset if the nearby nuclear power plant unexpectedly goes down.
Pollegio-Loderio Tunnel ALACAES Demonstration Plant	500	4:0.00	A demonstration plant to test a novel advanced adiabatic compressed air energy storage concept. An abandoned tunnel in the Swiss alps is used as the air storage cavern and a packed bed of rocks thermal energy storage is used to store the heat created during compression. The thermal energy storage is placed inside the pressure cavern. Project construction concluded in April 2016. The project is operating in the commissioning phase from April 2016 until June 2016. In June 2016 the plant will start full operation.
Pre-Commercial Liquid Air Energy Storage Technology Demonstrator	5,000	3:0.00	Highview and project partners, leading UK renewable energy and recycling company Viridor, were awarded funding of more than £8 million ($11.6 million) by the British Government Department of Energy & Climate Change (DECC) for a 5 MW Liquid Air Energy Storage (LAES) technology system. The funding is supporting the design, build and testing of a Pre-Commercial LAES Technology Demonstrator alongside Viridor's landfill gas generation plant at Pilsworth in Greater Manchester UK. In addition to providing energy storage, the LAES technology plant will convert low grade waste heat from the onsite landfill gas engines to electrical power. The project will operate for at least one year and will demonstrate LAES providing a number of grid balancing services in the UK, including Short Term Operating Reserve (STOR), Secondary frequency response testing, Triad Avoidance (supporting the grid during the winter peaks) and also testing for the US regulation market.
ATK Launch Systems Microgrid CAES [1]	80	0:45.00	The Alliant Techsystems (ATK) Launch Systems project takes place at a single customer site – but, it's a large one. ATK Launch Systems in Promontory, Utah comprises over 540 buildings on a sprawling 19,900-acre site accessible by 75 miles of roads. Their power system of three main substations and 60 miles of power lines deliver about 17 MW (on-peak) to the facilities, with an annual energy bill of over $15 million. In recent years, utility tariff changes have significantly increased the portion of the monthly bills attributable to demand charges. ATK's Corporate Energy Team, established in 2003, and has already implemented a number of energy saving projects, realizing energy costs reductions of $2 million/year or more. As a result of a comprehensive plant-wide energy assessment (partially funded by DOE) in 2006/2007, ATK identified a new set of energy projects at the Promontory site. This project will integrate an ambitious and highly diverse set of distributed resources. These include four heat recovery systems using organic Rankin cycle (ORC) generators connected to Ormat energy converters, for a total of 1400 kW. Heat for the system will be supplied by a concentrating solar thermal array, air compressor waste heat and low pressure steam. The project will also incorporate about 140 kW of wind turbines, a yet-to-be-determined amount of hydro turbine capacity, and about 40 kW of micro-hydro turbines. For storage, the project includes up to 1440 kW of pumped hydro capacity for two - four hours, and an above-ground compressed air energy storage (CAES) and generation system (80 kW capacity for 30-60 minutes).
Hybrid Compressed Air Energy Storage and Thermal Energy Storage - UCLA - Southern California Edison [1]	0	0:0.00	Engineers from the University of California Los Angeles Henry Samueli School of Engineering and Applied Science have won a $1.62 million grant to build a hybrid energy storage system. The team with work with Southern California Edison, which will help operate the system on the Cal Poly Pomona campus upon completion, to build a system to store "energy harvested from intermittently productive renewable sources such as solar panels and wind farms, then releases that energy into the grid when demand is high," according to a news release. Lead by Pirouz Kavehpour, a professor of mechanical and aerospace engineering at UCLA, the team will build a system that uses both compressed air and thermal energy storage technologies to enhance capacity and reduce costs. "Our estimated cost of energy for this unit is about $100 per kilowatt hour, which is much lower than any battery system of which we are aware," said Kavehpour, in a prepared statement.
Adele CAES Project [1]	200,000	5:0.00	The first adiabatic CAES project; the heat that appears during compression is also stored, and then returned to the air when the air is expanded. Construction will begin in 2013 in Staßfurt, a city in Sachsen-Anhalt, Germany (ADELE stands for the German acronym for adiabatic compressed air energy storage for electricity supply). The project is a joint effort between RWE, General Electric, Zueblin, and the German Aerospace Center. The German Federal Ministry of Economics is also providing state funding. Altogether, the project members will contribute an amount of EUR 10 million.
Note 1: DOE still verifying record entry.			
Source: DOE Global Energy Storage Database (http://www.energystorageexchange.org/projects)			

Table 11 Magnum CAES Data

RESOURCE	CAES
Installation Name	320 MW Magnum CAES
Base Capital ($)	556,800,000
Pro-rated site development cost ($)	included in Base Capital
Net Capacity (MW)	320
Rated Energy Capacity (MWh)	15,360
Expected use cases	Energy, capacity, spinning, regulation, non-spinning, black start
Total Implementation Time (yrs)	3
Commercial Operation Year	2021
Design Life (yrs)	30+
Base Capital ($/KW)	1,740
Var O&M ($/MWh)	0.77
Fraction Var O&M Capitalized	0.41
Fixed O&M ($/KW-yr)	18.9
Fraction Fixed O&M Capitalized	0
Average Full Load Heat Rate (HHV Btu/KWh)	4,227
EFOR (%)	3%
POR (%)	1.5%
Heat Input for Warm Start (HHV, MMBtu)	0
Water Consumed (Gal/MWh)	294
SO2 (lbs/MMBtu)	0.001
NOx (lbs/MMBtu)	0.009
Hg (lbs/TBTu)	N/A
CO2 (lbs/MMBtu)	117
Minimum Capacity (MW)	3.3
Spinning Reserves (MW)	156.7
Run-up Rate (first fire to min capacity, warm start, MW/hr)	180
Ramp Up Rate (min capacity to full load, MW/min)	32
Ramp Down Rate (full load to min capacity, MW/min)	32
Start-Up Time to Minimum Capacity (min)	5 min
Minimum Operational Up Time (hr)	N/A
Minimum Operational Down Time (hr)	N/A
Recharge rate (MWh/hour)	150
AC to AC efficiency (%) [1]	~50%

Note 1: The basis for this efficiency value is unclear. PacifiCorp has requested Magnum to clarify the definition used to determine this value but at the time of this report, clarification had not been received. Given the technology for CAES can include the use of fuel during the discharge mode, parameters for Energy Charge Ratio (kWh_{in}/kWh_{out}) and Net Heat Rate (Btu/kWh) during discharge mode (which considers the fuel added) are metrics typically used.