Initial Portfolio Development

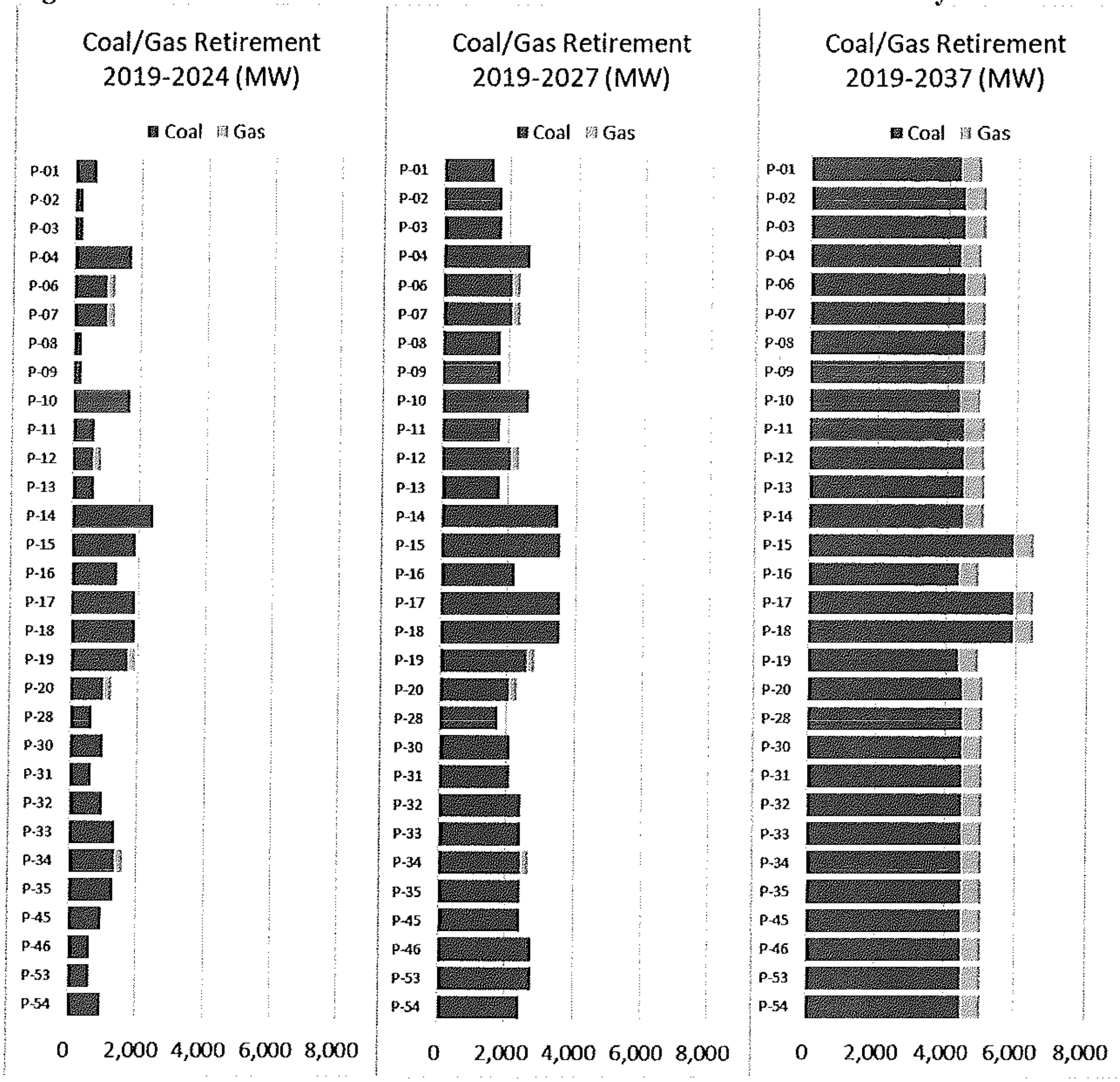
The following tables and figures present resource additions and system costs for the initial portfolios. Additional information is provided for these cases in Volume II, Appendix K (Capacity Expansion Results Detail), including detailed resource portfolio results showing new resource capacity and changes to existing resource capacity by year. Summary portfolio results are also shown in the case fact sheets presented in Volume II, Appendix M (Case Study Fact Sheets).

Coal and Gas Resource Retirements

Figure 8.1 summarizes the cumulative nameplate coal and gas retirements by case over the near-term, mid-term, and long-term among the initial portfolio cases. Note, in reporting cumulative capacity in this figure and in the similar figures that follow, the mid-term results include capacity retired in the near-term, and similarly, the long-term results include capacity retired in the near-term and in the mid-term. Unit-specific retirement dates for each case can be found in Volume II, Appendix M (Case Study Fact Sheets).

By the end of the study period, coal retirements are similar among nearly all cases (P-15, P-17 and P-18 are exceptions), with slight variations dependent upon timing for Colstrip Units 3 and 4. Cases P-15, P-17, and P-18 assume all coal is retired by the end of 2030. By the end of the study period, gas retirements are the same among all cases. Cases P-06, P-17, P-12, P-19, P-20, and P-34 assume the gas-fueled Gadsby Units 1-3 retire at the end of 2020. Among the five cases with the lowest PVRR (cases P-31, P-45, P-46, P-53, and P-54), coal unit retirements range from 667 MW to 1,023 MW through 2024 and range between 2,091 MW and 2,797 MW through the end of 2027.

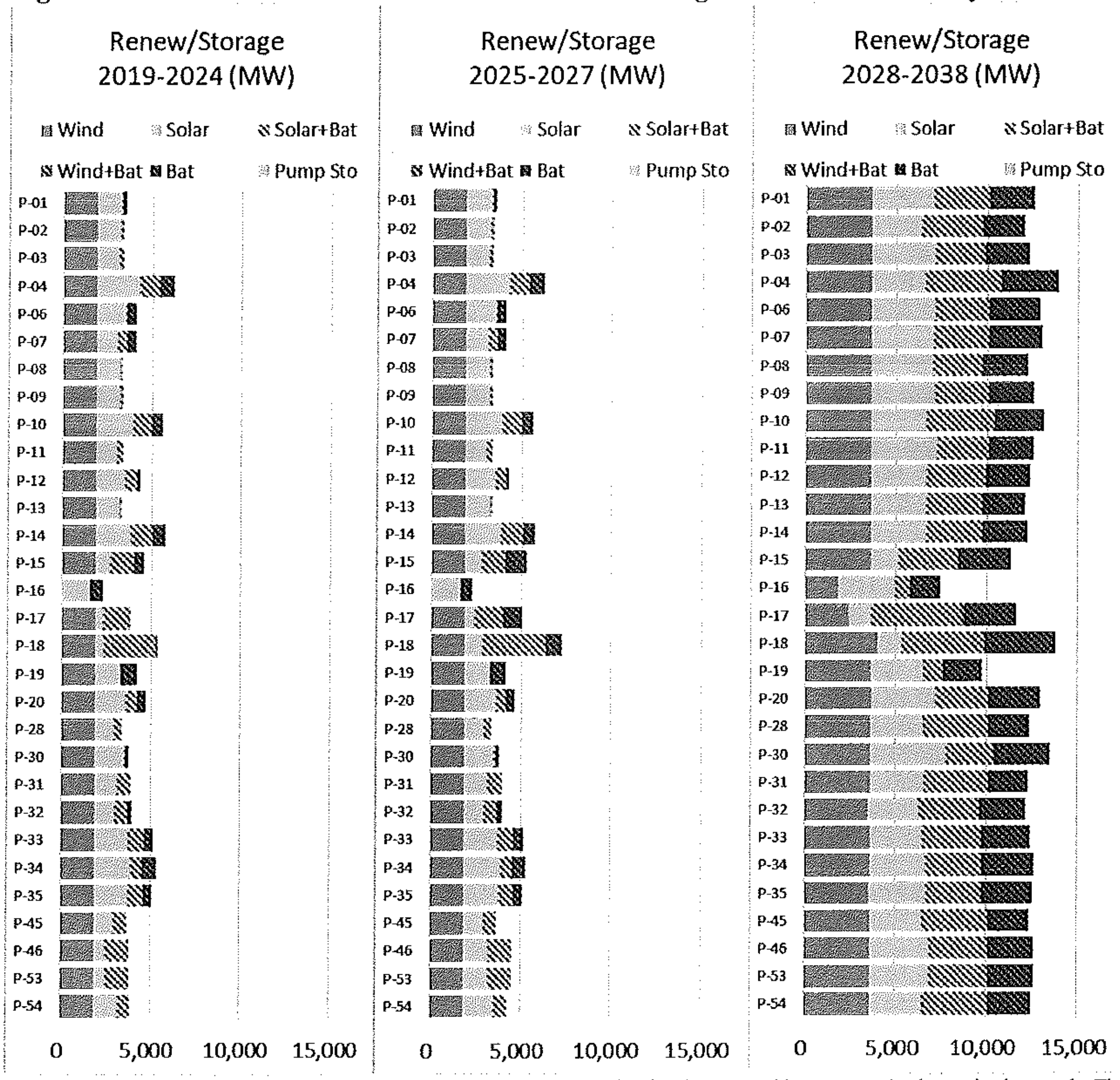
Figure 8.1 – Initial Portfolios Coal and Gas Resource Retirements Summary



New Renewable and Storage Resources

Figure 8.2 reports the nameplate capacity of new renewables and storage resource additions for each initial case. Near-term renewable additions through 2024 range from 1,633 MW to 5,475 MW. In all cases but one (case P-16, which eliminates CO_2 price assumptions through the study period), the SO model selects Energy Gateway South in 2024 (a proxy for year-end 2023) along with 1,920 MW of new wind in eastern Wyoming. Excluding case P-16, the minimum penetration of new renewable capacity is 3,290 MW through 2024 (a proxy for year-end 2023). Through the mid-term, renewable capacity grows up to 6,372 MW by 2027. Through 2027, new solar capacity ranges between 1,370 MW and 4,452 MW—cases with more early coal retirements have more solar capacity. Through 2038, the total new renewable capacity ranges between 5,574 MW and 10,711 MW, and new battery storage capacity ranges between 1,903 MW and 4,558 MW. Among the five cases with the lower PVRR (cases P-31, P-45, P-46, P-53, and P-54), the total new renewable capacity ranges between 3,674 MW and 4,536 MW through 2027 and over 10,000 MW through 2038.

Figure 8.2 – Initial Portfolios New Renewable and Storage Resources Summary

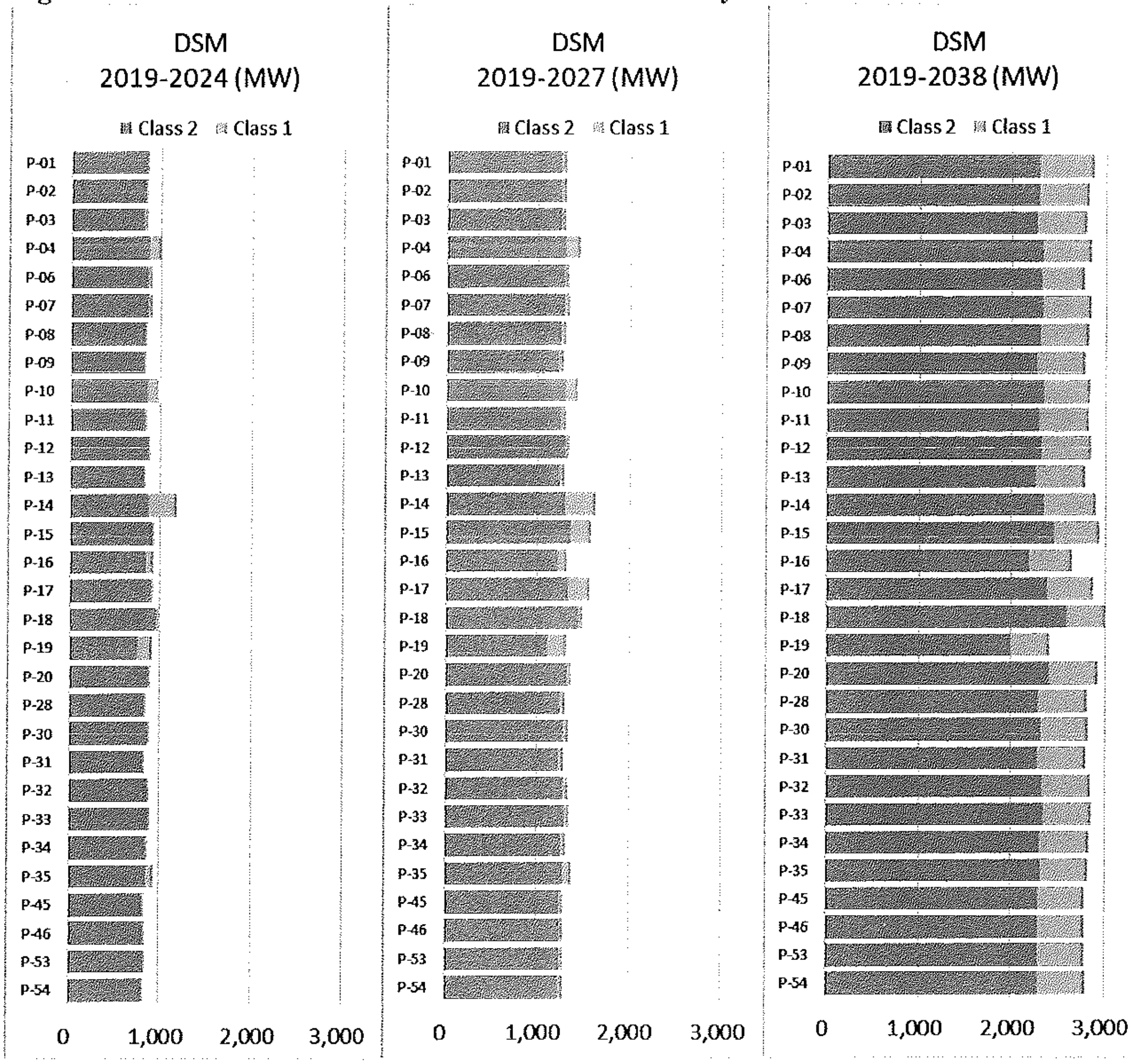


Note: For wind or renewable resources paired with battery, the capacity for the renewable resource is shown in the graph. The battery capacity paired with these resources is 25 percent of the renewable resource capacity.

Incremental Demand-Side Management (DSM)

Figure 8.3 summarizes aggregated demand-side Management (DSM) selections by case. Selected volumes of DSM are relatively stable among all initial cases. Through 2024, Class 2 DSM (energy efficiency) selections range between 763 MW (case P-19) and 965 MW (case P-18) and Class 1 DSM (demand response and direct-load control) ranges between 11 MW and 19 MW. Through 2027, Class 2 DSM selections range between 1,116 MW (case P-19) and 1,455 MW (case P-18) and Class 1 DSM ranges between 45 MW and 322 MW. More Class 1 DSM resources are accelerated into the mid-term among those cases that have higher levels of accelerated coal and gas retirements (cases P-04, P-10, P-14, P-15, P-16, P-17 and P-19). Through 2038, Class 2 DSM selections range between 2,005 MW (case P-19) and 2,603 MW (case P-18) and Class 1 DSM ranges between 417 MW and 583 MW.

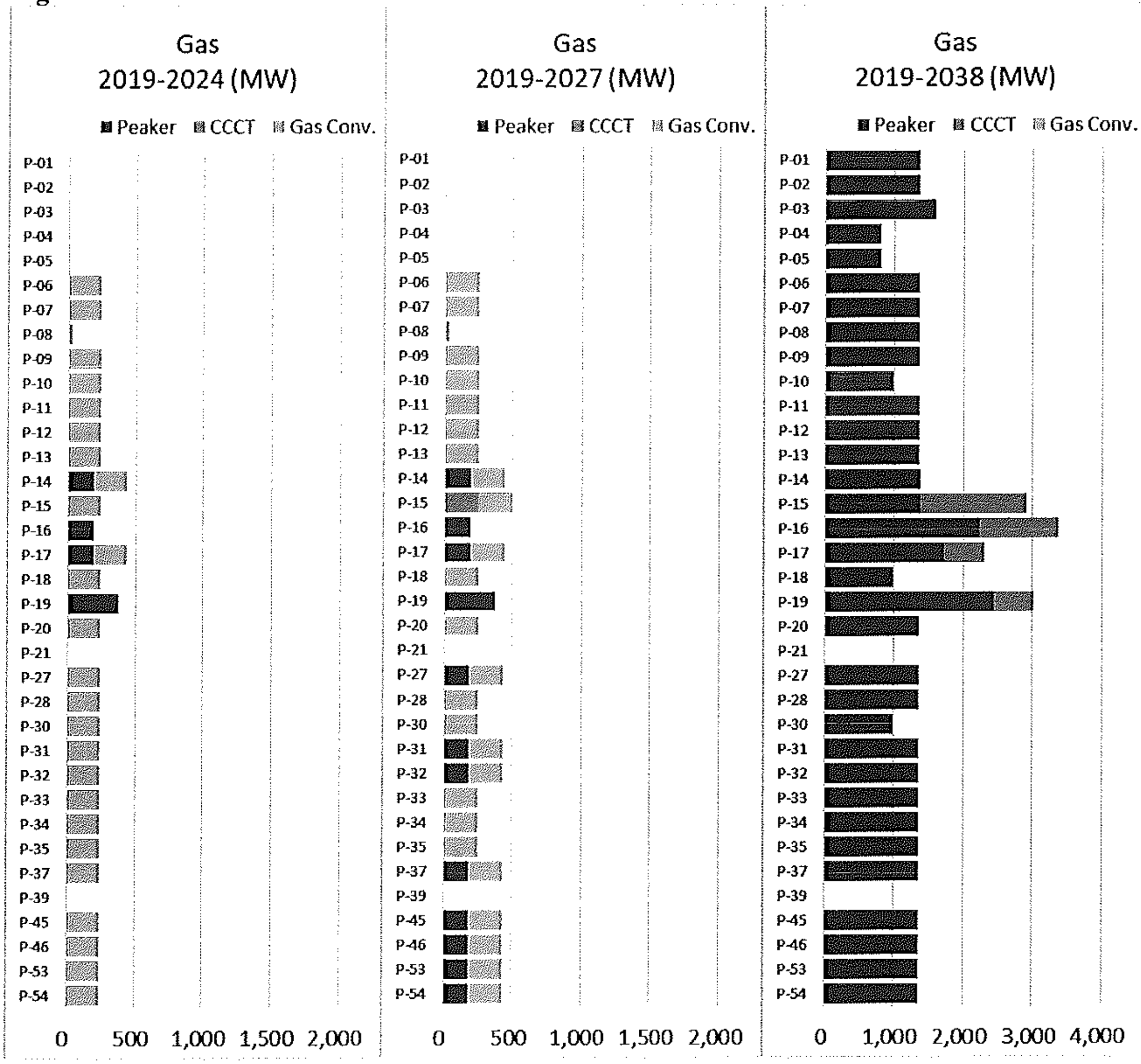
Figure 8.3 – Initial Portfolios Incremental DSM Summary



New Natural Gas Resources

Figure 8.4 summarizes cumulative natural gas expansion resources for each initial portfolio. In cases where Naughton Unit 3 converts to natural gas in 2020, it is assumed to retire at the end of 2029, so it does not show up in the results through 2038. Four cases (P-14, P-16, P-17, and P-19) include new gas peaking capacity in 2023. Through 2038, new peaking gas capacity ranges between 813 MW and 2,458 MW. Case P-15 includes new combined-cycle combustion turbine (CCCT) gas capacity beginning 2027—through 2038, new CCCT capacity in this case totals 1,541 MW. Three additional cases include CCCT capacity, albeit at reduced levels relative to case P-15 (cases P-16, P-17 and P-19). Among the five cases with the lowest PVRR (cases P-31, P-45, P-46, P-53, and P-54), new peaking gas capacity is added in 2026 (185 MW)—by 2038, new gas peaking capacity totals 1,367 MW.

Figure 8.4 – Initial Portfolios New Natural Gas Resources

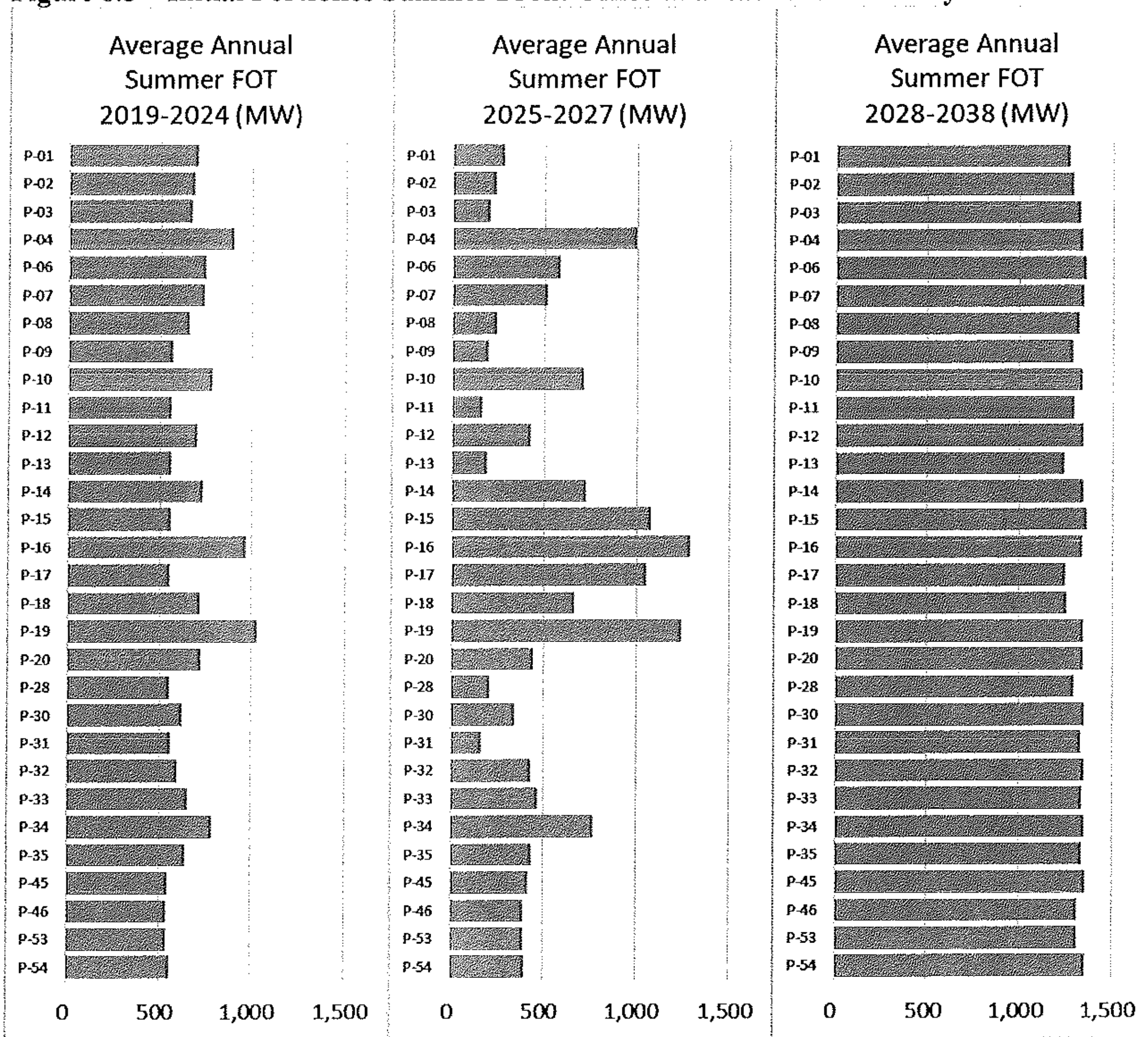


- Note: Scale change in the 'through 2038' column due to P15's addition of CCCT resources.

Summer Front Office Transactions (FOT)

Figure 8.5 summarizes the average of FOTs for each initial portfolio during the summer peak. The summer FOT limit assumed for the 2019 IRP is 1,425 MW. Through the near-term, average annual summer FOT purchases range between 543 MW (cases P-46 and P-53) and 1,031 MW (case P-19). In the 2025-2027 timeframe, a period where there are resource-adequacy concerns in the region, summer average annual FOT purchases range between 168 MW (case P-31) and 1,290 MW (case P-16)—reliance on the market grows in cases with more accelerated coal retirements. Over the long term, the level of summer FOTs is relatively stable among all cases, ranging between 1,241 MW (Case P-13) and 1,362 MW (Case P-15).

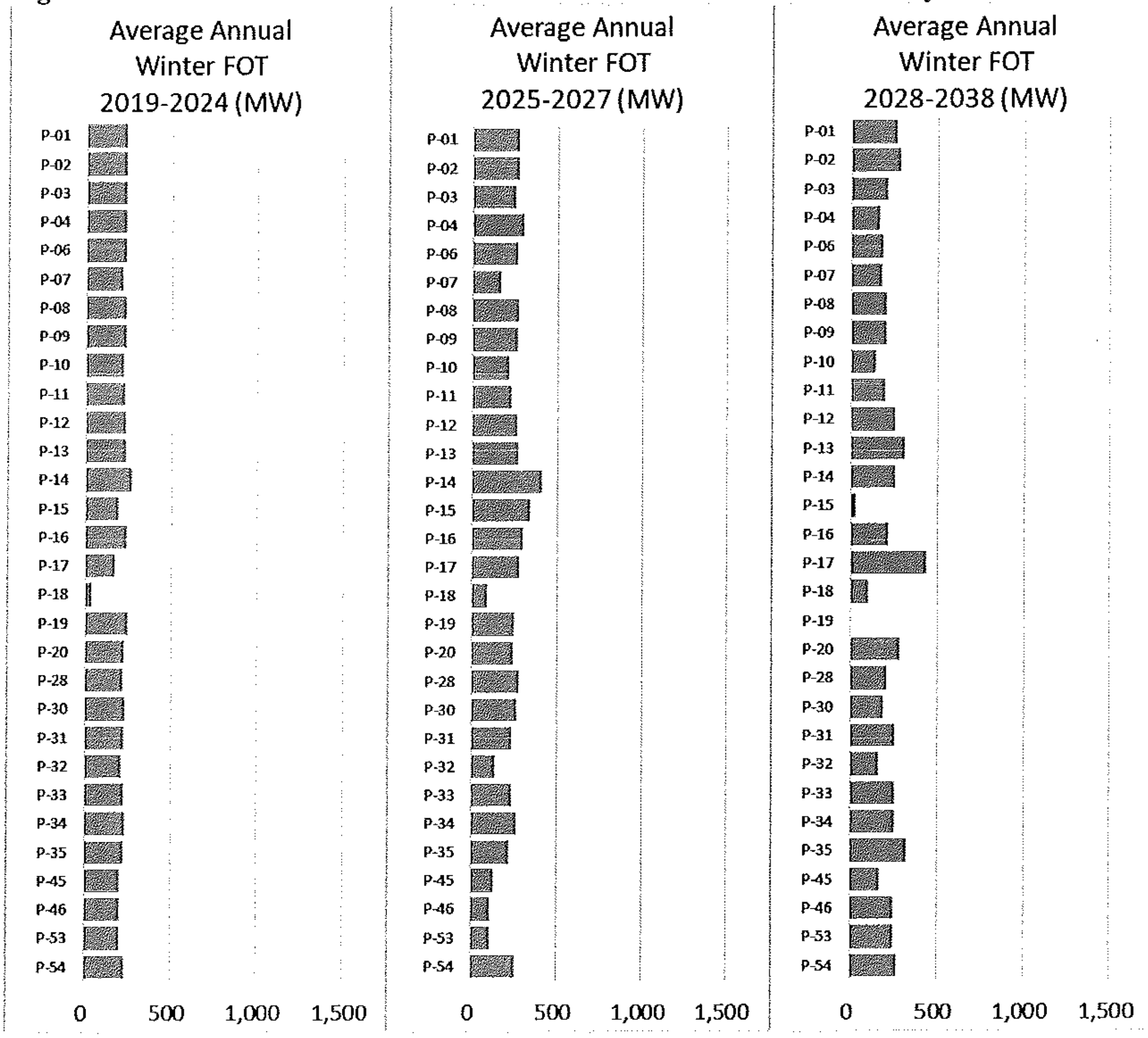
Figure 8.5 – Initial Portfolios Summer Front Office Transactions Summary



Winter Front Office Transactions

Figure 8.6 summarizes the average of FOTs for each initial portfolio during the winter peak. The winter FOT limit assumed for the 2019 IRP is 1,425 MW. Relative to the summer period, winter FOTs are much smaller among all cases and timeframes. Winter FOT purchases are also relatively stable among most cases through both the short and mid-term. Over the long term, winter FOT purchases are reduced when incremental capacity is added to the system—CCCT additions in P-15 and P-19 significantly reduce winter FOT purchases.

Figure 8.6 – Initial Portfolios Winter Front Office Transactions Summary



CO_2 Emissions

Figure 8.7 reports cumulative CO_2 emissions for each initial portfolio. Total CO_2 emissions through 2022 are very stable, ranging between 162 and 164 million tons. Through 2027, total CO_2 emissions range between 318 and 353 million tons. Through 2038, total CO_2 emissions range between 427 and 670 million tons. Among the five cases with the lowest PVRR (cases P-31, P-45, P-46, P-53, and P-54), total CO_2 emissions through 2038 range between 560 and 588 million tons.

Figure 8.7 – Initial Portfolios CO_2 Emissions Summary

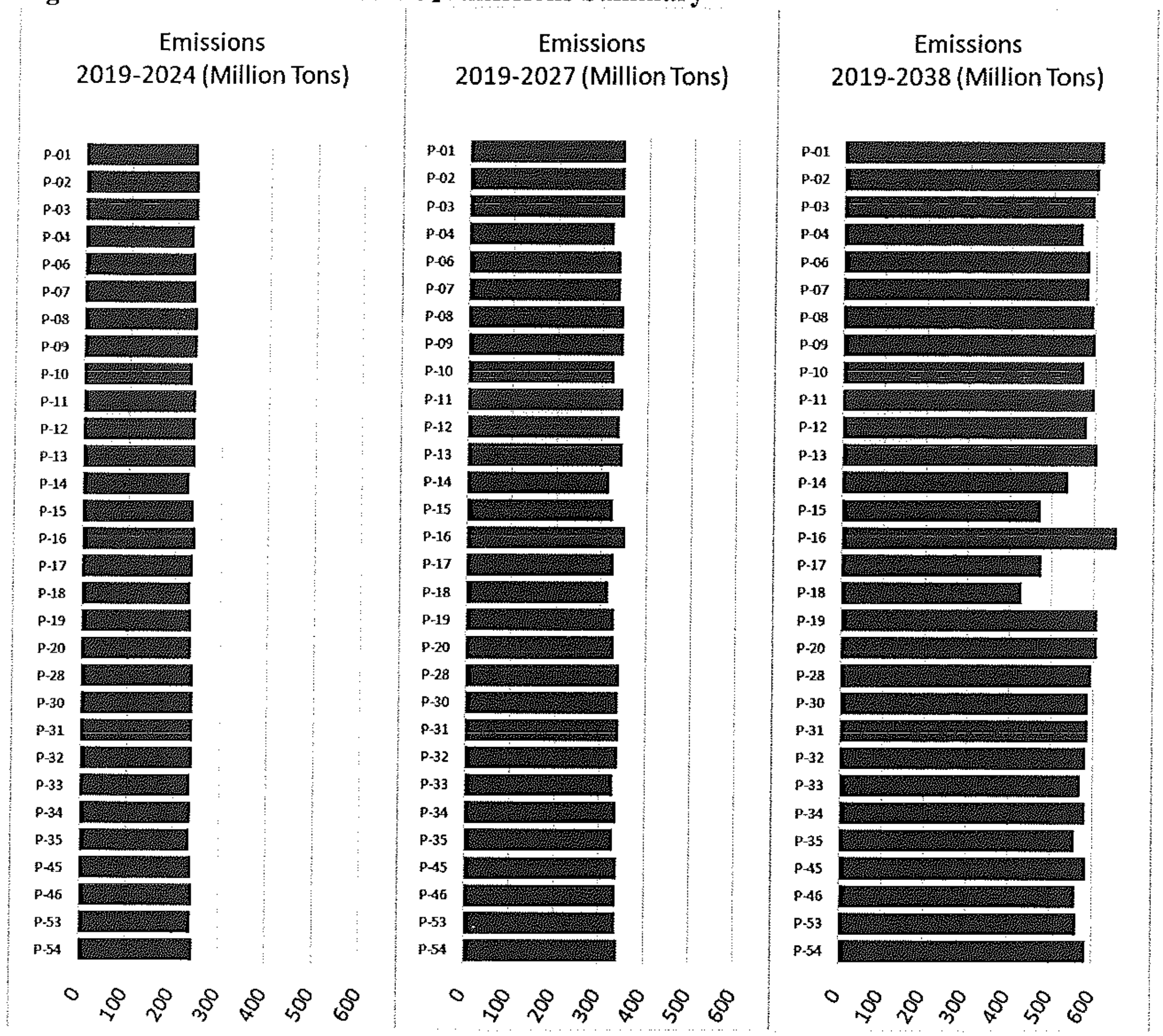


Table 8.1 summarizes results for the initial portfolios, including the stochastic mean PVRR, the risk-adjusted PVRR, amount of energy not served (ENS) as a percentage of load, and CO_2 emissions for each case.

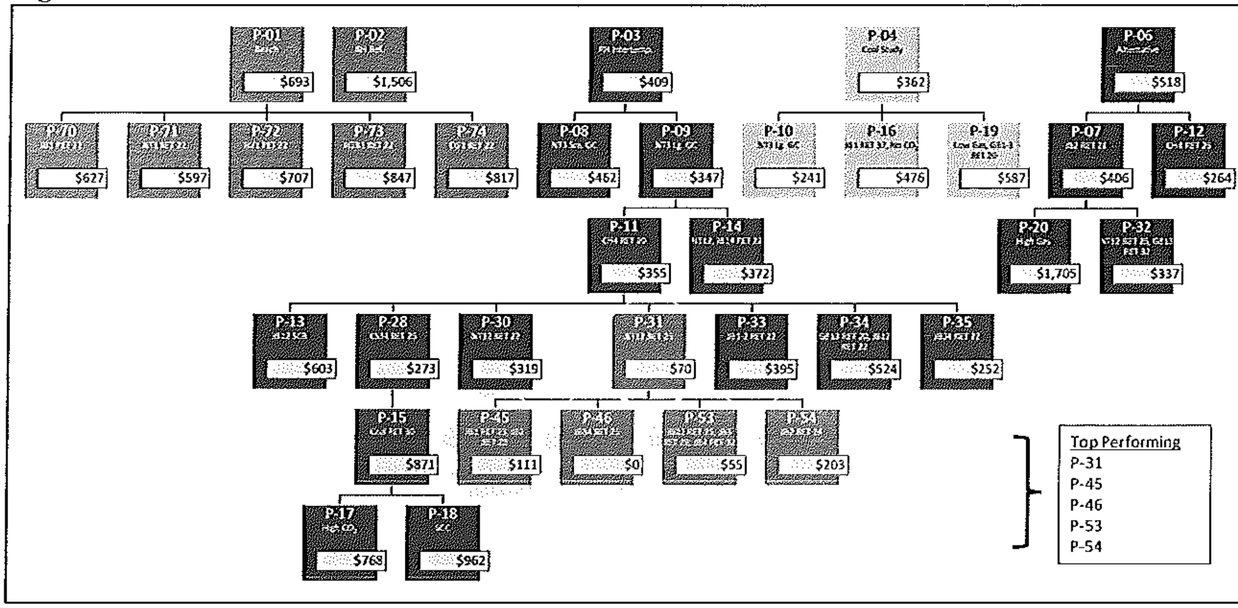
Table 8.1 – Initial Portfolio Cost and Risk Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P46	**23,413**	**0**	1	**24,605**	**0**	1	**0.012%**	**0.006%**	26	**560,199**	**133,090**	6
P53	**23,468**	**55**	2	**24,662**	**57**	2	**0.012%**	**0.006%**	27	**562,025**	**134,915**	7
P31	**23,484**	**70**	3	**24,678**	**72**	3	**0.009%**	**0.002%**	19	**588,421**	**161,312**	19
P45	**23,525**	**111**	4	**24,722**	**116**	4	**0.008%**	**0.001%**	10	**583,981**	**156,872**	15
P54	**23,616**	**203**	5	**24,819**	**213**	5	**0.009%**	**0.002%**	17	**584,377**	**157,267**	16
P10	23,655	241	6	24,864	259	6	0.009%	0.003%	21	571,707	144,597	11
P35	23,666	252	7	24,871	266	7	0.010%	0.004%	23	557,489	130,379	5
P28	23,686	273	9	24,888	283	9	0.008%	0.002%	14	594,322	167,212	20
P30	23,733	319	10	24,941	336	10	0.010%	0.003%	22	587,905	160,795	18
P11	23,768	355	13	24,976	370	13	0.008%	0.001%	9	596,911	169,801	23
P12	23,678	264	8	24,886	281	8	0.008%	0.002%	13	579,167	152,057	12
P13	24,016	603	24	25,234	629	24	0.008%	0.001%	11	604,396	177,286	25
P14	23,786	372	15	25,000	394	15	0.015%	0.009%	28	535,774	108,664	4
P32	23,750	337	11	24,959	354	11	0.008%	0.002%	15	583,565	156,455	14
P09	23,760	347	12	24,970	365	12	0.009%	0.002%	20	597,855	170,745	24
P04	23,775	362	14	24,993	387	14	0.011%	0.004%	24	567,901	140,792	8
P33	23,809	395	16	25,024	419	16	0.007%	0.001%	7	569,586	142,476	10
P07	23,819	406	17	25,033	427	18	0.007%	0.000%	5	581,583	154,474	13
P03	23,822	409	18	25,033	427	17	0.008%	0.002%	12	595,728	168,619	21
P08	23,875	462	19	25,092	486	19	0.009%	0.002%	18	595,956	168,846	22
P16	23,889	476	20	25,097	491	20	0.007%	0.000%	2	669,944	242,834	30
P06	23,932	518	21	25,151	546	21	0.007%	0.001%	6	585,907	158,798	17
P34	23,938	524	22	25,157	551	22	0.008%	0.001%	8	568,422	141,312	9
P19	24,000	587	23	25,211	606	23	0.007%	0.000%	3	607,157	180,047	27
P01	24,106	693	25	25,327	721	25	0.006%	0.000%	1	616,896	189,786	29
P17	24,182	768	26	25,400	795	26	0.057%	0.051%	29	475,390	48,281	3
P15	24,285	871	27	25,516	911	27	0.012%	0.005%	25	472,569	45,459	2
P18	24,376	962	28	25,602	997	28	0.111%	0.104%	30	427,110	0	1
P02	24,919	1,506	29	26,183	1,577	29	0.009%	0.002%	16	605,872	178,763	26
P20	25,118	1,705	30	26,385	1,780	30	0.007%	0.000%	3	607,157	180,047	27

PacifiCorp identified the first five cases in the table (in bold) as top-performing cases selected for more refined C-series analysis.

Figure 8.8 summarizes the stochastic mean PVRR relationships among the initial portfolio cases in the "family tree" format summarized in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach). Dollar figures associated with each case represent the increase in system PVRR relative to the lowest-cost case (case P-46). Note, that cases P-70 through P-74 were developed in response to stakeholder interests to reaffirm conclusions from the coal study, which indicate that potential early coal unit retirements should be focused on Naughton and Jim Bridger units.

Figure 8.8 – Relative Cost of Stochastic Mean to the Lowest-Cost Initial Case



C-Series Portfolios

In the C-series of cases, top-performing portfolios from the initial set of portfolios, and additional portfolios produced in response to stakeholder interest, receive an expanded reliability analysis. For each of these cases, PacifiCorp produced six additional deterministic hourly studies to ensure that each year is analyzed through 2030 (i.e., adding test years for 2024-2029). This improves the granularity at which reliability resources are applied and provides for a better comparison of cost and risk metrics between these cases.

As described in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), in addition to expanding the reliability assessment step of portfolio development the C-series also removes proxy stand-alone solar resources from the resource options available to the SO model. This allows the SO model to efficiently combine renewables and storage resources in order to accrue combined economic benefits that would otherwise be lost.

As noted above, in addition to the five top performing cases derived from the initial portfolios, the C-series includes five additional cases developed after stakeholder discussion at the September 5-6, 2019 public-input meeting. Table 8.2 summarizes the five additional C-series cases.

Table 8.2 – Additional C-Series Cases

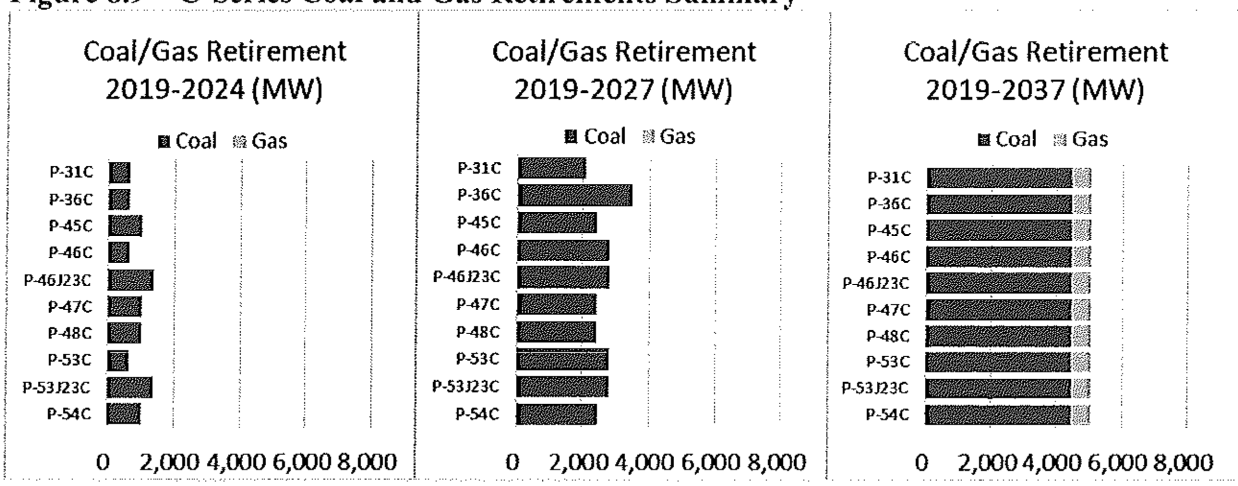
Case	Description
P-36C	A variant of Case P-14 with Jim Bridger 1-2 and Naughton 1-2 retired at the end of 2025.
P-46J23C	A variant of Case P-46 with Jim Bridger 3-4 retired at the end of 2023.
P-47C	A variant of Case P-45 with Jim Bridger 3-4 retired at the end of 2035.
P-48C	A variant of Case P-45 with Jim Bridger 3-4 retired at the end of 2033.
P-53J23C	A variant of Case P-53 with Jim Bridger 1-2 retired at the end of 2023.

C-Series Portfolio Development

Coal and Gas Resource Retirements

Figure 8.9 summarizes cumulative nameplate coal and gas retirements for each C-series case over the near-term, mid-term, and long-term. Note, in reporting cumulative capacity in this figure and the similar figures that follow, the mid-term results include capacity retired in the near-term, and similarly, the long-term results include capacity retired in the near-term and in the mid-term. Unit-specific retirement dates for each case can be found in Volume II, Appendix M (Case Study Fact Sheets). Through 2027, total coal retirements range between 2,091 MW (case P-31C) and 3,499 MW (case P-36C). Through the end of 2037, total coal retirements approach 4,500 MW in each case.

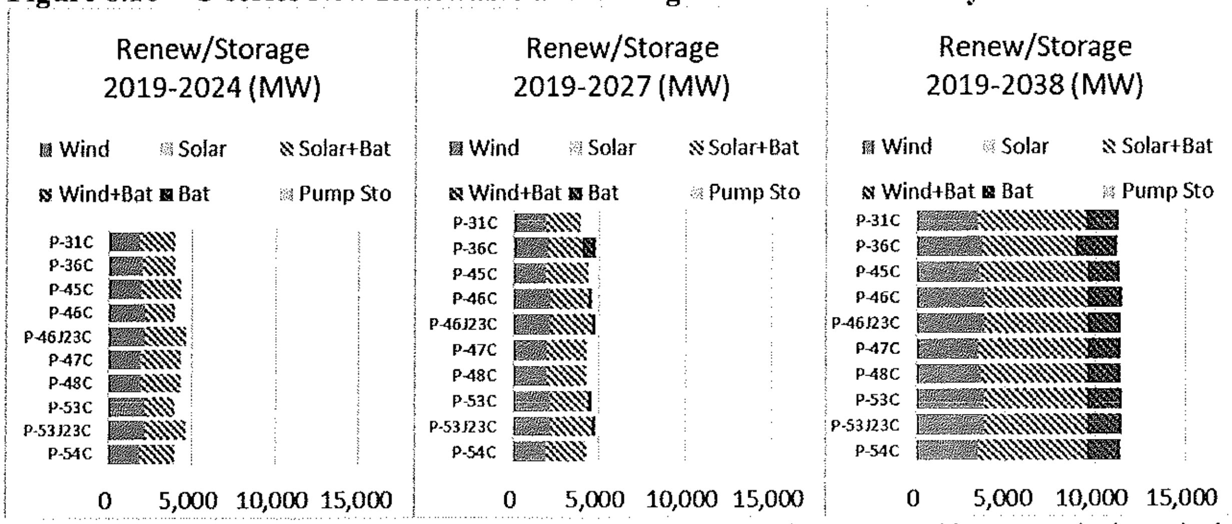
Figure 8.9 – C-Series Coal and Gas Retirements Summary



New Renewable and Storage Resources

Figure 8.10 summarizes the nameplate capacity of new renewables and storage resource additions for each C-series case. In all cases the SO model selects Energy Gateway South in 2024 (a proxy for year-end 2023) along with 1,920 MW of new wind in eastern Wyoming. Through 2027, new renewable capacity ranges between 3,992 MW (case P-31C) and 4,645 MW (cases P-46J23C and P-53J23C). By the end of 2038, new renewable capacity ranges between 8,905 MW (case P-36C) and 9,574 MW (cases P-46C, P-47C, P-48C, P-53C, P-53J23C and P-54C). New battery capacity ranges between 518 MW and 729 MW through 2027 and over 3,300 MW by the end of 2038.

Figure 8.10 – C-series New Renewable and Storage Resources Summary

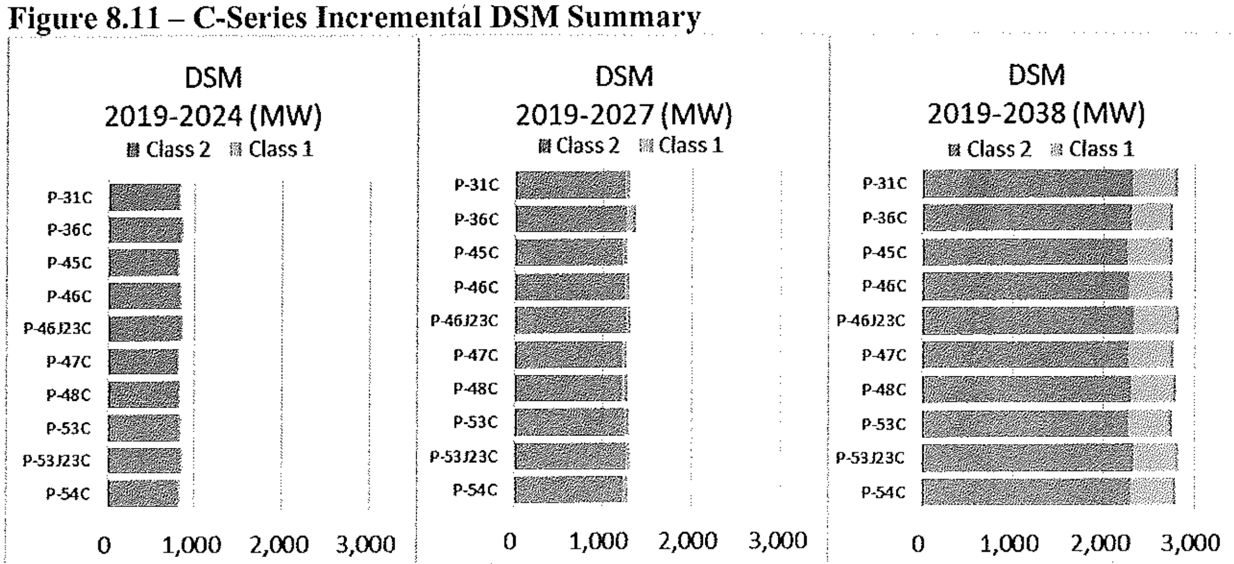


Note: For wind or renewable resources paired with battery, the capacity for the renewable resource is shown in the graph. The battery capacity paired with these resources is 25 percent of the renewable resource capacity.

Incremental Demand-Side Management (DSM)

Figure 8.11 summarizes aggregated DSM selections by case. Selected volumes of DSM are relatively stable among all C-series cases. On average, Class 2 DSM capacity totals 826 MW through 2024, 1,257 MW through 2027, and 2,299 MW through 2038. On average, Class 1 DSM capacity totals 29 MW through 2022, 45 MW through 2027, and 485 MW through 2038.

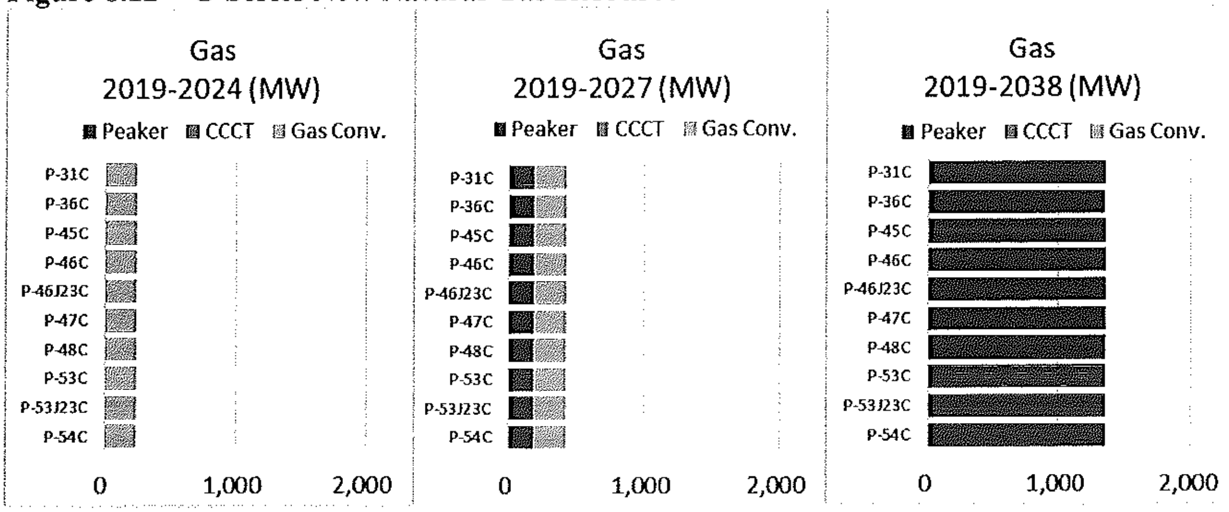
Figure 8.11 – C-Series Incremental DSM Summary



New Natural Gas Resources

Figure 8.12 summarizes cumulative natural gas expansion resources for each C-series portfolio. In cases where Naughton 3 converts to natural gas, it is assumed to retire at the end of 2029, so it does not show up in the results through 2038. Each case includes the large gas conversion of Naughton Unit 3 in 2020, and includes 185 MW of new peaking gas capacity in 2026. Case P-36C includes 1,356 MW of new peaking gas through the end of 2038; all other C-series cases include 1,367 MW of new gas peaking gas capacity through the end of 2038. None of these cases include new gas CCCT capacity.

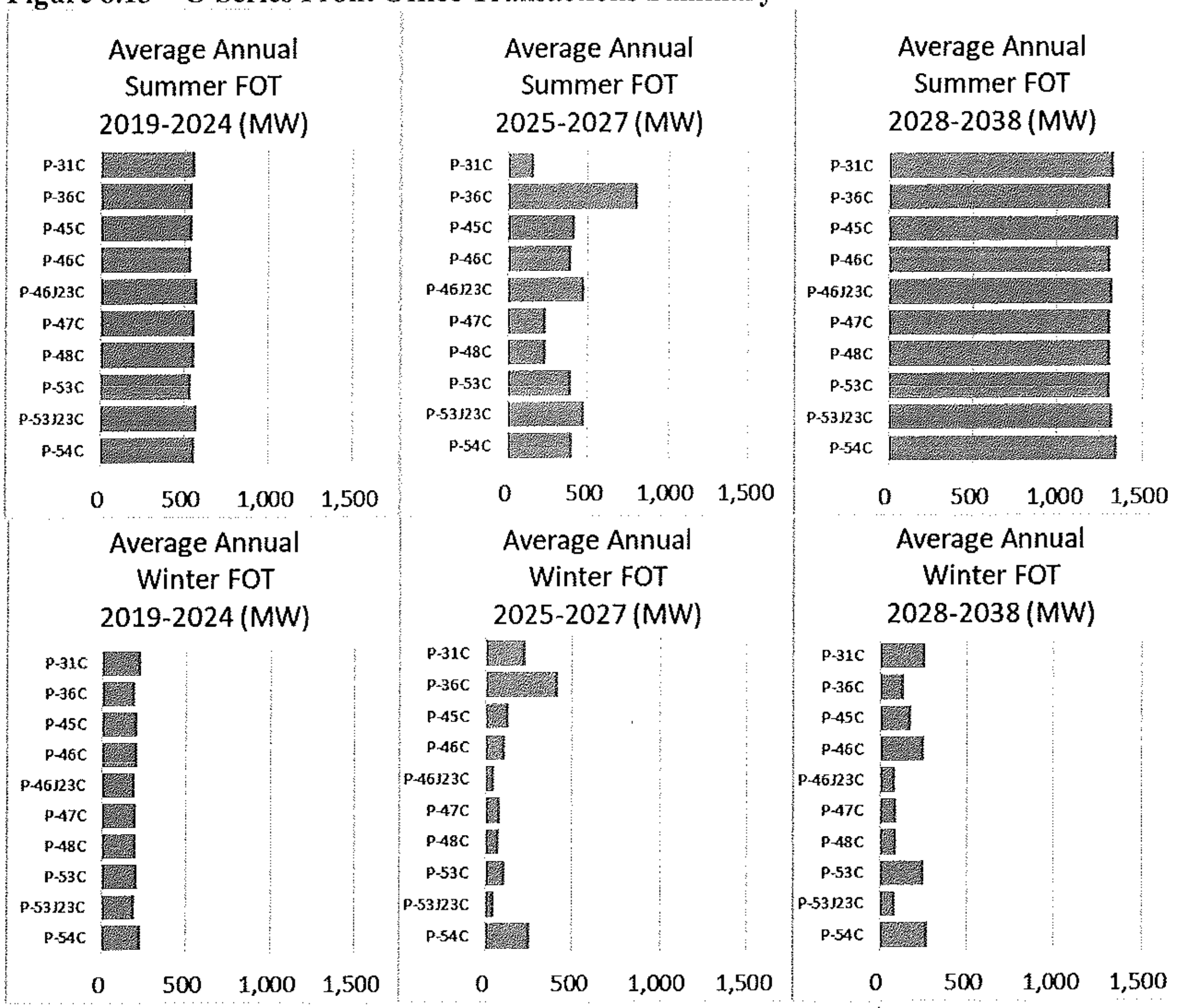
Figure 8.12 – C-Series New Natural Gas Resource



Front Office Transactions

Figure 8.13 summarizes the average of FOTs for each C-Series portfolio during the summer and winter peak periods. The summer and winter FOT limit assumed for the 2019 IRP is 1,425 MW. Market reliance is reduced in the 2025 to 2027 timeframe, coinciding with the addition of new transmission, new wind, and new solar+battery resources—on average, summer FOT purchases are 406 MW per year over this period. Longer-term, summer FOTs increase similarly among these cases, on average ranging between 1,310 MW and 1,361 MW each year from 2028-2038. Winter FOTs remain well below the volumes included in each portfolio to cover the summer peak period.

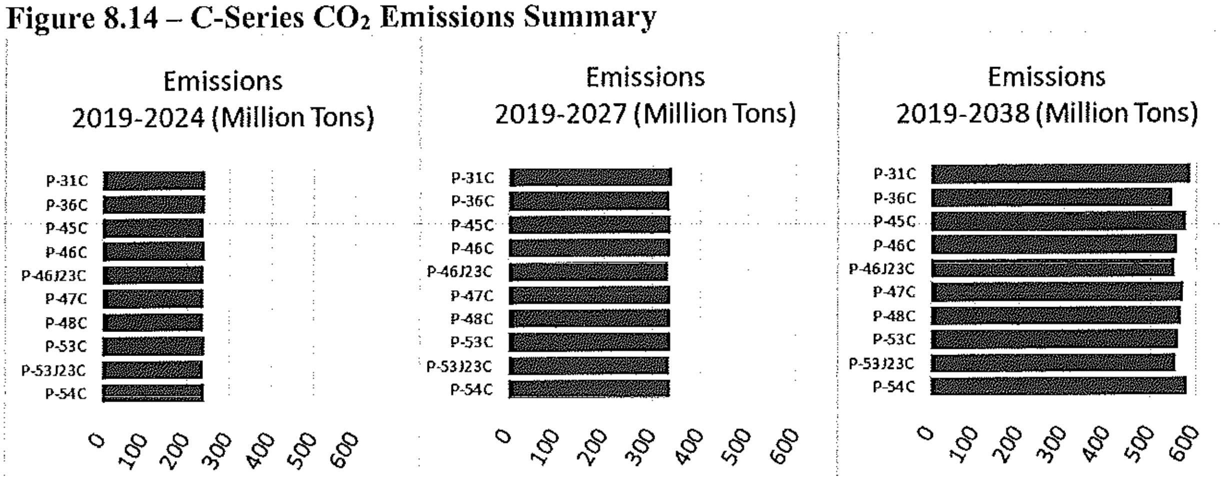
Figure 8.13 – C-Series Front Office Transactions Summary



CO_2 Emissions

Figure 8.14 reports cumulative CO_2 emissions for each C-series portfolio. Total CO_2 emissions is similar among these cases through 2027. Through 2038, total CO_2 emissions range between 550 million tons (case P-36C) and 588 million tons (case P-31C).

Figure 8.14 – C-Series CO_2 Emissions Summary



C Series Case Cost and Risk Summary

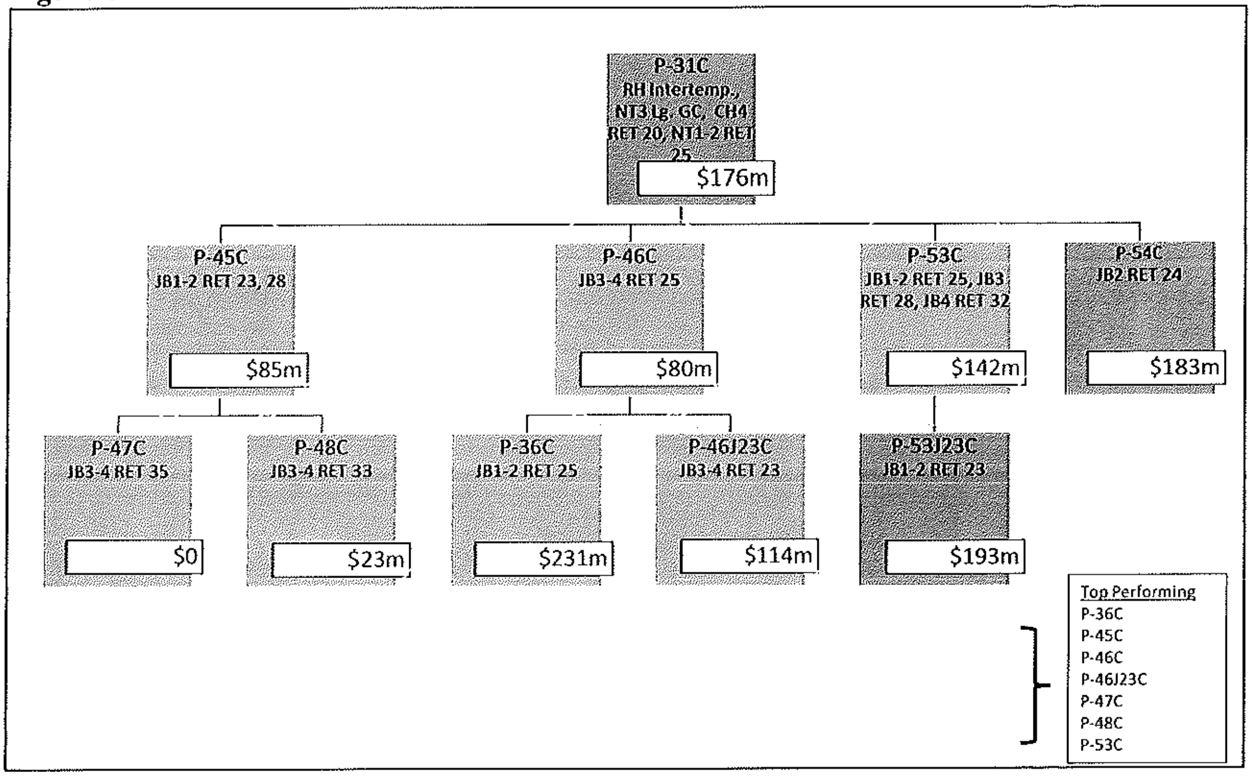
Table 8.3 – C Series Case Cost and Risk Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P47C	**23,198**	**$0**	**1**	**24,367**	**$0**	**1**	**0.012%**	**0.002%**	**7**	**573,088**	**22,855**	**7**
P48C	**23,221**	**$23**	**2**	**24,391**	**$24**	**2**	**0.011%**	**0.001%**	**5**	**567,025**	**16,792**	**6**
P46C	**23,278**	**$80**	**3**	**24,462**	**$95**	**3**	**0.011%**	**0.001%**	**3**	**560,210**	**9,977**	**4**
P45C	**23,283**	**$85**	**4**	**24,468**	**$101**	**4**	**0.010%**	**0.000%**	**1**	**578,607**	**28,374**	**8**
P46J23C	**23,312**	**$114**	**5**	**24,488**	**$121**	**5**	**0.013%**	**0.002%**	**9**	**553,673**	**3,440**	**2**
P53C	**23,340**	**$142**	**6**	**24,528**	**$161**	**6**	**0.011%**	**0.001%**	**4**	**562,972**	**12,739**	**5**
P31C	23,374	$176	7	24,562	$195	8	0.010%	0.000%	2	588,334	38,101	10
P54C	23,381	$183	8	24,558	$191	7	0.012%	0.002%	6	581,465	31,232	9
P53J23C	23,391	$193	9	24,570	$203	9	0.012%	0.002%	8	556,990	6,757	3
P36C	**23,430**	**$231**	**10**	**24,614**	**$247**	**10**	**0.013%**	**0.003%**	**10**	**550,233**	**0**	**1**

PacifiCorp identified the cases in bold in Table 8.3 as top-performing cases selected for more refined analysis in the next step of the portfolio-development process (cases P-36C, P-46JC23C, P-47C, P-48C, P-46C, P-45C, and P53C). While cases P36C does not perform well on cost metrics relative to the other cases, in response to stakeholder interests, PacifiCorp included this case the list of top-performing C-series cases given its high ranking in total CO_2 emissions.

Figure 8.15 summarizes the stochastic mean PVRR relationships among the C-series cases in the "family tree" format summarized in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach). Dollar figures associated with each case represent the increase in system PVRR relative to the lowest-cost case (case P-47C).

Figure 8.15 – Relative Cost of Stochastic Mean to the Lowest-Cost C Series Case



CP-Series Portfolios

In the CP-series of cases, top-performing portfolios from the C-series of cases are further refined. The CP-series includes the additional solar+battery analysis, and to ensure that there is no potential for an inconsistent application of annual reliability requirements beyond 2030, adds seven additional years (i.e., 2031-2037) of hourly deterministic analysis to the reliability assessment. This addition yields a total of 16 deterministic studies covering the period 2023-2038.

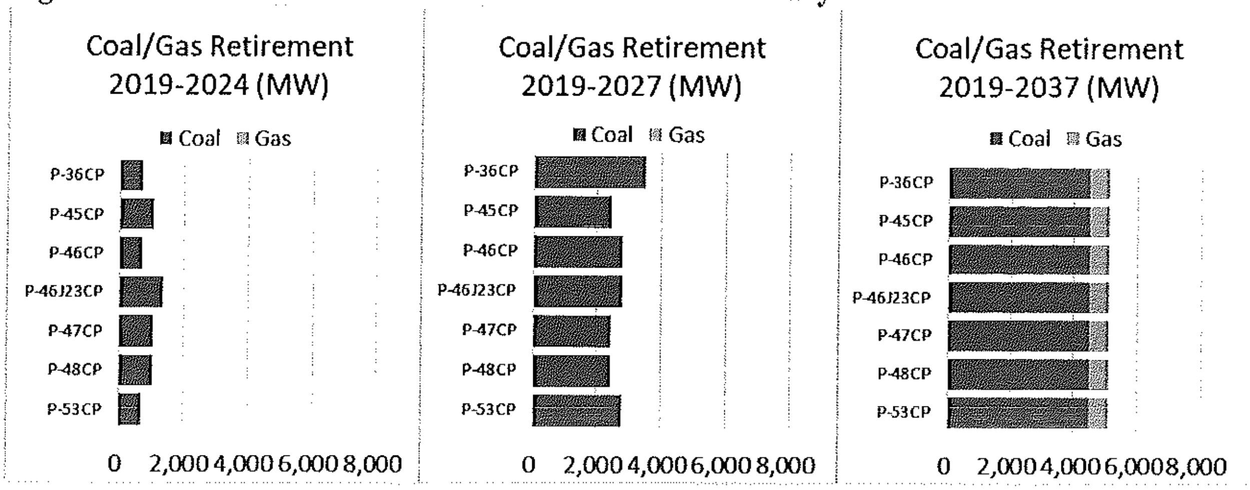
This refinement further improves the granularity at which reliability resources are applied and therefore provides an improved comparison of cost and risk metrics between the top-performing cases. The resulting portfolios were also evaluated among a range of price-policy scenarios.

CP-Series Portfolio Development

Coal and Gas Resource Retirements

Figure 8.16 summarizes cumulative nameplate coal and gas retirements for each CP-series case over the near-term, mid-term, and long-term. Note, in reporting cumulative capacity in this figure and the similar figures that follow, the mid-term results include capacity retired in the near-term, and similarly, the long-term results include capacity retired in the near-term and in the mid-term. Unit-specific retirement dates for each case can be found in Volume II, Appendix M (Case Study Fact Sheets). Through 2027, total coal retirements range between 2,441 MW (case P-45CP, P-47CP, P-48CP) and 3,499 MW (case P-36CP). Through the end of 2037, total coal retirements approach 4,500 MW in each case.

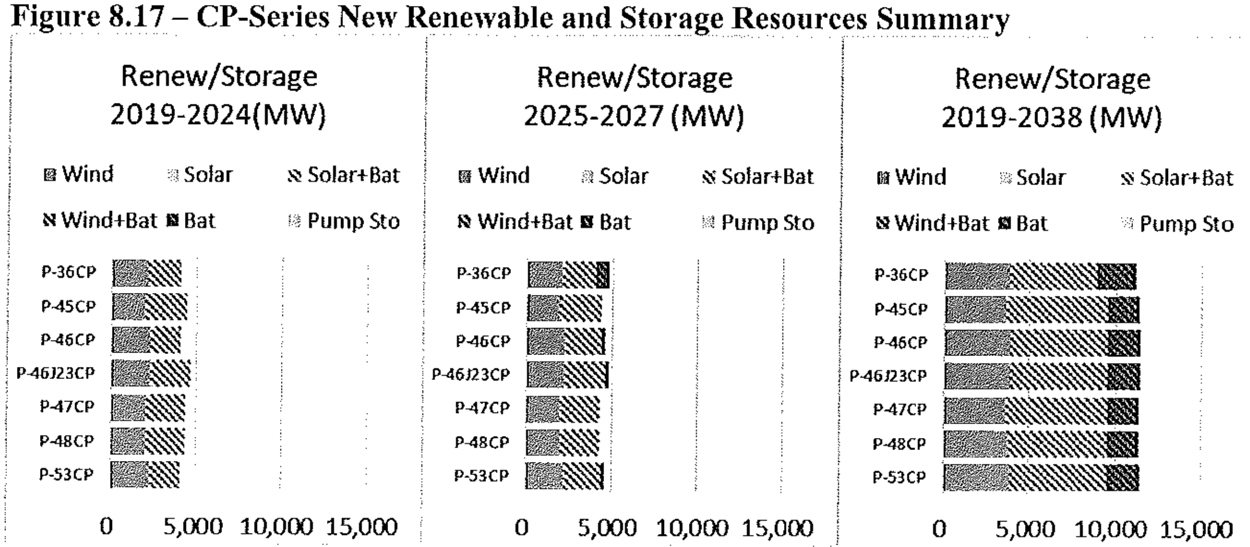
Figure 8.16 – CP-Series Coal and Gas Retirements Summary



New Renewable and Storage Resources

Figure 8.17 summarizes the nameplate capacity of new renewables and storage resource additions for each CP-series case. In all cases the SO model selects Energy Gateway South in 2024 (a proxy for year-end 2023) along with 1,920 MW of new wind in eastern Wyoming. Through 2027, new renewable capacity ranges between 3,339 MW (case P-47CP) and 4,409 MW (cases P-46CP and P-53CP). By the end of 2038, new renewable capacity ranges between 9,512 MW (case P-45CP) and 9,574 MW in the other four cases. New battery capacity ranges between 587 MW and 729 MW through 2027 and over 3,300 MW by the end of 2038.

Figure 8.17 – CP-Series New Renewable and Storage Resources Summary

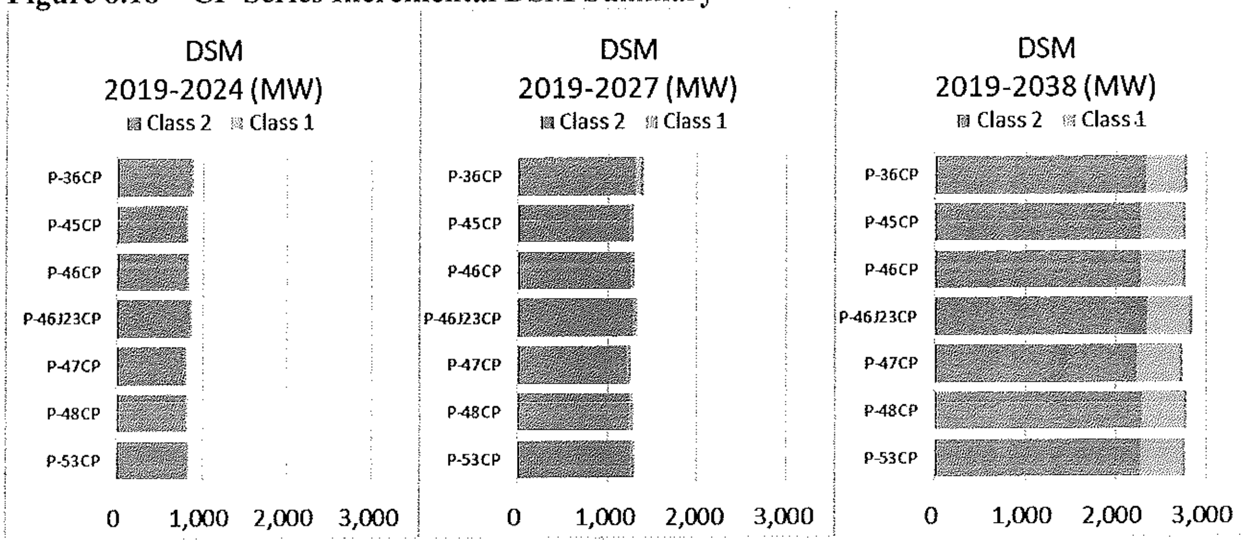


Note: For wind or renewable resources paired with battery, the capacity for the renewable resource is shown in the graph. The battery capacity paired with these resources is 25 percent of the renewable resource capacity.

Incremental Demand-Side Management (DSM)

Figure 8.18 summarizes aggregated DSM selections by case. Selected volumes of DSM are relatively stable among all CP-series cases. On average, Class 2 DSM capacity totals 826 MW through 2024, 1,259 MW through 2027, and 2,306 MW through 2038. On average, Class 1 DSM capacity totals 29 MW through 2024, 45 MW through 2027, and 487 MW through 2038.

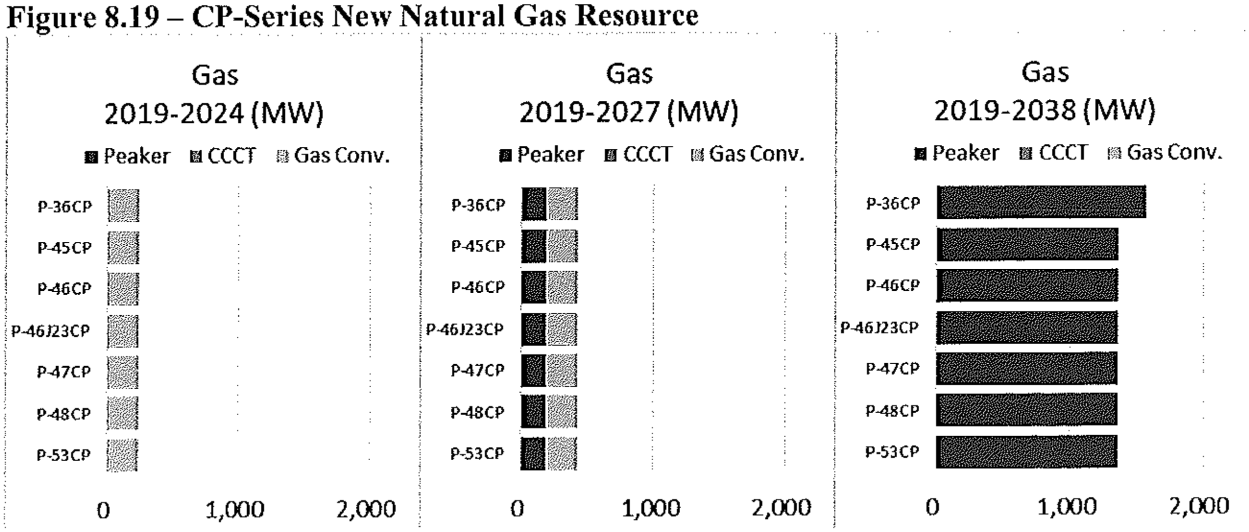
Figure 8.18 – CP-Series Incremental DSM Summary



New Natural Gas Resources

Figure 8.19 summarizes cumulative natural gas expansion resources for each CP series portfolio. In cases where Naughton Unit 3 converts to natural gas, it is assumed to retire at the end of 2029, so it does not show up in the results through 2038. Each case includes 185 MW of new peaking gas capacity in 2026. All CP-series cases except case P-36C include 1,367 MW of new gas peaking gas capacity through the end of 2038. Case P-36CP, includes 210 MW of gas peaking capacity over and above the other CP-series cases, added in 2028. None of the cases include new gas CCCT capacity.

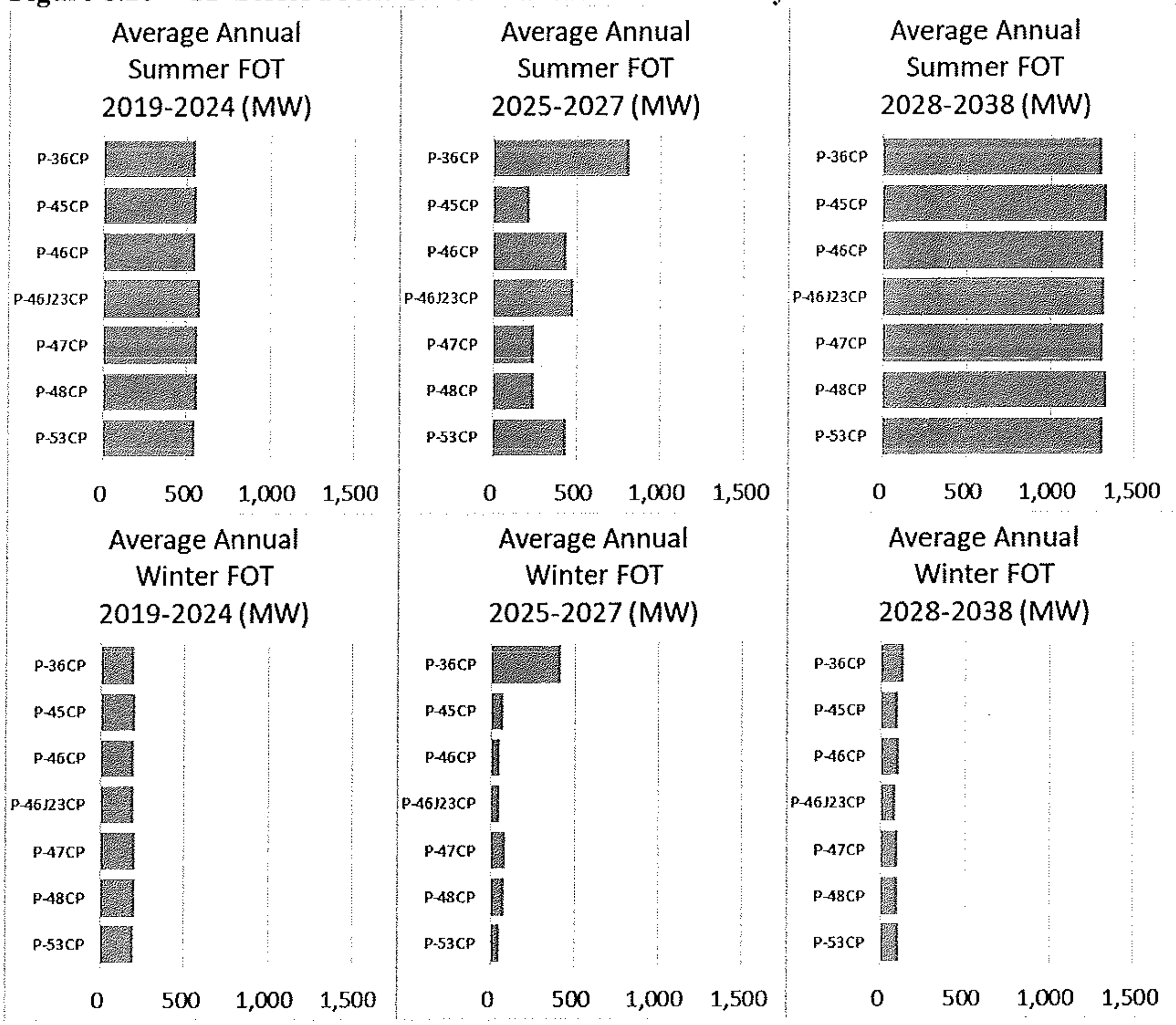
Figure 8.19 – CP-Series New Natural Gas Resource



Front Office Transactions

Figure 8.20 summarizes summer and winter FOTs for each CP-series case. The summer and winter FOT limit assumed for the 2019 IRP is 1,425 MW. Market reliance is reduced in the 2025 to 2027 timeframe, coinciding with the addition of new transmission, new wind, and new solar+battery resources—on average, summer FOT purchases are 411 MW per year over this period. Removing P-36CP (an outlier with nearly double the FOTs of other CP-series cases) from the mix yields an average of 344 MW per year. Longer-term, summer FOTs increase similarly among these cases, on average ranging between 1,310 MW and 1,334 MW each year from 2028-2038. Winter FOTs remain well below the volumes included in each portfolio to cover the summer peak period.

Figure 8.20 – CP-Series Front Office Transactions Summary



CO_2 Emissions

Figure 8.21 reports cumulative CO_2 emissions for each CP-series portfolio. Total CO_2 emissions is similar among these cases through 2027. Through 2038, total CO_2 emissions range between 558 million tons (case P-46CP) and 577 million tons (case P-45CP).

Figure 8.21 – CP-Series CO2 Emissions Summary

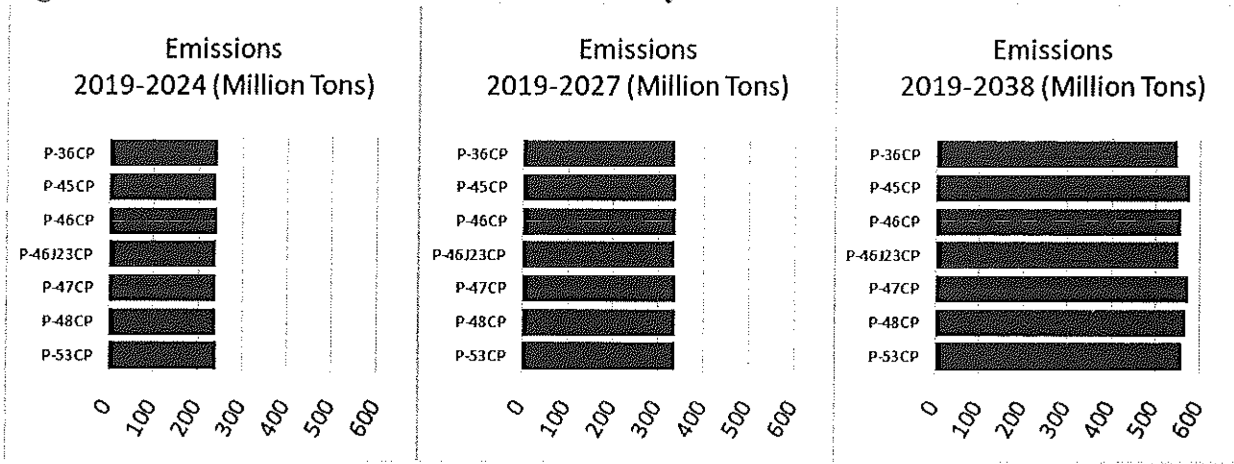
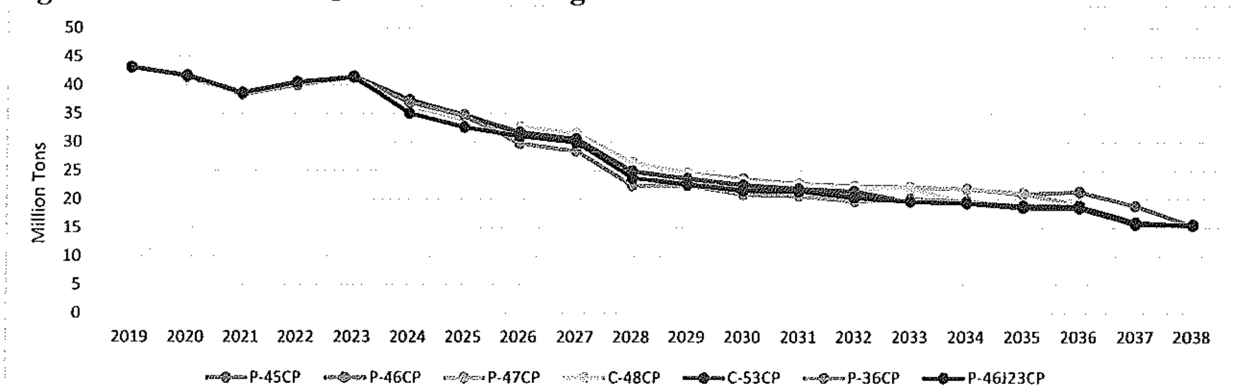


Figure 8.22 shows the annual emissions profile for each of the seven CP-series cases through the end of the planning period in 2038.

Figure 8.22 – Annul CO_2 Emissions among CP-Series Cases



CP-Series Cost and Risk Summary

The following tables and figures report the results of the CP-series cases for four price-policy scenarios. Each scenario assumes a low, medium or high gas price future, combined with either a zero, medium or high CO_2 price future. In addition to the seven CP-series cases, results from the five initial portfolios that were developed under varying natural gas price and CO_2 price assumptions are presented (cases P-16 through P-20).

CP-Series Medium Gas/Medium CO_2 Scenario

In the medium gas/medium CO_2 price-policy scenario, Case P-45CP outperforms other cases on stochastic mean costs, risk-adjusted costs, and energy not served (ENS). While case P-45CP has higher cumulative CO_2 emissions, the case with the lowest cumulative emissions (case P-36CP) has a risk-adjusted cost that is \$235m higher than case P-45CP. Further, as shown in the figure above, the annual emissions profile among the CP-series of cases is similar. None of the price-policy cases outperform case P-45CP on cost metrics.

Table 8.4 – CP-Series, Medium Gas/Medium CO_2 Results Summary

Case	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P45CP	**23,192**	**$0**	**1**	**24,360**	**$0**	**1**	**0.010%**	**0.000%**	**1**	**577,439**	**28,013**	**7**
P48CP	23,205	$13	2	24,374	$13	2	0.013%	0.003%	2	567,889	18,463	5
P47CP	23,219	$27	3	24,388	$28	3	0.013%	0.004%	7	573,649	24,222	6
P46CP	23,292	$100	4	24,465	$105	4	0.013%	0.003%	6	557,824	8,397	3
P46J23CP	23,303	$112	5	24,478	$118	5	0.013%	0.003%	2	552,065	2,639	2
P53CP	23,348	$156	6	24,524	$164	6	0.013%	0.003%	5	560,553	11,127	4
P36CP	23,413	$221	7	24,595	$235	7	0.013%	0.003%	2	549,427	0	1

Table 8.5 – Price-Policy Cases, Medium Gas/Medium CO_2 Results Summary

Case	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P16	23,889	$0	1	25,097	$0	1	0.007%	0.000%	1	669,944	242,834	5
P19	24,000	$111	2	25,211	$115	2	0.007%	0.000%	2	607,157	180,047	3
P17	24,182	$292	3	25,400	$303	3	0.057%	0.051%	4	475,390	48,281	2
P18	24,376	$487	4	25,602	$506	4	0.111%	0.104%	5	427,110	0	1
P20	25,118	$1,229	5	26,385	$1,289	5	0.007%	0.000%	2	607,157	180,047	3

CP-Series Low Gas/No CO_2 Scenario

In the low gas/zero CO_2 scenario, Case P-45CP outperforms other cases on stochastic mean costs, risk-adjusted costs, and ENS. While P-45CP has higher cumulative CO_2 emissions, the case with the lowest cumulative emissions (case P-46J23CP) has a risk-adjusted cost that is $222m higher than case P-45CP. Further, as shown in the figure above, the annual emissions profile among the CP-series of cases is similar. Cases P-16 and P-19, which were developed without a CO_2 price assumption and with low gas price assumptions, respectively, are among the top-performing price-policy cases when analyzed in a low gas/zero CO_2 price-policy scenario.

Table 8.6 – CP-Series, Low Gas/Zero CO_2 Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P45CP	**20,094**	**$0**	1	**21,105**	**$0**	1	**0.010%**	**0.000%**	1	**577,806**	**28,502**	7
P47CP	20,130	$36	2	21,143	$38	2	0.013%	0.004%	7	572,966	23,661	5
P48CP	20,173	$79	3	21,187	$83	3	0.013%	0.003%	3	567,163	17,859	4
P46CP	20,285	$191	4	21,305	$201	4	0.013%	0.003%	6	555,322	6,018	2
P46J23CP	20,306	$212	5	21,327	$222	5	0.013%	0.003%	3	549,304	0	1
P53CP	20,327	$233	6	21,349	$245	6	0.013%	0.003%	5	558,186	8,882	3
P36CP	23,192	$3,098	7	24,360	$3,256	7	0.010%	0.000%	1	577,439	28,135	6

Table 8.7 – Price-Policy Cases, Low Gas/No CO_2 Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P16	19,448	$0	1	20,427	$0	1	0.007%	0.000%	1	674,184	255,509	5
P19	20,194	$746	2	21,209	$782	2	0.007%	0.000%	2	607,941	189,266	4
P20	20,833	$1,386	3	21,881	$1,453	3	0.007%	0.000%	3	579,150	160,476	3
P17	21,013	$1,565	4	22,071	$1,643	4	0.057%	0.051%	4	465,998	47,324	2
P18	22,456	$3,008	5	23,587	$3,160	5	0.111%	0.105%	5	418,674	0	1

CP-Series High Gas/High CO_2 Scenario

In the high gas/high CO_2 scenario, Case P-48CP outperforms other cases on stochastic mean costs and risk-adjusted costs. Case P-45CP ranks second in stochastic mean and risk-adjusted cost and first in ENS. While P-45CP has higher cumulative CO_2 emissions, the case with the lowest cumulative emissions (case P-36CP) has a risk-adjusted cost that is $155m higher than case P-45CP. Further, as shown in the figure above, the annual emissions profile among the CP-series of cases is similar. Cases P-18, P-20, and P-17, which were developed using a social cost of carbon CO_2 price assumption, a high gas price assumption, and a high CO_2 price assumption, respectively, are among the top-performing price-policy cases when analyzed in a high gas/high CO_2 price-policy scenario.

Table 8.8 – CP-Series, High Gas/High CO_2 Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P48CP	27,736	$0	1	29,135	$0	1	0.013%	0.003%	2	562,313	18,221	5
P45CP	**27,786**	**$51**	**2**	**29,188**	**$53**	**2**	**0.010%**	**0.000%**	**1**	**571,643**	**27,550**	**7**
P47CP	27,805	$69	3	29,208	$72	3	0.013%	0.004%	7	568,183	24,090	6
P46J23CP	27,812	$76	4	29,215	$79	4	0.013%	0.003%	2	549,152	5,059	2
P46CP	27,814	$78	5	29,217	$82	5	0.013%	0.003%	6	553,331	9,239	3
P36CP	27,881	$145	6	29,290	$155	6	0.013%	0.003%	2	544,092	0	1
P53CP	27,889	$153	7	29,296	$161	7	0.013%	0.003%	5	556,201	12,108	4

Table 8.9 – Price-Policy Cases, High Gas/High CO_2 Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P18	27,785	$0	1	29,187	$0	1	0.112%	0.105%	5	431,628	0	1
P20	28,397	$612	2	29,832	$646	2	0.007%	0.000%	3	572,793	141,165	3
P17	28,858	$1,073	3	30,312	$1,125	3	0.057%	0.051%	4	478,795	47,167	2
P19	29,224	$1,439	4	30,701	$1,514	4	0.007%	0.000%	2	598,587	166,960	4
P16	29,847	$2,062	5	31,357	$2,170	5	0.007%	0.000%	1	653,963	222,335	5

CP-Series Social Cost of Carbon Scenario

In the social cost of carbon scenario, case P-46J23CP outperforms other cases on stochastic mean costs and risk-adjusted costs. While case P-45CP ranks sixth in these metrics and first in ENS, case P-46J23CP has a risk-adjusted PVRR cost that is $118m higher cost than P-45CP when the medium gas/medium CO_2 price-policy assumptions is applied. The highest ranking portfolio with regard to cumulative CO_2 emissions is case P-36CP. Case P-18, which was developed using a social cost of carbon CO_2 price assumption, is among the top-performing price-policy cases when analyzed in a social cost of carbon price-policy scenario. Case P-18 has a risk-adjusted PVRR that is over $1.2b higher cost than case P-45CP when medium gas/medium CO_2 price-policy assumptions are applied.

As was discussed with stakeholders at the October 3-4, 2019 public-input meeting, PacifiCorp applied social cost of carbon CO_2 prices to this price-policy scenario analysis such that the price for the social cost of carbon is reflected in market prices and dispatch costs. Consequently, it assumes that system operations (plant dispatch and market transactions) are not aligned with actual market forces (i.e., market transactions at the Mid-Columbia market do not reflect the social cost of carbon and PacifiCorp does not directly incur emissions costs at the price assumed for the social cost of carbon). Consequently, and unlike the other price-policy scenarios reviewed above, the model results for the social cost of carbon price-policy scenario represent cost drivers that are materially divergent from the cost drivers in the market. This creates challenges in understanding how to interpret the results from this price-policy scenario.

Table 8.10 – CP-Series Social Cost of Carbon Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P46J23CP	36,555	$0	1	38,394	$0	1	0.013%	0.003%	3	411,129	5,160	2
P36CP	36,561	$6	2	38,405	$11	2	0.010%	0.000%	1	405,969	0	1
P46CP	36,703	$149	3	38,550	$155	3	0.013%	0.003%	6	414,320	8,351	3
P48CP	36,798	$243	4	38,649	$254	4	0.013%	0.003%	3	424,073	18,104	5
P53CP	36,829	$274	5	38,681	$287	5	0.013%	0.003%	5	418,116	12,147	4
P45CP	36,934	$379	6	38,791	$397	6	0.010%	0.000%	1	432,168	26,199	7
P47CP	36,936	$381	7	38,794	$399	7	0.013%	0.004%	7	429,251	23,282	6

Table 8.11 – Price-Policy Case Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P18	35,276	$0	1	37,051	$0	1	0.112%	0.105%	5	321,000	0	1
P17	36,415	$1,139	2	38,247	$1,197	2	0.057%	0.051%	4	366,220	45,221	2
P20	37,527	$2,251	3	39,421	$2,370	3	0.007%	0.000%	3	437,132	116,133	3
P19	38,396	$3,120	4	40,334	$3,283	4	0.007%	0.000%	2	459,469	138,469	4
P16	39,712	$4,436	5	41,717	$4,666	5	0.007%	0.000%	1	496,702	175,703	5

Based upon the results summarized above, PacifiCorp identified case P-45CP as the top-performing case in the CP-series of cases. Relative cost differences between case P-45CP and the cases with the lowest cumulative CO_2 emissions (cases P-36CP and P-46J23CP) do not support consideration of these two cases for potential selection as the preferred portfolio.

Front Office Transaction Portfolios

Five of the CP-series cases (all but cases P-36CP and P-46J23CP) were further analyzed for FOT risk. The FOT studies are designed to quantify the impact and risk of market reliance. As detailed in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), these cases use an escalating scalar to elevate market prices during the peak months of July, August and December of every study year. This has the effect of increasing costs for market purchases or for acquisition of the alternative resources required to avoid the high market prices.

Higher FOT costs from market risk increased the PVRR by similar amounts among the cases, $820 million (3.6 percent), on average. Case P-45CP has a risk-adjusted PVRR that is $25m higher than Case P-47CP, which has the lowest PVRR when higher FOT costs are applied.

These results suggest that the risk of higher FOT costs is not materially different between cases P-45CP and P-47CP and these results do not justify driving the selection of any over the other CP-series of cases as beneficial to case P-45CP.

Table 8.12 reports FOT case evaluation results. Table 8.13 quantifies the increased system cost of escalated FOT pricing compared to the system cost of each portfolio under the medium gas, medium CO_2 price-policy scenario.

Table 8.12 – FOT Case Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P47CP	24,001	$0	1	25,209	$0	1	0.010%	0.000%	2	535,827	13,317	4
P45CP	24,024	$23	2	25,233	$25	2	0.009%	0.000%	1	540,134	17,623	5
P48CP	24,098	$97	3	25,312	$104	3	0.012%	0.002%	3	533,930	11,419	3
P46CP	24,099	$98	4	25,314	$105	4	0.013%	0.004%	5	522,510	0	1
P53CP	24,164	$163	5	25,382	$173	5	0.013%	0.003%	4	525,364	2,854	2

Table 8.13 – FOT Case System Cost Impact Summary

	Stochastic Mean		
Case	PVRR ($m)	Change from CP Portfolio ($m)	Rank
P47CP	24,001	$782	1
P45CP	24,024	$832	4
P48CP	24,098	$892	5
P46CP	24,099	$807	2
P53CP	24,164	$815	3

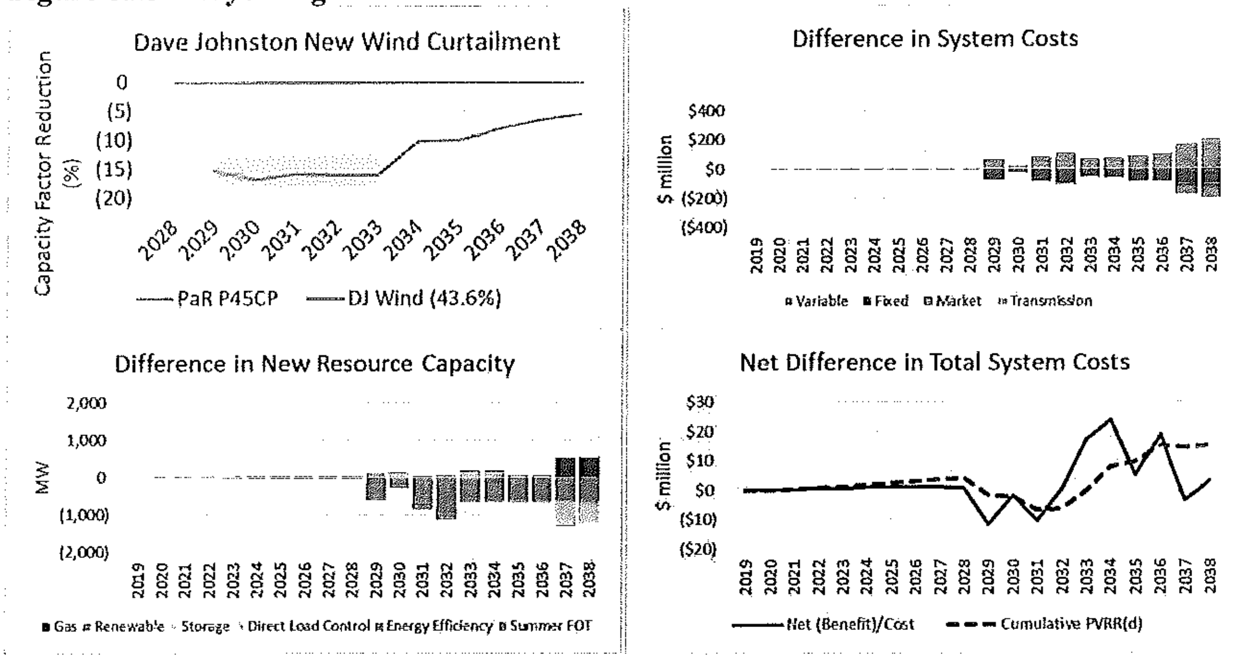
2028-2029 Wyoming Wind Case

As detailed in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), PacifiCorp identified that 620 MW of Wyoming wind resources added to each portfolio in the 2028-2029 timeframe, which coincides with the assumed retirement of Dave Johnston, were being curtailed at relatively significant levels—through 2038, capacity factors average 32 percent, down from the 43.6 percent assumed without curtailment. From 2029 through 2033 the level of curtailment is higher, with output falling below a 30 percent capacity factor.

Upon observing this modeled outcome, PacifiCorp produced an new portfolio as a variant of the least cost CP series case (P-45CP) that eliminated the 620 MW of incremental Wyoming wind coming online after the retirement of Dave Johnston. This case is referred to as P-45CNW.

While the stochastic mean PVRR of P-45CNW is $15m higher than case P-45CP, as illustrated in Figure 8.23, PacifiCorp advanced Case P-45CNW as the baseline for evaluating additional "No New Natural Gas" and Energy Gateway transmission cases on the basis that it is not reasonable to include heavily curtailed wind resources in the leading case for the preferred portfolio. Further, the shifts in system costs contributing to the $15m increase in system PVRR are all beyond the action plan window, which will allow PacifiCorp to continue to evaluate potential incremental wind additions in eastern Wyoming when Dave Johnston retires in future IRPs.

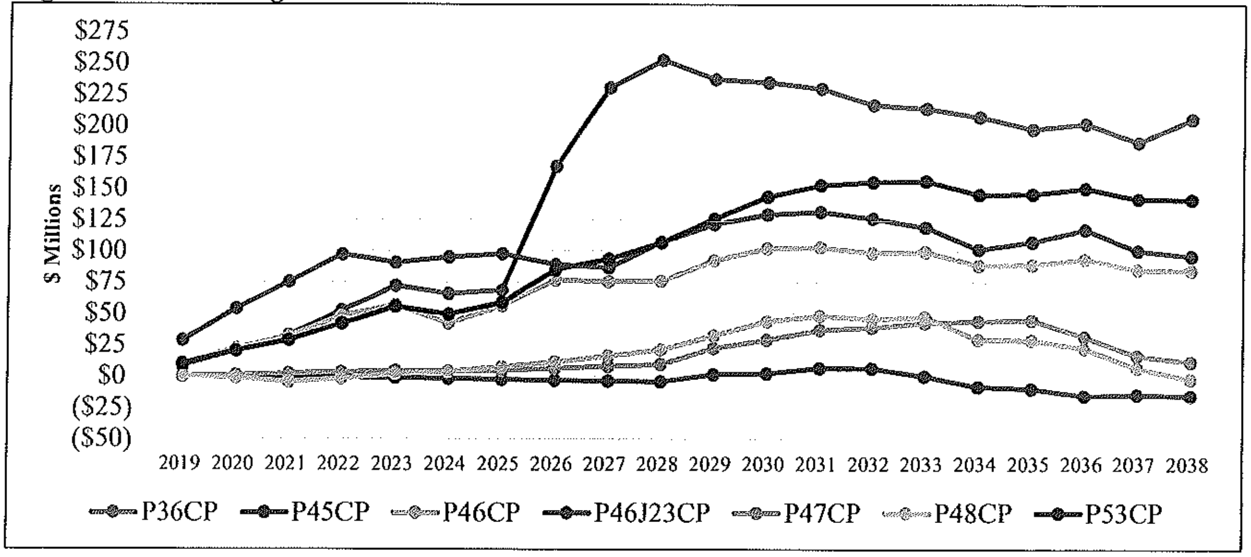
Figure 8.23 – Wyoming Wind Alternative Portfolio and Cost Evaluation



Customer Rate Pressure

Figure 8.24 shows the difference in the cumulative PVRR, as an indicator of rate pressure over time, between among the CP-series of cases discussed earlier relative to case P-45CNW when applying medium gas, medium CO_2 price-policy assumptions. Cases P-36CP, P-46CP, P-46J23CP, and P-53CP consistently trend higher than case P-45CNW. Through 2024, cases P-45CP, P-47CP, and P-48CP track relatively close to case P45-CNW. After 2024, cases P-47CP and P-48CP trend higher then case P-45CNW, and then start to converge with case P-45CNW over the longer-term.

Figure 8.24 – Change in the Cumulative PVRR relative to P-45CNW



Portfolio Development Conclusions

Based on the findings of the initial portfolios, C-series of cases, CP-series of cases, the FOT cases used to analyze market-reliance risk, and the case that eliminates highly curtailed Wyoming wind in the 2028-2029 timeframe, PacifiCorp identified case P-45CNW as the top-performing case at the conclusion of the portfolio-development process. As described below, case P-45CNW serves as the basis for additional analysis to inform final selection of the preferred portfolio.

Preferred Portfolio Selection

"No New Natural Gas" Portfolios

The "No New Natural Gas" cases, defined in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), provide two views of impacts stemming from an assumption that no new gas resources are acquired through the end of the study period. The first case, P-29 does not allow the model to select new natural gas resources (excluding the Naughton Unit 3 gas conversion). The second case, P-29PS is a variant of P-29 with the addition of a 400 MW pumped storage project located in northeast Wyoming that is assumed to come online in 2028 following retirement of the Dave Johnston plant.

As seen in Figure 8.25, case P-29 accelerates renewable resources from 2036 to 2032 and adds incremental battery storage resources beginning 2030 relative to case P-45CNW. Under P-29, system costs begin to decrease in 2027, however over the long term, incremental costs for new battery storage resources and market purchases reverse the trend.

Figure 8.25 – P-29 No Gas Case Resource and Cost Compared to P-45CNW

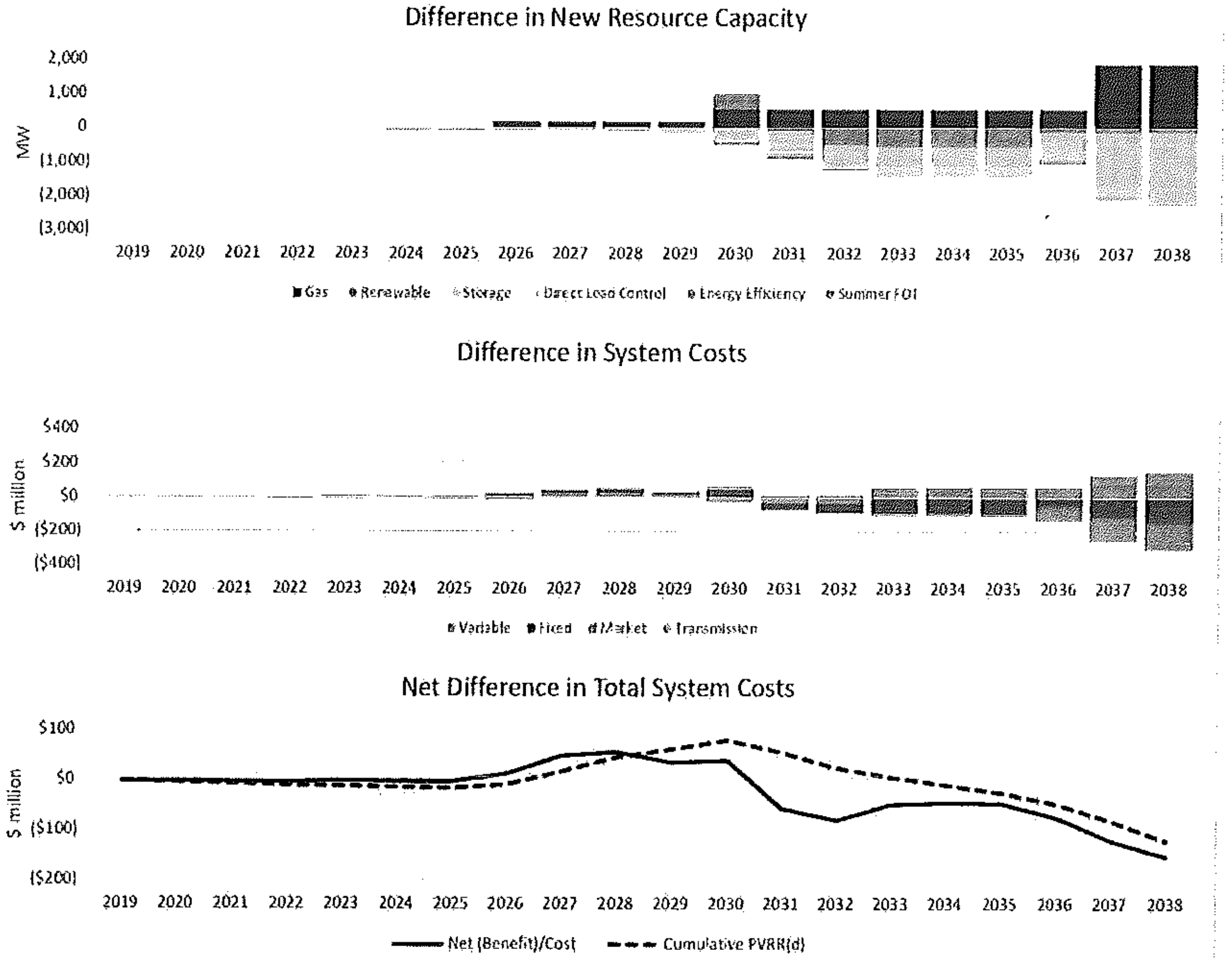


Figure 8.26 summarizes P-29PS portfolio and cost differences compared to P-45CNW, eliminating new gas and adding pumped storage (400 MW) and battery storage (227 MW) in 2028. By the end of the study period, case P-29PS adds an additional 1,575 MW of battery storage. System costs increase beginning 2028 with incremental fixed cost for the storage resources, and added market purchases costs increasingly contribute to the added system costs in the 2036-2038 timeframe.

Table 8.14 summarizes the results of the "No New Natural Gas" cases. Both of these cases result in higher costs than case P-45CNW. Neither case justifies altering selection of Case P-45CNW as the top-performing portfolio.

Figure 8.26 – P-29PS No Gas with Pumped Hydro Storage Compared to P-45CNW

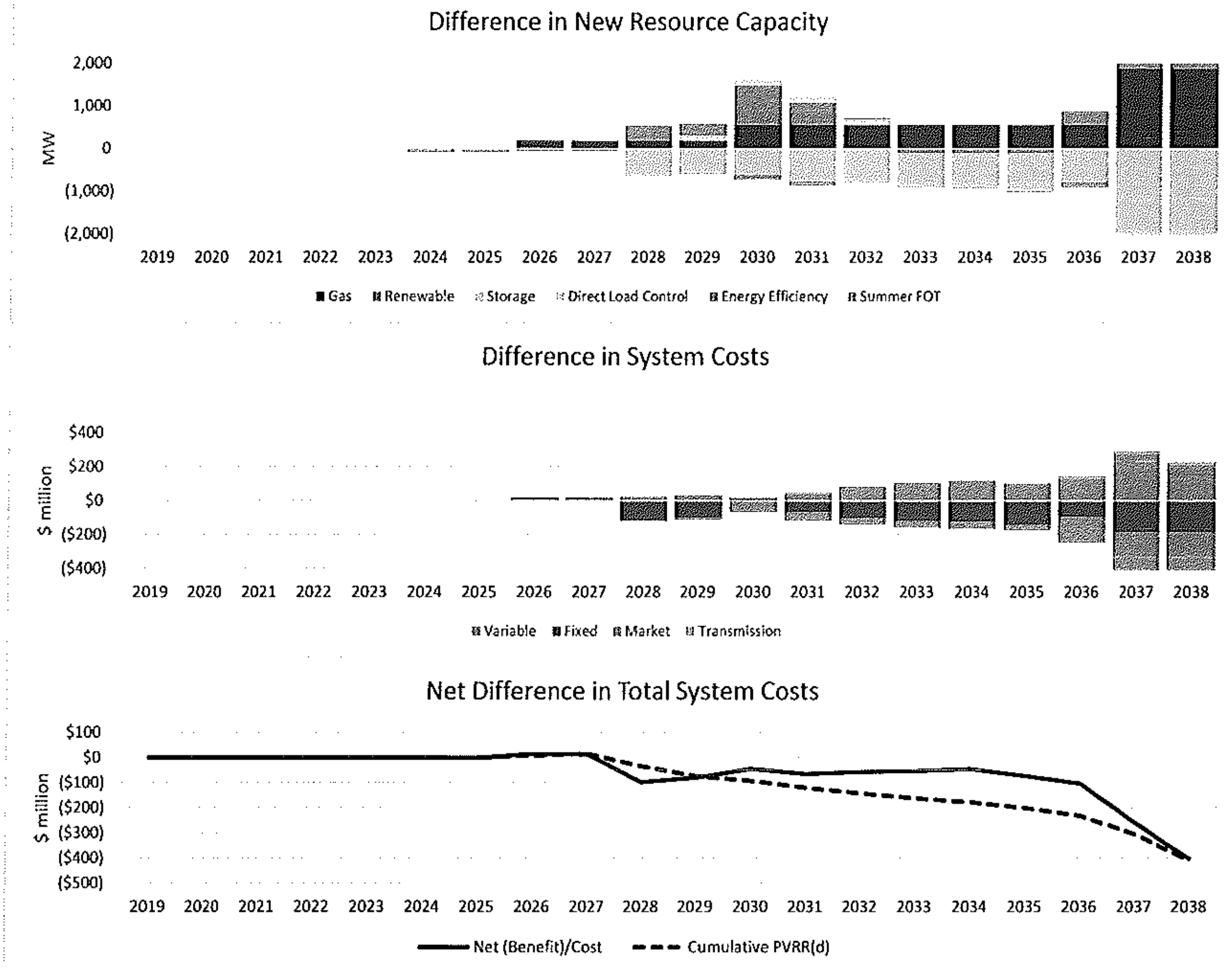


Table 8.14 – No Gas Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P45CNW	**23,207**	**$0**	**1**	**24,376**	**$0**	**1**	**0.008%**	**0.002%**	**2**	**585,641**	**8,835**	**3**
P29	23,328	$121	2	24,503	$127	2	0.006%	0.000%	1	580,126	3,320	2
P29PS	23,616	$409	3	24,806	$430	3	0.047%	0.040%	3	576,806	0	1

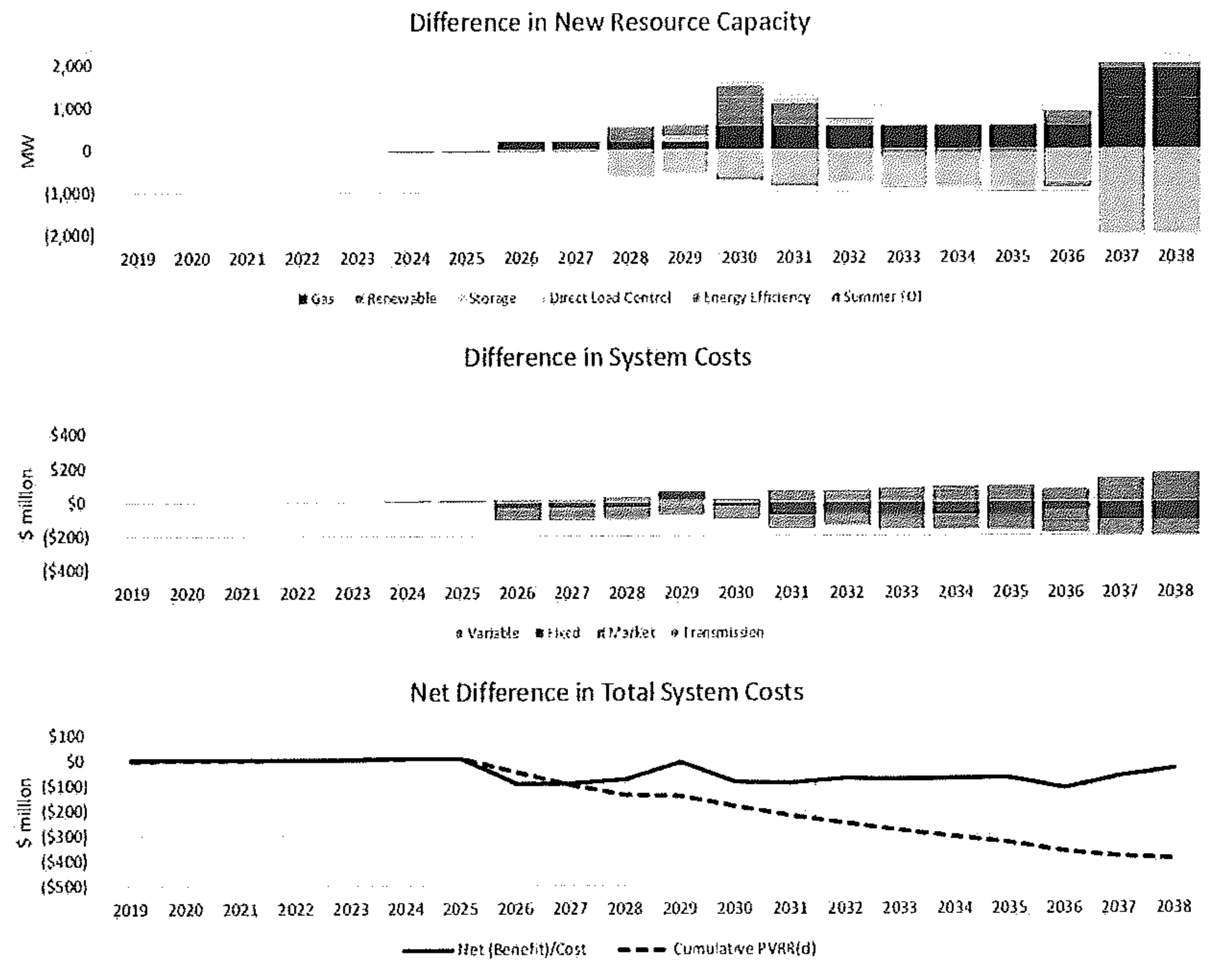
Energy Gateway Transmission Cases

PacifiCorp modeled four Energy Gateway transmission cases, expanding on scenarios defined in previous IRP cycles. The full build-out of all Energy Gateway segments was performed in two cases (P-23 and P-25) to assess the potential value in two different coal retirement scenarios. All of these cases include the endogenous selection of Gateway South in 2024 (as a proxy for year-end 2023). Full case definitions for the Energy Gateway studies are provided in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).

P-22 Evaluation

Case P-22 includes the approximately 200 mile Bridger/Anticline-to-Populus Energy Gateway transmission segment (sub-segment D.3). The stochastic mean PVRR of case P-45CNW is $396m lower cost than Case P-22, driven primarily by D.3 transmission project costs where the net portfolio cost impacts are largely offsetting. Case P-45CNW sees higher market, emissions and DSM costs, but reduced capital and fixed operations and maintenance costs that are aligned with the increased proportion of generating resources as opposed to storage resources. Figure 8.27 reports portfolio and cost differences compared to case P-45CNW.

Figure 8.27 – P-22 (Segments D.3 and F) Compared to P-45CNW



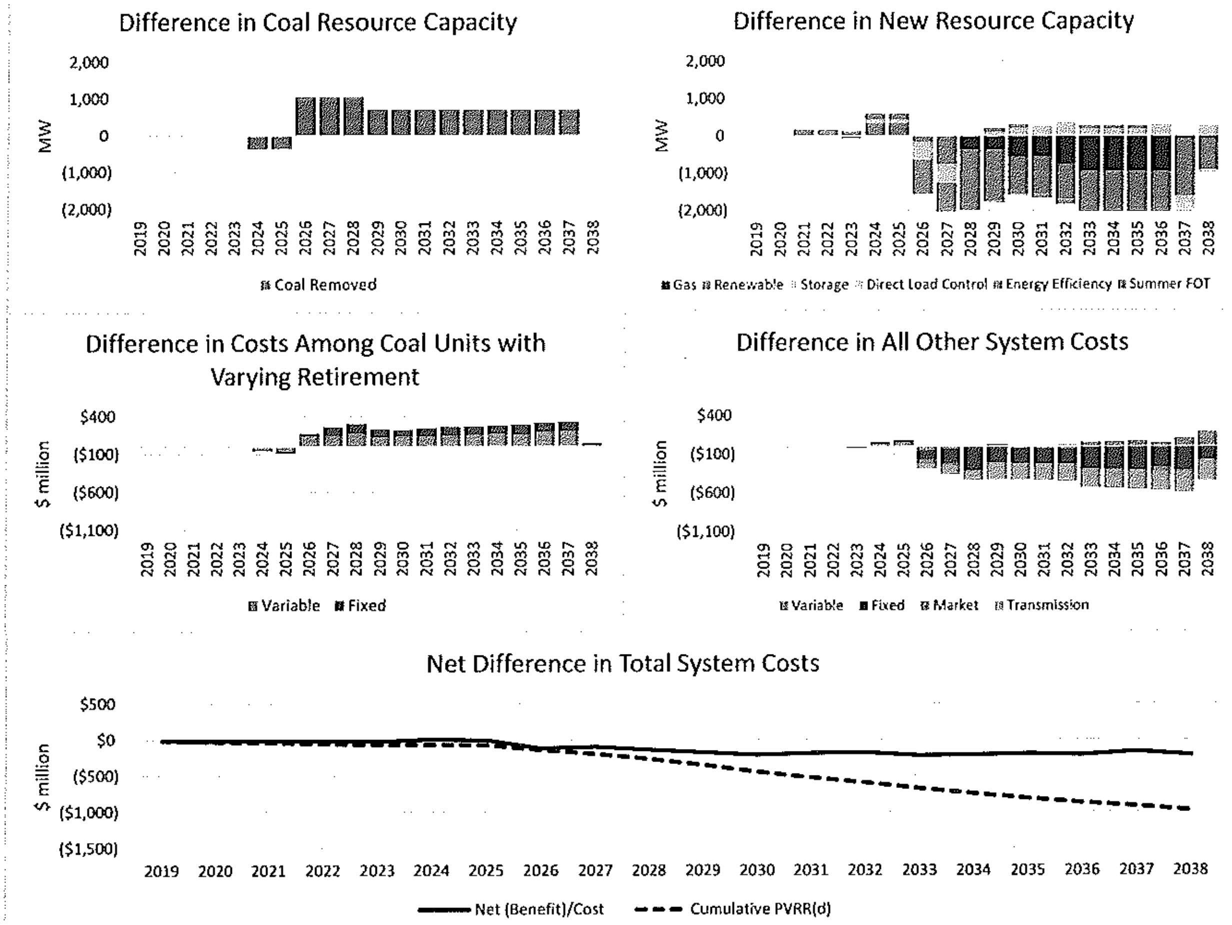
P-23 Evaluation

Relative to case P-36CNW, case P-23 includes the approximately 200 mile Bridger/Anticline-to-Populus transmission sub-segment (D.3), the approximately 500 mile Populus-to-Hemingway transmission segment (E), and the approximately 290 mile Boardman-to-Hemingway segment (H). A variant of stakeholder requested P-36CNW, P-23 features early retirement of the entire Bridger plant in 2025, and also Naughton Units 1-2 in 2025.

As seen in Figure 8.28, the reduction of thermal resources due to highly accelerated retirements causes P-23 to accelerate significant thermal and renewable additions into 2028.

The stochastic mean PVRR of case P-45CNW is $977m lower cost than case P-23, driven primarily by transmission project costs where the net portfolio variable and fixed cost impacts are largely offsetting.

Figure 8.28 – P-23 (Additional segments D.3, E, F and H) Compared to P-45CNW



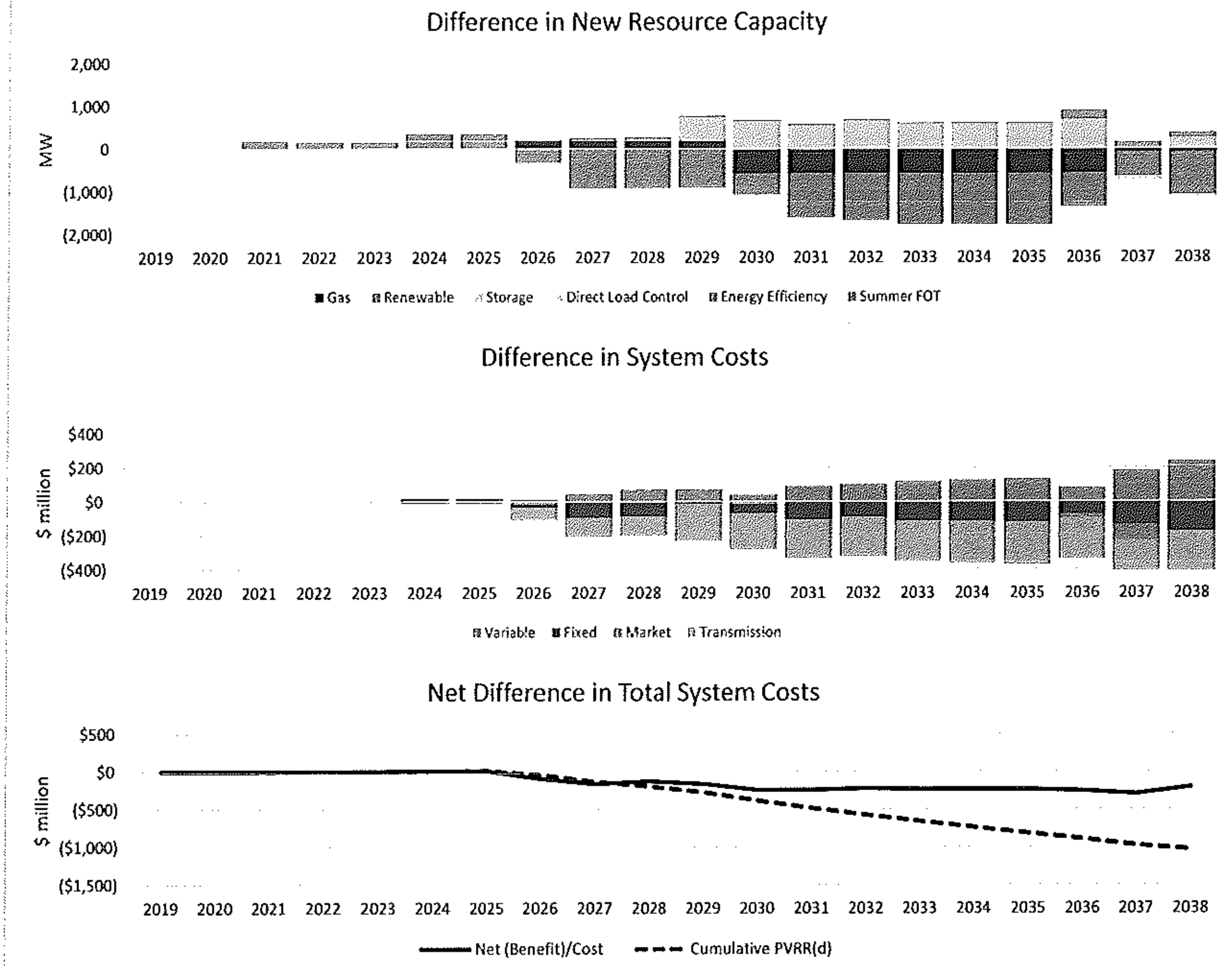
P-25 Evaluation

Case P-25 includes the approximately 200 mile Bridger/Anticline-to-Populus transmission sub-segment (D.3), the approximately 500 mile Populus-to-Hemingway transmission segment (E), and the approximately 290 mile Boardman-to*Hemingway segment (H). Although the Energy Gateway additions match case P-23, P-25 is a variant of P-45CNW.

As seen in Figure 8.29, Gas capacity is accelerated approximately 6 years (~500 MW) into 2030.

The stochastic mean PVRR of case P-45CNW is approximately $1.0b lower cost than case P-25, driven primarily by transmission project costs where the net portfolio variable and fixed cost impacts are largely offsetting.

Figure 8.29 – P-25 (Additional segments D.3, E, F and H) Compared to P-45CNW



P-26 Evaluation

Case P-26 includes the approximately 290 mile Boardman-to-Hemingway transmission segment (H). As seen in Figure 8.30 gas capacity is accelerated approximately 6 years (~500 MW) into 2030.

The stochastic mean PVRR of case P-45CNW is approximately $98m lower cost than case P-26. In Table 8.15 case P-26 ranks second among gateway cases in 3 of 4 categories, including stochastic mean, risk-adjusted PVRR and low ENS. These results are promising, and signal that with motivated project partners and potentially significant regional reliability benefits, updated modeling that can better capture the value of this project will ultimately support a business case to move forward with the project. Consequently, PacifiCorp has included an action item in its 2019 IRP action plan to continue to evaluate and support the Boardman-to-Hemmingway project.

Table 8.15 reports a summary of the Energy Gateway cases.

Figure 8.30 – P-26 (Segments F and H) Compared to P-45CNW

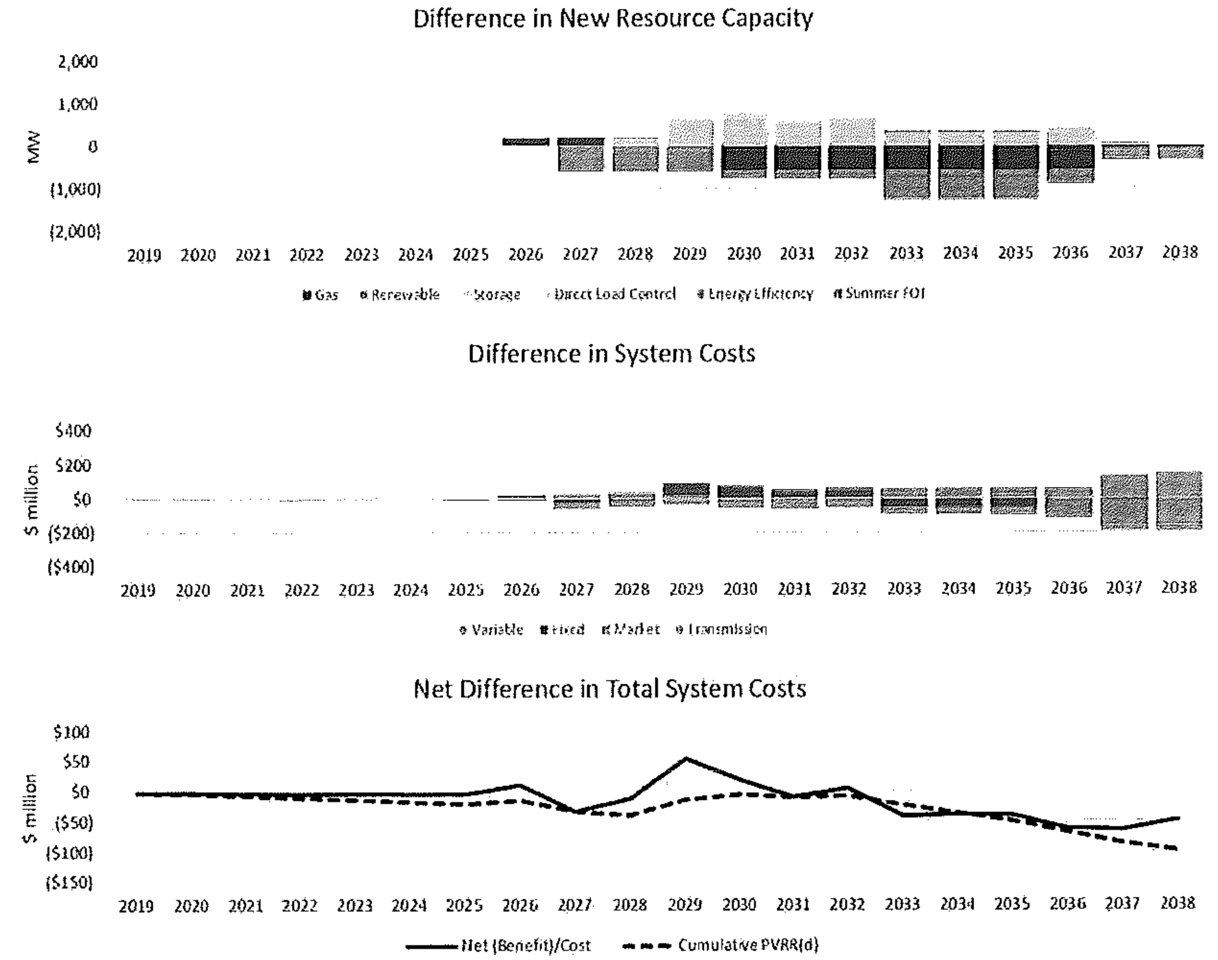


Table 8.15 – Gateway Case Results Summary

Case	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P45CNW	23,207	$0	1	24,376	$0	1	0.008%	0.002%	5	585,641	40,831	5
P-26	23,305	$98	2	24,479	$104	2	0.006%	0.000%	2	580,126	35,315	3
P-22	23,603	$396	3	24,792	$416	3	0.007%	0.001%	4	581,028	36,217	4
P-23	24,184	$977	4	25,402	$1,026	4	0.007%	0.001%	3	544,811	0	1
P-25	24,239	$1,032	5	25,460	$1,084	5	0.006%	0.000%	1	580,014	35,204	2

Gateway Studies Conclusions

While the results above did not compel PacifiCorp to alter its selection of case P-45CNW as the top-performing portfolio, the company remains confident that additional Energy Gateway segments will provide incremental regional and customer benefits with an ongoing transition to the regional resource mix and as new markets develop.

As discussed above, case P-26, which includes the Boardman-to-Hemingway transmission line, shows significant potential for producing customer benefits. This project has motivated partners and is expected to provide incremental benefits not captured in the current analysis that can be further explored in future IRPs and IRP Updates. Consequently, PacifiCorp will remain an active participate in the ongoing development of this project and has included an action item in its action plan to continue its partnership in this project. Some of the incremental benefits of Boardman-to-Hemmingway not captured in the analysis above include:

- Connecting geographical diversity to help balance the intermittency of resources like wind and solar, to help meet clean-energy standards and bolsters resource adequacy.
- Decreasing market reliance by providing incremental infrastructure that can connect additional resources to load.
- Improved reliability by increasing ability to share operating reserves among utilities and providing additional source for energy to flow.
- Help alleviate transmission congestion.
- Improved access to participate in the Energy Imbalance Market and generate customer benefits.

PacifiCorp has also included an action item to continue permitting the Energy Gateway transmission plan, as it is anticipated these additional segments will also provide incremental value that can continue to be evaluated in future IRPs and IRP Updates.

Final Preferred Portfolio Selection
Case P-45CNW entered the final evaluations as the top candidate for preferred portfolio, and for purposes of the 2019 IRP, the "No New Natural Gas" and Energy Gateway cases did not change P-45CNW's top status. Consequently, PacifiCorp selected the resource portfolio from case P-45CNW as the 2019 IRP preferred portfolio.

The 2019 IRP Preferred Portfolio

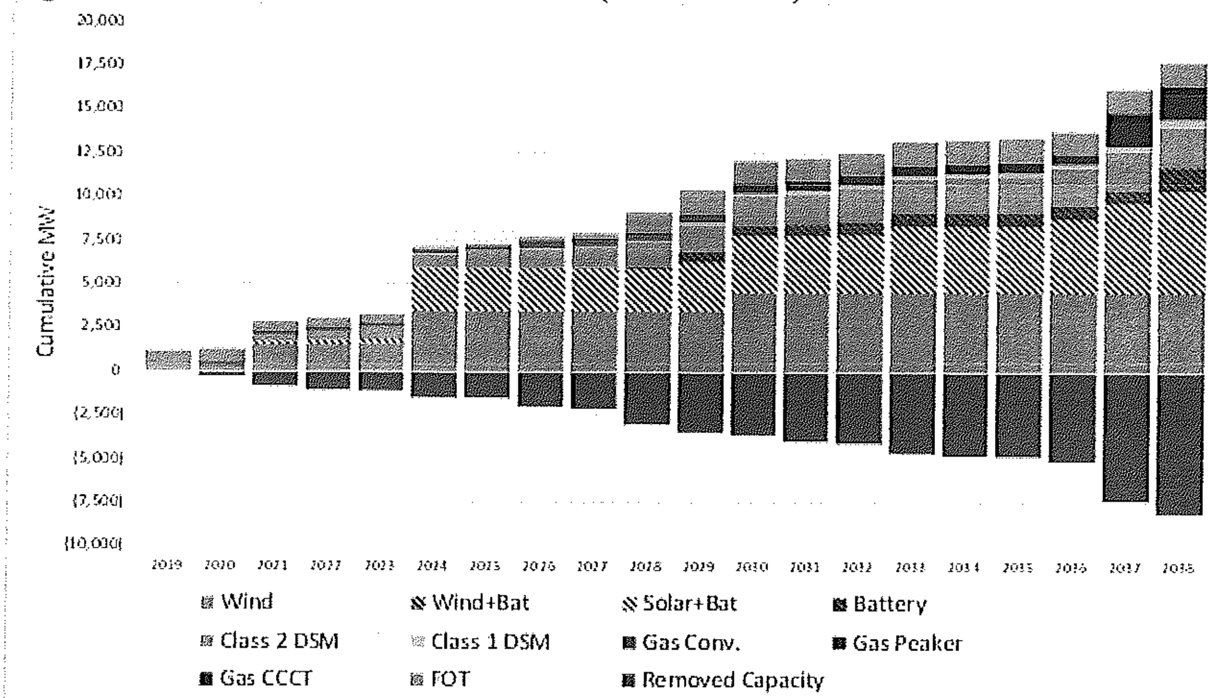
PacifiCorp's selection of the 2019 IRP preferred portfolio is supported by comprehensive data analysis and an extensive stakeholder-input process. Figure 8.31 shows that PacifiCorp's preferred portfolio continues to include new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, and for the first time, significant battery storage resources. By the end of 2023, the preferred portfolio includes nearly 3,000 MW of new solar resources and more than 3,500 MW of new wind resources, inclusive of resources that will come online by the end of 2020 that were not in the 2017 IRP.[3] The preferred portfolio also includes nearly 600 MW of battery storage capacity (all collocated with new solar resources), and over 700 MW of incremental energy efficiency and new direct load control resources.

Over the 20-year planning horizon, the preferred portfolio includes more than 4,600 MW of new wind resources, more than 6,300 MW of new solar resources, more than 2,800 MW of battery storage (nearly 1,400 MW of which are stand-alone storage resources starting in 2028), and more

[3] *Id.*

than 2,700 MW of incremental energy efficiency and new direct load control resources.[4] While the preferred portfolio includes new natural gas peaking capacity beginning 2026, this falls outside of the 2019 IRP action plan window, which provides time for PacifiCorp to continue to evaluate whether non-emitting capacity resources can be used to supply the flexibility necessary to maintain long-term system reliability.

Figure 8.31 – 2019 IRP Preferred Portfolio (All Resources)



To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes a 400-mile transmission line known as Gateway South, planned to come online by the end of 2023, that will connect southeastern Wyoming and northern Utah. The new transmission line is in addition to the 140-mile Gateway West transmission line in Wyoming currently under construction as part of PacifiCorp's Energy Vision 2020 initiative. The preferred portfolio further includes near-term transmission upgrades in Utah and Washington. Ongoing investment in transmission infrastructure in Idaho, Oregon, Utah, Washington, and Wyoming will facilitate continued and long-term growth in new renewable resources. Table 8.16 summarizes the incremental transmission projects included in the 2019 IRP preferred portfolio, and Table 8.17 summarizes the total amount of initial capital investment required to deliver incremental transmission and resource investments through the 20-year planning period of the 2019 IRP.

[4] *Id.*

Table 8.16 – Transmission Projects Included in the 2019 IRP Preferred Portfolio*

Year	Resource(s)	From	To	Description
2023	69 MW Wind (2023) 231 MW Solar (2024)	Within Southern UT Transmission Area		Enables 300 MW of interconnection: UT Valley 345-138 kV + 138 kV reinforcement ($8m)
2024	354 MW Solar (2024)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 1 ($0)
2024	674 MW Solar (2024)	Within Northern UT Transmission Area		Enables 600 MW of interconnection: Northern UT 345 kV reinforcement ($30m)
2024	1,920 MW Wind (2024)	Aeolus WY	UT North	Enables 1,920 MW of interconnection with 1,700 MW of TTC: Energy Gateway South ($1,752m)
2024	395 MW Solar (2024) 10 MW Wind (2029)	Within Yakima WA Transmission Area		Enables 405 MW of interconnection: local reinforcement ($3m)
2024	359 MW Solar (2024)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 2 ($0)
2030	1,040 MW Wind (2030) 60 MW Wind (2032)	Goshen ID	UT North	Enables 1,100 MW of interconnection with 800 MW of TTC ($254m)
2030	500 MW Solar (2030)	Within Southern UT Transmission Area		Enables 500 MW of interconnection: UT Valley local area reinforcement ($206m)
2033	475 MW Solar (2033)	Within Southern OR Transmission Area		Enables 475 MW of interconnection: Medford area 500 kV-230 kV reinforcement ($102m)
2036	419 MW Solar (2036)	Yakima WA	Southern OR	Enables 430 MW of interconnection with 450 MW of TTC: Yakima WA to Bend OR 230 kV ($255m)
2037	909 MW Solar (2037)	Southern UT	Northern UT	Reclaimed transmission upon retirement of Huntington 1-2 ($0)
2037	443 MW Gas (2037)	Within Willamette Valley OR Transmission Area		Enables 615 MW of interconnection: Albany OR area reinforcement ($40m)
2037	370 MW Gas (2037)	Within Southwest WY Transmission Area		Enables 500 MW of interconnection: separation of double circuit 230 kV lines ($39m)
2038	702 MW Solar (2038)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 3-4 ($0)

*Note: TTC = total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.

Table 8.17 – Total Initial Capital to Deliver Preferred Portfolio Transmission and Resource Investments ($ million)

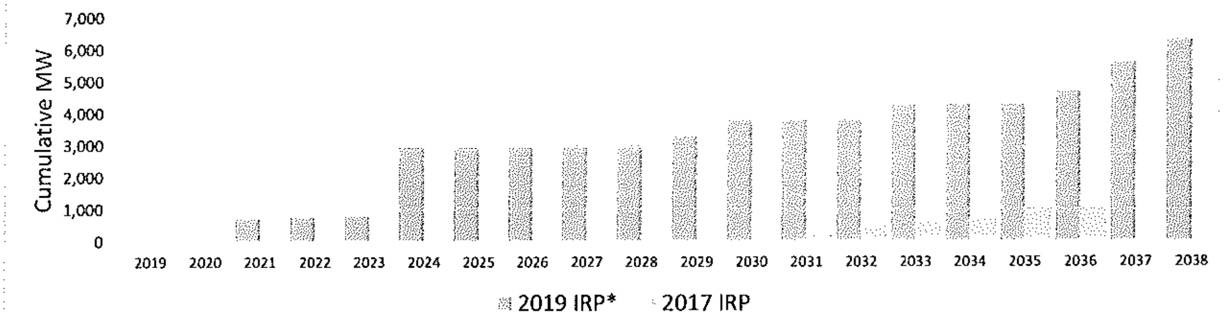
State	Transmission	Resources	Total
Idaho	$254	$1,659	$1,912
Oregon	$264	$2,540	$2,804
Utah	$1,004	$3,466	$4,470
Washington	$136	$1,509	$1,644
Wyoming	$765	$5,376	$6,141
Colorado	$370	$0	$370
Total	$2,792	$14,550	$17,342

New Solar Resources

The 2019 IRP preferred portfolio includes more than 3,000 MW of new solar by the end of 2023, which accounts for resources that will come online by the end of 2020 but not in the 2017 IRP, and more than 6,300 MW of new solar by 2038 as shown in Figure 8.32.[5]

[5] *Id.*

Figure 8.32 – 2019 IRP Preferred Portfolio New Solar Capacity*

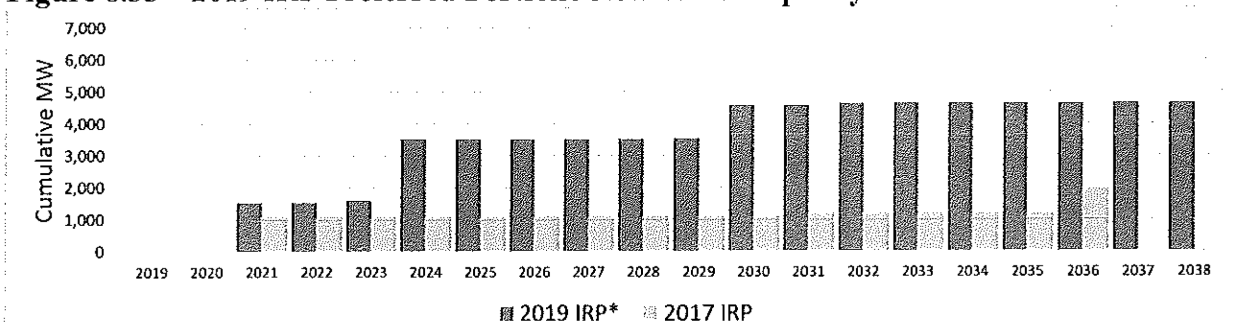


*Note: 2019 IRP solar capacity shown in the figure includes 559 MW of contracted new solar (all power-purchase agreements) that was not identified in the 2017 IRP. These resources will be online by the end of 2020 and are shown in the first full year of operation (the year after year-online dates). Resources acquired through customer partnerships, used for renewable portfolio standard compliance, or for third-party sales of renewable attributes are included in the total capacity figures quoted.

New Wind Resources

As shown in Figure 8.33, PacifiCorp's 2019 IRP preferred portfolio includes more than 3,500 MW of new wind generation by the end of 2023, which accounts for new resources that will come online by the end of 2020 but not in the 2017 IRP, and more than 4,600 MW of new wind by 2038.[6]

Figure 8.33 – 2019 IRP Preferred Portfolio New Wind Capacity*



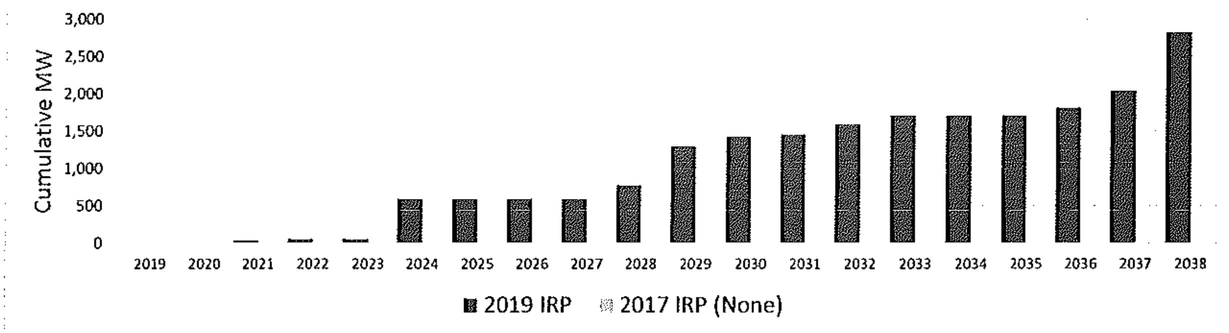
*Note: 2019 IRP wind capacity shown in the figure includes 1,533 MW of contracted new wind (21 percent power-purchase agreements) that was either identified in the 2017 IRP and is under construction or that was not identified in the 2017 IRP and is under contract. These resources will come on-line by the end of 2020. These resources are shown in the first full year of operation (the year after year-end online dates). Resources acquired through customer partnerships, used for renewable portfolio standard compliance, or for third-party sales of renewable attributes are included in the total capacity figures quoted.

New Storage Resources

This is the first PacifiCorp IRP that identifies new battery storage resources as part of its least-cost, least-risk portfolio. As shown in Figure 8.34, PacifiCorp's 2019 IRP preferred portfolio includes nearly 600 MW of battery storage by the end of 2023. All of the storage resources planned through this period are paired with new solar generation. The plan also adds nearly 1,400 MW of stand-alone storage resources starting in 2028.

[6] *Id.*

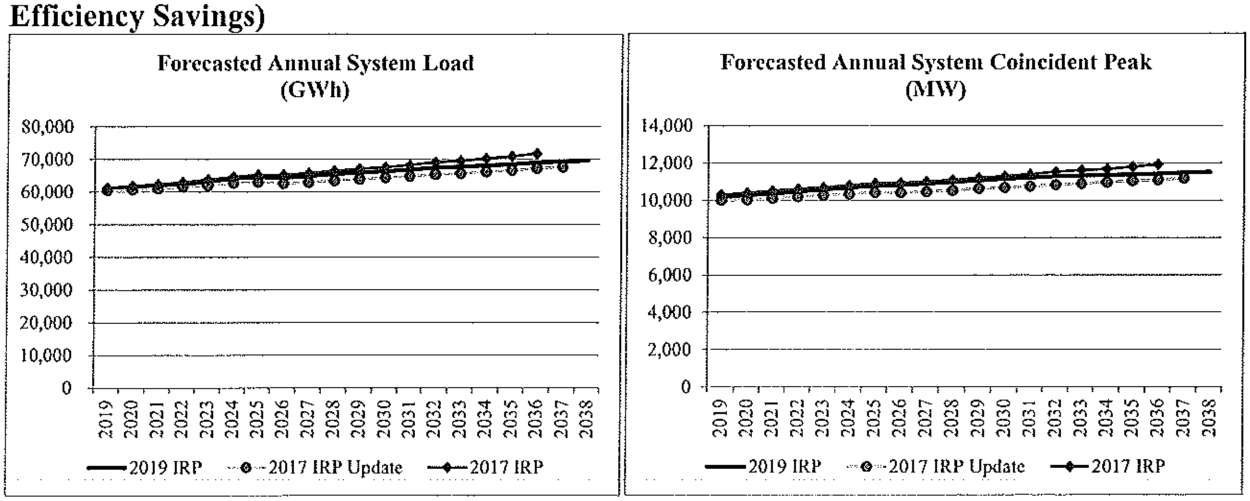
Figure 8.34 – 2019 IRP Preferred Portfolio New Storage Capacity



Demand-Side Management

PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and direct load control programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP. Figure 8.35 shows that PacifiCorp's load forecast before incremental energy efficiency savings has increased relative to projected loads used in the 2017 IRP and 2017 IRP Update. On average, forecasted system load is up 2.4 percent and forecasted coincident system peak is up 3.4 percent when compared to the 2017 IRP Update. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 0.73 percent for load and 0.64 percent for peak. Changes to PacifiCorp's load forecast are driven by higher projected demand from data centers driving up the commercial forecast and an increase the residential forecast.

Figure 8.35 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)

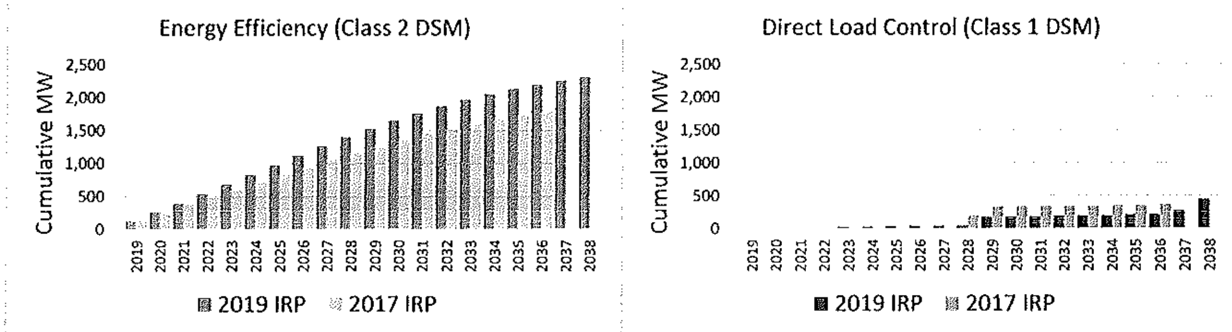


DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 8.36 compares total energy efficiency savings in the 2019 IRP preferred portfolio relative to the 2017 IRP preferred portfolio.

In addition to continued investment in energy efficiency programs, the preferred portfolio continues to show a role for incremental direct load control programs with total capacity reaching

444 MW by the end of the planning period. The chart to the right in Figure 8.36 compares total incremental capacity of direct load control program capacity in the 2019 IRP preferred portfolio relative to the 2017 IRP preferred portfolio and does not include capacity from existing programs.

Figure 8.36 – 2019 IRP Preferred Portfolio Energy Efficiency (Class 2 DSM) and Direct Load Control Capacity (Class 1 DSM)



Wholesale Power Market Prices and Purchases

Figure 8.37 shows that the 2019 IRP's base case forecast for natural gas and power prices has increased from those in the 2017 IRP and 2017 IRP Update. These forecasts are based on prices observed in the forward market and on projections from third-party experts. The higher power prices observed in the 2019 IRP are primarily driven by the assumption of a carbon price that is higher and starts earlier (2025) than what was assumed in the 2017 IRP Update (2030).[7] Moreover, the 2019 IRP assumed higher natural gas prices than either the 2017 IRP or 2017 IRP Update as Henry Hub, in particular, is boosted by increasing LNG exports. While not shown in the figure below, the 2019 IRP also evaluated low and high price scenarios when evaluating the cost and risk of different resource portfolios.

Figure 8.37 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs

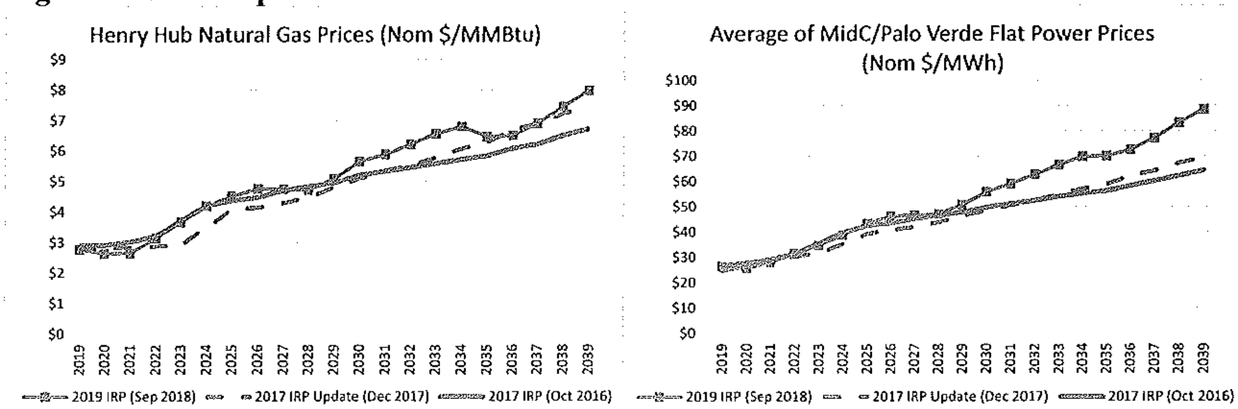
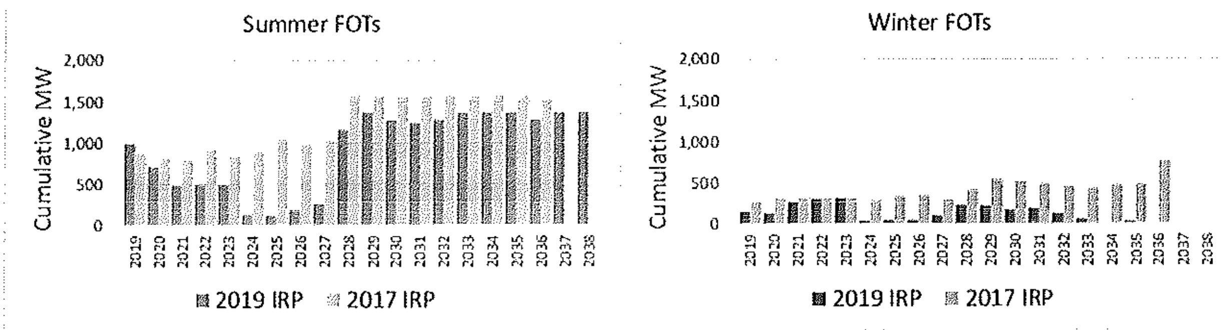


Figure 8.38 shows an overall decline in reliance on wholesale market firm purchases in the 2019 IRP preferred portfolio relative to the market purchases included in the 2017 IRP preferred portfolio. In particular, reliance on market purchases during summer peak periods averages 366 MW per year over the 2020-2027 timeframe—down 60 percent from market purchases identified in the 2017 IRP preferred portfolio. This reduction in market purchases coincides with the period

[7] The 2017 IRP did not assume a carbon price but, instead, reflected implementation of the Clean Power Plan.

over which there are resource adequacy concerns in the region. While market purchases increase beyond 2027, PacifiCorp is actively participating in regional efforts to develop day-ahead markets and a resource adequacy program that will help unlock regional diversity and facilitate market transactions over the long term.

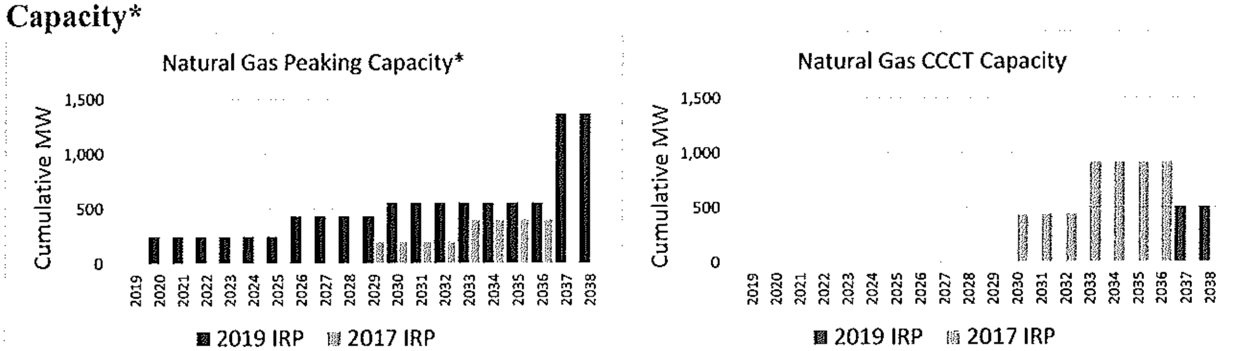
Figure 8.38 – 2019 IRP Preferred Portfolio Front Office Transactions (FOTs)



Natural Gas Resources

In the 2019 IRP preferred portfolio, Naughton Unit 3 is converted to natural gas in 2020, providing a low-cost reliable resource for meeting load and reliability requirements. New natural gas peaking resources appear in the preferred portfolio starting in 2026, which is outside the action-plan window. This provides time for PacifiCorp to continue to evaluate whether non-emitting capacity resources can be used to supply the flexibility necessary to maintain system reliability long into the future.

Figure 8.39 – 2019 IRP Preferred Portfolio Natural Gas Peaking and Combined Cycle Capacity*



* Note: 2019 IRP natural gas peaking capacity includes the conversion of Naughton Unit 3 to natural gas in 2020 (247 MW).

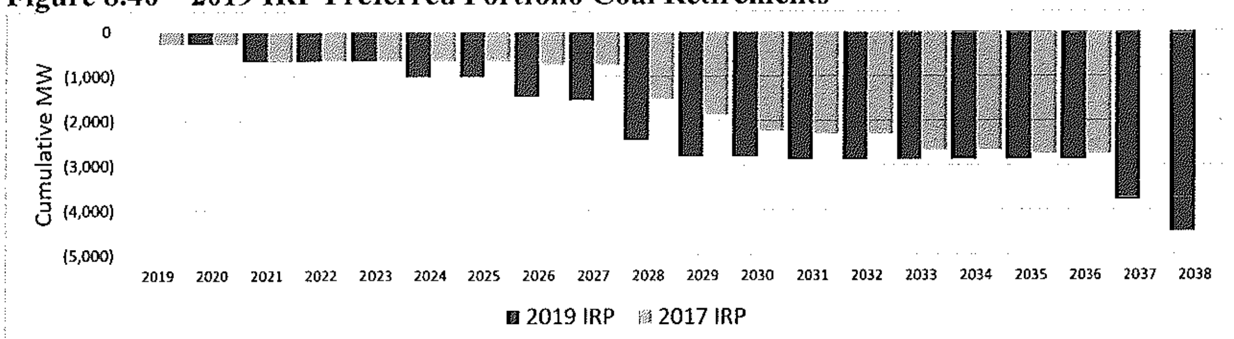
Coal Retirements

Coal resources have been an important resource in PacifiCorp's resource portfolio. Changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums) has allowed the company to buy increasingly low-cost, zero-emissions renewable energy from market participants, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy as those units approach retirement dates. Driven in part by ongoing cost pressures on existing coal-fired facilities and dropping costs for new resource alternatives, of the 24 coal units currently serving PacifiCorp customers, the preferred portfolio includes retirement of 16 of the units by 2030 and 20 of the units by the end of the planning period in 2038. As shown in Figure 8.40, coal unit retirements in the 2019 IRP preferred portfolio will reduce coal-fueled generation capacity by over 1,000 MW by the end of 2023, nearly 1,500 MW by the end of 2025, nearly 2,800 MW by 2030, and nearly 4,500 MW by 2038.

Coal unit retirements scheduled under the preferred portfolio include:

- 2019 = Naughton Unit 3 (same as 2017 IRP), converted to natural gas in 2020
- 2020-2023 = Cholla Unit 4 (same as 2017 IRP)
- 2023 = Jim Bridger Unit 1 (instead of 2028 in the 2017 IRP)
- 2025 = Naughton Units 1-2 (instead of 2029 in the 2017 IRP)
- 2025 = Craig Unit 1 (same as 2017 IRP)
- 2026 = Craig Unit 2 (instead of 2034 in the 2017 IRP)
- 2027 = Dave Johnston Units 1-4 (same as 2017 IRP)
- 2027 = Colstrip Units 3-4 (instead of 2046 in the 2017 IRP)
- 2028 = Jim Bridger Unit 2 (instead of 2032 in the 2017 IRP)
- 2030 = Hayden Units 1-2 (same as 2017 IRP)
- 2036 = Huntington Units 1-2 (same as 2017 IRP)
- 2037 = Jim Bridger Units 3-4 (same as 2017 IRP)

Figure 8.40 – 2019 IRP Preferred Portfolio Coal Retirements*



* Note: Coal retirements are assumed to occur by the end of the year before the year shown in the graph. The graph shows the year in which the capacity will not be available for meeting summer peak load. All figures represent PacifiCorp's ownership share of jointly owned facilities.

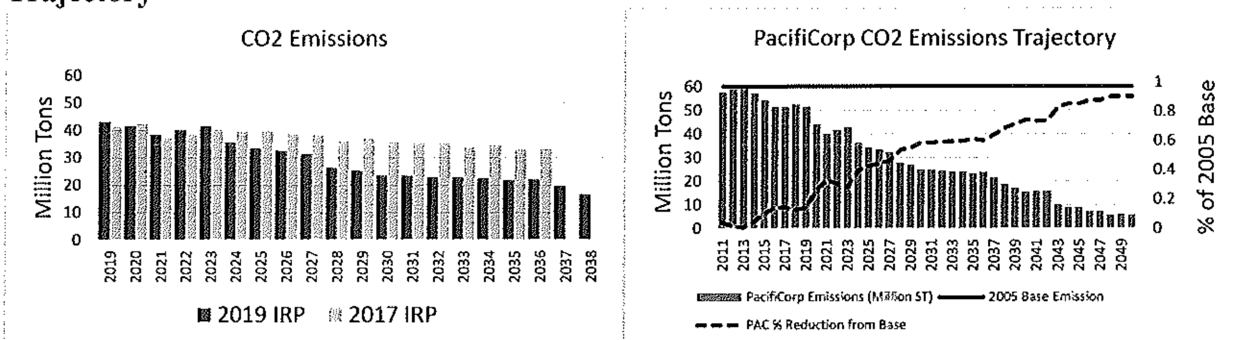
Carbon Dioxide Emissions

The 2019 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects a continued trajectory of declining carbon dioxide (CO_2) emissions. PacifiCorp's emissions have been declining and continue to decline as a result of a number of factors, including PacifiCorp's participation in the Energy Imbalance Market (EIM), which reduces customer costs and maximizes use of clean energy; PacifiCorp's on-going expansion of renewable resources and transmission; and Regional Haze compliance that capitalizes on flexibility.

The chart on the left in Figure 8.41 compares projected annual CO_2 emissions between the 2019 IRP and 2017 IRP preferred portfolios. In this graph, emissions are not assigned to market purchases or sales, and in 2025, annual CO_2 emissions are down sixteen percent relative to the 2017 IRP preferred portfolio. By 2030, average annual CO_2 emissions are down 34 percent relative to the 2017 IRP preferred portfolio, and down 35 percent in 2035. By the end of the planning horizon, system CO_2 emissions are projected to fall from 43.1 million tons in 2019 to 16.7 million tons in 2038—a 61.3 percent reduction.

The chart of the right in Figure 8.41 includes historical data, assigns emissions at a rate of 0.4708 tons/megawatt hours (MWh) to market purchases (with no credit to market sales), and extrapolates projections out through 2050. This graph demonstrates that relative to a 2005 baseline (a ubiquitous baseline year in the industry), system CO_2 emissions are down 43 percent in 2025, 59 percent in 2030, 61 percent in 2035, 74 percent in 2040, 85 percent in 2045, and 90 percent in 2050.

Figure 8.41 – 2019 IRP Preferred Portfolio CO_2 Emissions and PacifiCorp CO_2 Emissions Trajectory*



*Note: PacifiCorp CO_2 Emissions Trajectory reflects actual emissions through 2018 from owned facilities, specified sources and unspecified sources. From 2019 through the end of the twenty-year planning period in 2038, emissions reflect those from the 2019 IRP preferred portfolio with market purchases assigned the California Air Resources Board default emission factor (0.4708 tons/MWh) – emissions from sales are not removed. Beyond 2038, emissions reflect the rolling average emissions of each resource from the 2019 IRP preferred portfolio through the life of the resource.

Renewable Portfolio Standards

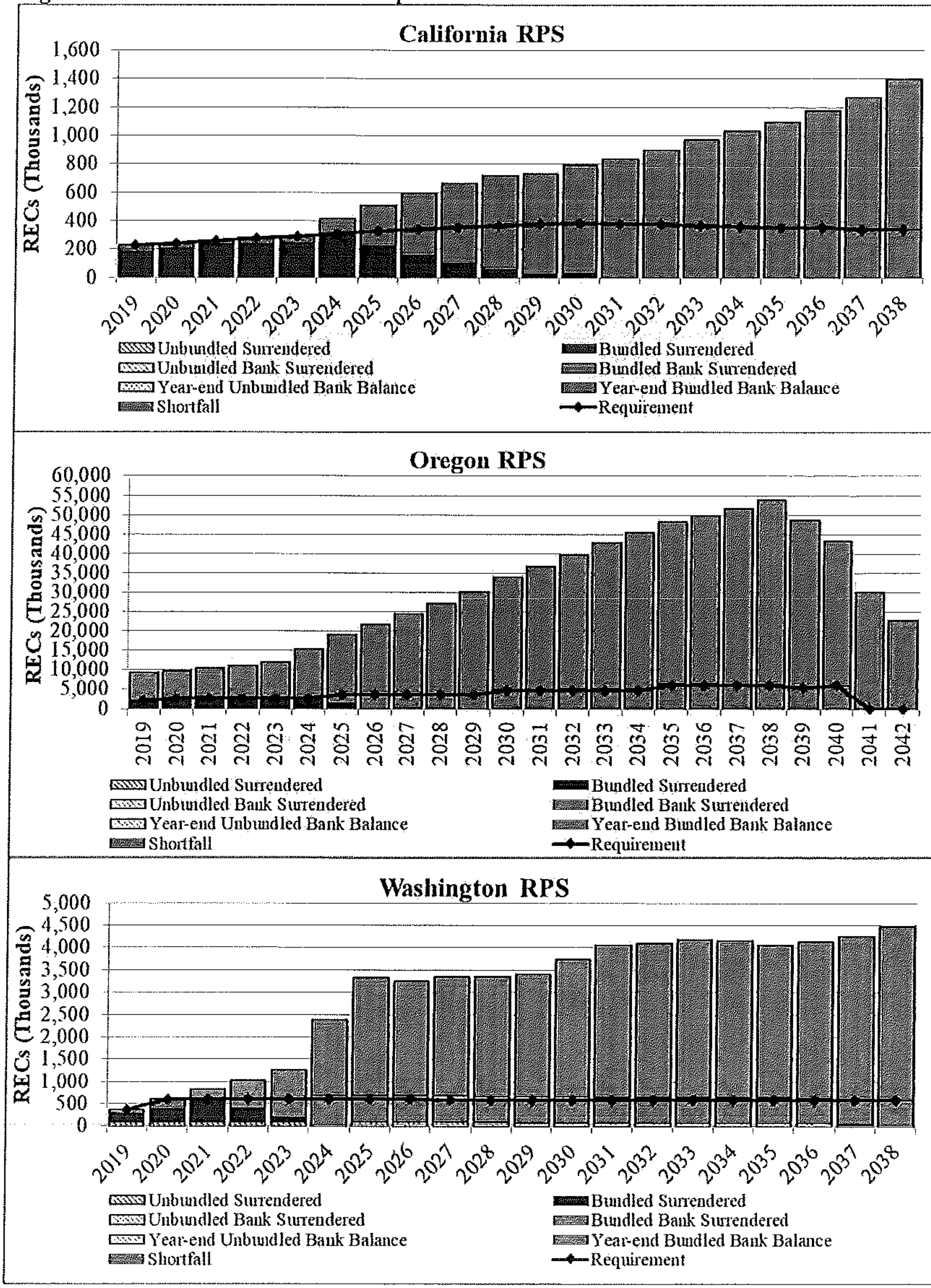
Figure 8.42 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for new renewable resources in the preferred portfolio. While these resources are not included in the preferred portfolio as cost-effective system resources and are not included to specifically meet RPS targets, they nonetheless contribute to meeting RPS targets in PacifiCorp's western states.

Oregon RPS compliance is achieved through 2038 with the addition of new renewable resources and transmission in the 2019 IRP preferred portfolio. The California RPS compliance position is also improved by the addition of new renewable resources and transmission in the 2019 IRP preferred portfolio but requires a small amount of unbundled renewable energy credit (REC) purchases under 150 thousand RECs per year to achieve compliance through Compliance Period 4. Washington RPS compliance is achieved with the benefit of repowered wind assets located in the west side, Marengo, Leaning Juniper and Goodnoe Hills, increased system renewable resources contributing to the west side beginning 2021[8], and unbundled REC purchases under 300 thousand

[8] PacifiCorp will propose the Multi-State Protocol allocation methodology in a December 13, 2019 Washington general rate case (GRC) filing. The methodology would allocate a system generation share of all non-emitting system resources to Washington. The 2019 IRP Annual State RPS Compliance Forecast reflected in Figure 8.42 reflects PacifiCorp's proposal to be filed in the rate case starting in 2021. Upon approval, the effective date of the new allocation methodology would be January 1, 2021.

RECs per year through 2021. Under current allocation mechanisms, Washington customers do not benefit from the new renewable resources added to the east side of PacifiCorp's system. While not shown in Figure 8.42, PacifiCorp meets the Utah 2025 state target to supply 20 percent of adjusted retail sales with eligible renewable resources with existing owned and contracted resources and new renewable resources and transmission in the 2019 IRP preferred portfolio.

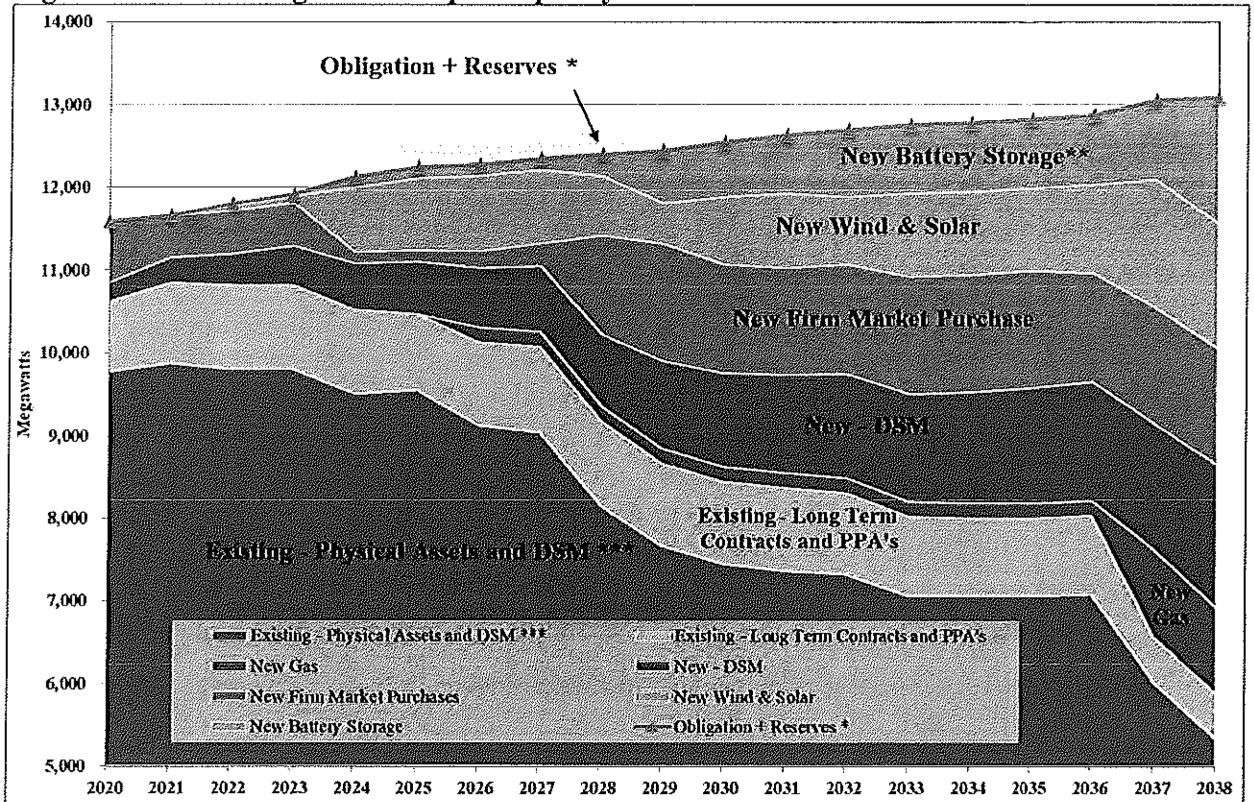
Figure 8.42 – Annual State RPS Compliance Forecast



Capacity and Energy

Figure 8.43 displays how preferred portfolio resources meet PacifiCorp's capacity needs over time. Through 2038, PacifiCorp meets its capacity needs, including a 13 percent target planning reserve margin, through incremental acquisition of wind and solar resources, enabled by investment in transmission infrastructure, battery storage resources, new DSM, natural gas and wholesale power market purchases.

Figure 8.43 – Meeting PacifiCorp's Capacity Needs with Preferred Portfolio Resources



* Includes 13% Planning Reserves, Sales and Non-Owned Reserves
** Includes Stand-alone Storage and the Storage component of Renewables + Storage
*** Includes retirements, and gas repower. DSM includes both Class 1 and 2

Figure 8.44 and Figure 8.45 show how PacifiCorp's system energy and nameplate capacity mix is projected to change over time. In developing these figures, purchased power is reported in identifiable resource categories where possible. Energy mix figures are based upon base price curve assumptions. Renewable capacity and generation reflect categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.[9] On an energy basis, coal generation drops below 40 percent by 2025, falls to 22 percent by 2030, and declines to less than 6 percent by the end of the planning period. On a capacity basis, coal resources drop to 24 percent by 2025, fall to 13 percent by 2030, and decline to 5 percent by the end of the

[9]The projected PacifiCorp 2019 IRP preferred portfolio "energy mix" is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with wind, biomass, geothermal and qualifying hydro facilities in PacifiCorp's energy mix may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements; (b) sold to third parties in the form of renewable energy credits or other environmental commodities; or (c) excluded from energy purchased. PacifiCorp's 2019 IRP preferred portfolio energy mix includes owned resources and purchases from third parties.

planning period. Reduced energy and capacity from coal is offset primarily by increased energy and capacity from renewable resources, DSM resources, and to a smaller extent later in the plan, new natural gas resources.

Figure 8.44 – Projected Energy Mix with Preferred Portfolio Resources

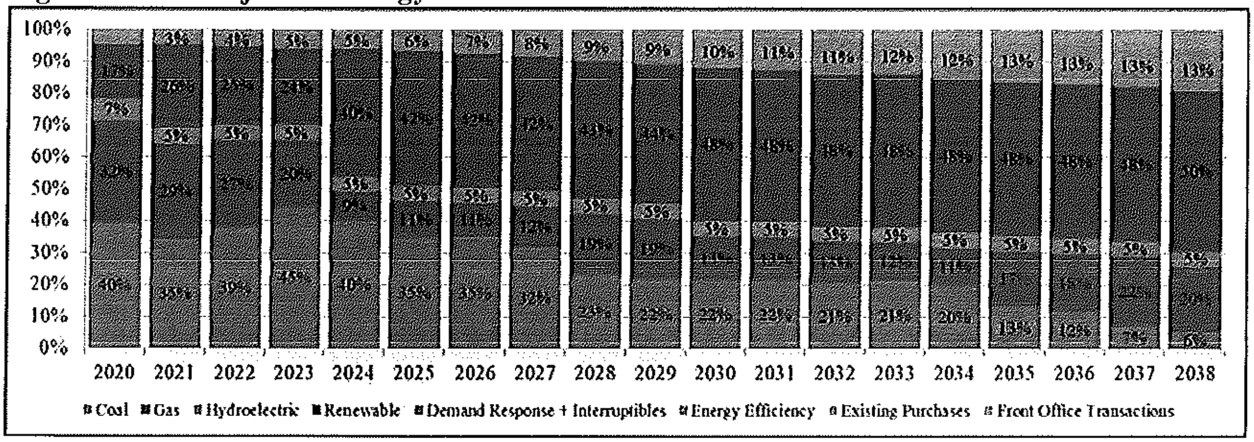
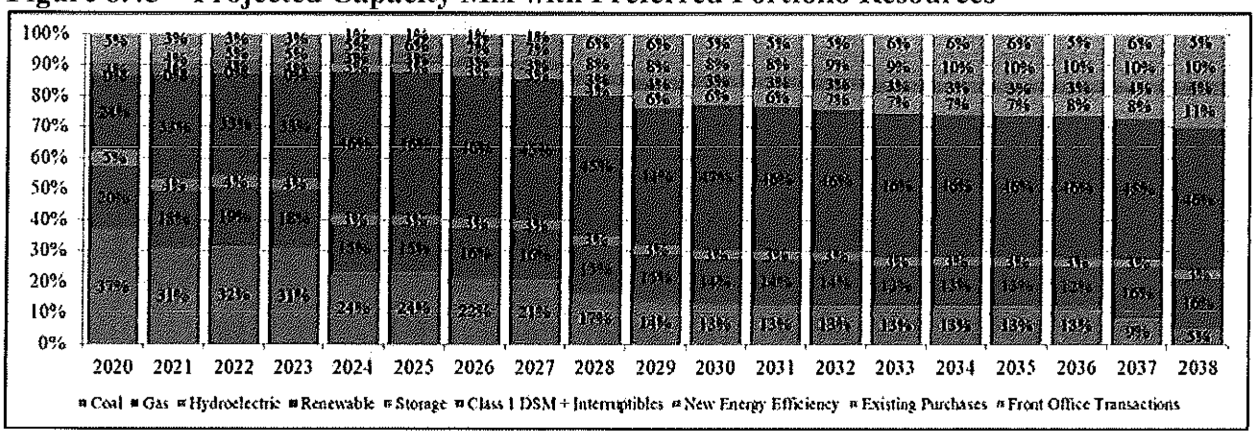


Figure 8.45 – Projected Capacity Mix with Preferred Portfolio Resources



Detailed Preferred Portfolio

Table 8.18 provides line-item detail of PacifiCorp's 2019 IRP preferred portfolio showing new resource capacity along with changes in existing resource capacity through the 20-year planning horizon. Table 8.19 and Table 8.20 show line-item detail of PacifiCorp's peak load and resource capacity balance for summer, including preferred portfolio resources, over the 20-year planning horizon. Table 8.21 and Table 8.22 show line-item detail of PacifiCorp's peak load and resource capacity balance for winter, including preferred portfolio resources, over the twenty year planning horizon.

Table 8.18 – PacifiCorp's 2019 IRP Preferred Portfolio (The 2019 Preferred Portfolio includes repowering 905 MW of existing wind resources, not shown in the table)

	PACNW	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(43)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	CCCT - [illegible]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	370	-	185	925
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,040	-	-	-	-	-	-	-	-	-	1,040
	Wind, UT	-	-	-	-	69	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	69	69
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Wind+Storage, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	60
	Total Wind	-	-	-	-	69	1,920	-	-	-	-	-	1,040	-	60	-	-	-	-	-	-	1,989	3,089
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	231	-	-	-	-	-	500	-	-	-	-	-	-	-	-	231	731
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	152	64	3	674	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	152	64	3	904	-	-	-	-	-	500	-	-	-	-	-	-	909	-	1,131	2,540
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76.7	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37.3	-	37.3
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	1.2	-	6.7
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	123.3	8.2	-	12.0	-	-	15.3	3.7	10.5	136.5	44.6	354.1
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	5	4	4	3	3	3	69	117
	Energy Efficiency, UT	58	67	67	68	69	68	67	65	65	62	57	56	52	52	48	36	32	25	22	23	656	1,058
	Energy Efficiency, WY	10	10	11	14	15	16	16	18	18	17	16	15	13	12	11	9	8	7	5	5	146	248
	Energy Efficiency Total	74	83	85	88	92	92	91	90	90	87	80	77	72	70	65	49	45	35	30	32	870	1,423
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	195	-	195.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.0	-	15.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	30.0	-	-	-	-	-	-	150.0	-	180.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	88	300	199	174	206	298	300	300	300	300	300	9	138
West	**Existing Plant Retirements and PPA Termination**																						
	Jim Bridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	Jim Bridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	Jim Bridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	Jim Bridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(73)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Wind+Storage, YK	-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	11	-	-	20
	Total Wind	-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	11	-	-	20
	Utility Solar+Storage - PV - Bridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	-	475	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	395	-	-	-	-	-	-	-	-	-	-	-	419	-	-	395	815
	Total Solar	-	-	-	-	-	1,249	-	-	-	-	359	-	-	-	475	-	-	419	-	702	1,249	3,205
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.9	-	10.9
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.9	-	10.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	-	-	-	48.8	32.1	-	90.2
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	37	37	42	41	46	43	41	41	38	35	32	31	30	26	26	25	25	24	23	405	680
	Energy Efficiency, WA	11	10	10	11	12	12	12	11	11	11	10	9	9	8	8	6	6	5	4	4	111	179
	Energy Efficiency Total	52	49	48	55	55	59	56	54	54	51	46	43	42	40	35	33	33	30	29	28	533	892
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	-	210	-	-	60	-	-	-	-	-	180	-	450
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	75	45	-	-	-	-	-	-	-	-	-	75	120
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	-	75	-	-	60	-	-	-	-	-	60	-	195
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	908	719	493	501	498	131	126	191	204	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,074	977	1,076	1,075	500	782
	FOT West - Winter	151	131	268	303	314	44	31	53	100	232	222	173	192	128	63	-	35	-	-	-	105	123
	Existing Plant Retirements/Conversions	-	(63)	(573)	(224)	(1)	(412)	-	(505)	(85)	(915)	(449)	(396)	(350)	(134)	(537)	(156)	(36)	(289)	(2,260)	(748)		
	Annual Additions, Long Term Resources	130	133	292	206	237	4,216	145	330	143	318	1,063	2,038	194	303	574	82	93	488	2,355	1,330		
	Annual Additions, Short Term Resources	1,149	850	761	806	812	175	177	244	304	1,394	1,597	1,947	1,441	1,409	1,435	1,374	1,410	1,277	1,374	1,375		
	Total Annual Additions	1,279	983	1,053	1,012	1,049	4,391	322	574	447	1,712	2,661	3,985	1,634	1,712	2,010	1,457	1,503	1,764	3,729	2,605		

Table 8.19 – Preferred Portfolio Summer Capacity Load and Resource Balance (2020-2029)

Calendar Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
East										
Thermal	5,963	5,634	5,634	5,634	5,634	5,634	5,217	5,140	4,481	4,481
Hydroelectric	74	74	74	74	74	74	74	74	74	74
Renewable	406	843	859	866	876	906	898	891	827	718
Purchases	242	215	215	215	215	115	115	115	115	115
Qualifying Facilities	891	666	665	665	617	619	621	620	610	590
Demand Response	323	323	323	323	323	323	323	323	323	323
Sales	(655)	(175)	(175)	(175)	(148)	(148)	(66)	0	0	0
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
Transfers	271	(140)	(137)	(134)	(392)	(388)	(322)	(292)	307	365
East Existing Resources	**7,481**	**7,405**	**7,423**	**7,433**	**7,163**	**7,100**	**6,826**	**6,836**	**6,703**	**6,632**
Front Office Transactions	0	0	0	0	0	0	0	0	90	309
Gas	0	0	0	0	0	0	179	179	179	179
Wind	0	0	0	15	324	339	345	342	309	255
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0
Solar+Storage	0	0	63	72	214	244	258	251	187	88
Demand Response	4	11	11	28	28	36	43	43	43	162
Other	1	1	1	1	1	1	1	1	1	1
East Planned Resources	**5**	**12**	**74**	**117**	**568**	**620**	**826**	**816**	**810**	**994**
East Total Resources	**7,486**	**7,416**	**7,498**	**7,550**	**7,731**	**7,720**	**7,652**	**7,652**	**7,512**	**7,626**
Load	7,039	7,108	7,185	7,276	7,405	7,442	7,460	7,523	7,604	7,678
Private Generation	(125)	(166)	(173)	(176)	(202)	(188)	(195)	(204)	(218)	(233)
Existing Resources:										
Interruptible	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)
Energy Efficiency	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)
New Resources:										
Energy Efficiency	(93)	(140)	(190)	(242)	(293)	(344)	(395)	(446)	(495)	(540)
East obligation	**6,592**	**6,572**	**6,593**	**6,629**	**6,681**	**6,682**	**6,641**	**6,644**	**6,663**	**6,677**
Planning Reserves (13%)	880	877	880	885	892	892	886	887	889	891
East Reserves	**880**	**877**	**880**	**885**	**892**	**892**	**886**	**887**	**889**	**891**
East Obligation + Reserves	**7,471**	**7,450**	**7,474**	**7,514**	**7,573**	**7,574**	**7,528**	**7,531**	**7,552**	**7,568**
East Position	**14**	**(34)**	**24**	**36**	**158**	**146**	**125**	**121**	**(40)**	**58**
East Reserve Margin	14%	13%	14%	14%	16%	16%	15%	15%	13%	14%
West										
Thermal	2,048	2,048	2,048	2,048	1,736	1,736	1,736	1,736	1,598	1,265
Hydroelectric	570	570	570	570	570	570	570	570	570	570
Renewable	383	379	287	289	289	298	302	300	273	240
Purchases	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	390	292	285	278	278	279	278	246	243	231
Demand Response	3	0	0	0	0	0	0	0	0	0
Sales	(165)	(161)	(110)	(110)	(80)	(80)	(80)	(80)	(80)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	(272)	139	136	133	391	387	320	291	(308)	(365)
West Existing Resources	**2,955**	**3,265**	**3,214**	**3,206**	**3,182**	**3,189**	**3,126**	**3,062**	**2,296**	**1,861**
Front Office Transactions	741	508	518	513	135	130	197	272	1,107	1,107
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Wind+Storage	0	0	0	0	0	0	0	0	0	7
Solar	0	0	0	0	0	0	0	0	0	0
Solar+Storage	0	0	0	0	253	288	305	297	221	132
Demand Response	0	0	0	0	0	0	0	0	0	9
Other	0	0	0	0	0	0	0	0	169	578
West Planned Resources	**741**	**508**	**518**	**513**	**388**	**419**	**502**	**569**	**1,497**	**1,833**
West Total Resources	**3,696**	**3,772**	**3,732**	**3,719**	**3,571**	**3,608**	**3,627**	**3,631**	**3,793**	**3,695**
Load	3,387	3,441	3,486	3,513	3,529	3,570	3,597	3,626	3,657	3,684
Private Generation	(21)	(26)	(29)	(32)	(45)	(39)	(44)	(51)	(58)	(66)
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)
New Resources:										
Energy Efficiency	(52)	(76)	(102)	(127)	(153)	(178)	(202)	(225)	(247)	(266)
West obligation	**3,285**	**3,310**	**3,325**	**3,324**	**3,301**	**3,323**	**3,321**	**3,321**	**3,323**	**3,321**
Planning Reserves (13%)	427	430	432	432	429	432	432	432	432	432
West Reserves	**427**	**430**	**432**	**432**	**429**	**432**	**432**	**432**	**432**	**432**
West Obligation + Reserves	**3,712**	**3,740**	**3,757**	**3,756**	**3,730**	**3,755**	**3,753**	**3,753**	**3,755**	**3,753**
West Position	**(15)**	**32**	**(25)**	**(37)**	**(159)**	**(147)**	**(126)**	**(122)**	**39**	**(59)**
West Reserve Margin	13%	14%	12%	12%	8%	9%	9%	9%	14%	11%
System										
Total Resources	11,182	11,189	11,229	11,269	11,302	11,327	11,279	11,283	11,305	11,320
Obligation	9,876	9,882	9,918	9,953	9,982	10,005	9,962	9,966	9,985	9,998
Reserves	1,307	1,308	1,312	1,317	1,321	1,324	1,318	1,319	1,321	1,323
Obligation + Reserves	11,183	11,190	11,231	11,270	11,303	11,328	11,281	11,284	11,306	11,321
System Position	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%

Table 8.20 – Preferred Portfolio Summer Capacity Load and Resource Balance (2030-2038)

Calendar Year	2030	2031	2032	2033	2034	2035	2036	2037	2038
East									
Thermal	4,242	4,169	4,169	3,838	3,838	3,838	3,838	2,984	2,984
Hydroelectric	74	74	74	74	74	74	74	74	74
Renewable	723	706	675	725	726	724	737	740	697
Purchases	115	115	115	115	115	115	115	115	115
Qualifying Facilities	595	599	587	555	536	536	503	125	120
Demand Response	323	323	323	323	323	323	323	323	323
Sales	0	0	0	0	0	0	0	0	0
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
Transfers	198	354	440	653	413	667	887	887	364
East Existing Resources	**6,235**	**6,306**	**6,348**	**6,248**	**5,991**	**6,242**	**6,443**	**5,213**	**4,643**
Front Office Transactions	205	179	213	307	309	309	309	309	309
Gas	179	179	179	179	179	179	179	831	831
Wind	479	508	475	527	528	526	539	553	540
Wind+Storage	0	0	24	27	27	27	27	28	28
Solar	0	0	0	0	0	0	0	0	0
Solar+Storage	163	188	154	188	184	182	186	456	392
Demand Response	170	170	182	183	183	199	203	214	349
Other	1	29	29	29	29	28	28	28	366
East Planned Resources	**1,197**	**1,254**	**1,257**	**1,439**	**1,440**	**1,450**	**1,472**	**2,419**	**2,816**
East Total Resources	**7,431**	**7,559**	**7,605**	**7,688**	**7,430**	**7,692**	**7,915**	**7,632**	**7,459**
Load	7,760	7,830	7,923	8,007	7,935	8,019	8,104	8,196	8,280
Private Generation	(249)	(264)	(281)	(316)	(227)	(261)	(295)	(330)	(374)
Existing Resources:									
Interruptible	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)
Energy Efficiency	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)
New Resources:									
Energy Efficiency	(583)	(623)	(662)	(698)	(725)	(750)	(769)	(785)	(802)
East obligation	**6,700**	**6,713**	**6,751**	**6,763**	**6,754**	**6,780**	**6,811**	**6,853**	**6,876**
Planning Reserves (13%)	894	896	901	902	901	904	909	914	917
East Reserves	**894**	**896**	**901**	**902**	**901**	**904**	**909**	**914**	**917**
East Obligation + Reserves	**7,594**	**7,609**	**7,652**	**7,665**	**7,655**	**7,684**	**7,720**	**7,767**	**7,793**
East Position	**(162)**	**(50)**	**(46)**	**22**	**(225)**	**8**	**195**	**(134)**	**(334)**
East Reserve Margin	11%	13%	13%	14%	10%	13%	16%	11%	8%
West									
Thermal	1,265	1,265	1,265	1,265	1,265	1,265	1,265	1,053	411
Hydroelectric	570	570	570	570	570	570	570	570	570
Renewable	249	259	248	266	266	265	270	275	270
Purchases	1	1	1	1	1	1	1	1	1
Qualifying Facilities	228	229	222	223	223	223	217	201	201
Demand Response	0	0	0	0	0	0	0	0	0
Sales	(78)	(78)	(78)	(78)	(78)	(78)	(24)	(24)	(24)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	(199)	(354)	(441)	(653)	(414)	(668)	(858)	(888)	(365)
West Existing Resources	**2,034**	**1,889**	**1,785**	**1,592**	**1,831**	**1,576**	**1,409**	**1,185**	**1,062**
Front Office Transactions	1,107	1,107	1,107	1,107	1,107	1,107	1,006	1,107	1,107
Gas	0	0	0	0	0	0	0	208	208
Wind	0	0	0	0	0	0	0	0	0
Wind+Storage	8	8	8	9	9	9	9	19	18
Solar	0	0	0	0	0	0	0	0	0
Solar+Storage	171	198	162	259	254	251	308	488	531
Demand Response	9	9	9	9	9	9	9	57	89
Other	578	578	690	690	690	690	690	690	916
West Planned Resources	**1,873**	**1,900**	**1,977**	**2,075**	**2,070**	**2,066**	**2,022**	**2,569**	**2,869**
West Total Resources	**3,907**	**3,790**	**3,762**	**3,666**	**3,901**	**3,642**	**3,431**	**3,754**	**3,931**
Load	3,709	3,745	3,773	3,803	3,788	3,814	3,842	3,881	3,912
Private Generation	(79)	(102)	(134)	(173)	(155)	(191)	(226)	(260)	(300)
Existing Resources:									
Interruptible	0	0	0	0	0	0	0	0	0
Energy Efficiency	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)
New Resources:									
Energy Efficiency	(285)	(303)	(320)	(335)	(349)	(363)	(376)	(387)	(399)
West obligation	**3,314**	**3,310**	**3,289**	**3,265**	**3,254**	**3,231**	**3,210**	**3,204**	**3,184**
Planning Reserves (13%)	431	430	428	424	423	420	417	417	414
West Reserves	**431**	**430**	**428**	**424**	**423**	**420**	**417**	**417**	**414**
West Obligation + Reserves	**3,745**	**3,740**	**3,717**	**3,689**	**3,677**	**3,651**	**3,627**	**3,621**	**3,598**
West Position	**161**	**49**	**46**	**(23)**	**224**	**(8)**	**(196)**	**133**	**333**
West Reserve Margin	18%	14%	14%	12%	20%	13%	7%	17%	23%
System									
Total Resources	11,338	11,349	11,368	11,354	11,331	11,334	11,346	11,386	11,390
Obligation	10,014	10,024	10,040	10,028	10,008	10,011	10,021	10,057	10,060
Reserves	1,325	1,326	1,328	1,327	1,324	1,324	1,326	1,330	1,331
Obligation + Reserves	11,339	11,350	11,368	11,355	11,332	11,335	11,347	11,387	11,391
System Position	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%

Table 8.21 – Preferred Portfolio Winter Capacity Load and Resource Balance (2020-2029)

Calendar Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
East										
Thermal	6,020	5,692	5,692	5,692	5,692	5,692	5,275	5,199	4,545	4,545
Hydroelectric	54	54	54	54	54	54	54	54	54	54
Renewable	992	1,536	1,594	1,579	1,020	1,020	1,010	1,009	1,010	1,001
Purchases	727	228	228	228	115	115	115	115	115	115
Qualifying Facilities	672	460	465	413	335	333	334	334	333	326
Demand Response	0	0	0	0	0	0	0	0	0	0
Sales	(173)	(173)	(173)	(173)	(148)	(148)	(66)	(52)	0	(77)
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
Transfers	(159)	(154)	(151)	(146)	(400)	(394)	(391)	(390)	(440)	(325)
East Existing Resources	**8,100**	**7,608**	**7,675**	**7,611**	**6,632**	**6,637**	**6,295**	**6,235**	**5,582**	**5,606**
Front Office Transactions	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	180	180	180	180
Wind	0	0	0	24	681	681	684	684	684	678
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0
Solar+Storage	0	0	39	35	61	61	64	64	64	68
Demand Response	0	0	0	0	0	0	0	0	0	0
Other	1	1	1	1	1	1	1	1	1	1
East Planned Resources	**1**	**1**	**40**	**60**	**743**	**743**	**929**	**929**	**929**	**927**
East Total Resources	**8,101**	**7,609**	**7,715**	**7,671**	**7,375**	**7,379**	**7,224**	**7,164**	**6,511**	**6,532**
Load	5,629	5,680	5,743	5,807	5,855	5,921	5,847	5,889	5,939	5,993
Private Generation	(1)	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(5)	(5)
Existing Resources:										
Interruptible	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)
Energy Efficiency	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
New Resources:										
Energy Efficiency	(79)	(119)	(161)	(205)	(249)	(293)	(337)	(381)	(424)	(463)
East obligation	**5,344**	**5,355**	**5,376**	**5,396**	**5,399**	**5,420**	**5,301**	**5,298**	**5,305**	**5,319**
Planning Reserves (13%)	718	719	722	724	725	728	712	712	713	714
East Reserves	**718**	**719**	**722**	**724**	**725**	**728**	**712**	**712**	**713**	**714**
East Obligation + Reserves	**6,062**	**6,074**	**6,098**	**6,120**	**6,123**	**6,148**	**6,014**	**6,010**	**6,018**	**6,033**
East Position	**2,039**	**1,535**	**1,617**	**1,551**	**1,252**	**1,232**	**1,211**	**1,154**	**493**	**499**
East Reserve Margin	52%	42%	44%	42%	37%	36%	36%	35%	23%	23%
West										
Thermal	2,040	2,040	2,040	2,040	1,728	1,728	1,728	1,728	1,590	1,258
Hydroelectric	670	670	670	670	670	670	670	670	670	670
Renewable	672	351	232	230	137	137	138	138	137	136
Purchases	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	142	102	93	88	75	75	72	45	45	33
Demand Response	0	0	0	0	0	0	0	0	0	0
Sales	(154)	(154)	(113)	(113)	(81)	(81)	(81)	(81)	(81)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	157	153	149	146	399	393	390	389	439	324
West Existing Resources	**3,526**	**3,161**	**3,071**	**3,059**	**2,926**	**2,920**	**2,915**	**2,888**	**2,799**	**2,342**
Front Office Transactions	135	277	312	323	46	52	54	103	239	256
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Wind+Storage	0	0	0	0	0	0	0	0	0	4
Solar	0	0	0	0	0	0	0	0	0	0
Solar+Storage	0	0	0	0	59	59	62	62	62	87
Demand Response	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	180	615
West Planned Resources	**135**	**277**	**312**	**323**	**104**	**111**	**116**	**164**	**481**	**962**
West Total Resources	**3,661**	**3,438**	**3,383**	**3,382**	**3,030**	**3,031**	**3,031**	**3,052**	**3,279**	**3,303**
Load	3,416	3,458	3,499	3,529	3,550	3,576	3,605	3,640	3,672	3,706
Private Generation	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(2)	(2)
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
New Resources:										
Energy Efficiency	(61)	(90)	(121)	(153)	(185)	(216)	(246)	(275)	(303)	(328)
West obligation	**3,327**	**3,340**	**3,350**	**3,347**	**3,335**	**3,331**	**3,329**	**3,335**	**3,340**	**3,347**
Planning Reserves (13%)	432	434	435	435	434	433	433	434	434	435
West Reserves	**432**	**434**	**435**	**435**	**434**	**433**	**433**	**434**	**434**	**435**
West Obligation + Reserves	**3,759**	**3,774**	**3,785**	**3,782**	**3,769**	**3,764**	**3,762**	**3,769**	**3,774**	**3,783**
West Position	(98)	(337)	(402)	(400)	(739)	(733)	(732)	(717)	(494)	(479)
West Reserve Margin	10%	3%	1%	1%	(9%)	(9%)	(9%)	(8%)	(2%)	(1%)
System										
Total Resources	11,762	11,047	11,098	11,053	10,406	10,411	10,255	10,216	9,791	9,836
Obligation	8,671	8,695	8,725	8,743	8,734	8,751	8,631	8,634	8,645	8,666
Reserves	1,150	1,153	1,157	1,160	1,158	1,161	1,145	1,145	1,147	1,150
Obligation + Reserves	9,821	9,848	9,883	9,902	9,892	9,912	9,776	9,779	9,792	9,815
System Position	1,941	1,198	1,215	1,151	513	499	479	437	(1)	20
Reserve Margin	36%	27%	27%	26%	19%	19%	19%	18%	13%	13%

Table 8.22 – Preferred Portfolio Winter Capacity Load and Resource Balance (2030-2038)

Calendar Year	2030	2031	2032	2033	2034	2035	2036	2037	2038
East									
Thermal	4,311	4,239	4,239	3,908	3,908	3,908	3,908	3,054	3,054
Hydroelectric	54	54	54	54	54	54	54	54	54
Renewable	942	891	846	1,015	1,036	1,039	1,045	1,099	1,073
Purchases	115	115	115	115	115	115	115	115	115
Qualifying Facilities	325	326	310	284	251	251	222	26	26
Demand Response	0	0	0	0	0	0	0	0	0
Sales	(77)	0	0	0	0	0	0	0	0
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
Transfers	(395)	(490)	(451)	(306)	(150)	(307)	(359)	82	(278)
East Existing Resources	**5,241**	**5,100**	**5,078**	**5,035**	**5,180**	**5,026**	**4,950**	**4,395**	**4,009**
Front Office Transactions	0	0	0	0	0	0	0	0	0
Gas	180	180	180	180	180	180	180	881	881
Wind	947	953	898	1,105	1,131	1,135	1,142	1,213	1,219
Wind+Storage	0	0	28	35	35	36	36	38	38
Solar	0	0	0	0	0	0	0	0	0
Solar+Storage	79	79	67	108	112	113	111	254	228
Demand Response	0	0	0	0	0	0	0	0	0
Other	1	31	31	31	31	30	30	30	390
East Planned Resources	**1,207**	**1,243**	**1,204**	**1,459**	**1,490**	**1,493**	**1,498**	**2,416**	**2,756**
East Total Resources	**6,449**	**6,343**	**6,282**	**6,494**	**6,670**	**6,519**	**6,449**	**6,811**	**6,765**
Load	6,023	6,074	6,113	6,180	6,232	6,287	6,320	6,380	6,431
Private Generation	(6)	(7)	(8)	(9)	(10)	(12)	(14)	(15)	(17)
Existing Resources:									
Interruptible	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)
Energy Efficiency	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
New Resources:									
Energy Efficiency	(502)	(537)	(572)	(604)	(628)	(650)	(668)	(683)	(698)
East obligation	**5,310**	**5,324**	**5,328**	**5,362**	**5,389**	**5,420**	**5,434**	**5,477**	**5,510**
Planning Reserves (13%)	713	715	716	720	724	728	729	735	739
East Reserves	**713**	**715**	**716**	**720**	**724**	**728**	**729**	**735**	**739**
East Obligation + Reserves	**6,023**	**6,040**	**6,044**	**6,083**	**6,113**	**6,147**	**6,163**	**6,212**	**6,249**
East Position	**425**	**303**	**238**	**412**	**558**	**372**	**286**	**599**	**516**
East Reserve Margin	21%	19%	18%	21%	24%	20%	19%	24%	23%
West									
Thermal	1,258	1,258	1,258	1,258	1,258	1,258	1,258	1,034	392
Hydroelectric	670	670	670	670	670	670	670	670	670
Renewable	135	135	128	155	159	159	160	169	170
Purchases	1	1	1	1	1	1	1	1	1
Qualifying Facilities	33	33	27	29	29	29	25	24	24
Demand Response	0	0	0	0	0	0	0	0	0
Sales	(78)	(78)	(78)	(78)	(78)	(78)	(78)	(78)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	394	488	450	305	148	305	358	(83)	277
West Existing Resources	**2,410**	**2,505**	**2,453**	**2,337**	**2,184**	**2,341**	**2,392**	**1,735**	**1,454**
Front Office Transactions	255	284	302	197	216	257	279	353	457
Gas	0	0	0	0	0	0	0	215	215
Wind	0	0	0	0	0	0	0	0	0
Wind+Storage	4	4	4	5	5	5	5	11	11
Solar	0	0	0	0	0	0	0	0	0
Solar+Storage	69	68	58	120	125	126	145	209	247
Demand Response	0	0	0	0	0	0	0	0	0
Other	615	615	735	735	735	735	735	735	975
West Planned Resources	**943**	**971**	**1,098**	**1,058**	**1,081**	**1,123**	**1,164**	**1,524**	**1,906**
West Total Resources	**3,353**	**3,476**	**3,551**	**3,395**	**3,264**	**3,464**	**3,555**	**3,259**	**3,360**
Load	3,727	3,751	3,782	3,816	3,849	3,880	3,902	3,933	3,967
Private Generation	(2)	(3)	(3)	(4)	(4)	(5)	(7)	(8)	(11)
Existing Resources:									
Interruptible	0	0	0	0	0	0	0	0	0
Energy Efficiency	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
New Resources:									
Energy Efficiency	(352)	(374)	(396)	(415)	(433)	(450)	(467)	(482)	(497)
West obligation	**3,345**	**3,346**	**3,355**	**3,369**	**3,384**	**3,396**	**3,400**	**3,415**	**3,431**
Planning Reserves (13%)	435	435	436	438	440	441	442	444	446
West Reserves	**435**	**435**	**436**	**438**	**440**	**441**	**442**	**444**	**446**
West Obligation + Reserves	**3,780**	**3,781**	**3,791**	**3,808**	**3,824**	**3,838**	**3,842**	**3,859**	**3,877**
West Position	**(426)**	**(305)**	**(239)**	**(413)**	**(559)**	**(373)**	**(287)**	**(600)**	**(517)**
West Reserve Margin	0%	4%	6%	1%	(4%)	2%	5%	(5%)	(2%)
System									
Total Resources	9,802	9,819	9,834	9,889	9,935	9,984	10,004	10,070	10,125
Obligation	8,655	8,670	8,683	8,732	8,773	8,816	8,834	8,892	8,941
Reserves	1,148	1,150	1,152	1,158	1,163	1,169	1,171	1,179	1,185
Obligation + Reserves	9,803	9,820	9,835	9,890	9,936	9,985	10,005	10,071	10,126
System Position	(1)	(2)	(1)	(1)	(2)	(1)	(1)	(1)	(1)
Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%

Additional Sensitivity Analysis

In addition to the resource portfolios developed and studied as part of the portfolio-development process that supports selection of the preferred portfolio, a number of additional sensitivity cases were completed to better understand how certain modeling assumptions influence the resource mix and timing of future resource additions. These sensitivity cases are useful in understanding how PacifiCorp's resource plan would be affected by changes to uncertain planning assumptions and to address how alternative resources and planning paradigms affect system costs and risk.

Table 8.23 lists additional sensitivity studies performed for the 2019 IRP. To isolate the impact of a given planning assumption, all sensitivity cases are compared to the preferred portfolio, case P-45CNW.

Table 8.23 – Summary of Additional Sensitivity Cases

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Customer Preference Target	First Year of New Thermal
S-01	Low Load	P-45CNW	20,617	Low	Base	Base	Base	Base	2030
S-02	High Load	P-45CNW	22,602	High	Base	Base	Base	Base	2026
S-03	1 in 20 Load Growth	P-45CNW	21,634	1 in 20	Base	Base	Base	Base	2026
S-04	Low Private Generation	P-45CNW	21,758	Base	Low	Base	Base	Base	2029
S-05	High Private Generation	P-45CNW	21,371	Base	High	Base	Base	Base	2030
S-06	Business Plan	P-45CNW	21,695	Base	Base	Base	Base	Base	2028
S-07	No Customer Preference	P-45CNW	21,609	Base	Base	Base	Base	None	2030
S-08	All Customer Preference	P-45CNW	21,636	Base	Base	Base	Base	High	2030

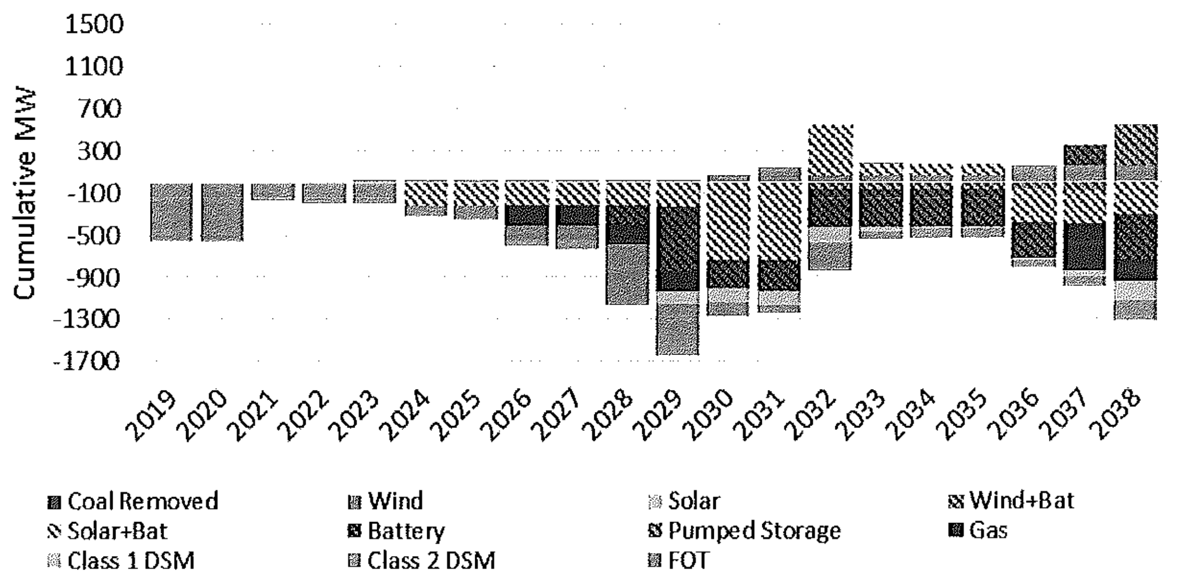
Low Load Growth Sensitivity (S-01)

Table 8.24 shows the PVRR impacts of the S-01 sensitivity relative to P-45CNW. The reduced loads lower system costs significantly over the 20-year study period. Figure 8.46 summarizes portfolio impacts. FOTs are reduced by an average of 275 MW from 2019 to 2024, and by an average of 129 MW from 2025 to 2027, followed thereafter by an average of 103 MW less per year. Over the full portfolio, cumulative wind is higher by 162 MW, offset by a decrease of 346 MW of wind with battery, solar with battery and standalone battery. Renewable and storage resources are reduced by 184 MW by the end of the study period, gas peakers are 221 MW less and DSM decreases by 251 MW.

Table 8.24 – Stochastic Mean PVRR (Benefit)/Cost of S-01 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	S-01	(Benefit) / Cost Relative to P-45CNW
$23,207	$22,080	($1,127)

Figure 8.46 – Increase/(Decrease) in Nameplate Capacity of S-01 Relative to Case P-45CNW



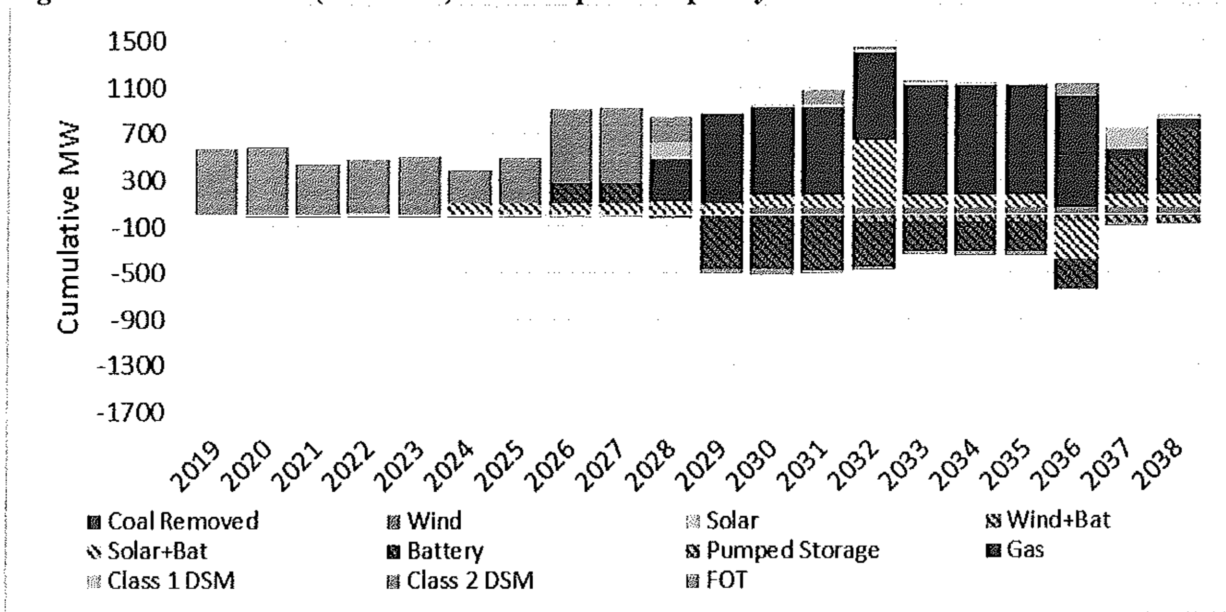
High Load Growth Sensitivity (S-02)

Table 8.25 shows the PVRR impacts of the S-02 sensitivity relative to P-45CNW. Higher loads result in significantly increased resource requirements which translate into higher system costs. Figure 8.47 summarizes the resource portfolio impacts. Annual FOTs increase by an average of 472 MW through 2024 and 556 MW from 2025 to 2027, followed by 35 MW thereafter. Renewable and storage resources increase by 670 MW by the end of the study period. An additional 953 MW of natural gas peaking capacity is shifted earlier, split between 2028, 2029 and 2033 instead of 370 MW of gas peaker and 505 MW of Gas CCCT in 2037, for a net increase of 78 MW. DSM increases by 23 MW by the end of the study period.

Table 8.25 – Stochastic Mean PVRR (Benefit)/Cost of S-02 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	S-02	(Benefit) / Cost Relative to P-45CNW
$23,207	$24,346	$1,139

Figure 8.47 – Increase/(Decrease) in Nameplate Capacity of S-02 Relative to Case P-45CNW



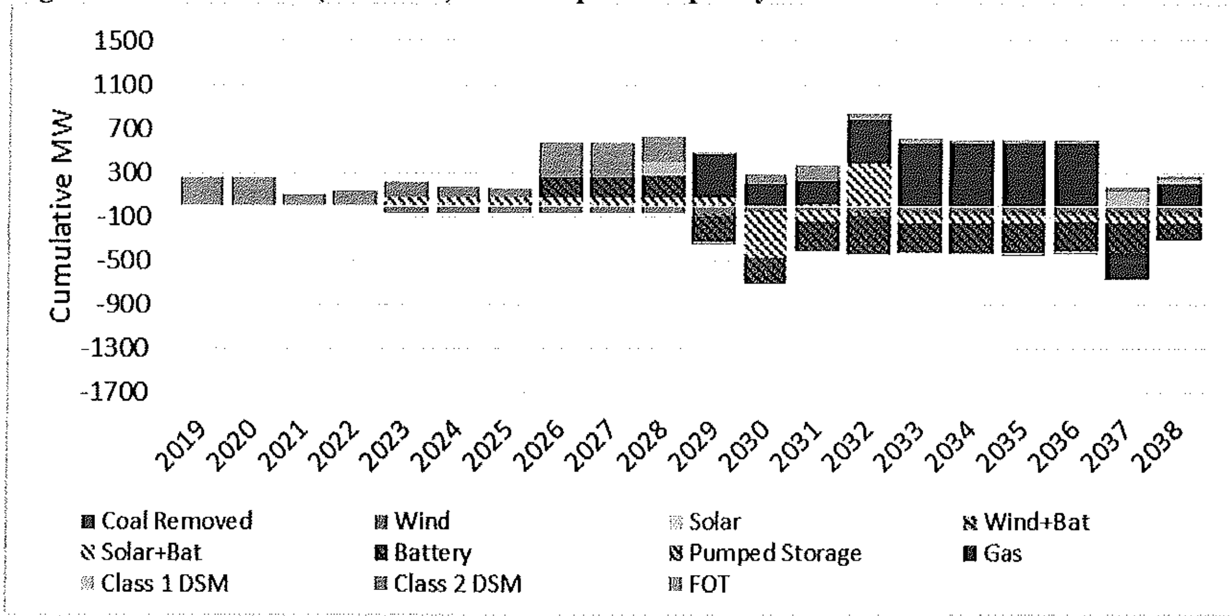
1-in-20 Load Growth Sensitivity (S-03)

Table 8.26 shows the PVRR impacts of the S-03 sensitivity relative to P-45CNW. This sensitivity assumes 1-in-20 extreme weather conditions during the summer (July) for each state. System costs are higher due to requirements to meet additional peak load. Figure 8.48 summarizes resource portfolio impacts. Higher peak loads require more annual FOTs, 158 MW greater on average from 2019-2024, 220 MW more 2025-2027 and 36 MW thereafter. Renewables and storage are decreased by 304 MW, offset by an increase of 210 MW in gas peakers and a 62 MW increase in DSM by the end of the study period.

Table 8.26 – Stochastic Mean PVRR (Benefit)/Cost of S-03 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	S-03	(Benefit) / Cost Relative to P-45CNW
$23,207	$23,388	$181

Figure 8.48 – Increase/(Decrease) in Nameplate Capacity of S-03 Relative to Case P-45CNW



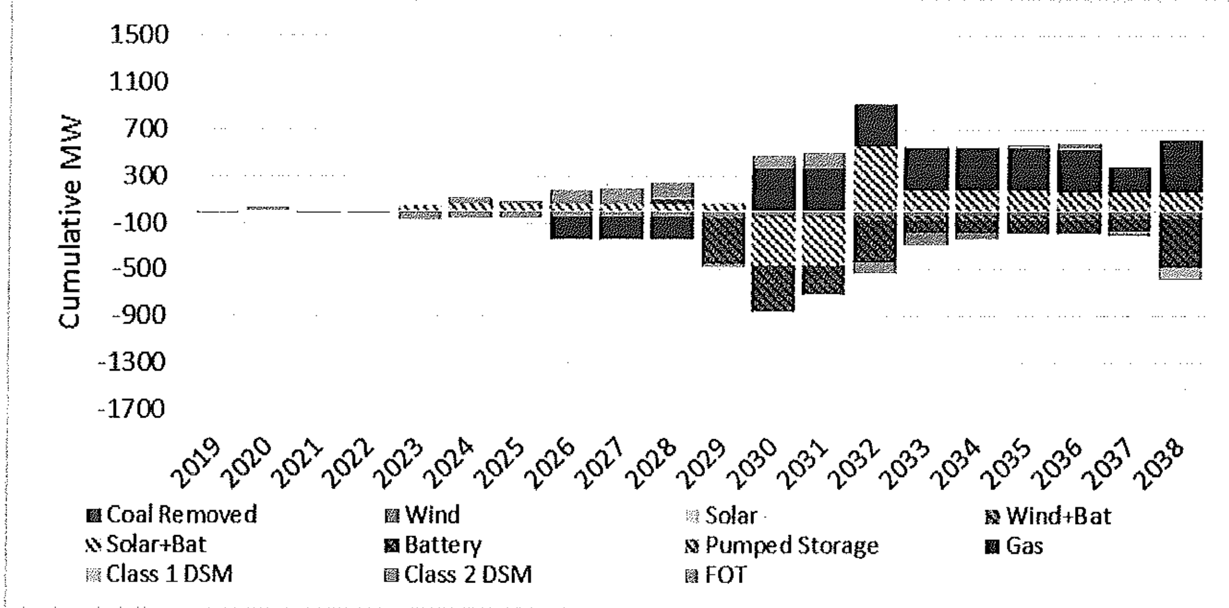
Low Private Generation Sensitivity (S-04)

Table 8.27 shows the PVRR impacts of the S-04 sensitivity relative to P-45CNW. The lower private generation assumption result in higher net loads, increasing system costs. Figure 8.49 summarizes portfolio impacts. Annual average FOTs increase by 6 MW from 2019-2024 and then 98 MW from 2025-2027, leveling out to 17 MW higher on average thereafter. Renewables and storage decrease by 305 MW over the long-term, along with 114 MW less DSM, which are offset by an increase of 443 MW in gas peakers.

Table 8.27 – Stochastic Mean PVRR (Benefit)/Cost of S-04 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	S-04	(Benefit) / Cost Relative to P-45CNW
$23,207	$23,308	$101

Figure 8.49 – Increase/(Decrease) in Nameplate Capacity of S-04 Relative to Case P-45CNW



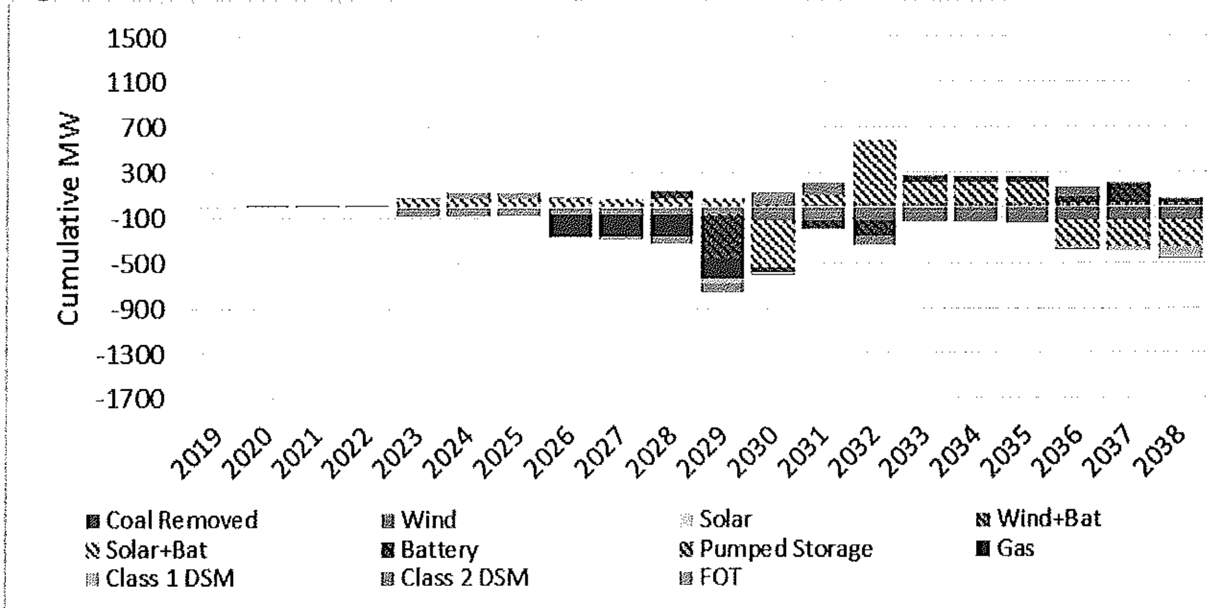
High Private Generation Sensitivity (S-05)

Table 8.28 shows the PVRR impacts of the S-05 sensitivity relative to P-45CNW. The higher private generation assumptions decrease net load, which in turn decreases system costs. Figure 8.50 summarizes portfolio impacts, which are minor for FOTs and natural gas over the long-term. There is 300 MW less renewable capacity and 92 MW less DSM.

Table 8.28 – Stochastic Mean PVRR (Benefit)/Cost of S-05 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	S-05	(Benefit) / Cost Relative to P-45CNW
$23,207	$22,970	($238)

Figure 8.50 – Increase/(Decrease) in Nameplate Capacity of S-05 Relative to Case P-45CNW



Business Plan Sensitivity (S-06)

Table 8.29 shows the PVRR impacts of the S-06 sensitivity relative to P-45CNW. System costs increase by $72m when studied in SO and $831m when analyzed using PaR. This sensitivity complies with Utah requirements to perform a business plan sensitivity consistent with the Public Service Commission of Utah's order in Docket No. 15-035-04, summarized as follows:

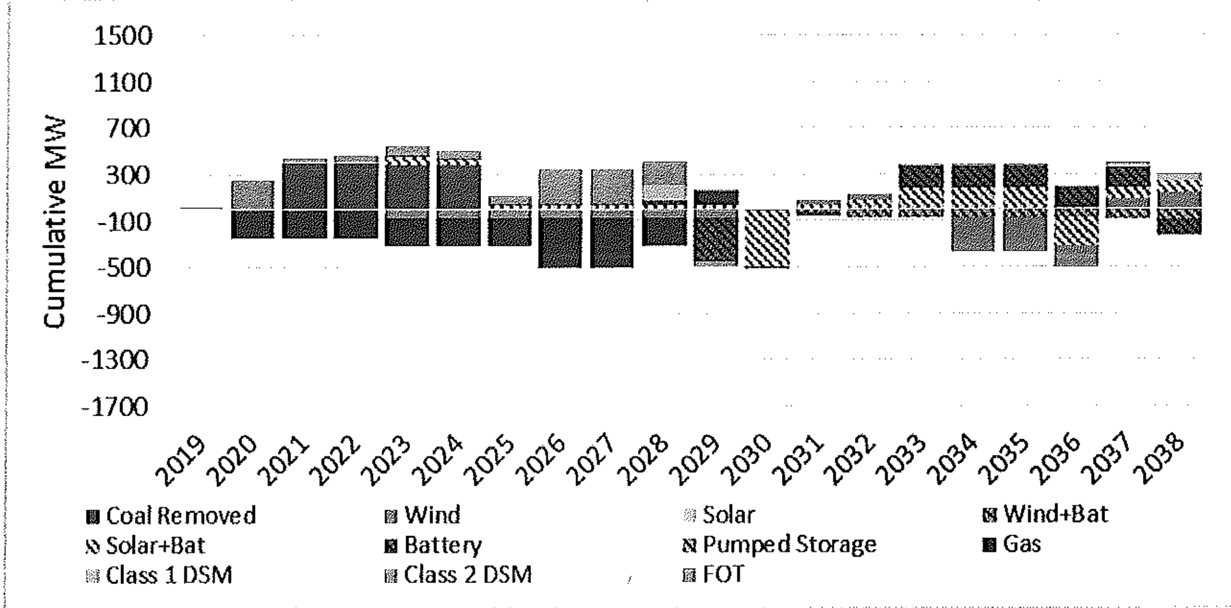
- Over the first three years, resources align with those assumed in PacifiCorp's December 2018 Business Plan.
- Beyond the first three years of the study period, unit retirement assumptions are aligned with the preferred portfolio.
- All other resources are optimized.

Figure 8.51 summarizes resource portfolio impacts, showing differences associated with the preferred portfolio's assumptions of Naughton Unit 3's gas conversion and Cholla Unit 4's 2020 retirement. These are coupled with an average annual increase of 77 MW FOTs 2019-2024, 207 MW higher average annual FOTs 2025-2027 and then 51 MW less FOTs thereafter. There is a difference in the timing of new renewable resources and storage, which net 23 MW higher through the longer term. DSM increases by 57 MW.

Table 8.29 – Stochastic Mean PVRR (Benefit)/Cost of S-06 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	S-06	(Benefit) / Cost Relative to P-45CNW
$23,207	$24,038	$831

Figure 8.51 – Increase/(Decrease) in Nameplate Capacity of S-06 Relative to Case P-45CNW



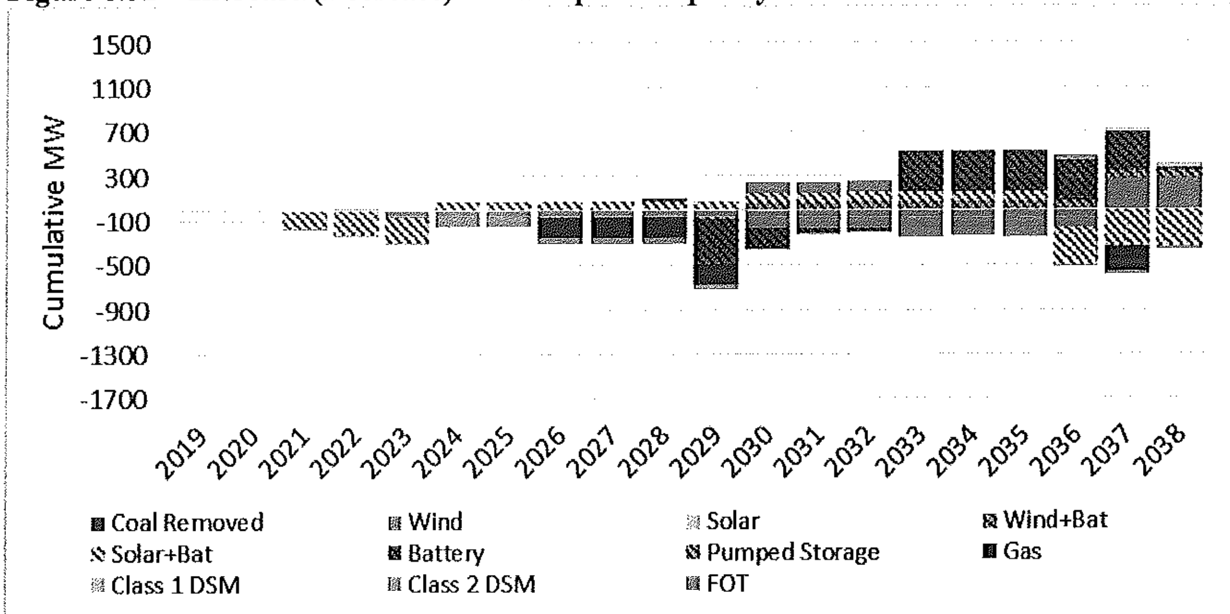
No Customer Preference Sensitivity (S-07)

Table 8.30 shows the PVRR impacts of the S-07 sensitivity relative to P-45CNW. The no customer preference sensitivity reflects no renewable resources specifically assigned to customer preference, compared to base renewable resource proxy options. Figure 8.52 summarizes portfolio impacts, which are zero for FOTs until 2024, when FOTs are 77 MW less, followed by an annual FOT average decrease of 55 MW 2025-2027 and an average annual increase of 3 MW thereafter. There is a 30 MW increase in renewable and storage capacity and 32 MW more DSM. Gas peaking resources are postponed and net to zero.

Table 8.30 – Stochastic Mean PVRR (Benefit)/Cost of S-07 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	S-07	(Benefit) / Cost Relative to P-45CNW
$23,207	$23,126	($81)

Figure 8.52 – Increase/(Decrease) in Nameplate Capacity of S-07 Relative to Case P-45CNW



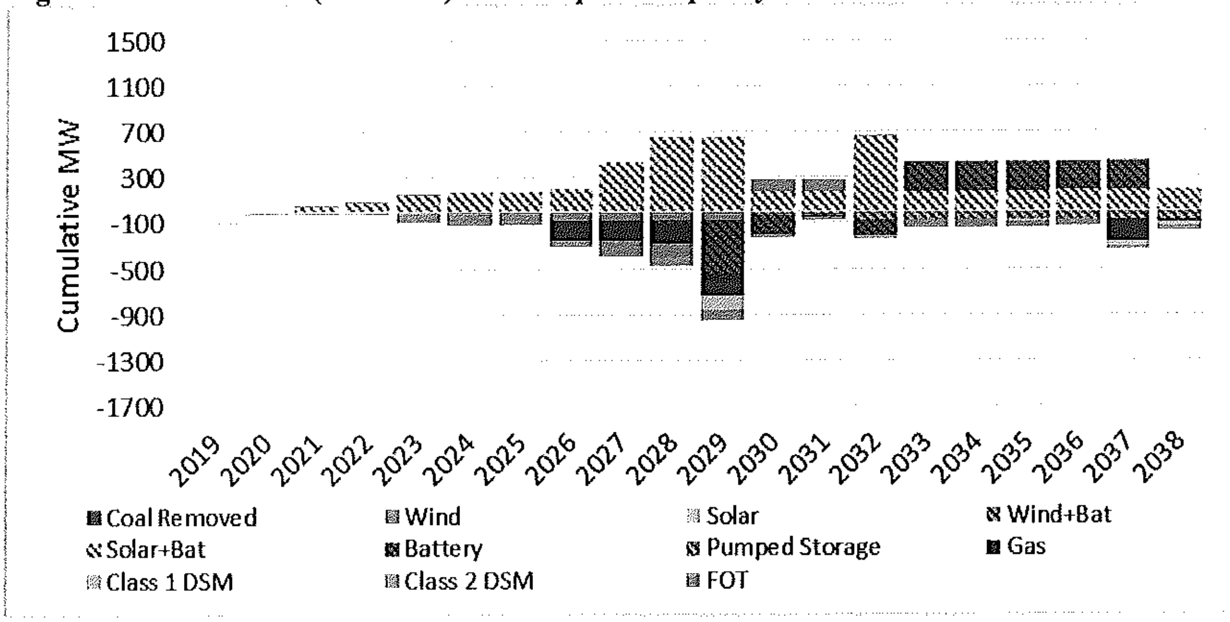
High Customer Preference Sensitivity (S-08)

Table 8.31 shows the PVRR impacts of the S-08 sensitivity relative to P-45CNW. The high customer preference sensitivity reflects a wider range of renewable resources assigned to customer preference, compared to base renewable resource proxy options. Figure 8.53 summarizes portfolio impacts, which are zero for natural gas over the long term, delaying peakers. The annual average FOTs are zero until a 2024 decrease of 20 MW followed by 51 MW less on average 2025-2027, and 12 MW less on average thereafter. Renewable resources and storage increase by 80 MW, slightly offset by a decrease of 62 MW DSM.

Table 8.31 – PVRR (Benefit)/Cost of S-08 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	S-08	(Benefit) / Cost Relative to P-45CNW
$23,207	$23,186	($22)

Figure 8.53 – Increase/(Decrease) in Nameplate Capacity of S-08 Relative to Case P-45CNW



Ex. AA-S-5

CHAPTER 9 – ACTION PLAN

CHAPTER HIGHLIGHTS

- The 2019 Integrated Resource Plan (IRP) action plan identifies steps that PacifiCorp will take over the next two-to-four years to deliver resources in the preferred portfolio.
- PacifiCorp's 2019 IRP action plan includes action items for existing resources, new resources, transmission, demand-side management (DSM) resources, short-term firm market purchases (front office transactions or FOTs), and the purchase and sale of renewable energy credits (RECs).
- The 2019 IRP acquisition path analysis provides insight on how changes in the planning environment might influence future resource procurement activities. Key uncertainties addressed in the acquisition path analysis include load, distributed generation, carbon dioxide (CO_2) emission polices, Regional Haze outcomes, and availability of purchases from the market.
- PacifiCorp further discusses how it can mitigate procurement delay risk, summarizes planned procurement activities tied to the action plan, assesses trade-offs between owning or purchasing third-party power, discusses its hedging practices, and identifies the types of risks borne by customers and the types of risks borne by shareholders.

Introduction

PacifiCorp's 2019 IRP action plan identifies the steps the company will take over the next two-to-four years to deliver its preferred portfolio, with a focus on the front ten years of the planning horizon. Associated with the action plan is an acquisition path analysis that anticipates potential major regulatory actions and other trigger events during the action plan time frame that could materially impact resource acquisition strategies.

Resources included in the 2019 IRP preferred portfolio help define the actions included in the action plan, focusing on the size, timing, type, and amount of resources needed to meet load obligations, and current and potential future state regulatory requirements.

The 2019 IRP action plan is based on the latest and most accurate information available at the time portfolios are being developed and analyzed on cost and risk metrics. PacifiCorp recognizes that the preferred portfolio, upon which the action plan is based, is developed in an uncertain planning environment and that resource acquisition strategies need to be regularly evaluated as planning assumptions change.

Resource information used in the 2019 IRP, such as capital and operating costs, are based upon recent cost-and-performance data. However, it is important to recognize that the resources identified in the plan are proxy resources, which act as a guide for resource procurement and not as a commitment. Resources evaluated as part of procurement initiatives may vary from the proxy resources identified in the plan with respect to resource type, timing, size, cost and location. PacifiCorp recognizes the need to support and justify resource acquisitions consistent with then-current laws, regulatory rules and commission orders.

In addition to presenting the 2019 IRP action plan, reporting on progress in delivering the prior action plan, and presenting the 2019 IRP acquisition path analysis, Chapter 9 covers the following resource procurement topics:

- Procurement delays;
- IRP action plan linkage to the business plan;
- Resource procurement strategy;
- Assessment of owning assets vs. purchasing power;
- Managing carbon risk for existing plants;
- Purpose of hedging; and
- Treatment of customer and investor risks.

The 2019 IRP Action Plan

The 2019 IRP action plan identifies specific actions PacifiCorp will take over the next two to four years to deliver its preferred portfolio. Action items are based on the type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2019 IRP public-input process. Table 9.1 details specific 2019 IRP action items by resource category.

Table 9.1 – 2019 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	**Naughton Unit 3:** • PacifiCorp will complete the gas conversion of Naughton Unit 3, including completion of all required regulatory notices and filings, in 2020. Initiate procurement of materials in Q4 2019. Conversion completed in 2020.
1b	**Cholla Unit 4:** • PacifiCorp will initiate the process of retiring Cholla Unit 4, including all required regulatory notices and filings, as soon as practicable, but will remove Cholla Unit 4 from service no later than January 2023 and earlier if possible. • PacifiCorp will continue to coordinate with the plant operator to transition employees, develop plans to cease plant operations, safely remove the unit from service, finalize decommissioning plans and confirm joint-ownership obligations; complete required regulatory notices and filings; administer termination, amendment, or close-out of existing permits, contracts and other agreements; and coordinate with state and local stakeholders as appropriate. • By the end of Q1 2020, the plant operator will be requested to develop plans to cease plant operations, safely remove the unit from service, finalize decommissioning plans, and confirm joint-ownership obligations. • By the end of Q2 2020, the plant operator will be requested to file required transmission interconnection and transmission services unit retirement notices/request for study. • By the end of Q4 2020, PacifiCorp will finalize an employee transition agreement with the plant operator.
1c	**Jim Bridger Unit 1:** • PacifiCorp will initiate the process of retiring Jim Bridger Unit 1 by the end of December 2023, including completion of all required regulatory notices and filings. By the end of Q2 2020, file a request with PacifiCorp transmission to study the year-end 2023 retirement of Jim Bridger Unit 1. By the end of Q2 2021, confirm transmission system reliability assessment and year-end 2023 retirement economics in 2021 IRP filing. • By the end of Q2 2021, finalize an employee transition plan. • By the end of Q2 2021, develop a community action plan in coordination with community leaders. • By the end of Q4 2021, initiate the process with the Wyoming Public Service Commission for approval of a reverse request for proposals for a potential sale of Jim Bridger Unit 1.

	• By the end of Q4 2023, administer termination, amendment, or close-out of existing permits, contracts, and other agreements.
1d	**<u>Naughton Units 1-2:</u>** • PacifiCorp will initiate the process of retiring Naughton Units 1-2 by the end of December 2025, including completion of all required regulatory notices and filings. By the end of Q2 2022, file a request with PacifiCorp transmission to study the year-end 2025 retirement of Naughton Units 1 and 2. • By the end of Q2 2022, finalize an employee transition plan. • By the end of Q2 2022, develop a community action plan in coordination with community leaders. • By the end of Q2 2023, confirm transmission system reliability assessment and year-end 2025 retirement economics in 2023 IRP filing. • By the end of Q4 2023, initiate the process with the Wyoming Public Service Commission for approval of a reverse request for proposals for a potential sale of Naughton Units 1 and 2. • By the end of Q4 2023, administer termination, amendment, or close-out of existing permits, contracts, and other agreements.
1e	**<u>Craig Unit 1:</u>** • The plant operator will be requested to administer termination, amendment, or close-out of existing permits, contracts, and other agreements to support retiring Craig Unit 1, including completion of all required regulatory notices and filings, by the end of December 2025.
Action Item	**2. New Resource Actions**
2a	**<u>Customer Preference Request for Proposals:</u>** • PacifiCorp will work with customers to achieve their respective resource preference requirements. By the end of Q4 2019, sign a fifteen year 80 megawatt (MW) Power Purchase Agreement (PPA) for Utah solar for six Utah Schedule 34 customers. By the end of Q4 2019, sign two 20-year PPAs of approximately 80 MW for a large Utah Schedule 34 customer. Monitor the finalization of rules by the Public Service Commission of Utah for House Bill (HB) 411 (anticipated by the end of Q1 2020), that provides a path forward for development of a program for participating communities to begin procuring renewable resources.
2b	**<u>All Source Request for Proposals:</u>** • PacifiCorp will issue an all-source request for proposals (RFP) to procure resources that can achieve commercial operations by the end of December 2023. • By the end of Q4 2019, file a request for interconnection queue reform with the Federal Energy Regulatory Commission (FERC) and make state filings to initiate the process of identifying an independent evaluator. • In Q1 2020, file a draft all-source RFP with the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, as applicable.

Action Item	3. Transmission Action Items
	• In Q2 2020, receive approval from FERC to reform the interconnection queue. • In Q2 2020, receive approval of the all-source RFP from applicable state regulatory commissions and issue the RFP to the market. • In Q3 2020, identify a preliminary final shortlist from the all-source RFP and initiate transmission interconnection studies consistent with queue reform as approved by FERC. • In Q2 2021, identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon, file, certificate of public convenience and necessity (CPCN) applications, as applicable. • By Q2 2022 execute definitive agreements with winning bids from the all-source RFP. • By Q4 2023, winning bids from the all-source RFP achieve commercial operation.
3a	**Energy Gateway South:** • By December 31, 2023, PacifiCorp will seek to build the approximately 400-mile, 500-kilovolt (kV) transmission line from the Aeolus substation near Medicine Bow, Wyoming to the Clover substation near Mona, Utah. • By Q2 2021, receive the final CPCN from the Wyoming Public Service Commission and the Public Service Commission of Utah (initial filing dates for the CPCN to be determined after stakeholder engagement). • By the end of Q4 2021, issue full notice to proceed to construct Energy Gateway South. • In Q4 2023, construction of Energy Gateway South is completed and placed in service.
3b	**Utah Valley Reinforcements:** • Utah Valley Reinforcements: As necessary to facilitate interconnection of customer-preference resources, PacifiCorp will proceed with system reinforcements in the Utah Valley. • In Q2 2020, complete the Spanish Fork 345 kV/138 kV transformer upgrade. • In Q4 2020, complete rebuild of approximately five miles of the Spanish Fork-Timp138 kV line in the Utah Valley.
3c	**Northern Utah Reinforcements:** • Rebuild two miles of the Morton Court –Fifth West 138 kV line. • Loop existing Populus Terminal 345 kV line into both Bridger and Ben Lomond; build 345 kV yard with 345/138 transformer and 138 kV yard buildout at Bridger plus ancillary 345 kV and 230 kV circuit breakers at Ben Lomond. • Complete identified plan of service supporting 2019 IRP preferred portfolio for resource additions in northern Utah.
3d	**Utah South Reinforcements:**

	• Develop plan of service in support of 2019 IRP preferred portfolio for resource additions in southern Utah. • Complete rebuild of the Mona –Clover #1 & #2 345 kV lines. • Identify route and terminals for new approximately 70-mile 345 kV line in southern/central Utah. • Yakima Washington Reinforcements: To facilitate interconnection of preferred portfolio resources in the Yakima area, PacifiCorp will proceed with protection system and remedial action scheme upgrades to local 230 kV and 115 kV substations not otherwise included in network upgrade requirements for generator interconnection requests. • In Q2 2020, complete the Vantage-Pomona Heights 230 kV line (in process). • By Q2 2022, establish the type and location of new resources and finalize project scope, as necessary.
3e	**<u>Yakima Washington Reinforcements:</u>** • To facilitate interconnection of preferred portfolio resources in the Yakima area, PacifiCorp will proceed with protection system and remedial action scheme upgrades to local 230 kV and 115 kV substations not otherwise included in network upgrade requirements for generator interconnection requests. • In Q2 2020, complete the Vantage-Pomona Heights 230 kV line (in process). • By Q2 2022, establish the type and location of new resources and finalize project scope, as necessary.
3f	**<u>Boardman to Hemmingway:</u>** • Continue to support the project under the conditions of the Boardman to Hemingway Transmission Project (B2H) Joint Permit Funding Agreement. • Continue to participate in the development and negotiations of the construction agreement. • Continue analysis in efforts to identify customer benefits that may include contributions to reliability, interconnection of additional resources, geographical diversity of intermittent resources, Energy Imbalance Market, and resource adequacy. • Continue negotiations for plan of service post B2H for parties to the permitting agreement.
3g	**<u>Energy Gateway West:</u>** • Energy Gateway West Segment D.2, continue construction with target in-service date of 12/31/2020. • Continue permitting for the Energy Gateway transmission plan, with near term targets as follows: • For Segments D.3, and E, continue funding of the required federal agency permitting environmental consultant actions required as part of the federal permits. Also, continue to support the projects by providing information and participating in public outreach.

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

<u>Energy Efficiency Targets:</u>

• PacifiCorp will acquire cost-effective Class 2 DSM (energy efficiency) resources targeting annual system energy and capacity selections from the preferred portfolio as summarized below. PacifiCorp's state-specific processes for planning for DSM acquisitions will be provided in Appendix D in Volume II of the 2019 IRP.

<table>
<tr><th>Year</th><th>Annual Incremental Energy (GWh)</th><th>Annual Incremental Capacity (MW)</th></tr>
<tr><td>2019</td><td>562</td><td>126</td></tr>
<tr><td>2020</td><td>536</td><td>132</td></tr>
<tr><td>2021</td><td>538</td><td>133</td></tr>
<tr><td>2022</td><td>571</td><td>143</td></tr>
</table>

* Note, Class 2 DSM capacity figures reflect projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply-side resource.

• Energy Efficiency Bundling: PacifiCorp will continue to evaluate alternate bundling methodologies of Class 2 DSM in the 2019 IRP.

• Direct-Load Control: PacifiCorp will acquire cost-effective Class 1 DSM (i.e., demand response) in Utah targeting approximately 29 MW of incremental capacity from 2020 through 2023.
</td></tr>
<tr><th>Action Item</th><th>5. Front Office Transactions</th></tr>
<tr><td>5a</td><td>

<u>Market Purchases:</u>

• Acquire short-term firm market purchases for on-peak delivery from 2019-2021 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price.

• Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price.

• Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.
</td></tr>
<tr><th>Action Item</th><th>6. Renewable Energy Credit Actions</th></tr>
<tr><td>6a</td><td>

<u>Renewable Portfolio Standards (RPS):</u>

• PacifiCorp will pursue unbundled RFPs to meet its state RPS compliance requirements.

• As needed, issue RFPs seeking then current-year vintage unbundled RECs that will qualify in meeting California RPS targets through 2020. As needed, issue RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting Washington RPS targets.
</td></tr>
<tr><td>6b</td><td>

<u>Renewable Energy Credit Sales:</u>

• Maximize the sale of RECs that are not required to meet state RPS compliance obligations.
</td></tr>
</table>

Progress on Previous Action Plan Items

This section describes progress that has been made on previous action plan items documented in the 2017 IRP and the 2017 IRP Update reports filed with the state commissions on April 4, 2017 and May 1, 2018, respectively. Many of these action items have been superseded in some form by items identified in the current IRP action plan. The status for all action items is summarized in Table 9.2.

Table 9.2 – 2017 IRP Action Plan Status Update

Action Item	Activity	Status
1a	**Wind Repowering** • PacifiCorp will implement the wind repowering project, taking advantage of safe-harbor wind-turbine-generator equipment purchase agreements executed in December 2016. – Continue to refine and update the economic analysis of plant-specific wind repowering opportunities that maximize customer benefits before issuing the notice to proceed. – By September 2017, complete technical and economic analysis of other potential repowering opportunities at PacifiCorp wind plants not studied in the 2017 IRP (i.e., Foote Creek I and Goodnoe Hills). – Pursue regulatory review and approval as necessary. – By May 2018, issue the engineering, procurement, and construction (EPC) notice to proceed to begin implementing the wind repowering for specific projects consistent with updated financial analysis.	PacifiCorp has continued to refine and update its economic analysis of wind repowering, which has been provided in regulatory filings in California, Idaho, Oregon, Utah, and Wyoming. PacifiCorp completed technical and economic analysis of repowering Goodnoe Hills in 2018 and included this facility is in the scope of the wind repowering project described in regulatory filings. PacifiCorp completed technical and economic analysis of Foote Creek I in 2019, which demonstrated that repowering the facility provides economic benefits to customers. Regulatory approval of the wind repowering project was received from the Idaho Public Service Commission on December 28, 2017; the Public Service Commission of Wyoming on December 18, 2018, the Public Service Commission of Utah on May 29, 2018, and the Public Utility Commission of Oregon on September 16, 2019. Regulatory approval is pending in California. In June 2018, PacifiCorp issued notices to proceed to begin implementing certain wind repowering projects, consistent with the updated financial analysis. Except for Foote Creek I, PacifiCorp issued notices to proceed for the remainder of the wind repowering projects by the end of December 2018.

Action Item	Activity	Status
	– By December 31, 2020, complete installation of wind repowering equipment on all identified projects.	In July 2019, PacifiCorp acquired the Eugene Water & Electric Board's minority interest in the Foote Creek I wind project and cancelled the power purchase agreement with Bonneville Power Administration. PacifiCorp issued notices to proceed related to repowering efforts at Foote Creek I in late July 2019. The Public Service Commission of Wyoming issued a Certificate of Public Convenience and Necessity related to repowering the Foote Creek I facility on September 12, 2019. PacifiCorp is on track to complete installation of the wind repowering equipment on all of its existing projects by December 31, 2020.
1b	**<u>Wind Request for Proposals</u>** • PacifiCorp will issue a wind resource request for proposals (RFP) for at least 1,100 MW of Wyoming wind resources that will qualify for federal wind production tax credits and achieve commercial operation by December 31, 2020. – April 2017, notify the Utah Public Service Commission of intent to issue the Wyoming wind resource RFP. – May-June, 2017, file a draft Wyoming wind RFP with the Utah Public Service Commission and the Washington Utilities and Transportation Commission. – May-June, 2017, file to open a Wyoming wind RFP docket with the Public Utility Commission of Oregon and initiate the Independent Evaluator RFP. – June-July, 2017, file a draft Wyoming wind RFP with the Public Utility Commission of Oregon and file a Public Convenience and	PacifiCorp completed all of the notice and draft filing requirements related to the RFP (the 2017R Request for Proposals (2017R RFP)). In accordance with the Utah and Oregon RFP proceedings, the 2017R RFP was issued on September 27, 2017. Bid results were received, evaluated and PacifiCorp established a final shortlist that included four wind projects in Wyoming totaling 1,311. PacifiCorp ultimately executed contracts to move forward with four projects totaling 1,150 MW. The 2017R RFP was monitored by two independent evaluators. On April 12, 2018, PacifiCorp received conditional CPCNs for the TB Flats I & II wind project, the Cedar Springs wind project, the Ekola Flats wind project, and associated network upgrades from the Wyoming Public Service Commission. These conditional CPCNs were required to secure the necessary rights-of-way. Final CPCNs to allow construction to initiate were issued by the Wyoming Public Service Commission on March 12, 2019 for TB Flats I &

Action Item	Activity	Status
	Necessity (CPCN) application with the Public Service Commission of Wyoming. – By August 2017, obtain approval of the Wyoming wind resource RFP from the Public Utility Commission of Oregon, the Utah Public Service Commission, and the Washington Utilities and Transportation Commission. – By August 2017, issue the Wyoming wind RFP to the market. – By October 2017, Wyoming wind RFP bids are due. – November-December, 2017, complete initial shortlist bid evaluation. – By January 2018, complete final shortlist bid evaluation, seek acknowledgement of the final shortlist from the Public Utility Commission of Oregon, and seek approval of winning bids from the Utah Public Service Commission. – By March 2018, receive CPCN approval from the Wyoming Public Service Commission. – Complete construction of new wind projects by December 31, 2020.	II, April 17, 2019 for Ekola Flats and network upgrades, and September 6, 2019 for Cedar Springs. All of the new wind projects resulting from the 2017R RFP are underway and on track to achieve commercial operation by the end of 2020.
1c	**Renewable Portfolio Standard Compliance** • PacifiCorp will issue unbundled REC request for proposals (RFP) to meet its state RPS compliance requirements. – As needed, issue RFPs seeking then-current-year or forward-year vintage unbundled RECs that will qualify in meeting California renewable portfolio standard targets through 2020.	PacifiCorp will continue to evaluate the need for unbundled RECs and issue RFPs to meet its state RPS compliance requirements as needed for both California Oregon, and Washington. PacifiCorp will issue an RFP seeking unbundled RECs in the fourth quarter of 2019 to meet state RPS compliance requirements in California and Washington.

Action Item	Activity	Status
	– As needed, issue RFPs seeking low-cost then-current-year, forward-year, or older vintage unbundled RECs that will qualify in meeting Oregon renewable portfolio standard targets, deferring the currently projected 2035 initial shortfall after accounting for preferred portfolio renewable resources.	
1d	**Renewable Energy Credit Optimization** • Before filing the 2017 IRP Update, evaluate potential opportunities to re-allocate RECs from Utah, Wyoming, and Idaho to Oregon, Washington, or California. • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.	PacifiCorp issued reverse RFPs in June 2017, September 2017, My 2018, October 2018, and April 2019. PacifiCorp will continue to engage in bilateral REC sales and issue reverse RFPs to maximize the sale of RECs that are not required to meet state RPS compliance obligations.
Action Item	**2. Transmission Actions**	**Status**
2a	**Aeolus to Bridger/Anticline** • By December 31, 2020, PacifiCorp will build the 140-mile, 500 kV transmission line running from the Aeolus substation near Medicine Bow, Wyoming, to the Jim Bridger power plant (a sub-segment of the Energy Gateway West transmission project). This includes pursuing regulatory review and approval as necessary – June-July 2017, file a CPCN application with the Public Service Commission of Wyoming. – By March 2018, receive conditional CPCN approval from the Wyoming Public Service Commission pending acquisition of rights of way.	PacifiCorp filed a CPCN application with the Public Service Commission of Wyoming on June 30, 2017. On April 12, 2018, PacifiCorp received a conditional CPCN for the Aeolus-to-Bridger/Anticline transmission line from the Wyoming Public Service Commission. This CPCN was required to secure the necessary rights-of-way. The Wyoming Industrial Siting Counsel issued the siting permit on October 24, 2018. On April 9, 2019, the Public Service Commission of Wyoming issued the full CPCN. PacifiCorp issued full notice to proceed to the EPC contractors. Construction began on April 10, 2019

Action Item	Activity	Status
	– By December 2018, obtain Wyoming Industrial Siting permit and issue EPC limited notice to proceed. – By April 2019, issue EPC final notice to proceed. – Complete construction of the transmission line by December 31, 2020.	The 140-mile, 500 kV Aeolus to Bridger transmission project is underway and on-track to achieve commercial operation by the end of 2020.
2b	**Energy Gateway Permitting** • Continue permitting for the Energy Gateway transmission plan, with the following near-term targets: – For Segments D1, D3, E, and F, continue funding of the required federal agency permitting environmental consultant actions required as part of the federal permits. – For Segments D, E, and F, continue to support the projects by providing information and participating in public outreach. – For Segment H (Boardman to Hemingway), continue to support the project under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement.	Final environmental and records of decision have been issued for Gateway Segments D1, D3, E and F. PacifiCorp will continue the work necessary to meet requirements within the records of decision and will continue to meet regularly with the Bureau of Land Management to review progress. PacifiCorp continues to support Gateway Segment H (Boardman-to-Hemingway) consistent with the Joint Permit Funding Agreement. As a participant in the project PacifiCorp continues to collaborate with Idaho Power, the lead organization in the permitting process, by providing guidance on activities and plans associated with the permitting phase of the project.
2c	**Wallula to McNary 230 kV Transmission Line** • Complete Wallula to McNary project construction per plan with a 2018 expected in-service date. Continue to support the permitting and construction process for Walla Walla to McNary.	Wallula to McNary project is complete, and the line went in-service January 2019.

2d	**Planning Studies** • Complete planning studies that include proposed coal unit retirement assumptions from the 2017 IRP preferred portfolio and two other scenarios. • Summarize studies in the 2017 IRP Update.	Planning studies were completed in 2018 and included in PacifiCorp's 2017 IRP Update.
3a	**Front Office Transactions** • Acquire economic short-term firm market purchases for on-peak summer deliveries from 2017 through 2019 consistent with the Risk Management Policy and Commercial and Trading Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: – Balance of month and day-ahead brokered transactions in which the broker provides the service of providing a competitive price. – Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as Intercontinental Exchange (ICE), in which the exchange provides the service of providing a competitive price. – Prompt month-forward, balance-of-month, day-ahead, and hour-ahead non-brokered transactions.	For 2018, PacifiCorp acquired approximately 2,225 MW to 2,765 MW of short-term firm market purchases inclusive of forward hedging transactions, not accounting for any offsetting hedging or balancing sales for delivery during the on-peak summer period. For 2019, as of end of September 2019, the company has acquired approximately 1,100 MW to 2,030 MW of short-term market purchases inclusive of forward hedging transactions, not accounting for any offsetting hedging sales for delivery during the on-peak summer period. For 2020, as of end of September 2019, the company has acquired approximately 150 MW of short-term firm market purchases explicitly for delivery during the on-peak summer period inclusive of forward hedging transaction, not accounting for any offsetting hedging sales for delivery during the on-peak summer period.
4a	**Class 2 DSM** • Acquire cost-effective Class 2 DSM (energy efficiency) resources targeting annual system energy and capacity selections from the preferred portfolio as summarized in the following table. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2017 IRP.	In 2017, PacifiCorp achieved the Action Plan target of 646 gigawatt hours (GWh). In 2018, PacifiCorp achieved 98 percent of the Action Plan target of 559 GWh.

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Year	Annual Incremental Energy (GWh)	Annual Incremental Capacity* (MW)
2017	646	154
2018	559	128

*Class 2 DSM capacity figures reflect projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply-side resource.</td><td></td></tr>
<tr><td>5a</td><td><u>Hunter Units 1 and 2</u>
• The U.S. Environmental Protection Agency (EPA)'s final Regional Haze Federal Implementation Plan (FIP) for Utah requires the installation of selective catalytic reduction (SCR) on Hunter Units 1 and 2 in 2021 and is currently under appeal by the state of Utah and other parties in the U.S. Tenth Circuit Court of Appeals.
• As influenced by the litigation schedule and outcomes, PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units, as applicable, and will provide the associated analysis in a future IRP or IRP Update.</td><td>PacifiCorp continues to support the state of Utah in its appeal of the EPA's FIP for Utah as it pertains to Hunter Units 1 and 2. The state of Utah submitted a revised Regional Haze State Implementation Plan (SIP) on July 3, 2019, for EPA review and approval. The EPA requested an additional minor revision to the SIP which Utah anticipates it will submit before year-end 2019. Litigation of the FIP appeal is currently held in abeyance while EPA reviews the revised SIP. Please see Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates and the associated analysis in future IRP filings, as applicable.</td></tr>
<tr><td>5b</td><td><u>Huntington Units 1 and 2</u>
• The EPA's final Regional Haze FIP for Utah requires the installation of SCR on Huntington Units 1 and 2 in 2021 and is currently under appeal by the state of Utah and other parties in the U.S. Tenth Circuit Court of Appeals.
• As influenced by the litigation schedule and outcomes, PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units, as applicable, and will provide the associated analysis in a future IRP or IRP Update.</td><td>PacifiCorp continues to support the state of Utah in its appeal of the EPA's FIP for Utah as it pertains to Hunter Units 1 and 2. The state of Utah submitted a revised Regional Haze State Implementation Plan (SIP) on July 3, 2019, for EPA review and approval. The EPA requested an additional minor revision to the SIP which Utah anticipates it will submit before year-end 2019. Litigation of the FIP appeal is currently held in abeyance while EPA reviews the revised SIP. Please see Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates and the associated analysis in future IRP filings, as applicable.</td></tr>
</table>

5c	**Dave Johnston Unit 3** • The EPA's final Regional Haze FIP requires the installation of SCR at Dave Johnston Unit 3 in 2019 or a commitment to shut down Dave Johnston Unit 3 by the end of 2027. PacifiCorp's commitment to the latter must be included in a permit before the 2019 compliance deadline. • PacifiCorp will update its analysis of the commitment to shut down Dave Johnston Unit 3 by the end of 2027 as part of its 2017 IRP Update.	PacifiCorp studied retirement of Dave Johnston Unit 3 in the 2017 IRP Update and the 2019 IRP. PacifiCorp does not plan to proceed with installation of SCR on Dave Johnston Unit 3, and will submit a permit revision before the end of 2019 to make the 2027 shut down date enforceable. Please see Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates in future IRP filings as applicable.
5d	**Jim Bridger Units 1 and 2** • The Wyoming Regional Haze SIP and EPA's final Regional Haze FIP for Wyoming require the installation of SCR on Jim Bridger Units 1 and 2 in 2021 and 2022. • PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units and will provide the associated analysis in its 2017 IRP Update.	PacifiCorp developed a Jim Bridger Regional Haze compliance alternative for the state of Wyoming and EPA to consider in 2018, and submitted a permit application with the state of Wyoming in February 2019. The state of Wyoming has incorporated the compliance alternative into a revised Wyoming Regional Haze SIP and a state permit. Wyoming is currently in the process of responding to public comments on the plan. It is expected that the state of Wyoming will submit the revised Wyoming Regional Haze SIP by year-end 2019 for EPA review and approval. Please see Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates and analysis on Jim Bridger Units 1 and 2 in future IRP filings as applicable.
5e	**Naughton Unit 3** • PacifiCorp will update its economic analysis of natural gas conversion in its 2017 IRP Update.	PacifiCorp studied Naughton Unit 3 gas conversion in the 2017 IRP Update and the 2019 IRP. Please see Chapter 6 (Resource Options) of the 2019 IRP for more information.
5f	**Wyodak** • Continue to pursue PacifiCorp's appeal of the portion of EPA's final Regional Haze FIP that requires the installation of SCR at Wyodak, recognizing that the	PacifiCorp continues to support the state of Wyoming in its appeal of the EPA's FIP for Wyoming as it pertains to Wyodak. The requirement for SCR at Wyodak is currently stayed as part of the FIP litigation proceedings. Please see

	compliance deadline for SCR under the FIP is currently stayed by the court. • If following appeal, EPA's final FIP as it pertains to installation of SCR at Wyodak is upheld (with a modified schedule that reflects the final stay duration), PacifiCorp will update its evaluation of alternative compliance strategies that will meet Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.	Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates and the associated analysis in future IRP filings, as applicable.
5g	**Cholla Unit 4** • EPA has approved the Arizona SIP incorporating an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Cholla Unit 4 as a coal-fueled resource by the end of April 2025, with the option of natural gas conversion thereafter. • PacifiCorp will update its evaluation of Cholla Unit 4 alternatives that meet its Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.	Please see Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates and the associated analysis in future IRP filings, as applicable.
5h	**Craig Unit 1** • EPA is yet to approve the Colorado SIP incorporating an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Craig Unit 1 as a coal-fueled resource by the end of 2025, with an option for natural gas conversion. • PacifiCorp will update its evaluation of Craig Unit 1 alternatives that meet its Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update, as required.	Please see Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates and the associated analysis in future IRP filings as applicable.

Acquisition Path Analysis

Resource and Compliance Strategies

PacifiCorp worked with stakeholders to define portfolio cost and risk analysis in the 2019 IRP. This analysis reflects a combination of specific planning assumptions related to coal unit retirements, potential Regional Haze compliance outcomes, Energy Gateway transmission investments, customer-preference renewable resources, targeted resource procurement outcomes (i.e., no new natural gas), market-reliance risk, market price assumptions, and CO_2 price assumptions. PacifiCorp further analyzed sensitivity cases on planning assumptions related primarily to the load forecasts and private generation penetration levels. The array of planning assumptions that define the studies used to develop resource portfolios provides the framework for a resource acquisition path analysis by evaluating how resource selections are impacted by changes to planning assumptions.

Given current load expectations, portfolio modeling performed for the 2019 IRP shows the resource acquisition path in the preferred portfolio is robust among a wide range of policy and market conditions, particularly in the near-term, when cost-effective renewable resources that qualify for federal income tax credits, FOTs, and energy efficiency resources are consistently selected. With regard to renewable resource acquisition, the portfolio development modeling performed in the 2019 IRP shows that new renewable resource needs are driven primarily by economics and reliability. Beyond load, CO_2 policy also influences resource selections in the 2019 IRP. For these reasons, the acquisition path analysis focuses on economic, load, reliability, and environmental policy trigger events that would require alternative resource acquisition strategies. For each trigger event, PacifiCorp identifies the planning scenario assumption affecting both short-term (2019-2028) and long-term (2029-2038) resource strategies.

Acquisition Path Decision Mechanism

The Utah Commission requires that PacifiCorp provide "[a] plan of different resource acquisition paths with a decision mechanism to select among and modify as the future unfolds."[1] PacifiCorp's decision mechanism is centered on the IRP process and ongoing updates to the IRP modeling tools between IRP cycles. The same modeling tools used in the IRP are also used to evaluate and inform the procurement of resources. The IRP models are used on a macro-level to evaluate alternative portfolios and futures as part of the IRP process, and then on a micro-level to evaluate the economics and system benefits of individual resources as part of the supply-side resource procurement and DSM target-setting/valuation processes. PacifiCorp uses the IRP and the IRP modeling tools to serve as decision support tools that can be used to guide prudent resource acquisition paths that maintain system reliability at a reasonable cost. Table 9.3 summarizes PacifiCorp's 2019 IRP acquisition path analysis, which provides insight on how changes in the planning environment might influence future resource procurement activities. Changes in procurement activities driven by changes in the planning environment will ultimately be reflected in future IRPs and resource procurement decisions.

[1] Public Service Commission of Utah, In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp, Report and Order, Docket No. 90-2035-01, June 1992, p. 28.

Table 9.3 – Near-term and Long-term Resource Acquisition Paths

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2020-2028)	Long Term Resource Acquisition Strategy (2029-2038)
Higher sustained load growth	High economic drivers and high Utah and Wyoming industrial loads	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Increase acquisition of summer FOTs: on average, annual purchases are up 460 MW per year. • Increase and accelerate solar+battery procurement: solar+battery capacity begins to rise as early as 2021—by 2028, solar+battery capacity is increased by 103 MW. • Increase and accelerate stand-alone battery procurement: 165 MW of stand-alone battery capacity is accelerated into 2026. • Increase flexible capacity procurement: in 2028, new gas-peaking capacity increases by 370 MW. • Accelerate Class I DSM procurement: in 2028, new direct-load control capacity increases by 149 MW.	• Accelerate flexible capacity procurement: new peaking gas capacity is accelerated—increased by 759 MW in 2029 and by 959 MW in 2033. By the end of 2038, gas capacity is similar to a base load forecast case. • Defer procurement of stand-alone battery capacity: with an accelerated deployment of new gas capacity, stand-alone battery storage capacity is down by 450 MW in 2029, down by 255 MW by 2033.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2020-2028)	Long Term Resource Acquisition Strategy (2029-2038)
Lower sustained load growth	Low economic drivers suppress load requirements with reduced demand from Utah and Wyoming industrial loads	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Reduce acquisition of summer FOTs: on average, annual purchases are down 220 MW per year. • Reduce and defer solar+battery capacity procurement: solar+battery capacity begins to fall as early as 2021—by 2028, solar+battery capacity is reduced by 220 MW. • Reduce and defer stand-alone battery procurement: stand-alone battery storage capacity declines beginning 2028 (180 MW). • Reduce flexible capacity procurement: 185 MW of new peaking gas capacity is deferred from 2026 to 2030. • Reduce energy efficiency procurement: through 2028, incremental energy efficiency procurement is down by 67 MW.	• Defer flexible capacity procurement: new peaking gas capacity remains relatively stable from 2030 through 2036—by 2038 new peaking gas capacity is down by 221 MW. • Adjust timing of solar+battery procurement: the timing for solar+battery capacity shifts—reduced by 720 MW by 2031, higher by 109 MW by 2035, and down by over 300 MW by 2038. • Increase stand-alone solar procurement: stand-alone solar is higher through the last ten years of the planning period—by 2038 it's up by 162 MW. • Reduce stand-along battery storage procurement: stand-alone battery storage capacity is down through the last ten years of the planning period—by 2038 it is reduced by 420 MW.
Higher sustained private generation penetration levels	More aggressive technology cost reductions, improved technology performance, and higher electricity retail rates	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Small changes to the portfolio would require minimal changes to the resource acquisition strategy. • Delay procurement of flexible resource capacity: a 185 MW gas peaking plant is deferred by one year from 2026 to 2027.	• Small changes to the portfolio would require minimal changes to the resource acquisition strategy. • Timing differences in stand-alone solar, stand-alone battery and solar+battery capacity would need to be assessed in procurement processes to achieve the appropriate balance of energy and capacity.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2020-2028)	Long Term Resource Acquisition Strategy (2029-2038)
Lower sustained private generation penetration levels	Less aggressive technology cost reductions, reduced technology performance, and lower electricity retail rates	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Delay procurement of flexible resource capacity: a 185 MW gas peaking plant is deferred by three years from 2026 to 2029.	• Accelerate procurement of flexible resource capacity: new gas peaking capacity increases by 370 MW in 2030. • Timing differences in stand-alone solar, stand-alone battery and solar+battery capacity would need to be assessed in procurement processes to achieve the appropriate balance of energy and capacity.
High CO_2 prices with accelerated coal retirements	Fossil-fired generation is faced with a high CO_2 price beginning in 2025 at $22.57/ton and reaching $83.69/ton by 2038 that drives all coal to be retired by 2030	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Accelerate procurement of flexible resource capacity: new gas peaking capacity increases by 195 MW as early as 2023 and is 514 MW higher than the base case by 2028. • Increase procurement of market purchases: summer FOTs increase with the potential for accelerated coal retirements. • Increase procurement of energy efficiency: energy efficiency capacity is accelerated and increases by 80 MW by 2028. • Accelerate procurement of direct-load control resources: by 2028, direct-load control capacity is up by 194 MW.	• Accelerate and increase procurement of flexible resource capacity: by 2029, new gas peaking capacity is 1,151 MW higher than in the base case and by 2038 it is 434 MW higher than the base case. • Accelerate and increase procurement of battery storage capacity: by 2038 battery storage capacity is increased by over 1,200 MW. • Accelerate procurement of direct-load control resources: by 2030, direct-load control capacity is up by 68 MW and in the 2031-2037 timeframe it is up by over 240 MW.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2020-2028)	Long Term Resource Acquisition Strategy (2029-2038)
Jim Bridger and Naughton Units retire by the end of 2025	Retirements for Naughton Units 1-2 and Jim Bridger Units 3-4 all occur by the end of 2025.	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Increase procurement of market purchases: summer FOTs increase beginning 2026 and through 2028 by as much as 960 MW per year. • Accelerate procurement of flexible resource capacity: new gas peaking capacity is 210 MW higher in 2028. • Adjust timing and volumes for procurement of battery storage capacity: battery storage capacity is down by about 100 MW in 2024, but increases by about by about 500 MW by 2026. • Increase procurement of energy efficiency: energy efficiency capacity is accelerated and increases by over 40 MW by 2028. • Accelerate procurement of direct-load control resources: by 2028, direct-load control capacity is up by 161 MW.	• Accelerate procurement of flexible resource capacity: new gas peaking capacity is between about 400 MW and 600 MW higher over the 2029 to 2034 timeframe, over 800 MW higher in the 2035-2036, and down by about 300 MW in 2037-2038. • Increase procurement of battery storage capacity: battery storage capacity is up by over 100 MW from 2030-2036, and is up by about 700 MW by 2038. • Accelerate procurement of renewable capacity: total renewable capacity is up by between 350 MW and over 1,200 MW from 2029-2037.
Low market prices	On average, levelized gas and power prices are down by approximately 25 percent relative to the base forecast	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • The near-term RFP process would assess potential changes to the resource mix, based on market bids that maximize value for customers, with potential changes to wind, solar, battery storage, and battery storage collated with solar.	• Accelerate procurement of flexible resource capacity: new gas peaking capacity increases by 342 MW in 2029 and by 1,518 MW in 2038. • Shifts in the precise timing and need for wind, solar, battery storage, and battery storage collated with solar would need to be evaluated through future competitive solicitation processes. • Reduce energy efficiency procurement: energy efficiency capacity is down by about 100 MW in this timeframe.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2020-2028)	Long Term Resource Acquisition Strategy (2029-2038)
High market prices	On average, levelized gas prices are up by about 25 percent and power prices by about 10 percent relative to the base forecast	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Increase renewable procurement and battery storage procurement in the 2023 timeframe: higher prices increase renewable capacity by about 260 MW and battery storage capacity by over 400 MW. • Increase procurement of energy efficiency: energy efficiency capacity is accelerated and increases by over 60 MW by 2028.	• Increase renewable procurement: higher prices increase renewable capacity by 720 MW in 2029 rising to over 1,200 MW by 2038. • Accelerate procurement of flexible resource capacity: new gas peaking capacity is higher by between 130 MW and 370 MW in the 2032-2036 timeframe, but down by over 500 MW in the 2037-2038 timeframe. • Battery storage capacity procurement would be adjusted in accordance with changes to gas capacity: battery storage capacity is down by about 300 MW in the 2032-2036 timeframe and up by 300-700 MW in the 2037-2038 timeframe. • Increase procurement of direct-load control resources: direct-load control capacity is up by between 40 MW and over 200 MW over the long term.
No customer-preference resource demand	No resources are added to meet customer-preference targets	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Reduce procurement of customer-preference renewables: total renewable capacity is down by nearly 300 MW through 2023, but up by 10 MW from 2024-2028.	• Longer term, the total volume of renewables is similar without customer preference resource demand. • Future RFP processes would evaluate timing adjustments for battery storage capacity and new gas peaking capacity; however, in aggregate, these capacity resources are not materially different from the base case.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2020-2028)	Long Term Resource Acquisition Strategy (2029-2038)
High customer-preference resource demand	Additional resources are added to meet higher customer-preference targets that exceed base case levels by over 3.5x in 2025 (5.7 GWh) rising to over 4.8x by 2038 (9.3 GWh).	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Accelerate procurement of renewable resources: by the 2024-2025 timeframe, renewable capacity is up by about 100 MW and by 2028, it is up by over 550 MW. • Accelerate procurement of battery storage capacity: by the 2024-2025 timeframe, battery storage capacity is up by about 50 MW and by 2028, it is up by over 130 MW. • Delay procurement of flexible resource capacity: new gas peaking capacity is 185 MW lower from 2026-2029. • Reduce procurement of market purchases: summer FOTs increase beginning 2026 and through 2028 by 20 to 160 MW over the 2024-2028 timeframe.	• Accelerate procurement of renewable resources: in the 2029-2038 timeframe, renewable capacity is up by over 570 MW in 2029 and up by 100 MW by 2030. • Accelerate procurement of battery storage capacity: in 2029 battery storage capacity is up by over 550 MW and in the 2029-2038 timeframe, battery storage capacity is up by over 280 MW.

Procurement Delays

The main procurement risk is an inability to procure resources in the required timeframe to meet the least-cost, least-risk mix of resources identified in the preferred portfolio. There are various reasons why a particular proxy resource cannot be procured in the timeframe identified in the 2019 IRP. There may not be any cost-effective opportunities available through an RFP, the successful RFP bidder may experience delays in permitting and/or default on their obligations, or there might be a material and sudden change in the market for fuel and materials. Moreover, there is always the risk of unforeseen environmental or other electric utility regulations that may influence the PacifiCorp's entire resource procurement strategy.

Possible paths PacifiCorp could take in the event of a procurement delay or sudden change in procurement need can include combinations of the following:

- In circumstances where PacifiCorp is engaged in an active RFP where a specific bidder is unable to perform, alternative bids can be pursued.

- PacifiCorp can issue an emergency RFP for a specific resource and with specified availability.
- PacifiCorp can seek to negotiate an accelerated delivery date of a potential resource with the supplier/developer.
- PacifiCorp can seek to procure near-term purchased power and transmission until a longer-term alternative is identified, acquired through customized market RFPs, exchange transactions, brokered transactions or bi-lateral, sole source procurement.
- Accelerate acquisition timelines for direct load control programs.
- Procure and install temporary generators to address some or all of the capacity needs.
- Temporarily drop below the target 13 percent planning reserve margin.
- Implement load control initiatives, including calls for load curtailment via existing load curtailment contracts.

IRP Action Plan Linkage to Business Planning

The 2019 IRP includes a sensitivity (case S-06) that complies with the Utah requirement to perform a business plan sensitivity case consistent with the commission's order in Docket No. 15-035-04. This order sets forth the following parameters for this sensitivity case:

- Over the first three years, resources align with those assumed in PacifiCorp's December 2018 Business Plan.
- Beyond the first three years of the study period, unit retirement assumptions are aligned with the preferred portfolio.
- All other resources are optimized.

Differences between PacifiCorp's 2019 IRP preferred portfolio and case S-07 are driven by assumptions for Naughton Unit 3 and Cholla Unit 4. Case S-07 does not include the Naughton Unit 3 gas conversion and assumes Cholla Unit 4 retires in early 2025 instead of 2020. In the near-term, the preferred portfolio has lower summer FOTs, slight changes in the volumes and timing associated with DSM resources, and slight changes in customer-preference renewable resources. None of these differences have any bearing on the 2019 IRP action plan, which calls for, among other things, issuance of an all-source RFP and advancement of transmission investments that will enable adding new renewable resources to the system. Over the long term, the change in resources from case S-06 relative to the preferred portfolio are largely associated with timing; however, the overall long-term portfolio resource mix is similar to the resources included in the preferred portfolio and would not materially alter PacifiCorp's long-term resource procurement plans. Table 9.4 compares the 2019 IRP preferred portfolio with portfolio from sensitivity case S-06.

Table 9.4 – Comparison of the 2019 IRP Preferred Portfolio with Sensitivity Case S-06

2019 IRP Preferred Portfolio

Resource	Capacity (MW) 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Resource Totals 2019-2038
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	505
Gas- Peaking	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	813	-	1,367
DSM - Energy Efficiency	126	132	133	141	147	151	147	144	143	138	126	120	114	110	99	82	77	65	58	59	2,315
DSM - Load Control	4	-	7	-	18	-	8	7	-	-	133	8	-	12	-	-	15	4	59	100	444
Renewable - Wind	-	-	-	-	60	1,920	-	-	-	-	-	1,040	-	-	-	-	-	-	-	-	3,029
Renewable - Wind+Storage	-	-	-	-	-	-	-	-	-	-	10	-	-	60	-	-	-	-	11	-	81
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar+Storage	-	-	159	64	3	2,154	-	-	-	-	350	500	-	-	475	-	-	419	909	702	5,744
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	180	435	-	30	120	-	-	-	-	-	600	1,365
Front Office Transactions - Summer	998	719	493	503	498	131	126	191	264	1,163	1,375	1,274	1,240	1,281	1,373	1,375	1,374	1,277	1,374	1,375	921
Front Office Transactions - Winter	151	131	268	303	314	44	51	53	100	232	222	173	192	128	63	-	35	-	-	-	123
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	(280)	(387)	-	-	(351)	-	(439)	(82)	(148)	(350)	-	-	-	-	-	-	-	-	-	(2,042)
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	(755)	-	-	(77)	-	(356)	-	-	-	(909)	(702)	(2,799)
Retire - Hydro	-	(1)	(169)	-	(1)	(20)	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(282)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	(40)
Expire - Wind PPA	-	(27)	(17)	(224)	(0)	(41)	-	(65)	(3)	-	(93)	(109)	(200)	(65)	(201)	(80)	-	(70)	(90)	-	(1,284)
Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	(2)	-	-	(67)	(49)	-	-	(36)	(209)	(1,024)	(11)	(1,399)
Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	(33)
Coal Plant Gas Conversion Additions	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	-
Total	1,279	922	488	788	1,048	3,988	333	75	422	800	2,211	3,089	1,234	1,598	1,453	1,301	1,467	1,485	1,706	2,160	

Study includes Naughton 3 conversion at the beginning of 2020.
FOT in resource total are 20-year averages.

2019 IRP Preferred Portfolio less Sensitivity Case S-06

Resource	Capacity (MW) 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Resource Totals 2019-2038
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	185	-	(185)	(370)	370	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	(9)	(2)	3	0	(5)	-	0	(4)	(0)	(0)	2	(0)	5	7	(0)	0	1	(1)	(1)	(3)	(7)
DSM - Load Control	-	-	(8)	-	8	-	-	-	-	(126)	126	8	(8)	-	-	-	-	-	(21)	(26)	(56)
Renewable - Wind	-	-	-	-	69	-	-	-	-	-	-	(60)	-	-	-	-	-	-	(92)	(58)	(141)
Renewable - Wind+Storage	-	-	-	-	-	-	-	-	-	-	10	-	-	60	-	-	-	-	11	-	81
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar+Storage	-	-	-	-	(69)	36	-	-	-	-	-	500	(500)	(45)	(100)	-	-	419	(338)	-	(97)
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	(15)	-	-	-	-	-	-	(30)	420	(360)	30	(45)	(195)	-	-	15	-	315	135
Front Office Transactions - Summer	(13)	(245)	(29)	(52)	(62)	(60)	(60)	(280)	(281)	(195)	37	4	(32)	(45)	(2)	298	298	191	(1)	5	(526)
Front Office Transactions - Winter	2	8	9	9	9	(9)	(9)	(9)	(11)	(11)	3	1	4	(8)	(4)	(300)	(299)	(305)	-	-	(46)
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	(280)	(387)	-	-	(351)	-	(439)	(82)	(148)	(350)	-	-	-	-	-	-	-	-	-	(2,042)
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	(755)	-	-	(77)	-	(356)	-	-	-	(909)	(702)	(2,799)
Retire - Hydro	-	(1)	(169)	-	(1)	(20)	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(282)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	(40)
Expire - Wind PPA	-	(27)	(17)	(224)	(0)	(41)	-	(65)	(3)	-	(93)	(109)	(200)	(65)	(201)	(80)	-	(70)	(90)	-	(1,284)
Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	(2)	-	-	(67)	(49)	-	-	(36)	(209)	(1,024)	(11)	(1,399)
Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	(33)
Coal Plant Gas Conversion Additions	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	-
Total	(20)	(300)	(611)	(267)	(51)	(446)	(69)	(614)	(378)	(1,459)	(221)	67	(852)	(191)	(859)	(158)	(36)	38	(2,467)	(512)	

FOT in resource total are 20-year averages.

Sensitivity Case S-06

Resource	Capacity (MW) 2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Resource Totals 2019-2038
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	505
Gas- Peaking	-	-	-	-	-	-	-	-	-	185	370	-	-	-	-	-	-	-	813	-	1,367
DSM - Energy Efficiency	135	134	129	142	151	151	147	148	144	138	124	120	109	104	100	81	76	67	59	63	2,322
DSM - Load Control	4	-	15	-	10	-	8	7	-	126	7	-	8	12	-	-	15	4	83	105	494
Renewable - Wind	-	-	-	-	-	1,920	-	-	-	-	-	1,100	-	-	-	-	-	-	92	58	3,170
Renewable - Wind+Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar+Storage	-	-	159	64	73	2,118	-	-	-	-	199	-	500	45	575	-	-	-	1,247	702	5,842
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	15	-	-	-	-	-	-	210	15	360	-	165	195	-	-	(13)	-	285	1,230
Front Office Transactions - Summer	1,010	964	521	555	560	191	187	472	545	1,357	1,338	1,269	1,281	1,327	1,375	1,077	1,077	1,086	1,375	1,370	947
Front Office Transactions - Winter	149	123	259	294	305	53	60	62	111	241	219	172	188	136	67	300	334	305	-	-	169
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	1,299	1,222	1,099	1,055	1,099	4,433	402	688	800	2,259	2,432	3,022	2,087	1,788	2,312	1,459	1,503	1,447	4,173	2,672	

Study includes Naughton 3 retirement at the end of 2019.
FOT in resource total are 20-year averages.

Resource Procurement Strategy

To acquire resources outlined in the 2019 IRP action plan, PacifiCorp intends to continue using competitive solicitation processes in accordance with applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. PacifiCorp will also continue to pursue opportunistic acquisitions identified outside of a competitive procurement process that provide economic benefits to customers. Regardless of the method for acquiring resources, PacifiCorp will support its resource procurement activities with the appropriate financial analysis using then-current assumptions for inputs such as load forecasts, commodity prices, resource costs, and policy developments. Any such financial analysis will account for any applicable long-term system benefits with least-cost, least-risk planning principles in mind. The sections below profile the general procurement approaches for the key resource categories covered in the 2019 IRP action plan.

Renewable Resources, Storage Resources, and Dispatchable Resources

PacifiCorp will use a competitive RFPs to procure supply-side resources consistent applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. In Oregon and Utah, these state requirements involve the oversight of an independent evaluator, which is also being considered in revised rules being developed in Washington. The all-source RFPs outline the types of resources being pursued, defines specific information required of potential bidders and details both price and non-price scoring metrics that will be used to evaluate proposals.

Renewable Energy Credits

PacifiCorp uses shelf RFPs as the primary mechanism under which REC RFPs and reverse REC RFPs will be issued to the market. The shelf RFPs are updated to define the product definition, timing, and volume and further provide schedule and other applicable criteria to bidders.

Demand-side Management

PacifiCorp offers a robust portfolio of Class 1 (demand response and direct-load control) and Class 2 (energy efficiency) DSM programs and initiatives, most of which are offered in multiple states, depending on size of the opportunity and the need. Programs are reassessed on a regular bases. PacifiCorp provides Class 4 DSM offerings, and has continued *watt*smart outreach and communications. Educating customers regarding energy efficiency and load management opportunities is an important component of PacifiCorp's long-term resource acquisition plan. PacifiCorp will evaluate how to best incorporate potential Class 1 DSM programs into the broader all-source RFP process discussed above.

Assessment of Owning Assets versus Purchasing Power

As PacifiCorp acquires new resources, it will need to determine whether it is better to own a resource or purchase power from another party. While the ultimate decision will be made at the time resources are acquired, and will primarily be based on cost, there are other considerations that may be relevant.

With owned resources, PacifiCorp is in a better position to control costs, make life extension improvements (as is being implemented with the wind repower project analyzed in the 2017 IRP), use the site for additional resources in the future, change fueling strategies or sources (as is being implemented for the Naughton Unit 3 gas conversion), efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and utilize the plant at embedded cost as long as it remains economic. In addition, by owning a plant, PacifiCorp can hedge itself against the uncertainty of third-party performance consistent with the terms and conditions outlined in a power purchase agreement over time.

Alternately and depending on contractual terms, purchasing power from a third party in a long term contract may help mitigate and may avoid liabilities associated with closure of a plant. A long-term power purchase agreement relinquishes control of construction cost, schedule, ongoing costs and environmental and regulatory compliance. Purchase power agreements can also protect and cap the buyer's exposure to events that may not cover actual seller financial impacts. However, credit rating agencies can impute debt associated with long-term resource contracts that may result from a competitive procurement process, and such imputation may affect PacifiCorp's credit ratios and credit rating.

Managing Carbon Risk for Existing Plants

CO_2 reduction regulations at the federal, regional, or state levels could prompt PacifiCorp to continue to look for measures to lower CO_2 emissions of fossil-fired power plants through cost-effective means. The cost, timing, and compliance flexibility afforded by CO_2 reduction rules will impact what types of measures might be cost-effective and practical from operational and regulatory perspectives. As evident in the 2019 IRP, known and prospective environmental regulations can impact utilization of resources and investment decisions.

Compliance strategies will be affected by how and whether states or the federal government choose to implement greenhouse gas policies. State or federal frameworks could impute a carbon tax or implement a cap-and-trade framework. Under a cap-and-trade policy framework, examples of factors affecting carbon compliance strategies include the allocation of emission allowances, the cost of allowances in the market, and any flexible compliance mechanisms such as opportunities to use carbon offsets, allowance/offset banking and borrowing, and safety valve mechanisms. Under a CO_2 tax framework, the tax level and details around how the tax might be assessed would affect compliance strategies.

To lower the emission levels for existing fossil-fired power plants, options include changes in plant dispatch, unit retirements, changing the fuel type, deployment of plant efficiency improvement projects, and adoption of new technologies such as CO_2 capture with sequestration, when commercially proven. As mentioned above, plant CO_2 emission risk may also be addressed by acquiring offsets or other environmental attributes that could become available in the market under certain regulatory frameworks. PacifiCorp's compliance strategies will evolve and continue to be reassessed in future IRP cycles as market forces and regulatory outcomes evolve.

Purpose of Hedging

While PacifiCorp focuses every day on minimizing net power costs for customers, the company also focuses every day on mitigating price risk to customers, which is done through hedging consistent with a robust risk management policy. For years PacifiCorp has followed a consistent hedging program that limits risk to customers, has tracked risk metrics assiduously and has diligently documented hedging activities. PacifiCorp's risk management policy and hedging program exists to achieve the following goals: (1) ensure reliable sources of electric power are available to meet PacifiCorp's customers' needs; (2) reduce volatility of net power costs for PacifiCorp's customers. The purpose is solely to reduce customer exposure to net power cost volatility and adverse price movement. PacifiCorp does not engage in a material amount of proprietary trading activities. Hedging is done solely for the purpose of limiting financial losses due to unfavorable wholesale market changes. Hedging modifies the potential losses and gains in net power costs associated with wholesale market price changes. The purpose of hedging is not to reduce or minimize net power costs. PacifiCorp cannot predict the direction or sustainability of changes in forward prices. Therefore, PacifiCorp hedges, in the forward market, to reduce the volatility of net power costs consistent with good industry practice as documented in the company's risk management policy.

Risk Management Policy and Hedging Program

PacifiCorp's risk management policy and hedging program were designed to follow electric industry best practices and are periodically reviewed at least annually by the company's risk oversight committee. The risk oversight committee includes PacifiCorp representatives from the front office, finance, risk management, treasury, and legal department. The risk oversight committee makes recommendations to the president of Pacific Power, who ultimately must approve any change to the risk management policy. PacifiCorp's current policy is also consistent with the guidelines that resulted from collaborative hedging workshops with parties in Utah, Oregon, Idaho and Wyoming that took place in 2011 and 2012.

The main components of PacifiCorp's risk management policy and hedging program are natural gas percent hedged volume limits, value-at-risk (VaR) limits and time to expiry VaR (TEVaR) limits. These limits force PacifiCorp to monitor the open positions it holds in power and natural gas on behalf of its customers on a daily basis and limit the size of these open positions by prescribed time frames in order to reduce customer exposure to price concentration and price volatility. The hedge program requires purchases of natural gas at fixed prices in gradual stages in advance of when it is required to reduce the size of this short position and associated customer risk. Likewise, on the power side, PacifiCorp either purchases or sells power in gradual stages in advance of anticipated open short or long positions to manage price volatility on behalf of customers.

Since 2003, PacifiCorp's hedge program has employed a portfolio approach of dollar cost averaging to progressively reduce net power cost risk exposure over a defined time horizon while adhering to best practice risk management governance and guidelines. PacifiCorp's current portfolio hedging approach is defined by increasing risk tolerance levels represented by progressively increasing percentage of net power costs across the forward hedging period. PacifiCorp incorporated a time to expiry value at risk (TEVaR) metric in May 2010. In May 2012, as a result of multiple hedging collaboratives, the company reintroduced natural gas percent hedge volume limits of forecast requirements into its policy. There has been no conflict to-date between the new volume limits and PacifiCorp's VaR and TEVaR limits, although the volume limits would supersede in such conflict, consistent with the guidelines from the hedging collaboratives.

The primary governance of PacifiCorp's hedging activities is documented in the company's Risk Management Policy. In May 2010, PacifiCorp moved from hedging targets based on volume percentages to targets based on the "to expiry value-at-risk" or TEVaR metric. The primary goal of this change was to increase the transparency of the combined natural gas and power exposure by period. It enhances the progressive approach to hedging that PacifiCorp has employed for many years and provides the benefit of a more sophisticated measure of risk that responds to changes in the market and changes in open natural gas and power positions. Importantly, the TEVaR metric automatically reduces hedge requirements as commodity price volatility decreases and increases hedge requirements as correlations among commodities diverge, all the while maintaining the same customer risk exposure.

Dollar cost averaging is the term used to describe gradually hedging over a period of time rather than all at once. This method of hedging, which is widely used by many utilities, captures time diversification and eliminates speculative bursts of market timing activity. Its use means that at times PacifiCorp buys at relatively higher prices and at other times relatively lower prices, essentially capturing an array of prices at many levels. While doing so, PacifiCorp steadily and adaptively meets its hedge goals through the use of this technique while staying within VaR and TEVaR and natural gas percent hedge volume limits.

The result of these program changes in combination with changes in the market (such as reduced volatility to which PacifiCorp's program automatically responds), has been a significant decrease in PacifiCorp's longer-dated hedge activity, *i.e.*, four years forward on a rolling basis.

As a result of the hedging collaboratives, PacifiCorp made the following material changes to its policy in May 2012: (l) a reduction in the standard hedge horizon from 48 months to 36 months and (2) a percent hedged range guideline for natural gas for each of the three forward l2-month periods, which includes a minimum natural gas open position in each of the forward 12-month periods. The percent hedged range guideline is greater for the first rolling twelve months and gradually smaller for the second and third rolling twelve-month periods. PacifiCorp also agreed to provide a new confidential semi-annual hedging report.

Cost Minimization

While hedging does not minimize net power costs, PacifiCorp takes many actions to minimize net power costs for customers. First, the company is engaged in integrated resource planning to plan resource acquisitions that are anticipated to provide the lowest cost resources to our customers in the long-run. PacifiCorp then issues competitive requests for proposals to assure that the resources we acquire are the lowest cost resources available on a risk-adjusted basis. In operations, PacifiCorp optimizes its portfolio of resources on behalf of customers by maintaining and operating a portfolio of assets that diversifies customer exposure to fuel, power market and emissions risk and utilize an extensive transmission network that provides access to markets across the western United States. Independent of any natural gas and electric price hedging activity, to provide reliable supply and minimize net power costs for customers, PacifiCorp commits generation units daily, dispatches in real time all economic generation resources and all must-take contract resources, serves retail load, and then sells any excess generation to generate wholesale revenue to reduce net power costs for customers. PacifiCorp also purchases power when it is less expensive to purchase power than to generate power from our owned and contracted resources.

Hedging cannot be used to minimize net power costs. Hedging does not produce a different expected outcome than not hedging and therefore cannot be considered a cost minimization tool. Hedging is solely a tool to mitigate customer exposure to net power cost volatility and the risk of adverse price movement. However, PacifiCorp does minimize the cost of hedging by transacting in liquid markets and utilizing robust protections to mitigate the risk of counterparty default. In addition, PacifiCorp reduces the amount of hedging required to achieve a given risk tolerance through its portfolio hedge management approach, which takes into account offsetting exposures when these commodities are correlated, as opposed to hedging commodity exposures to natural gas and power in isolation without regard for offsets.

Portfolio

PacifiCorp has a short position in natural gas because of its ownership of gas-fired electric generation that requires it to purchase large quantities of natural gas to generate electricity to serve its customers. PacifiCorp may have short or long positions in power depending on the shortfall or excess of the company's total economic generation relative to customer load requirements at a given point in time.

PacifiCorp hedges its net energy (combined natural gas and power) position on a portfolio basis to take full advantage of any natural offsets between its long power and short natural gas positions. Analysis has shown that a "hedge only power" or "hedge only natural gas" approach results in higher risk (*i.e.,* a wider distribution of outcomes). There is a natural need for an electric company with natural gas fired electricity generation assets to have a hedge program that simultaneously manages natural gas and power open positions with appropriate coordinated metrics. PacifiCorp's risk management department incorporates daily updates of forward prices for natural gas, power, volatilities and correlations to establish daily changes in open positions and risk metrics which inform the hedging decisions made every day by company traders.

PacifiCorp's hedge program does not rely on a long power position. However, the company's hedge program takes into account its full portfolio and utilizes continuously updated correlations of natural gas and power prices and thereby takes advantage of offsetting natural gas and power positions in circumstances when prices are correlated and a forecast long power position offsets a forecast short natural gas position. This has the effect of reducing the amount of natural gas hedging that PacifiCorp would otherwise pursue. Ignoring this correlation would instead result in the need for more natural gas hedges to achieve the same level of customer risk reduction.

PacifiCorp's customers have benefited from offsetting power and natural gas positions. Power and natural gas prices are closely related because natural gas is often the fuel on the margin in efficient dispatch, as is practiced throughout the western U.S. This means power sales tend to be more valuable in periods when natural gas is high cost, producing revenues that are a credit or offset to the high cost fuel. If spot natural gas prices depart from prior forward prices, power prices will tend to do so in the same direction, thereby naturally hedging some of the unexpected cost variance.

Effectiveness Measure

The goal of the hedging program is to reduce volatility in PacifiCorp's net power costs primarily due to changes in market prices. The goal is not to "beat the market" and, therefore, should not be measured on the basis of whether it has made or lost money for customers. This reduction in volatility is calculated and reported in the company's confidential semi-annual hedging report which it began producing as a result of the hedging collaborative.

Instruments

PacifiCorp's hedging program allows the use of several instruments including financial swaps, fixed price physical and options for these products. PacifiCorp chooses instruments that generally have greater liquidity and lower transaction costs. The company also considers, with respect to options, the likelihood of disallowance of the option premium in its six jurisdictions. There is no functional difference between financial swaps and fixed price physical transactions; both instruments are equally effective in hedging the PacifiCorp's fixed price exposure.

Treatment of Customer and Investor Risks

The IRP standards and guidelines in Utah require that PacifiCorp "identify which risks will be borne by ratepayers and which will be borne by shareholders." This section addresses this requirement. Three types of risk are covered: stochastic risk, capital cost risk, and scenario risk.

Stochastic Risk Assessment

Several of the uncertain variables that pose cost risks to different IRP resource portfolios are quantified in the IRP production cost model using stochastic statistical tools. The variables addressed with such tools include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long-term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not reflected in rates, and are therefore borne by investors unless specific regulatory mechanisms provide otherwise. Consequently, over time, these risks are shared between customers and investors. Between rate cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

Capital Cost Risks

The actual cost of a generating or transmission asset is expected to vary from the cost assumed in the IRP. State commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risk of such a determination is borne by investors. To the extent that capital costs vary from those assumed in this IRP for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

Scenario Risk Assessment

Scenario risk assessment pertains to abrupt or fundamental changes to variables that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risks of this type facing PacifiCorp continues to be government actions related to emissions and changes in load and transmission infrastructure. These scenario risks relate to the uncertainty in predicting the scope, timing, and cost impact of emission and policies and renewable standard compliance rules.

To address these risks, PacifiCorp evaluates resources in the IRP and for competitive procurements using a range of CO_2 policy assumptions consistent with the scenario analysis methodology adopted for PacifiCorp's 2019 IRP portfolio development and evaluation process. The company's use of IRP sensitivity analysis covering different resource policy and cost assumptions also addresses the need for consideration of scenario risks for long-term resource planning. The extent to which future regulatory policy shifts do not align with PacifiCorp's resource investments determined to be prudent by state commissions is a risk borne by customers.