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.

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Transmission: *Sigurd to Red Butte Transmission Line*
Demand-Side Management: *Smart thermostat*
Pacific Power wattsmart Business Customer Meeting
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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.

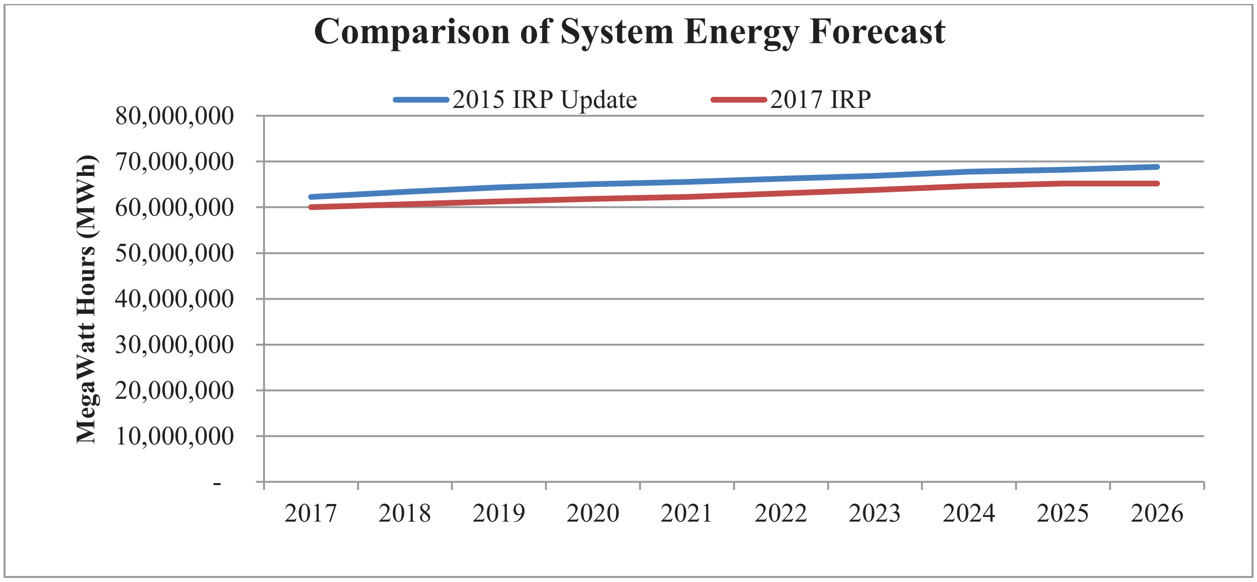
In the development of its load forecast PacifiCorp employs econometric models that use historical data and inputs such as regional and national economic growth, weather, seasonality, and other customer usage and behavior changes. The forecast is divided into classes that use energy for similar purposes 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

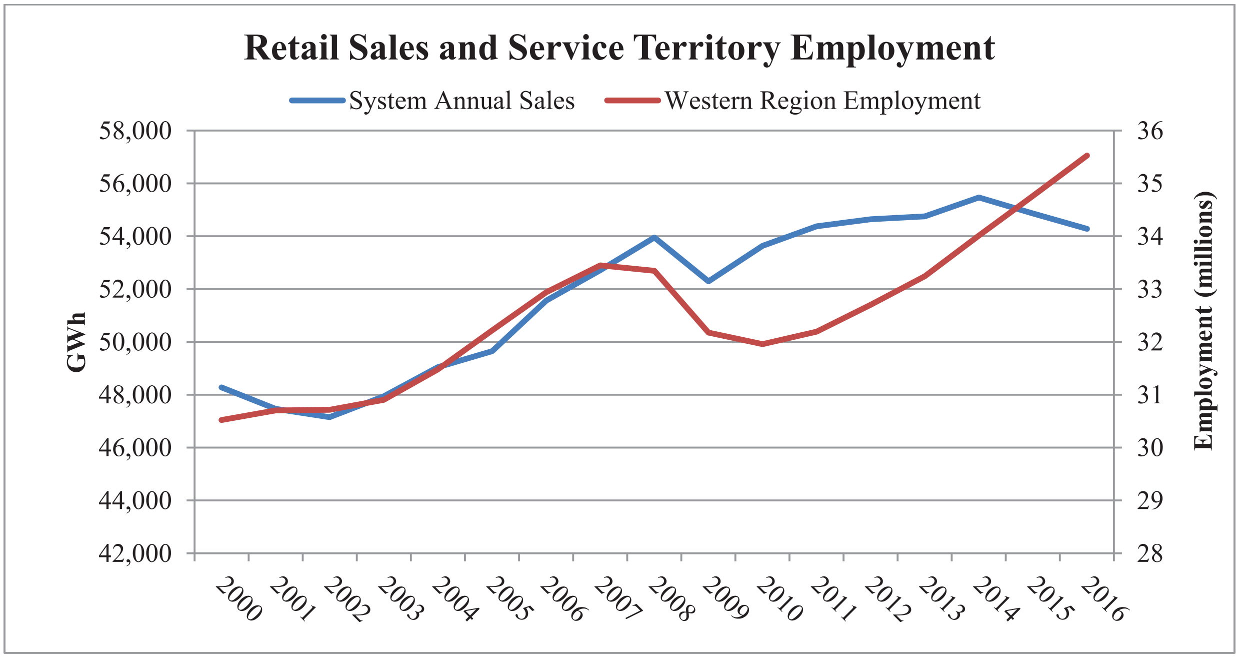
Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2017	(153)	(23)	(25)	4	7	(111)	(4)	-
2018	(245)	(29)	(26)	4	(66)	(125)	(2)	-
2019	(306)	(6)	(15)	4	(145)	(143)	(2)	-
2020	(319)	(11)	(18)	6	(177)	(126)	6	-
2021	(323)	(9)	(17)	5	(199)	(118)	14	-
2022	(326)	(6)	(17)	5	(215)	(108)	16	-
2023	(343)	(5)	(16)	4	(231)	(99)	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

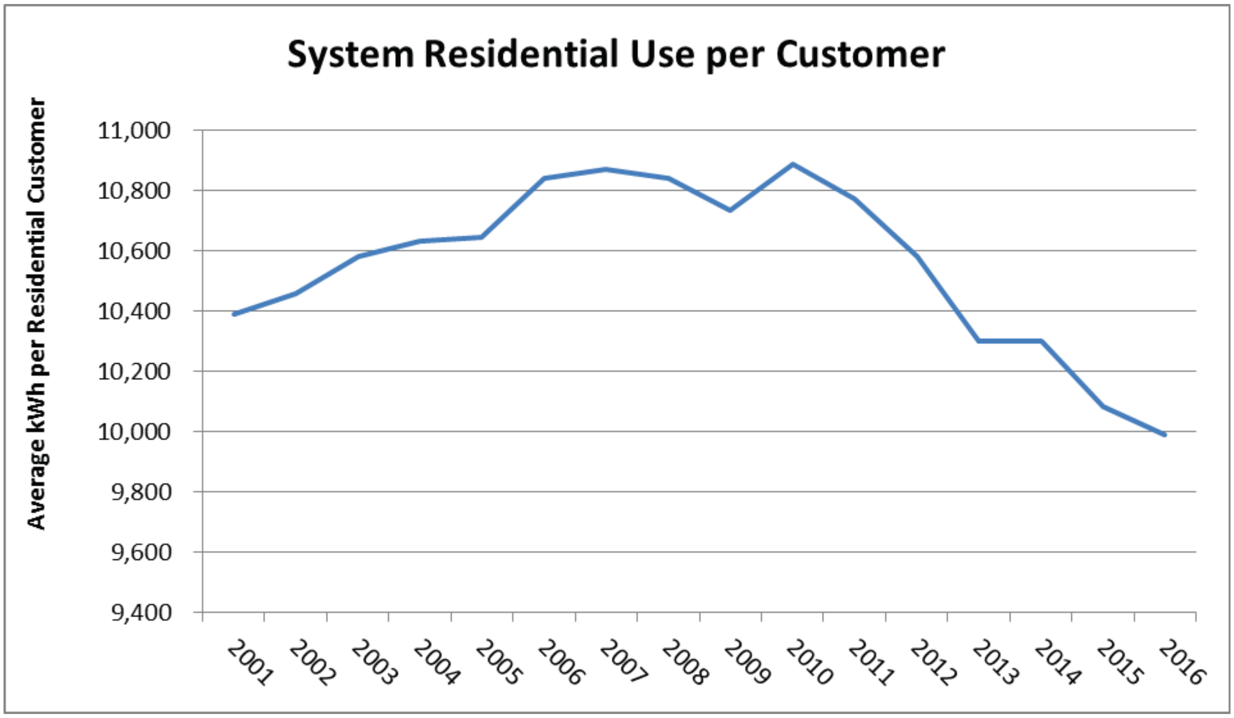


Sources: PacifiCorp and United States Department of Labor, Bureau of Labor Statistics

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

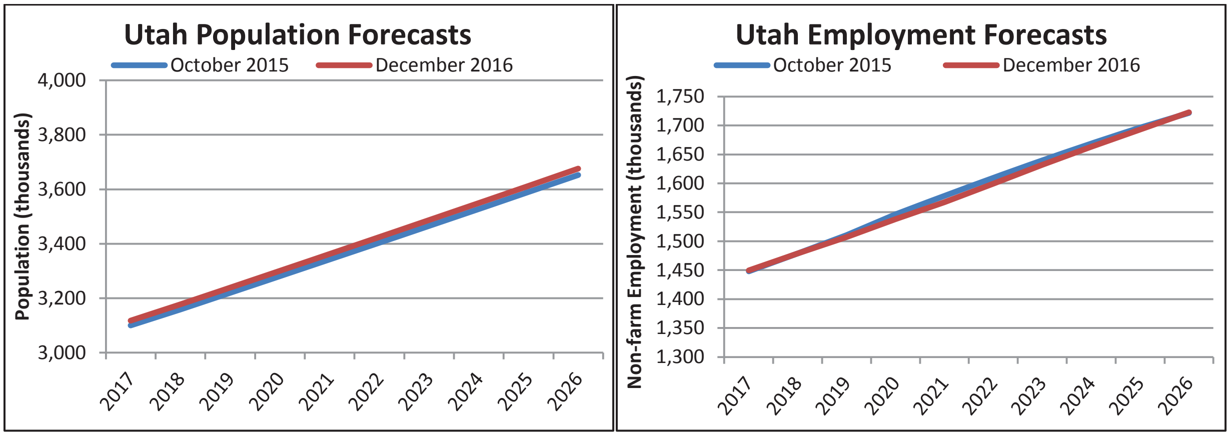


Residential use per customer across all six of PacifiCorp's states is changing due to increased energy efficiency driven primarily by lighting efficiency standards resulting from the 2007 Federal Energy legislation. In addition, there has been a shift from single-family and manufactured housing to multi-dwelling 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

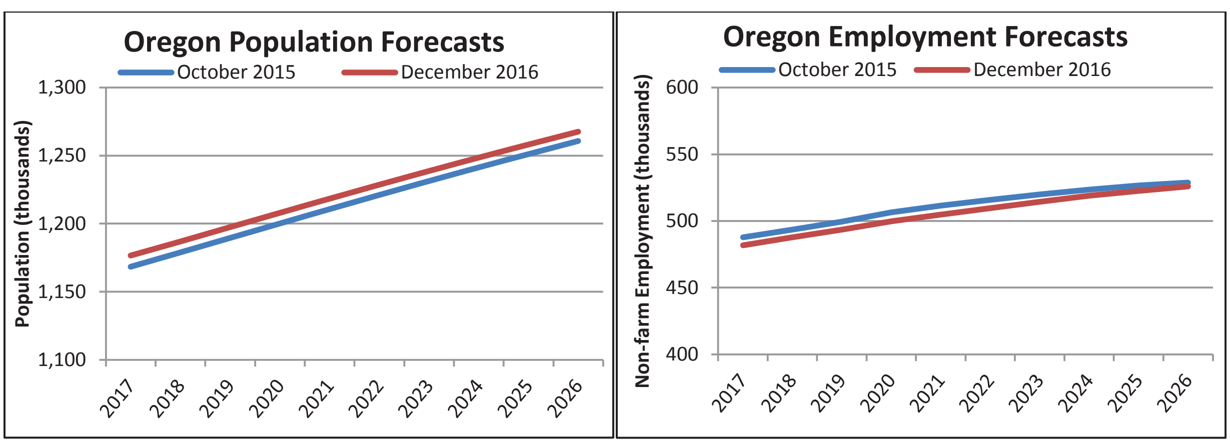


A risk to the Utah forecast is commodity prices, such as oil and natural gas, where volatility in prices and profitability can lead to swings in production and employment potentially translating to swings in the retail sales forecast.

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

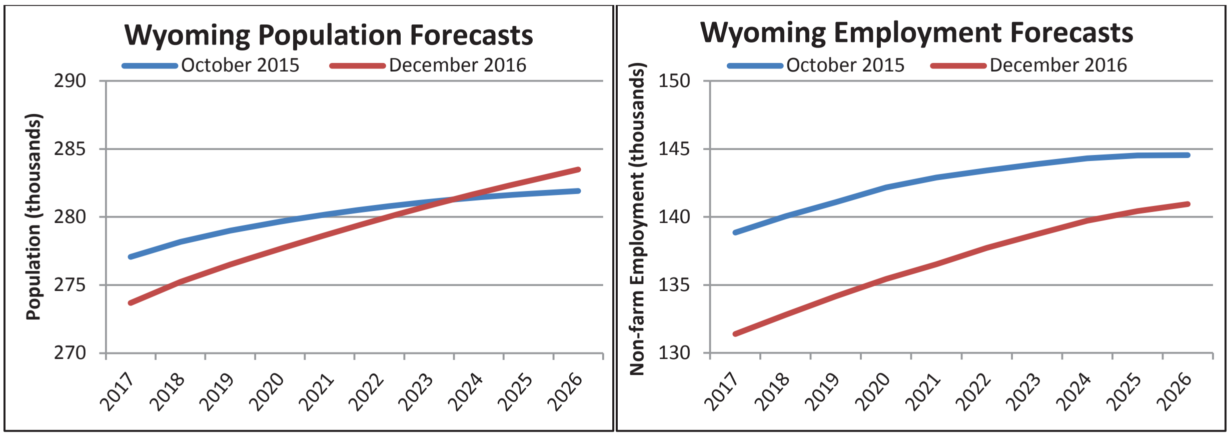


2 Source: Oregon Public Utility Commission, 2015 Oregon Utility Statistics.
3 Source: Bureau of Labor Statistics.

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

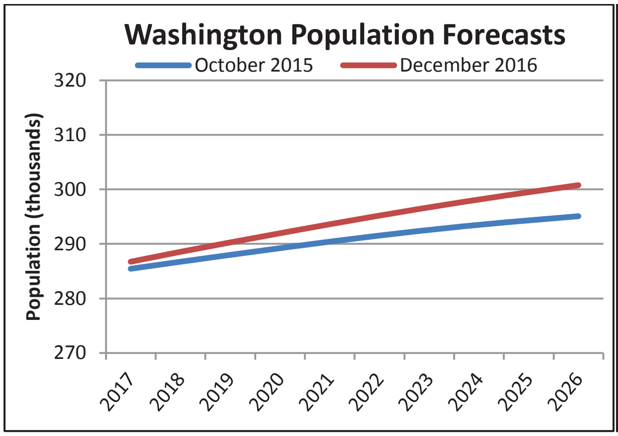


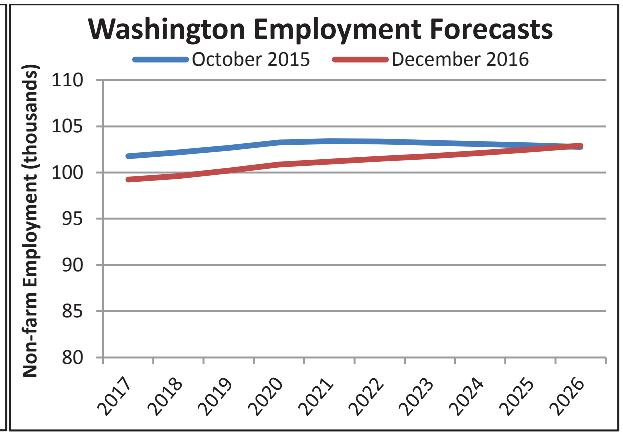
A risk to the Wyoming forecast is commodity prices, such as oil and natural gas, where volatility in prices and profitability can lead to swings in production and employment which translates to potential swings in the retail sales forecast.

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

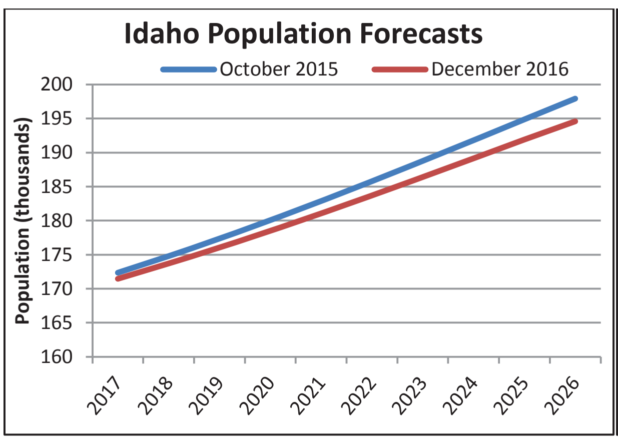


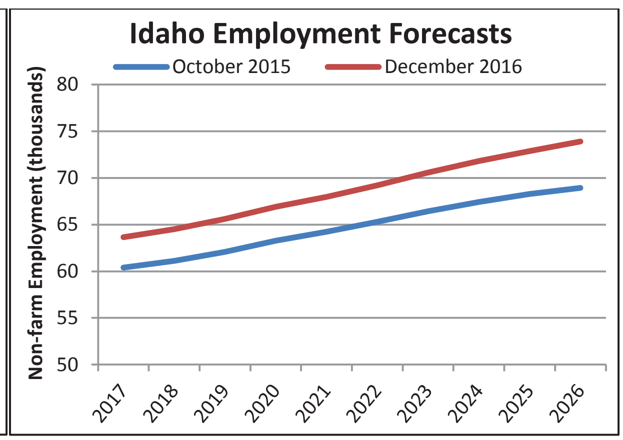


Idaho

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

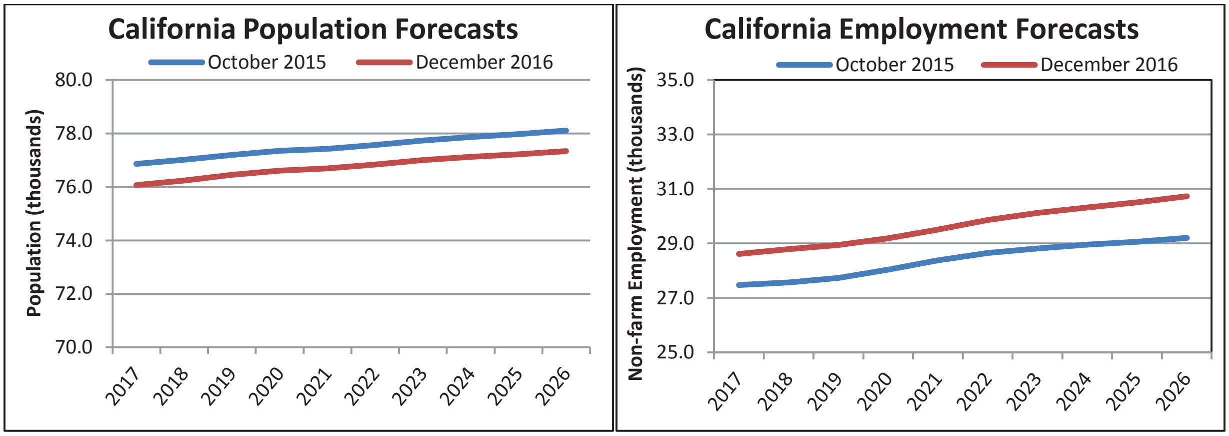




California

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

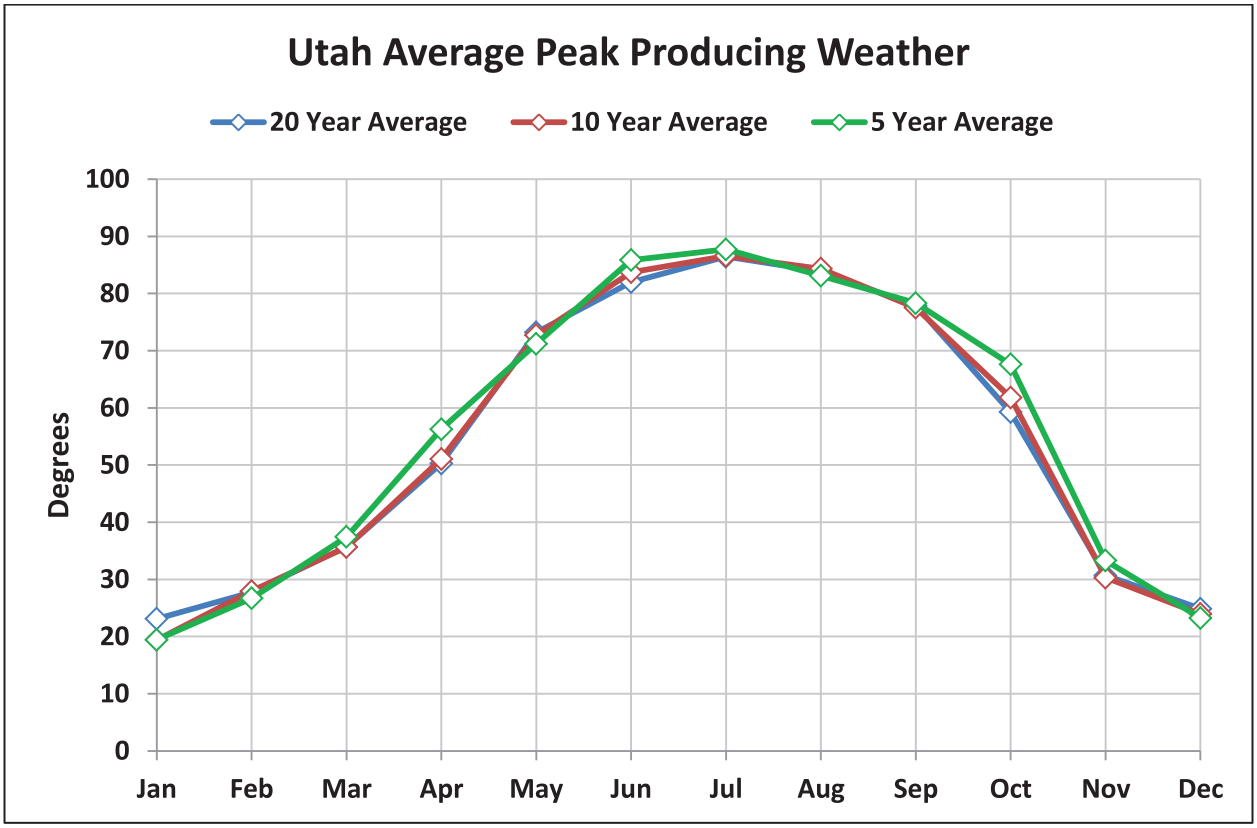


Weather

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

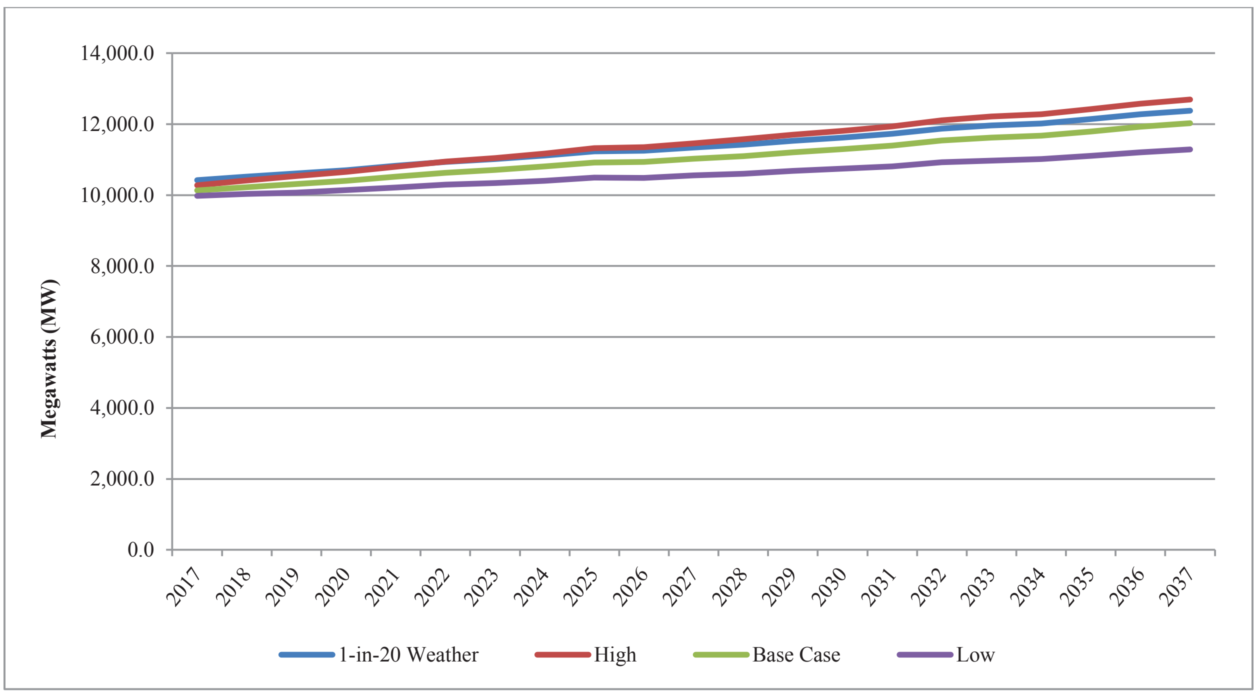
Company's load forecasting models. These growth assumptions were extended for the entire forecast horizon.

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	√	√	√	√	√	√
Public Relations	√	√	√		√	√
Business Advocacy (awards at customer meetings, sponsorships, chamber partnership, university partnership)	√	√	√	√	√	√
Wattsmart Workshops		√				
Bewattsmart, Begin at Home - in school energy education			√		√	

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*

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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

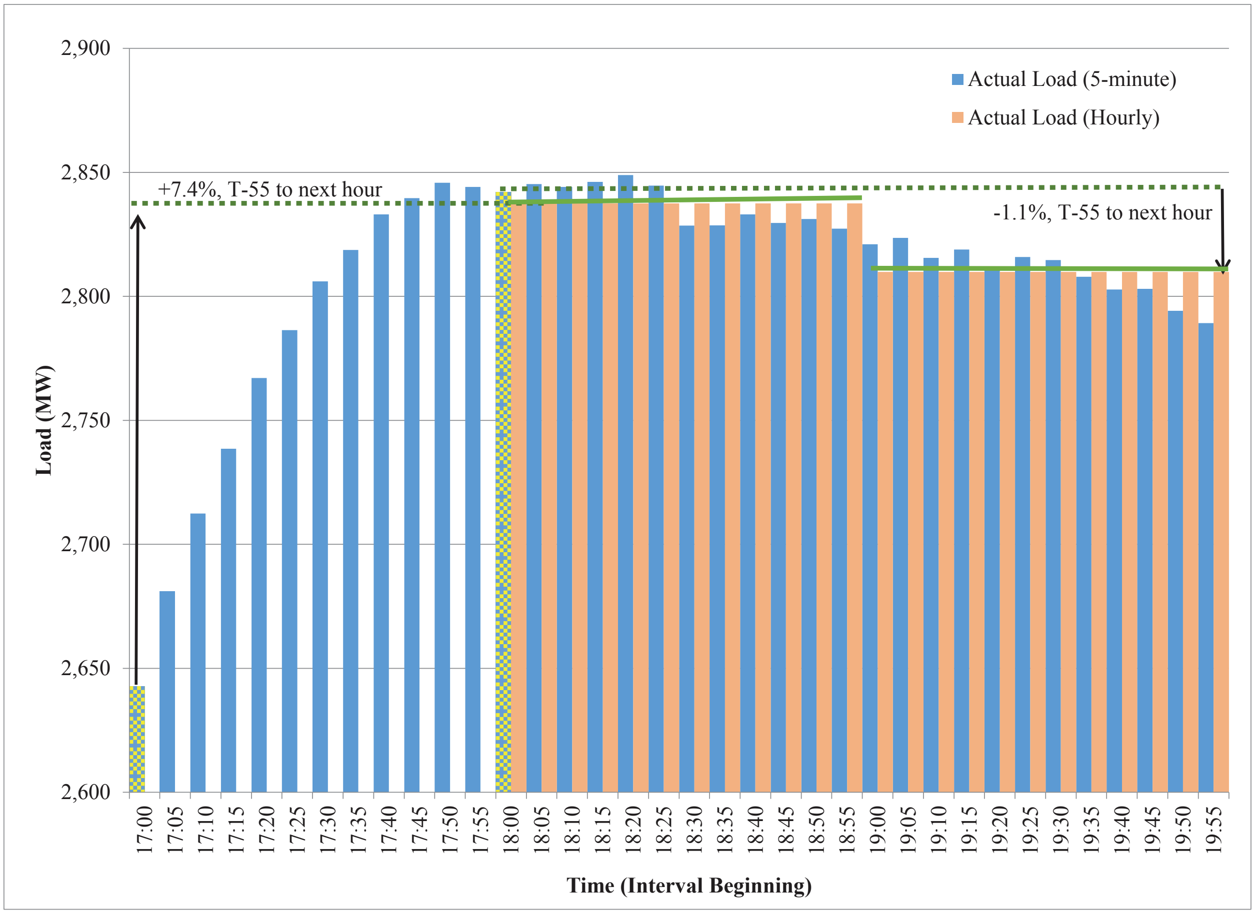
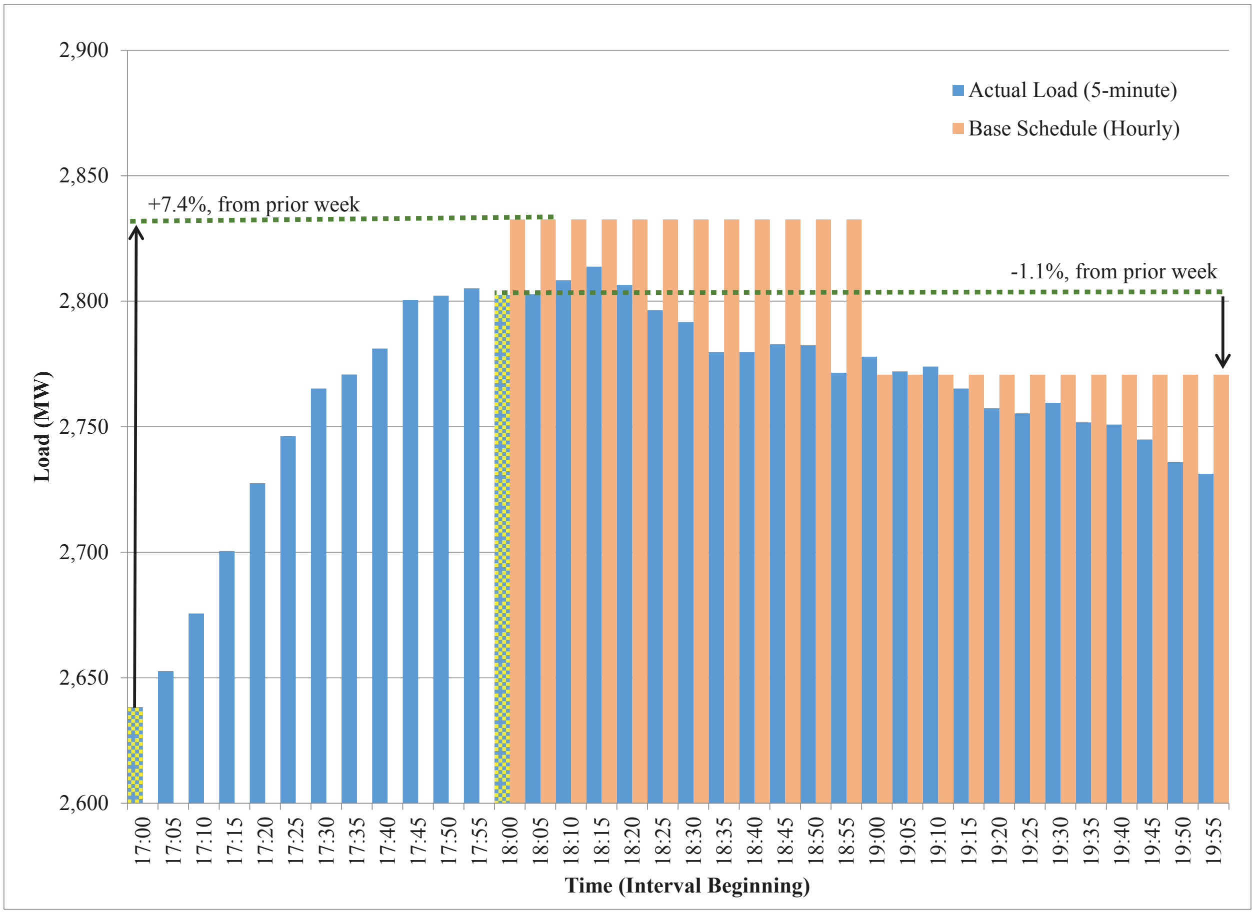


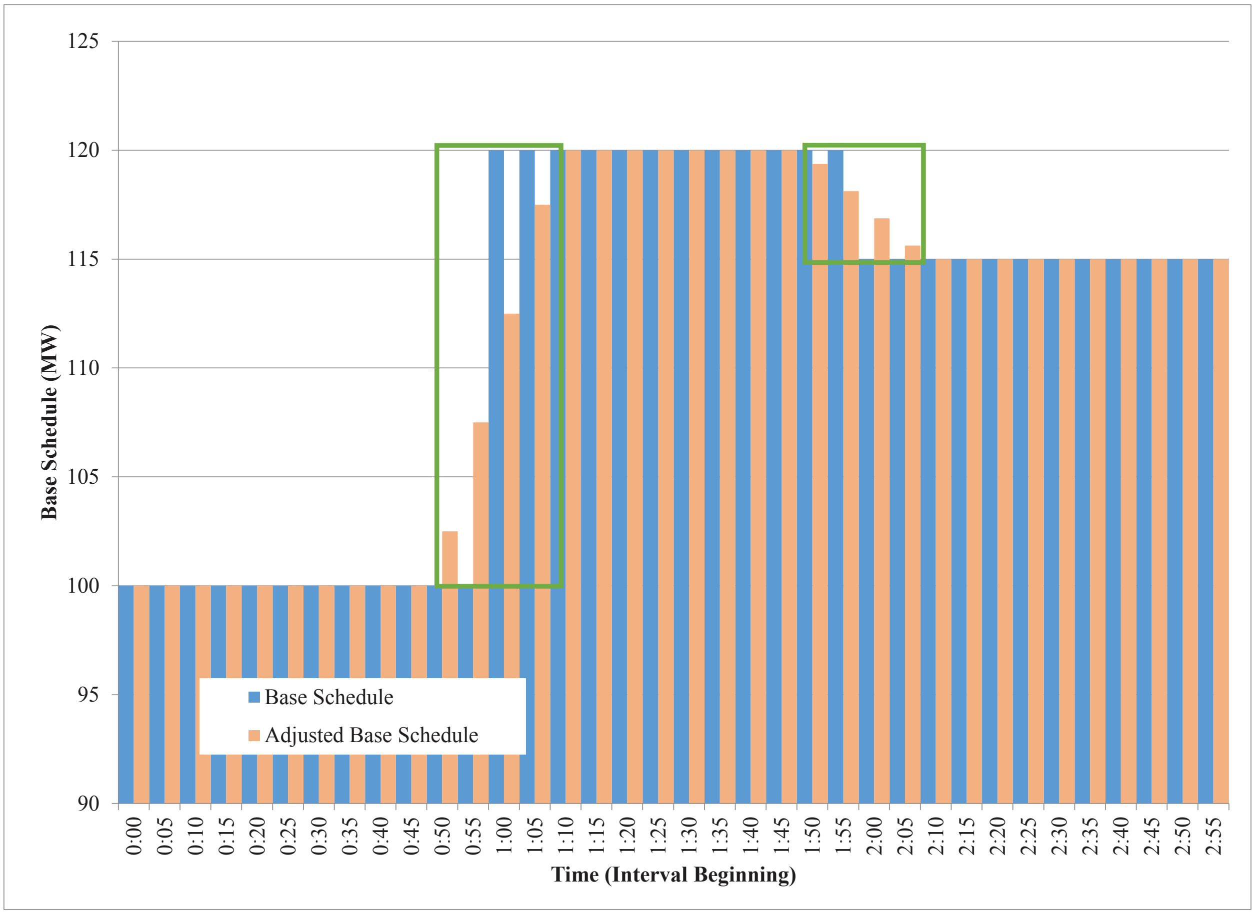
Figure F.2 - Proxy Load Base Schedule



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.

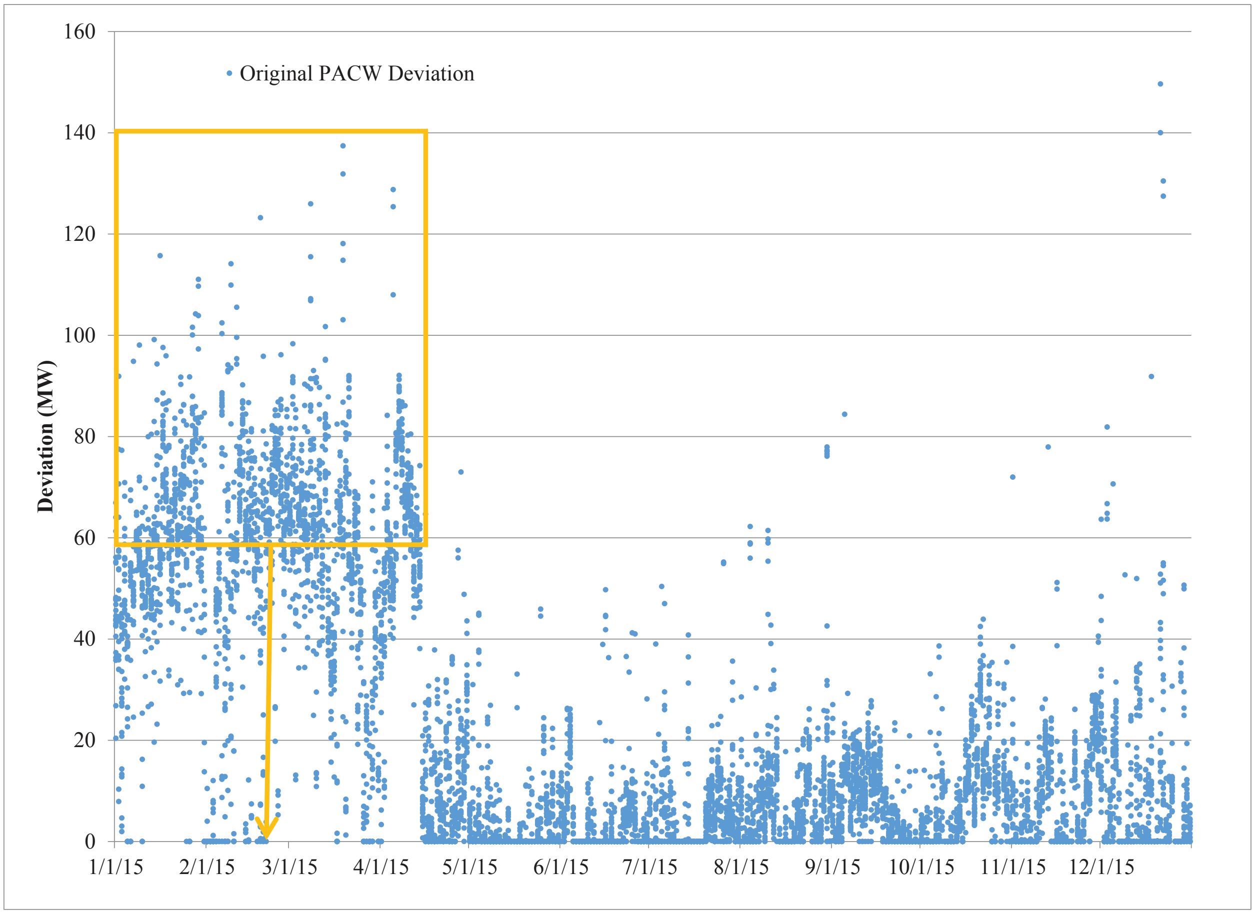
After review of the data for each of the above anomaly types, and out of 105,120 five-minute intervals in the Study Term, only 5.9 percent and 3.6 percent of the total FRS term hours were removed from PACW and PACE, respectively. The system-wide error rate was 9.1 percent, slightly lower than the sum 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.

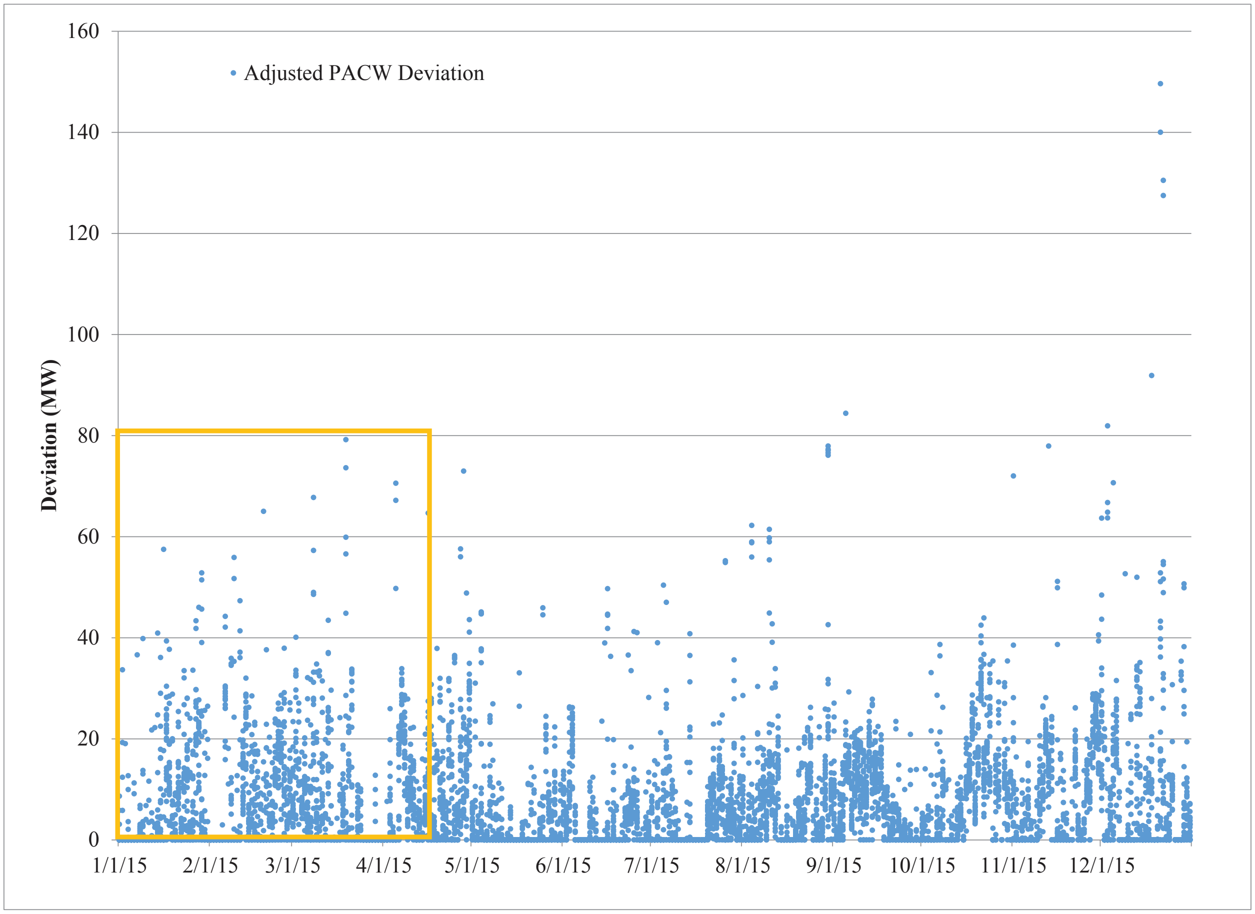
The Colstrip EIM base schedule of 50 percent to PACE and 50 percent to PACW was compared to the EMS output of 100 percent to PACW to determine the deviation. This resulted in a positive deviation to base schedule for PACW. When the EIM model mismatch was discovered it was corrected to align to PacifiCorp's 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

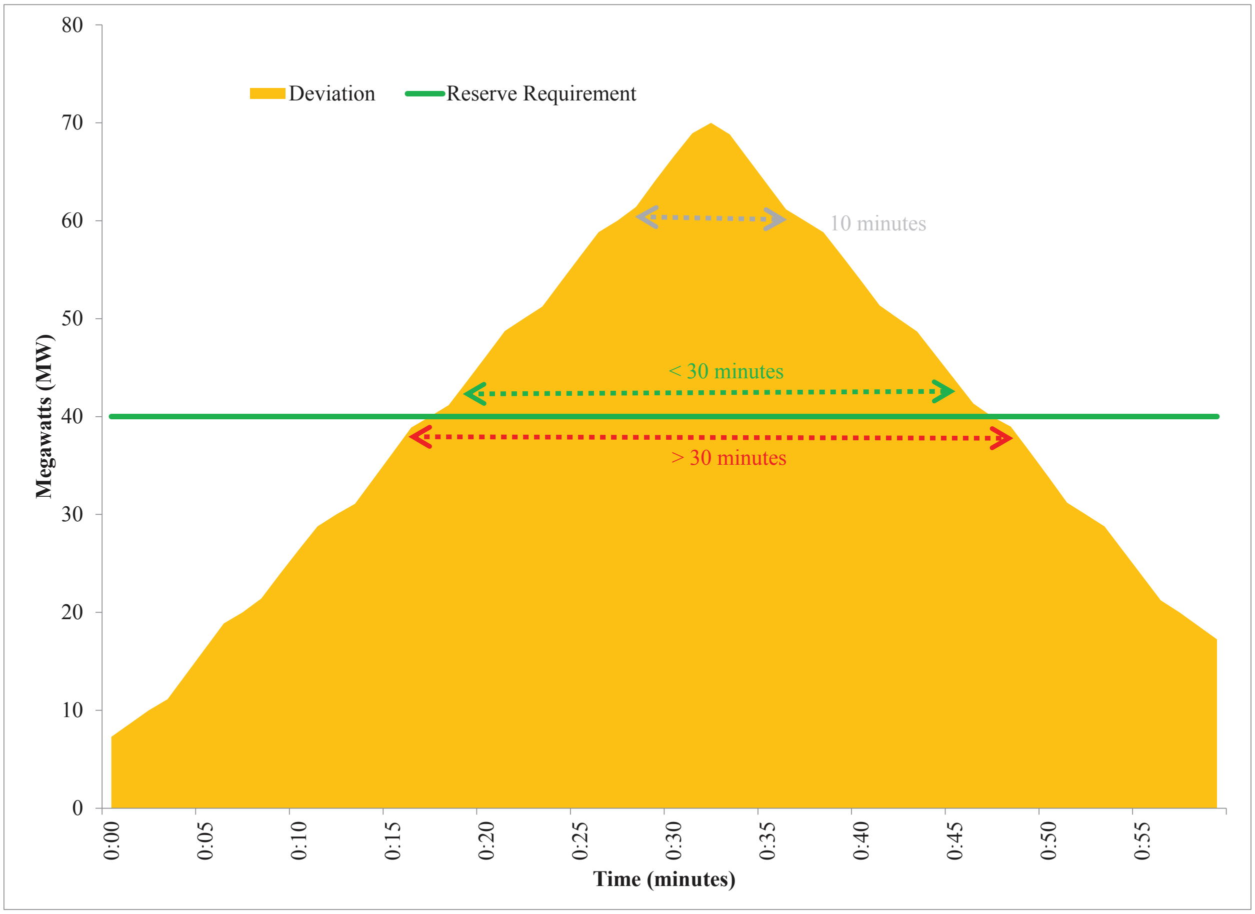
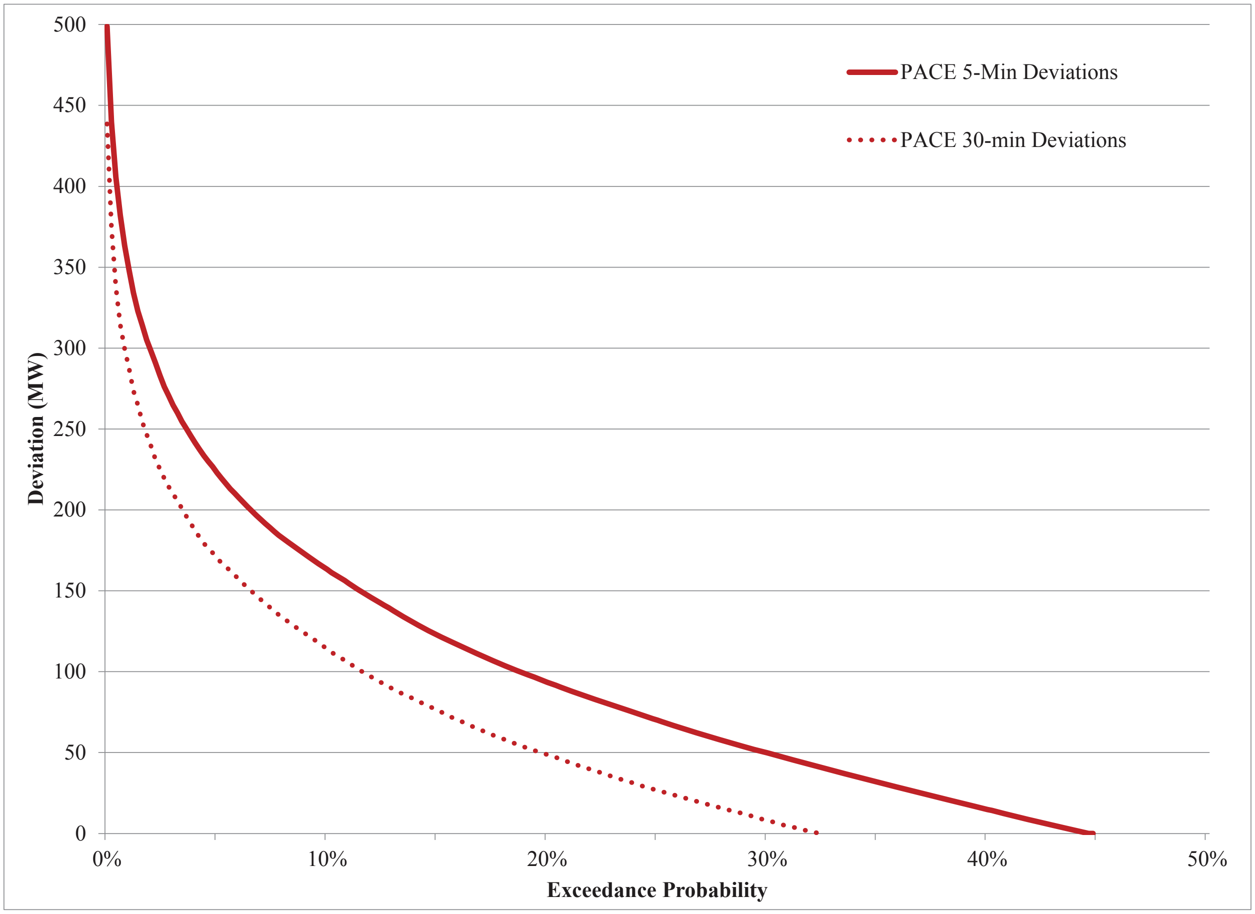


Figure F.7 below illustrates the distribution of the combined five-minute deviations for Load, Wind, and Non-VERs in PACE during 2015, as well as the distribution of thirty-minute sustained deviations relevant to the BAL-001-2 standard. The effect for PACW was comparable (not shown). The thirty-minute 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

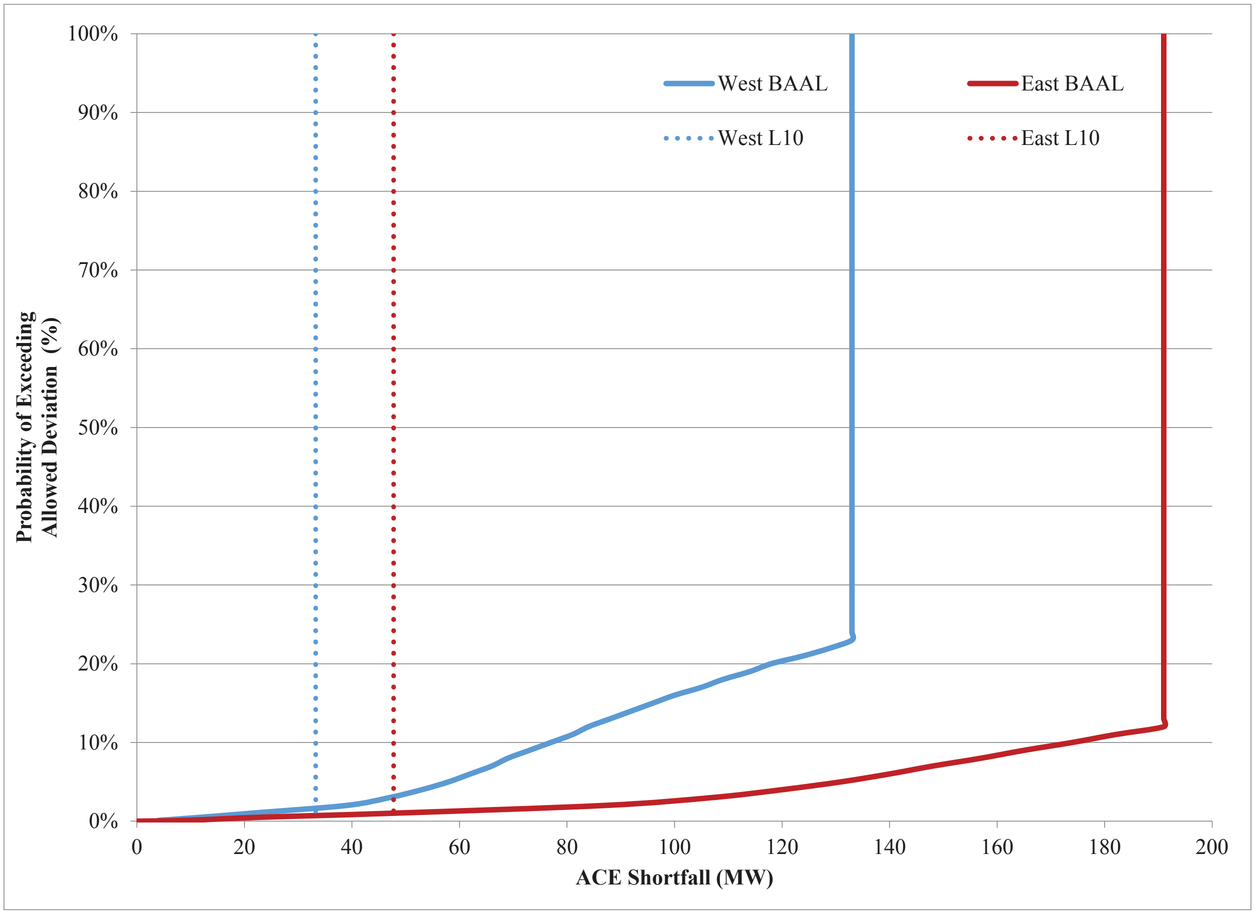
Even if insufficient regulation reserve capability is available to compensate for a thirty-minute sustained deviation, a violation of BAL-001-2 does not occur unless the deviation also exceeds the Balancing Authority ACE Limit.

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.

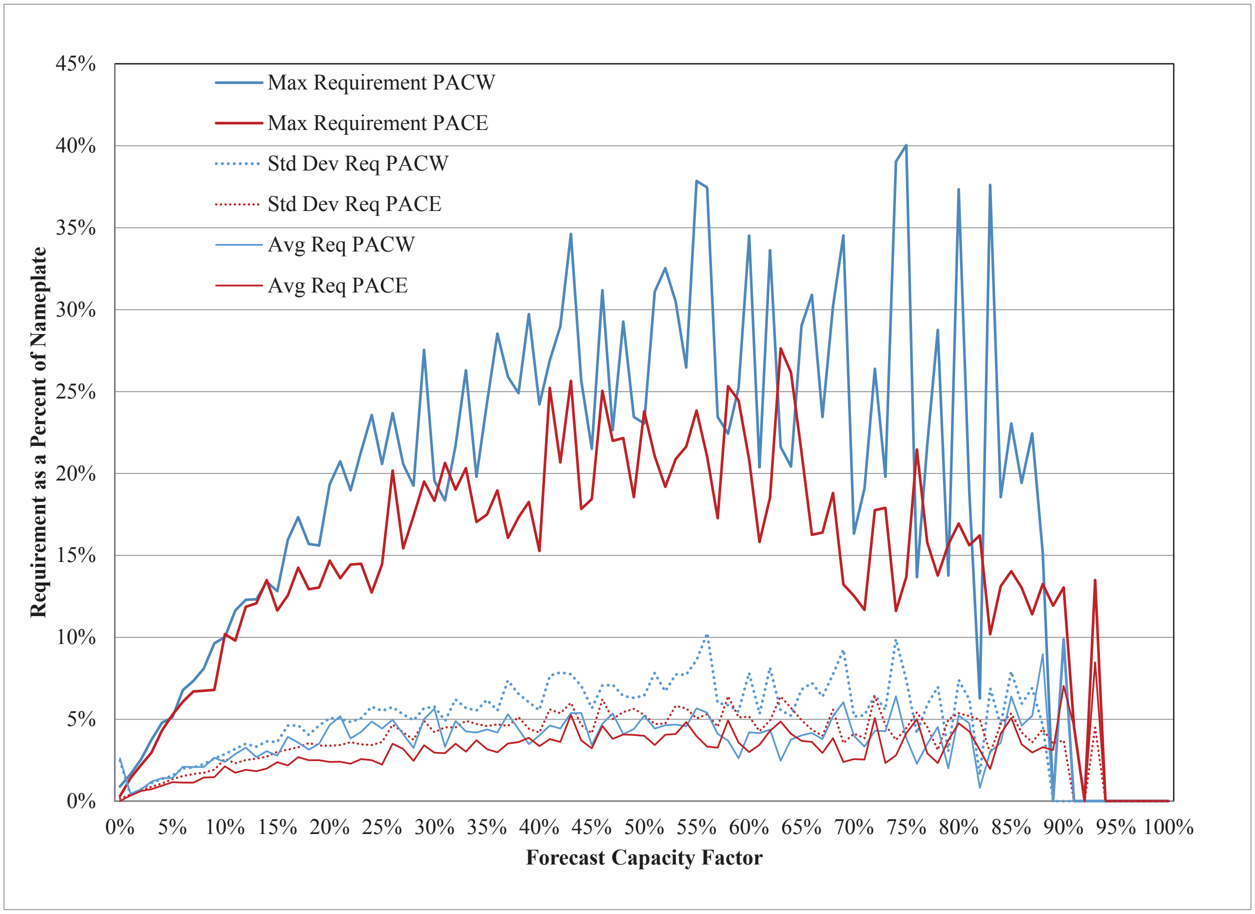
2015 Regulation Reserve Forecast

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.

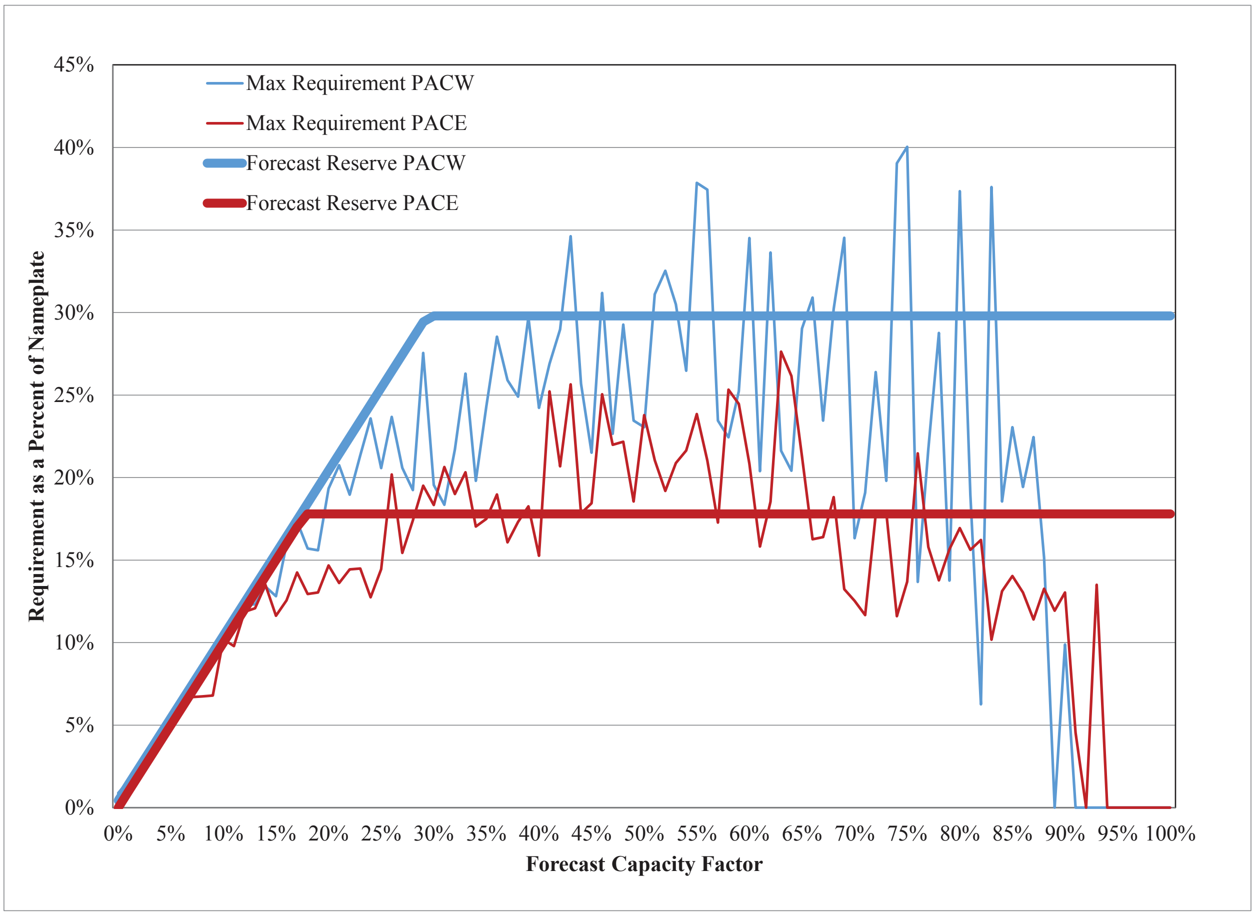
The sample size of each forecasted capacity factor varies, with very high capacity factors occurring less frequently. With this consideration in mind, the decline in observed maximum requirements at high capacity factors can be viewed as an artifact of the sample rather than a real trend related to the 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

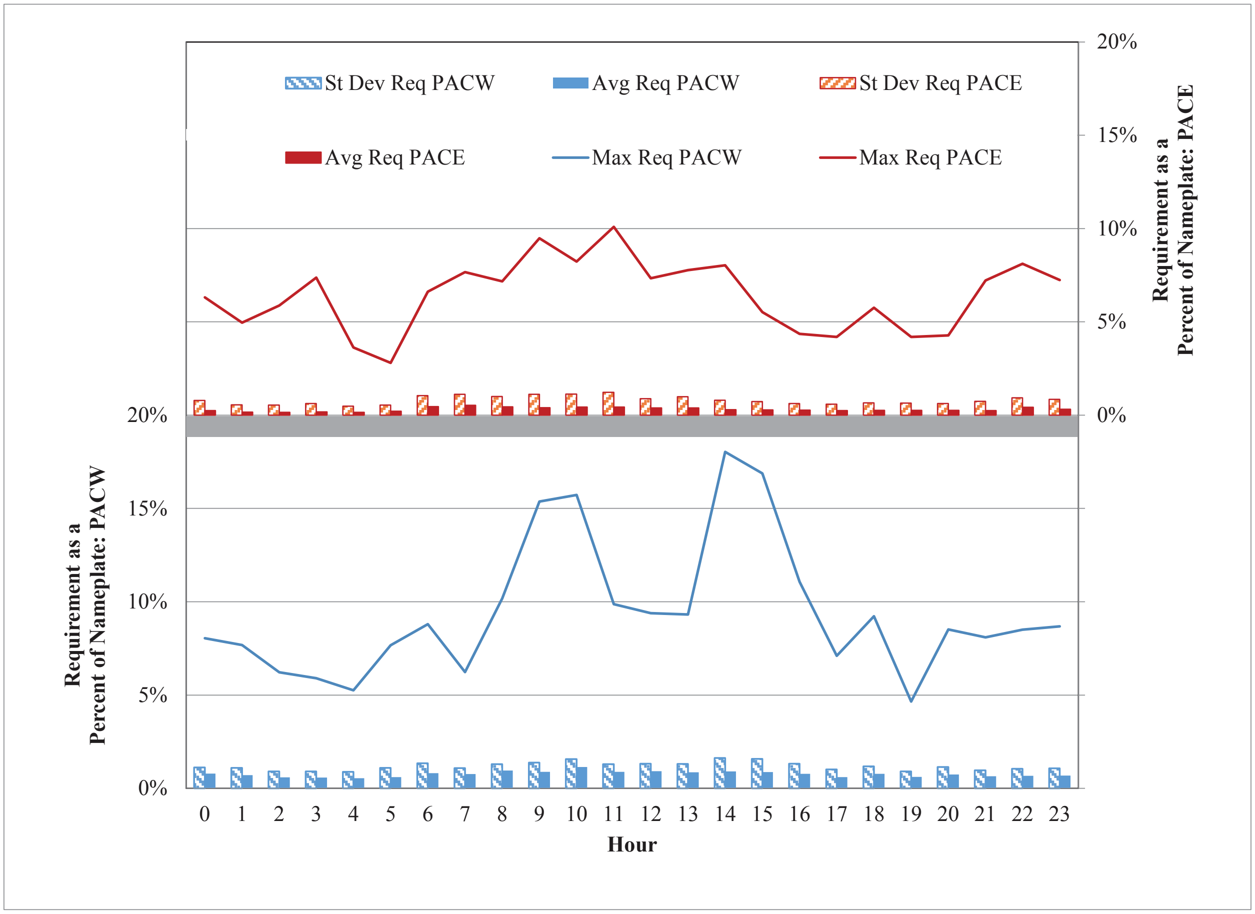
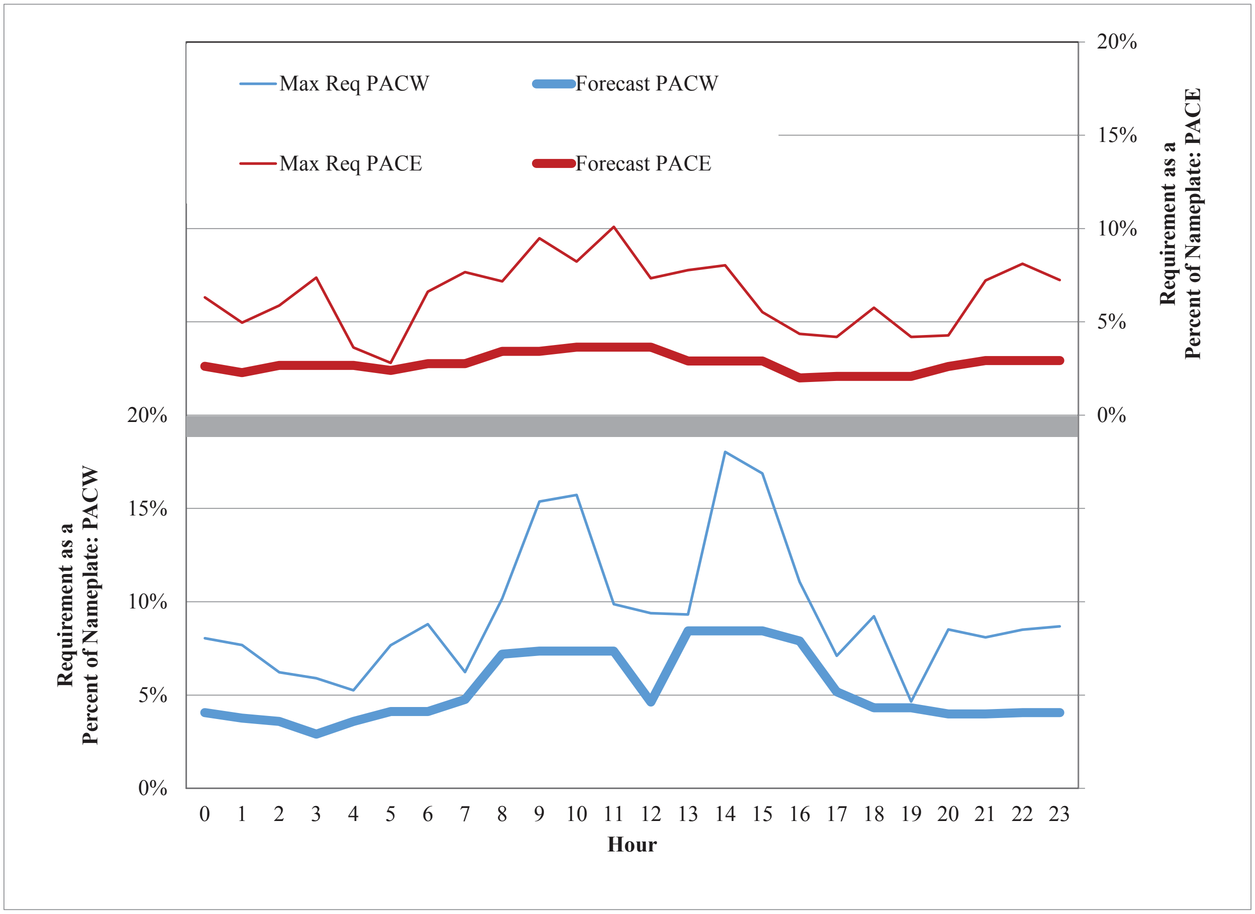


Figure F.13 below presents the regulation reserve forecast for each hour of the day for PACE and PACW Non-VERs. The forecast is based on the rolling three-hour maximum of regulation reserve requirements from 2015. This produces a smoother forecast, reflecting realistic hourly variation rather than just 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

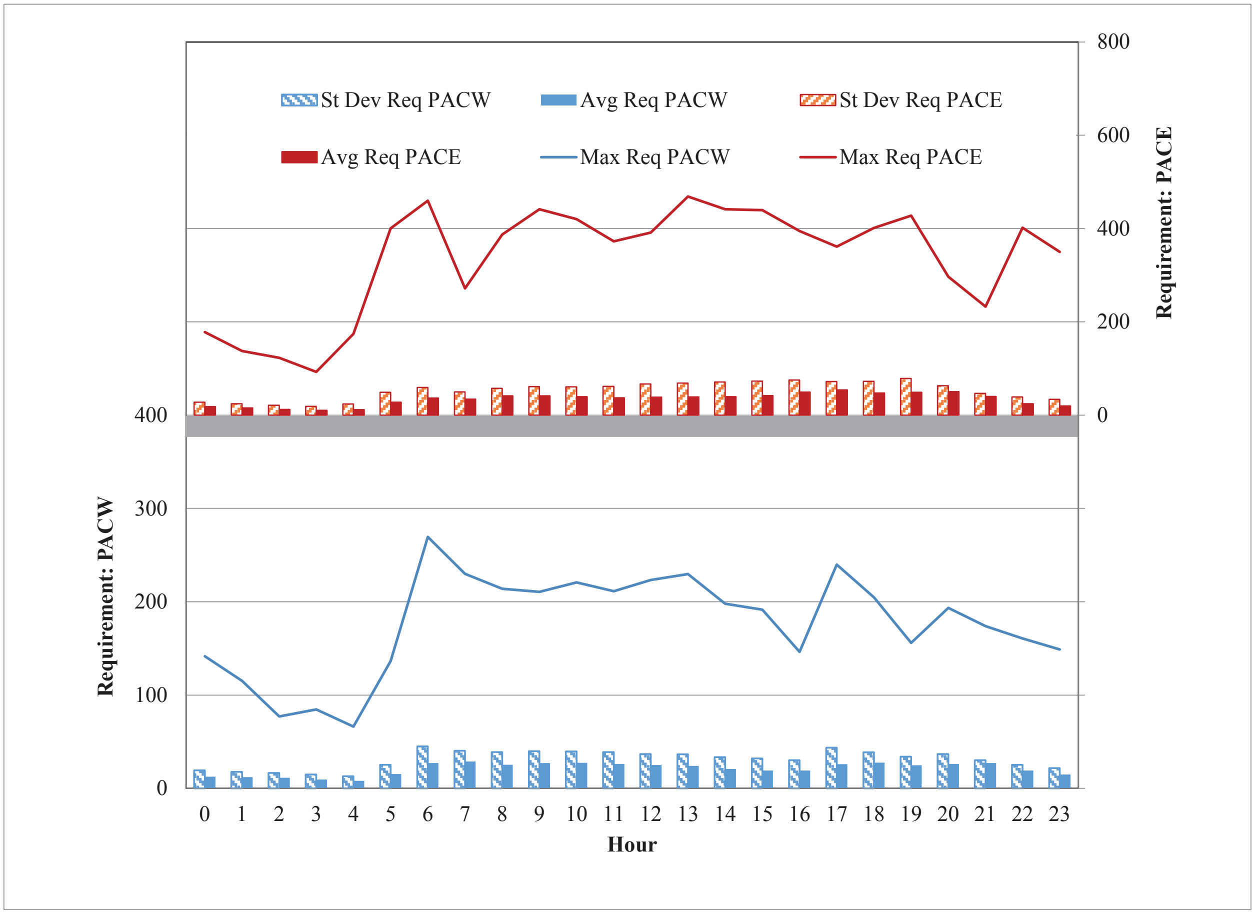
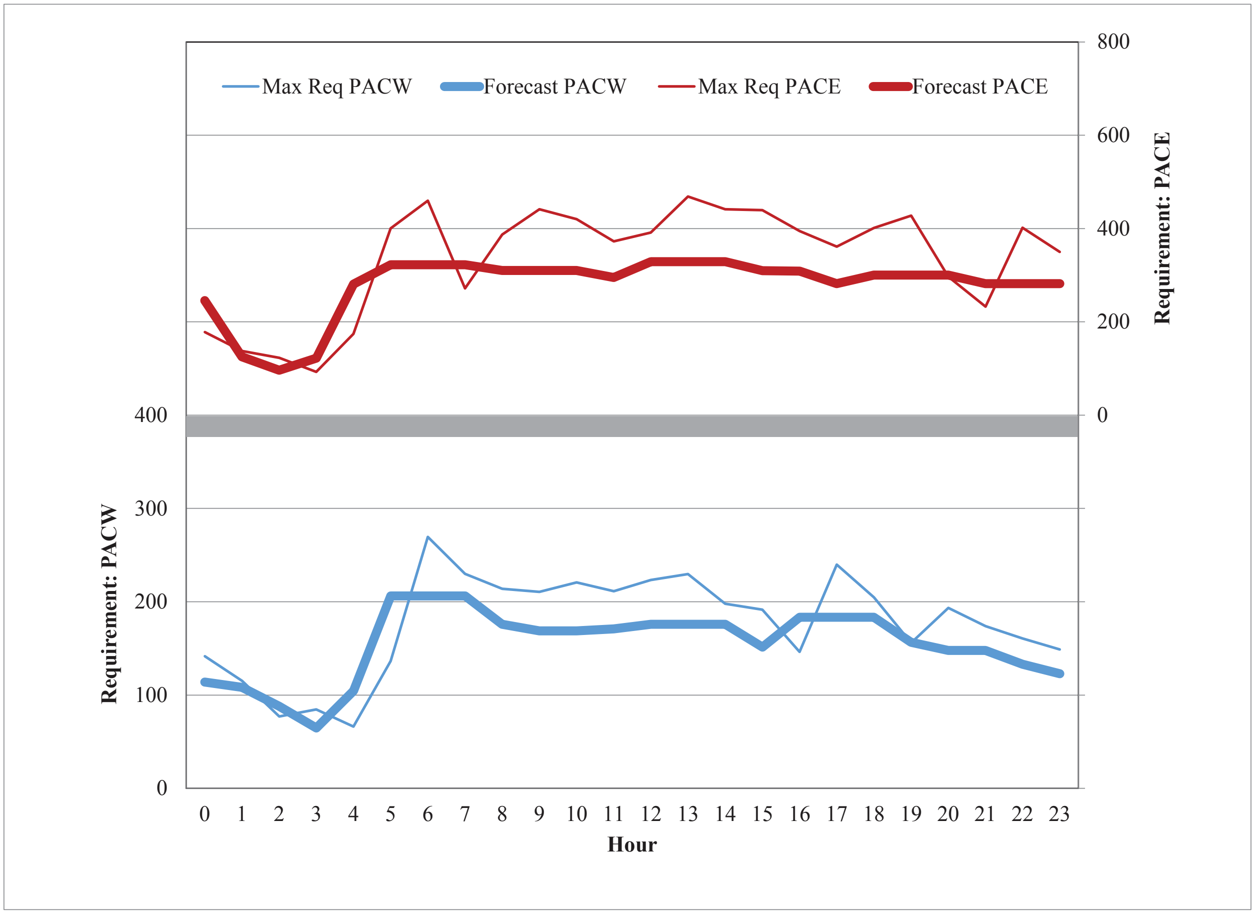


Figure F.15 below presents the regulation reserve forecast for each hour of the day for PACE and PACW load. The forecast is based on the rolling three-hour maximum of regulation reserve requirements from 2015. This produces a smoother forecast, reflecting realistic hourly variation rather than just aligning 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.

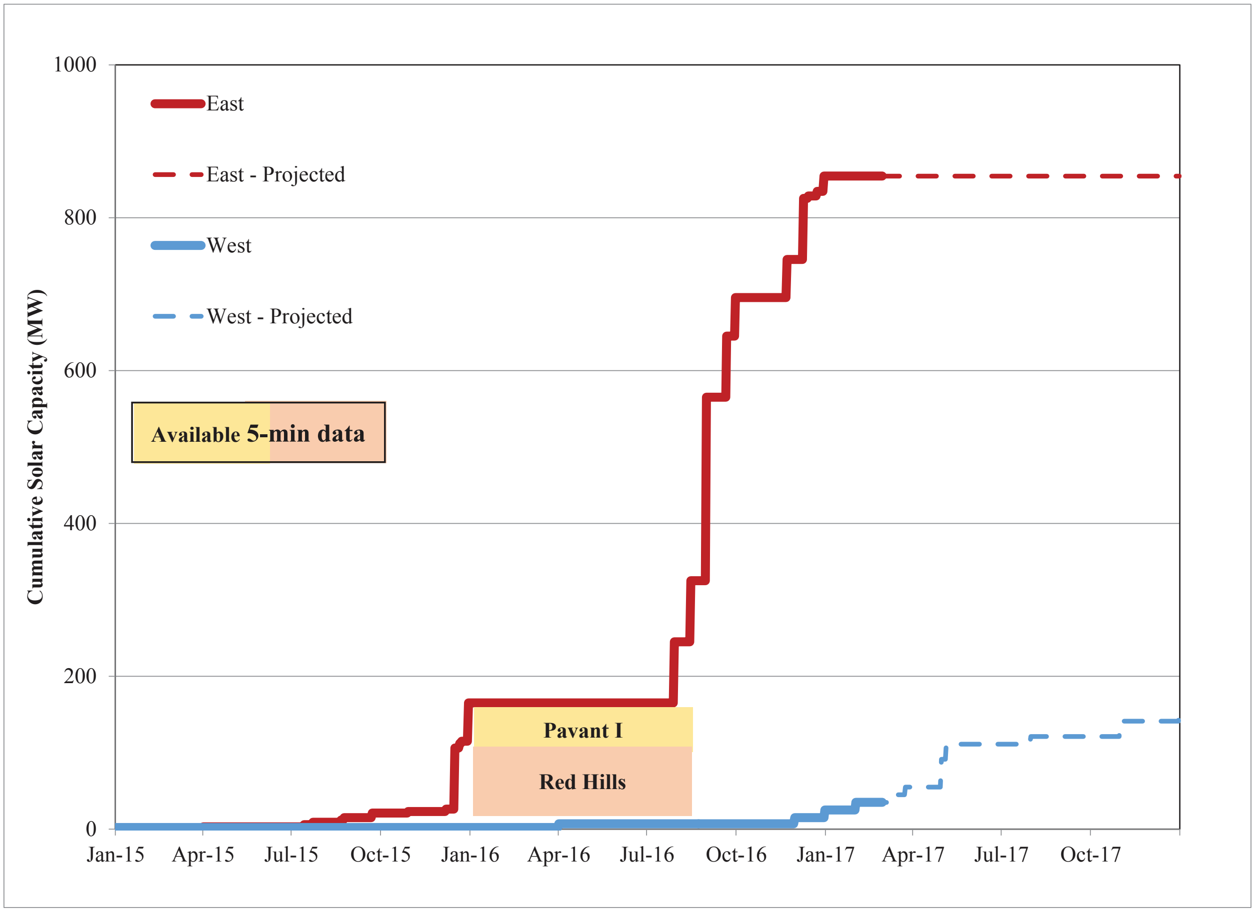
Regulation reserve requirements for PacifiCorp's system-wide portfolio dropped by 6.1percent of the wind capacity removed. This is lower than the average requirement of 9.2 percent in the 2015 portfolio results shown in Table F.7 above. This indicates that diversity is increasing as the pool of requirements 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.

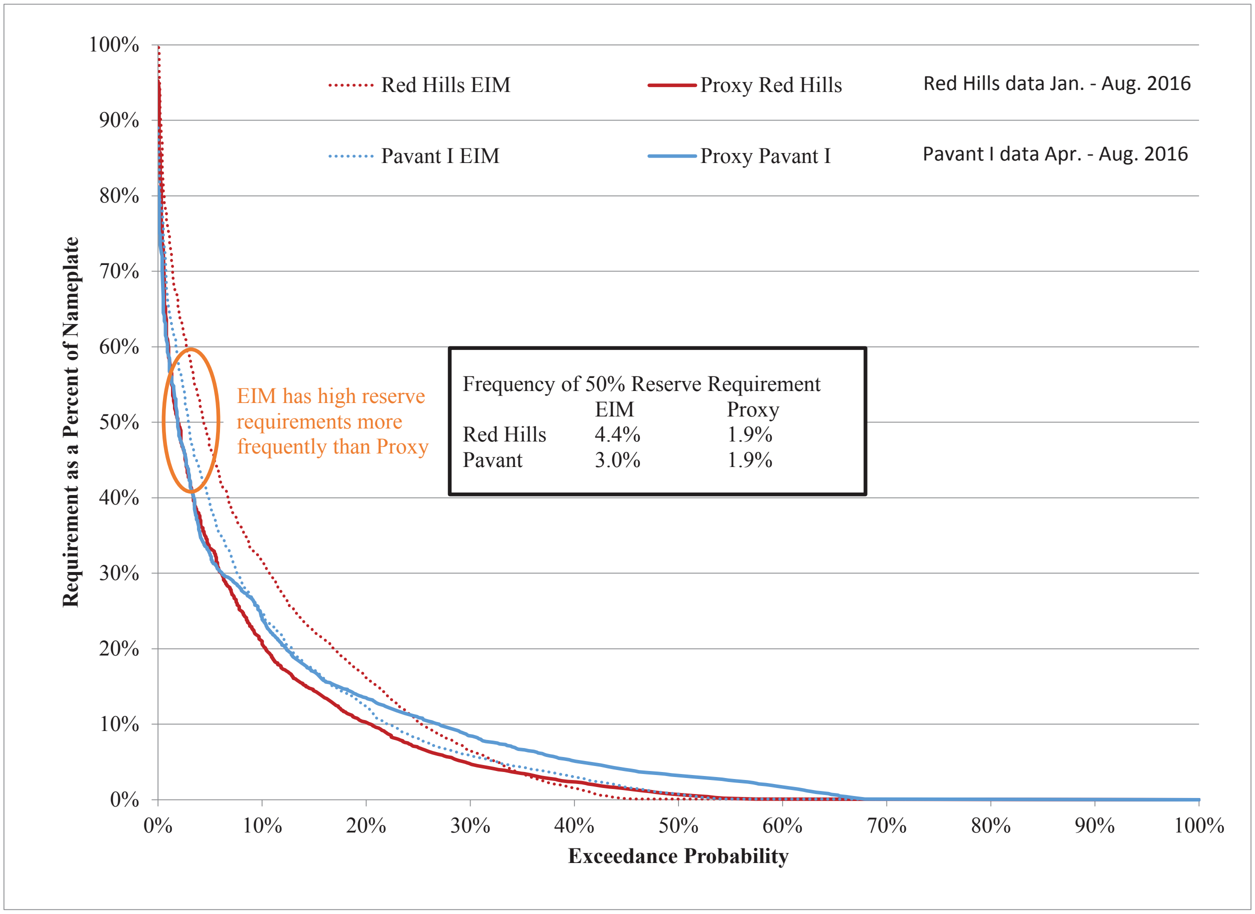
To estimate the amount of cloud cover, the solar availability is calculated by dividing the actual output in each five-minute interval by the maximum output for that interval, as identified above. This removes the effect of the position of the sun, and the changes that remain should primarily be primarily 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.

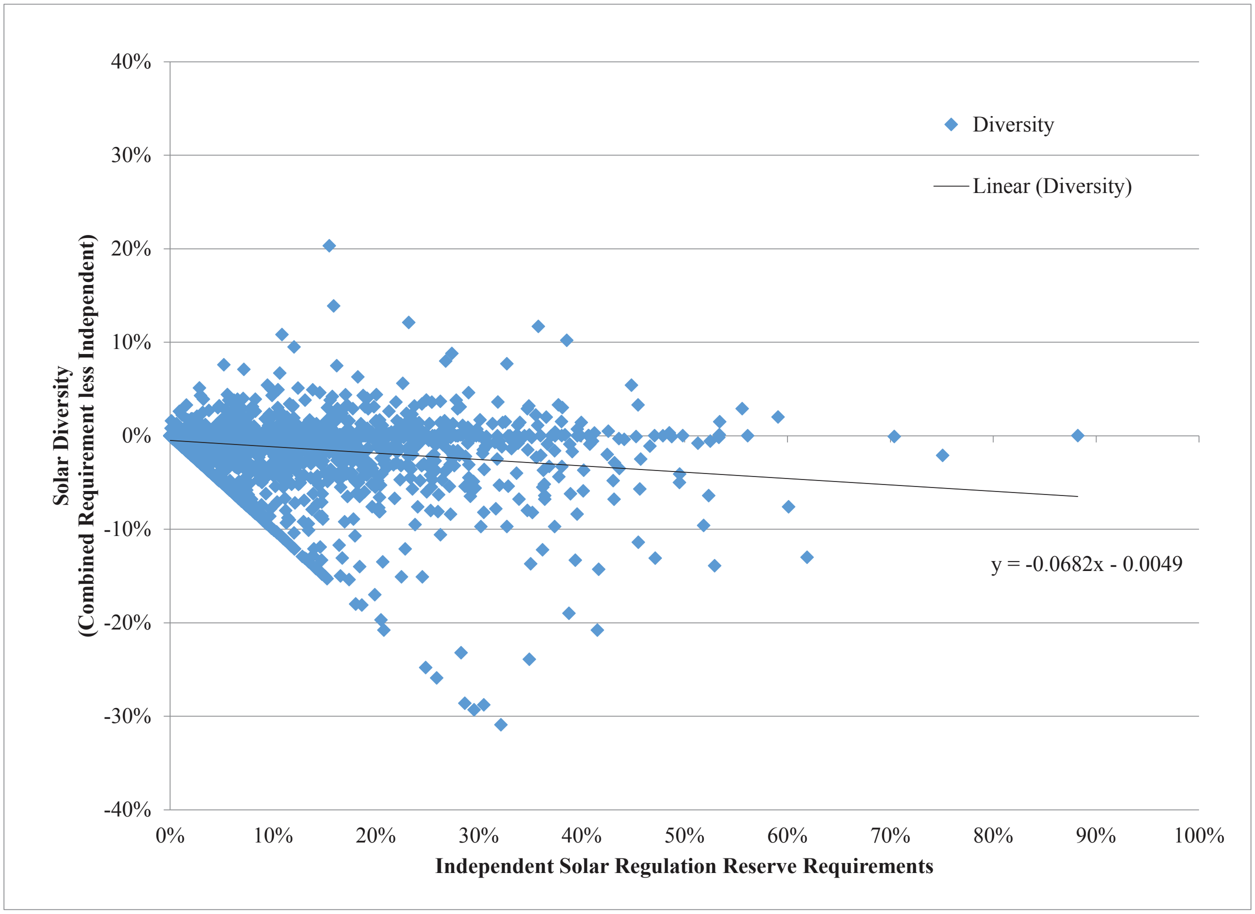
Figure F.17 - Solar Regulation Reserve Requirements: Proxy vs EIM



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



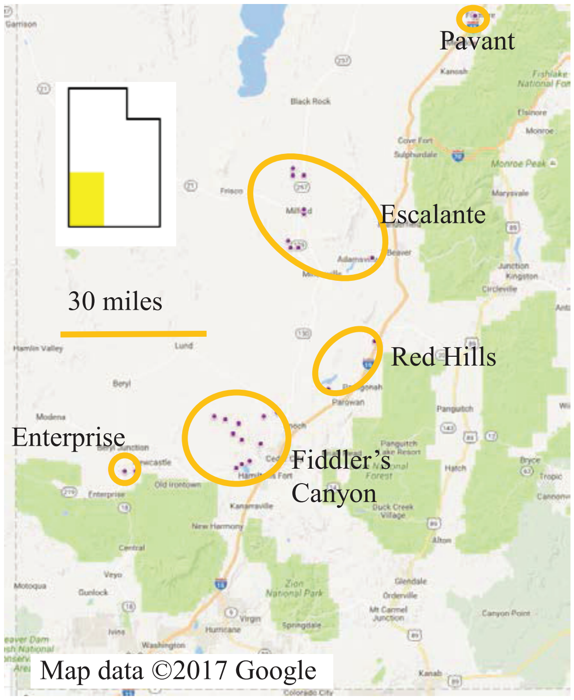
As shown in Figure F.18, diversity is not guaranteed to reduce hourly regulation reserve requirements. While this is not intuitive, it is a direct result of the 30 minute maximum time limit for deviations under BAL-001-2. If two resources each have deviations that are only 20 minutes long, the regulation 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.

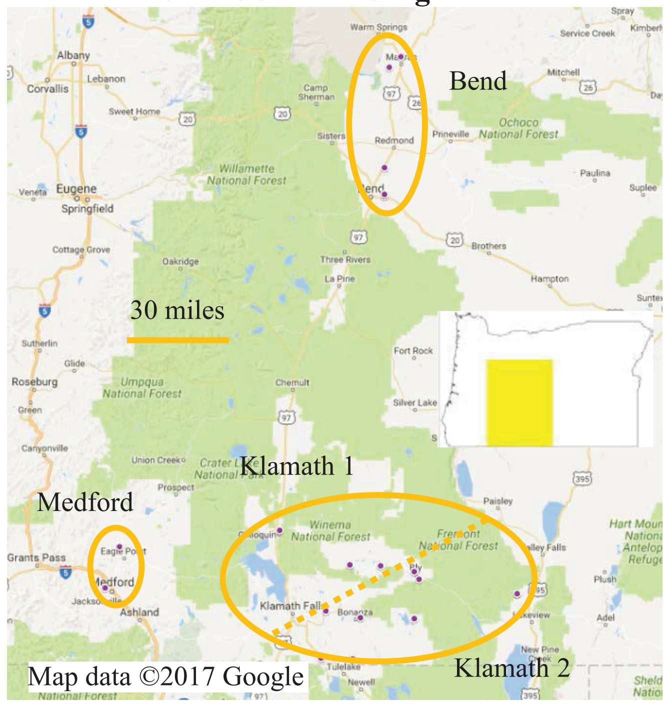
Despite the potential for increased aggregate requirements in some instances, on average the aggregate requirements are lower as a result of diversity. Because the regulation requirements are bounded by zero, the diversity benefit is limited to the size of the independent requirement.
As a result, the 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.

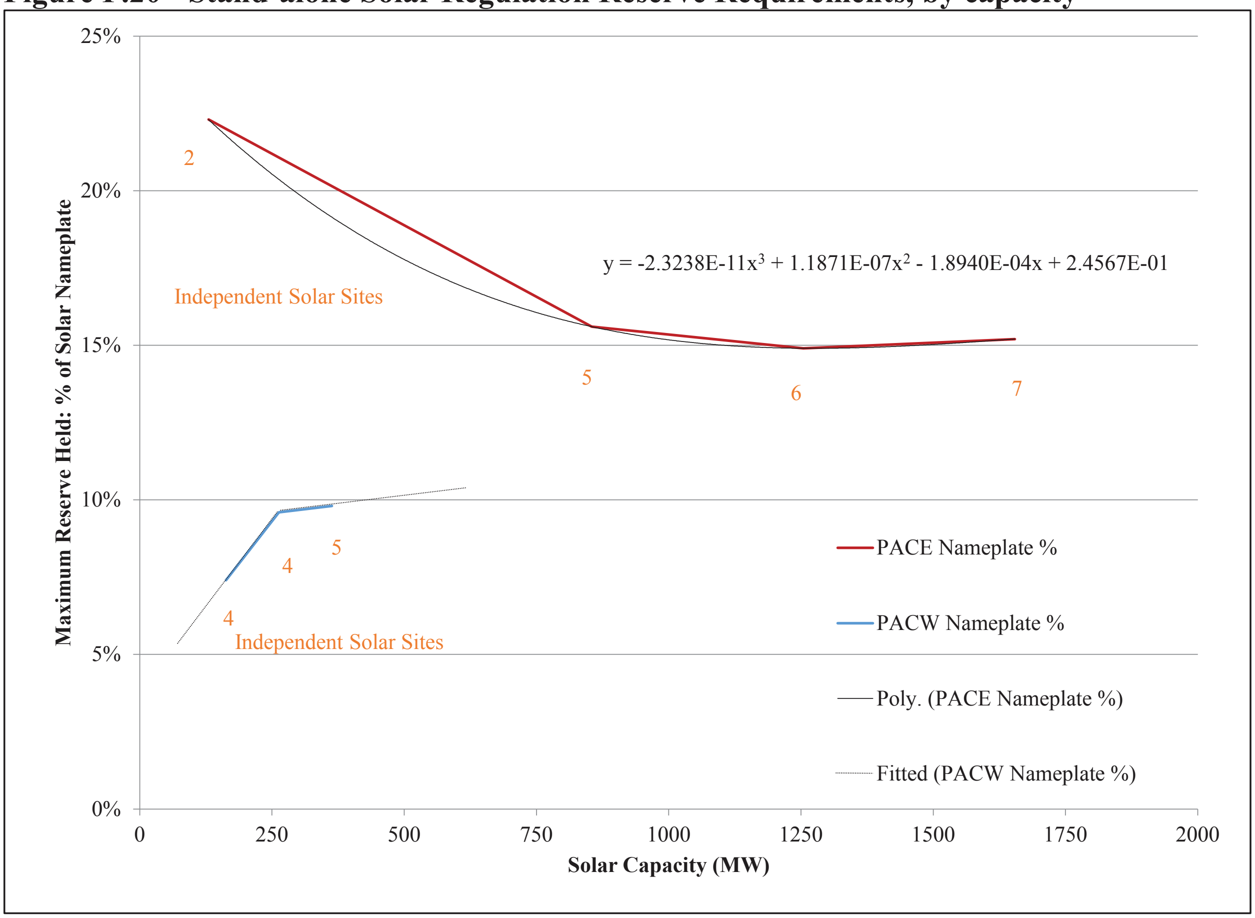
The results of the solar regulation requirements in the various scenarios is shown in Table F.10 below, with the wind results shown for comparison. Note that while the fixed percentage of nameplate capacity (i.e. the maximum reserve held) for solar and wind in PACE is similar, ranging from 14.9 percent 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: <u>When the minimum imbalances in every rolling thirty-minute period are compared,</u> 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)

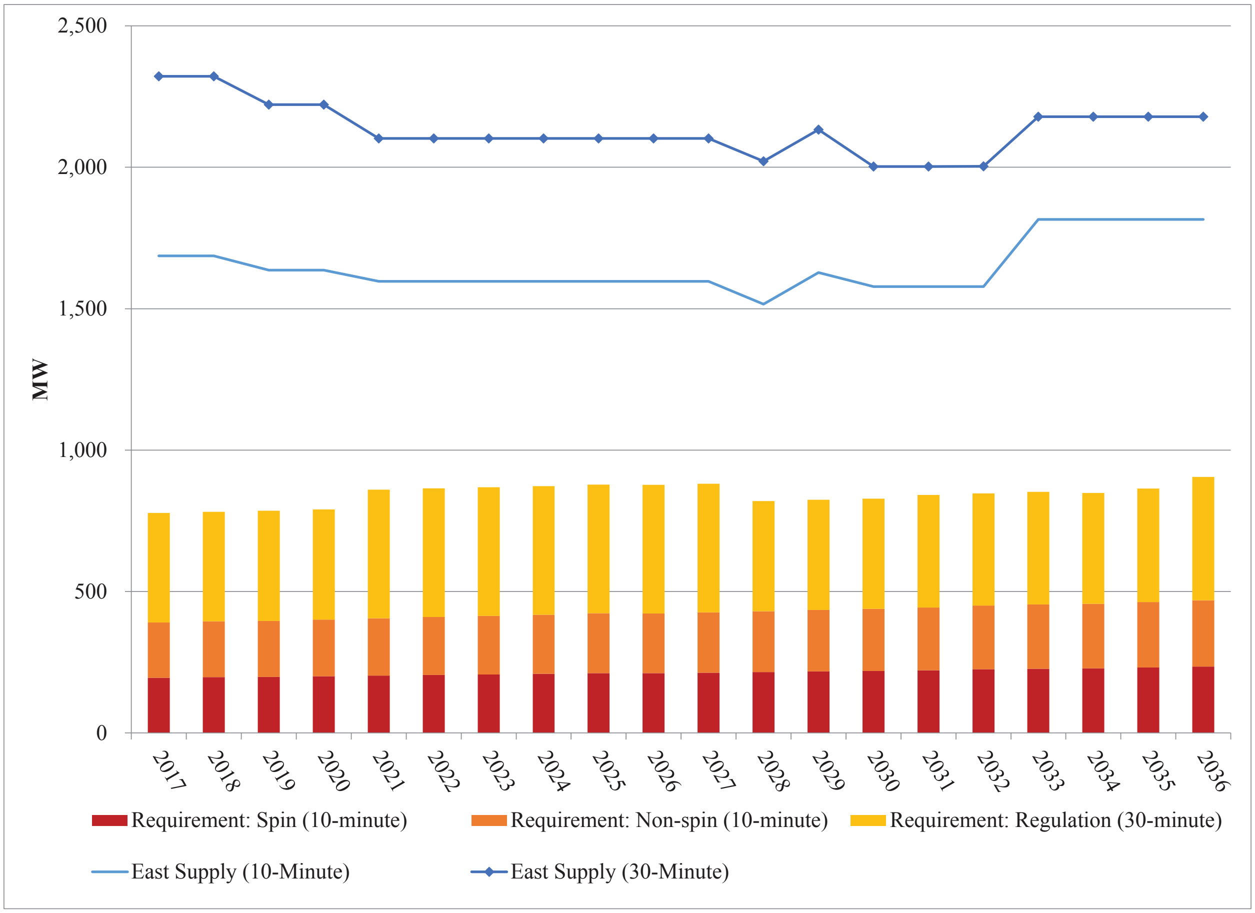
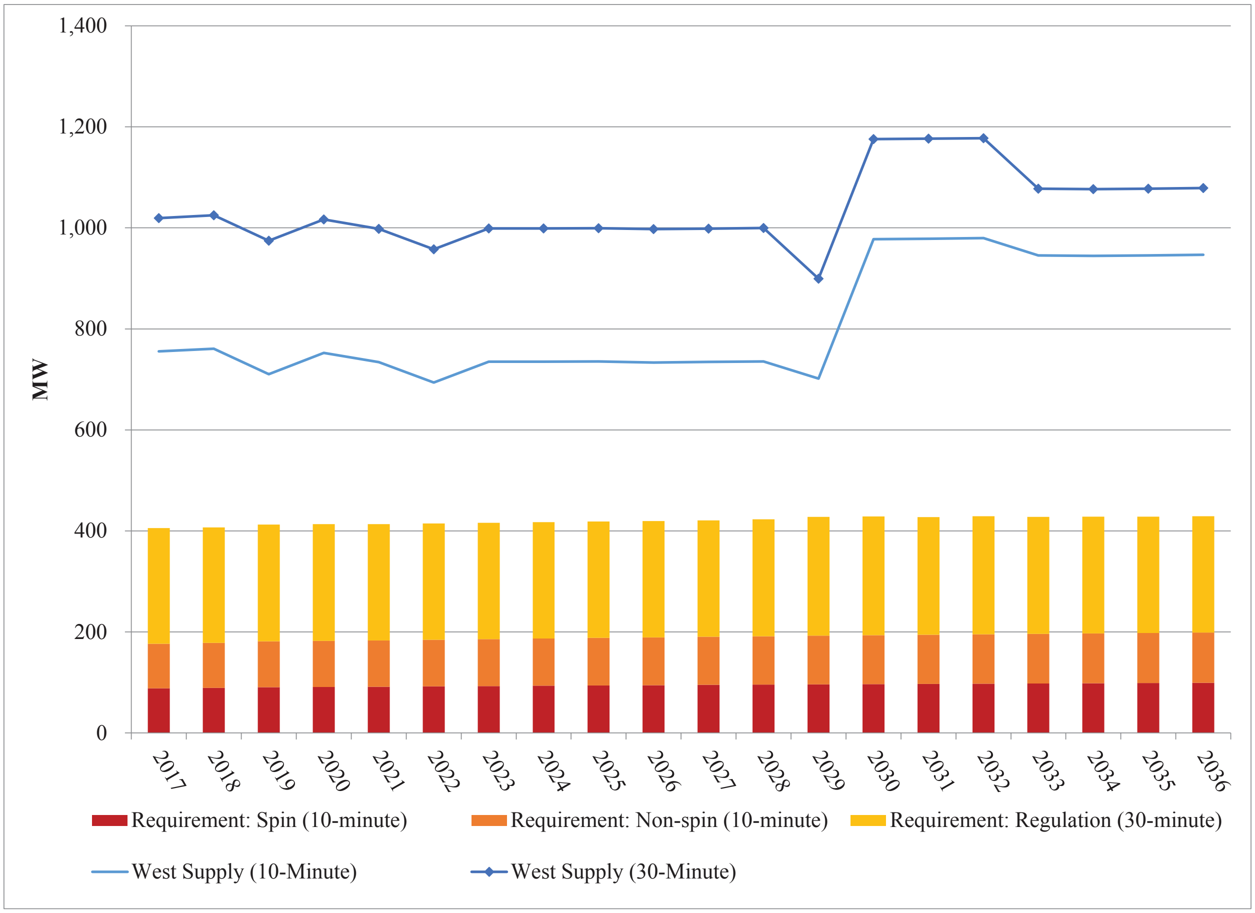


Figure F.22 - Comparison of Reserve Requirements and Resources, West Balancing Authority Area (MW)



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 deviation[3](σ) is a measure of how widely values are dispersed from the average value:

$$\sigma = \sqrt{\frac{\sum_{i=1}^{n}(x_i - \mu)^2}{(n-1)}}$$

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 (σ_T):

$$\sigma_T = \sigma\sqrt{T}$$

Volatilities are typically quoted on an annual basis but can be specified for any desired time period (T). Suppose the annual volatility of load is two percent. This implies that the standard deviation of the range of possible loads a year from now is two percent, while the standard deviation four years from now is four percent.

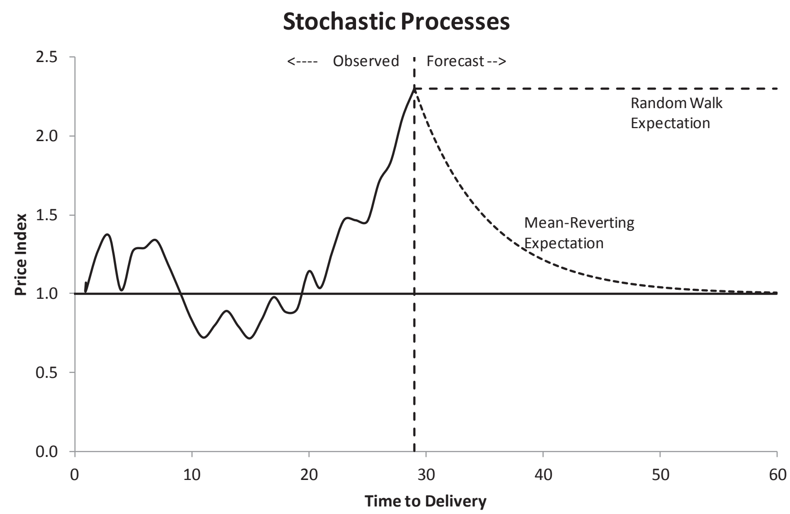
Mean Reversion

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.

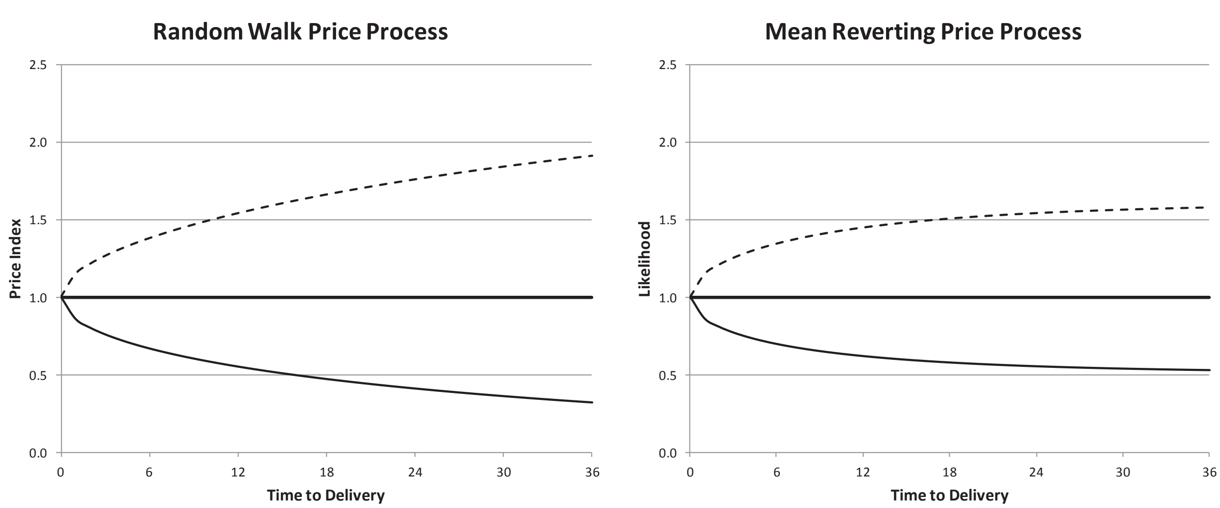
[3] "Standard Deviation" and "Variance" are standard statistical terms describing the spread of possible outcomes. The Variance equals the Standard Deviation squared.

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.

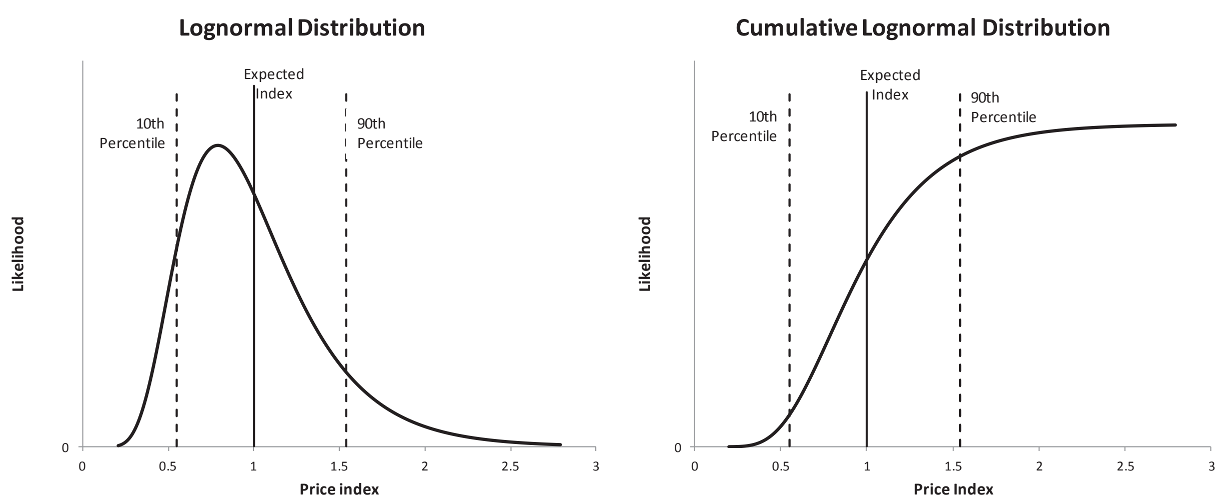
Estimating Short-term Process Parameters

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

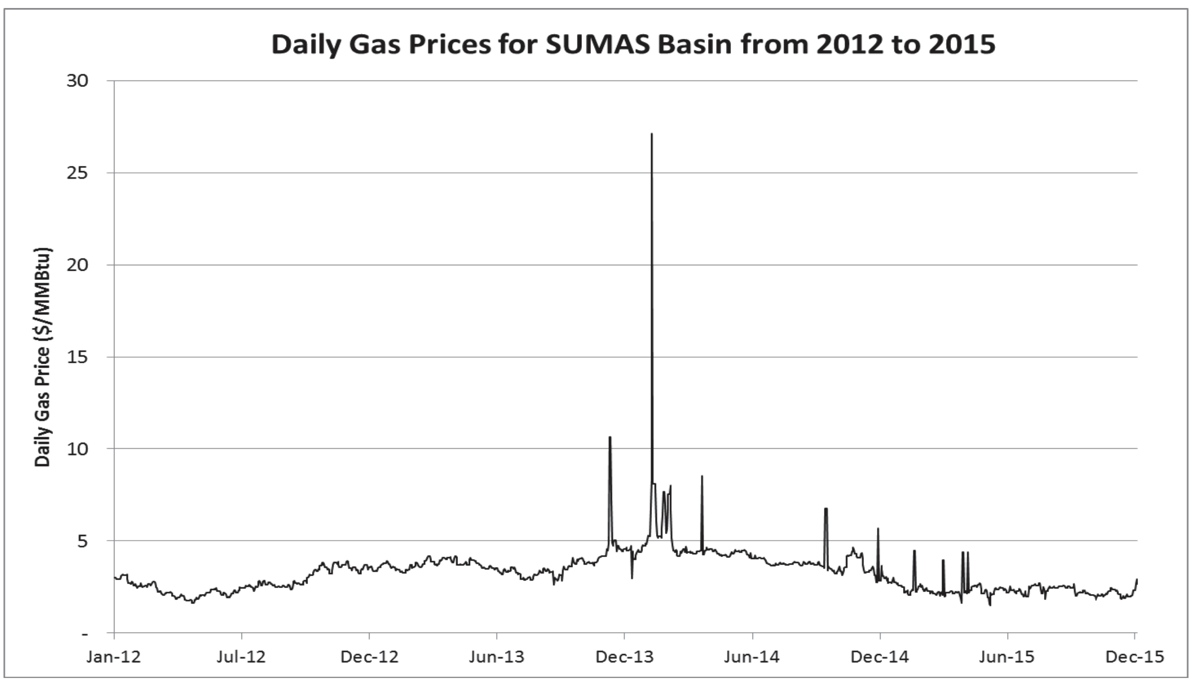
Winter	December, January, and February
Spring	March, April, and May
Summer	June, July, and August

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:

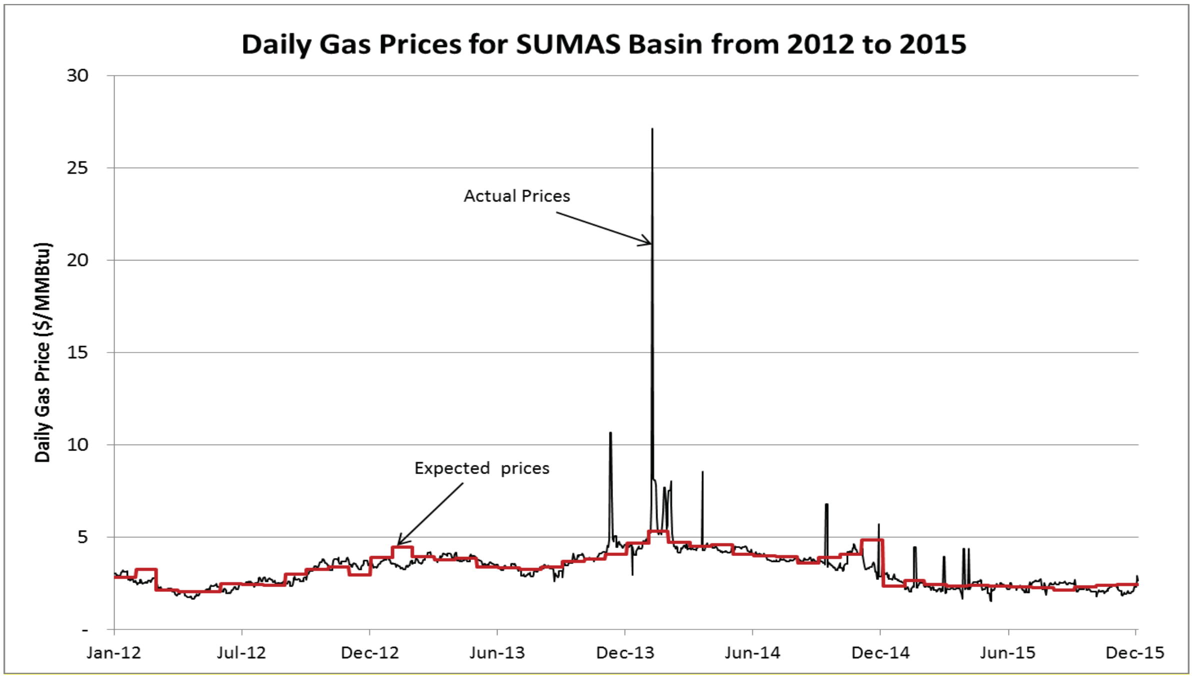
> <u>Seasonal Average</u>: The level of gas prices may be different from one year to the next. While this can be attributed to random movements or shocks in the gas markets, it is not a short-term event and should not be included in the short-term uncertainty process. In order to account for this possible 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.
> <u>Monthly Average</u>: 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.
> <u>Weekly Shape</u>: 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

$$Expected\ Gas\ Price\ = Seasonal\ Avg.Price * Monthly\ Shape\ within\ the\ Season$$

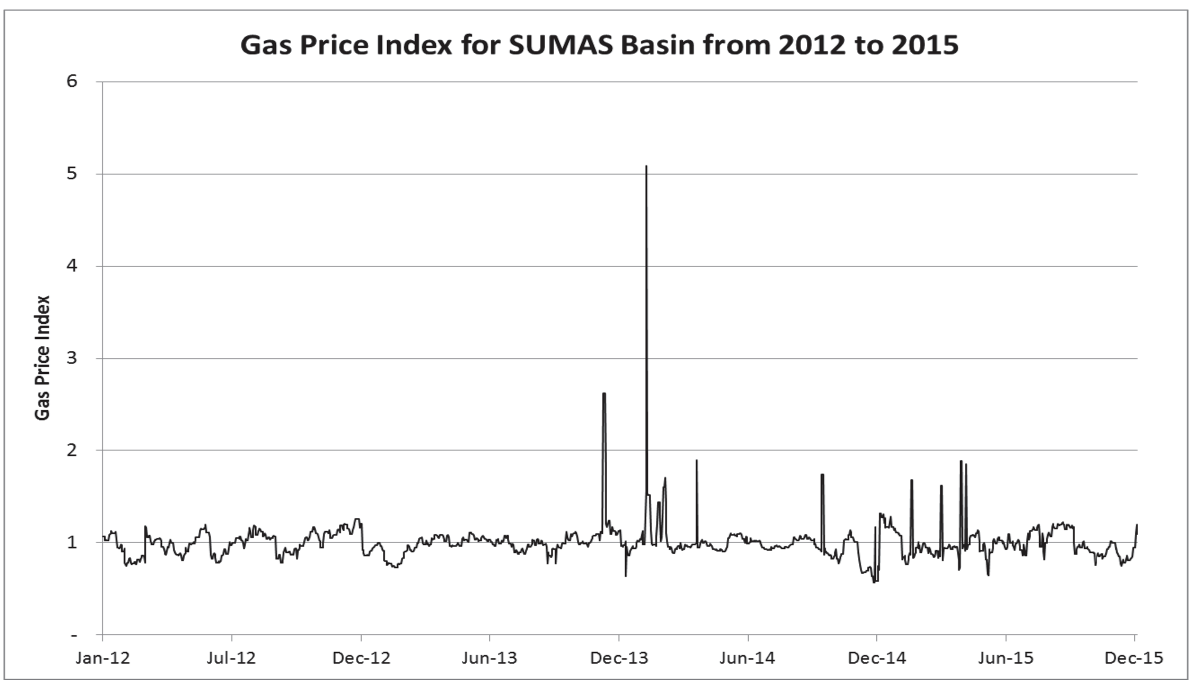
The chart below shows the comparison of the actual Sumas prices with the "expected" prices:

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



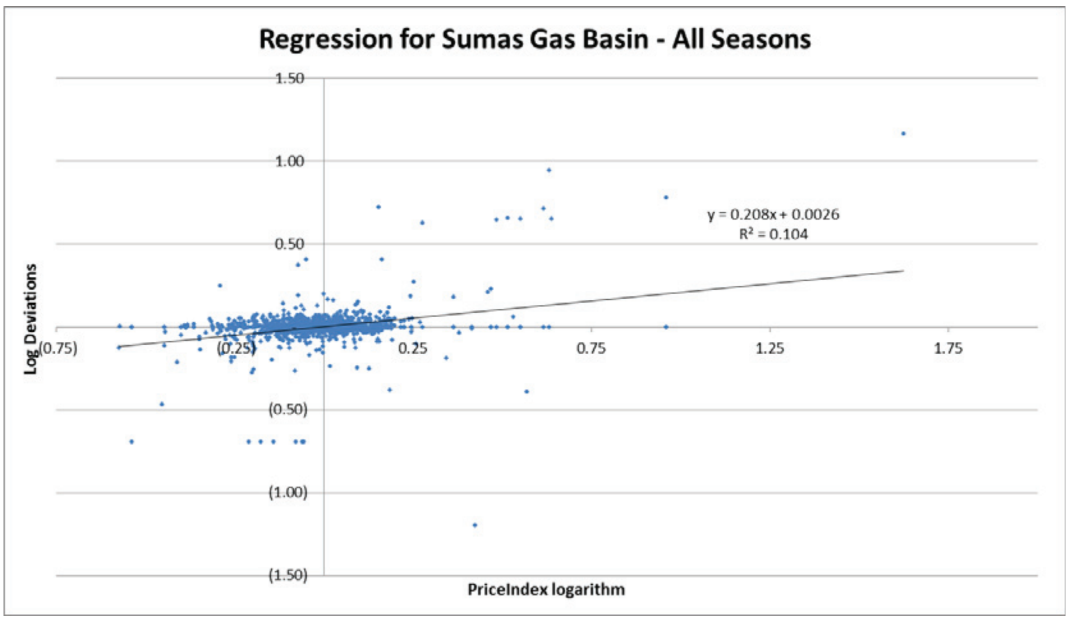
Parameter Estimation – Autoregressive Model

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

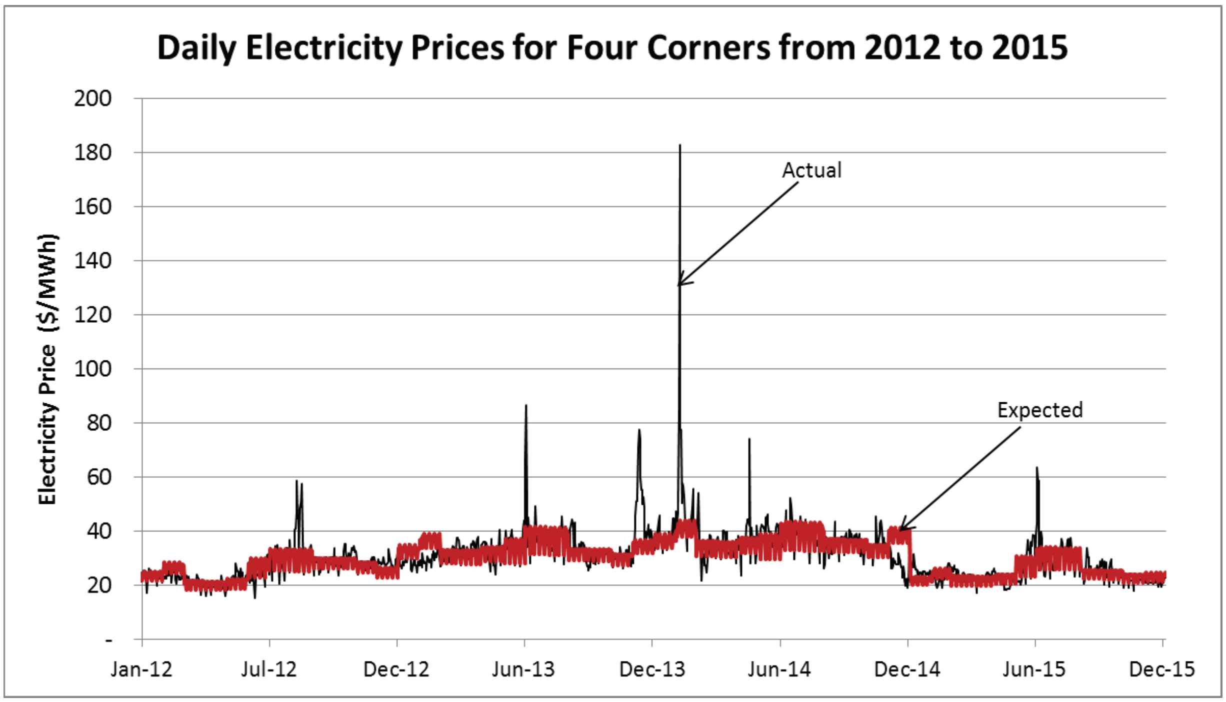
Electricity Price Process

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.

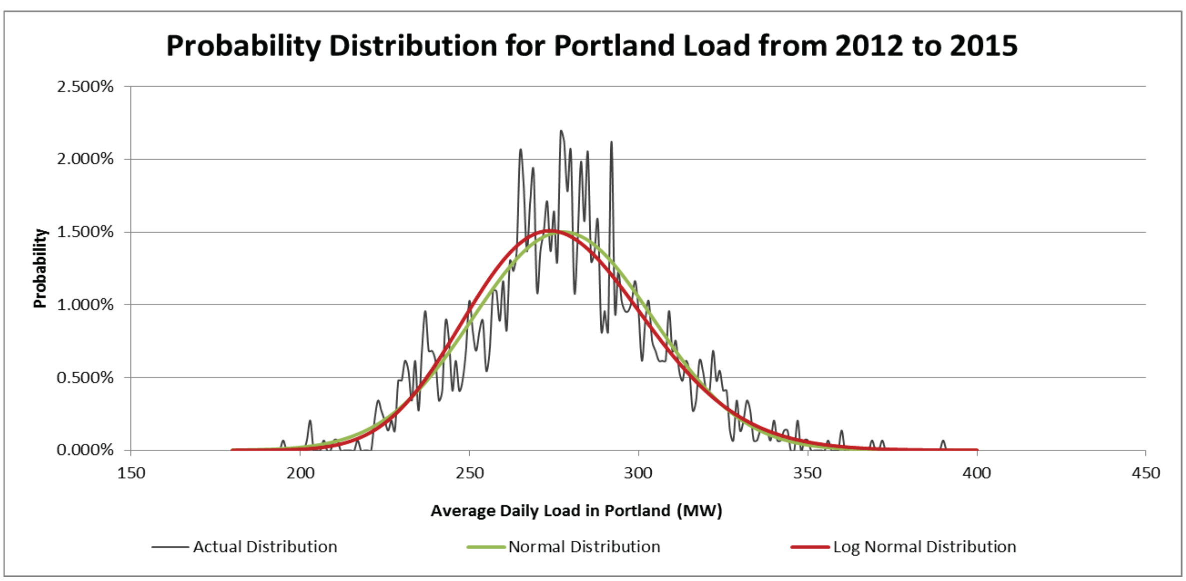
Table H.3 - Uncertainty Parameters for Electricity Regions

	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

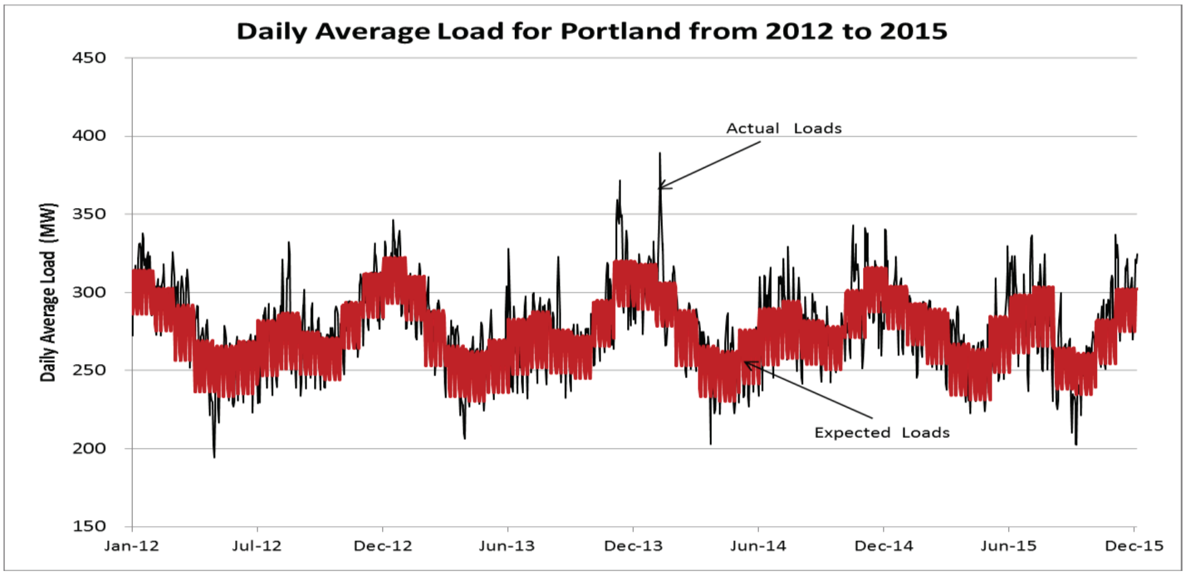
There are only two significant differences between the uncertainty analysis for regional loads and natural gas prices. The distribution of daily loads is somewhat better represented by a normal distribution rather than a lognormal distribution. And, similar to electricity prices, loads have a significant 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

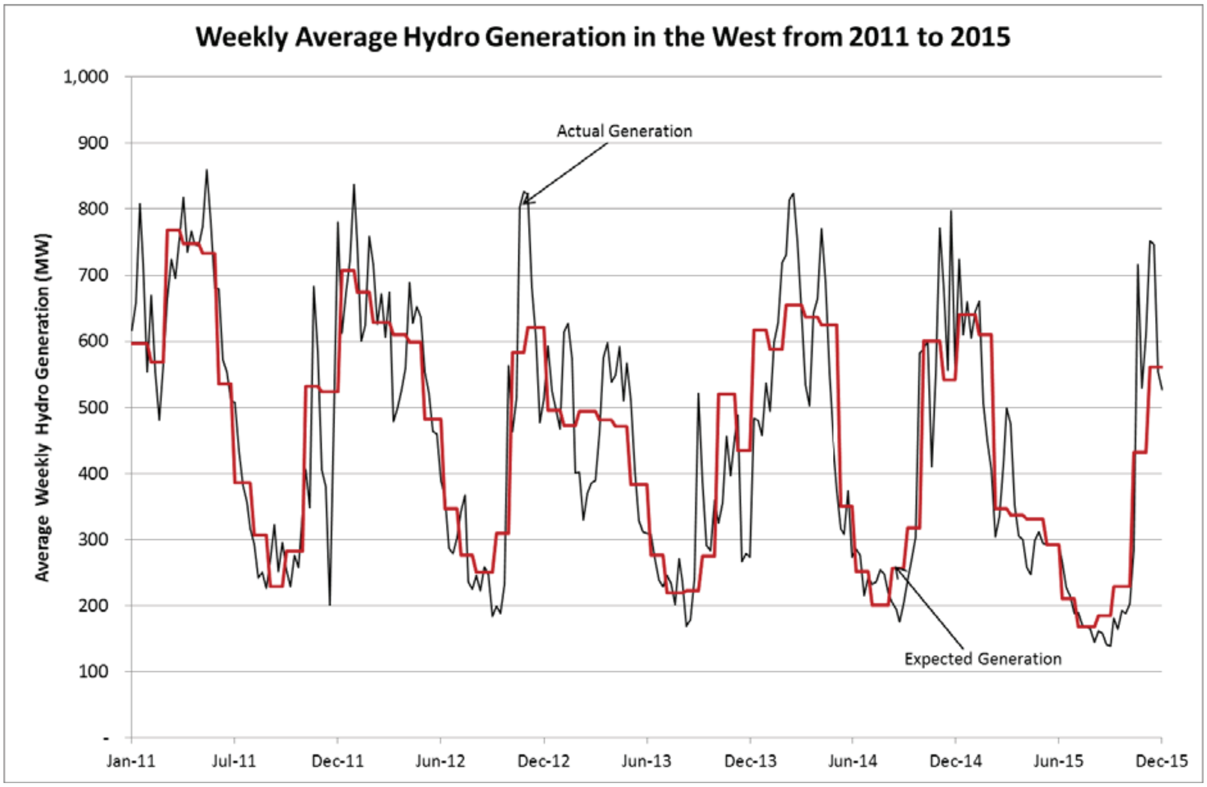
	Winter	Spring	Summer	Fall
California				
Daily Volatility	4.5%	4.1%	3.6%	4.8%
Daily Mean Reversion Rate	0.268	0.263	0.156	0.296
Idaho				
Daily Volatility	3.1%	5.2%	4.8%	4.9%
Daily Mean Reversion Rate	0.175	0.097	0.101	0.210
Portland				
Daily Volatility	3.3%	2.9%	3.9%	3.4%
Daily Mean Reversion Rate	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.

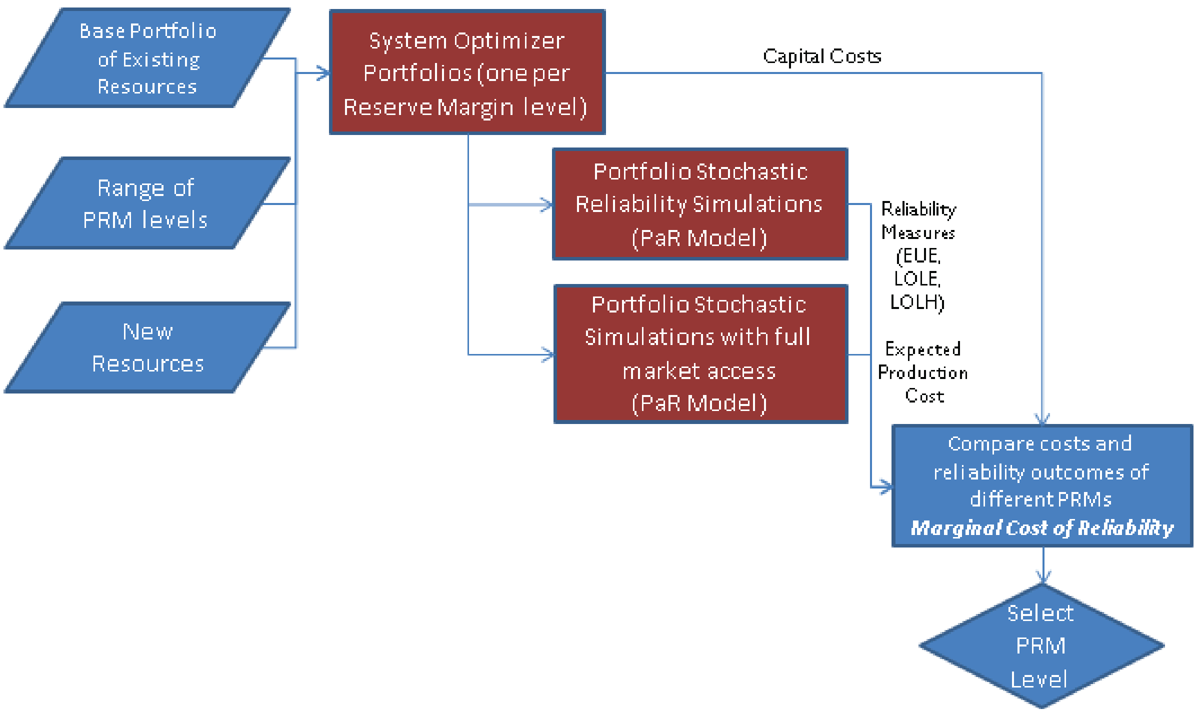
PacifiCorp's loss of load study results reflect its participation in the Northwest Power Pool (NWPP) reserve sharing agreement. This agreement allows a participant to receive energy from other participants within the first hour of a contingency event, defined as an event when there is an unexpected failure 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 reliability 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

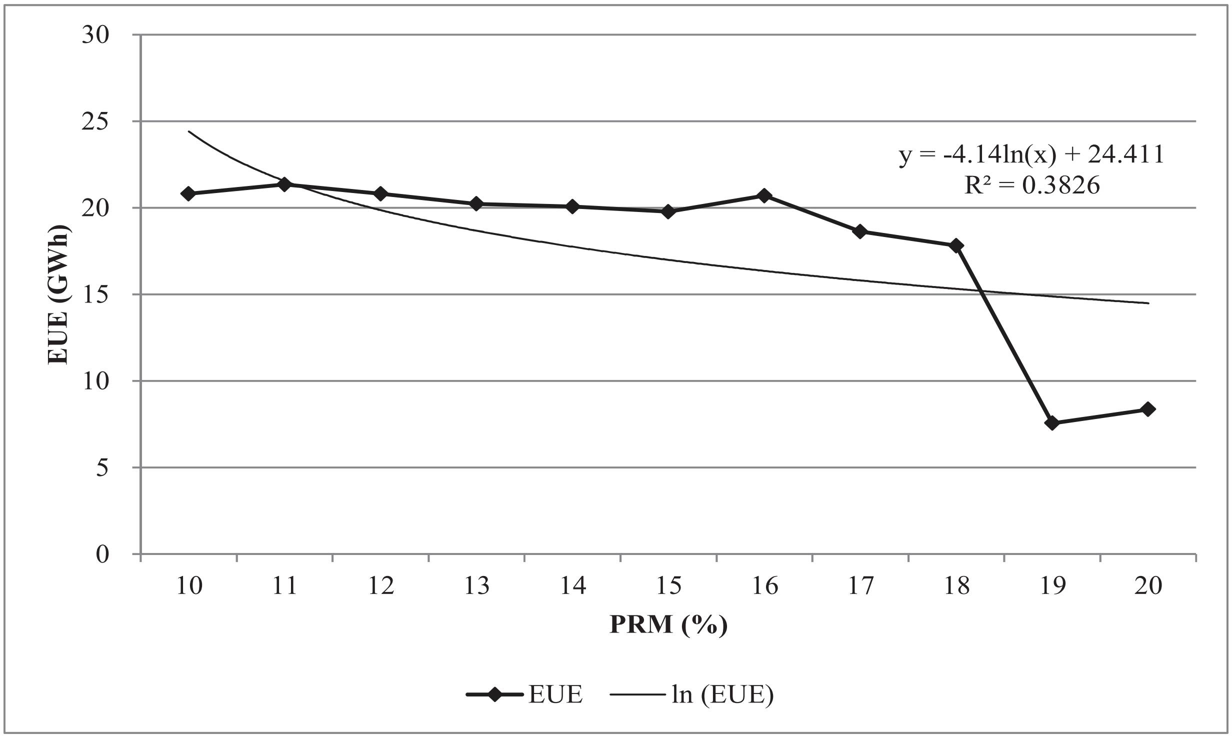


Figure I.3 - Expected and Fitted Relationship of LOLH to PRM

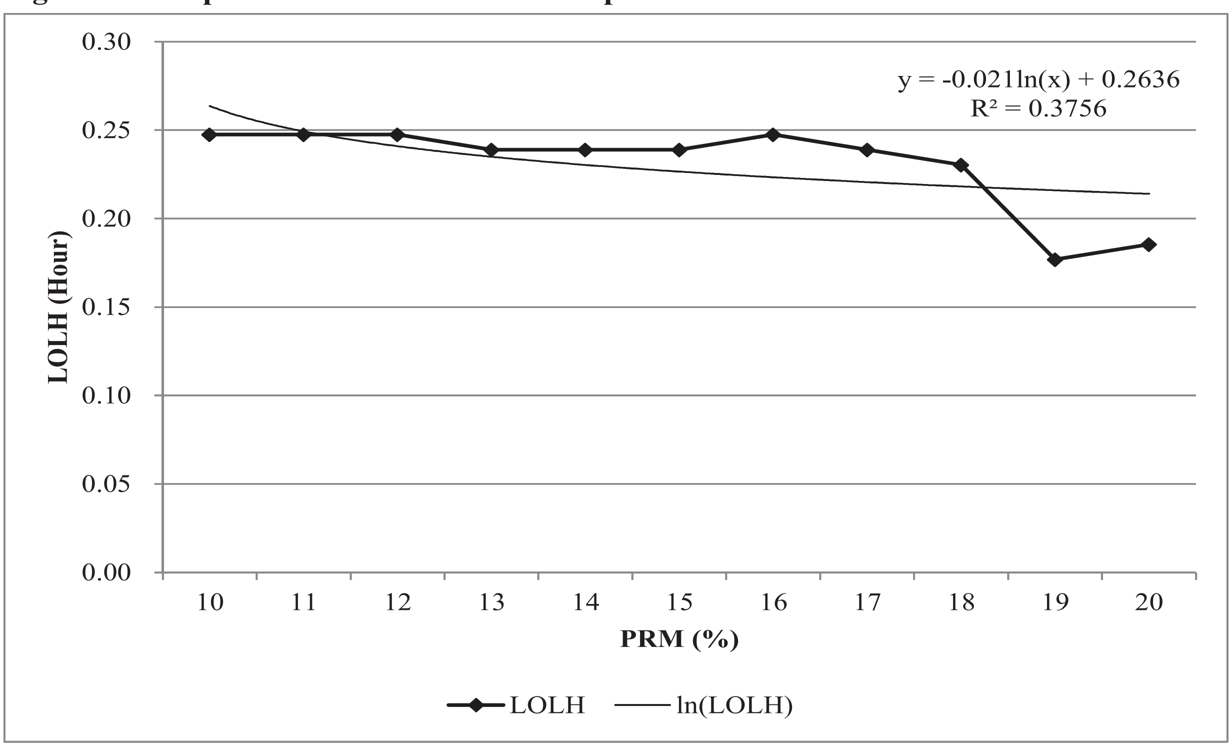
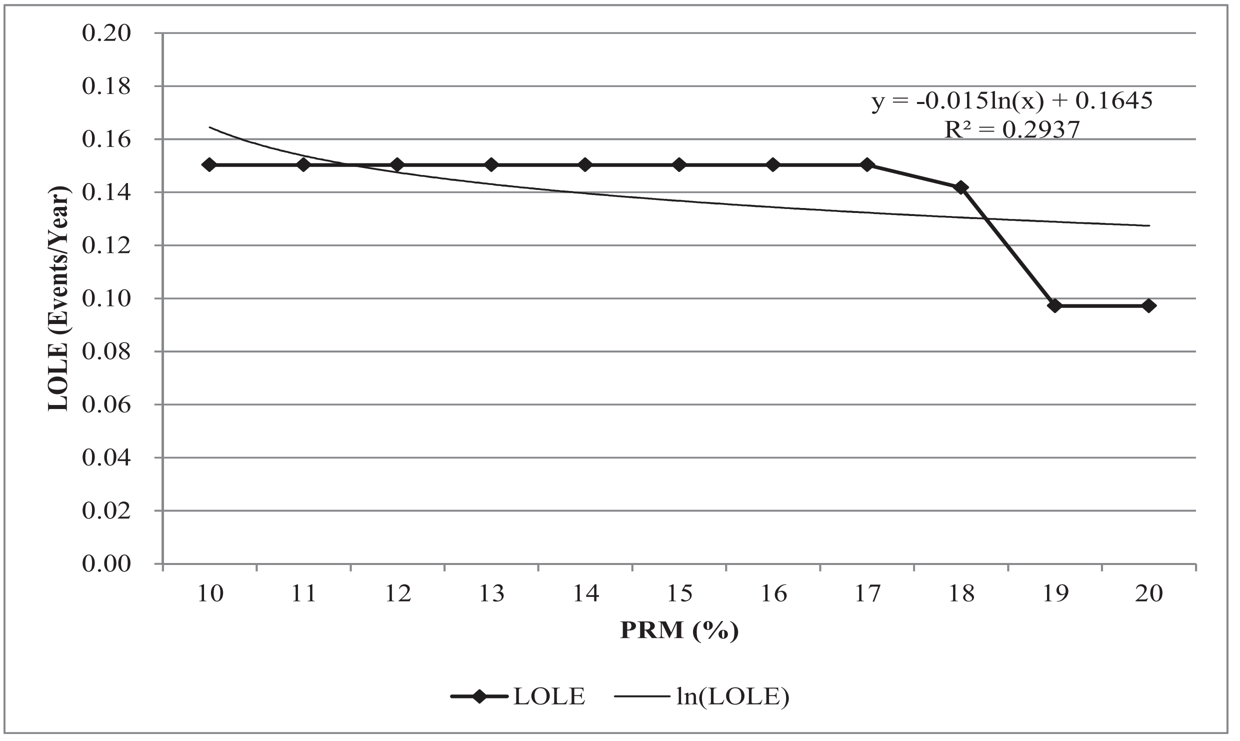


Figure I.4 - Simulated Relationship of Loss of Load Episode to PRM



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

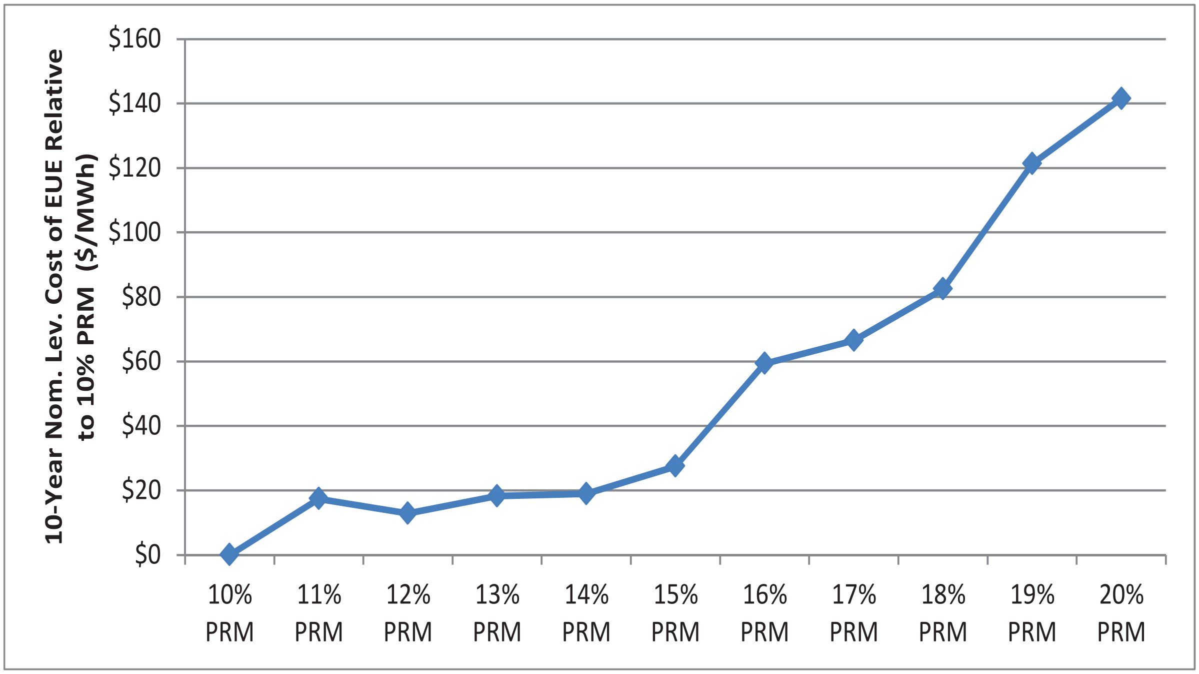
Incremental Cost of Reliability

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.

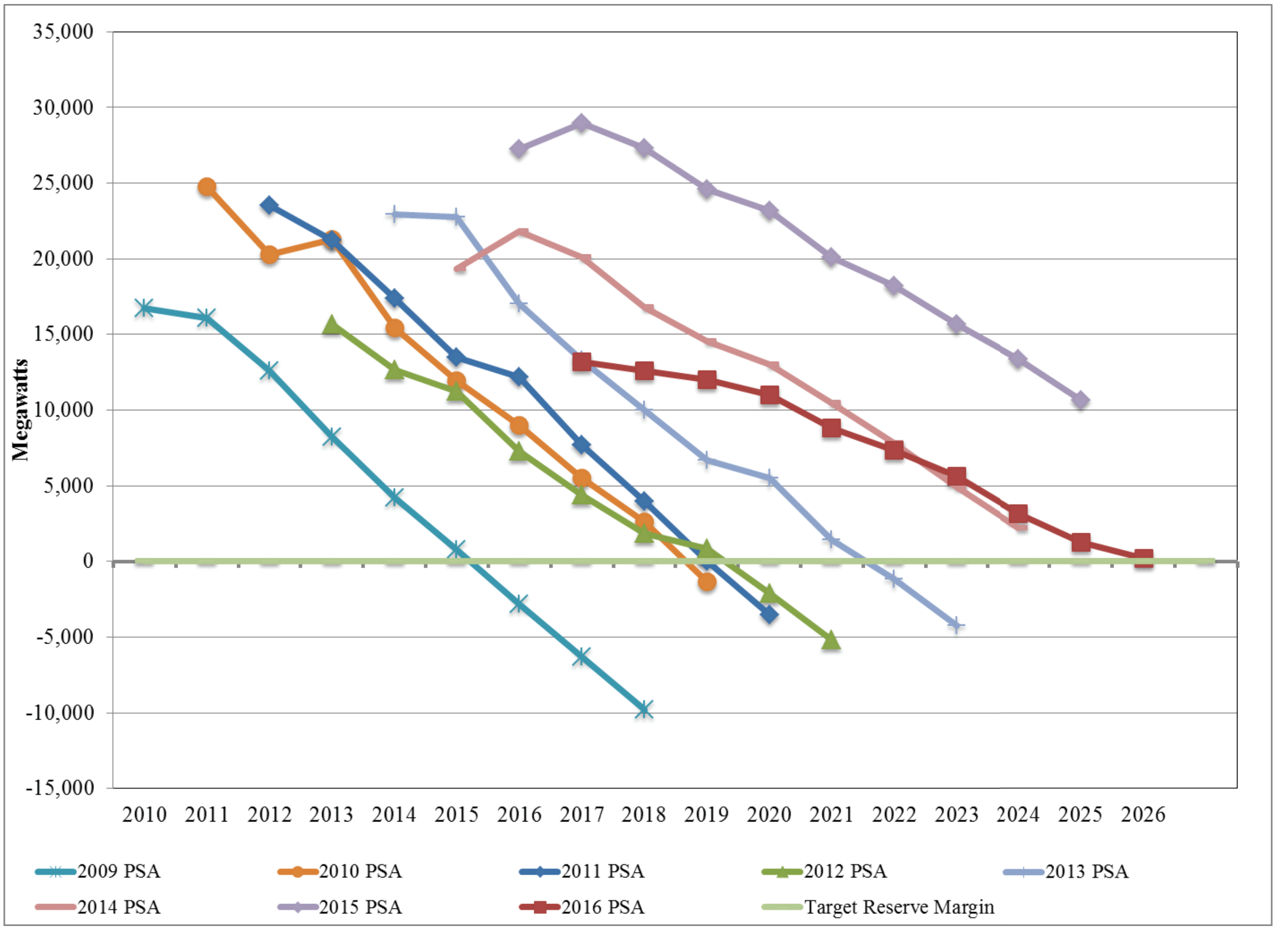
3. Reserves for Generation Forced Outages – The capacity lost to forced outages for both the summer (July) and winter (December) is added by sub-region and divided by the total capacity reported for each sub-region. The seasonal forced out rates are then averaged across five years to give the forced 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

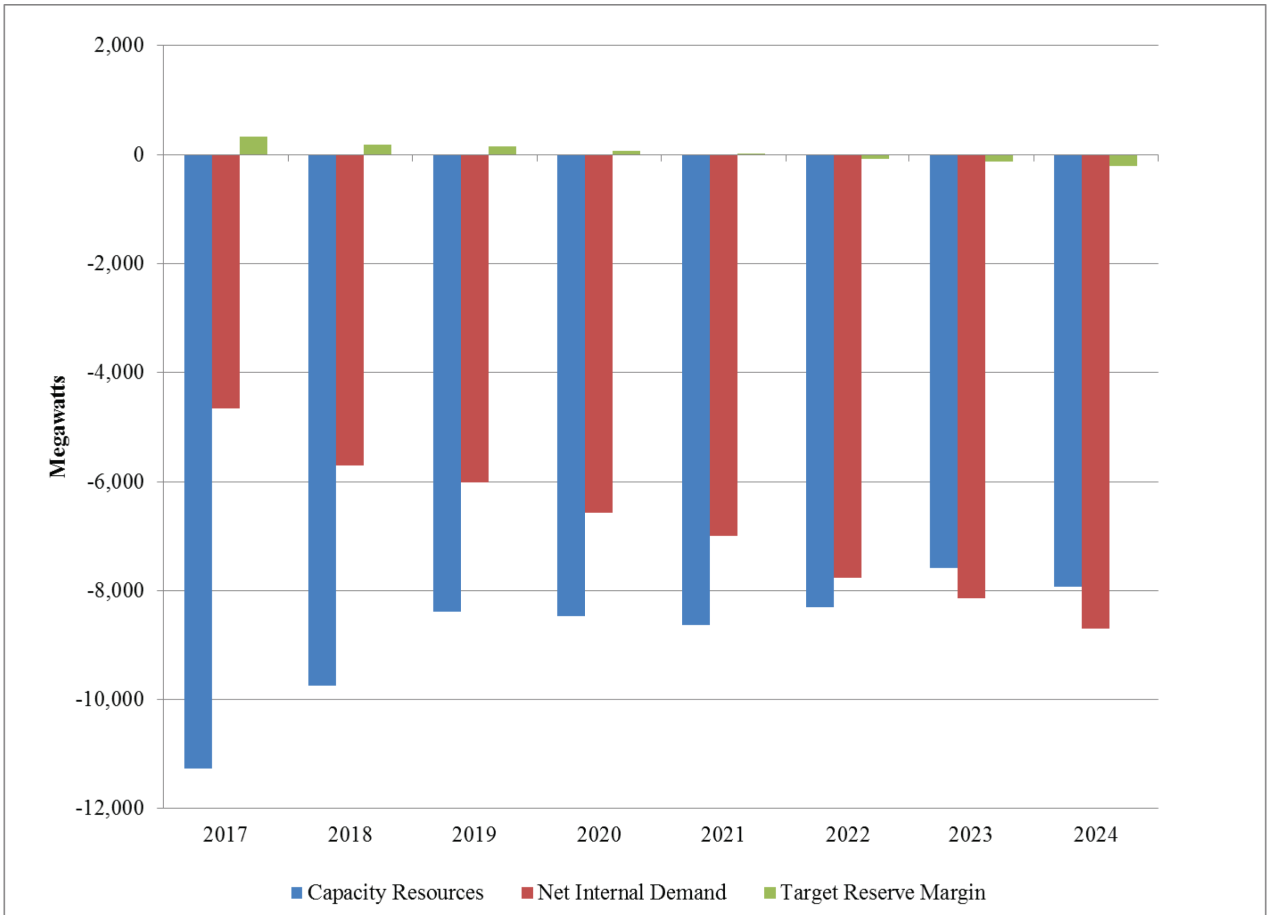
Figure J.1 - WECC Forecasted Power Supply Margins, Issued 2009 to 2016 (Summer)



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

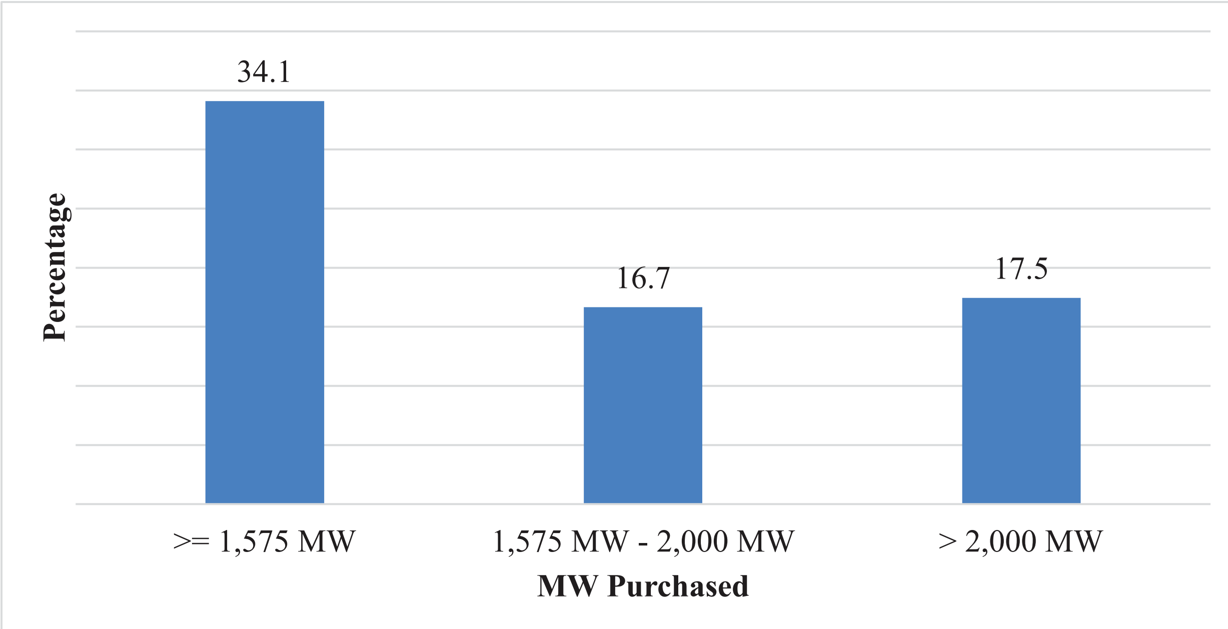
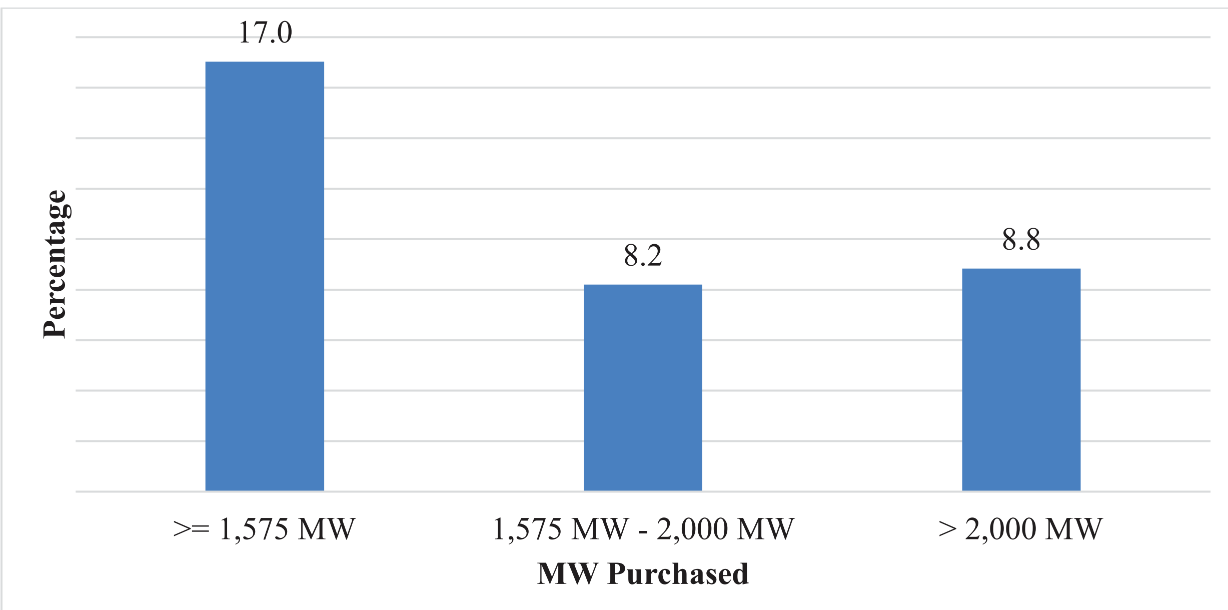


Figure J.4 - PacifiCorp Winter Peak Market Purchases 2009-2015



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	$23,110
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-R1c	OR & WA RPS Just in Time	FS-GW4	Base	Base	Mass Cap B	Base	Segment D2	2029	$23,006
FS-R2	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 - WillamValc - 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 1xl	-	-	-	-	-	-	-	-	-	-	-	-	-	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 1xl	-	-	-	-	-	-	-	-	-	-	-	-	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 - WillamValc - 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, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	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 - WillamValc - 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 - WillamValc - 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) 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Resource Totals 1/ 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, GO	-	-	-	-	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, GO	-	-	-	-	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 - WillamValc - 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 - WillamValc - 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, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	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.

	$C0_2$-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 - WillamValc - 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.

	FS-R2	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	-	-	-	-	61	1	-	-	-	-	-	-	-	-	-	-	-	-	-	774	62	836
	Wind, WYAE	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,100	1,100
	Total Wind	-	-	-	-	1,161	1	-	-	-	-	-	-	-	-	85	-	-	-	-	774	1,162	2,022
	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	56	59	62	58	66	66	63	65	64	61	57	57	56	49	44	37	34	35	637	1,130
	DSM, Class 2, WY	8	10	11	10	11	13	14	14	14	14	12	11	11	10	11	9	8	7	7	7	119	212
	DSM, Class 2 Total	97	74	74	75	78	77	85	85	82	84	82	77	73	72	71	62	55	47	43	44	812	1,438
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	297	297	288	299	299	299	299	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	-	-	7	-	-	37	-	6	163	72	134	400	400	400	400	400	400	400	400	364	29	199
	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	311	296	375	341	375	375	375	375	375	375	375	375	375	375	375	375	375	284	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	-	307	319	-	-	-	295	297	-	-	400	400	387	-	-	-	376	288	183	184
	FOT MidColumbia - WTR2	-	-	273	-	-	308	306	287	-	-	289	308	46	11	-	347	333	373	-	375	117	163
	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	126	122	1,282	115	118	118	112	111	108	306	563	536	300	323	980	117	356	861		
	Annual Additions, Short Term Resources	781	853	1,154	1,119	1,115	1,220	1,146	1,168	1,386	1,326	1,333	1,979	2,118	2,074	2,061	2,022	2,007	2,048	2,051	2,302		
	Total Annual Additions	935	981	1,281	1,240	2,397	1,335	1,264	1,286	1,498	1,437	1,442	2,285	2,680	2,610	2,361	2,345	2,987	2,165	2,407	3,162		

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