Purchase

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

Qualifying Facilities

All QFs that provide capacity and energy are included in this category. Wind and solar QFs are handled in the same manner as non-QF renewable resources, as described above. Other QFs are handled in the same manner as other power purchases, the capacity balance counts them at maximum system summer peak availability and the energy balance counts them at optimal economic model dispatch.

Demand Response (Class 1 DSM)

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

Sales

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

Non-owned Reserves

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

**Obligation**

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

Load Net of Private Generation

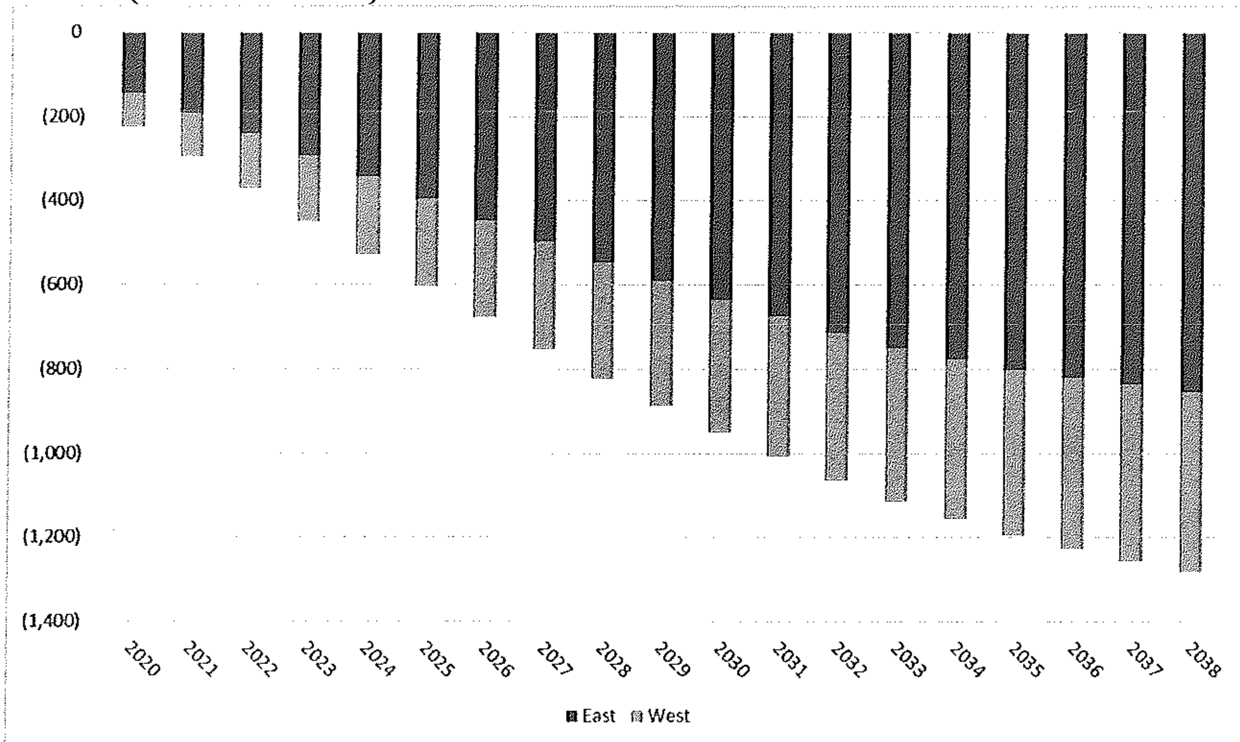
The largest component of the obligation is retail load. In the 2019 IRP, the hourly retail load at a location is first reduced by hourly private generation at the same location. The system coincident peak is determined by summing the net loads for all locations (topology bubbles with loads) and then finding the highest hourly system load by year. Loads reported by east and west BAAs thus reflect loads at the time of PacifiCorp's coincident system summer peak. The energy balance

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

counts the load on monthly basis by on-peak and off-peak hours. The net load is simply referred to as load in the context of load and resources balances and portfolio selection and evaluation.

Energy Efficiency (Class 2 DSM)
An adjustment is made to load to remove the projected embedded energy efficiency as a reduction to load. Due to timing issues with the vintage of the load forecast, there is a level of 2018 Energy Efficiency that is not incorporated in the forecast. The 2018 energy efficiency forecast (81 MW) has been accounted for by adding an existing energy efficiency resource in the load and resource balance. The energy efficiency line also includes the selected energy efficiency from the 2019 IRP preferred portfolio. Figure 5.5 shows the energy efficiency for the east and west control areas in the 2019 IRP preferred portfolio.

**Figure 5.5 – Energy Efficiency Peak Contribution in Summer Capacity Load and Resource Balance (reduction to load)**




Interruptible Contracts
PacifiCorp has interruptible contracts for approximately 177 MW of load interruption capability beginning in 2019. These contracts allow the use of 177 MW of capacity for meeting reserve requirements. Both the capacity balance and energy balance count these resources at the level of full load interruption on the executed hours. Interruptible resources directly curtail load and thus full planning reserves are not held for the load that may be curtailed. As with demand response, this resource is categorized as a decrease to the peak load.

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

### Position

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

## Capacity Balance Determination

### Methodology

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

> **Existing Resources** = Thermal + Hydro + Renewable + Firm Purchases + Qualifying Facilities + Existing Demand Response – Firm Sales – Non-owned Reserves

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

> **Obligation** = Load – Interruptible Contracts – New and Existing Energy Efficiency

The amount of reserves to be added to the obligation is then calculated. This is accomplished by the net system obligation calculated above multiplied by the 13 percent target PRM adopted for the 2019 IRP. The formula for this calculation is:

> **Planning Reserves** = Obligation x PRM

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

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

### Capacity Balance Results

Table 5.12 and Table 5.13 show the annual capacity balances and component line items for the summer peak and winter peak, respectively, using a target PRM of 13 percent to calculate the planning reserve amount. Balances for PacifiCorp's system as well as the east and west control areas are shown. While east and west control area balances are broken out separately, the PacifiCorp system is planned for and dispatched on a system basis. Also note that new QF wind and solar projects listed earlier in the chapter are reported under the QF line item rather than the renewables line item.

# Table 5.12 -- Summer Peak – System Capacity Loads and Resources without Resource Additions[1/]

| 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 |
| Class 1 DSM | 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) |
| **East Existing Resources** | **7,210** | **7,545** | **7,560** | **7,567** | **7,555** | **7,488** | **7,148** | **7,128** | **6,395** | **6,267** |
| | | | | | | | | | | |
| 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) |
| Interruptible | (177) | (177) | (177) | (177) | (177) | (177) | (177) | (177) | (177) | (177) |
| Energy Efficiency | (144) | (192) | (241) | (293) | (345) | (396) | (446) | (497) | (546) | (591) |
| **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 Obligation + Reserves** | **7,471** | **7,450** | **7,474** | **7,514** | **7,573** | **7,574** | **7,528** | **7,531** | **7,552** | **7,568** |
| **East Position** | **0** | **95** | **86** | **53** | **(17)** | **(85)** | **(380)** | **(403)** | **(1,156)** | **(1,300)** |
| **Available Front Office Transactions** | **309** | **309** | **309** | **309** | **309** | **309** | **309** | **309** | **309** | **309** |
| **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 |
| Class 1 DSM | 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) |
| **West Existing Resources** | **3,227** | **3,126** | **3,078** | **3,074** | **2,792** | **2,802** | **2,805** | **2,771** | **2,604** | **2,227** |
| | | | | | | | | | | |
| 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) |
| Interruptible | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Energy Efficiency | (81) | (106) | (131) | (157) | (183) | (208) | (232) | (255) | (276) | (296) |
| **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 Obligation + Reserves** | **3,712** | **3,740** | **3,757** | **3,756** | **3,730** | **3,755** | **3,753** | **3,753** | **3,755** | **3,753** |
| **West Position** | **(484)** | **(614)** | **(679)** | **(683)** | **(938)** | **(953)** | **(948)** | **(982)** | **(1,151)** | **(1,527)** |
| **Available Front Office Transactions** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** |
| **System** | | | | | | | | | | |
| **Total Resources** | 10,437 | 10,671 | 10,638 | 10,641 | 10,347 | 10,290 | 9,953 | 9,899 | 8,999 | 8,494 |
| **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** | (746) | (519) | (592) | (630) | (956) | (1,038) | (1,328) | (1,385) | (2,307) | (2,827) |
| | | | | | | | | | | |
| **Available Front Office Transactions** | 1,468 | 1,468 | 1,468 | 1,468 | 1,468 | 1,468 | 1,468 | 1,468 | 1,468 | 1,468 |
| **Uncommitted FOT's to meet remaining Need** | 746 | 519 | 592 | 630 | 956 | 1,038 | 1,328 | 1,385 | 1,468 | 1,468 |
| **Net Surplus (Deficit)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (839) | (1,359) |

1/ The Energy Efficiency line includes selected Energy Efficiency from the 2019 IRP preferred portfolio.

# Table 5.12 (cont.) – Summer Peak System Capacity Loads and Resources without Resource Additions[1/]

| 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 |
| Class 1 DSM | 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) |
| **East Existing Resources** | **6,036** | **5,952** | **5,908** | **5,596** | **5,577** | **5,575** | **5,556** | **4,326** | **4,279** |
| 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) |
| Interruptible | (177) | (177) | (177) | (177) | (177) | (177) | (177) | (177) | (177) |
| Energy Efficiency | (634) | (674) | (713) | (750) | (777) | (801) | (820) | (836) | (854) |
| **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 Obligation + Reserves** | **7,594** | **7,609** | **7,652** | **7,665** | **7,655** | **7,684** | **7,720** | **7,767** | **7,793** |
| **East Position** | **(1,557)** | **(1,657)** | **(1,744)** | **(2,070)** | **(2,078)** | **(2,109)** | **(2,164)** | **(3,440)** | **(3,514)** |
| **Available Front Office Transactions** | **309** | **309** | **309** | **309** | **309** | **309** | **309** | **309** | **309** |
| **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 |
| Class 1 DSM | 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) |
| **West Existing Resources** | **2,233** | **2,244** | **2,226** | **2,245** | **2,245** | **2,244** | **2,297** | **2,073** | **1,427** |
| 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) |
| Interruptible | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Energy Efficiency | (315) | (333) | (350) | (365) | (379) | (393) | (406) | (417) | (428) |
| **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 Obligation + Reserves** | **3,745** | **3,740** | **3,717** | **3,689** | **3,677** | **3,651** | **3,627** | **3,621** | **3,598** |
| **West Position** | **(1,512)** | **(1,497)** | **(1,491)** | **(1,444)** | **(1,431)** | **(1,406)** | **(1,330)** | **(1,548)** | **(2,171)** |
| **Available Front Office Transactions** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** |
| **System** | | | | | | | | | |
| **Total Resources** | 8,270 | 8,196 | 8,134 | 7,841 | 7,822 | 7,819 | 7,853 | 6,399 | 5,706 |
| **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** | (3,070) | (3,154) | (3,234) | (3,514) | (3,510) | (3,516) | (3,495) | (4,988) | (5,685) |
| **Available Front Office Transactions** | **1,468** | **1,468** | **1,468** | **1,468** | **1,468** | **1,468** | **1,468** | **1,468** | **1,468** |
| **Uncommitted FOT's to meet remaining Need** | 1,468 | 1,468 | 1,468 | 1,468 | 1,468 | 1,468 | 1,468 | 1,468 | 1,468 |
| **Net Surplus (Deficit)** | (1,602) | (1,686) | (1,766) | (2,046) | (2,042) | (2,048) | (2,027) | (3,520) | (4,217) |

1/ The Energy Efficiency line includes selected Energy Efficiency from the 2019 IRP preferred portfolio.

# Table 5.13 – Winter Peak System Capacity Loads and Resources without Resource Additions[1/]

| 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 |
| Class 1 DSM | 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) |
| **East Existing Resources** | **8,258** | **7,762** | **7,825** | **7,758** | **7,032** | **7,031** | **6,687** | **6,625** | **6,022** | **5,931** |
| | | | | | | | | | | |
| 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) |
| Interruptible | (177) | (177) | (177) | (177) | (177) | (177) | (177) | (177) | (177) | (177) |
| Energy Efficiency | (107) | (147) | (189) | (233) | (277) | (321) | (365) | (409) | (452) | (492) |
| **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 Obligation + Reserves** | **6,062** | **6,074** | **6,098** | **6,120** | **6,123** | **6,148** | **6,014** | **6,010** | **6,018** | **6,033** |
| **East Position** | **0** | **1,688** | **1,727** | **1,638** | **909** | **883** | **673** | **615** | **4** | **(102)** |
| **Available Front Office Transactions** | **309** | **309** | **309** | **309** | **309** | **309** | **309** | **309** | **309** | **309** |
| **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 |
| Class 1 DSM | 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) |
| **West Existing Resources** | **3,369** | **3,008** | **2,921** | **2,913** | **2,527** | **2,527** | **2,525** | **2,499** | **2,360** | **2,018** |
| | | | | | | | | | | |
| 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) |
| Interruptible | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Energy Efficiency | (89) | (118) | (150) | (181) | (214) | (244) | (274) | (303) | (331) | (356) |
| **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 Obligation + Reserves** | **3,759** | **3,774** | **3,785** | **3,782** | **3,769** | **3,764** | **3,762** | **3,769** | **3,774** | **3,783** |
| **West Position** | **(390)** | **(766)** | **(864)** | **(869)** | **(1,242)** | **(1,237)** | **(1,237)** | **(1,270)** | **(1,414)** | **(1,765)** |
| **Available Front Office Transactions** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** |
| **System** | | | | | | | | | | |
| **Total Resources** | 11,627 | 10,770 | 10,746 | 10,671 | 9,560 | 9,558 | 9,212 | 9,124 | 8,382 | 7,949 |
| **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** | 1,806 | 922 | 864 | 769 | (333) | (354) | (564) | (655) | (1,410) | (1,867) |
| | | | | | | | | | | |
| **Available Front Office Transactions** | **1,468** | **1,468** | **1,468** | **1,468** | **1,468** | **1,468** | **1,468** | **1,468** | **1,468** | **1,468** |
| **Uncommitted FOTs to meet remaining Need** | 0 | 0 | 0 | 0 | 333 | 354 | 564 | 655 | 1,410 | 1,468 |
| **Net Surplus (Deficit)** | 1,806 | 922 | 864 | 769 | 0 | 0 | 0 | 0 | 0 | (399) |

1/ The Energy Efficiency line includes selected Energy Efficiency from the 2019 IRP preferred portfolio.

## Table 5.13 (cont.) – Winter Peak System Capacity Loads and Resources without Resource Additions[1/]

| 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 |
| Class 1 DSM | 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) |
| **East Existing Resources** | **5,636** | **5,590** | **5,529** | **5,341** | **5,330** | **5,333** | **5,309** | **4,313** | **4,287** |
| | | | | | | | | | |
| 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) |
| Interruptible | (177) | (177) | (177) | (177) | (177) | (177) | (177) | (177) | (177) |
| Energy Efficiency | (530) | (565) | (600) | (632) | (656) | (678) | (696) | (711) | (726) |
| **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 Obligation + Reserves** | **6,023** | **6,040** | **6,044** | **6,083** | **6,113** | **6,147** | **6,163** | **6,212** | **6,249** |
| **East Position** | (387) | (450) | (515) | (741) | (783) | (815) | (854) | (1,899) | (1,962) |
| **Available Front Office Transactions** | **309** | **309** | **309** | **309** | **309** | **309** | **309** | **309** | **309** |
| **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 |
| Class 1 DSM | 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) |
| **West Existing Resources** | **2,016** | **2,017** | **2,003** | **2,032** | **2,036** | **2,036** | **2,034** | **1,818** | **1,177** |
| | | | | | | | | | |
| 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) |
| Interruptible | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Energy Efficiency | (380) | (403) | (424) | (443) | (461) | (479) | (495) | (510) | (525) |
| **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 Obligation + Reserves** | **3,780** | **3,781** | **3,791** | **3,808** | **3,824** | **3,838** | **3,842** | **3,859** | **3,877** |
| **West Position** | (1,763) | (1,764) | (1,787) | (1,775) | (1,788) | (1,801) | (1,808) | (2,041) | (2,700) |
| **Available Front Office Transactions** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** | **1,159** |
| **System** | | | | | | | | | |
| **Total Resources** | 7,653 | 7,607 | 7,532 | 7,373 | 7,365 | 7,369 | 7,343 | 6,131 | 5,464 |
| **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** | (2,150) | (2,214) | (2,302) | (2,517) | (2,571) | (2,616) | (2,662) | (3,940) | (4,662) |
| | | | | | | | | | |
| **Available Front Office Transactions** | **1,468** | **1,468** | **1,468** | **1,468** | **1,468** | **1,468** | **1,468** | **1,468** | **1,468** |
| **Uncommitted FOTs to meet remaining Need** | 1,468 | 1,468 | 1,468 | 1,468 | 1,468 | 1,468 | 1,468 | 1,468 | 1,468 |
| **Net Surplus (Deficit)** | (682) | (746) | (835) | (1,049) | (1,103) | (1,148) | (1,194) | (2,472) | (3,194) |

1/ The Energy Efficiency line includes selected Energy Efficiency from the 2019 IRP preferred portfolio.

Figure 5.6 through Figure 5.9 are graphic representations of the above tables for annual capacity position for the summer system, winter system, east control area, and west control area. Also shown in the system capacity position graph are available FOTs, which can be used to meet capacity needs. The market availability assumptions used for portfolio modeling are discussed further in Chapter 6 (Resource Options) and Volume II, Appendix J (Western Resource Adequacy Evaluation).

**Figure 5.6 – Summer System Capacity Position Trend**

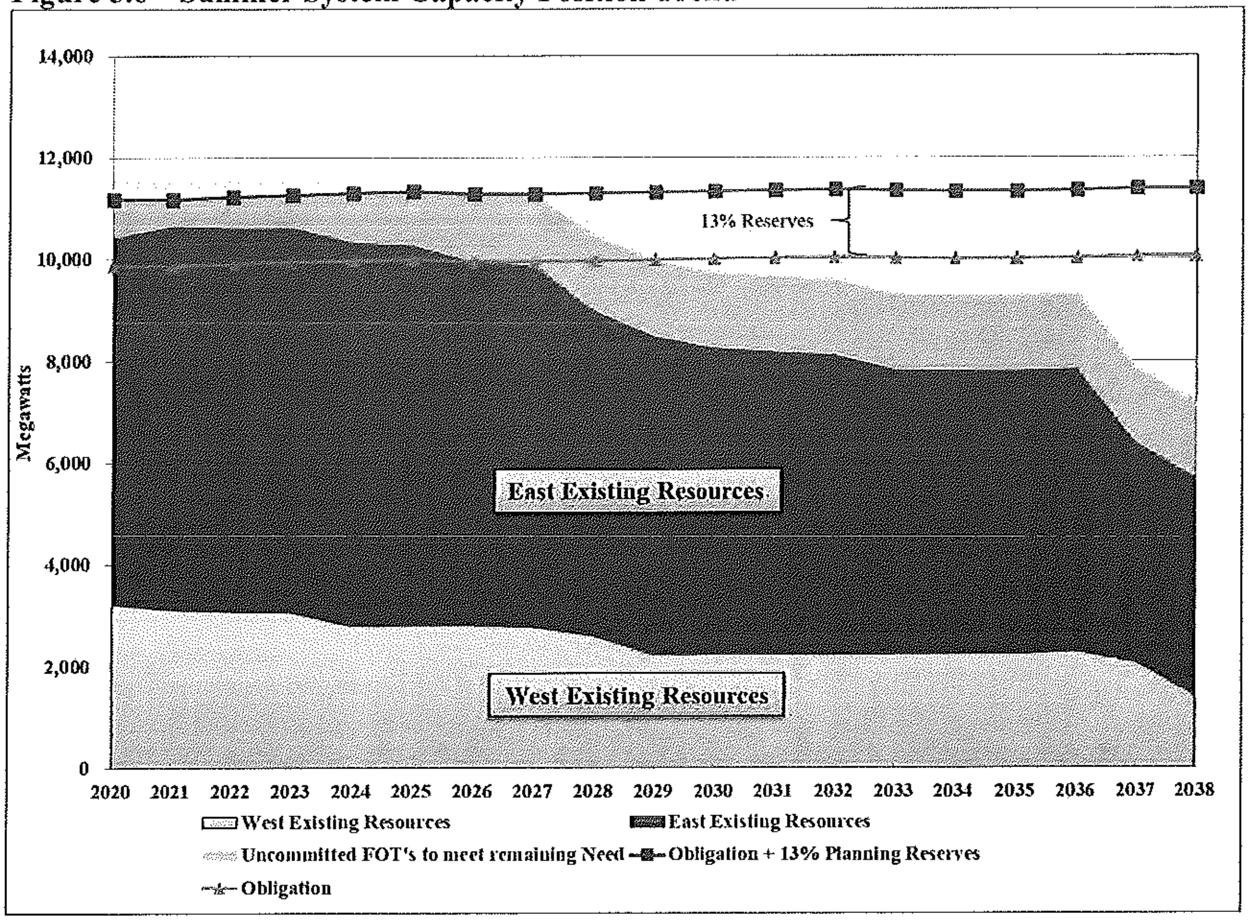


**Figure 5.7 – Winter System Capacity Position Trend**

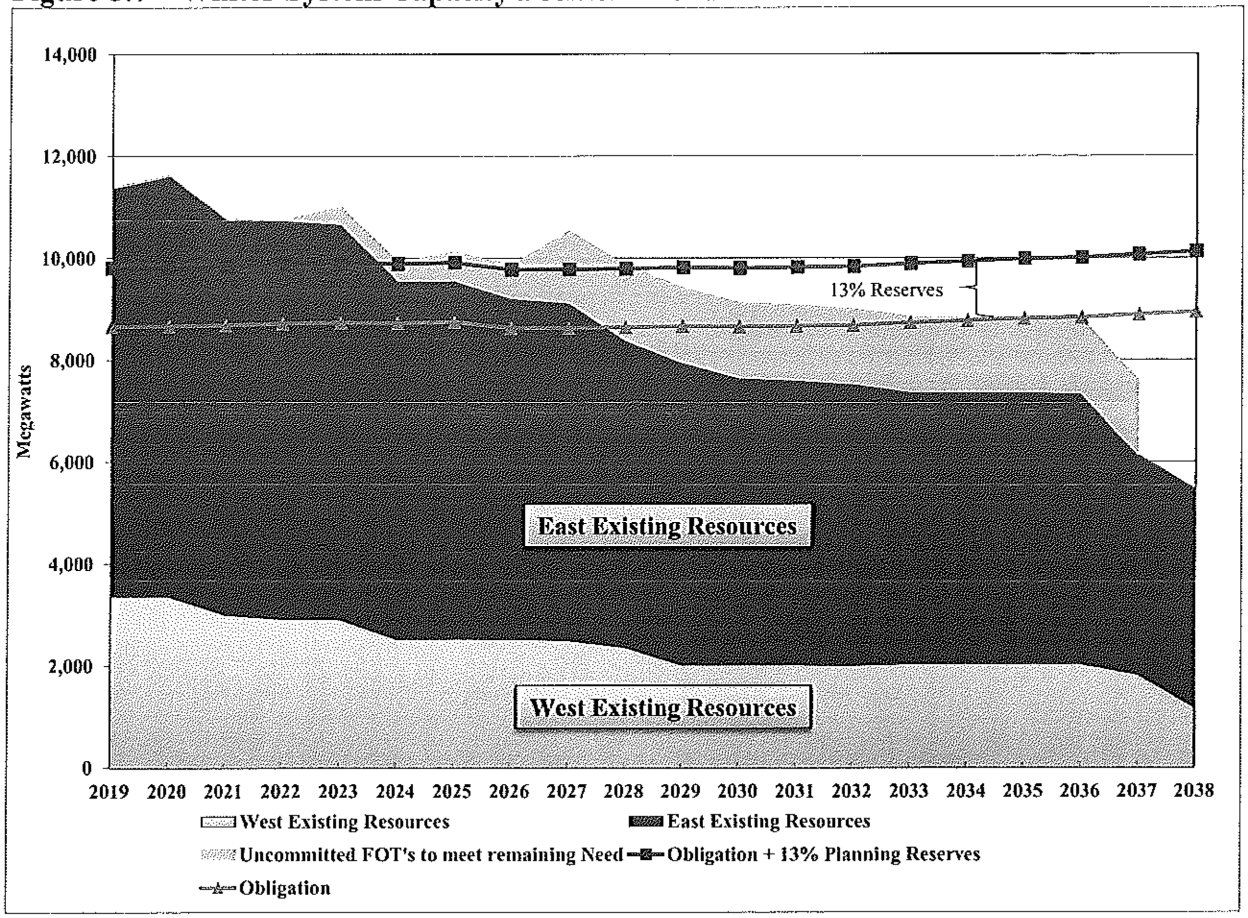


Figure 5.8 – East Summer Capacity Position Trend

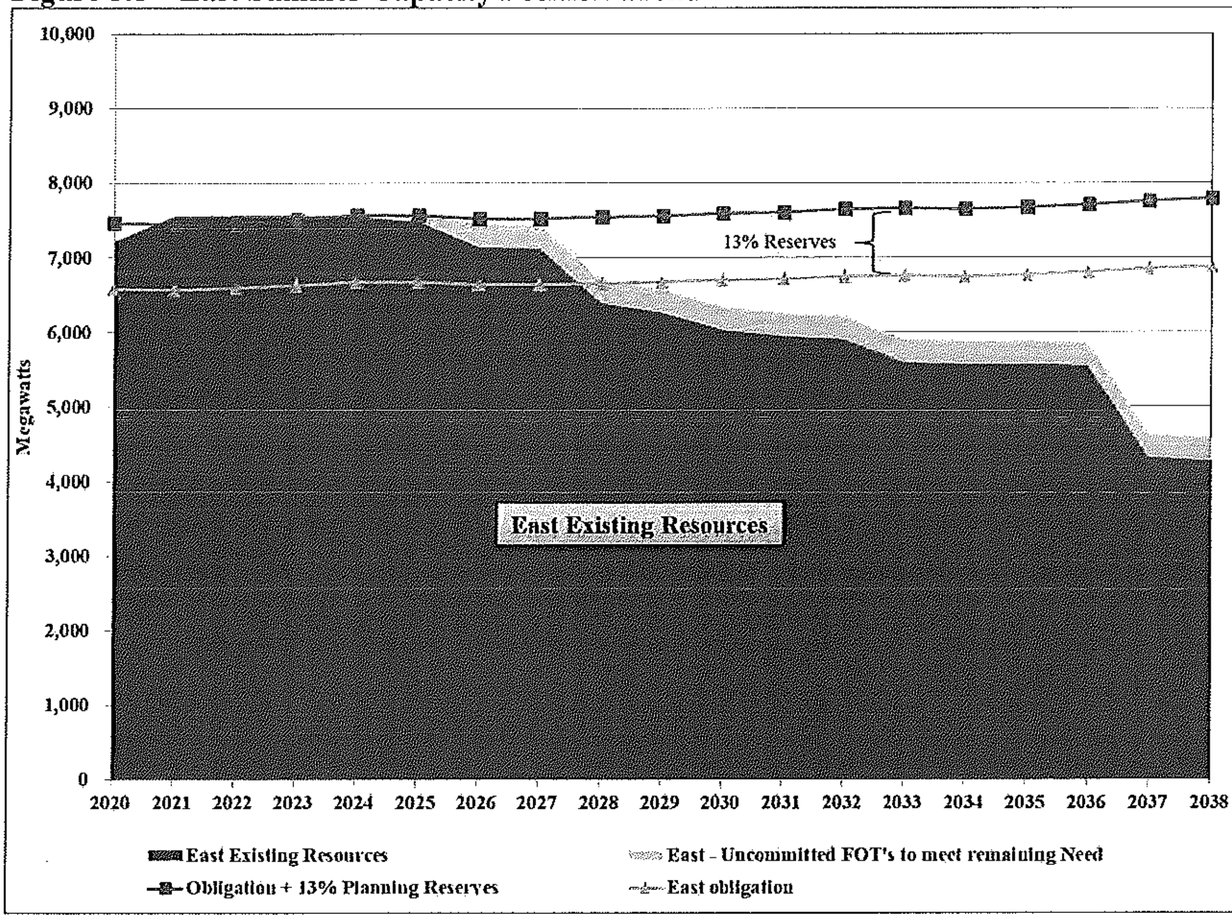
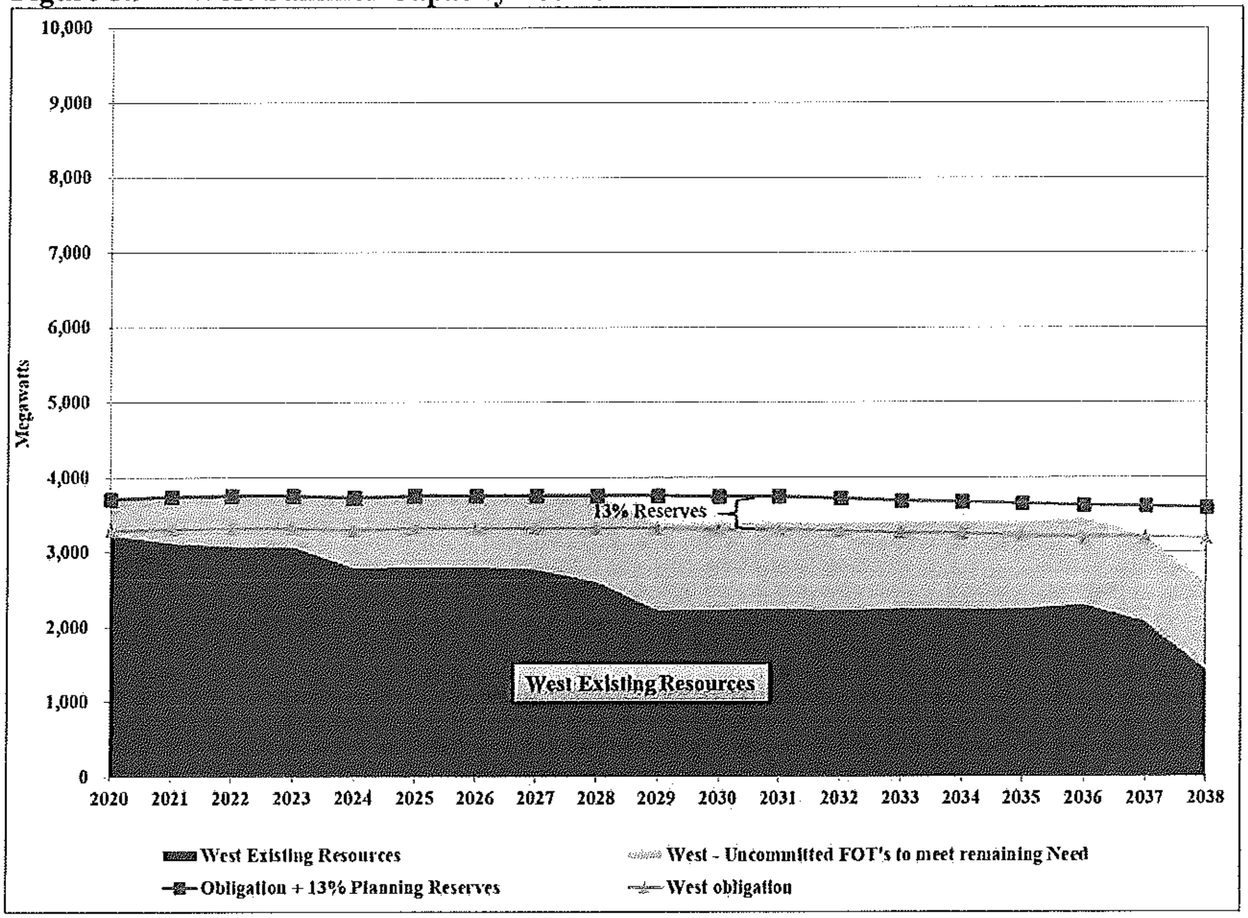


**Figure 5.9 – West Summer Capacity Position Trend**




## Energy Balance Determination

### Methodology

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

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

The average obligation is computed using the following formula:

> **Obligation** = Load + Firm Sales

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

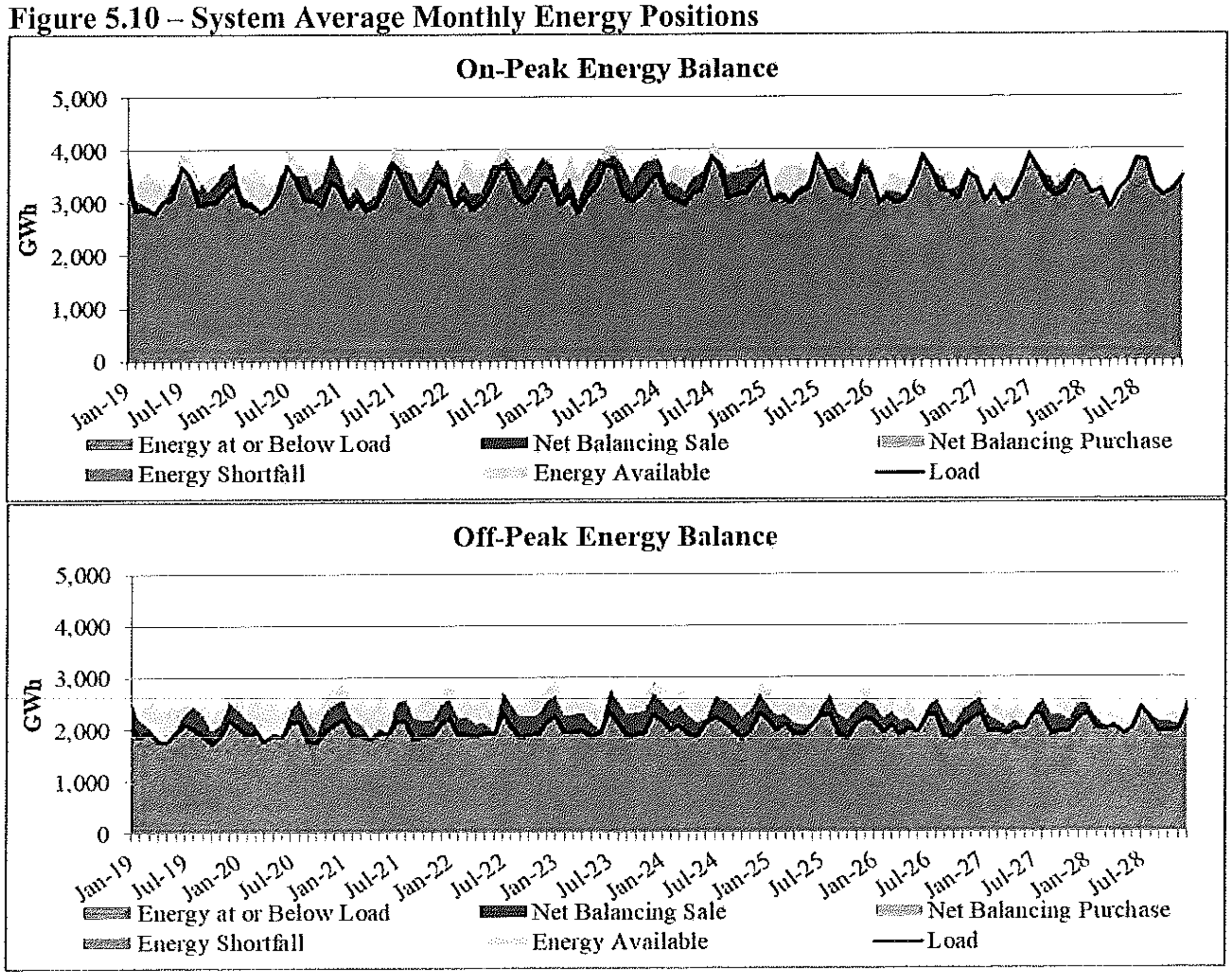
> **Energy Position** = Existing Resources – Obligation – Operating Reserve Requirements

## Energy Balance Results

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

Figure 5.10 provides a snapshot of how existing system resources could be used to meet forecasted load across on-peak and off-peak periods given the assumptions about resource availability and wholesale power and natural gas prices. At times, resources are economically dispatched above load levels facilitating net system balancing sales. At other times, economic conditions result in net system balancing purchases, which occur more often during on-peak periods. Figure 5.10 also shows how much energy is available from existing resources at any given point in time. Those periods where all available resource energy falls below forecasted loads are highlighted in red, and indicate short energy positions without the addition of incremental resources to the portfolio.

**Figure 5.10 – System Average Monthly Energy Positions**



Ex. AA-S-5

# CHAPTER 6 – RESOURCE OPTIONS

## CHAPTER HIGHLIGHTS

- PacifiCorp developed resource attributes and costs for expansion resources that reflect updated information from project experience, industry vendors, public meeting comments and studies.
- Resource costs have been generally stable since the previous integrated resource plan (IRP) and cost increases have been modest to declining. The cost of solar photovoltaic modules and balance of plant equipment decreased in 2018, continuing the downward cost trend of the past several years. Likewise, costs of wind turbines and batteries, and associated balance of plant costs, have shown a decline.
- Geothermal power purchase agreements (PPAs) are included as supply-side options in this IRP and updated to reflect current conditions.
- The combustion turbine types, configurations, and siting locations are identified in the supply-side resource options table. Performance and costs have been updated.
- Energy storage systems continue to be of interest to PacifiCorp, its stakeholders, and the industry at large. Options for advanced large batteries (15 megawatts (MW) and larger), renewable (wind and solar) plus storage, pumped hydro and compressed air energy storage are included in this IRP.
- For this IRP, PacifiCorp developed the capability for the System Optimizer (SO) model to endogenously model transmission upgrades.
- A 2018 Long Term Generation Resource Assessment study that was conducted by Navigant Consulting, Inc. served as the basis for updated resource characterizations covering private generation. The demand-side resource information was converted into supply curves grouped into cost bundles by measure or product type and competed against other resource alternatives in IRP modeling.
- PacifiCorp continued to apply cost reduction credits to energy efficiency, reflecting risk mitigation benefits, transmission and distribution investment deferral benefits, and a ten percent market price credit for Washington and Oregon as allowed by the Northwest Power Act.

## Introduction

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

## Supply-side Resources

The list of supply-side resource options reflect the realities evidenced through permitting, internally generated studies and externally commissioned studies undertaken to better understand details of available generation resources. Capital costs for some resource options have declined while others have remained stable compared to the 2017 IRP. New wind resources were given particular attention after the 2017 IRP selected a combination of wind and transmission resources for investment that would provide value for PacifiCorp's customers. Energy storage options of at least one MW continue to be of interest to PacifiCorp, its stakeholders, and the industry at large. PacifiCorp analyzed options for large pumped hydro projects and utility scale batteries. In response to stakeholder requests and utility industry trends, PacifiCorp studied multiple different battery energy storage configurations and combined battery configurations collocated with wind and solar projects. Solar resource options examined 200 MW single axis tracking facilities to reflect the industry trend of larger utility-size photovoltaic (PV) systems. A variety of gas-fueled generating resources were identified after consultation with major suppliers, large engineering-consulting firm and stakeholders. The combustion turbine types and configurations identified for consideration in the 2019 IRP are the same as those used in the 2017 IRP. Combustion turbine types and configurations remained the same because the market continued to improve the ability of existing technology to provide firming for variable energy resources. The capital and operating costs of simple and combined-cycle gas turbine plants have remained relatively low in recent years, with a flat to slightly decreasing cost trend. New coal-fueled and nuclear resources received minimal focus during this cycle due to ongoing environmental, economic, permitting and sociopolitical obstacles.

## Derivation of Resource Attributes

The supply-side resource options were developed from a combination of resources. The process began with the list of major generating resources from the 2017 IRP. This resource list was reviewed and modified to reflect stakeholder input, new technology developments, environmental factors, cost dynamics and anticipated permitting requirements. Once the basic list of resources was determined, the cost-and-performance attributes for each resource were estimated. The information sources used are listed below, followed by a brief description on how they were used in the development of the supply-side resource table (SSR), which is used to develop inputs for IRP modeling:

- Recent (2018) third-party, cost-and-performance estimates;
- Publicly available cost and performance estimates;
- Actual PacifiCorp or electric utility industry installations, providing current construction/maintenance costs and performance data with similar resource attributes;
- Projected PacifiCorp or electric utility industry installations, providing projected construction/maintenance costs and performance data of similar or identical resource options; and
- Recent requests for proposals (RFP) and requests for information (RFI).

Recent third-party engineering information from original equipment manufacturers were used to develop capital, operating and maintenance costs, performance and operating characteristics and planned outage cycle estimates. Engineering-consultants or government agencies have access to this data based on prior research studies, academia, actual installations, and direct information exchanges with original equipment manufacturers. Examples of this type of effort include the 2018 Black & Veatch estimates prepared for simple cycle and combined cycle options. For this IRP cycle, the energy storage effort was performed by Burns & McDonnell and covers solar and wind resources. The Burns & McDonnell study builds upon prior energy storage studies, updates cost and technical information, and adds combined renewables plus energy storage resource options.

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

Recent RFIs and RFPs also provide a useful source of cost-and-performance data. In these cases, original equipment manufacturers provided technology specific information. Examples of RFIs informing the SSR include obtaining updated equipment pricing for wind turbine equipment from original equipment suppliers and reviews of capital costs prepared by engineering firms by engineer-procure-construct firms.

## Handling of Technology Improvement Trends and Cost Uncertainties

The capital cost uncertainty for some generation technologies is relatively high. Various factors contribute to this uncertainty, including the relatively small number of facilities that have been built, especially for new and emerging technologies, as well as prolonged economic uncertainty. Despite this uncertainty, the cost profile between the 2017 IRP and the 2019 IRP has not changed significantly. For example, Figure 6.1 shows the trend in North American carbon steel sheet prices over the period from October 2015 through June 2018. The 2017 IRP included the historic carbon steel pricing shown in Figure 6.2. These figures illustrate near-term changes in capital costs of generation resources.

**Figure 6.1 – World Carbon Steel Pricing by Type**

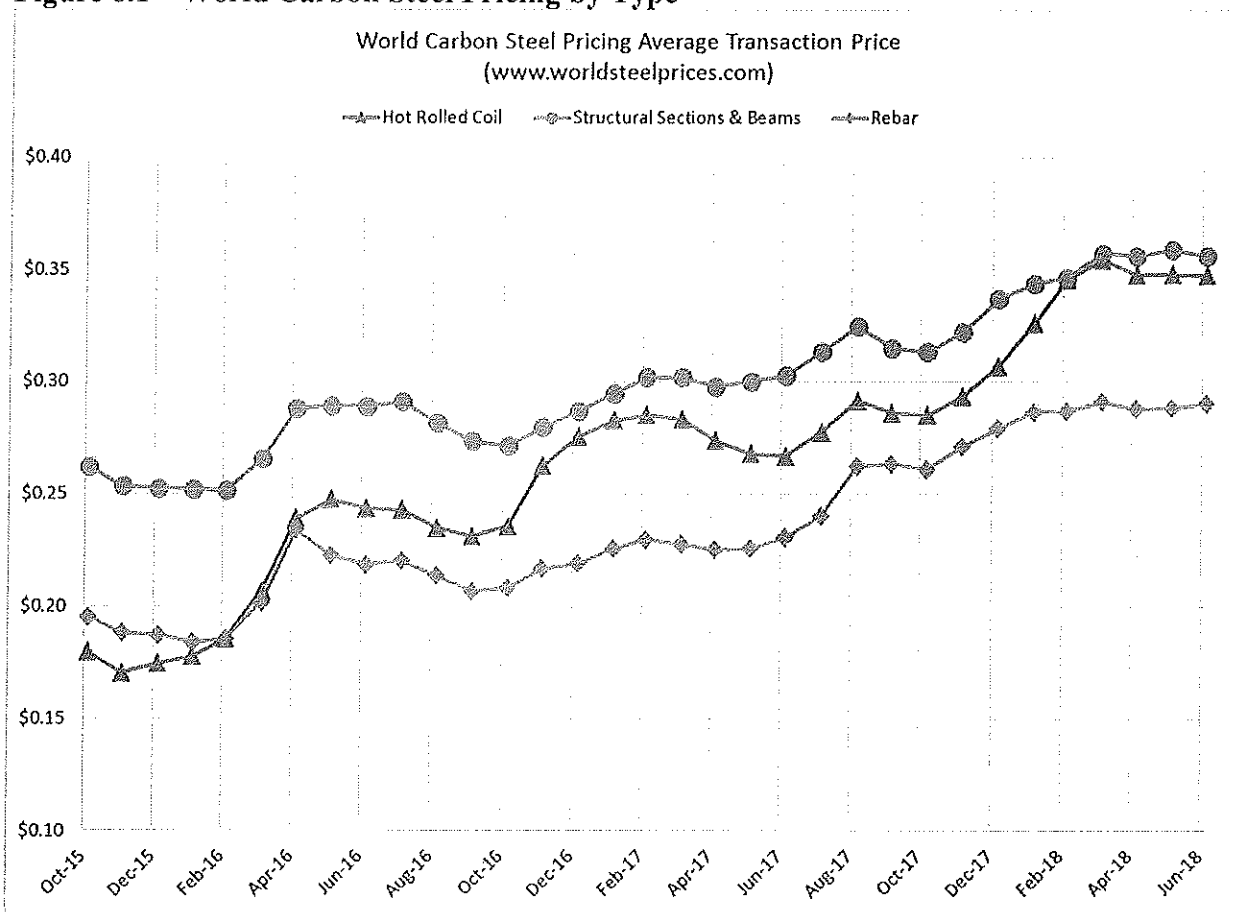
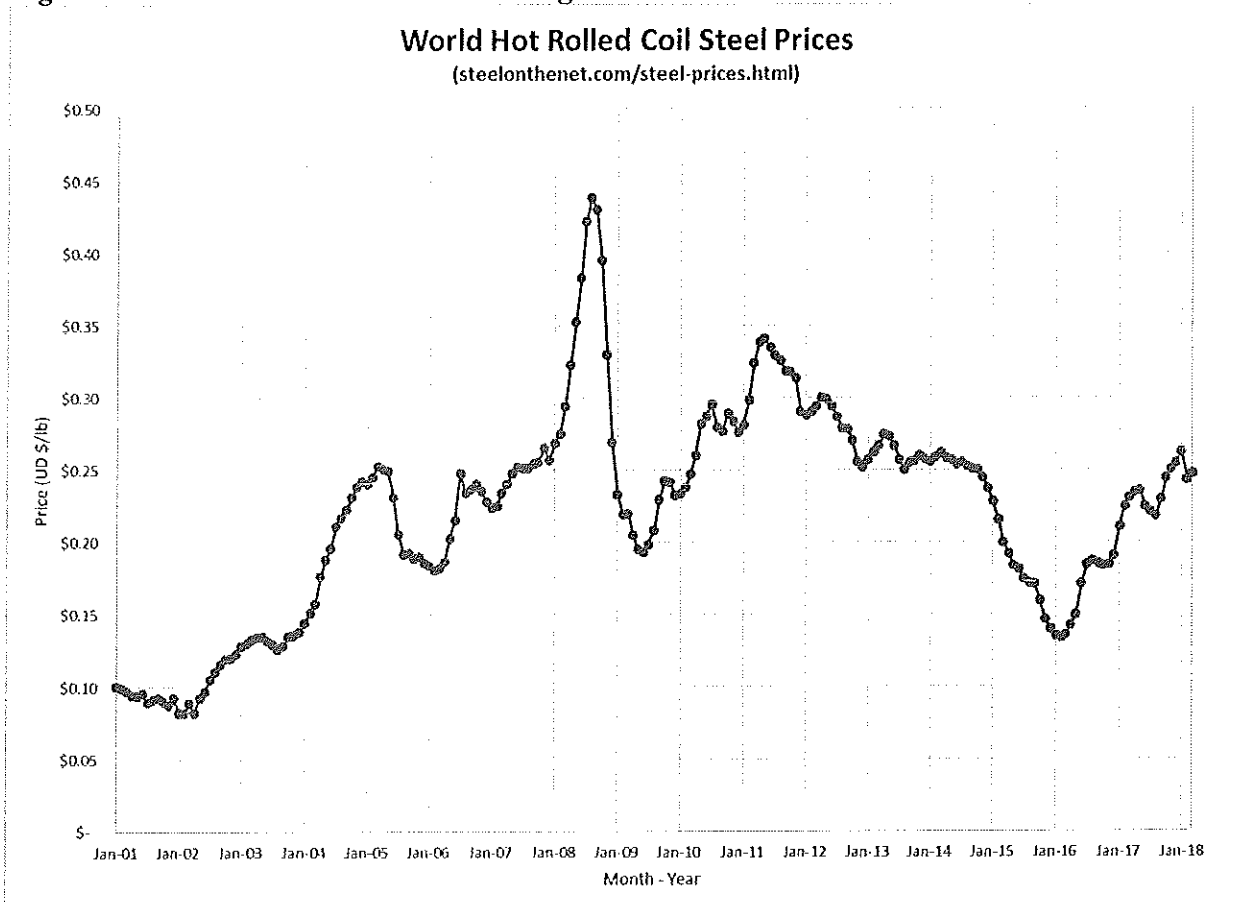


**Figure 6.2 - Historic Carbon Steel Pricing**



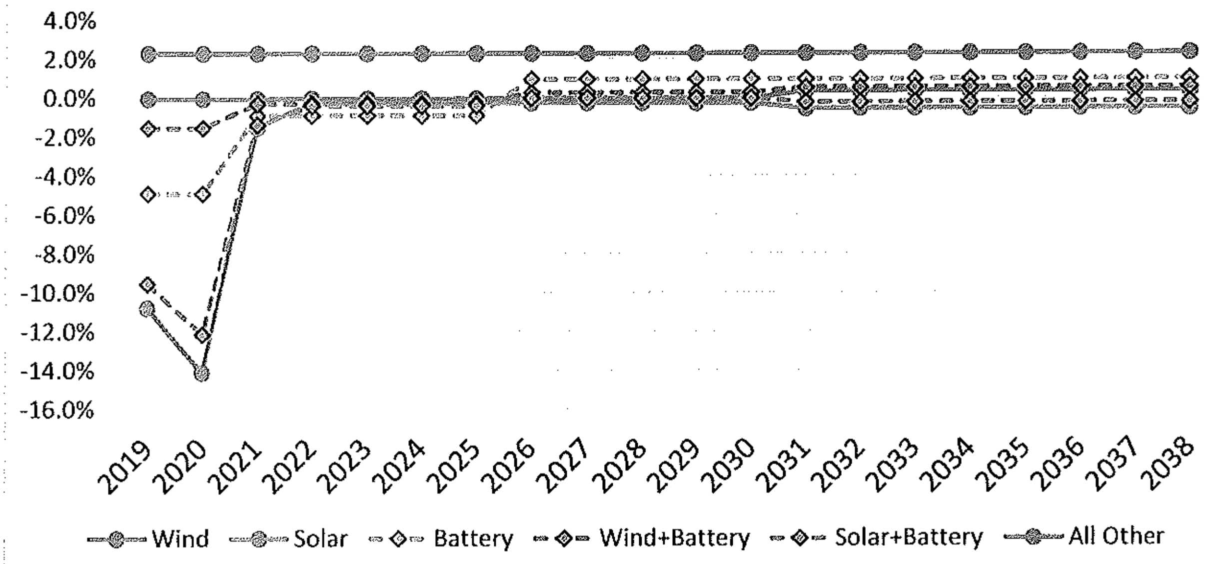

Prices for solar PV modules and balance of plant costs have come down since the 2017 IRP. Real prices are projected to continue to decline based upon technological and manufacturing improvements, but tariffs on Chinese imports and high demand for PV modules ahead of the phase out of the federal investment tax credits (ITC) for solar projects creates some degree of uncertainty in the solar market. The 2019 IRP anticipates the cost of new solar projects to decline approximately five percent per year during next three years and then to decline at a rate of approximately one percent per year beginning in year four.

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

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

Figure 6.3 shows nominal year-by-year capital cost escalation rates for wind, solar, battery, wind+battery, solar+battery, and all other resources.

**Figure 6.3 – Nominal Year-by-Year Escalation for Resource Capital Costs**




Solar annual capital cost escalation rates are based on unweighted median scenarios from General Electric Renewable Energy, the U.S. Energy Administration, and Burns and McDonnell—note, rates for 2019 and 2020 are adjusted to calibrate levelized costs to be consistent with pricing received in the 2017S RFP.

Wind annual capital cost escalation rates are based on unweighted median scenarios from Energy+Environmental Economics, General Electric Renewable Energy, Berkley Labs, ArcTechnica, the Office of Energy Efficiency & Renewable Energy Administration, and Burns and McDonnell—note, rates for 2019 and 2020 are adjusted to calibrate levelized costs consistent with pricing received in the 2017R RFP. Annual capital cost escalation rates for batteries are based on data from Burns and McDonnell. All other resources are assumed to escalate at 2.28 percent per year.

## Resource Options and Attributes

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

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

- 5,050 feet elevation: central Utah, southern Idaho, central Wyoming.
- 6,500 feet elevation: southwestern Wyoming.

Table 6.2 and Table 6.3 present the total resource cost attributes for supply-side resource options, and are based on estimates of the first-year, real-levelized costs for resources, stated in June 2018 dollars. Similar to the approach taken in previous IRPs, it is not currently envisioned that new combined cycle resources could be economically permitted in northern Utah, specifically Salt Lake/Utah/Davis/Box Elder counties due to state implementation plans for these counties regarding particulate matter of 2.5 microns and less ($PM_{2.5}$).

A Glossary of Terms and a Glossary of Acronyms from the SSR is summarized in Table 6.4 and Table 6.5.

## Table 6.1 – 2019 Supply-Side Resource Table (2018$)

| Description | | Resource Characteristics | | | | Costs | | | Operating Characteristics | | | | Environmental | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Fuel | Resource | Elevation (AFSL) | Net Capacity (MW) | Commercial Operation Year | Design Life (yrs) | Base Capital ($/KW) | Var O&M ($/MWh) | Fixed O&M ($/KW-yr) | Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency | EFOR (%) | POR (%) | Water Consumed (Gal/MWh) | SO2 (lbs/MMBtu) | NOx (lbs/MMBtu) | Hg (lbs/TBTu) | CO2 (lbs/MMBtu) |
| Natural Gas | SCCT Aero x3, ISO | 0 | 142 | 2023 | 30 | 1,570 | 7.54 | 27.14 | 9279 | 2.6 | 3.9 | 58 | 0.0006 | 0.009 | 0.255 | 117 |
| Natural Gas | Intercooled SCCT Aero x2, ISO | 0 | 231 | 2023 | 30 | 1,092 | 5.05 | 18.78 | 8725 | 2.9 | 3.9 | 80 | 0.0006 | 0.009 | 0.255 | 117 |
| Natural Gas | SCCT Frame "F" x1, ISO | 0 | 233 | 2023 | 35 | 704 | 5.50 | 13.28 | 9811 | 2.7 | 3.9 | 20 | 0.0006 | 0.009 | 0.255 | 117 |
| Natural Gas | IC Recips x 6, ISO | 0 | 111 | 2023 | 35 | 1,810 | 7.45 | 29.82 | 8272 | 2.5 | 5.0 | 5 | 0.0006 | 0.0288 | 0.255 | 117 |
| Natural Gas | CCCT Dry "G/H", 1x1, ISO | 0 | 419 | 2024 | 40 | 1,469 | 1.76 | 20.52 | 6847 | 2.5 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "G/H", DF, 1x1, ISO | 0 | 51 | 2024 | 40 | 478 | 0.15 | 5.39 | 6847 | 0.8 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "G/H", 2x1, ISO | 0 | 840 | 2025 | 40 | 1,060 | 1.67 | 13.79 | 6861 | 2.5 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "G/H", DF, 2x1, ISO | 0 | 102 | 2025 | 40 | 365 | 0.16 | 4.44 | 6861 | 0.8 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "J/HA.02", 1x1, ISO | 0 | 539 | 2024 | 40 | 1,218 | 1.70 | 17.66 | 6787 | 2.5 | 3.8 | 0 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "J/HA.02", DF, 1x1, ISO | 0 | 63 | 2024 | 40 | 407 | 0.16 | 4.86 | 6787 | 0.8 | 3.8 | 0 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry, "J/HA.02" 2X1, ISO | 0 | 1,083 | 2025 | 40 | 881 | 1.62 | 12.00 | 6787 | 2.5 | 3.8 | 0 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "J/HA.02", DF, 2X1, ISO | 0 | 126 | 2025 | 40 | 316 | 0.16 | 4.05 | 6787 | 0.8 | 3.8 | 0 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | SCCT Aero x3 | 1,500 | 138 | 2023 | 30 | 1,612 | 7.76 | 27.96 | 9228 | 2.6 | 3.9 | 58 | 0.0006 | 0.009 | 0.255 | 117 |
| Natural Gas | Intercooled SCCT Aero x2 | 1,500 | 221 | 2023 | 30 | 1,143 | 5.35 | 19.88 | 8689 | 2.9 | 3.9 | 80 | 0.0006 | 0.009 | 0.255 | 117 |
| Natural Gas | SCCT Frame "F" x1 | 1,500 | 221 | 2023 | 35 | 741 | 5.81 | 14.02 | 9792 | 2.7 | 3.9 | 20 | 0.0006 | 0.009 | 0.255 | 117 |
| Natural Gas | IC Recips x 6 | 1,500 | 111 | 2023 | 35 | 1,810 | 7.45 | 29.82 | 8272 | 2.5 | 5.0 | 5 | 0.0006 | 0.0288 | 0.255 | 117 |
| Natural Gas | CCCT Dry "G/H", 1x1 | 1,500 | 396 | 2024 | 40 | 1,552 | 1.86 | 21.68 | 6788 | 2.5 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "G/H", DF, 1x1 | 1,500 | 51 | 2024 | 40 | 478 | 0.15 | 5.39 | 6788 | 0.8 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "G/H", 2x1 | 1,500 | 795 | 2025 | 40 | 1,120 | 1.77 | 14.57 | 6800 | 2.5 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "G/H", DF, 2x1 | 1,500 | 102 | 2025 | 40 | 365 | 0.16 | 4.44 | 6800 | 0.8 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "J/HA.02", 1x1 | 1,500 | 510 | 2024 | 40 | 1,288 | 1.80 | 18.67 | 6732 | 2.5 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "J/HA.02", DF, 1x1 | 1,500 | 63 | 2024 | 40 | 407 | 0.16 | 4.86 | 6732 | 0.8 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry, "J/HA.02" 2X1 | 1,500 | 1,023 | 2025 | 40 | 932 | 1.71 | 12.69 | 6732 | 2.5 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "J/HA.02", DF, 2X1 | 1,500 | 126 | 2025 | 40 | 316 | 0.16 | 4.05 | 6732 | 0.8 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | SCCT Aero x3 | 3,000 | 131 | 2023 | 30 | 1,704 | 8.21 | 29.58 | 9232 | 2.6 | 3.9 | 58 | 0.0006 | 0.009 | 0.255 | 117 |
| Natural Gas | Intercooled SCCT Aero x2 | 3,000 | 209 | 2023 | 30 | 1,209 | 5.67 | 21.10 | 8687 | 2.9 | 3.9 | 80 | 0.0006 | 0.009 | 0.255 | 117 |
| Natural Gas | SCCT Frame "F" x1 | 3,000 | 210 | 2023 | 35 | 782 | 6.13 | 14.81 | 9799 | 2.7 | 3.9 | 20 | 0.0006 | 0.009 | 0.255 | 117 |
| Natural Gas | IC Recips x 6 | 3,000 | 111 | 2023 | 35 | 1,810 | 7.45 | 29.82 | 8273 | 2.5 | 5.0 | 5 | 0.0006 | 0.0288 | 0.255 | 117 |
| Natural Gas | CCCT Dry "G/H", 1x1 | 3,000 | 375 | 2024 | 40 | 1,641 | 1.97 | 22.92 | 6762 | 2.5 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "G/H", DF, 1x1 | 3,000 | 51 | 2024 | 40 | 478 | 0.15 | 5.39 | 6762 | 0.8 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "G/H", 2x1 | 3,000 | 752 | 2025 | 40 | 1,184 | 1.86 | 15.39 | 6775 | 2.5 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "G/H", DF, 2x1 | 3,000 | 102 | 2025 | 40 | 365 | 0.16 | 4.44 | 6775 | 0.8 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "J/HA.02", 1x1 | 3,000 | 482 | 2024 | 40 | 1,363 | 1.90 | 19.73 | 6690 | 2.5 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "J/HA.02", DF, 1x1 | 3,000 | 63 | 2024 | 40 | 407 | 0.16 | 4.86 | 6690 | 0.8 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry, "J/HA.02" 2X1 | 3,000 | 967 | 2025 | 40 | 986 | 1.81 | 13.41 | 6692 | 2.5 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "J/HA.02", DF, 2X1 | 3,000 | 126 | 2025 | 40 | 316 | 0.16 | 4.05 | 6692 | 0.8 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | SCCT Aero x3 | 5,050 | 122 | 2023 | 30 | 1,829 | 8.85 | 31.86 | 9229 | 2.6 | 3.9 | 58 | 0.0006 | 0.009 | 0.255 | 117 |
| Natural Gas | Intercooled SCCT Aero x2 | 5,050 | 194 | 2023 | 30 | 1,305 | 6.14 | 22.82 | 8680 | 2.9 | 3.9 | 80 | 0.0006 | 0.009 | 0.255 | 117 |
| Natural Gas | SCCT Frame "F" x1 | 5,050 | 194 | 2023 | 35 | 843 | 6.61 | 15.97 | 9805 | 2.7 | 3.9 | 20 | 0.0006 | 0.009 | 0.255 | 117 |
| Natural Gas | IC Recips x 6 | 5,050 | 111 | 2023 | 35 | 1,810 | 7.45 | 29.82 | 8280 | 2.5 | 5.0 | 5 | 0.0006 | 0.0288 | 0.255 | 117 |
| Natural Gas | CCCT Dry "G/H", 1x1 | 5,050 | 344 | 2024 | 40 | 1,788 | 2.12 | 24.74 | 6510 | 2.5 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "G/H", DF, 1x1 | 5,050 | 51 | 2024 | 40 | 478 | 0.15 | 5.39 | 6510 | 0.8 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "G/H", 2x1 | 5,050 | 687 | 2025 | 40 | 1,297 | 2.01 | 16.63 | 6520 | 2.5 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "G/H", DF, 2x1 | 5,050 | 102 | 2025 | 40 | 365 | 0.16 | 4.44 | 6520 | 0.8 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "J/HA.02", 1x1 | 5,050 | 442 | 2024 | 40 | 1,485 | 2.05 | 21.26 | 6464 | 2.5 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "J/HA.02", DF, 1x1 | 5,050 | 63 | 2024 | 40 | 407 | 0.16 | 4.86 | 6464 | 0.8 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry, "J/HA.02" 2X1 | 5,050 | 884 | 2025 | 40 | 1,079 | 1.95 | 14.45 | 6469 | 2.5 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "J/HA.02", DF, 2X1 | 5,050 | 126 | 2025 | 40 | 316 | 0.16 | 4.05 | 6469 | 0.8 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | SCCT Aero x3 | 6,500 | 113 | 2023 | 30 | 1,975 | 9.60 | 34.56 | 9209 | 2.6 | 3.9 | 58 | 0.0006 | 0.009 | 0.255 | 117 |
| Natural Gas | Intercooled SCCT Aero x2 | 6,500 | 181 | 2023 | 30 | 1,394 | 6.45 | 24.00 | 8694 | 2.9 | 3.9 | 80 | 0.0006 | 0.009 | 0.255 | 117 |
| Natural Gas | SCCT Frame "F" x1 | 6,500 | 185 | 2023 | 35 | 887 | 6.96 | 16.81 | 9786 | 2.7 | 3.9 | 20 | 0.0006 | 0.009 | 0.255 | 117 |
| Natural Gas | IC Recips x 6 | 6,500 | 111 | 2023 | 35 | 1,810 | 7.75 | 31.04 | 8320 | 2.5 | 5.0 | 5 | 0.0006 | 0.0288 | 0.255 | 117 |
| Natural Gas | CCCT Dry "G/H", 1x1 | 6,500 | 333 | 2024 | 40 | 1,843 | 2.25 | 26.20 | 6757 | 2.5 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "G/H", DF, 1x1 | 6,500 | 51 | 2024 | 40 | 478 | 0.15 | 5.39 | 6757 | 0.8 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "G/H", 2x1 | 6,500 | 669 | 2025 | 40 | 1,330 | 2.13 | 17.61 | 6772 | 2.5 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "G/H", DF, 2x1 | 6,500 | 102 | 2025 | 40 | 365 | 0.16 | 4.44 | 6772 | 0.8 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "J/HA.02", 1x1 | 6,500 | 424 | 2024 | 40 | 1,549 | 2.15 | 22.33 | 6681 | 2.5 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "J/HA.02", DF, 1x1 | 6,500 | 63 | 2024 | 40 | 407 | 0.16 | 4.86 | 6681 | 0.8 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry, "J/HA.02" 2X1 | 6,500 | 851 | 2025 | 40 | 1,120 | 2.05 | 15.18 | 6681 | 2.5 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |
| Natural Gas | CCCT Dry "J/HA.02", DF, 2X1 | 6,500 | 126 | 2025 | 40 | 316 | 0.16 | 4.06 | 6681 | 0.8 | 3.8 | 11 | 0.0006 | 0.0072 | 0.255 | 117 |

# Table 6.1 – 2019 Supply-Side Resource Table (2018$) (Continued)

| Description | | Resource Characteristics | | | | Costs | | | Operating Characteristics | | | | Environmental | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Fuel | Resource | Elevation (AFSL) | Net Capacity (MW) | Commercial Operation Year | Design Life (yrs) | Base Capital ($/KW) | Var O&M ($/MWh) | Fixed O&M ($/KW-yr) | Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency | EFOR (%) | POR (%) | Water Consumed (Gal/MWh) | SO2 (lbs/MMBtu) | NOx (lbs/MMBtu) | Hg (lbs/TBTu) | CO2 (lbs/MMBtu) |
| Coal | SCPC with CCS | 4,500 | 526 | 2036 | 40 | 6,462 | 7.00 | 72.22 | 13087 | 5.0 | 5.0 | 1,004 | 0.009 | 0.070 | 0.022 | 20.5 |
| Coal | IGCC with CCS | 4,500 | 466 | 2036 | 40 | 6,257 | 11.77 | 58.20 | 10823 | 8.0 | 7.0 | 394 | 0.009 | 0.050 | 0.333 | 20.5 |
| Coal | PC CCS retrofit @ 500 MW | 4,500 | -139 | 2033 | 20 | 1,419 | 6.47 | 77.76 | 14372 | 5.0 | 5.0 | 1,004 | 0.005 | 0.070 | 1.200 | 20.5 |
| Coal | SCPC with CCS | 6,500 | 692 | 2036 | 40 | 7,318 | 7.58 | 67.09 | 13242 | 5.0 | 5.0 | 1,004 | 0.009 | 0.070 | 0.022 | 20.5 |
| Coal | IGCC with CCS | 6,500 | 456 | 2036 | 40 | 7,085 | 14.11 | 63.40 | 11047 | 8.0 | 7.0 | 394 | 0.009 | 0.050 | 0.333 | 20.5 |
| Coal | PC CCS retrofit @ 500 MW | 6,500 | -139 | 2031 | 20 | 1,607 | 7.00 | 72.22 | 14372 | 5.0 | 5.0 | 1,004 | 0.005 | 0.070 | 1.200 | 20.5 |
| Geothermal | Blundell Dual Flash 90% CF | 4,500 | 35 | 2021 | 40 | 5,708 | 1.16 | 103.85 | n/a | 5.0 | 5.0 | 10 | n/a | n/a | n/a | n/a |
| Geothermal | Greenfield Binary 90% CF | 4,500 | 43 | 2023 | 40 | 5,973 | 1.16 | 103.85 | n/a | 5.0 | 5.0 | 270 | n/a | n/a | n/a | n/a |
| Geothermal | Generic Geothermal PPA 90% CF | 4,500 | 30 | 2021 | 20 | 0 | 77.34 | 0.00 | n/a | 5.0 | 5.0 | 270 | n/a | n/a | n/a | n/a |
| Wind | 3.6 MW Wind turbine 37.1% CF WA, 2020 | 4,500 | 200 | 2020 | 30 | 1,354 | 0.00 | 27.99 | n/a | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Wind | 3.6 MW Wind turbine 37.1% CF OR, 2020 | 1,500 | 200 | 2020 | 30 | 1,334 | 0.00 | 27.99 | n/a | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Wind | 3.6 MW Wind turbine 37.1% CF ID, 2020 | 4,500 | 200 | 2020 | 30 | 1,358 | 0.00 | 27.99 | n/a | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Wind | 3.6 MW Wind turbine 29.5% CF UT, 2020 | 6,500 | 200 | 2020 | 30 | 1,301 | 0.00 | 27.99 | n/a | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Wind | 3.6 MW Wind turbine 43.6% CF WY, 2020 | 1,500 | 240 | 2020 | 30 | 1,301 | 0.65 | 27.99 | n/a | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Wind + Storag | Wind + Stor, Pocatello, ID, 200 MW+ 50 MW \| 100 MWh | 4,500 | 200 | 2023 | 30 | 1,738 | 0.00 | 29.18 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Wind + Storag | Wind + Stor, Arlington, OR, 200 MW+ 50 MW \| 100 MWh | 1,500 | 200 | 2023 | 30 | 1,765 | 0.00 | 29.18 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Wind + Storag | Wind + Stor, Monticello, UT, 200 MW+ 50 MW \| 100 MWh | 4,500 | 200 | 2023 | 30 | 1,735 | 0.00 | 29.18 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Wind + Storag | Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW \| 100 MWh | 6,500 | 200 | 2023 | 30 | 1,730 | 0.65 | 29.18 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Wind + Storag | Wind + Stor, Goldendale, WA, 200 MW+ 50 MW \| 100 MWh | 1,500 | 200 | 2023 | 30 | 1,772 | 0.00 | 29.18 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Wind + Storag | Wind + Stor, Pocatello, ID, 200 MW+ 50 MW \| 200 MWh | 4,500 | 200 | 2023 | 30 | 1,880 | 0.00 | 29.88 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Wind + Storag | Wind + Stor, Arlington, OR, 200 MW+ 50 MW \| 200 MWh | 1,500 | 200 | 2023 | 30 | 1,917 | 0.00 | 29.88 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Wind + Storag | Wind + Stor, Monticello, UT, 200 MW+ 50 MW \| 200 MWh | 4,500 | 200 | 2023 | 30 | 1,877 | 0.00 | 29.88 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Wind + Storag | Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW \| 200 MWh | 6,500 | 200 | 2023 | 30 | 1,872 | 0.65 | 29.88 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Wind + Storag | Wind + Stor, Goldendale, WA, 200 MW+ 50 MW \| 200 MWh | 1,500 | 200 | 2023 | 30 | 1,924 | 0.00 | 29.88 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Wind + Storag | Wind + Stor, Pocatello, ID, 200 MW+ 50 MW \| 400 MWh | 4,500 | 200 | 2023 | 30 | 2,158 | 0.00 | 31.03 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Wind + Storag | Wind + Stor, Arlington, OR, 200 MW+ 50 MW \| 400 MWh | 1,500 | 200 | 2023 | 30 | 2,214 | 0.00 | 31.03 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Wind + Storag | Wind + Stor, Monticello, UT, 200 MW+ 50 MW \| 400 MWh | 4,500 | 200 | 2023 | 30 | 2,155 | 0.00 | 31.03 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Wind + Storag | Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW \| 400 MWh | 6,500 | 200 | 2023 | 30 | 2,150 | 0.65 | 31.03 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Wind + Storag | Wind + Stor, Goldendale, WA, 200 MW+ 50 MW \| 400 MWh | 1,500 | 200 | 2023 | 30 | 2,221 | 0.00 | 31.03 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar | PV Idaho Falls, ID, 50 MW, 28.1% CF | 4,700 | 50 | 2021 | 25 | 1,366 | 0.00 | 21.72 | n/a | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar | PV Idaho Falls, ID, 200 MW, 2021, 28.1% CF | 4,700 | 200 | 2021 | 25 | 1,271 | 0.00 | 21.72 | n/a | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar | PV Lakeview, OR, 50 MW, 2021, 29.7% CF | 4,800 | 50 | 2021 | 25 | 1,424 | 0.00 | 22.35 | n/a | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar | PV Lakeview, OR, 200 MW, 2021, 29.7% CF | 4,800 | 200 | 2021 | 25 | 1,329 | 0.00 | 22.35 | n/a | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar | PV Milford, UT, 50 MW, 2021, 32.5% CF | 5,000 | 50 | 2021 | 25 | 1,363 | 0.00 | 22.32 | n/a | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar | PV Milford, UT, 200 MW, 2021, 32.5% CF | 5,000 | 200 | 2021 | 25 | 1,268 | 0.00 | 22.32 | n/a | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar | PV Utah North, 200 MW, 2021, 30.1% CF | 5,000 | 200 | 2021 | 25 | 1,266 | 0.00 | 21.13 | n/a | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar | PV Rock Springs, WY, 50 MW, 2021, 30.1% CF | 6,400 | 50 | 2021 | 25 | 1,360 | 0.00 | 21.13 | n/a | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar | PV Rock Springs, WY, 200 MW, 2021, 30.1% CF | 6,400 | 200 | 2021 | 25 | 1,266 | 0.00 | 21.13 | n/a | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar | PV Yakima, WA, 50 MW, 2021, 26% CF | 1,000 | 50 | 2021 | 25 | 1,422 | 0.00 | 22.35 | n/a | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar | PV Yakima, WA, 200 MW, 2021, 26% CF | 1,000 | 200 | 2021 | 25 | 1,327 | 0.00 | 22.35 | n/a | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor, Idaho Falls, ID, 50 MW + 10 MW X 20 MWh | 4,700 | 50 | 2021 | 25 | 1,628 | 0.00 | 23.48 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 100 MWh | 4,700 | 200 | 2021 | 25 | 1,470 | 0.00 | 22.91 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor,, Idaho Falls, ID, 50 MW + 10 MW X 40 MWh | 4,700 | 50 | 2021 | 25 | 1,756 | 0.00 | 25.03 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 200 MWh | 4,700 | 200 | 2021 | 25 | 1,614 | 0.00 | 24.24 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor, Idaho Falls, ID, 50 MW + 10 MW X 80 MWh | 4,700 | 50 | 2021 | 25 | 1,992 | 0.00 | 26.46 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 400 MWh | 4,700 | 200 | 2021 | 25 | 1,897 | 0.00 | 25.36 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor, Lakeview, OR, 50 MW + 10 MW X 20 MWh | 4,800 | 50 | 2021 | 25 | 1,706 | 0.00 | 23.48 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor, Lakeview, OR, 200 MW + 50 MW X 100 MWh | 4,800 | 200 | 2021 | 25 | 1,543 | 0.00 | 22.91 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor, Lakeview, OR, 50 MW + 10 MW X 40 MWh | 4,800 | 50 | 2021 | 25 | 1,844 | 0.00 | 25.03 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor, Lakeview, OR, 200 MW + 50 MW X 200 MWh | 4,800 | 200 | 2021 | 25 | 1,699 | 0.00 | 24.24 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor, Lakeview, OR, 50 MW + 10 MW X 80 MWh | 4,800 | 50 | 2021 | 25 | 2,098 | 0.00 | 26.46 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor,, Lakeview, OR, 200 MW + 50 MW X 400 MWh | 4,800 | 200 | 2021 | 25 | 2,004 | 0.00 | 25.36 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor., Milford, UT, 50 MW + 10 MW X 20 MWh | 5,000 | 50 | 2021 | 25 | 1,626 | 0.00 | 23.48 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor., Milford, UT, 200 MW + 50 MW X 100 MWh | 5,000 | 200 | 2021 | 25 | 1,467 | 0.00 | 22.91 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor., Milford, UT 50 MW + 10 MW X 40 MWh | 5,000 | 50 | 2021 | 25 | 1,754 | 0.00 | 25.03 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor., Milford, UT, 200 MW + 50 MW X 200 MWh | 5,000 | 200 | 2021 | 25 | 1,612 | 0.00 | 24.24 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor., Milford, UT, 50 MW + 10 MW X 80 MWh | 5,000 | 50 | 2021 | 25 | 1,990 | 0.00 | 26.46 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor., Milford, UT, 200 MW + 50 MW X 400 MWh | 5,000 | 200 | 2021 | 25 | 1,895 | 0.00 | 25.36 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor, Utah North, 200 MW + 50 MW X 200 MWh | 5,000 | 200 | 2021 | 25 | 1,609 | 0.00 | 24.24 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor., Rock Springs, WY, 50 MW + 10 MW X 20 MWh | 6,400 | 50 | 2021 | 25 | 1,623 | 0.00 | 23.48 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor., Rock Springs, WY, 200 MW + 50 MW X 100 MWh | 6,400 | 200 | 2021 | 25 | 1,464 | 0.00 | 22.91 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor., Rock Springs, WY, 50 MW + 10 MW X 40 MWh | 6,400 | 50 | 2021 | 25 | 1,751 | 0.00 | 25.03 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor., Rock Springs, WY, 200 MW + 50 MW X 200 MWh | 6,400 | 200 | 2021 | 25 | 1,609 | 0.00 | 24.24 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor., Rock Springs, WY, 50 MW + 10 MW X 80 MWh | 6,400 | 50 | 2021 | 25 | 1,987 | 0.00 | 26.46 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor., Rock Springs, WY, 200 MW + 50 MW X 400 MWh | 6,400 | 200 | 2021 | 25 | 1,892 | 0.00 | 25.36 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor., Yakima, WA, 50 MW + 10 MW X 20 MWh | 1,000 | 50 | 2021 | 25 | 1,704 | 0.00 | 23.48 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor, Yakima, WA, 200 MW + 50 MW X 100 MWh | 1,000 | 200 | 2021 | 25 | 1,541 | 0.00 | 22.91 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor, Yakima, WA, 50 MW + 10 MW X 40 MWh | 1,000 | 50 | 2021 | 25 | 1,842 | 0.00 | 25.03 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor, Yakima, WA, 200 MW + 50 MW X 200 MWh | 1,000 | 200 | 2021 | 25 | 1,697 | 0.00 | 24.24 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor, Yakima, WA, 50 MW + 10 MW X 80 MWh | 1,000 | 50 | 2021 | 25 | 2,097 | 0.00 | 26.46 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |
| Solar + Storag | PV + Stor, Yakima, WA, 200 MW + 50 MW X 400 MWh | 1,000 | 200 | 2021 | 25 | 2,002 | 0.00 | 25.36 | 1 | Included with CF | 0 | n/a | n/a | n/a | n/a | n/a |

## Table 6.1 – 2019 Supply-Side Resource Table (2018$) (Continued)

| Description | | Resource Characteristics | | | | Costs | | | Operating Characteristics | | | | Environmental | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Fuel | Resource | Elevation (AFSL) | Net Capacity (MW) | Commercial Operation Year | Design Life (yrs) | Base Capital ($/KW) | Var O&M ($/MWh) | Fixed O&M ($/KW-yr) | Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency | EFOR (%) | POR (%) | Water Consumed (Gal/MWh) | SO2 (lbs/MMBtu) | NOx (lbs/MMBtu) | Hg (lbs/TBTu) | CO2 (lbs/MMBtu) |
| Storage | Oregon PS, 400 MW X 3,800 MWh | 4,457 | 400 | 2025 | 60 | 3,095 | 0.00 | 16.76 | 79% | 3 | 7 | 0 | 0 | 0 | 0 | 0 |
| Storage | Oregon PS joint ownership, 100 MW X 950 MWh | 4,457 | 100 | 2025 | 60 | 3,099 | 0.00 | 16.76 | 79% | 3 | 7 | 0 | 0 | 0 | 0 | 0 |
| Storage | Washington PS, 1,200 MW X 16,800 MWh | 500 | 1,200 | 2029 | 60 | 2,719 | 0.00 | 12.50 | 79% | 3 | 7 | 0 | 0 | 0 | 0 | 0 |
| Storage | Wyoming PS, 700 MW X 7,000 MWh | 580 | 700 | 2027 | 60 | 3,255 | 0.00 | 17.00 | 79% | 3 | 7 | 0 | 0 | 0 | 0 | 0 |
| Storage | Wyoming PS, 400 MW X 3,400 MWh | 6,000 | 400 | 2028 | 60 | 2,348 | 0.00 | 17.00 | 79% | 3 | 7 | 0 | 0 | 0 | 0 | 0 |
| Storage | Utah PS, 300 MW X 1,800 MWh | 6,359 | 300 | 2025 | 60 | 2,991 | 0.00 | 17.00 | 79% | 3 | 7 | 0 | 0 | 0 | 0 | 0 |
| Storage | Idaho PS, 360 MW X 2,880 MWh | 5,000 | 360 | 2031 | 60 | 2,680 | 0.00 | 17.00 | 79% | 3 | 7 | 0 | 0 | 0 | 0 | 0 |
| Storage | Idaho PS, 360 MW X 2,880 MWh | 5,000 | 360 | 2031 | 60 | 2,680 | 0.00 | 17.00 | 79% | 3 | 7 | 0 | 0 | 0 | 0 | 0 |
| Storage | CAES, 320 MW X 15,360 MWh | 4,600 | 320 | 2022 | 30 | 1,625 | 0.00 | 7.01 | 4230 / 55% | 1 | 3 | 0 | 0 | 0 | 0 | 117 |
| Storage | Li-Ion 1 MW X 250 kWh | 0 | 1 | 2020 | 15 | 1,473 | 11.42 | 8.29 | 88% | 1 | 3 | 0 | 0 | 0 | 0 | 0 |
| Storage | Li-Ion 1 MW X 2 MWh | 0 | 1 | 2020 | 15 | 2,615 | 15.70 | 23.56 | 88% | 1 | 3 | 0 | 0 | 0 | 0 | 0 |
| Storage | Li-Ion 1 MW X 4 MWh | 0 | 1 | 2020 | 15 | 3,412 | 14.98 | 35.23 | 88% | 1 | 3 | 0 | 0 | 0 | 0 | 0 |
| Storage | Li-Ion 1 MW X 8 MWh | 0 | 1 | 2020 | 15 | 5,455 | 14.98 | 52.09 | 88% | 1 | 3 | 0 | 0 | 0 | 0 | 0 |
| Storage | Li-Ion 15 MW X 60 MWh | 0 | 15 | 2020 | 15 | 1,766 | 15.07 | 11.50 | 88% | 1 | 3 | 0 | 0 | 0 | 0 | 0 |
| Storage | Flow 1 MW X 6 MWh | 0 | 1 | 2021 | 15 | 3,996 | 0.00 | 32.00 | 65% | 2 | 3 | 0 | 0 | 0 | 0 | 0 |
| Nuclear | Advanced Fission | 5,000 | 2,234 | 2030 | 40 | 6,765 | 11.75 | 101.62 | 10,710 | 7.7 | 7.3 | 96 | 0 | 0 | 0 | 0 |
| Nuclear | Small Modular Reactor x 12 | 5,000 | 570 | 2028 | 40 | 6,028 | 15.50 | 173.35 | 10,710 | 7.7 | 7.3 | 65 | 0 | 0 | 0 | 0 |

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

| Supply Side Resource Options<br>Mid-Calendar Year 2018 Dollars ($) | | Capital Cost $/kW | | | Fixed Cost | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Fixed O&M $/kW-Yr | | | | | |
| Resource Description | Elevation (AFSL) | Total Capital Cost 1/ | Payment Factor 1/ | Annual Payment ($/kW-Yr) | O&M 1/ | Capitalized Premium | O&M Capitalized 1/ | Gas Transportation 1/ | Total | Total Fixed ($/kW-Yr) |
| SCCT Aero x3, ISO | 0 | $1,570 | 7.411% | $116.34 | 27.14 | 1.262% | 0.34 | 31.94 | 59.42 | $175.76 |
| Intercooled SCCT Aero x2, ISO | 0 | $1,092 | 7.411% | $80.97 | 18.78 | 0.273% | 0.05 | 30.03 | 48.87 | $129.84 |
| SCCT Frame "F" x1, ISO | 0 | $704 | 6.959% | $48.96 | 13.28 | 1.135% | 0.15 | 33.77 | 47.21 | $96.17 |
| IC Recips x 6, ISO | 0 | $1,810 | 6.959% | $125.94 | 29.82 | 0.136% | 0.04 | 28.47 | 58.33 | $184.27 |
| CCCT Dry "G/H", 1x1, ISO | 0 | $1,469 | 6.790% | $99.72 | 20.52 | 0.146% | 0.03 | 23.57 | 44.12 | $143.84 |
| CCCT Dry "G/H", DF, 1x1, ISO | 0 | $478 | 6.790% | $32.45 | 5.39 | 0.000% | 0.00 | 23.57 | 28.96 | $61.42 |
| CCCT Dry "G/H", 2x1, ISO | 0 | $1,060 | 6.790% | $71.98 | 13.79 | 0.146% | 0.02 | 23.62 | 37.43 | $109.41 |
| CCCT Dry "G/H", DF, 2x1, ISO | 0 | $365 | 6.790% | $24.75 | 4.44 | 0.000% | 0.00 | 23.62 | 28.05 | $52.81 |
| CCCT Dry "J/HA.02", 1x1, ISO | 0 | $1,218 | 6.790% | $82.69 | 17.66 | 0.000% | 0.00 | 23.36 | 41.02 | $123.70 |
| CCCT Dry "J/HA.02", DF, 1x1, ISO | 0 | $407 | 6.790% | $27.67 | 4.86 | 0.000% | 0.00 | 23.36 | 28.22 | $55.89 |
| CCCT Dry, "J/HA.02" 2X1, ISO | 0 | $881 | 6.790% | $59.80 | 12.00 | 0.146% | 0.02 | 23.36 | 35.38 | $95.18 |
| CCCT Dry "J/HA.02", DF, 2X1, ISO | 0 | $316 | 6.790% | $21.45 | 4.05 | 0.000% | 0.00 | 23.36 | 27.42 | $48.86 |
| SCCT Aero x3 | 1,500 | $1,612 | 7.411% | $119.50 | 27.96 | 1.262% | 0.35 | 31.76 | 60.07 | $179.57 |
| Intercooled SCCT Aero x2 | 1,500 | $1,143 | 7.411% | $84.71 | 19.88 | 0.273% | 0.05 | 29.91 | 49.85 | $134.56 |
| SCCT Frame "F" x1 | 1,500 | $741 | 6.959% | $51.54 | 14.02 | 1.135% | 0.16 | 33.71 | 47.89 | $99.43 |
| IC Recips x 6 | 1,500 | $1,810 | 6.959% | $125.94 | 29.82 | 0.136% | 0.04 | 28.47 | 58.33 | $184.27 |
| CCCT Dry "G/H", 1x1 | 1,500 | $1,552 | 6.790% | $105.38 | 21.68 | 0.146% | 0.03 | 23.37 | 45.08 | $150.46 |
| CCCT Dry "G/H", DF, 1x1 | 1,500 | $478 | 6.790% | $32.45 | 5.39 | 0.000% | 0.00 | 23.37 | 28.76 | $61.21 |
| CCCT Dry "G/H", 2x1 | 1,500 | $1,120 | 6.790% | $76.07 | 14.57 | 0.146% | 0.02 | 23.41 | 38.00 | $114.07 |
| CCCT Dry "G/H", DF, 2x1 | 1,500 | $365 | 6.790% | $24.75 | 4.44 | 0.000% | 0.00 | 23.41 | 27.84 | $52.60 |
| CCCT Dry "J/HA.02", 1x1 | 1,500 | $1,288 | 6.790% | $87.46 | 18.67 | 0.000% | 0.00 | 23.17 | 41.84 | $129.30 |
| CCCT Dry "J/HA.02", DF, 1x1 | 1,500 | $407 | 6.790% | $27.67 | 4.86 | 0.000% | 0.00 | 23.17 | 28.03 | $55.70 |
| CCCT Dry, "J/HA.02" 2X1 | 1,500 | $932 | 6.790% | $63.30 | 12.69 | 0.146% | 0.02 | 23.17 | 35.88 | $99.17 |
| CCCT Dry "J/HA.02", DF, 2X1 | 1,500 | $316 | 6.790% | $21.45 | 4.05 | 0.000% | 0.00 | 23.17 | 27.23 | $48.67 |
| SCCT Aero x3 | 3,000 | $1,704 | 7.411% | $126.26 | 29.58 | 1.262% | 0.37 | 16.94 | 46.89 | $173.15 |
| Intercooled SCCT Aero x2 | 3,000 | $1,209 | 7.411% | $89.58 | 21.10 | 0.273% | 0.06 | 15.94 | 37.10 | $126.68 |
| SCCT Frame "F" x1 | 3,000 | $782 | 6.959% | $54.43 | 14.81 | 1.135% | 0.17 | 17.98 | 32.95 | $87.38 |
| IC Recips x 6 | 3,000 | $1,810 | 6.959% | $125.94 | 29.82 | 0.136% | 0.04 | 15.18 | 45.03 | $170.97 |
| CCCT Dry "G/H", 1x1 | 3,000 | $1,641 | 6.790% | $111.41 | 22.92 | 0.146% | 0.03 | 23.28 | 46.23 | $157.64 |
| CCCT Dry "G/H", DF, 1x1 | 3,000 | $478 | 6.790% | $32.45 | 5.39 | 0.000% | 0.00 | 23.28 | 28.67 | $61.12 |
| CCCT Dry "G/H", 2x1 | 3,000 | $1,184 | 6.790% | $80.42 | 15.39 | 0.146% | 0.02 | 12.43 | 27.85 | $108.27 |
| CCCT Dry "G/H", DF, 2x1 | 3,000 | $365 | 6.790% | $24.75 | 4.44 | 0.000% | 0.00 | 12.43 | 16.87 | $41.62 |
| CCCT Dry "J/HA.02", 1x1 | 3,000 | $1,363 | 6.790% | $92.58 | 19.73 | 0.000% | 0.00 | 12.27 | 32.01 | $124.58 |
| CCCT Dry "J/HA.02", DF, 1x1 | 3,000 | $407 | 6.790% | $27.67 | 4.86 | 0.000% | 0.00 | 12.27 | 17.13 | $44.80 |
| CCCT Dry, "J/HA.02" 2X1 | 3,000 | $986 | 6.790% | $66.98 | 13.41 | 0.146% | 0.02 | 12.28 | 25.71 | $92.69 |
| CCCT Dry "J/HA.02", DF, 2X1 | 3,000 | $316 | 6.790% | $21.45 | 4.05 | 0.000% | 0.00 | 12.28 | 16.33 | $37.78 |

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

| Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($) | | Capital Cost $/kW | | | Fixed Cost | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Fixed O&M $/kW-Yr | | | | | |
| Resource Description | Elevation (AFSL) | Total Capital Cost 1/ | Payment Factor 1/ | Annual Payment ($/kW-Yr) | O&M 1/ | Capitalized Premium | O&M Capitalized 1/ | Gas Transportation 1/ | Total | Total Fixed ($/kW-Yr) |
| SCCT Aero x3 | 5,050 | $1,829 | 7.411% | $135.58 | 31.86 | 1.262% | 0.40 | 14.06 | 46.32 | $181.90 |
| Intercooled SCCT Aero x2 | 5,050 | $1,305 | 7.411% | $96.74 | 22.82 | 0.273% | 0.06 | 13.22 | 36.10 | $132.84 |
| SCCT Frame "F" x1 | 5,050 | $843 | 6.959% | $58.69 | 15.97 | 1.135% | 0.18 | 14.93 | 31.08 | $89.77 |
| IC Recips x 6 | 5,050 | $1,810 | 6.959% | $125.94 | 29.82 | 0.136% | 0.04 | 12.61 | 42.47 | $168.41 |
| CCCT Dry "G/H", 1x1 | 5,050 | $1,788 | 6.790% | $121.40 | 24.74 | 0.146% | 0.04 | 9.91 | 34.69 | $156.09 |
| CCCT Dry "G/H", DF, 1x1 | 5,050 | $478 | 6.790% | $32.45 | 5.39 | 0.000% | 0.00 | 9.91 | 15.30 | $47.76 |
| CCCT Dry "G/H", 2x1 | 5,050 | $1,297 | 6.790% | $88.06 | 16.63 | 0.146% | 0.02 | 9.93 | 26.58 | $114.64 |
| CCCT Dry "G/H", DF, 2x1 | 5,050 | $365 | 6.790% | $24.75 | 4.44 | 0.000% | 0.00 | 9.93 | 14.37 | $39.12 |
| CCCT Dry "J/HA.02", 1x1 | 5,050 | $1,485 | 6.790% | $100.84 | 21.26 | 0.000% | 0.00 | 9.84 | 31.10 | $131.95 |
| CCCT Dry "J/HA.02", DF, 1x1 | 5,050 | $407 | 6.790% | $27.67 | 4.86 | 0.000% | 0.00 | 9.84 | 14.70 | $42.37 |
| CCCT Dry, "J/HA.02" 2X1 | 5,050 | $1,079 | 6.790% | $73.29 | 14.45 | 0.146% | 0.02 | 9.85 | 24.33 | $97.61 |
| CCCT Dry "J/HA.02", DF, 2X1 | 5,050 | $316 | 6.790% | $21.45 | 4.05 | 0.000% | 0.00 | 9.85 | 13.91 | $35.35 |
| SCCT Aero x3 | 6,500 | $1,975 | 7.411% | $146.35 | 34.56 | 1.262% | 0.44 | 9.13 | 44.13 | $190.47 |
| Intercooled SCCT Aero x2 | 6,500 | $1,394 | 7.411% | $103.31 | 24.00 | 0.273% | 0.07 | 8.62 | 32.68 | $136.00 |
| SCCT Frame "F" x1 | 6,500 | $887 | 6.959% | $61.71 | 16.81 | 1.135% | 0.19 | 9.70 | 26.70 | $88.42 |
| IC Recips x 6 | 6,500 | $1,810 | 6.959% | $125.94 | 31.04 | 0.136% | 0.04 | 8.24 | 39.33 | $165.27 |
| CCCT Dry "G/H", 1x1 | 6,500 | $1,843 | 6.790% | $125.17 | 26.20 | 0.146% | 0.04 | 20.66 | 46.90 | $172.07 |
| CCCT Dry "G/H", DF, 1x1 | 6,500 | $478 | 6.790% | $32.45 | 5.39 | 0.000% | 0.00 | 20.66 | 26.05 | $58.50 |
| CCCT Dry "G/H", 2x1 | 6,500 | $1,330 | 6.790% | $90.33 | 17.61 | 0.146% | 0.03 | 6.71 | 24.34 | $114.67 |
| CCCT Dry "G/H", DF, 2x1 | 6,500 | $365 | 6.790% | $24.75 | 4.44 | 0.000% | 0.00 | 6.71 | 11.15 | $35.90 |
| CCCT Dry "J/HA.02", 1x1 | 6,500 | $1,549 | 6.790% | $105.16 | 22.33 | 0.000% | 0.00 | 6.62 | 28.95 | $134.11 |
| CCCT Dry "J/HA.02", DF, 1x1 | 6,500 | $407 | 6.790% | $27.67 | 4.86 | 0.000% | 0.00 | 6.62 | 11.48 | $39.15 |
| CCCT Dry, "J/HA.02" 2X1 | 6,500 | $1,120 | 6.790% | $76.08 | 15.18 | 0.146% | 0.02 | 6.62 | 21.82 | $97.90 |
| CCCT Dry "J/HA.02", DF, 2X1 | 6,500 | $316 | 6.790% | $21.45 | 4.06 | 0.000% | 0.00 | 6.62 | 10.68 | $32.12 |
| Blundell Dual Flash 90% CF | 4,500 | $5,708 | 6.185% | $0.00 | 103.85 | 0.918% | 0.95 | 0.00 | 104.80 | $104.80 |
| Generic Geothermal PPA 90% CF | 4,500 | $0 | 6.185% | $0.00 | 0.00 | 0.000% | 0.00 | 0.00 | 0.00 | $0.00 |
| 3.6 MW Wind turbine 37.1% CF WA, 2020 (100% PTC) | 4,500 | $1,354 | 6.899% | $93.42 | 27.99 | 2.902% | 0.81 | 0.00 | 28.80 | $122.22 |
| 3.6 MW Wind turbine 37.1% CF OR, 2020 (100% PTC) | 1,500 | $1,334 | 6.899% | $92.01 | 27.99 | 2.902% | 0.81 | 0.00 | 28.80 | $120.81 |
| 3.6 MW Wind turbine 37.1% CF ID, 2020 (100% PTC) | 4,500 | $1,358 | 6.899% | $93.71 | 27.99 | 2.902% | 0.81 | 0.00 | 28.80 | $122.52 |
| 3.6 MW Wind turbine 29.5% CF UT, 2020 (100% PTC) | 6,500 | $1,301 | 6.899% | $89.79 | 27.99 | 2.902% | 0.81 | 0.00 | 28.80 | $118.59 |
| 3.6 MW Wind turbine 43.6% CF WY, 2020 (100% PTC) | 1,500 | $1,301 | 6.899% | $89.79 | 27.99 | 2.902% | 0.81 | 0.00 | 28.80 | $118.59 |
| 3.6 MW Wind turbine 37.1% CF WA,2023 (40% PTC) | 4,500 | $1,354 | 6.899% | $93.42 | 27.99 | 2.902% | 0.81 | 0.00 | 28.80 | $122.22 |
| 3.6 MW Wind turbine 37.1% CF OR, 2023 (40% PTC) | 1,500 | $1,334 | 6.899% | $92.01 | 27.99 | 2.902% | 0.81 | 0.00 | 28.80 | $120.81 |
| 3.6 MW Wind turbine 37.1% CF ID, 2023 (40% PTC) | 4,500 | $1,358 | 6.899% | $93.71 | 27.99 | 2.902% | 0.81 | 0.00 | 28.80 | $122.52 |
| 3.6 MW Wind turbine 29.5% CF UT, 2023 (40% PTC) | 6,500 | $1,301 | 6.899% | $89.79 | 27.99 | 2.902% | 0.81 | 0.00 | 28.80 | $118.59 |

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

| Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($) | | Capital Cost $/kW | | | Fixed Cost | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Fixed O&M $/kW-Yr | | | | | |
| Resource Description | Elevation (AFSL) | Total Capital Cost 1/ | Payment Factor 1/ | Annual Payment ($/kW-Yr) | O&M 1/ | Capitalized Premium | O&M Capitalized 1/ | Gas Transportation 1/ | Total | Total Fixed ($/kW-Yr) |
| Wind + Stor, Pocatello, ID, 200 MW+ 50 MW \| 200 MWh | 4,500 | $1,880 | 6.899% | $129.66 | 29.88 | 2.902% | 0.87 | 0.00 | 30.74 | $160.41 |
| Wind + Stor, Arlington, OR, 200 MW+ 50 MW \| 200 MWh | 1,500 | $1,917 | 6.899% | $132.26 | 29.88 | 2.902% | 0.87 | 0.00 | 30.74 | $163.00 |
| Wind + Stor, Monticello, UT, 200 MW+ 50 MW \| 200 MWh | 4,500 | $1,877 | 6.899% | $129.51 | 29.88 | 2.902% | 0.87 | 0.00 | 30.74 | $160.25 |
| Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW \| 200 MWh | 6,500 | $1,872 | 6.899% | $129.12 | 29.88 | 2.902% | 0.87 | 0.00 | 30.74 | $159.86 |
| Wind + Stor, Goldendale, WA, 200 MW+ 50 MW \| 200 MWh | 1,500 | $1,924 | 6.899% | $132.71 | 29.88 | 2.902% | 0.87 | 0.00 | 30.74 | $163.45 |
| PV Idaho Falls, ID, 200 MW, 2021, 28.1% CF (30% ITC) | 4,500 | $1,271 | 7.712% | $98.02 | 21.72 | 1.379% | 0.30 | 0.00 | 22.02 | $120.04 |
| PV Lakeview, OR, 200 MW, 2021, 29.7% CF (30% ITC) | 4,800 | $1,329 | 7.712% | $102.53 | 22.35 | 1.379% | 0.31 | 0.00 | 22.66 | $125.19 |
| PV Milford, UT, 200 MW, 2021, 32.5% CF (30% ITC) | 4,500 | $1,268 | 7.712% | $97.83 | 22.32 | 1.379% | 0.31 | 0.00 | 22.63 | $120.46 |
| PV Utah North, 200 MW, 2021, 30.1% CF (30% ITC) | 4,501 | $1,266 | 7.712% | $97.62 | 21.13 | 1.379% | 0.29 | 0.00 | 21.42 | $119.04 |
| PV Rock Springs, WY, 200 MW, 2021, 30.1% CF (30% ITC) | 4,800 | $1,266 | 7.712% | $97.62 | 21.13 | 1.379% | 0.29 | 0.00 | 21.42 | $119.04 |
| PV Yakima, WA, 200 MW, 2021, 26% CF (30% ITC) | 4,802 | $1,327 | 7.712% | $102.36 | 22.35 | 1.379% | 0.31 | 0.00 | 22.66 | $125.02 |
| PV Idaho Falls, ID, 200 MW, 2026, 28.1% CF (10% ITC) | 4,802 | $1,271 | 7.712% | $98.02 | 21.72 | 1.379% | 0.30 | 0.00 | 22.02 | $120.04 |
| PV Lakeview, OR, 200 MW, 2026, 29.7% CF (10% ITC) | 4,802 | $1,329 | 7.712% | $102.53 | 22.35 | 1.379% | 0.31 | 0.00 | 22.66 | $125.19 |
| PV Milford, UT, 200 MW, 2026, 32.5% CF (10% ITC) | 4,802 | $1,268 | 7.712% | $97.83 | 22.32 | 1.379% | 0.31 | 0.00 | 22.63 | $120.46 |
| PV Utah North, 200 MW, 2021, 30.1% CF (10% ITC) | 4,803 | $1,266 | 7.712% | $97.62 | 21.13 | 1.379% | 0.29 | 0.00 | 21.42 | $119.04 |
| PV Rock Springs, WY, 200 MW, 2026, 30.1% CF (10% ITC) | 4,802 | $1,266 | 7.712% | $97.62 | 21.13 | 1.379% | 0.29 | 0.00 | 21.42 | $119.04 |
| PV Yakima, WA, 200 MW, 2026, 26% CF (10% ITC) | 4,802 | $1,327 | 7.712% | $102.36 | 22.35 | 1.379% | 0.31 | 0.00 | 22.66 | $125.02 |
| PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 200 MWh (30% ITC) | 4,802 | $1,614 | 7.712% | $124.48 | 24.24 | 1.379% | 0.33 | 0.00 | 24.57 | $149.05 |
| PV + Stor, Lakeview, OR, 200 MW + 50 MW X 200 MWh (30% ITC) | 4,802 | $1,699 | 7.712% | $131.01 | 24.24 | 1.379% | 0.33 | 0.00 | 24.57 | $155.58 |
| PV + Stor,, Milford, UT, 200 MW + 50 MW X 200 MWh (30% ITC) | 4,802 | $1,612 | 7.712% | $124.29 | 24.24 | 1.379% | 0.33 | 0.00 | 24.57 | $148.86 |
| PV + Stor, Utah North, 200 MW + 50 MW X 200 MWh (30% ITC) | 4,803 | $1,609 | 7.712% | $124.08 | 24.24 | 1.379% | 0.33 | 0.00 | 24.57 | $148.65 |
| PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 200 MWh (30% ITC) | 4,802 | $1,609 | 7.712% | $124.08 | 24.24 | 1.379% | 0.33 | 0.00 | 24.57 | $148.65 |
| PV + Stor, Yakima, WA, 200 MW + 50 MW X 200 MWh (30% ITC) | 4,802 | $1,697 | 7.712% | $130.86 | 24.24 | 1.379% | 0.33 | 0.00 | 24.57 | $155.43 |
| PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 200 MWh (10% ITC) | 4,802 | $1,614 | 7.712% | $124.48 | 24.24 | 1.379% | 0.33 | 0.00 | 24.57 | $149.05 |
| PV + Stor, Lakeview, OR, 200 MW + 50 MW X 200 MWh (10% ITC) | 4,802 | $1,699 | 7.712% | $131.01 | 24.24 | 1.379% | 0.33 | 0.00 | 24.57 | $155.58 |
| PV + Stor,, Milford, UT, 200 MW + 50 MW X 200 MWh (10% ITC) | 4,802 | $1,612 | 7.712% | $124.29 | 24.24 | 1.379% | 0.33 | 0.00 | 24.57 | $148.86 |
| PV + Stor, Utah North, 200 MW + 50 MW X 200 MWh (10% ITC) | 4,803 | $1,609 | 7.712% | $124.08 | 24.24 | 1.379% | 0.33 | 0.00 | 24.57 | $148.65 |
| PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 200 MWh (10% ITC) | 4,802 | $1,609 | 7.712% | $124.08 | 24.24 | 1.379% | 0.33 | 0.00 | 24.57 | $148.65 |
| PV + Stor, Yakima, WA, 200 MW + 50 MW X 200 MWh (10% ITC) | 4,802 | $1,697 | 7.712% | $130.86 | 24.24 | 1.379% | 0.33 | 0.00 | 24.57 | $155.43 |
| Oregon PS, 400 MW X 3,800 MWh | 4,457 | $3,095 | 6.142% | $190.09 | 16.76 | 0.000% | 0.00 | 0.00 | 16.76 | $206.85 |
| Oregon PS joint ownership, 100 MW X 950 MWh | 580 | $3,099 | 6.142% | $190.38 | 16.76 | 0.000% | 0.00 | 0.00 | 16.76 | $207.14 |
| Washington PS, 1,200 MW X 16,800 MWh | 580 | $2,719 | 6.142% | $166.98 | 12.50 | 0.000% | 0.00 | 0.00 | 12.50 | $179.48 |
| Wyoming PS, 700 MW X 7,000 MWh | 6,359 | $3,255 | 6.142% | $199.94 | 17.00 | 0.000% | 0.00 | 0.00 | 17.00 | $216.94 |
| Wyoming PS, 400 MW X 3,400 MWh | 6,360 | $2,348 | 6.142% | $144.20 | 17.00 | 0.000% | 0.00 | 0.00 | 17.00 | $161.20 |
| Utah PS, 300 MW X 1,800 MWh | 6,360 | $2,991 | 6.142% | $183.72 | 17.00 | 0.000% | 0.00 | 0.00 | 17.00 | $200.72 |
| Idaho PS, 360 MW X 2,880 MWh | 6,361 | $2,680 | 6.142% | $164.61 | 17.00 | 0.000% | 0.00 | 0.00 | 17.00 | $181.61 |
| CAES, 320 MW X 15,360 MWh | 4,640 | $1,625 | 7.411% | $120.41 | 7.01 | 0.000% | 0.00 | 0.00 | 7.01 | $127.41 |
| Li-Ion 15 MW X 60 MWh | 6,359 | $1,766 | 11.126% | $196.44 | 11.50 | 0.000% | 0.00 | 0.00 | 11.50 | $207.93 |

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

| Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($) | | Capital Cost $/kW | | | Fixed Cost | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Fixed O&M $/kW-Yr | | | | | |
| Resource Description | Elevation (AFSL) | Total Capital Cost 1/ | Payment Factor 1/ | Annual Payment ($/kW-Yr) | O&M 1/ | Capitalized Premium | O&M Capitalized 1/ | Gas Transportation 1/ | Total | Total Fixed ($/kW-Yr) |
| **Brownfield Site** | | | | | | | | | | |
| **Dave Johnston** | | | | | | | | | | |
| SCCT Frame "F" x1 | 5,050 | $709 | 6.959% | $49.31 | 15.97 | 1.135% | 0.18 | 14.93 | 31.08 | $80.39 |
| 3.6 MW Wind turbine 43.6% CF WY, 2023 (40% PTC) | 6,400 | $1,301 | 6.899% | $89.79 | 27.99 | 2.902% | 0.81 | 0.00 | 28.80 | $118.59 |
| CCCT Dry "J/HA.02", 1x1 | 5,050 | $1,342 | 6.790% | $91.12 | 21.26 | 0.000% | 0.00 | 19.76 | 41.02 | $132.14 |
| CCCT Dry "J/HA.02", DF, 1x1 | 5,050 | $368 | 6.790% | $25.00 | 4.86 | 0.000% | 0.00 | 19.76 | 24.62 | $49.62 |
| **Hunter** | | | | | | | | | | |
| SCCT Frame "F" x1 | 5,050 | $709 | 6.959% | $49.31 | 15.97 | 1.135% | 0.18 | 14.93 | 31.08 | $80.39 |
| PV, 200 MW, 2026, 32.5% CF (10% ITC) | 5,000 | $1,268 | 7.712% | $97.83 | 22.32 | 1.379% | 0.31 | 0.00 | 22.63 | $120.46 |
| PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC) | 5,000 | $1,612 | 7.712% | $124.29 | 24.24 | 1.379% | 0.33 | 0.00 | 24.57 | $148.86 |
| CCCT Dry "J/HA.02", 1x1 | 5,050 | $1,342 | 6.790% | $91.12 | 21.26 | 0.000% | 0.00 | 9.84 | 31.10 | $122.22 |
| CCCT Dry "J/HA.02", DF, 1x1 | 5,050 | $368 | 6.790% | $25.00 | 4.86 | 0.000% | 0.00 | 9.84 | 14.70 | $39.70 |
| **Huntington** | | | | | | | | | | |
| SCCT Frame "F" x1 | 5,050 | $709 | 6.959% | $49.31 | 15.97 | 1.135% | 0.18 | 14.93 | 31.08 | $80.39 |
| PV, 200 MW, 2026, 32.5% CF (10% ITC) | 5,000 | $1,268 | 7.712% | $97.83 | 22.32 | 1.379% | 0.31 | 0.00 | 22.63 | $120.46 |
| PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC) | 5,000 | $1,612 | 7.712% | $124.29 | 24.24 | 1.379% | 0.33 | 0.00 | 24.57 | $148.86 |
| CCCT Dry "J/HA.02", 1x1 | 5,050 | $1,342 | 6.790% | $91.12 | 21.26 | 0.000% | 0.00 | 9.84 | 31.10 | $122.22 |
| CCCT Dry "J/HA.02", DF, 1x1 | 5,050 | $368 | 6.790% | $25.00 | 4.86 | 0.000% | 0.00 | 9.84 | 14.70 | $39.70 |
| **Jim Bridger** | | | | | | | | | | |
| 3.6 MW Wind turbine 43.6% CF WY, 2023 (40% PTC) | 6,400 | $1,301 | 6.899% | $89.79 | 27.99 | 2.902% | 0.81 | 0.00 | 28.80 | $118.59 |
| Wind + Stor, 200 MW+ 50 MW \| 400 MWh | 6,500 | $2,150 | 6.899% | $148.30 | 31.03 | 2.902% | 0.90 | 0.00 | 31.93 | $180.23 |
| SCCT Frame "F" x1 | 6,500 | $745 | 6.959% | $51.85 | 16.81 | 1.135% | 0.19 | 9.70 | 26.70 | $78.56 |
| PV, 200 MW, 2026, 32.5% CF (10% ITC) | 6,400 | $1,266 | 7.712% | $97.62 | 21.13 | 1.379% | 0.29 | 0.00 | 21.42 | $119.04 |
| PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC) | 6,400 | $1,609 | 7.712% | $124.08 | 24.24 | 1.379% | 0.33 | 0.00 | 24.57 | $148.65 |
| CCCT Dry "J/HA.02", 1x1 | 6,500 | $1,399 | 6.790% | $95.01 | 22.33 | 0.000% | 0.00 | 6.62 | 28.95 | $123.97 |
| CCCT Dry "J/HA.02", DF, 1x1 | 6,500 | $368 | 6.790% | $25.00 | 4.86 | 0.000% | 0.00 | 6.62 | 11.48 | $36.48 |
| **Naughton** | | | | | | | | | | |
| SCCT Frame "F" x1 | 6,500 | $745 | 6.959% | $51.85 | 16.81 | 1.135% | 0.19 | 14.90 | 31.91 | $83.76 |
| PV 200 MW, 2026, 30.1% CF (10% ITC) | 6,400 | $1,266 | 7.712% | $97.62 | 21.13 | 1.379% | 0.29 | 0.00 | 21.42 | $119.04 |
| CCCT Dry "J/HA.02", 1x1 | 6,500 | $1,399 | 6.790% | $95.01 | 22.33 | 0.000% | 0.00 | 10.17 | 32.51 | $127.52 |
| CCCT Dry "J/HA.02", DF, 1x1 | 6,500 | $368 | 6.790% | $25.00 | 4.86 | 0.000% | 0.00 | 10.17 | 15.03 | $40.03 |
| **Wyodak** | | | | | | | | | | |
| SCCT Frame "F" x1 | 6,500 | $745 | 6.959% | $51.85 | 16.81 | 1.135% | 0.19 | 29.92 | 46.92 | $98.78 |

1/ Input into IRP SO and PAR Model
Results presented without credits
Information Presented is Illustrative

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

Resources not Modeled in 2019 IRP

| Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($) | | Capital Cost $/kW | | | Fixed Cost | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Fixed O&M $/kW-Yr | | | | | |
| Resource Description | Elevation (AFSL) | Total Capital Cost | Payment Factor | Annual Payment ($/kW-Yr) | O&M | Capitalized Premium | O&M Capitalized | Gas Transportation | Total | Total Fixed ($/kW-Yr) |
| SCPC with CCS | 4,500 | $6,462 | 6.726% | $434.61 | 72.22 | 5.541% | 4.00 | 0.00 | 76.23 | $510.84 |
| IGCC with CCS | 4,500 | $6,257 | 6.533% | $408.75 | 58.20 | 0.000% | 0.00 | 0.00 | 58.20 | $466.95 |
| PC CCS retrofit @ 500 MW | 4,500 | $1,419 | 6.726% | $95.42 | 77.76 | 0.000% | 0.00 | 0.00 | 77.76 | $173.17 |
| SCPC with CCS | 6,500 | $7,318 | 6.726% | $492.18 | 67.09 | 5.541% | 0.00 | 0.00 | 67.09 | $559.27 |
| IGCC with CCS | 6,500 | $7,085 | 6.533% | $462.83 | 63.40 | 0.000% | 0.00 | 0.00 | 63.40 | $526.23 |
| PC CCS retrofit @ 500 MW | 6,500 | $1,607 | 6.712% | $107.84 | 72.22 | 0.000% | 0.00 | 0.00 | 72.22 | $180.07 |
| Greenfield Binary 90% CF | 4,500 | $5,973 | 6.185% | $369.45 | 103.85 | 0.918% | 0.95 | 0.00 | 104.80 | $474.26 |
| Wind + Stor, Pocatello, ID, 200 MW+ 50 MW \| 100 MWh | 4,500 | $1,738 | 6.899% | $119.87 | 29.18 | 2.902% | 0.85 | 0.00 | 30.03 | $149.90 |
| Wind + Stor, Arlington, OR, 200 MW+ 50 MW \| 100 MWh | 1,500 | $1,765 | 6.899% | $121.79 | 29.18 | 2.902% | 0.85 | 0.00 | 30.03 | $151.83 |
| Wind + Stor, Monticello, UT, 200 MW+ 50 MW \| 100 MWh | 4,500 | $1,735 | 6.899% | $119.71 | 29.18 | 2.902% | 0.85 | 0.00 | 30.03 | $149.74 |
| Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW \| 100 MWh | 6,500 | $1,730 | 6.899% | $119.32 | 29.18 | 2.902% | 0.85 | 0.00 | 30.03 | $149.35 |
| Wind + Stor, Goldendale, WA, 200 MW+ 50 MW \| 100 MWh | 1,500 | $1,772 | 6.899% | $122.24 | 29.18 | 2.902% | 0.85 | 0.00 | 30.03 | $152.27 |
| Wind + Stor, Pocatello, ID, 200 MW+ 50 MW \| 400 MWh | 4,500 | $2,158 | 6.899% | $148.85 | 31.03 | 2.902% | 0.90 | 0.00 | 31.93 | $180.78 |
| Wind + Stor, Arlington, OR, 200 MW+ 50 MW \| 400 MWh | 1,500 | $2,214 | 6.899% | $152.75 | 31.03 | 2.902% | 0.90 | 0.00 | 31.93 | $184.68 |
| Wind + Stor, Monticello, UT, 200 MW+ 50 MW \| 400 MWh | 4,500 | $2,155 | 6.899% | $148.69 | 31.03 | 2.902% | 0.90 | 0.00 | 31.93 | $180.62 |
| Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW \| 400 MWh | 6,500 | $2,150 | 6.899% | $148.30 | 31.03 | 2.902% | 0.90 | 0.00 | 31.93 | $180.23 |
| Wind + Stor, Goldendale, WA, 200 MW+ 50 MW \| 400 MWh | 1,500 | $2,221 | 6.899% | $153.22 | 31.03 | 2.902% | 0.90 | 0.00 | 31.93 | $185.15 |
| PV Idaho Falls, ID, 50 MW, 28.1% CF (30% ITC) | 4,500 | $1,366 | 7.712% | $105.31 | 21.72 | 1.379% | 0.30 | 0.00 | 22.02 | $127.33 |
| PV Lakeview, OR, 50 MW, 2021, 29.7% CF (30% ITC) | 4,800 | $1,424 | 7.712% | $109.83 | 22.35 | 1.379% | 0.31 | 0.00 | 22.66 | $132.48 |
| PV Milford, UT, 50 MW, 2021, 32.5% CF (30% ITC) | 4,500 | $1,363 | 7.712% | $105.12 | 22.32 | 1.379% | 0.31 | 0.00 | 22.63 | $127.75 |
| PV Rock Springs, WY, 50 MW, 2021, 30.1% CF (30% ITC) | 4,800 | $1,360 | 7.712% | $104.91 | 21.13 | 1.379% | 0.29 | 0.00 | 21.42 | $126.34 |
| PV Yakima, WA, 50 MW, 2021, 26% CF (30% ITC) | 4,801 | $1,422 | 7.712% | $109.66 | 22.35 | 1.379% | 0.31 | 0.00 | 22.66 | $132.31 |
| PV Idaho Falls, ID, 50 MW, 2026, 28.1% CF (10% ITC) | 4,802 | $1,366 | 7.712% | $105.31 | 21.72 | 1.379% | 0.30 | 0.00 | 22.02 | $127.33 |
| PV Lakeview, OR, 50 MW, 2026, 29.7% CF (10% ITC) | 4,802 | $1,424 | 7.712% | $109.83 | 22.35 | 1.379% | 0.31 | 0.00 | 22.66 | $132.48 |
| PV Milford, UT, 50 MW, 2026, 32.5% CF (10% ITC) | 4,802 | $1,363 | 7.712% | $105.12 | 22.32 | 1.379% | 0.31 | 0.00 | 22.63 | $127.75 |
| PV Rock Springs, WY, 50 MW, 2026, 30.1% CF (10% ITC) | 4,802 | $1,360 | 7.712% | $104.91 | 21.13 | 1.379% | 0.29 | 0.00 | 21.42 | $126.34 |
| PV Yakima, WA, 50 MW, 2026, 26% CF (10% ITC) | 4,802 | $1,422 | 7.712% | $109.66 | 22.35 | 1.379% | 0.31 | 0.00 | 22.66 | $132.31 |
| PV + Stor, Idaho Falls, ID, 50 MW + 10 MW X 20 MWh (30% ITC) | 4,802 | $1,628 | 7.712% | $125.57 | 23.48 | 1.379% | 0.32 | 0.00 | 23.81 | $149.37 |
| PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 100 MWh (30% ITC) | 4,802 | $1,470 | 7.712% | $113.34 | 22.91 | 1.379% | 0.32 | 0.00 | 23.23 | $136.57 |
| PV + Stor., Idaho Falls, ID, 50 MW + 10 MW X 40 MWh (30% ITC) | 4,802 | $1,756 | 7.712% | $135.46 | 25.03 | 1.379% | 0.35 | 0.00 | 25.38 | $160.83 |
| PV + Stor, Idaho Falls, ID, 50 MW + 10 MW X 80 MWh (30% ITC) | 4,802 | $1,992 | 7.712% | $153.67 | 26.46 | 1.379% | 0.36 | 0.00 | 26.82 | $180.49 |
| PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 400 MWh (30% ITC) | 4,802 | $1,897 | 7.712% | $146.31 | 25.36 | 1.379% | 0.35 | 0.00 | 25.71 | $172.01 |
| PV + Stor, Lakeview, OR, 50 MW + 10 MW X 20 MWh (30% ITC) | 4,802 | $1,706 | 7.712% | $131.56 | 23.48 | 1.379% | 0.32 | 0.00 | 23.81 | $155.37 |
| PV + Stor, Lakeview, OR, 200 MW + 50 MW X 100 MWh (30% ITC) | 4,802 | $1,543 | 7.712% | $119.00 | 22.91 | 1.379% | 0.32 | 0.00 | 23.23 | $142.23 |
| PV + Stor, Lakeview, OR, 50 MW + 10 MW X 40 MWh (30% ITC) | 4,802 | $1,844 | 7.712% | $142.22 | 25.03 | 1.379% | 0.35 | 0.00 | 25.38 | $167.59 |
| PV + Stor, Lakeview, OR, 50 MW + 10 MW X 80 MWh (30% ITC) | 4,802 | $2,098 | 7.712% | $161.83 | 26.46 | 1.379% | 0.36 | 0.00 | 26.82 | $188.66 |
| PV + Stor., Lakeview, OR, 200 MW + 50 MW X 400 MWh (30% ITC) | 4,802 | $2,004 | 7.712% | $154.52 | 25.36 | 1.379% | 0.35 | 0.00 | 25.71 | $180.23 |
| PV + Stor., Milford, UT, 50 MW + 10 MW X 20 MWh (30% ITC) | 4,802 | $1,626 | 7.712% | $125.37 | 23.48 | 1.379% | 0.32 | 0.00 | 23.81 | $149.18 |
| PV + Stor., Milford, UT, 200 MW + 50 MW X 100 MWh (30% ITC) | 4,802 | $1,467 | 7.712% | $113.14 | 22.91 | 1.379% | 0.32 | 0.00 | 23.23 | $136.37 |
| PV + Stor., Milford, UT 50 MW + 10 MW X 40 MWh (30% ITC) | 4,802 | $1,754 | 7.712% | $135.27 | 25.03 | 1.379% | 0.35 | 0.00 | 25.38 | $160.64 |
| PV + Stor., Milford, UT, 50 MW + 10 MW X 80 MWh (30% ITC) | 4,802 | $1,990 | 7.712% | $153.48 | 26.46 | 1.379% | 0.36 | 0.00 | 26.82 | $180.30 |
| PV + Stor., Milford, UT, 200 MW + 50 MW X 400 MWh (30% ITC) | 4,802 | $1,895 | 7.712% | $146.11 | 25.36 | 1.379% | 0.35 | 0.00 | 25.71 | $171.82 |
| PV + Stor., Rock Springs, WY, 50 MW + 10 MW X 20 MWh (30% ITC) | 4,802 | $1,623 | 7.712% | $125.17 | 23.48 | 1.379% | 0.32 | 0.00 | 23.81 | $148.97 |
| PV + Stor., Rock Springs, WY, 200 MW + 50 MW X 100 MWh (30% ITC) | 4,802 | $1,464 | 7.712% | $112.94 | 22.91 | 1.379% | 0.32 | 0.00 | 23.23 | $136.17 |
| PV + Stor., Rock Springs, WY, 50 MW + 10 MW X 40 MWh (30% ITC) | 4,802 | $1,751 | 7.712% | $135.06 | 25.03 | 1.379% | 0.35 | 0.00 | 25.38 | $160.43 |
| PV + Stor., Rock Springs, WY, 50 MW + 10 MW X 80 MWh (30% ITC) | 4,802 | $1,987 | 7.712% | $153.27 | 26.46 | 1.379% | 0.36 | 0.00 | 26.82 | $180.09 |
| PV + Stor., Rock Springs, WY, 200 MW + 50 MW X 400 MWh (30% ITC) | 4,802 | $1,892 | 7.712% | $145.91 | 25.36 | 1.379% | 0.35 | 0.00 | 25.71 | $171.61 |
| PV + Stor., Yakima, WA, 50 MW + 10 MW X 20 MWh (30% ITC) | 4,802 | $1,704 | 7.712% | $131.40 | 23.48 | 1.379% | 0.32 | 0.00 | 23.81 | $155.21 |
| PV + Stor, Yakima, WA, 200 MW + 50 MW X 100 MWh (30% ITC) | 4,802 | $1,541 | 7.712% | $118.85 | 22.91 | 1.379% | 0.32 | 0.00 | 23.23 | $142.08 |
| PV + Stor, Yakima, WA, 50 MW + 10 MW X 40 MWh (30% ITC) | 4,802 | $1,842 | 7.712% | $142.07 | 25.03 | 1.379% | 0.35 | 0.00 | 25.38 | $167.45 |
| PV + Stor, Yakima, WA, 50 MW + 10 MW X 80 MWh (30% ITC) | 4,802 | $2,097 | 7.712% | $161.70 | 26.46 | 1.379% | 0.36 | 0.00 | 26.82 | $188.53 |
| PV + Stor, Yakima, WA, 200 MW + 50 MW X 400 MWh (30% ITC) | 4,802 | $2,002 | 7.712% | $154.39 | 25.36 | 1.379% | 0.35 | 0.00 | 25.71 | $180.10 |
| Li-Ion 1 MW X 250 kWh | 6,359 | $1,473 | 11.126% | $163.90 | 8.29 | 0.000% | 0.00 | 0.00 | 8.29 | $172.19 |
| Li-Ion 1 MW X 2 MWh | 6,359 | $2,615 | 11.126% | $290.96 | 23.56 | 0.000% | 0.00 | 0.00 | 23.56 | $314.52 |
| Li-Ion 1 MW X 4 MWh | 6,359 | $3,412 | 11.126% | $379.58 | 35.23 | 0.000% | 0.00 | 0.00 | 35.23 | $414.82 |
| Li-Ion 1 MW X 8 MWh | 6,359 | $5,455 | 11.126% | $606.91 | 52.09 | 0.000% | 0.00 | 0.00 | 52.09 | $659.00 |
| Flow 1 MW X 6 MWh | 6,360 | $3,996 | 11.126% | $444.59 | 32.00 | 0.000% | 0.00 | 0.00 | 32.00 | $476.59 |
| Advanced Fission | 5,000 | $6,765 | 6.639% | $449.13 | 101.62 | 5.687% | 5.78 | 0.00 | 107.40 | $556.53 |
| Small Modular Reactor x 12 | 5,000 | $6,028 | 6.639% | $400.24 | 173.35 | 11.228% | 19.46 | 0.00 | 192.82 | $593.06 |

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

| Supply Side Resource Options<br>Mid-Calendar Year 2018 Dollars ($) | | Convert to $/MWh | | | | | Variable Costs ($/MWh) | | | | | Total Costs and Credits ($/MWh) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Levelized Fuel | | | | | | | | Credits | |
| Resource Description | Elevation (AFSL) | Capacity Factor 2/ | Total Fixed ($/MWh) | Storage Efficiency | ¢/mmBtu | $/MWh | O&M 1/ | Capitalized Premium | O&M Capitalized 1/ | Integration Cost 1/ | Environmental | Total Resource Cost | PTC Tax Credits / ITC (Solar Only) | Total Resource Cost - with PTC / ITC Credits |
| SCCT Aero x3, ISO | 0 | 33% | 60.80 | na | 320 | 29.73 | 7.54 | 11.48% | 0.87 | - | - | 98.93 | - | 98.93 |
| Intercooled SCCT Aero x2, ISO | 0 | 33% | 44.91 | na | 320 | 27.96 | 5.05 | 13.23% | 0.67 | - | - | 78.59 | - | 78.59 |
| SCCT Frame "F" x1, ISO | 0 | 33% | 33.27 | na | 320 | 31.44 | 5.50 | 11.48% | 0.63 | - | - | 70.84 | - | 70.84 |
| IC Recips x 6, ISO | 0 | 33% | 63.74 | na | 320 | 26.51 | 7.45 | 8.73% | 0.65 | - | - | 98.35 | - | 98.35 |
| CCCT Dry "G/H", 1x1, ISO | 0 | 78% | 21.05 | na | 320 | 21.94 | 1.76 | 10.21% | 0.18 | - | - | 44.93 | - | 44.93 |
| CCCT Dry "G/H", DF, 1x1, ISO | 0 | 12% | 58.42 | na | 320 | 21.94 | 0.15 | 0.00% | 0.00 | - | - | 80.52 | - | 80.52 |
| CCCT Dry "G/H", 2x1, ISO | 0 | 78% | 16.01 | na | 320 | 21.99 | 1.67 | 10.79% | 0.18 | - | - | 39.85 | - | 39.85 |
| CCCT Dry "G/H", DF, 2x1, ISO | 0 | 12% | 50.24 | na | 320 | 21.99 | 0.16 | 0.00% | 0.00 | - | - | 72.38 | - | 72.38 |
| CCCT Dry "J/HA.02", 1x1, ISO | 0 | 78% | 18.10 | na | 320 | 21.75 | 1.70 | 10.21% | 0.17 | - | - | 41.72 | - | 41.72 |
| CCCT Dry "J/HA.02", DF, 1x1, ISO | 0 | 12% | 53.17 | na | 320 | 21.75 | 0.16 | 0.00% | 0.00 | - | - | 75.07 | - | 75.07 |
| CCCT Dry, "J/HA.02" 2X1, ISO | 0 | 78% | 13.93 | na | 320 | 21.75 | 1.62 | 10.79% | 0.17 | - | - | 37.47 | - | 37.47 |
| CCCT Dry "J/HA.02", DF, 2X1, ISO | 0 | 12% | 46.48 | na | 320 | 21.75 | 0.16 | 0.00% | 0.00 | - | - | 68.39 | - | 68.39 |
| SCCT Aero x3 | 1500 | 33% | 62.12 | na | 320 | 29.57 | 7.76 | 11.48% | 0.89 | - | - | 100.34 | - | 100.34 |
| Intercooled SCCT Aero x2 | 1500 | 33% | 46.55 | na | 320 | 27.84 | 5.35 | 13.23% | 0.71 | - | - | 80.45 | - | 80.45 |
| SCCT Frame "F" x1 | 1500 | 33% | 34.40 | na | 320 | 31.38 | 5.81 | 11.48% | 0.67 | - | - | 72.25 | - | 72.25 |
| IC Recips x 6 | 1500 | 33% | 63.74 | na | 320 | 26.51 | 7.45 | 8.73% | 0.65 | - | - | 98.35 | - | 98.35 |
| CCCT Dry "G/H", 1x1 | 1500 | 78% | 22.02 | na | 320 | 21.75 | 1.86 | 10.21% | 0.19 | - | - | 45.82 | - | 45.82 |
| CCCT Dry "G/H", DF, 1x1 | 1500 | 12% | 58.23 | na | 320 | 21.75 | 0.15 | 0.00% | 0.00 | - | - | 80.14 | - | 80.14 |
| CCCT Dry "G/H", 2x1 | 1500 | 78% | 16.69 | na | 320 | 21.79 | 1.77 | 10.79% | 0.19 | - | - | 40.44 | - | 40.44 |
| CCCT Dry "G/H", DF, 2x1 | 1500 | 12% | 50.04 | na | 320 | 21.79 | 0.16 | 0.00% | 0.00 | - | - | 71.98 | - | 71.98 |
| CCCT Dry "J/HA.02", 1x1 | 1500 | 78% | 18.92 | na | 320 | 21.57 | 1.80 | 10.21% | 0.18 | - | - | 42.48 | - | 42.48 |
| CCCT Dry "J/HA.02", DF, 1x1 | 1500 | 12% | 52.99 | na | 320 | 21.57 | 0.16 | 0.00% | 0.00 | - | - | 74.71 | - | 74.71 |
| CCCT Dry, "J/HA.02" 2X1 | 1500 | 78% | 14.51 | na | 320 | 21.57 | 1.71 | 10.79% | 0.18 | - | - | 37.98 | - | 37.98 |
| CCCT Dry "J/HA.02", DF, 2X1 | 1500 | 12% | 46.30 | na | 320 | 21.57 | 0.16 | 0.00% | 0.00 | - | - | 68.03 | - | 68.03 |
| SCCT Aero x3 | 3000 | 33% | 59.90 | na | 324 | 29.90 | 8.21 | 11.48% | 0.94 | - | - | 98.95 | - | 98.95 |
| Intercooled SCCT Aero x2 | 3000 | 33% | 43.82 | na | 324 | 28.14 | 5.67 | 13.23% | 0.75 | - | - | 78.38 | - | 78.38 |
| SCCT Frame "F" x1 | 3000 | 33% | 30.23 | na | 324 | 31.74 | 6.13 | 11.48% | 0.70 | - | - | 68.80 | - | 68.80 |
| IC Recips x 6 | 3000 | 33% | 59.14 | na | 324 | 26.80 | 7.45 | 8.73% | 0.65 | - | - | 94.04 | - | 94.04 |
| CCCT Dry "G/H", 1x1 | 3000 | 78% | 23.07 | na | 324 | 21.90 | 1.97 | 10.21% | 0.20 | - | - | 47.14 | - | 47.14 |
| CCCT Dry "G/H", DF, 1x1 | 3000 | 12% | 58.15 | na | 324 | 21.90 | 0.15 | 0.00% | 0.00 | - | - | 80.20 | - | 80.20 |
| CCCT Dry "G/H", 2x1 | 3000 | 78% | 15.85 | na | 324 | 21.94 | 1.86 | 10.79% | 0.20 | - | - | 39.86 | - | 39.86 |
| CCCT Dry "G/H", DF, 2x1 | 3000 | 12% | 39.60 | na | 324 | 21.94 | 0.16 | 0.00% | 0.00 | - | - | 61.70 | - | 61.70 |
| CCCT Dry "J/HA.02", 1x1 | 3000 | 78% | 18.23 | na | 324 | 21.67 | 1.90 | 10.21% | 0.19 | - | - | 42.00 | - | 42.00 |
| CCCT Dry "J/HA.02", DF, 1x1 | 3000 | 12% | 42.62 | na | 324 | 21.67 | 0.16 | 0.00% | 0.00 | - | - | 64.44 | - | 64.44 |
| CCCT Dry, "J/HA.02" 2X1 | 3000 | 78% | 13.56 | na | 324 | 21.67 | 1.81 | 10.79% | 0.19 | - | - | 37.24 | - | 37.24 |
| CCCT Dry "J/HA.02", DF, 2X1 | 3000 | 12% | 35.94 | na | 324 | 21.67 | 0.16 | 0.00% | 0.00 | - | - | 57.77 | - | 57.77 |

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

| Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($) | | Convert to $/MWh | | | | | Variable Costs ($/MWh) | | | | | Total Costs and Credits ($/MWh) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Levelized Fuel | | | | | | | | Credits | |
| Resource Description | Elevation (AFSL) | Capacity Factor 3/ | Total Fixed ($/MWh) | Storage Efficiency | ¢/mmBtu | $/MWh | O&M 1/ | Capitalized Premium | O&M Capitalized 1/ | Integration Cost 1/ | Environmental | Total Resource Cost | PTC Tax Credits / ITC (Solar Only) | Total Resource Cost - with PTC / ITC Credits |
| SCCT Aero x3 | 5050 | 33% | 62.92 | na | 327 | 30.14 | 8.85 | 11.48% | 1.02 | - | - | 102.93 | - | 102.93 |
| Intercooled SCCT Aero x2 | 5050 | 33% | 45.95 | na | 327 | 28.35 | 6.14 | 13.23% | 0.81 | - | - | 81.25 | - | 81.25 |
| SCCT Frame "F" x1 | 5050 | 33% | 31.05 | na | 327 | 32.02 | 6.61 | 11.48% | 0.76 | - | - | 70.45 | - | 70.45 |
| IC Recips x 6 | 5050 | 33% | 58.26 | na | 327 | 27.04 | 7.45 | 8.73% | 0.65 | - | - | 93.40 | - | 93.40 |
| CCCT Dry "G/H", 1x1 | 5050 | 78% | 22.84 | na | 327 | 21.26 | 2.12 | 10.21% | 0.22 | - | - | 46.45 | - | 46.45 |
| CCCT Dry "G/H", DF, 1x1 | 5050 | 12% | 45.43 | na | 327 | 21.26 | 0.15 | 0.00% | 0.00 | - | - | 66.85 | - | 66.85 |
| CCCT Dry "G/H", 2x1 | 5050 | 78% | 16.78 | na | 327 | 21.29 | 2.01 | 10.79% | 0.22 | - | - | 40.30 | - | 40.30 |
| CCCT Dry "G/H", DF, 2x1 | 5050 | 12% | 37.21 | na | 327 | 21.29 | 0.16 | 0.00% | 0.00 | - | - | 58.66 | - | 58.66 |
| CCCT Dry "J/HA.02", 1x1 | 5050 | 78% | 19.31 | na | 327 | 21.11 | 2.05 | 10.21% | 0.21 | - | - | 42.68 | - | 42.68 |
| CCCT Dry "J/HA.02", DF, 1x1 | 5050 | 12% | 40.31 | na | 327 | 21.11 | 0.16 | 0.00% | 0.00 | - | - | 61.57 | - | 61.57 |
| CCCT Dry, "J/HA.02" 2X1 | 5050 | 78% | 14.29 | na | 327 | 21.13 | 1.95 | 10.79% | 0.21 | - | - | 37.57 | - | 37.57 |
| CCCT Dry "J/HA.02", DF, 2X1 | 5050 | 12% | 33.63 | na | 327 | 21.13 | 0.16 | 0.00% | 0.00 | - | - | 54.91 | - | 54.91 |
| SCCT Aero x3 | 6500 | 33% | 65.89 | na | 320 | 29.50 | 9.60 | 11.48% | 1.10 | - | - | 106.09 | - | 106.09 |
| Intercooled SCCT Aero x2 | 6500 | 33% | 47.04 | na | 320 | 27.85 | 6.45 | 13.23% | 0.85 | - | - | 82.20 | - | 82.20 |
| SCCT Frame "F" x1 | 6500 | 33% | 30.59 | na | 320 | 31.35 | 6.96 | 11.48% | 0.80 | - | - | 69.69 | - | 69.69 |
| IC Recips x 6 | 6500 | 33% | 57.17 | na | 320 | 26.65 | 7.75 | 8.73% | 0.68 | - | - | 92.25 | - | 92.25 |
| CCCT Dry "G/H", 1x1 | 6500 | 78% | 25.18 | na | 320 | 21.64 | 2.25 | 10.21% | 0.23 | - | - | 49.31 | - | 49.31 |
| CCCT Dry "G/H", DF, 1x1 | 6500 | 12% | 55.65 | na | 320 | 21.64 | 0.15 | 0.00% | 0.00 | - | - | 77.45 | - | 77.45 |
| CCCT Dry "G/H", 2x1 | 6500 | 78% | 16.78 | na | 320 | 21.69 | 2.13 | 10.79% | 0.23 | - | - | 40.84 | - | 40.84 |
| CCCT Dry "G/H", DF, 2x1 | 6500 | 12% | 34.15 | na | 320 | 21.69 | 0.16 | 0.00% | 0.00 | - | - | 56.00 | - | 56.00 |
| CCCT Dry "J/HA.02", 1x1 | 6500 | 78% | 19.63 | na | 320 | 21.40 | 2.15 | 10.21% | 0.22 | - | - | 43.39 | - | 43.39 |
| CCCT Dry "J/HA.02", DF, 1x1 | 6500 | 12% | 37.24 | na | 320 | 21.40 | 0.16 | 0.00% | 0.00 | - | - | 58.80 | - | 58.80 |
| CCCT Dry, "J/HA.02" 2X1 | 6500 | 78% | 14.33 | na | 320 | 21.40 | 2.05 | 10.79% | 0.22 | - | - | 38.00 | - | 38.00 |
| CCCT Dry "J/HA.02", DF, 2X1 | 6500 | 12% | 30.56 | na | 320 | 21.40 | 0.16 | 0.00% | 0.00 | - | - | 52.12 | - | 52.12 |
| Blundell Dual Flash 90% CF | 4500 | 90% | 13.26 | na | 0 | - | 1.16 | 0.00% | 0.00 | - | - | 14.42 | (15.55) | (1.14) |
| Generic Geothermal PPA 90% CF | 4500 | 90% | - | na | 0 | - | 77.34 | 0.00% | 0.00 | - | - | 77.34 | - | 77.34 |
| 3.6 MW Wind turbine 37.1% CF WA, 2020 (100% PTC) | 4500 | 37% | 37.61 | na | 0 | - | 10.00 | 0.00% | 0.00 | 0.93 | - | 48.54 | (15.55) | 32.98 |
| 3.6 MW Wind turbine 37.1% CF OR, 2020 (100% PTC) | 1500 | 37% | 37.17 | na | 0 | - | 10.00 | 0.00% | 0.00 | 0.93 | - | 48.10 | (15.55) | 32.55 |
| 3.6 MW Wind turbine 37.1% CF ID, 2020 (100% PTC) | 4500 | 37% | 37.70 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.93 | - | 38.63 | (15.55) | 23.07 |
| 3.6 MW Wind turbine 29.5% CF UT, 2020 (100% PTC) | 6500 | 30% | 45.89 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.93 | - | 46.82 | (15.55) | 31.27 |
| 3.6 MW Wind turbine 43.6% CF WY, 2020 (100% PTC) | 1500 | 44% | 31.05 | na | 0 | - | 0.65 | 0.00% | 0.00 | 0.93 | - | 32.63 | (15.55) | 17.08 |
| 3.6 MW Wind turbine 37.1% CF WA,2023 (40% PTC) | 4500 | 37% | 37.61 | na | 0 | - | 10.00 | 0.00% | 0.00 | 0.93 | - | 48.54 | (6.22) | 42.31 |
| 3.6 MW Wind turbine 37.1% CF OR, 2023 (40% PTC) | 1500 | 37% | 37.17 | na | 0 | - | 10.00 | 0.00% | 0.00 | 0.93 | - | 48.10 | (6.22) | 41.88 |
| 3.6 MW Wind turbine 37.1% CF ID, 2023 (40% PTC) | 4500 | 37% | 37.70 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.93 | - | 38.63 | (6.22) | 32.41 |
| 3.6 MW Wind turbine 29.5% CF UT, 2023 (40% PTC) | 6500 | 30% | 45.89 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.93 | - | 46.82 | (6.22) | 40.60 |
| 3.6 MW Wind turbine 43.6% CF WY, 2023 (40% PTC) | 1500 | 44% | 31.05 | na | 0 | - | 0.65 | 0.00% | 0.00 | 0.93 | - | 32.63 | (6.22) | 26.41 |

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

| Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($) | | Convert to $/MWh | | | | | Variable Costs ($/MWh) | | | | | Total Costs and Credits ($/MWh) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Levelized Fuel | | | | | | | | Credits | |
| Resource Description | Elevation (AFSL) | Capacity Factor 3/ | Total Fixed ($/MWh) | Storage Efficiency | ¢/mmBtu | $/MWh | O&M 1/ | Capitalized Premium | O&M Capitalized 1/ | Integration Cost 1/ | Environmental | Total Resource Cost | PTC Tax Credits / ITC (Solar Only) | Total Resource Cost - with PTC / ITC Credits |
| Wind + Stor, Arlington, OR, 200 MW+ 50 MW \| 200 MWh | 1500 | 37% | 50.15 | 88% | 0 | - | 10.00 | 0.00% | 0.00 | 0.93 | - | 61.08 | (6.22) | 54.86 |
| Wind + Stor, Monticello, UT, 200 MW+ 50 MW \| 200 MWh | 4500 | 30% | 62.01 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.93 | - | 62.94 | (6.22) | 56.72 |
| Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW \| 200 MWh | 6500 | 44% | 41.86 | 88% | 0 | - | 0.65 | 0.00% | 0.00 | 0.93 | - | 43.43 | (6.22) | 37.21 |
| Wind + Stor, Goldendale, WA, 200 MW+ 50 MW \| 200 MWh | 1500 | 37% | 50.29 | 88% | 0 | - | 10.00 | 0.00% | 0.00 | 0.93 | - | 61.22 | (6.22) | 55.00 |
| PV Idaho Falls, ID, 200 MW, 2021, 28.1% CF (30% ITC) | 4700 | 28% | 48.77 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 49.47 | (13.57) | 35.90 |
| PV Lakeview, OR, 200 MW, 2021, 29.7% CF (30% ITC) | 4800 | 30% | 48.12 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 48.82 | (13.43) | 35.40 |
| PV Milford, UT, 200 MW, 2021, 32.5% CF (30% ITC) | 5000 | 33% | 42.31 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 43.01 | (11.71) | 31.31 |
| PV Utah North, 200 MW, 2021, 30.1% CF (30% ITC) | 5000 | 30% | 45.15 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 45.85 | (12.61) | 33.24 |
| PV Rock Springs, WY, 200 MW, 2021, 30.1% CF (30% ITC) | 6400 | 30% | 45.15 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 45.85 | (12.61) | 33.24 |
| PV Yakima, WA, 200 MW, 2021, 26% CF (30% ITC) | 1000 | 26% | 54.89 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 55.60 | (15.31) | 40.28 |
| PV Idaho Falls, ID, 200 MW, 2026, 28.1% CF (10% ITC) | 4700 | 28% | 48.77 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 49.47 | (4.97) | 44.50 |
| PV Lakeview, OR, 200 MW, 2026, 29.7% CF (10% ITC) | 4800 | 30% | 48.12 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 48.82 | (4.92) | 43.91 |
| PV Milford, UT, 200 MW, 2026, 32.5% CF (10% ITC) | 5000 | 33% | 42.31 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 43.01 | (4.29) | 38.73 |
| PV Utah North, 200 MW, 2021, 30.1% CF (10% ITC) | 5000 | 30% | 45.15 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 45.85 | (4.62) | 41.23 |
| PV Rock Springs, WY, 200 MW, 2026, 30.1% CF (10% ITC) | 6400 | 30% | 45.15 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 45.85 | (4.62) | 41.23 |
| PV Yakima, WA, 200 MW, 2026, 26% CF (10% ITC) | 1000 | 26% | 54.89 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 55.60 | (5.61) | 49.99 |
| PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 200 MWh (30% ITC) | 4700 | 28% | 60.55 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 61.25 | (17.25) | 44.01 |
| PV + Stor, Lakeview, OR, 200 MW + 50 MW X 200 MWh (30% ITC) | 4800 | 30% | 59.80 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 60.50 | (17.07) | 43.43 |
| PV + Stor,, Milford, UT, 200 MW + 50 MW X 200 MWh (30% ITC) | 5000 | 33% | 52.29 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 52.99 | (14.88) | 38.11 |
| PV + Stor, Utah North, 200 MW + 50 MW X 200 MWh (30% ITC) | 5000 | 30% | 56.38 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 57.08 | (16.04) | 41.04 |
| PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 200 MWh (30% ITC) | 6400 | 30% | 56.38 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 57.08 | (16.04) | 41.04 |
| PV + Stor, Yakima, WA, 200 MW + 50 MW X 200 MWh (30% ITC) | 1000 | 26% | 68.24 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 68.95 | (19.47) | 49.48 |
| PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 200 MWh (10% ITC) | 4700 | 28% | 60.55 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 61.25 | (6.32) | 54.94 |
| PV + Stor, Lakeview, OR, 200 MW + 50 MW X 200 MWh (10% ITC) | 4800 | 30% | 59.80 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 60.50 | (6.25) | 54.25 |
| PV + Stor,, Milford, UT, 200 MW + 50 MW X 200 MWh (10% ITC) | 5000 | 33% | 52.29 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 52.99 | (5.45) | 47.54 |
| PV + Stor, Utah North, 200 MW + 50 MW X 200 MWh (10% ITC) | 5000 | 30% | 56.38 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 57.08 | (5.87) | 51.21 |
| PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 200 MWh (10% ITC) | 6400 | 30% | 56.38 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 57.08 | (5.87) | 51.21 |
| PV + Stor, Yakima, WA, 200 MW + 50 MW X 200 MWh (10% ITC) | 1000 | 26% | 68.24 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 68.95 | (7.13) | 61.82 |
| Oregon PS, 400 MW X 3,800 MWh | 4457 | 36% | 65.59 | 79% | 324 | 27.44 | 0.00 | 0.00% | 0.00 | - | - | 93.03 | - | 93.03 |
| Oregon PS joint ownership, 100 MW X 950 MWh | 4457 | 36% | 65.68 | 79% | 324 | 27.44 | 0.00 | 0.00% | 0.00 | - | - | 93.12 | - | 93.12 |
| Washington PS, 1,200 MW X 16,800 MWh | 500 | 36% | 56.91 | 79% | 320 | 27.14 | 0.00 | 0.00% | 0.00 | - | - | 84.06 | - | 84.06 |
| Wyoming PS, 700 MW X 7,000 MWh | 580 | 36% | 68.79 | 79% | 320 | 27.13 | 0.00 | 0.00% | 0.00 | - | - | 95.92 | - | 95.92 |
| Wyoming PS, 400 MW X 3,400 MWh | 6000 | 36% | 51.12 | 79% | 320 | 27.13 | 0.00 | 0.00% | 0.00 | - | - | 78.25 | - | 78.25 |
| Utah PS, 300 MW X 1,800 MWh | 6359 | 36% | 63.65 | 79% | 327 | 27.67 | 0.00 | 0.00% | 0.00 | - | - | 91.31 | - | 91.31 |
| Idaho PS, 360 MW X 2,880 MWh | 5000 | 36% | 57.59 | 79% | 327 | 27.67 | 0.00 | 0.00% | 0.00 | - | - | 85.25 | - | 85.25 |
| CAES, 320 MW X 15,360 MWh | 4600 | 72% | 20.20 | 55% | 327 | 39.74 | 0.00 | 0.00% | 0.00 | - | - | 59.94 | - | 59.94 |
| Li-Ion 15 MW X 60 MWh | 0 | 17% | 142.42 | 88% | 327 | 24.84 | 15.07 | 0.00% | 0.00 | - | - | 182.32 | - | 182.32 |

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

| Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($) | | Convert to $/MWh | | | | | Variable Costs ($/MWh) | | | | | Total Costs and Credits ($/MWh) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Levelized Fuel | | | | | | | | Credits | |
| Resource Description | Elevation (AFSL) | Capacity Factor 3/ | Total Fixed ($/MWh) | Storage Efficiency | ¢/mmBtu | $/MWh | O&M 1/ | Capitalized Premium | O&M Capitalized 1/ | Integration Cost 1/ | Environmental | Total Resource Cost | PTC Tax Credits / ITC (Solar Only) | Total Resource Cost - with PTC / ITC Credits |
| **Brownfield Site** | | | | | | | | | | | | | | |
| **Dave Johnston** | | | | | | | | | | | | | | |
| SCCT Frame "F" x1 | 5050 | 33% | 27.81 | na | 327 | 32.11 | 6.61 | 11.48% | 0.76 | - | - | 67.29 | - | 67.29 |
| 3.6 MW Wind turbine 43.6% CF WY, 2023 (40% PTC) | 6400 | 44% | 31.05 | na | 0 | - | 0.65 | 0.00% | 0.00 | 0.93 | - | 32.63 | (6.22) | 26.41 |
| CCCT Dry "J/HA.02", 1x1 | 5050 | 78% | 19.34 | na | 320 | 20.66 | 2.05 | 10.21% | 0.21 | - | - | 42.25 | - | 42.25 |
| CCCT Dry "J/HA.02", DF, 1x1 | 5050 | 12% | 47.20 | na | 320 | 20.66 | 0.16 | 0.00% | 0.00 | - | - | 68.02 | - | 68.02 |
| **Hunter** | | | | | | | | | | | | | | |
| SCCT Frame "F" x1 | 5050 | 33% | 27.81 | na | 327 | 32.11 | 6.61 | 11.48% | 0.76 | - | - | 67.29 | - | 67.29 |
| PV, 200 MW, 2026, 32.5% CF (10% ITC) | 5000 | 33% | 42.31 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 43.01 | (4.29) | 38.73 |
| PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC) | 5000 | 33% | 52.29 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 52.99 | (5.45) | 47.54 |
| CCCT Dry "J/HA.02", 1x1 | 5050 | 78% | 17.89 | na | 327 | 21.17 | 2.05 | 10.21% | 0.21 | - | - | 41.31 | - | 41.31 |
| CCCT Dry "J/HA.02", DF, 1x1 | 5050 | 12% | 37.77 | na | 327 | 21.17 | 0.16 | 0.00% | 0.00 | - | - | 59.09 | - | 59.09 |
| **Huntington** | | | | | | | | | | | | | | |
| SCCT Frame "F" x1 | 5050 | 33% | 27.81 | na | 327 | 32.11 | 6.61 | 11.48% | 0.76 | - | - | 67.29 | - | 67.29 |
| PV, 200 MW, 2026, 32.5% CF (10% ITC) | 5000 | 33% | 42.31 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 43.01 | (4.29) | 38.73 |
| PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC) | 5000 | 33% | 52.29 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 52.99 | (5.45) | 47.54 |
| CCCT Dry "J/HA.02", 1x1 | 5050 | 78% | 17.89 | na | 327 | 21.17 | 2.05 | 10.21% | 0.21 | - | - | 41.31 | - | 41.31 |
| CCCT Dry "J/HA.02", DF, 1x1 | 5050 | 12% | 37.77 | na | 327 | 21.17 | 0.16 | 0.00% | 0.00 | - | - | 59.09 | - | 59.09 |
| **Jim Bridger** | | | | | | | | | | | | | | |
| 3.6 MW Wind turbine 43.6% CF WY, 2023 (40% PTC) | 6400 | 44% | 31.05 | na | 0 | - | 0.65 | 0.00% | 0.00 | 0.93 | - | 32.63 | (6.22) | 26.41 |
| Wind + Stor, 200 MW+ 50 MW [ 400 MWh | 6500 | 44% | 47.19 | 88% | 0 | - | 0.65 | 0.00% | 0.00 | 0.93 | - | 48.77 | (6.22) | 42.55 |
| SCCT Frame "F" x1 | 6500 | 33% | 27.17 | na | 321 | 31.43 | 6.96 | 11.48% | 0.80 | - | - | 66.36 | - | 66.36 |
| PV, 200 MW, 2026, 32.5% CF (10% ITC) | 6400 | 30% | 45.15 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 45.85 | (4.62) | 41.23 |
| PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC) | 6400 | 30% | 56.38 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 57.08 | (5.87) | 51.21 |
| CCCT Dry "J/HA.02", 1x1 | 6500 | 78% | 18.14 | na | 321 | 21.45 | 2.15 | 10.21% | 0.22 | - | - | 41.97 | - | 41.97 |
| CCCT Dry "J/HA.02", DF, 1x1 | 6500 | 12% | 34.70 | na | 321 | 21.45 | 0.16 | 0.00% | 0.00 | - | - | 56.31 | - | 56.31 |
| **Naughton** | | | | | | | | | | | | | | |
| SCCT Frame "F" x1 | 6500 | 33% | 28.98 | na | 327 | 32.05 | 6.96 | 11.48% | 0.80 | - | - | 68.78 | - | 68.78 |
| PV 200 MW, 2026, 30.1% CF (10% ITC) | 6400 | 30% | 45.15 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 45.85 | (4.62) | 41.23 |
| CCCT Dry "J/HA.02", 1x1 | 6500 | 78% | 18.66 | na | 327 | 21.88 | 2.15 | 10.21% | 0.22 | - | - | 42.91 | - | 42.91 |
| CCCT Dry "J/HA.02", DF, 1x1 | 6500 | 12% | 38.08 | na | 327 | 21.88 | 0.16 | 0.00% | 0.00 | - | - | 60.11 | - | 60.11 |
| **Wyodak** | | | | | | | | | | | | | | |
| SCCT Frame "F" x1 | 6500 | 33% | 34.17 | na | 323 | 31.58 | 6.96 | 11.48% | 0.80 | - | - | 73.51 | - | 73.51 |

1/ Input into IRP SO and PAR Model

2/ Wind and solar shapes are input into IRP SO and PAR Model

NC = Not Calculated

Results presented without credits

Information Presented is Illustrative

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

Resources not Modeled in 2019 IRP

| Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($) | | Convert to $/MWh | | | | | Variable Costs ($/MWh) | | | | | | Total Costs and Credits ($/MWh) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Levelized Fuel | | | | | | | | Credits | |
| Resource Description | Elevation (AFSL) | Capacity Factor | Total Fixed ($/MWh) | Storage Efficiency | ¢/mmBtu | $/MWh | O&M | Capitalized Premium | O&M Capitalized | Integration Cost | Environmental | Total Resource Cost | PTC Tax Credits / ITC (Solar Only) | Total Resource Cost - with PTC / ITC Credits |
| SCPC with CCS | 4500 | 90% | 64.62 | na | 178 | 23.30 | 7.00 | 0.00% | 0.00 | - | - | 94.91 | - | 94.91 |
| IGCC with CCS | 4500 | 86% | 62.30 | na | 178 | 19.27 | 11.77 | 11.52% | 1.36 | - | - | 94.69 | - | 94.69 |
| PC CCS retrofit @ 500 MW | 4500 | 90% | 21.90 | na | 178 | 25.58 | 6.47 | 0.00% | 0.00 | - | - | 53.96 | - | 53.96 |
| SCPC with CCS | 6500 | 90% | 70.74 | na | 178 | 23.57 | 7.58 | 0.00% | 0.00 | - | - | 101.89 | - | 101.89 |
| IGCC with CCS | 6500 | 86% | 70.21 | na | 178 | 19.66 | 14.11 | 0.00% | 0.00 | - | - | 103.98 | - | 103.98 |
| PC CCS retrofit @ 500 MW | 6500 | 90% | 22.78 | na | 178 | 25.58 | 7.00 | 0.00% | 0.00 | - | - | 55.36 | - | 55.36 |
| Greenfield Binary 90% CF | 4500 | 90% | 59.99 | na | 0 | - | 1.16 | 0.00% | 0.00 | - | - | 61.15 | (15.55) | 45.60 |
| Wind + Stor, Pocatello, ID, 200 MW+ 50 MW \| 100 MWh | 4500 | 37% | 46.12 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.93 | - | 47.05 | (6.22) | 40.83 |
| Wind + Stor, Arlington, OR, 200 MW+ 50 MW \| 100 MWh | 1500 | 37% | 46.72 | 88% | 0 | - | 10.00 | 0.00% | 0.00 | 0.93 | - | 57.65 | (6.22) | 51.42 |
| Wind + Stor, Monticello, UT, 200 MW+ 50 MW \| 100 MWh | 4500 | 30% | 57.95 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.93 | - | 58.87 | (6.22) | 52.65 |
| Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW \| 100 MWh | 6500 | 44% | 39.10 | 88% | 0 | - | 0.65 | 0.00% | 0.00 | 0.93 | - | 40.68 | (6.22) | 34.46 |
| Wind + Stor, Goldendale, WA, 200 MW+ 50 MW \| 100 MWh | 1500 | 37% | 46.85 | 88% | 0 | - | 10.00 | 0.00% | 0.00 | 0.93 | - | 57.78 | (6.22) | 51.56 |
| Wind + Stor, Pocatello, ID, 200 MW+ 50 MW \| 400 MWh | 4500 | 37% | 55.62 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.93 | - | 56.55 | (6.22) | 50.33 |
| Wind + Stor, Arlington, OR, 200 MW+ 50 MW \| 400 MWh | 1500 | 37% | 56.82 | 88% | 0 | - | 10.00 | 0.00% | 0.00 | 0.93 | - | 67.75 | (6.22) | 61.53 |
| Wind + Stor, Monticello, UT, 200 MW+ 50 MW \| 400 MWh | 4500 | 30% | 69.89 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.93 | - | 70.82 | (6.22) | 64.60 |
| Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW \| 400 MWh | 6500 | 44% | 47.19 | 88% | 0 | - | 0.65 | 0.00% | 0.00 | 0.93 | - | 48.77 | (6.22) | 42.55 |
| Wind + Stor, Goldendale, WA, 200 MW+ 50 MW \| 400 MWh | 1500 | 37% | 56.97 | 88% | 0 | - | 10.00 | 0.00% | 0.00 | 0.93 | - | 67.90 | (6.22) | 61.68 |
| PV Idaho Falls, ID, 50 MW, 28.1% CF (30% ITC) | 4700 | 28% | 51.73 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 52.43 | (14.58) | 37.86 |
| PV Lakeview, OR, 50 MW, 2021, 29.7% CF (30% ITC) | 4800 | 30% | 50.92 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 51.63 | (14.38) | 37.24 |
| PV Milford, UT, 50 MW, 2021, 32.5% CF (30% ITC) | 5000 | 33% | 44.87 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 45.58 | (12.58) | 32.99 |
| PV Rock Springs, WY, 50 MW, 2021, 30.1% CF (30% ITC) | 6400 | 30% | 47.91 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 48.62 | (13.56) | 35.06 |
| PV Yakima, WA, 50 MW, 2021, 26% CF (30% ITC) | 1000 | 26% | 58.09 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 58.80 | (16.40) | 42.39 |
| PV Idaho Falls, ID, 50 MW, 2026, 28.1% CF (10% ITC) | 4700 | 28% | 51.73 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 52.43 | (5.34) | 47.09 |
| PV Lakeview, OR, 50 MW, 2026, 29.7% CF (10% ITC) | 4800 | 30% | 50.92 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 51.63 | (5.27) | 46.36 |
| PV Milford, UT, 50 MW, 2026, 32.5% CF (10% ITC) | 5000 | 33% | 44.87 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 45.58 | (4.61) | 40.97 |
| PV Rock Springs, WY, 50 MW, 2026, 30.1% CF (10% ITC) | 6400 | 30% | 47.91 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 48.62 | (4.96) | 43.65 |
| PV Yakima, WA, 50 MW, 2026, 26% CF (10% ITC) | 1000 | 26% | 58.09 | na | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 58.80 | (6.01) | 52.79 |
| PV + Stor, Idaho Falls, ID, 50 MW + 10 MW X 20 MWh (30% ITC) | 4700 | 28% | 60.68 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 61.39 | (18.53) | 42.85 |
| PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 100 MWh (30% ITC) | 4700 | 28% | 55.48 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 56.18 | (17.25) | 38.93 |
| PV + Stor., Idaho Falls, ID, 50 MW + 10 MW X 40 MWh (30% ITC) | 4700 | 28% | 65.34 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 66.04 | (18.53) | 47.51 |
| PV + Stor, Idaho Falls, ID, 50 MW + 10 MW X 80 MWh (30% ITC) | 4700 | 28% | 73.32 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 74.03 | (18.53) | 55.50 |
| PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 400 MWh (30% ITC) | 4700 | 28% | 69.88 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 70.58 | (17.25) | 53.34 |
| PV + Stor, Lakeview, OR, 50 MW + 10 MW X 20 MWh (30% ITC) | 4800 | 30% | 59.72 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 60.42 | (18.28) | 42.14 |
| PV + Stor, Lakeview, OR, 200 MW + 50 MW X 100 MWh (30% ITC) | 4800 | 30% | 54.67 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 55.37 | (17.07) | 38.30 |
| PV + Stor, Lakeview, OR, 50 MW + 10 MW X 40 MWh (30% ITC) | 4800 | 30% | 64.42 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 65.12 | (18.28) | 46.84 |
| PV + Stor, Lakeview, OR, 50 MW + 10 MW X 80 MWh (30% ITC) | 4800 | 30% | 72.51 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 73.22 | (18.28) | 54.93 |
| PV + Stor., Lakeview, OR, 200 MW + 50 MW X 400 MWh (30% ITC) | 4800 | 30% | 69.27 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 69.98 | (17.07) | 52.91 |
| PV + Stor., Milford, UT, 50 MW + 10 MW X 20 MWh (30% ITC) | 5000 | 33% | 52.40 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 53.10 | (15.99) | 37.11 |
| PV + Stor., Milford, UT, 200 MW + 50 MW X 100 MWh (30% ITC) | 5000 | 33% | 47.90 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 48.60 | (14.88) | 33.72 |
| PV + Stor., Milford, UT 50 MW + 10 MW X 40 MWh (30% ITC) | 5000 | 33% | 56.43 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 57.13 | (15.99) | 41.14 |
| PV + Stor., Milford, UT, 50 MW + 10 MW X 80 MWh (30% ITC) | 5000 | 33% | 63.33 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 64.03 | (15.99) | 48.04 |
| PV + Stor., Milford, UT, 200 MW + 50 MW X 400 MWh (30% ITC) | 5000 | 33% | 60.35 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 61.06 | (14.88) | 46.17 |
| PV + Stor., Rock Springs, WY, 50 MW + 10 MW X 20 MWh (30% ITC) | 6400 | 30% | 56.50 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 57.20 | (17.23) | 39.97 |
| PV + Stor., Rock Springs, WY, 200 MW + 50 MW X 100 MWh (30% ITC) | 6400 | 30% | 51.64 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 52.34 | (16.04) | 36.31 |
| PV + Stor., Rock Springs, WY, 50 MW + 10 MW X 40 MWh (30% ITC) | 6400 | 30% | 60.85 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 61.55 | (17.23) | 44.31 |
| PV + Stor., Rock Springs, WY, 50 MW + 10 MW X 80 MWh (30% ITC) | 6400 | 30% | 68.30 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 69.00 | (17.23) | 51.77 |
| PV + Stor., Rock Springs, WY, 200 MW + 50 MW X 400 MWh (30% ITC) | 6400 | 30% | 65.09 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 65.79 | (16.04) | 49.75 |
| PV + Stor., Yakima, WA, 50 MW + 10 MW X 20 MWh (30% ITC) | 1000 | 26% | 68.15 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 68.85 | (20.85) | 48.00 |
| PV + Stor, Yakima, WA, 200 MW + 50 MW X 100 MWh (30% ITC) | 1000 | 26% | 62.38 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 63.08 | (19.47) | 43.62 |
| PV + Stor, Yakima, WA, 50 MW + 10 MW X 40 MWh (30% ITC) | 1000 | 26% | 73.52 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 74.22 | (20.85) | 53.37 |
| PV + Stor, Yakima, WA, 50 MW + 10 MW X 80 MWh (30% ITC) | 1000 | 26% | 82.77 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 83.48 | (20.85) | 62.62 |
| PV + Stor, Yakima, WA, 200 MW + 50 MW X 400 MWh (30% ITC) | 1000 | 26% | 79.07 | 88% | 0 | - | 0.00 | 0.00% | 0.00 | 0.70 | - | 79.78 | (19.47) | 60.31 |
| Li-Ion 1 MW X 250 kWh | 0 | 1% | 1,886.99 | 88% | 327 | 24.84 | 11.42 | 0.00% | 0.00 | - | - | 1,923.24 | - | 1,923.24 |
| Li-Ion 1 MW X 2 MWh | 0 | 8% | 430.85 | 88% | 327 | 24.84 | 15.70 | 0.00% | 0.00 | - | - | 471.38 | - | 471.38 |
| Li-Ion 1 MW X 4 MWh | 0 | 17% | 284.12 | 88% | 327 | 24.84 | 14.98 | 0.00% | 0.00 | - | - | 323.94 | - | 323.94 |
| Li-Ion 1 MW X 8 MWh | 0 | 33% | 225.69 | 88% | 327 | 24.84 | 14.98 | 0.00% | 0.00 | - | - | 265.50 | - | 265.50 |
| Flow 1 MW X 6 MWh | 0 | 25% | 217.62 | 65% | 327 | 33.62 | 0.00 | 0.00% | 0.00 | - | - | 251.24 | - | 251.24 |
| Advanced Fission | 5000 | 86% | 74.25 | na | 0 | - | 11.75 | 0.00% | 0.00 | - | - | 86.00 | - | 86.00 |
| Small Modular Reactor x 12 | 5000 | 86% | 79.12 | na | 0 | - | 15.50 | 0.00% | 0.00 | - | - | 94.62 | - | 94.62 |

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

**Table 6.3 - Total Resource Cost, for various Capacity Factors ($/MWh, 2018$)**

| Total Resource Cost ($/MWh) | | | |
|---|---|---|---|
| **Capacity Factor CCCT** | **40%** | **78%** | **94%** |
| **Capacity Factor Duct Fire** | **10%** | **12%** | **22%** |
| CCCT Dry "G/H", 1x1 | $68.15 | $46.45 | $42.56 |
| CCCT Dry "G/H", DF, 1x1 | $75.94 | $66.85 | $46.20 |
| CCCT Dry "G/H", 2x1 | $56.24 | $40.30 | $37.45 |
| CCCT Dry "G/H", DF, 2x1 | $66.11 | $58.66 | $41.75 |
| CCCT Dry "J/HA.02", 1x1 | $61.02 | $42.68 | $39.39 |
| CCCT Dry "J/HA.02", DF, 1x1 | $69.63 | $61.57 | $43.25 |
| CCCT Dry, "J/HA.02" 2X1 | $51.14 | $37.57 | $35.14 |
| CCCT Dry "J/HA.02", DF, 2X1 | $61.64 | $54.91 | $39.63 |

**Table 6.4 - Glossary of Terms from the SSR**

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

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

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

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

## Resource Option Descriptions

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

**Natural Gas, Simple Combined Cycle Turbine (SCCT) Aero x 3** – a resource based on three General Electric LM6000PF-Sprint simple cycle aero-derivative combustion turbines fueled on natural gas. The scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/volatile organic compounds (VOC) emissions.

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

**Natural Gas, SCCT Frame "F" x 1** – a resource based on one General Electric 7FA.05 simple cycle frame type combustion turbine fueled on natural gas. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions.

**Natural Gas, Internal Combustion (IC) Recips x 6** – a resource based on six Wartsila 18V50SG reciprocating engines fueled on natural gas. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions.

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

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

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

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

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

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

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

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

**Wind, 3.6 MW turbine 37 percent NCF WA/OR/ID** – a wind resource based on 3.6 MW wind turbines located in Washington, Oregon or Idaho with an estimated annual net capacity factor of 37 percent. The scope would include developing, permitting, engineering, procuring equipment and constructing a wind farm.

**Wind, 3.6 MW turbine 29 percent Net Capacity Factor (NCF) UT** – a wind resource based on 3.6 MW wind turbines located in Utah with an estimated annual net capacity factor of 29 percent. The scope would include developing, permitting, engineering, procuring equipment and constructing a wind farm.

**Wind, 3.6 MW turbine 43 percent NCF WY** – a wind resource based on 3.6 MW wind turbines located in Wyoming with an estimated annual net capacity factor of 43 percent. The scope would include developing, permitting, engineering, procuring equipment and constructing a wind farm.

**Solar, PV Single Axis Tracking in ID, OR, UT, WA, and WY with NCF between 26.0 and 32.5 percent depending upon location (1.46 MWdc/MWac)** – a large utility scale (50 MW or 200 MW) solar photovoltaic resource using crystalline silica solar panels in a single axis tracking system located in southwestern Utah.

**Storage, Pumped Hydro Storage** – a range (400 - 1,200 MW) of pumped storage systems using a combination of natural and constructed water storage combined with elevation difference to enable a system capable of discharging the rated capacity for eight hours combined with recharging that capacity over 16 hours. Total development time is estimated at six-to-12 years due to various progress on permitting. The recharge ratio for this resource is 79 percent. Actual pumped hydro storage projects within PacifiCorp's territory were analyzed.

**Storage, Lithium Ion Battery** – a battery technology of lithium ion batteries located close to the load center. Based on current commercial options such a system is modeled with an acquisition and implementation schedule of one year. The recharge ratio for this storage resource is 88 percent.

**Storage, Flow Battery** – a battery technology based vanadium ReDOx or other flow battery types. Based on current commercial options such a system is modeled with an acquisition and implementation schedule of one year. The recharge ratio for this storage resource is 65 percent.

**Storage, CAES** – compressed air energy storage (CAES) system consists of air storage reservoir replacing the compressor on a conventional gas turbine. The gas turbine exhaust powers a power turbine providing a simple cycle gas turbine energy at lower costs than a conventional gas turbine. Off-peak energy is used to compress air into the storage reservoir. A system size of 320 MW is assumed. The air storage reservoir is assumed to be solution mined to size. Natural gas is required to generate power. Although the recharge ratio is difficult to separate from the fuel combustion a recharge ratio assumed for this storage resource is 55 percent which includes the fuel required during the power generation cycle.

**Nuclear, Advanced Fission** – a large 2,234 MW nuclear resource reflects the current state-of-the-art advanced nuclear plant and is modeled after the Westinghouse AP1000 technology. The assumed location for this resource is the proposed Blue Castle site near Green River, Utah which is in development. It is expected that the resource would not be available earlier than 2025.

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

## Resource Types

### Renewables

PacifiCorp retained Burns & McDonnell Engineering Company (BMcD) to evaluate various renewable energy resources in support of the development of the 2019 IRP and associated resource acquisition portfolios and/or products. The 2018 Renewable Resources Assessment and Summary Tables (Assessment) (See Volume II, Appendix P) is screening-level in nature and includes a comparison of technical capabilities, capital costs, and O&M costs that are representative of renewable energy and storage technologies listed below. The Assessment contains preliminary information in support of the long-term power supply planning process. Any technologies of interest to PacifiCorp shall be followed by additional detailed studies to further investigate each technology and its direct application within the owner's long-term plans.

- Single Axis Tracking Solar
- Onshore Wind
- Energy Storage
    - Pumped hydro energy storage (PHES)

  - CAES
  - Li-Ion Battery
  - Flow Battery
- Solar + Energy Storage
- Wind + Energy Storage

Each renewable resource is defined within the Assessment. General assumptions, technology specific assumptions and cost inclusions and exclusions are described within the Assessment. The following paragraphs discuss highlights from the Assessment, a comparison to previous IRP data and additional assessment performed by PacifiCorp.

***Costs***

The following costs which were excluded from the renewables costs estimates were added by the PacifiCorp:

- AFUDC
- Escalation
- Sales tax
- Property taxes and insurance
- Utility demand costs

***Solar***

The BMcD Assessment includes 5 MW, 50 MW, and 200 MW single axis tracking (SAT), PV options evaluated at five locations within the PacifiCorp services area. The 2019 differs from previous IRP's in the following ways:

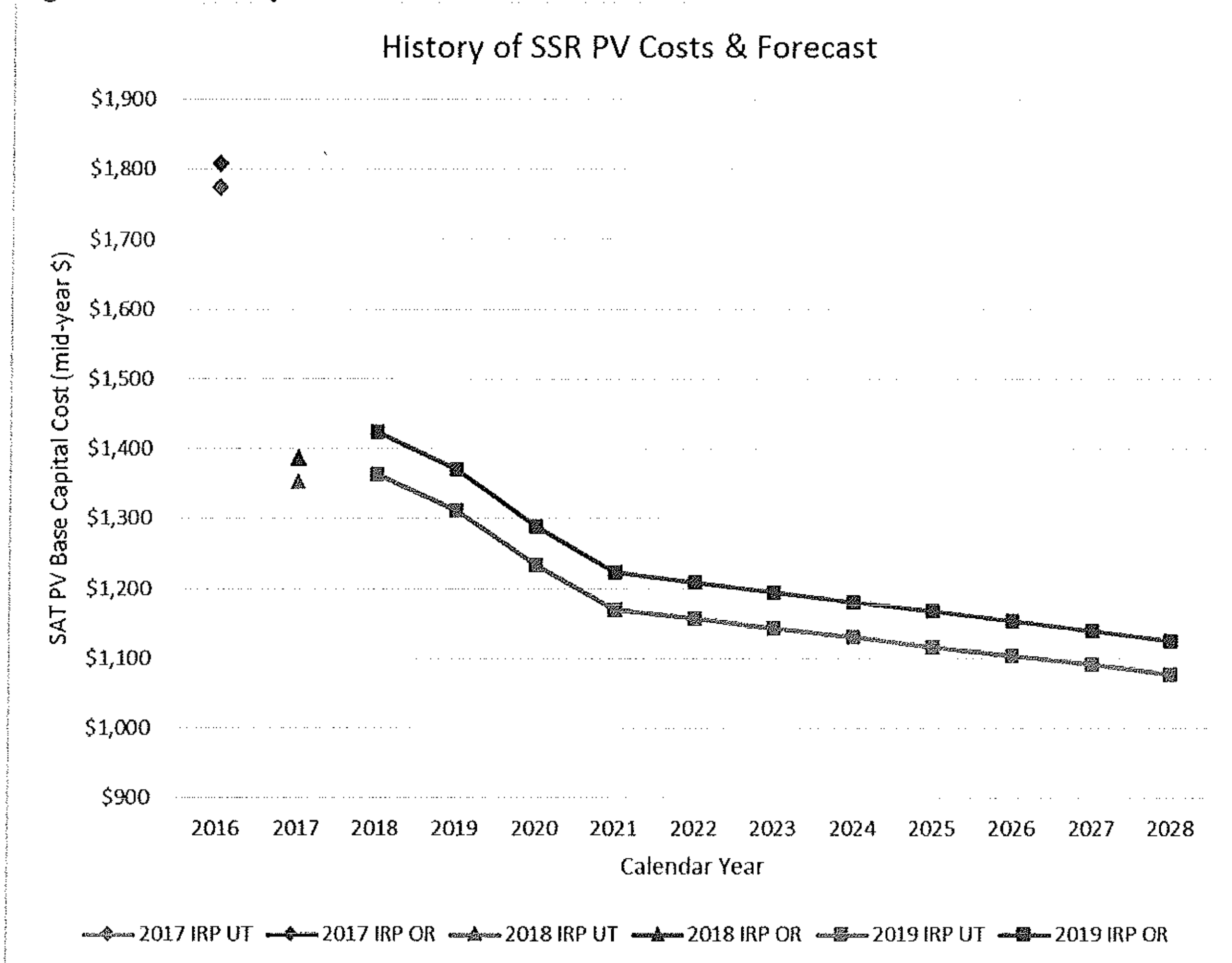
- The number of locations for solar development were expanded from two states (OR & UT) to five states (ID, OR, UT, WA, and WY) to reflect expanding solar development activity within PacifiCorp's service territory.
- A 200 MW option was added for each of the five locations based upon industry trends of building larger solar facilities.
- Fixed tilt PV and concentrated solar are not included based to findings in the 2017 IRP that SAT PV resources have lower costs and are better suited to PacifiCorp's service territory than fixed tilt PV or concentrated solar systems for the system sizes considered.

Solar costs (including forecasted costs) used for the 2019 IRP are higher than those used in the 2017 IRP Update, but are significantly lower than those used in the 2017 IRP. The increase from the 2017 IRP Update is partially due to a different assumed design. The inverter loading ratio results in a higher base capital cost, but a lower levelized cost of energy (LCOE). In addition to the different design basis two significant events have occurred with respect to solar costs since the 2017 IRP.

In late September 2017 the International Trade Commission passed a finding of injury to US solar manufacturers. A significant increase in solar prices in the US occurred following the ITC ruling. Solar costs have since resumed a declining trend, though at a reduced rate of decline. On January 22, 2018, the United States levied a 30 percent tariff on solar imports. The tariff covers both imported solar cells and solar modules. The tariff is expected to last for four years falling by five percent annually, dropping to a 15 percent tariff in 2021. At the time the tariff was levied solar prices briefly halted their decline from the peak price which occurred after the ITC ruling. Figure

6.4 shows a history of capital costs and a forecast used in the SSR for PV resources in Utah and Oregon. The forecast data for the solar 2019 IRP PV costs were provided via NREL data on an annual basis. The decreasing slope starting in 2021 shows that NREL is expecting storage pricing to drop more over the next three years than the years after that.

**Figure 6.4 – History of SSR PV Cost & Forecast**




There was significant solar development activity in PacifiCorp's service territory between 2012 and 2018. Over the course of those seven years, 332 solar projects with nameplates of 10 MW or greater have initiated generation interconnection requests with PacifiCorp. The total nameplate capacity of those 330 projects is over 27,500 MW. There were 66 new renewable generation projects greater than 10 MW that entered PacifiCorp's generation interconnection queue during 2018; of these 67 new projects, 51 are solar, six are solar & battery storage, seven are wind, one is battery energy storage, and one is nuclear. The nameplate capacity of the 57 solar projects added in 2018 alone is over 7,300 MW. While many projects that have initiated generation interconnection studies over the past 17 years have not been built, the number and size of the 2018 interconnection solar projects is testament to the tremendous solar development activity that is underway within PacifiCorp's service territory.

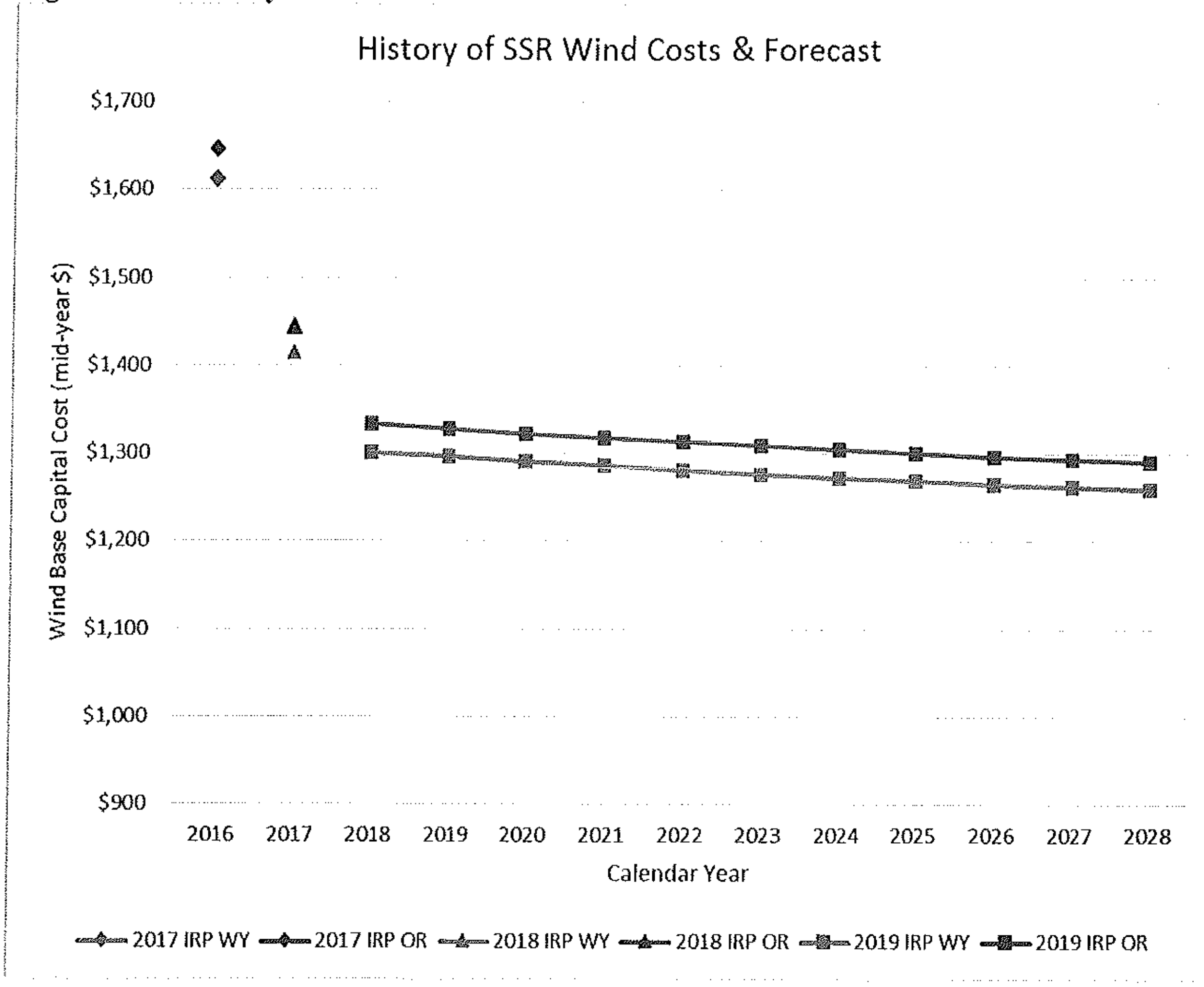
### *Wind*

The 2017 IRP found wind energy to be one of the most cost effective new generation resources for PacifiCorp's customers and led to PacifiCorp's Energy Vision 2020 initiative. Energy Vision 2020 includes three new wind projects, a new 500-kV transmission line, and upgrades to existing infrastructure to deliver the new wind generation to PacifiCorp's customers. The three new wind projects will add 1,150 MW of new wind power to PacifiCorp's generation resources. Wind capital costs in the 2019 IRP are lower than the cost estimates in the 2017 IRP and will push the LCOE for new projects lower. However, reductions in federal production tax credits (PTCs) will push the LCOE for new wind projects built after 2020 higher, assuming there are no changes to PTC policy.

The BMcD Assessment includes 200 MW onshore wind generating facilities in the states of Idaho, Oregon, Utah, Washington, and Wyoming to reflect strong wind resources available within or near PacifiCorp's service areas. BMcD relied on publicly available data and proprietary computational programs to complete the net capacity factor characterization. Generic project locations were selected by the company based on viable wind project locations where there are favorable wind profiles. Figure 6.5 shows a history of capital costs and a forecast used in the SSR for wind resources in Wyoming and Oregon. Utility scale wind farm costs have declined significantly in recent years on a per MW nameplate basis due in large part to substantial increases in the MW size of wind turbines on the market.

Federal PTCs were extended in December 2015 and included a graduated phase out structure that reduces the value of the credits for projects completed after 2021 and eliminates PTCs completely for projects completed after 2023. The PTC extension has led to increasing demand for safe harbor and follow-on wind turbine generators (WTGs) in the United States since 2016 as developers and owners have chosen to purchase safe harbor equipment between 2016 and 2019 to qualify projects that will be commercially operational no later than 2020 to 2023. Burns & McDonnell estimates the cost of wind projects will remain mostly flat with cost decreases of less than five percent over the next ten years, while other estimates indicate the LCOE for wind production could decline as much as 20 percent over the next ten years. While the wind industry has faced PTC cliffs in the past, it is difficult to predict how the scheduled phase out of PTC benefits will impact the cost of future wind projects in the market over the next five to ten years.

**Figure 6.5 – History of SSR Wind Costs & Forecast**




## Capital Costs

Capital cost estimates for wind resources in the IRP are based upon a combination of the Burns & McDonnell study, communications with wind equipment and construction companies, and PacifiCorp's active wind construction projects. All wind resources are specified in 200 MW blocks, but the model can choose multiple blocks or a fractional amount of a block.

## Wind Resource Capacity Factors and Energy Shapes

Resource options in the topology bubbles are assigned capacity factors based upon historic or expected project performance. Assigned capacity factor values for wind resources are 43 percent in Wyoming, 37 percent in Washington, Oregon and Idaho, and 29 percent in Utah. Capacity factor is a separate modeled parameter from the capital cost, and is used to scale wind energy shapes used by both the SO model and the Planning and Risk model (PaR). The hourly generation shape reflects average hourly wind variability. The hourly generation shape is repeated for each year of the simulation.

## Wind Integration Costs

To capture the costs of integrating wind into the system, PacifiCorp applied a value of $1.11/MWh (in 2018 dollars) for resource selection. To capture the costs of integrating solar into the system, PacifiCorp applied a value of $0.85/MWh (in 2018 dollars). Additional detailed information can be found in PacifiCorp's 2019 flexible reserve study (Volume II, Appendix F). Integration costs were incorporated into wind capital costs based on a 30-year project life expectancy and generation performance, and into solar capital costs based on a 25-year life expectancy and generation performance.

**Geothermal**

Geothermal resources can produce base-load energy and have high reliability and availability. However, geothermal resources have significantly higher development costs and exploration risks than other renewable technologies such as wind and solar. PacifiCorp has commissioned several studies of geothermal options during the past ten years to determine if additional sources of production can be added to the company's generation portfolio in a cost effective manner. A 2010 study commissioned by PacifiCorp and completed by Black & Veatch focused on geothermal projects near to PacifiCorp's service territory that were in advanced phases of development and could demonstrate commercial viability. PacifiCorp commissioned Black & Veatch to perform additional analysis of geothermal projects in the early stages of development and a report was issued in 2012. An evaluation of the PacifiCorp's Roosevelt Hot Springs geothermal resource was commissioned in 2013. The geothermal capital costs in the 2019 supply side resource option are built on the understanding gained from these earlier reports, publically available capital costs from the Geothermal Resources Council and publicly available prices for energy supplied under power purchase agreements.

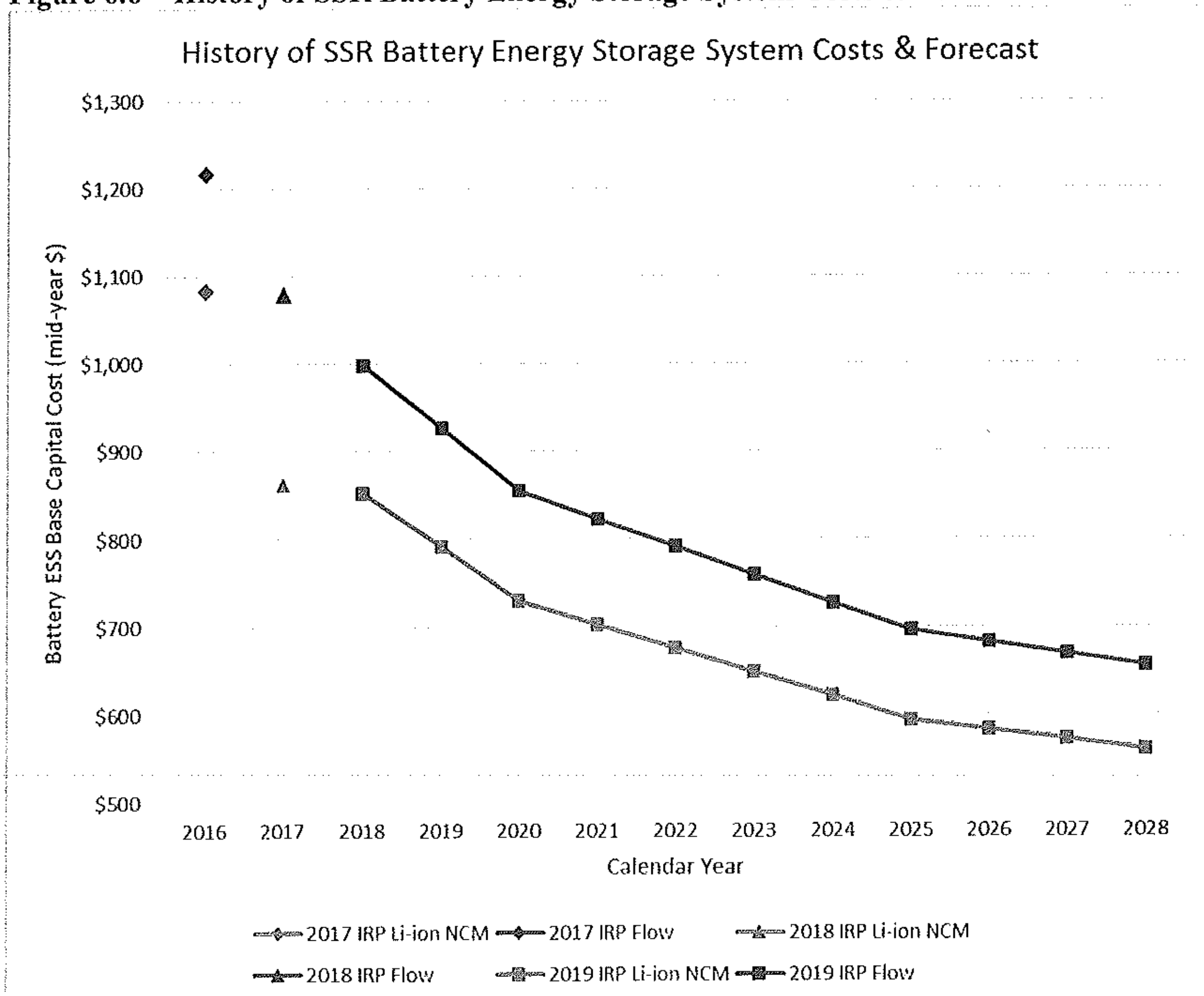
The cost recovery mechanisms currently available to PacifiCorp as a regulated electric utility are not compatible with the inherent risks associated with the development of geothermal resources for power generation. The primary risks of geothermal development are dry holes, well integrity and insufficient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

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

**Energy Storage**

The BMcD Assessment discusses three energy storage resource options: 1) PHES), 2) CAES, and 3) battery storage. Battery storage was also considered in combination with solar and wind. The addition of wind plus storage and solar plus storage created a large number of new resource options in the SSR. To mitigate the impact of the additional information less emphasis was placed on the various battery chemistries. Two of the three pumped hydro projects included in both the 2017 and 2019 IRP's showed modest capital cost declines while one showed a modest cost increase. The capital cost for CAES showed a 24 percent cost decrease. No forecasts have been used for pumped hydro and CAES. Both technologies are expected to have a flat forecast despite the recent movement in costs. Figure 6.6 shows a history of capital costs and a forecast used in the SSR for Li-Ion and flow battery resources. Battery costs are expected to continue to decline for the next ten years. Due to the complexity and maturity of the battery market, O&M costs continue to be an area of some uncertainty. PacifiCorp currently has two battery projects under development, one in Utah and one in Oregon, which will provide real market data to validate or indicate if an adjustment is needed for O&M costs.

**Figure 6.6 – History of SSR Battery Energy Storage System Costs & Forecast**



**Natural Gas**

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

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

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

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

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

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

(NOx) control is expected. All of the combined cycle options included dry cooling allowing them to be located in areas with water resource concerns.

Duct Firing (DF) of the combined cycle is shown in the Supply Side Resource table. Duct firing is not a stand-alone resource option, but is considered to be an available option for any combined cycle configuration and represents a low cost option to add peaking capability at relatively high efficiency and also a mechanism to recover lost power generation capability at high ambient temperatures. Duct firing is shown in the Supply Side Resource table as a fixed value for each combined cycle combination. In practice the amount of duct firing is a design consideration which is selected during the development of combined cycle generating facilities.

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

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

**Coal**
Potential coal resources are shown in the SSR as supercritical pulverized coal (PC) boilers and IGCC, located in both Utah and Wyoming. Both resource types include carbon dioxide capture and compression needed for sequestration.

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

**Carbon Capture**
The requirement for $CO_2$ CCS represents a significant cost for both new and existing coal resources. In order for a coal-fueled generating facility to meet the Federal New Source Performance Standards for Greenhouse Gases (NSPS-GHG) carbon dioxide emissions limit of 1,100 lbs per megawatt-hour would require $CO_2$ capture and permanent sequestration.[1] Capital

[1] This limit is still in effect and applies as it relates carbon capture analysis for the 2019 IRP. It should also be noted that on December 2018, EPA proposed revisions to the NSPS for GHG. Under the proposed rule, newly constructed plant $CO_2$ limits will be based on the most efficient demonstrated steam cycle in combination with the best operating practices. For large units, the BSER is proposed to be super-critical steam conditions, and if revised the emission rate would be 1,900 pounds of $CO_2$ per megawatt-hour on a gross output basis. For large units, the BSER

costs do not include the 45Q tax credit for carbon dioxide sequestration or enhanced oil recovery. Based on this requirement, only coal resource options that include carbon capture are included in the SSR.

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

The Petra Nova project is especially meaningful in that the project entailed a retrofit of an existing coal-fueled plant using amine based system and captures approximately 5,000 tons per day from the 240 MWh equivalent flue gas slipstream from NRG's W.A. Parish unit 8. Captured $CO_2$ is transported through an 81-mile pipeline and used for EOR at the West Ranch Oilfield, located on the Gulf Coast of Texas. It is the largest retrofit of a carbon capture technology of a pulverized coal plant in the world. Petra Nova is 50-50 joint venture by NRG and JX Nippon. The United States DOE is provided up to $190 million in grants as part of the Clean Coal Power Initiative Program (CCPI), a cost-shared collaboration between the federal government and private industry. The amine-based capture system utilizes Mitsubishi's proprietary KM CDR Process® and uses its KS-1™ amine solvent.

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

To address the availability of commercial sequestration, three PacifiCorp power plants participated in federally funded research to conduct a Phase I pre-feasibility study of carbon capture and storage. A grant from the U.S. DOE to the University of Wyoming was used to assess the storage of carbon dioxide in the Rock Springs Uplift, a geologic formation located adjacent to the Jim Bridger Plant in southwest Wyoming. Similar funding was allocated to the University of Utah to study the feasibility of long-term carbon dioxide storage in the San Rafael Swell near the Hunter and Huntington plants in central Utah. Both of projects showed that geological formations exist near the plants that may support carbon sequestration, though further study would be required. Neither site was selected by the U.S. DOE for advance study in the Phase II of the grant program.

is proposed to be subcritical conditions, and if revised the emission rate would be 2,200 pounds of $CO_2$ per megawatt-hour regardless of the size of the unit.

PacifiCorp issued a request for expression of interest to potential carbon capture, utilization, and storage (CCUS) counterparties on September 7, 2018. The request focused on possible deployment of CCUS technologies at PacifiCorp's Dave Johnston generating facility for potential enhanced oil recovery (EOR). On February 28, 2019, a phase I feasibility study was received by each of the three interested parties selected to participate (Jupiter Oxygen, ION Clean Energy [previously Eco2Source], and Glenrock Energy). On April 23, 2019, the participants were notified they may progress to phase II engagement of front-end engineering design (FEED) study at their discretion. None of the participants received DOE grant funds to support their FEED studies. PacifiCorp remains open to a CCUS project with the three parties if they secure funding in their own efforts.

An alternative to supercritical pulverized-coal technology for coal-based generation is the application of IGCC technology. A significant advantage for IGCC when compared to pulverized coal with amine-based carbon capture, is the reduced cost of capturing $CO_2$ from the process. Only a limited number of IGCC plants have been built and operated around the world. In the United States, these facilities have been demonstration projects, resulting in capital and operating costs that are significantly greater than those costs for conventional coal plants. These projects have been constructed with significant federal funding. One large, utility-scale IGCC plant with carbon capture capability recently went into service. Southern Company's 582 MW (net) $6.8 billion Kemper County project includes carbon capture (65 percent capture) and sequestration (for EOR). The plant produced electric power using syngas in October of 2016. Leaks caused the plant to miss the scheduled March 2017 completion date. Kemper power plant suspended coal gasification in June 2017.

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

A consortium of Japanese firms received orders on December 1, 2016 for two 540 MW IGCC plants to be constructed in Japan based on Mitsubishi's IGCC technology that was tested at the Nakoso Power Station from 2007 through 2013. A number of countries, including China, Turkey, Dubai, India, Kenya, Philippines, South Korea, Japan, and Malaysia have also announced plans to construct new conventional coal-fueled electric generating resources which will be monitored from a cost and technology deployment perspective.

No new cost studies were performed for coal-fueled generation options in 2018. Updated capital and O&M costs for coal-fuel generation options were based on escalating costs used in the 2017 IRP.

**Coal Plant Efficiency Improvements**

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

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

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

**Nuclear**

PacifiCorp revisited two of the nuclear options presented in the 2017 for the 2019 IRP: 1) the AP 1000 plant being developed by Blue Castle Holdings in Green River, Utah rated at 2,234 MW and 2) the 570 MW NuScale Small Modular Reactor (SMR) being developed for construction at the Idaho National Lab site. Blue Castle Holdings (BCH) did not provide updated pricing, therefore costs were escalated by two years from the costs used in the 2017 IRP. NuScale provided an update on their design, licensing and costs. NuScale's update resulted in a significant decline in the capital cost number for the Small Modular Reactor (SMR) resource option.

In 2016 BCH provided a detailed cost analysis of the Vogtle plant construction and eliminated unexpected costs which would not apply to the Green River site such as geotechnical problems encountered at the Vogtle site. The Vogtle plant was a first of a kind (FOAK) plant but the Green River plant would be an Nth of a kind (NOAK) plant based on the Vogtle plant AP 1000 design. PacifiCorp added a 3.7 percent delay cost to BCH's capital cost estimate for potential unforeseen problems not encountered on the Vogtle project. Details of the BCH project can be found at www.bluecastleproject.com.

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

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

# Demand-side Resources

## Resource Options and Attributes

### Source of Demand-Side Management Resource Data

PacifiCorp conducted a Conservation Potential Assessment (CPA) with for 2019-2038, which provided DSM resource opportunity estimates for the 2019 IRP. The study was conducted by

Applied Energy Group (AEG) on behalf of the company. The CPA provided a broad estimate of the size, type, location and cost of demand-side resources.[2] For the purpose of integrated resource planning, the DSM information from the CPA was converted into supply curves by type of resource (i.e. energy-based energy efficiency and demand response) for modeling against competing supply-side alternatives.

**Demand-Side Management Supply Curves**

DSM resource supply curves are a compilation of point estimates showing the relationship between the cumulative quantity and cost of resources, providing a representative look at how much of a particular resource can be acquired at a particular price point. Resource modeling utilizing supply curves allows the selection of least-cost resources (e.g. products and quantities) based on each resource's competitiveness against alternative resource options. Due to the timing of the 2019 IRP planning and modeling, PacifiCorp had established, funded and begun acquiring 2019 DSM program acquisition targets. To ensure that the 2019 IRP analysis is consistent with existing planned energy efficiency acquisition levels (i.e., Class 2 DSM), expected DSM savings in each state were fixed for calendar year 2019. Beyond 2019, the model optimized DSM selections.

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

- Resource quantities available in each year either in terms of megawatts or megawatt-hours, recognizing that some resources may come from stock additions not yet built, and that elective resources cannot all be acquired in the first year of the planning period;
- Persistence of resource savings (e.g., energy efficiency equipment measure lives);
- Seasonal availability and hours available (e.g., irrigation load control programs);
- The hourly shape of the resource (e.g., load shape of the resource); and
- Levelized resource costs (e.g., dollars per kilowatt per year for energy efficiency, or dollars per megawatt-hour over the resource's life for demand response resources).

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

**Demand Response: DSM Capacity Supply Curves**

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

Table 6.6 and Table 6.7 show the summary level demand response resource supply curve information, by control area. For additional detail on demand response resource assumptions used to develop these supply curves, see Volume 3 of the 2019 CPA.[3] Potential shown is incremental to the existing DSM resources identified in Table 5.12. For existing program offerings, it is

[2] The 2019 Conservation Potential Study is available on PacifiCorp's demand-side management web page. www.pacificorp.com/energy/integrated-resource-plan/support.html.

[3] The CPA can be found at: www.pacificorp.com/energy/integrated-resource-plan/support.html.

assumed that the PacifiCorp could begin acquiring incremental potential in 2019. For resources representing new product offerings, it is assumed PacifiCorp could begin acquiring potential in 2020, accounting for the time required for program design, regulatory approval, vendor selection, etc.

**Table 6.6 – Demand Response Program Attributes West Control Area**

| Product | Summer | | Winter | |
|---|---|---|---|---|
| | 20-Year Potential (MW) | Levelized Cost ($/kW-yr) | 20-Year Potential (MW) | Levelized Cost ($/kW-yr) |
| DLC Cooling & WH - Res and C&I | 33 | $44 - $48 | 18 | $136 - $157 |
| DLC Space Heating Res & C&I | n/a | n/a | 82 | $7 - $27 |
| DLC Room AC - Res | 1 | $352 | n/a | n/a |
| DLC Smart Thermostat - Res | 84 | $31 - $54 | 84 | $30 - $91 |
| DLC Smart Appliance - Res | 4 | $210 | 4 | $221 |
| DLC Elec Vehicle Charging - Res | 1 | $763 | 1 | $773 |
| DLC Irrigation | 26 | $37 - $40 | n/a | n/a |
| Third Party Contracts | 50 | $55 - $56 | 43 | $94 - $100 |
| Ice Energy Storage | 3 | $134 | n/a | n/a |
| Ancillary Services | 9 | $14 - $20 | n/a | n/a |

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

**Table 6.7 – Demand Response Program Attributes East Control Area**

| Product | Summer | | Winter | |
|---|---|---|---|---|
| | 20-Year Potential (MW) | Levelized Cost ($/kW-yr) | 20-Year Potential (MW) | Levelized Cost ($/kW-yr) |
| DLC Cooling & WH - Res and C&I | 64 | ($4) - $49 | 20 | $171 - $458 |
| DLC Space Heating Res & C&I | n/a | n/a | 55 | $9 - $18 |
| DLC Room AC - Res | 2 | $185 | n/a | n/a |
| DLC Smart Thermostat - Res | 167 | $5 - $56 | 41 | $77 - $285 |
| DLC Smart Appliance - Res | 8 | $211 | 8 | $222 |
| DLC Elec Vehicle Charging - Res | 4 | $686 | 5 | $696 |
| DLC Irrigation | 14 | $14 - $44 | n/a | n/a |
| Third Party Contracts | 118 | $53 - $63 | 90 | $100 - $142 |
| Ice Energy Storage | 2 | $143 | n/a | n/a |
| Ancillary Services | 20 | ($3) - $2 | n/a | n/a |

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

**Energy Efficiency DSM, Energy Supply Curves**

The 2019 CPA provided the information to fully assess the potential contribution from DSM energy efficiency resources over the IRP planning horizon. The CPA analysis accounts for known changes in building codes, advancing equipment efficiency standards, market transformation, resource cost changes, changes in building characteristics and state-specific resource evaluation considerations (e.g. cost-effectiveness criteria).

DSM energy efficiency resource potential was assessed by state down to the individual measure and building levels (e.g. specific appliances, motors, lighting configurations for residential buildings, and small offices). The CPA provided DSM energy efficiency resource information at the following granularity:

- **State:** Washington, California, Idaho, Utah, Wyoming[4]
- **Measure:**
  - 89 residential measures
  - 130 commercial measures
  - 111 industrial measures
  - 22 irrigation measures
  - 11 street lighting measures

- **Facility type[5]:**
  - Six residential facility types
  - 28 commercial facility types
  - 30 industrial facility types
  - Two irrigation facility type
  - Four street lighting types

The 2019 CPA levelized total resource costs over the study period at PacifiCorp's cost of capital, consistent with the treatment of supply-side resources. Costs include measure costs and a state-specific adder for program administrative costs for all states except Utah and Idaho. Consistent with regulatory mandates, Utah and Idaho DSM energy efficiency resource costs were levelized using utility costs instead of total resource costs (i.e. incentive and a state specific adder for program administration costs).

The technical potential for all DSM energy efficiency resources across all states except Oregon over the twenty-year CPA planning horizon totaled 12.1 million MWh.[6] The technical potential represents the total universe of possible savings before adjustments for what is likely to be realized (i.e. technical achievable potential). When the achievable assumptions described below are considered the technical potential is reduced to a technical achievable potential for modeling consideration of 9.6 million MWh for all five states. The technical achievable potential for all six states for modeling consideration is 13.2 million MWh. The technical achievable potential, representing available potential at all costs, is provided to the IRP model for economic screening relative to supply-side alternatives.

Despite the granularity of DSM energy efficiency resource information available, it was impractical to model the resource supply curves at this level of detail. The combination of measures

[4] Oregon's DSM potential was assessed in a separate study commissioned by the Energy Trust of Oregon.
[5] Facility type includes such attributes as existing or new construction, single or multi-family. Facility types are more fully described in Chapter 4 of Volume 2 of the 2019 CPA.
[6] The identified technical potential represents the cumulative impact of DSM measure installations in the 20th year of the study period for California, Idaho, Washington, Wyoming, and Utah. This may differ from the sum of individual years' incremental impacts due to the introduction of improved codes and standards over the study period. ETO provides PacifiCorp with technical achievable potential.

by building type and state generated over 37,880 separate permutations or distinct measures that could be modeled using the supply curve methodology. To reduce the resource options for consideration without losing the overall resource quantity available or its relative cost, resources were consolidated into bundles, using ranges of levelized costs to reduce the number of combinations to a more manageable number. The range of measure costs in each of the 27 bundles used in the development of the DSM supply curves for the 2019 IRP are the same as those developed for the 2017 IRP.

Bundle development began with the energy efficiency technical potential identified by the 2019 CPA. To account for the practical limits associated with acquiring all available resources in any given year, the technical potential by measure was adjusted to reflect the amount that is realistically achievable over the 20-year planning horizon. Consistent with the Northwest Power and Conservation Council's aggressive regional planning assumptions, it was assumed that 85 percent of the technical potential for discretionary (retrofit) resources and on average up to 74 percent of lost-opportunity (new construction or equipment upgrade on failure) could be achievable over the 20-year planning period.[7]

For Wyoming, the 2017 CPA applied market ramp rates on top of measure ramp rates to reflect state-specific considerations affecting acquisition rates, such as age of programs, small and rural markets, and current delivery infrastructure for the industrial market. This mechanism was used solely in the Wyoming industrial sector to reflect that program momentum is still building. Recent program accomplishments within this market indicate that this trend has come to an end, therefore the "emerging" market ramp rate was removed from the 2019 CPA.

For Oregon, the company does not assess potential for the Energy Trust of Oregon (ETO). Neither PacifiCorp nor the ETO performed an economic screening of measures in the development of the DSM energy efficiency supply curves used in the development of the 2019 IRP, allowing resource opportunities to be economically screened against supply-side alternatives in a consistent manner across PacifiCorp's six states.

Twenty-seven cost bundles were available across six states (including Oregon), which equates to 189 DSM energy efficiency resource supply curves. Table 6.9 shows the 20-year MWh potential for DSM energy efficiency cost bundles, designated by ranges of $/MWh. Table 6.10 shows the associated bundle price after applying cost credits afforded to DSM energy efficiency resources within the model. These cost credits include the following:

- A state-specific transmission and distribution investment deferral cost credit (Table 6.8)
- Stochastic risk reduction credit of $4.74/MWh[8]
- Northwest Power Act 10-percent credit (Oregon and Washington resources only)[9]

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

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

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

**Table 6.8 – State-specific Transmission and Distribution Credits**

| State | Transmission Deferral Value ($/KW-year) | Distribution Deferral Value ($/KW-year) | Total |
|---|---|---|---|
| California | $4.16 | $6.58 | $10.74 |
| Oregon | $4.16 | $9.20 | $13.36 |
| Washington | $4.16 | $11.79 | $15.95 |
| Idaho | $4.16 | $11.07 | $15.22 |
| Utah | $4.16 | $9.02 | $13.18 |
| Wyoming | $4.16 | $5.26 | $9.41 |

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

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

**Table 6.9 – 20-Year Cumulative Energy Efficiency Potential by Cost Bundle (MWh)**

| Bundle | California | Idaho | Oregon | Utah | Washington | Wyoming |
|---|---|---|---|---|---|---|
| <= 10 | 38,912 | 98,747 | 549,917 | 1,418,505 | 210,292 | 394,131 |
| 10 - 20 | 5,902 | 35,788 | 109,045 | 566,451 | 76,449 | 111,399 |
| 20 - 30 | 4,600 | 67,228 | 344,713 | 693,917 | 69,502 | 68,278 |
| 30 – 40 | 33,081 | 47,387 | 611,481 | 583,173 | 166,070 | 251,490 |
| 40 – 50 | 13,351 | 24,007 | 527,253 | 347,710 | 52,089 | 233,920 |
| 50 - 60 | 6,383 | 38,617 | 260,480 | 243,779 | 46,787 | 167,890 |
| 60 – 70 | 3,769 | 18,357 | 200,163 | 126,915 | 47,964 | 74,670 |
| 70 – 80 | 7,788 | 8,773 | 168,229 | 187,482 | 29,400 | 30,877 |
| 80 – 90 | 2,953 | 12,369 | 70,325 | 137,044 | 24,985 | 14,797 |
| 90 – 100 | 4,346 | 14,246 | 11,637 | 143,151 | 23,308 | 41,359 |
| 100 – 110 | 4,338 | 7,669 | 56,015 | 183,773 | 18,899 | 85,951 |
| 110 – 120 | 2,303 | 15,195 | 39,623 | 136,567 | 14,302 | 20,700 |
| 120 – 130 | 2,189 | 13,926 | 15,688 | 86,346 | 25,419 | 13,837 |
| 130 – 140 | 10,391 | 7,160 | 115,146 | 93,739 | 35,915 | 6,266 |
| 140 – 150 | 7,600 | 4,996 | 62,573 | 174,762 | 18,017 | 19,605 |
| 150 - 160 | 1,930 | 5,055 | 137,281 | 43,708 | 13,759 | 9,608 |
| 160 – 170 | 1,947 | 9,360 | 33,284 | 46,478 | 10,014 | 6,732 |
| 170 – 180 | 2,458 | 2,396 | 72,957 | 44,581 | 7,050 | 17,150 |
| 180 – 190 | 1,723 | 1,843 | 15,798 | 37,927 | 11,791 | 10,135 |
| 190 – 200 | 795 | 1,362 | 2,294 | 34,678 | 20,928 | 4,693 |
| 200 – 250 | 14,147 | 32,139 | 2,924 | 115,841 | 56,428 | 44,598 |
| 250 – 300 | 10,007 | 8,305 | 4,795 | 100,695 | 17,555 | 19,324 |
| 300 – 400 | 11,658 | 13,731 | 4,220 | 170,174 | 31,286 | 23,599 |
| 400 – 500 | 1,848 | 4,078 | 17,134 | 55,579 | 11,608 | 9,894 |
| 500 – 750 | 6,087 | 10,509 | 46,965 | 131,028 | 24,455 | 12,672 |
| 750 – 1,000 | 5,567 | 4,268 | 42,758 | 26,471 | 22,776 | 16,008 |
| > 1,000 | 5,423 | 9,639 | 21,631 | 110,459 | 23,582 | 29,420 |

**Table 6.10 – Energy Efficiency Adjusted Prices by Cost Bundle**

| Bundle | Levelized Bundle Price after Adjustments ($/Mwh) | | | | | |
|---|---|---|---|---|---|---|
| | California | Idaho | Oregon | Utah | Washington | Wyoming |
| <= 10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 10 - 20 | 7.17 | 7.38 | 3.78 | 8.51 | 3.22 | 9.15 |
| 20 - 30 | 17.16 | 19.50 | 16.95 | 18.80 | 13.09 | 19.80 |
| 30 – 40 | 30.89 | 26.09 | 24.24 | 28.65 | 21.00 | 29.79 |
| 40 – 50 | 39.40 | 37.37 | 30.92 | 36.97 | 32.09 | 38.65 |
| 50 - 60 | 48.22 | 47.70 | 45.59 | 47.03 | 42.11 | 49.10 |
| 60 – 70 | 58.30 | 56.11 | 55.38 | 58.39 | 51.24 | 59.58 |
| 70 – 80 | 68.96 | 68.95 | 61.14 | 68.37 | 61.77 | 68.31 |
| 80 – 90 | 75.19 | 78.50 | 75.41 | 77.77 | 71.98 | 77.34 |
| 90 – 100 | 85.37 | 86.97 | 80.72 | 87.31 | 84.14 | 89.22 |
| 100 – 110 | 96.01 | 97.72 | 93.21 | 97.58 | 93.27 | 101.60 |
| 110 – 120 | 106.63 | 106.27 | 104.52 | 106.11 | 102.29 | 109.79 |
| 120 – 130 | 116.57 | 116.90 | 111.81 | 118.16 | 108.59 | 118.19 |
| 130 – 140 | 128.80 | 128.48 | 122.02 | 126.21 | 122.26 | 129.51 |
| 140 – 150 | 136.45 | 137.75 | 130.87 | 133.88 | 131.34 | 137.47 |
| 150 - 160 | 149.00 | 149.10 | 146.47 | 146.57 | 141.99 | 145.73 |
| 160 – 170 | 156.75 | 155.37 | 150.50 | 158.40 | 152.30 | 159.28 |
| 170 – 180 | 167.97 | 167.15 | 160.56 | 167.95 | 163.07 | 168.35 |
| 180 – 190 | 179.45 | 175.72 | 174.23 | 177.40 | 170.44 | 178.51 |
| 190 – 200 | 188.51 | 187.27 | 187.86 | 187.81 | 179.70 | 189.38 |
| 200 – 250 | 226.03 | 203.75 | 221.72 | 213.95 | 209.13 | 225.45 |
| 250 – 300 | 272.36 | 272.99 | 266.16 | 264.04 | 260.89 | 261.66 |
| 300 – 400 | 324.14 | 347.69 | 345.42 | 322.75 | 314.55 | 339.77 |
| 400 – 500 | 423.36 | 432.51 | 402.40 | 431.52 | 431.94 | 430.26 |
| 500 – 750 | 604.98 | 655.21 | 618.22 | 611.51 | 583.68 | 576.48 |
| 750 – 1,000 | 903.32 | 836.74 | 871.60 | 878.69 | 867.09 | 890.11 |
| > 1,000 | 4,170.84 | 3,473.61 | 1,977.88 | 3,913.95 | 4,293.67 | 3,965.04 |

**Distribution Efficiency**

PacifiCorp continues to evaluate distribution energy efficiency. The company's streetlight efficiency improvements continue, with older mercury vapor, metal halide and incandescent company owned streetlights being replaced with more efficient lights; high pressure sodium or light emitting diode (LED) each year. The savings associated with this ongoing effort is expected to be too small to warrant reporting.

PacifiCorp continues to develop its CYME CYMDIST® (power flow software) investment in ways that improve engineering response time and, indirectly, distribution system efficiency. In the last biennial period, more than 300 large (Level 2 and Level 3) distributed energy resource (DER) applications were studied in CYME. This resulted in more than 29 MW (nameplate) of approved private generation across the company. Any energy savings resulting from these approvals across the service territory has not been determined.

Neither of these distribution energy efficiency related activities have been modeled as potential resources in this IRP.

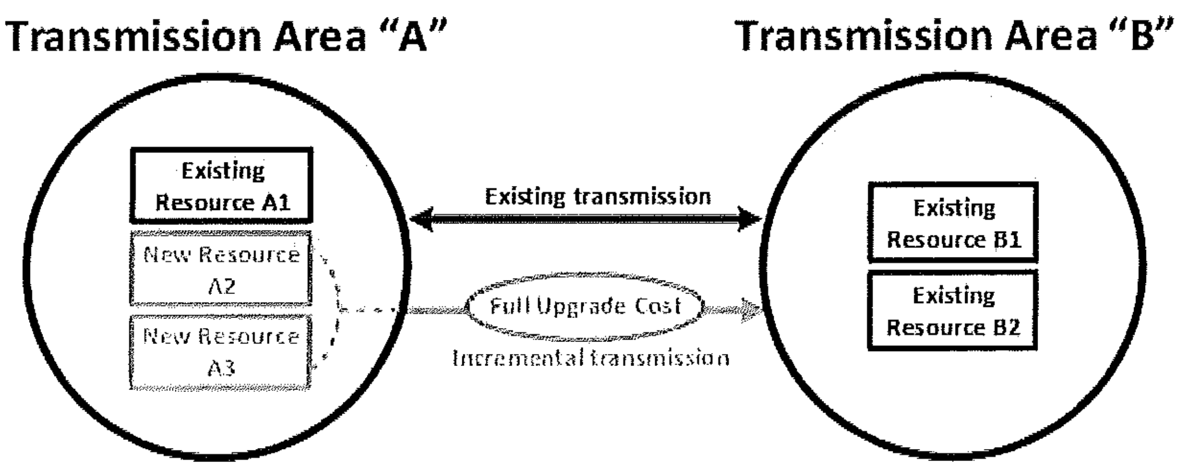
## Transmission Resources

As part of it 2019 IRP, PacifiCorp was successfully able to provide the SO model with the ability to view costs and transmission capability associated with certain transmission upgrades that the model could incorporate along with new resource selections as it deemed optimal. This is an improvement from previous IRPs, where transmission upgrades and associated costs had to be determined and accounted for post-portfolio development. New transmission modeling capabilities include the endogenous consideration of 1) new incremental transmission options tied to resource selections, 2) existing transmission rights tied to the use of post-retirement brownfield sites, and 3) incorporation of costs associated with these transmission options.

Limitations of this approach include transmission options that interact with multiple or complex elements of the IRP transmission topology. Transmission options that are too complex to be captured by the modeling enhancements were therefore studied as sensitivity cases.

Figure 6.7 illustrates the new incremental transmission option modeling capability between two generic transmission areas in the IRP topology. Because the incremental transmission segment (shown in blue) is associated with new resource additions, the model selects them together, endogenously considering the upgrade cost in relation to the benefits of the new expansion resources.

**Figure 6.7 – Endogenous Transmission Modeling**




In many cases, transmission upgrades do not add incremental transmission capacity to the system, but rather increase interconnection capability. The upgrade cost in such cases is to accommodate additional capacity at a location, and the transmission topology itself is unaffected. For example, additional transmission capacity or transmission reinforcements that are confined to a transmission area incur an upgrade cost but would not add transmission capacity to the larger system. A map of PacifiCorp's transmission system model topology is provided in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).

Table 6.11 reports the endogenous incremental transmission options included in the 2019 IRP.

**Table 6.11 – Transmission Integration Options by Location and Capacity Increment**

| IRP Bubble | Added Resource MW | | IRP Year | Description of Integration [1] | Affected Topology Path(s) [1] | | |
|---|---|---|---|---|---|---|---|
| | Min | Max | | | Incremental Capacity (if any) | From Bubble | To Bubble |
| Portland/N. Coast | 1 | 130 | 2024 | Portland area local reinforcement | - | - | - |
| | 131 | 580 | 2030 | Portland area (Troutdale) to Albany area 230 kV transmission | 450 | Portland | Willamette |
| Willamette | 1 | 615 | 2024 | Albany area local reinforcement | - | - | - |
| | 616 | 1115 | 2030 | Albany area to Roseburg area 500 kV transmission | 1500 | Willamette | South-Central Oregon |
| Yakima | 1 | 405 | 2024 | Yakima area local reinforcement | - | - | - |
| | 406 | 835 | 2030 | Yakima area to Bend area 230 kV transmission | 450 | Yakima | South-Central Oregon |
| Walla Walla | 1 | 100 | 2030 | Walla Walla area to Yakima lower valley transmission | 200 | Walla Walla | Yakima |
| South-Central OR/N. California | 1 | 500 | 2024 | Medford area 500-230 kV and 230 kV reinforcement | - | - | - |
| | 501 | 975 | 2025 | Medford area 500-230 kV and 230 kV reinforcement | - | - | - |
| Bridger | 1 | 650 | 2026 | Energy Gateway segment D.2 (Anticline-Populus 500 kV transmission line) | 650 | Bridger | Bridger West (Populus) |
| Goshen | 1 | 450 | 2023 | Southern Idaho reinforcement | - | - | - |
| | 451 | 1100 | 2029 | Southern Idaho reinforcement | 800 | Goshen | Utah North |
| Wyoming NE | 1 | 460 | 2023 | Energy Gateway segment D.1 (Windstar - Shirley Basin 230 kV line) | - | - | - |
| Wyoming SW | 1 | 100 | 2024 | Southwest Wyoming area reinforcement | - | - | - |
| | 101 | 500 | 2026 | Separation of double circuit 230 kV lines, Southwest Wyoming/northern Utah area | - | - | - |
| Aeolus | 1 | 1920 | 2024 | Energy Gateway segment F (Aeolus-Clover 500 kV transmission line) | 1700 | Aeolus | Utah South |
| Utah North | 1 | 300 | 2021 | Northern Utah 345 kV reinforcement | - | - | - |
| | 301 | 900 | 2024 | Northern Utah 345 kV reinforcement | - | Utah North | Utah North |
| Utah South | 1 | 300 | 2021 | Utah Valley area 345-138 kV and 138 kV local reinforcement | - | - | - |
| | 301 | 800 | 2027 | Utah Valley area local 138 kV reinforcement | - | - | - |

## Market Purchases

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

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

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

Three FOT types were included for portfolio analysis in the 2019 IRP: an annual flat product, a HLH July for summer, and a HLH December for winter product. An annual flat product reflects energy provided to PacifiCorp at a constant delivery rate over all the hours of a year. The HLH transactions represent purchases received 16 hours per day, six days per week for July and December. Table 6.12 shows the FOT resources included in the IRP models, identifying the market hub, product type, annual megawatt capacity limit, and availability. PacifiCorp develops its FOT limits based upon its active participation in wholesale power markets, its view of physical delivery constraints, market liquidity and market depth, and with consideration of regional resource supply (see Volume II, Appendix J for an assessment of western resource adequacy). Prices for FOT purchases are associated with specific market hubs and are set to the relevant forward market prices, time period, and location, plus appropriate wheeling charges, as applicable. Additional discussion of how FOTs are modeled during the resource portfolio development process of the IRP is included in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).

**Table 6.12 - Maximum Available Front Office Transaction Quantity by Market Hub**

| Market Hub/Proxy FOT Product Type Available over Study Period | Megawatt Limit and Availability (MW) | |
|---|---|---|
| | Summer (July) | Winter (December) |
| ***Mid-Columbia (Mid-C)*** | | |
| Flat Annual ("7x24") or Heavy Load Hour ("6X16") | 400 | 400 |
| Heavy Load Hour ("6X16") | 375 | 375 |
| ***California Oregon Border (COB)*** | | |
| Flat Annual ("7x24") or Heavy Load Hour ("6X16") | 250 | 250 |
| ***Nevada Oregon Border (NOB)*** | | |
| Heavy Load Hour ("6X16") | 100 | 100 |
| ***Mona*** | | |
| Heavy Load Hour ("6X16") | 300 | 300 |

# CHAPTER 7 – MODELING AND PORTFOLIO EVALUATION APPROACH

## CHAPTER HIGHLIGHTS

- The Integrated Resource Plan (IRP) modeling approach is used to assess the comparative cost, risk, and reliability attributes of resource portfolios. The 2019 IRP modeling and evaluation approach consists of three basic steps used to select a preferred portfolio—coal studies, portfolio development, and final portfolio screening.
- PacifiCorp uses the System Optimizer (SO) model to produce unique resource portfolios across a range of different planning cases. Informed by the public-input process, PacifiCorp ultimately produced over 50 different resource portfolios, informed by the coal studies summarized in Volume II, Appendix R (Coal Studies). Each resource portfolio is unique with regard to the type, timing, location, and amount of new resources that could be pursued to serve customers over the next 20 years.
- PacifiCorp uses the Planning and Risk model (PaR) to perform stochastic risk analysis of the portfolios produced by the SO model. For top-performing resource portfolios, PaR studies were developed to evaluate cost and risk among three natural gas price scenarios (low, medium, and high) and three carbon dioxide ($CO_2$) price scenarios (zero, medium, high). An additional price-policy scenario was developed to evaluate performance assuming a $CO_2$ price signal that aligns with the social cost of carbon. Taken together, there are four distinct price-policy scenarios (medium gas/medium $CO_2$, high gas/high $CO_2$, low gas/zero $CO_2$, and the social cost of carbon). The resulting cost and risk metrics are then used to compare portfolio alternatives and inform selection of the preferred portfolio.
- Taking into consideration stakeholder comments received during the public-input process, PacifiCorp also developed eight sensitivity cases designed to highlight the impact of specific planning assumptions on future resource selections along with the associated impact on system costs and stochastic risks. These sensitivities are informative in nature and support development of an acquisition path analysis, but were not considered for selection of the preferred portfolio.
- Informed by comprehensive modeling, PacifiCorp's preferred portfolio selection process involves evaluating cost and risk metrics reported from PaR, comparing resource portfolios on the basis of expected costs, low-probability high-cost outcomes, reliability, $CO_2$ emissions and other criteria.

## Introduction

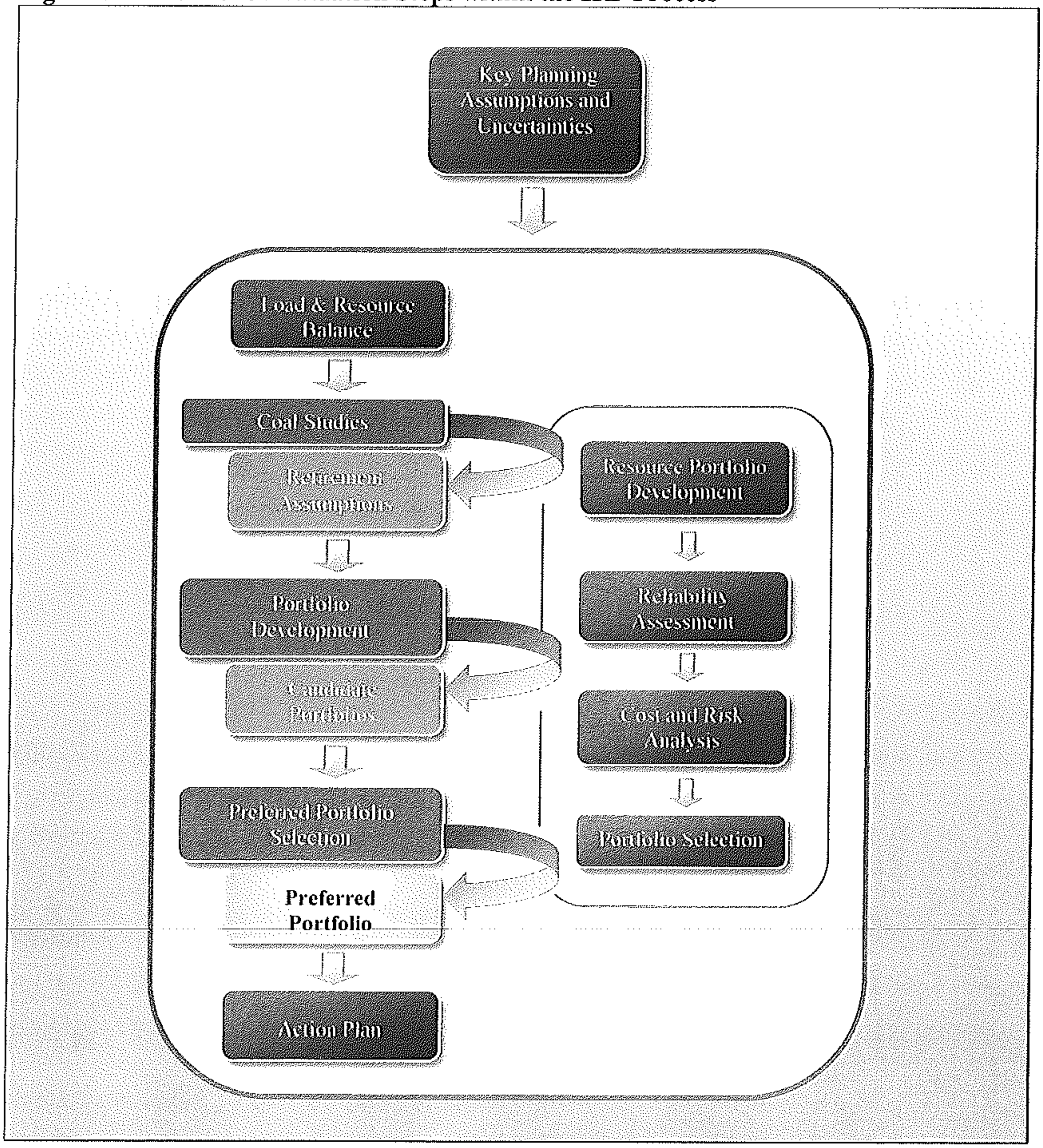
IRP modeling is used to assess the comparative cost, risk, and reliability attributes of different resource portfolios, each meeting a target planning reserve margin. These portfolio attributes form the basis of an overall quantitative portfolio performance evaluation.

The first section of this chapter describes the screening and evaluation processes for portfolio selection. Following sections summarize portfolio risk analyses, document key modeling assumptions, and describe how this information is used to select the preferred portfolio. The last section of this chapter describes the cases examined at each modeling and evaluation step. The results of PacifiCorp's modeling and portfolio analysis are summarized in Chapter 8 (Modeling and Portfolio Evaluation Approach).

## Modeling and Evaluation Steps

Figure 7.1 summarizes the three modeling and evaluation steps for the 2019 IRP, highlighted in green. The three steps are (1) coal studies, (2) portfolio development, and (3) the final portfolio screening. The result of the final screening step is selection of the preferred portfolio.

**Figure 7.1 – Portfolio Evaluation Steps within the IRP Process**



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

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

- Reliability Assessment
  The 2019 IRP adds a reliability assessment phase to its portfolio processing, accounting for demonstrated reliability shortfalls driven by the replacement of flexible, dispatchable resources with intermittent variable resources. The reliability assessment uses up to 16 PaR deterministic model runs to assess hourly capacity shortfalls for years 2023 through 2038. This information is then used in the SO model to optimize the selection of additional reliability resources.

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

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

## Resource Portfolio Development

Resource expansion plan modeling, performed with the SO model, is used to produce resource portfolios with sufficient capacity to achieve a target planning reserve margin over the 20-year study horizon. Each resource portfolio is uniquely characterized by the type, timing, location, and amount of new resources in PacifiCorp's system over time. These resource portfolios reflect a combination of planning assumptions such as resource retirements, $CO_2$ prices, wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, cost and performance attributes of potential transmission upgrades, and new and existing resource cost and performance data, including assumptions for new supply-side resources and incremental demand-side resources (DSM). Changes to these input variables cause changes to the resource mix, which influences system costs and risks.

## System Optimizer

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

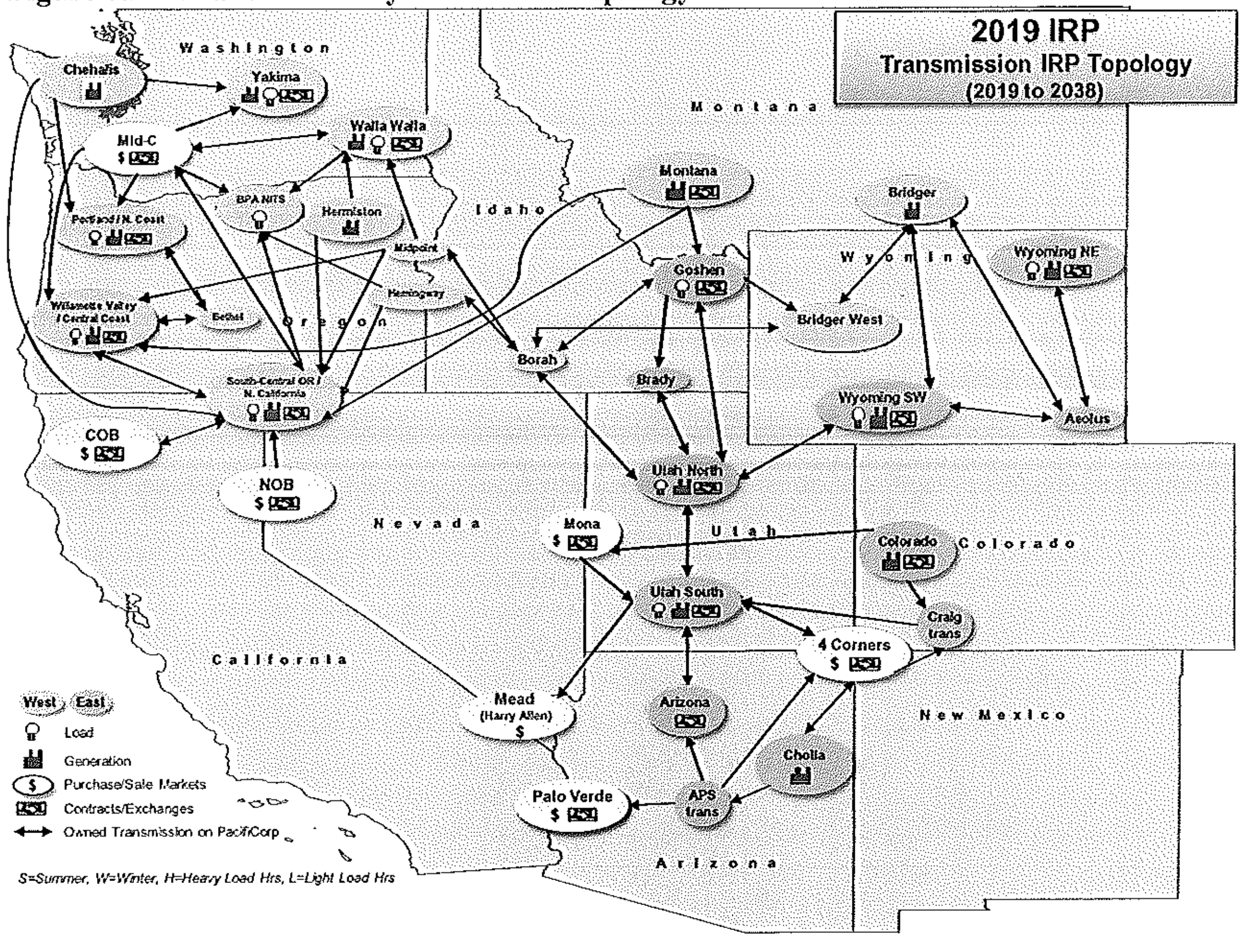
To accomplish these optimization objectives, the SO model performs a time-of-day least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new DSM alternatives within PacifiCorp's transmission system. Resource dispatch is based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

The SO model is also used in developing the reliability portfolio for each case, receiving reliability requirements determined by the PaR model as described in Volume II, Appendix R, Figure R.1 (Coal Studies), applies to all resource portfolio-development in the 2019 IRP.

**Transmission System**

PacifiCorp uses a transmission topology that captures major load centers, generation resources, and market hubs interconnected via firm transmission paths. Transfer capabilities across transmission paths are based upon the firm transmission rights of PacifiCorp's merchant function, including transmission rights from PacifiCorp's transmission function and other regional transmission providers. Figure 7.2 shows the 2019 IRP transmission system model topology.

**Figure 7.2 – Transmission System Model Topology**




## Transmission Costs

In developing resource portfolios for the 2019 IRP, PacifiCorp includes new modeling to endogenously select transmission options, in consideration of relevant costs and benefits. These costs are influenced by the type, timing, location, and amount of new resources as well as any assumed resource retirements, as applicable, in any given portfolio. Additional details on endogenous transmission modeling are provided in Volume I, Chapter 6 (Resource Options).

## Resource Adequacy

Resource adequacy is modeled in the portfolio-development process by ensuring each portfolio meets a target planning reserve margin. In its 2019 IRP, PacifiCorp continues to apply a 13 percent target planning reserve margin. The planning reserve margin, which influences the need for new resources, is applied to PacifiCorp's coincident system peak load forecast net of offsetting "load resources" such as energy efficiency. Planning to achieve a 13 percent planning reserve margin ensures that PacifiCorp has sufficient resources to meet its peak load, recognizing that there is a possibility for load fluctuation and extreme weather conditions, fluctuation of variable generation resources, a possibility for unplanned resource outages, and reliability requirements to carry sufficient contingency and regulating reserves. Volume II, Appendix I (Planning Reserve Margin Study) summarizes PacifiCorp's updated planning reserve margin study that supports selection of a 13 percent target planning reserve margin in the 2019 IRP.

**New Resource Options**

Dispatchable Thermal Resources

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

Front Office Transactions

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

From a modeling perspective, it is not feasible to incorporate all of the short-term firm physical power products, which differ by delivery pattern and delivery period, that are available through brokers, exchanges, and non-brokered transactions. However, considering that PacifiCorp routinely uses these types of firm transactions, which obligate the seller to back the transaction with reserves when balancing its system, it is important that the capacity contribution of short-term firm market purchases are accounted for in the portfolio-development process. For capacity optimization modeling, short-term firm forward transactions are represented as FOTs and configured in the SO model with either an annual flat, summer-on-peak (July), or winter on-peak (December) delivery pattern in every year of the twenty-year planning horizon. As configured in SO, FOTs contribute capacity toward meeting the 2019 IRP's 13 percent target planning reserve margin and supply system energy consistent with the assumed FOT delivery pattern.

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

A description of FOT limits assumed in the 2019 IRP is included in Volume I, Chapter 6 (Resource Options). PacifiCorp's evaluation of resource adequacy in the western power markets is summarized in Volume II, Appendix J (Western Resource Adequacy Evaluation).

Demand-Side Management

The SO model can select incremental DSM resources during portfolio optimization development in each modeling and evaluation step. Selection of DSM resources is made from supply curves that define how much of a DSM resource can be acquired at a given cost.

Energy Efficiency (Class 2 DSM) resources are characterized with supply curves that represent achievable technical potential of the resource by state, by year, and by measures specific to PacifiCorp's service territory. For modeling purposes, these data are aggregated into cost bundles. Each cost bundle of the energy efficiency supply curves specifies the aggregate energy savings profile of all measures included within the cost bundle. Each cost bundle has both a summer and winter capacity contribution based on aggregate energy savings during on-peak hours in July and December aligning with periods where PacifiCorp is most likely to exhibit capacity shortfalls.

Demand Response (Class 1 DSM) resources, representing direct load control capacity resources, are also characterized with supply curves representing achievable technical potential by state and by year for specific direct load control program categories (i.e., air conditioning, irrigation, and commercial curtailment). The SO model evaluates demand response resources by considering capacity contribution, cost, and operating characteristics. Operating characteristics include variables such as total number of hours per year and hours per event that the demand response resource is available. Additional discussion of DSM resources modeled in the 2019 IRP is included in Volume I, Chapter 6 (Resource Options) and in Volume II, Appendix D (Demand-Side Management Resources).

Wind and Solar Resources

Certain wind and solar resources are dispatchable by the model up to fixed energy profiles that vary by day and month. The fixed energy profiles for wind and solar resources represents the expected generation levels in which half of the time actual generation would fall below expected levels, and half of the time actual generation would be above expected levels assuming no curtailments.

The capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand over time. These values are dependent on the underlying portfolio, and are expected to decline as the penetration of resources of the same type increases. For the purposes of portfolio selection, PacifiCorp developed capacity-contribution values specific to the five wind profiles and five solar profiles used for proxy resources. In addition, PacifiCorp developed contribution values for two levels of wind and solar penetration. A "high" capacity-contribution block allowed for up to 2,000 MW of new wind capacity and 1,000 MW of new solar capacity (roughly a 50 percent increase from the initial portfolio levels). Any additional wind and solar capacity beyond the first block was assigned a "low" capacity-contribution value, calculated based on an additional 2,000 MW of new wind capacity and 1,000 MW of new solar capacity. PacifiCorp also developed capacity-contribution values for each of the wind and solar locations when combined with lithium-ion battery storage with a maximum output equal to 25 percent of the renewable resource nameplate capacity and assuming a four-hour storage duration. Volume II, Appendix N (Capacity Contribution Study) summarizes PacifiCorp's capacity contribution study and the resulting values.

Energy Storage Resources

Energy storage resources are distinguished from other resources by the following three attributes:

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

Modeling energy storage resources requires specification of the size of the storage reservoir, defined in gigawatt-hours. The SO model dispatches a storage resource to optimize energy used by the resource subject to constraints such as storage-cycle efficiency, the daily balance of take and return energy, and fuel costs (for example, the cost of natural gas for expanding air with gas turbine expanders). To determine the least-cost resource expansion plan, the SO model accounts for conventional generation system performance and cost characteristics of the storage resource, including capital cost, size of the storage and time to fill the storage, heat rate (if fuel is used), operating and maintenance cost, minimum capacity, and maximum capacity. Because they are energy-limited, an energy storage resource may not be able to cover the entirety of an extended outage. For the 2019 IRP, PacifiCorp calculated capacity contribution values based on the duration of energy storage. Volume II, Appendix N (Capacity Contribution Study) summarizes the capacity contribution study and the resulting values for energy storage.

**Capital Costs and End-Effects**

The SO model uses annual capital recovery factors to convert capital dollars into real levelized revenue requirement costs to address end-effects that arise with capital-intensive projects that have different lives and in-service dates. All capital costs evaluated in the IRP are converted to real levelized revenue requirement costs. Use of real levelized revenue requirement costs is an established and preferred methodology for analyzing capital-intensive resource decisions among resource alternatives that have unequal lives and/or when it is not feasible to capture operating costs and benefits over the entire life of any given resource. To achieve this, the real levelized revenue requirement method spreads the return of investment (book depreciation), return on investment (equity and debt), property taxes and income taxes over the life of the investment. The result is an annuity or annual payment that grows at inflation such that the PVRR is identical to the PVRR of the nominal annual requirement when using the same nominal discount rate. For the 2019 IRP, the PVRR is calculated inclusive of real levelized capital revenue requirement through the end of the 2038 planning period.

**General Assumptions**

Study Period and Date Conventions

PacifiCorp executes its 2019 IRP models for a 20-year period beginning January 1, 2019 and ending December 31, 2038. Future IRP resources reflected in model simulations are given an in-service date of January 1st of a given year, with the exception of coal unit natural gas conversions, which are given an in-service date of June 1st of a given year, recognizing the desired need for these alternatives to be available during the summer peak load period.

Inflation Rates

The 2019 IRP model simulations and cost data reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. A single annual escalation rate value of 2.28 percent is assumed. The annual escalation rate reflects the average of annual inflation rate projections for the period 2019 through 2038, using PacifiCorp's September 2018 inflation curve. PacifiCorp's inflation curve is a straight average of forecasts for the Gross Domestic Product inflator and the Consumer Price Index.

Discount Factor

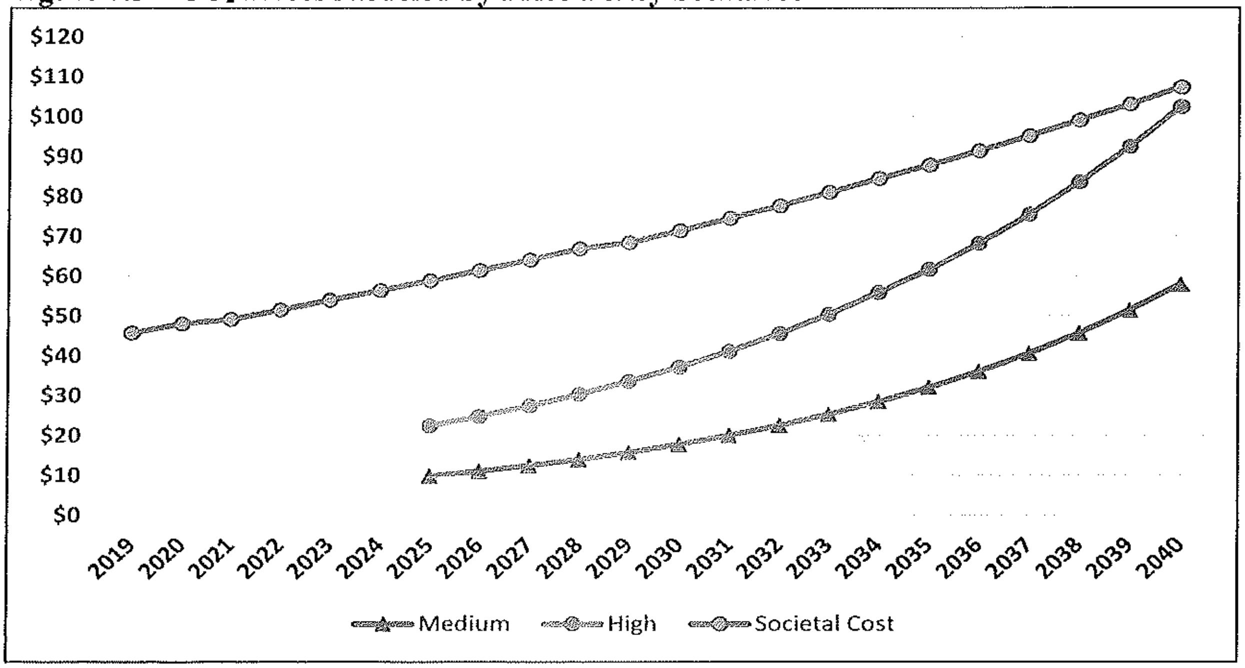
The discount rate used in present-value calculations is based on PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2017 IRP is 6.92 percent. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.[1] PVRR figures reported in the 2019 IRP are reported in January 1, 2019 dollars.

CO2 Price Scenarios

PacifiCorp uses four different $CO_2$ price scenarios in the 2019 IRP—zero, medium, high, and a price forecast that aligns with the social cost of carbon. The medium and high scenario are derived from expert third-party multi-client "off-the-shelf" subscription services. Both of these scenarios apply a $CO_2$ price as a tax beginning 2025. PacifiCorp initially proposed using a medium $CO_2$ price forecast beginning in 2030, consistent with the start year assumed by the third-party forecast reviewed, but in response to stakeholder interests, PacifiCorp agreed to align the start year in the medium case with the start year proposed for the high case (2025). Figure 7.3 summarizes the $CO_2$ price assumptions used in the 2019 IRP (the zero price, no $CO_2$ scenario is not shown).

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

**Figure 7.3 – $CO_2$ Prices Modeled by Price-Policy Scenarios**




Wholesale Electricity and Natural Gas Forward Prices

For 2019 IRP modeling purposes, eight electricity price forecasts were used: the official forward price curve (OFPC) and seven scenarios. Unlike scenarios, which are alternative spot price forecasts, the OFPC represents PacifiCorp's official quarterly outlook. The OFPC is compiled using market forwards, followed by a market-to-fundamentals blending period that transitions to a pure fundamentals-based forecast.

At the time PacifiCorp's 2019 IRP modeling was initiated, the September 2018 OFPC was the most current OFPC available. For both gas and electricity, starting with the prompt month, the front 36 months of the OFPC reflects market forwards at the close of a given trading day.[2] As such, these 36 months are market forwards as of September 28, 2018. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forward from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects an expert third-party multi-client "off-the-shelf" price forecast. The fundamentals portion of the electricity OFPC reflects prices as forecast by AURORAxmp[3] (Aurora), a WECC-wide market model. Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. PacifiCorp updates its natural gas price forecasts each quarter for the OFPC and, as a corollary, the electricity OFPC is also updated.

Scenarios pairing medium gas prices with alternative $CO_2$ price assumptions reflect OFPC forwards through October 2021 before transitioning to a pure fundamentals forecast. Scenarios using high or low gas prices, regardless of $CO_2$ price assumptions, do not incorporate any market forwards since scenarios are designed to reflect an alternative view to that of the market. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural

[2] The September 2018 OFPC prompt month is November 2018; October 2018 is "balance of month".
[3] AURORAxmp is a proprietary production cost simulation model, developed by Energy Exemplar, LLC.

gas price scenarios are also derived from expert third-party multi-client "off-the-shelf" subscription services.

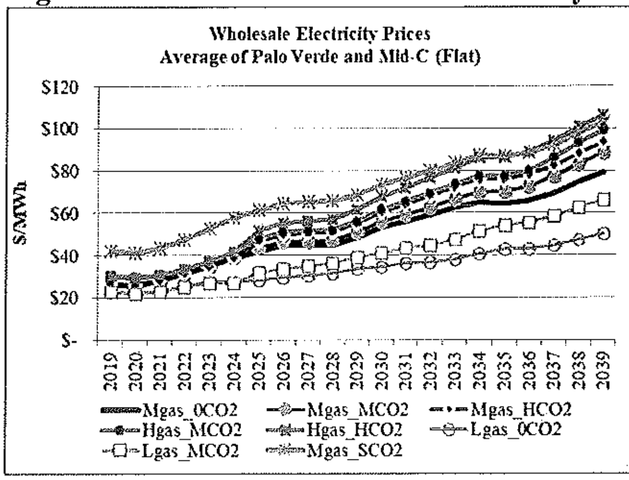
PacifiCorp's OFPC for electricity and each of its seven scenarios were developed from one of three (medium, low, high) underlying expert third-party natural gas price forecasts in conjunction with one of four $CO_2$ price scenarios.[4] The September 2018 OFPC does not assume any $CO_2$ policy or tax in conjunction with its medium gas price forecast. However, PacifiCorp's 2019 IRP "medium case" price forecast is not the OFPC but a scenario that couples medium gas with a medium $CO_2$ price, applied for forecasting purposes as a tax. Thus, the 2019 IRP medium case differs from that of the September 2018 OFPC by assuming a medium $CO_2$ price starting in 2025. This medium $CO_2$ price serves as a proxy for a potential future $CO_2$ policy, whose implementation and design specifics are not known.

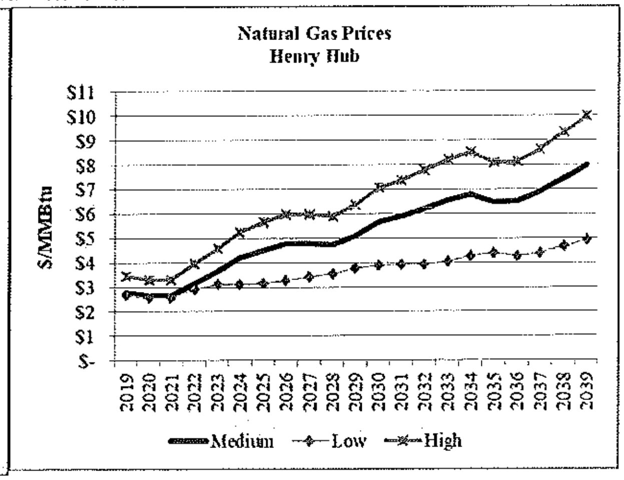
The 2019 IRP medium $CO_2$ compliance assumption differs from that used in either PacifiCorp's 2015 or 2017 IRPs. In its 2015 IRP PacifiCorp's OFPC incorporated the U.S. Environmental Protection Agency's (EPA's)[5] proposed Clean Power Plan (CPP) rule to improve $CO_2$ emissions performance rates for affected power plants. To reflect the CPP in Aurora, PacifiCorp applied state emission rate constraints in the model, assuming energy efficiency goals assumed by EPA in its calculation of state emission rate targets. Upon finalization of the CPP, and in its 2017 IRP, PacifiCorp's OFPC for electricity and each of its six scenarios were developed from one of three (low, medium, high) underlying expert third-party natural gas price forecasts in conjunction with one of three $CO_2$ compliance designs tied to the CPP. But on March 28, 2017, President Trump issued an Executive Order directing the EPA to review the CPP and, if appropriate, suspend, revise, or rescind the CPP, as well as related rules and agency actions. Thus, essentially rendering the CPP an artifact of the Obama Administration. On June 19, 2019 the EPA issued its Affordable Clean Energy (ACE) Rule replacing the CPP. ACE does not set $CO_2$ emission cuts by state but, instead, allows states to determine efficiency improvements.

Figure 7.4 summarizes the eight wholesale electricity price forecasts and three natural gas price forecasts used in the base and scenario cases for the 2019 IRP.

[4] Zero $CO_2$, medium $CO_2$ price, high $CO_2$ price, and a social based cost of $CO_2$.
[5] EPA: Environmental Protection Agency.

**Figure 7.4 – Nominal Wholesale Electricity and Natural Gas Price Scenarios**




## Cost and Risk Analysis

### Planning and Risk

PaR uses the same common input assumptions described for SO model with additional data provided by the SO model results (e.g., the capacity expansion portfolio including reliability resource additions). While the SO model supplies a capacity view developing an optimized portfolio for each case, PaR is able to bring the advantages of stochastic-driven risk metrics to the evaluation of the studies while also capturing additional operational considerations that the SO model does not asses (i.e., operating reserve requirements). While PaR cost-risk metrics are ultimately used in the preferred portfolio selection, the SO model results can be informative, especially in their role as a magnitude and direction indicator to compare to PaR outcomes.

PaR is also used to perform the hourly deterministic reliability assessments for each case, as described in detail in Volume II, Appendix R (Coal Studies). The PaR reliability assessment informs selection of reliability resources in the SO model. Figure R.1 (Reliability Studies Methodology Process), presented in Volume II, Appendix R (Coal Studies) applies to all resource portfolio development in the 2019 IRP.

**Cost and Risk Analysis**

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

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

PacifiCorp's updated flexible reserve study is provided in Volume II, Appendix F (Flexible Reserve Study).

The stochastic parameters used in PaR for the 2019 IRP are developed with a short-run mean reverting process, whereby mean reversion represents a rate at which a disturbed variable returns to its expected value. Stochastic variables may have log-normal or normal distribution as appropriate. The log-normal distribution is often used to describe prices because such distribution is bounded on the low end by zero and has a long, asymmetric "tail" reflecting the possibility that prices could be significantly higher than the average. Unlike prices, load generally does not have such skewed distribution and is generally better described by a normal distribution. Volatility and mean reversion parameters are used for modeling the volatilities of the variables, while accounting for seasonal effects. Correlation measures how much the random variables tend to move together.

**Stochastic Model Parameter Estimation**

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

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

Volume II, Appendix H (Stochastic Parameters) discusses the methodology on how the stochastic parameters for the 2019 IRP were developed.

For unplanned thermal outages, PacifiCorp assumes a uniform distribution around an expected rate. For existing units, the expected unplanned outage rates by unit are based on its historical performance during the 4-year period ending December 2015. For new resources, the unplanned outage rates are as specified for those resources as listed in the supply-side resource table in Volume I, Chapter 6 (Resource Options). Table 7.1 through Table 7.8 summarize updated stochastic parameters and seasonal price correlations for the 2019 IRP.

**Table 7.1 – Short-Term Load Stochastic Parameters**

| Short-Term Volatility | CA/OR without Portland | Portland | ID | UT | WA | WY |
|---|---|---|---|---|---|---|
| Winter 2019 IRP | 0.042 | 0.039 | 0.035 | 0.021 | 0.053 | 0.016 |
| Spring 2019 IRP | 0.035 | 0.033 | 0.065 | 0.028 | 0.037 | 0.018 |
| Summer 2019 IRP | 0.042 | 0.050 | 0.051 | 0.045 | 0.050 | 0.016 |
| Fall 2019 IRP | 0.042 | 0.039 | 0.042 | 0.035 | 0.043 | 0.017 |
| **Short-Term Mean Reversion** | **CA/OR without Portland** | **Portland** | **ID** | **UT** | **WA** | **WY** |
| Winter 2019 IRP | 0.188 | 0.177 | 0.153 | 0.363 | 0.181 | 0.273 |
| Spring 2019 IRP | 0.368 | 0.241 | 0.204 | 0.595 | 0.341 | 0.254 |
| Summer 2019 IRP | 0.194 | 0.280 | 0.095 | 0.213 | 0.157 | 0.235 |
| Fall 2019 IRP | 0.257 | 0.242 | 0.218 | 0.249 | 0.203 | 0.267 |

**Table 7.2 – Short-Term Gas Price Parameters**

| Short-Term Volatility | East Gas | West Gas |
|---|---|---|
| Winter 2019 IRP | 0.111 | 0.120 |
| Spring 2019 IRP | 0.039 | 0.061 |
| Summer 2019 IRP | 0.025 | 0.049 |
| Fall 2019 IRP | 0.036 | 0.044 |
| **Short-Term Mean Reversion** | **East Gas** | **West Gas** |
| Winter 2019 IRP | 0.110 | 0.092 |
| Spring 2019 IRP | 0.152 | 0.265 |
| Summer 2019 IRP | 0.102 | 0.105 |
| Fall 2019 IRP | 0.071 | 0.107 |

**Table 7.3 – Short-Term Electricity Price Parameters**

| Short-Term Volatility | Four Corners | COB | Mid-Columbia | Palo Verde |
|---|---|---|---|---|
| Winter 2019 IRP | 0.098 | 0.134 | 0.166 | 0.092 |
| Spring 2019 IRP | 0.104 | 0.261 | 0.475 | 0.075 |
| Summer 2019 IRP | 0.155 | 0.300 | 0.213 | 0.141 |
| Fall 2019 IRP | 0.101 | 0.102 | 0.103 | 0.098 |
| **Short-Term Mean Reversion** | **Four Corners** | **COB** | **Mid-Columbia** | **Palo Verde** |
| Winter 2019 IRP | 0.125 | 0.119 | 0.140 | 0.110 |
| Spring 2019 IRP | 0.434 | 0.551 | 0.551 | 0.211 |
| Summer 2019 IRP | 0.338 | 0.463 | 0.271 | 0.220 |
| Fall 2019 IRP | 0.370 | 0.257 | 0.279 | 0.415 |

**Table 7.4 – Winter Season Price Correlation**

| | Natural Gas East | Four Corners | COB | Mid - Columbia | Palo Verde | Natural Gas West |
|---|---|---|---|---|---|---|
| Natural Gas East | 1.000 | | | | | |
| Four Corners | 0.629 | 1.000 | | | | |
| COB | 0.353 | 0.576 | 1.000 | | | |
| Mid - Columbia | 0.382 | 0.573 | 0.942 | 1.000 | | |
| Palo Verde | 0.662 | 0.835 | 0.610 | 0.594 | 1.000 | |
| Natural Gas West | 0.891 | 0.567 | 0.395 | 0.421 | 0.609 | 1.000 |

**Table 7.5 – Spring Season Price Correlation**

| | Natural Gas East | Four Corners | COB | Mid - Columbia | Palo Verde | Natural Gas West |
|---|---|---|---|---|---|---|
| Natural Gas East | 1.000 | | | | | |
| Four Corners | 0.204 | 1.000 | | | | |
| COB | 0.099 | 0.338 | 1.000 | | | |
| Mid - Columbia | 0.069 | 0.358 | 0.864 | 1.000 | | |
| Palo Verde | 0.327 | 0.621 | 0.392 | 0.307 | 1.000 | |
| Natural Gas West | 0.553 | 0.058 | 0.080 | 0.070 | 0.132 | 1.000 |

**Table 7.6 – Summer Season Price Correlation**

| | Natural Gas East | Four Corners | COB | Mid - Columbia | Palo Verde | Natural Gas West |
|---|---|---|---|---|---|---|
| Natural Gas East | 1.000 | | | | | |
| Four Corners | 0.052 | 1.000 | | | | |
| COB | -0.004 | 0.272 | 1.000 | | | |
| Mid - Columbia | 0.024 | 0.290 | 0.848 | 1.000 | | |
| Palo Verde | -0.001 | 0.521 | 0.444 | 0.506 | 1.000 | |
| Natural Gas West | 0.453 | 0.054 | 0.050 | 0.096 | 0.009 | 1.000 |

**Table 7.7 – Fall Season Price Correlation**

| | Natural Gas East | Four Corners | COB | Mid - Columbia | Palo Verde | Natural Gas West |
|---|---|---|---|---|---|---|
| Natural Gas East | 1.000 | | | | | |
| Four Corners | 0.135 | 1.000 | | | | |
| COB | 0.149 | 0.362 | 1.000 | | | |
| Mid - Columbia | 0.124 | 0.223 | 0.780 | 1.000 | | |
| Palo Verde | 0.129 | 0.528 | 0.627 | 0.444 | 1.000 | |
| Natural Gas West | 0.731 | 0.100 | 0.128 | 0.133 | 0.066 | 1.000 |

**Table 7.8 – Hydro Short-Term Stochastic**

| | Short Term Volatility | Short-Term Mean Reversion |
|---|---|---|
| Winter 2019 IRP | 0.212 | 0.632 |
| Spring 2019 IRP | 0.162 | 0.501 |
| Summer 2019 IRP | 0.168 | 1.512 |
| Fall 2019 IRP | 0.301 | 0.863 |

Figure 7.5 and Figure 7.6 show annual electricity prices at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles for Mid-C and Palo Verde market hubs based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. For Mid-C electricity prices, differences between the first and 99th percentiles range from $21.64/MWh to $79.88/MWh during the 20-year study period. For Palo Verde electricity prices, the difference between the first and 99th percentiles range from $26.57/MWh to $99.34/MWh.

**Figure 7.5 – Simulated Annual Mid-C Electricity Market Prices**

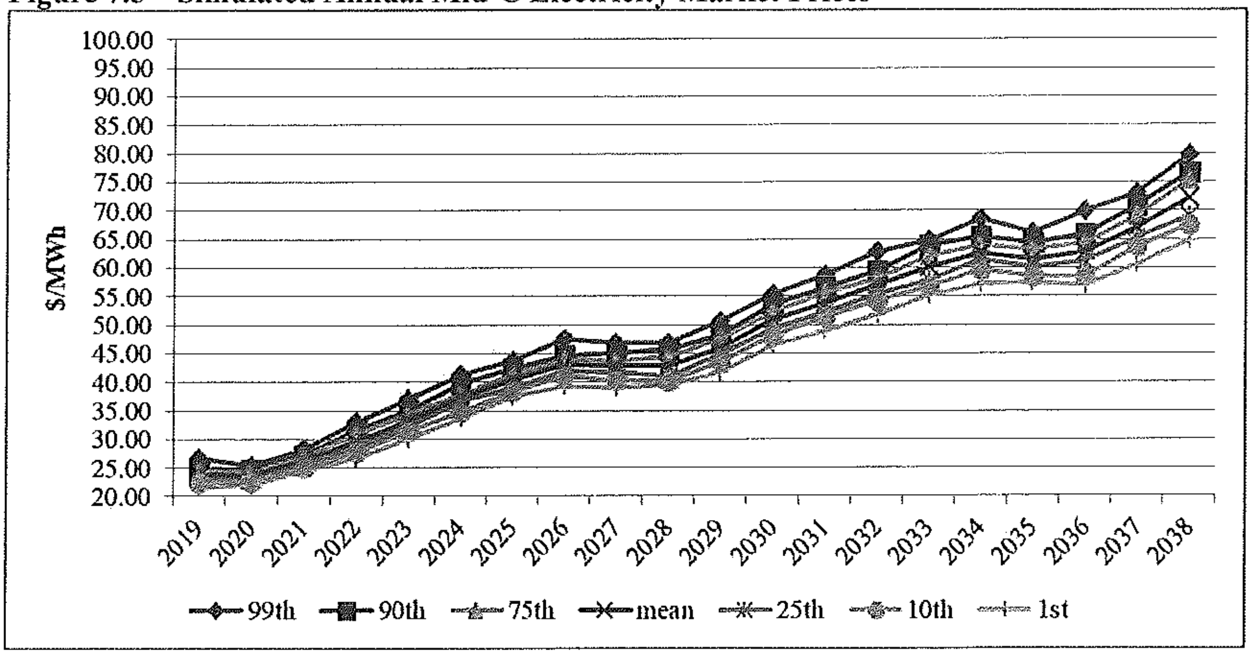


**Figure 7.6 – Simulated Annual Palo Verde Electricity Market Prices**

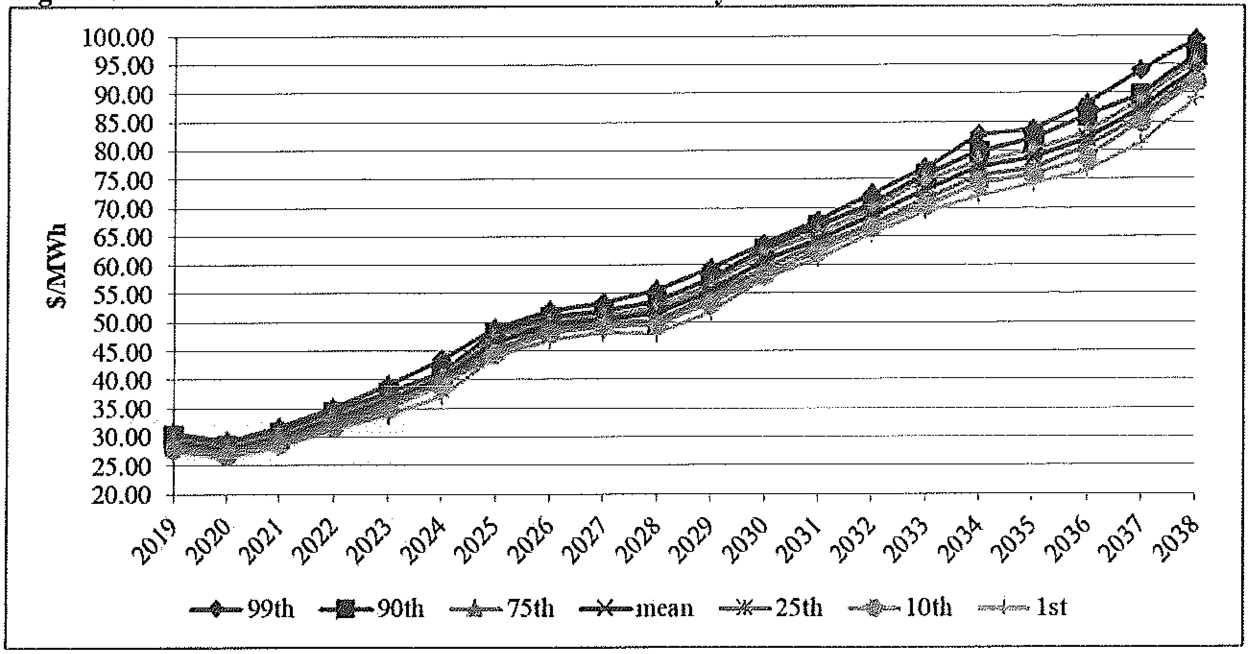



Figure 7.7 and Figure 7.8 show annual electricity prices at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles for west and east natural gas prices. For west natural gas prices, differences between the first and 99th percentiles range from \$1.85/ Million British thermal units (MMBtu) to \$7.22/MMBtu during the 20-year study period. For east natural gas prices, differences between the first and 99th percentiles range from \$2.00/MMBtu to \$7.64/MMBtu.

**Figure 7.7 – Simulated Annual Western Natural Gas Market Prices**

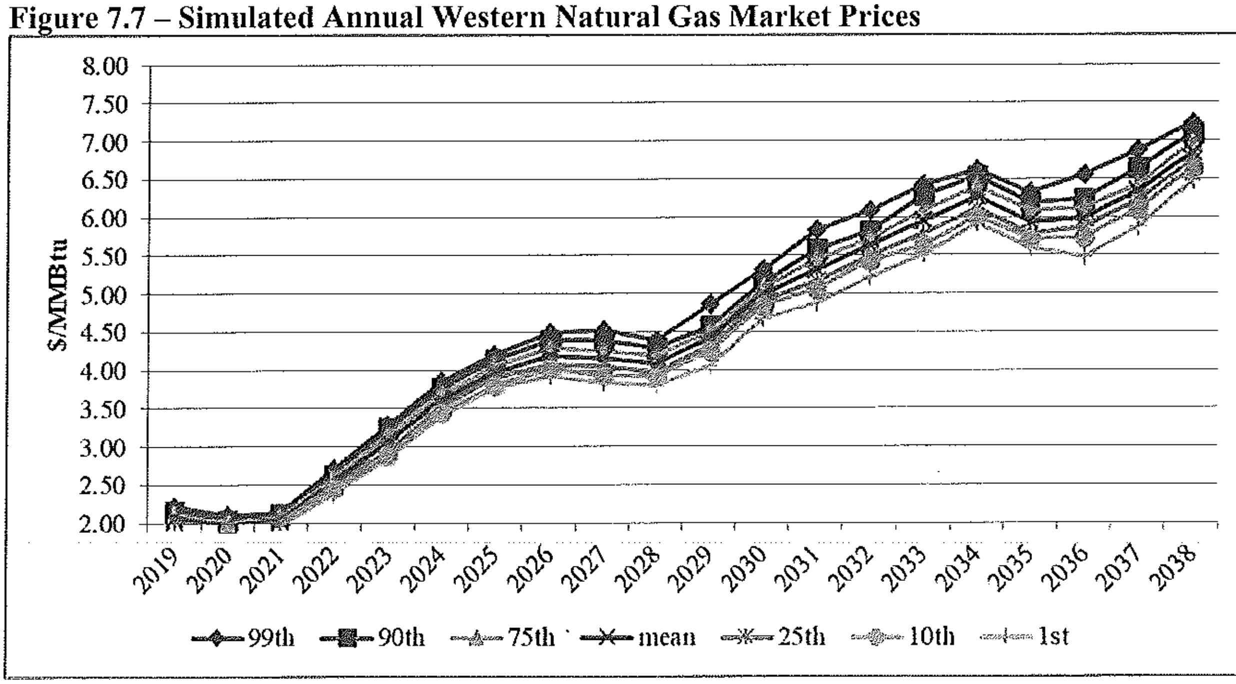


**Figure 7.8 - Simulated Annual Eastern Natural Gas Market Prices**

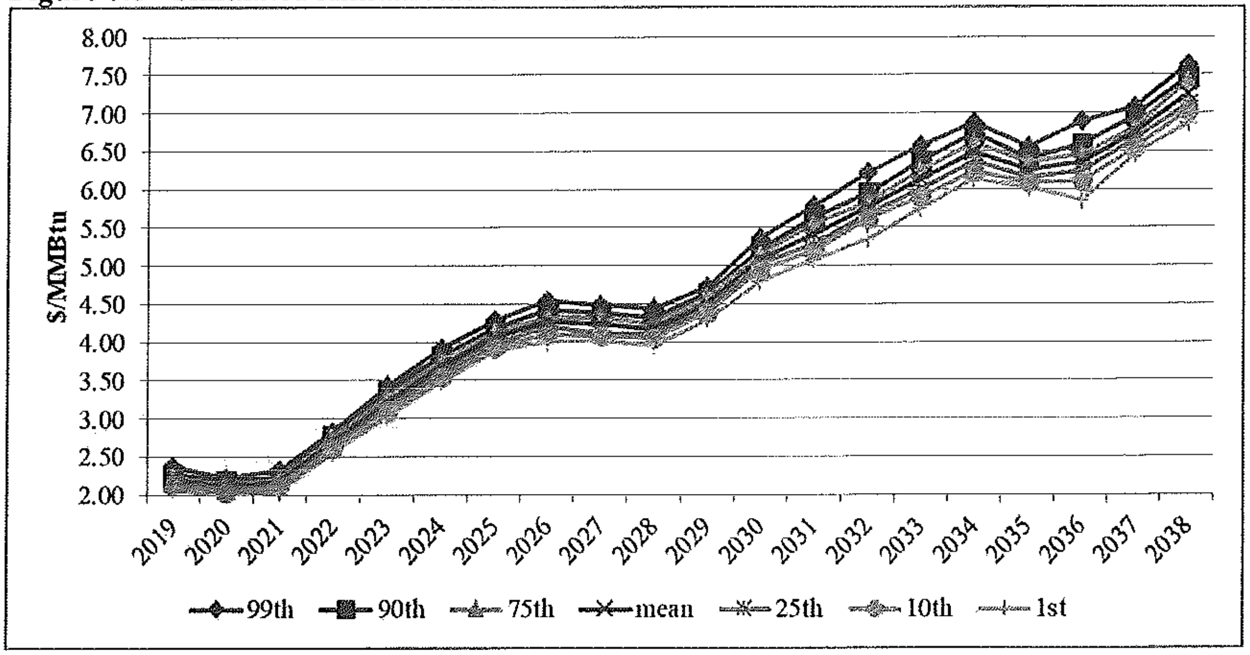



Figure 7.9 through Figure 7.14 show annual loads by load area and for PacifiCorp's system at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. For Idaho (Goshen) load, the annual differences between the first and 99th percentiles range from 192 gigawatt-hours (GWh) to 348 GWh. For Utah load, the annual difference ranges from 1,204 GWh to 2,772 GWh. For Wyoming load, the annual difference range from 137 GWh to 271 GWh. For Oregon/California load, annual differences range from 746 GWh to 1,528 GWh. For Washington load, the annual difference ranges from 315 GWh to 557 GWh. For PacifiCorp's system load, the annual difference ranges from 2,386 GWh to 4,354 GWh.

**Figure 7.9 - Simulated Annual Idaho (Goshen) Load**

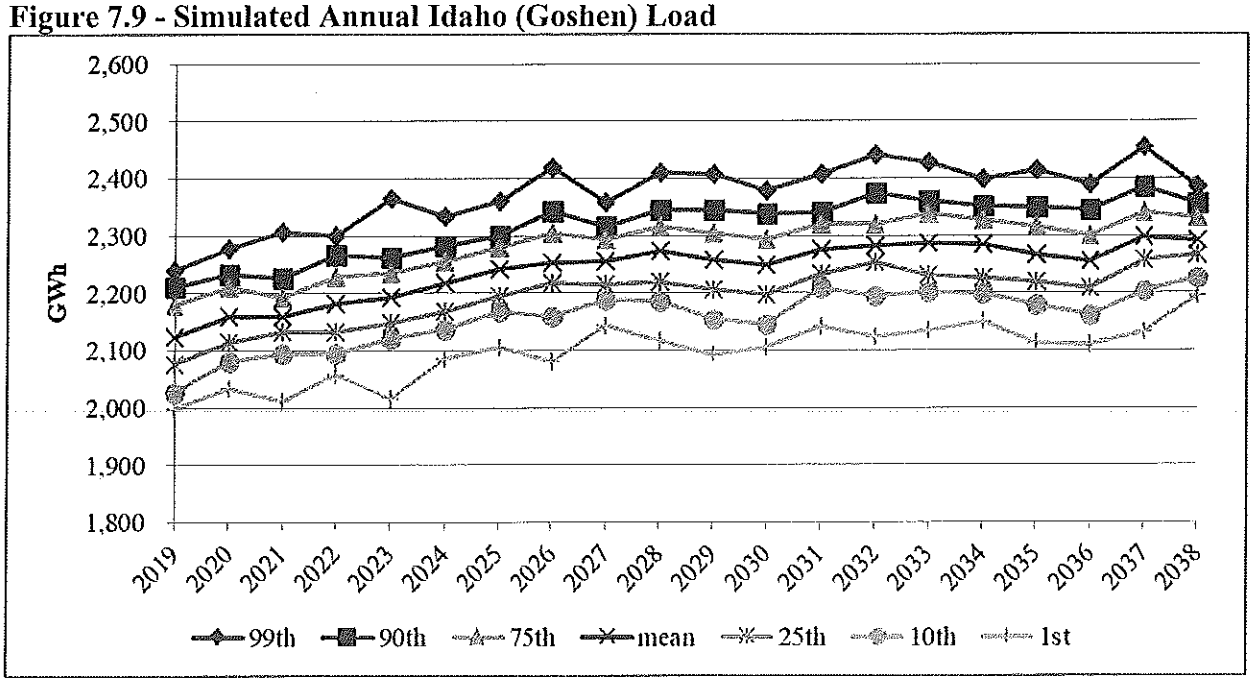


**Figure 7.10 - Simulated Annual Utah Load**

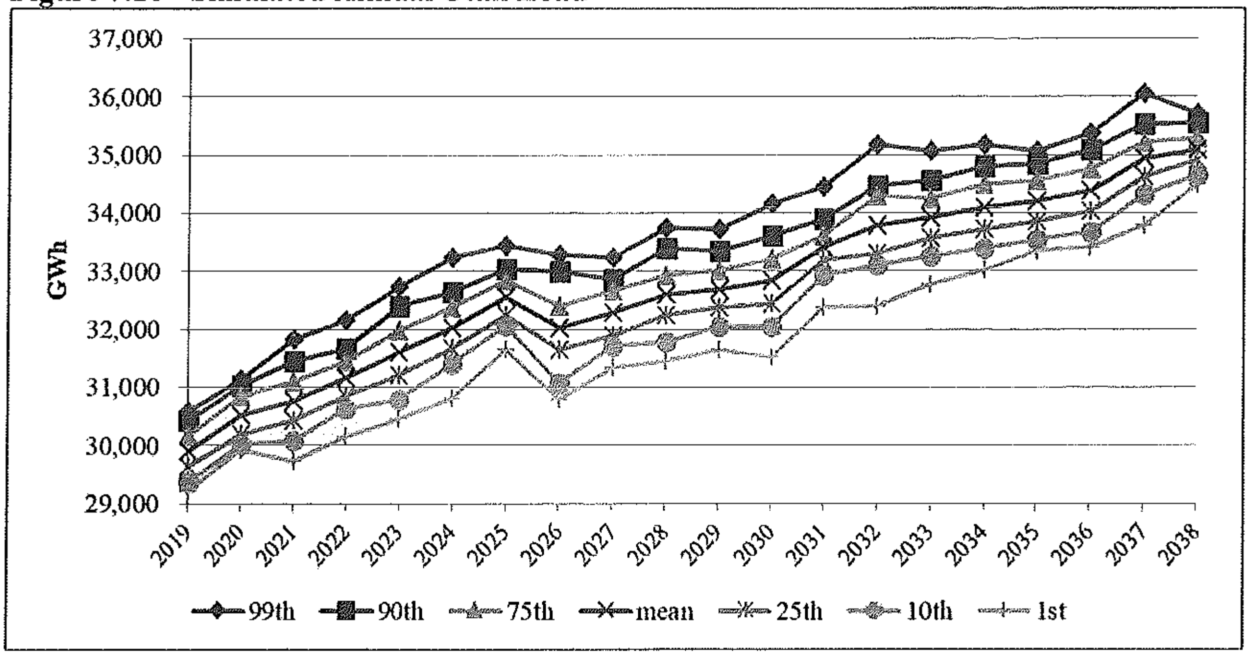



**Figure 7.11 - Simulated Annual Wyoming Load**

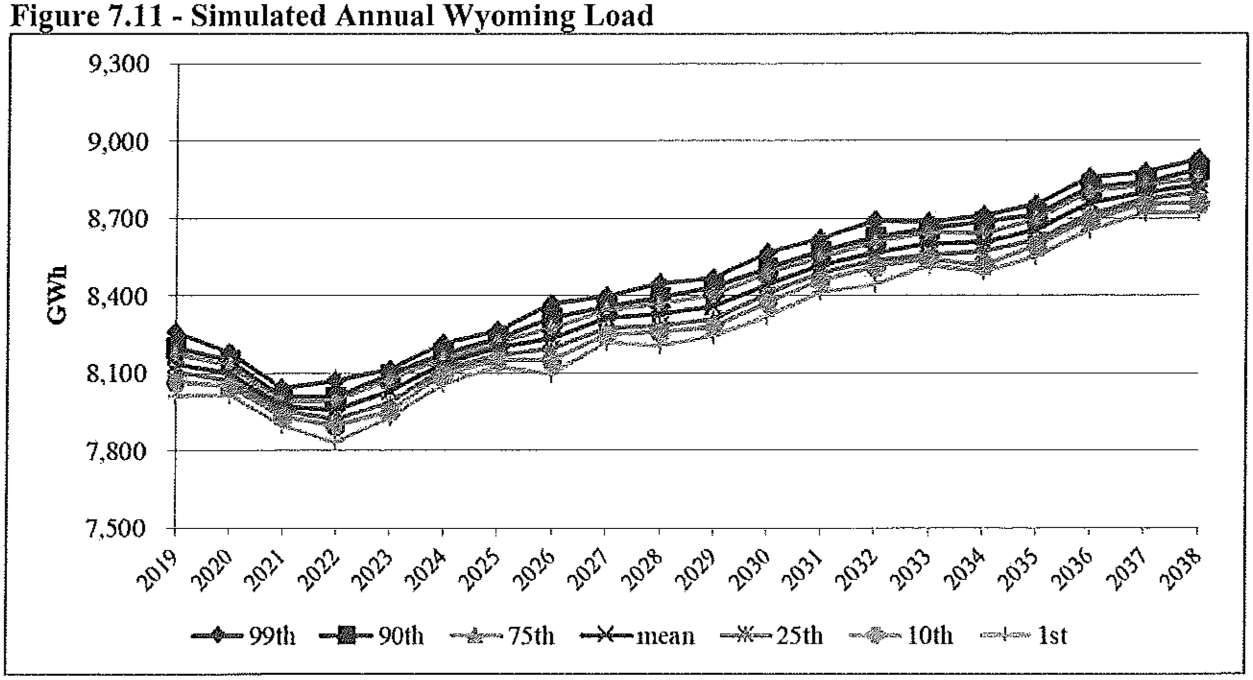


**Figure 7.12 - Simulated Annual Oregon/California Load**

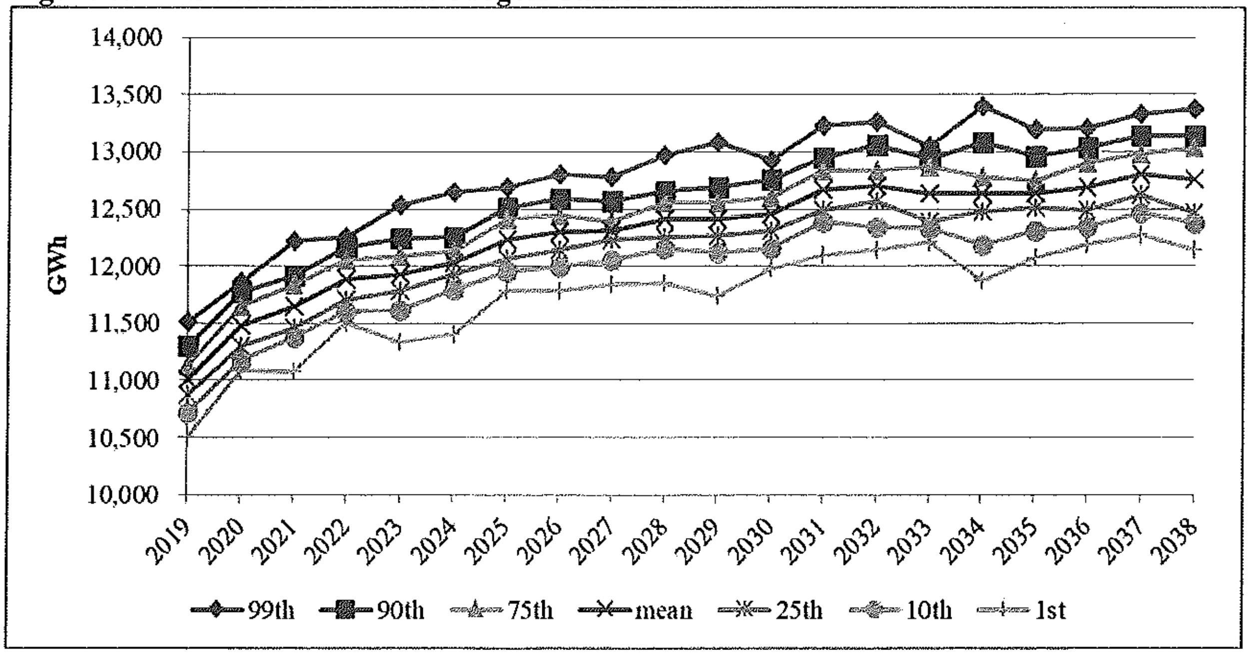



**Figure 7.13 - Simulated Annual Washington Load**

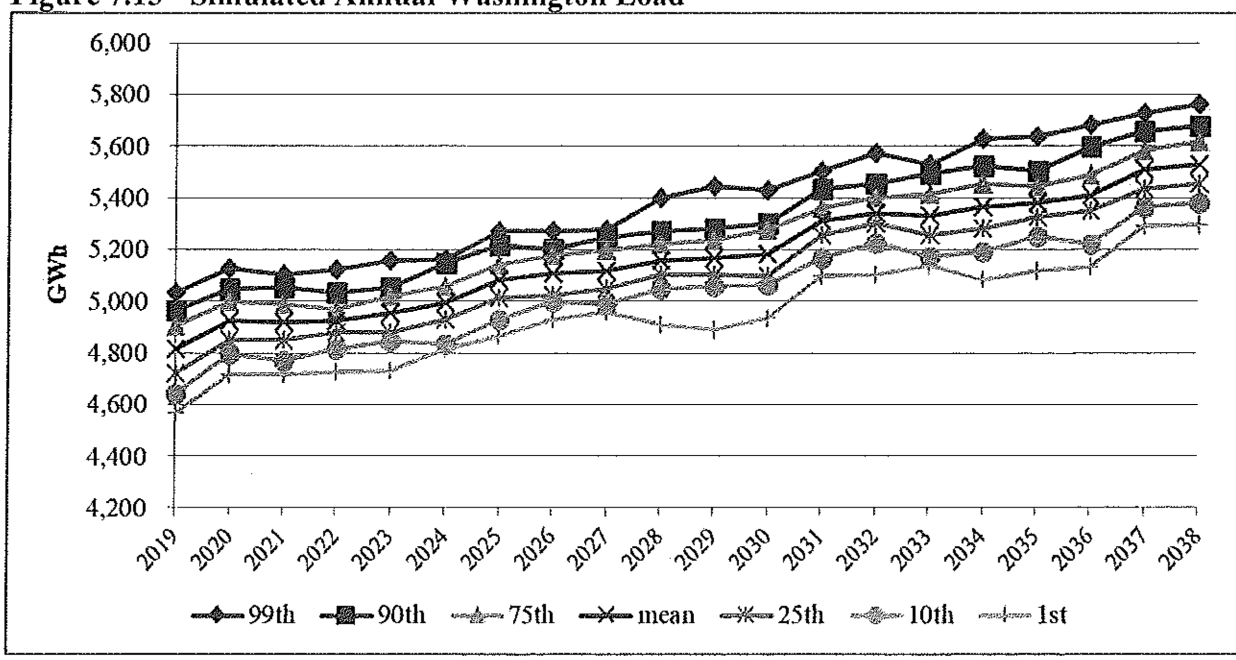


**Figure 7.14 - Simulated Annual System Load**

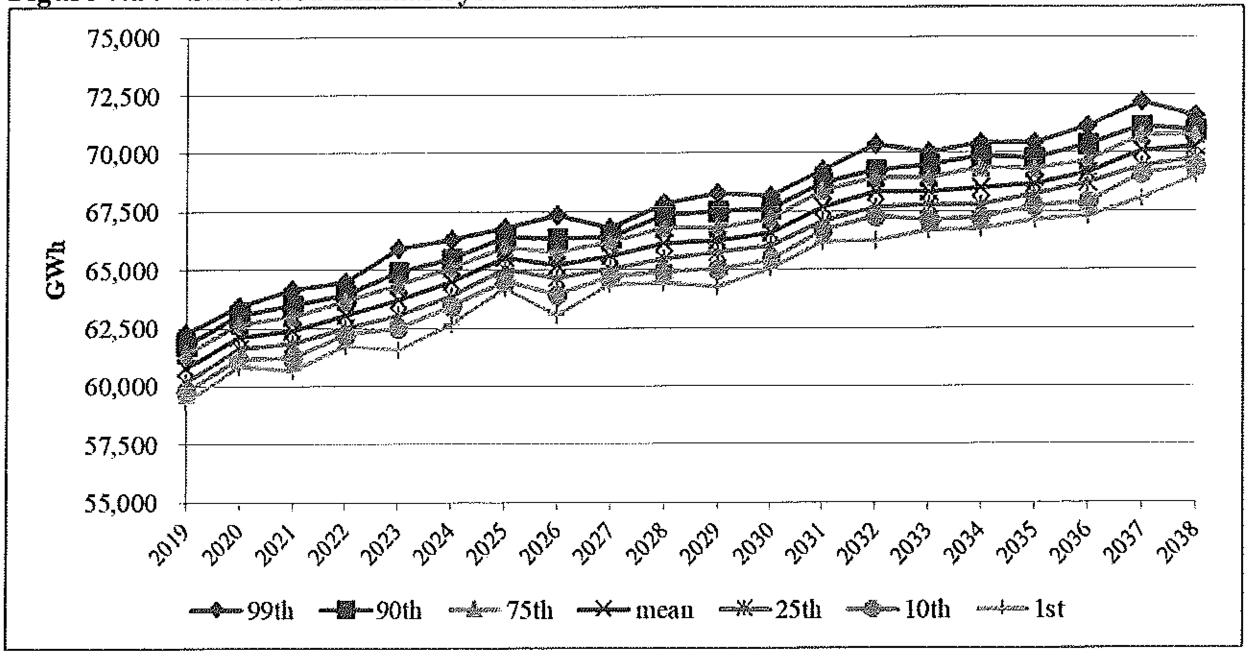
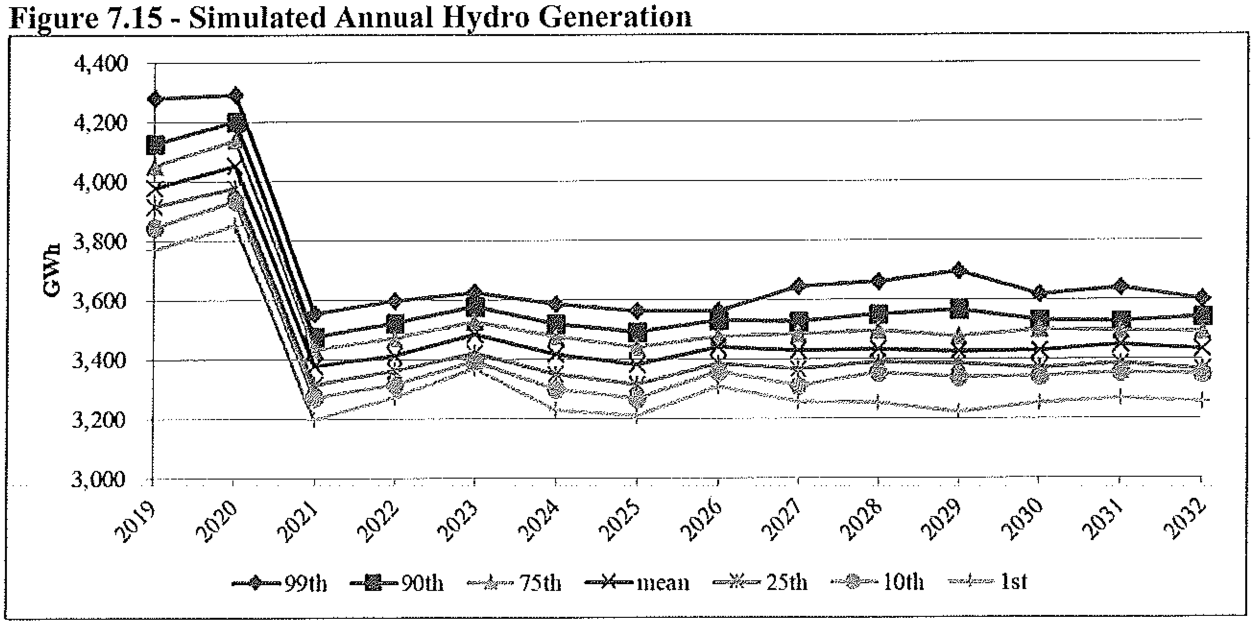



Figure 7.15 shows hydro generation at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. PacifiCorp can dispatch its hydro generation on a limited basis to meet load and reserve obligations. The parameters developed for the hydro stochastic process approximate the volatility of hydro conditions as opposed to variations due to dispatch. The drop in 2021 is due to the assumed decommissioning of the Klamath River projects. Annual differences in hydro generation between the first and 99th percentiles range from 253 GWh to 512 GWh.

**Figure 7.15 - Simulated Annual Hydro Generation**



**Monte Carlo Simulation**

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

For the 2019 IRP, PaR is configured to conduct 50 Monte Carlo iterations for the 20-year study period. For each of the 50 Monte Carlo iterations, PaR generates a set of natural gas prices, electricity prices, loads, hydroelectric generation and thermal outages. Then, the model optimizes resource dispatch to minimize costs while meeting load and wholesale sale obligations subject to operating and physical constraints. In a 50-iteration simulation, the resource portfolio is fixed. The end result of the Monte Carlo simulation is 50 production cost figures for the 20-year study period reflecting a wide range of cost outcomes for the portfolio.

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

**Stochastic Portfolio Performance Measures**

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

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

<u>Stochastic Mean PVRR</u>

The stochastic mean PVRR is the average of system net variable operating costs among 50 iterations, combined with the real levelized capital costs and fixed costs taken from the SO model for any given resource portfolio.[6] The net variable cost from stochastic simulations, expressed as a net present value, includes system costs for fuel, variable O&M, unit start-up, market contracts, system balancing market purchases expenses and sales revenues, and ENS costs applicable when available resources fall short of load obligations. Capital costs for new and existing resources, taken from the SO model, are calculated on an escalated real-levelized basis. Other components in the stochastic mean PVRR include fixed costs for new DSM resources in the portfolio, also taken from the SO model, and $CO_2$ emission costs for any scenarios that include a $CO_2$ price assumption.

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

Risk-Adjusted PVRR

The risk-adjusted PVRR incorporates the expected-value cost of low-probability, high cost outcomes. This measure is calculated as the PVRR of stochastic mean system variable costs plus five percent of system variable costs from the 95$^{th}$ percentile. The PVRR of system fixed costs, taken from the SO model, are then added to this system variable cost metric. This metric expresses a low-probability portfolio cost outcome as a risk premium applied to the expected (or mean) PVRR based on 50 Monte Carlo simulations for each resource portfolio. The rationale behind the risk-adjusted PVRR is to have a consolidated stochastic cost indicator for portfolio ranking, combining expected cost and high-end cost risk concepts.

Upper-Tail Mean PVRR

The upper-tail mean PVRR is a measure of high-end stochastic cost risk. This measure is derived by identifying the Monte Carlo iterations with the three highest production costs on a net present value basis. The portfolio's real levelized fixed costs, taken from the SO model, are added to these three production costs, and the arithmetic average of the resulting PVRRs is computed.

95th and 5th Percentile PVRR

The 5$^{th}$ and 95$^{th}$ percentile PVRRs are also reported from the 50 Monte Carlo iterations. These measures capture the extent of upper-tail (high cost) and lower-tail (low cost) stochastic outcomes. As described above, the 95$^{th}$ percentile PVRR is used to derive the high-end cost risk premium for the risk-adjusted mean PVRR measure. The 5$^{th}$ percentile PVRR is reported for informational purposes.

Production Cost Standard Deviation

To capture production cost volatility risk, PacifiCorp uses the standard deviation of the stochastic production cost from the 50 Monte Carlo iterations. The production cost is expressed as a net present value of annual costs over the period 2019 through 2038. This measure meets Oregon IRP guidelines to report a stochastic measure that addresses the variability of costs in addition to a measure addressing the severity of bad outcomes.

Average and Upper-Tail Energy Not Served

Certain iterations of a stochastic simulation will have ENS, a condition where there are insufficient resources, inclusive of system balancing purchases, available to meet load or operating reserve requirements because of physical constraints. This occurs when Monte Carlo draws of stochastic variables result in a load obligation that is higher than the capability of the available resources in the portfolio. For example, this might occur in Monte Carlo draws with large load shocks concurrent with a random unplanned plant outage event. Consequently, ENS, when averaged across all 50 iterations, serves as a measure of reliability that can be compared among resource portfolios. PacifiCorp calculates an average annual value over the 2019 through 2038 planning horizon as well as the upper-tail ENS (average of the three iterations with the highest ENS). In the 2019 IRP, ENS is nominally priced at $1,000/MWh.

Loss of Load Probability

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

Cumulative $CO_2$ Emissions

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

**Forward Price Curve Scenarios**

Top-performing resource portfolios developed with the SO model during the portfolio-development process are analyzed in PaR with up to four price-policy scenarios. The price curve scenarios are developed from PacifiCorp's September 2018 OFPC. PaR results using each of these scenarios inform selection of the preferred portfolio.

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

**Other PaR Modeling Methods and Assumptions**

Transmission System

The base transmission topology used for the SO model, shown in Figure 7.2, is identical to the transmission topology used for PaR simulations. Any transmission upgrades selected by the SO model that provide incremental transfer capability among bubbles in this topology are also included in PaR.

Resource Adequacy

The resource portfolio developed with the SO model, which meets an assumed 13 percent target planning reserve margin, is fixed in all PaR simulations. With fixed resources, the unit commitment and dispatch logic in PaR accounts for operating reserve requirements. These reserve requirements include contingency reserves, which are calculated as 3 percent of load and 3 percent of generation. In addition, PaR reserve requirements account for regulation reserves. PacifiCorp's regulation reserve assumptions are outlined in PacifiCorp's flexible reserve study, provided in Volume II, Appendix F (Flexible Reserve Study), including PaR's use in the reliability assessment phase of the portfolio-development process.

Energy Storage Resources

Given the complexity of PacifiCorp's system, the PaR model experienced difficulty optimizing the dispatch for battery storage resources. To improve upon this shortcoming in the PaR model, PacifiCorp developed and tested a method to produce an optimized peak-shave/valley-fill profile for these resource outside of PaR that is based on load net of wind, solar, energy efficiency resources, and private generation resources in any given portfolio. Fixed hourly dispatch, charging, and operating reserves are entered as inputs to PaR. This methodological enhance was presented and discussed with stakeholders at the March 21, 2019 IRP public-input meeting.

General Assumptions

The general assumptions applied in the SO model for the study period (20-years beginning 2019) annual inflation rates (2.28 percent), and discount rates (6.92 percent) are also applied in PaR.

## Other Cost and Risk Considerations

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

### Fuel Source Diversity

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

### Customer Rate Impacts

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

### Market Reliance

To assess market reliance risk, PacifiCorp develops a series of portfolios designed to quantify the risk associated with relying on FOTs for a given portfolio. These studies apply a price scalar to market prices in the peak months of July, August, and December. In the SO model, FOTs include a premium to capture the risk of price spikes where the magnitude of these price spikes are based upon the variance between historical forward prices and actual prices from an historical period. This approach, which captures the severity and volume of potential high-price hours while maintaining the shape of the underlying price curve.

## Portfolio Selection

The final action in each modeling and evaluation step is portfolio selection. In the first step, to performing portfolios are identified based on their relative performance with regard to mean system costs, risk-adjusted system costs, which account for upper tail stochastic risk, reliability metrics and cumulative $CO_2$ emissions.

Additional refined analysis is performed on these cases to ensure there relative cost and risk metrics are comparable by performing more granular reliability analysis that also better captures potential cost savings of combining battery storage resources with solar resources. Additional analysis can be performed to further assess the relative differences among top-performing portfolios.

Within each step, each portfolio that is under examination is compared on the basis of cost-risk metrics, and the least-cost, least-risk portfolio is chosen. Risk metrics examined include the mean PVRR, upper-tail PVRR, risk-adjusted PVRR, mean ENS, upper-tail ENS, and emissions. As noted above, market reliance risk was also evaluated and quantified. The comparisons of outcomes are detailed, ranked and assessed in the next chapter.

## Final Evaluation and Preferred Portfolio Selection

Due to the lengthy nature of the IRP cycle, the final step is the last opportunity to consider whether top-performing portfolios merit additional study based on observations in the model results across all studies, additional sensitivities, possible updates driven by recent events, and additional stakeholder feedback. Additional sensitivities may refine the portfolio selection based on portfolio optimization and cost and risk analysis steps. For the 2019 IRP this included additional analysis to assess market price risk, the impact of relying on new natural gas resources, and additional studies to assess incremental transmission investments that cannot be adequately captured in the improved endogenous transmission upgrade methodology discussed earlier in this chapter and in Chapter 6 (Resource Options).

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

## Case Definitions

Case definitions specify a combination of planning assumptions used to develop each unique resource portfolio analyzed in the 2019 IRP, organized here into major development categories:

- Coal Studies
- Portfolio Development Cases
  - Initial portfolio cases
  - C-series cases
  - CP-series cases
  - FOT cases
- Preferred Portfolio Selection

  - No new gas cases
  - Energy Gateway Transmission cases
  - Dave Johnston wind alternative
- Sensitivity Cases

Additional detail for all portfolios can be found in Volume II, Appendix M (Case Study Fact Sheets).

## Coal Studies

The coal study cases are described in detail in Volume II, Appendix R (Coal Studies). Results from the coal studies informed the portfolio-development phase of the 2019 IRP by driving coal retirement assumptions in the initial portfolio development step of the portfolio-development process.

## Portfolio Development Cases

Informed by the public-input process and focused on the retirement outcomes of the coal studies, these cases build diversity around varying key retirement dates, and implement modeling refinements to improve results and test evolving outcomes through the IRP process.

**Initial Portfolio Cases**

As informed by the Coal Studies, the over half of initial portfolios explore variations in retirement timing for Jim Bridger Units 1 and 2 and Naughton Units 1 and 2. The initial portfolios also explore potentially significant interactions with additional retirement options including the potential to convert Naughton Unit 3 to natural gas, potential tradeoffs to retire Gadsby steam units early, and the timing of other coal unit retirements that were not a focus of the Coal Study (i.e., Cholla Unit 4 and jointly owned facilities where PacifiCorp is not the operator). The initial portfolios also consider how resource selections change with price-policy assumptions that deviate from the medium natural gas price and medium $CO_2$ price assumptions used to develop many resource portfolios. All of the initial portfolios include the new reliability assessment phase of portfolio development that was incorporated in the 2019 IRP cycle.

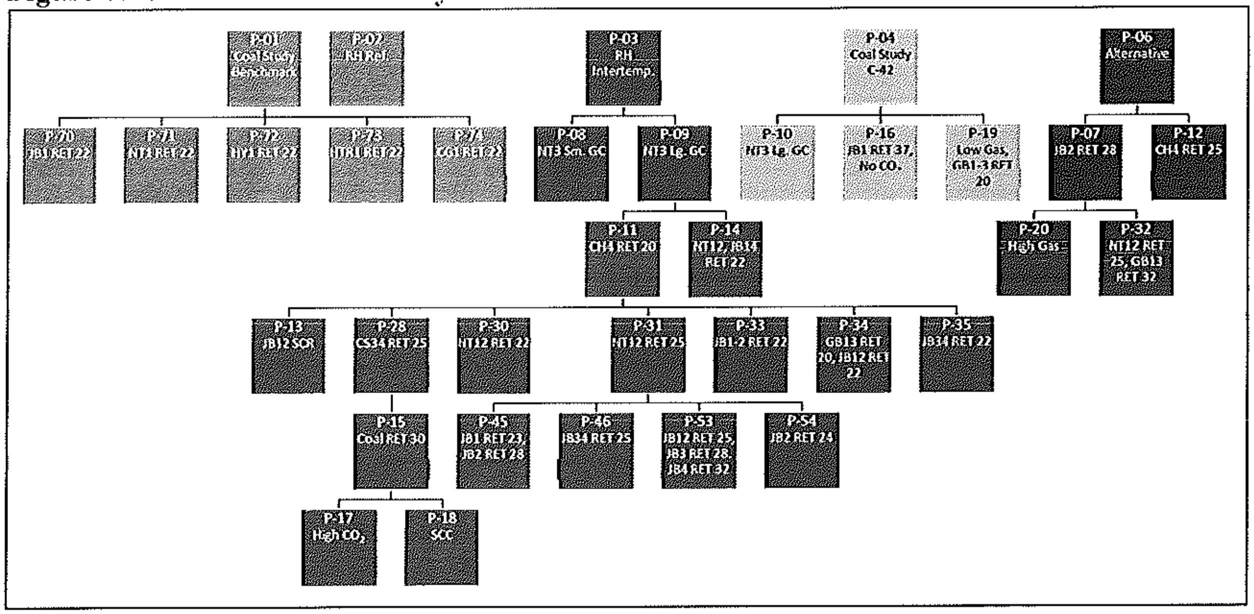
Table 7.9 provides the initial portfolio definitions for this IRP. Additional information, including coal unit retirement assumptions, are provided for each case in Volume II, Appendix M (Case Study Fact Sheets).

**Table 7.9 – Initial Portfolio Case Definitions**

| Case | Description | Parent Case |
|---|---|---|
| P-01 | Coal Study Benchmark | - |
| P-02 | Regional Haze Reference | - |
| P-03 | Regional Haze Intertemporal | - |
| P-04 | Coal Study C-42 | - |
| P-06 | Gadsby Alternative Case | - |
| P-07 | Gadsby Alternative Case | P-06 |
| P-08 | Naughton 3 Small Gas Conversion | P-03 |
| P-09 | Naughton 3 Large Gas Conversion | P-03 |
| P-10 | Naughton 3 Large Gas Conversion | P-04 |
| P-11 | Cholla 4 Retirement 2020 | P-09 |
| P-12 | Cholla 4 Retirement 2025 | P-06 |
| P-13 | Jim Bridger 1&2 SCRs | P-11 |
| P-14 | Naughton 1&2 and Jim Bridger 1-4 Retirement 2022 | P-09 |
| P-15 | Retire All Coal by 2030 | P28 |
| P-16 | Jim Bridger 1&2 Retirement 2022, No $CO_2$ | P04 |
| P-17 | High $CO_2$ | P-15 |
| P-18 | Social Cost of Carbon | P-15 |
| P-19 | Low Gas | P-04 |
| P-20 | High Gas | P-07 |
| P-28 | Colstrip 3&4 Retirement 2025 | P-11 |
| P-30 | Naughton 1&2 Retirement 2022 | P-11 |
| P-31 | Naughton 1&2 Retirement 2025 | P-11 |
| P-32 | Naughton 1&2 Retirement 2025 with Gadsby 1-3 Retirement 2032 | P-07 |
| P-33 | Jim Bridger 1&2 Retirement 2022 | P-11 |
| P-34 | Jim Bridger 1&2 Retirement 2022, with Gadsby 1-3 Retirement 2020) | P-11 |
| P-35 | Jim Bridger 3&4 Retirement 2022 | P-11 |
| P-45 | Jim Bridger 1 Retirement 2023 and Jim Bridger 2 Retirement 2038 | P-31 |
| P-46 | Jim Bridger 3&4 Retirement 2025 | P-31 |
| P-53 | Jim Bridger 1&2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032 | P-31 |
| P-54 | Jim Bridger 2 Retirement 2024 | P-31 |

Initial portfolio case refinements and additions were modeled on the basis of outcomes and stakeholder feedback throughout the 2019 IRP public-input process. This led to the developing assumptions for many cases as a variant from another case, lending itself to a "family tree" structure as a means to describe the relationship among cases. Figure 7.16 summarizes the case definitions in this family tree format. Note, cases P-70 through P-74 were developed in response to stakeholder interest to reaffirm Coal Study findings that early retirement of units at the Naughton and Jim Bridger plant were most likely to generate cost savings. These cases were higher cost than most of the other cases and were not evaluated as potential candidates for the preferred portfolio. The top row of cases in this figure represent "parent cases" from which all other cases were derived. The text in each box of the family tree describes what changed relative to the case from which it was derived (i.e., case P-08 retains all attributes of case P-03, except case P-08 assumes a small gas conversation at Naughton Unit 3 in 2020).

**Figure 7.16 – Initial Case Family Tree**




**C-Series Cases**

In the C-series, top-performing portfolios from the initial portfolio cases were examined with additional deterministic test years used to ascribe reliability resources covering 2023 through 2030, plus 2038. This provides a total of nine years of hourly PaR reliability assessment rather than the three years (2023, 2030, and 2038) employed in the initial portfolio cases.

When reliability resources are added in the two-step portfolio development process adopted for this IRP cycle, incremental battery resources are routinely added to remedy initial reliability shortfalls in each case. This indicates that if the SO model were able to assess the incremental reliability requirement in its *initial* resource portfolio, it would likely pair batteries with any of the new solar resources it initially added to take advantage of cost savings for this combined resource alternative.

Test runs performed by the IRP modeling team confirmed that if stand-alone solar resources were not allowed in the initial portfolio development case, that the SO model selected solar+battery combination resource options, and that when these portfolios were analyzed for reliability (using the additional test years as described above) and run through the PaR model, the overall system PVRR was lower.

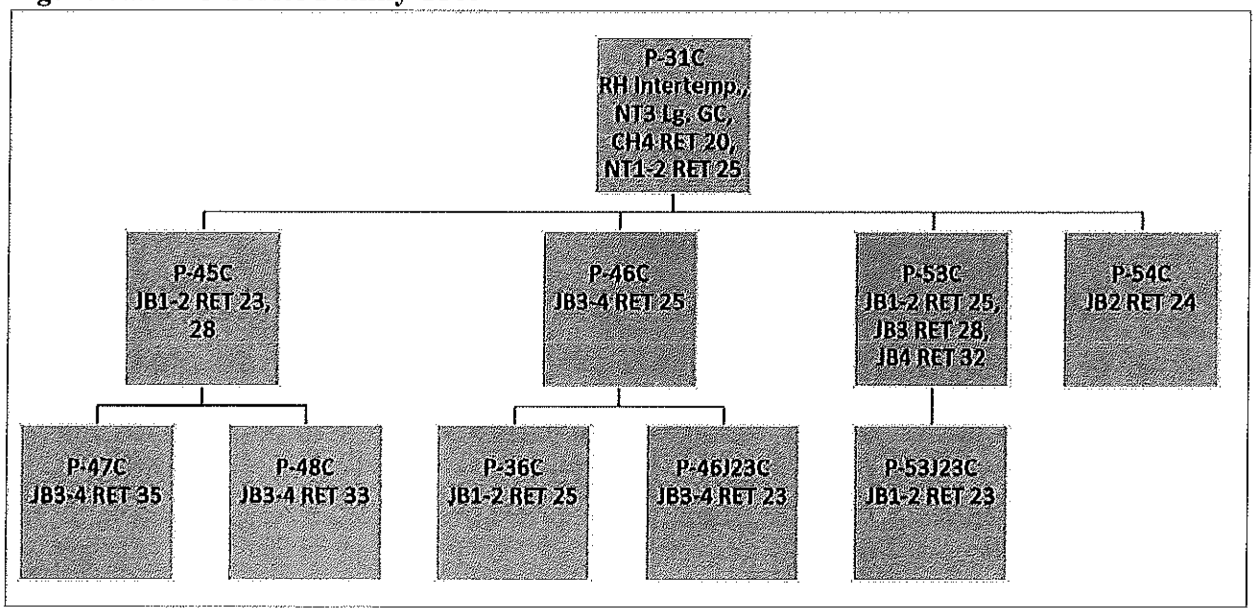
Consequently, for the five cases with the lowest system PVRR from the initial step of the portfolio-development process and for additional cases developed after stakeholder discussion at the September 2019 public-input meeting, PacifiCorp disabled stand-alone solar resources—in each case, solar+battery is added to the portfolio and system costs were reduced.

In addition to the five top performing cases derived from the initial portfolios (P-31C, P-45C, P-46C, P-53C and P-54C), the C-series includes five additional cases developed after discussion at the September 5-6, 2019 public-input meeting (P-36C, P-46J23C, P-47C, P-48C, P-53J23C). Table 7.10 provides the C-series portfolio definitions for this IRP. Figure 7.17 shows the family tree relationship for the C-series of cases.

**Table 7.10 – C-Series Case Definitions**

| Case | Description (Change from Parent Case) | Parent Case |
|---|---|---|
| P-31C | Naughton 1-2 Retire 2025 | P-11 |
| P-36C | Jim Bridger 1-2 Retire 2025 | P-46 |
| P-45C | Jim Bridger 1 & 2 Retire 2023 and 2038 | P-31 |
| P-46C | Jim Bridger 3 & 4 Retire 2025 | P-31 |
| P-46J23C | Jim Bridger 3 & 4 Retire 2023 | P-46 |
| P-47C | Jim Bridger 3 & 4 Retire 2035 | P-45 |
| P-48C | Jim Bridger 3 & 4 Retire 2033 | P-45 |
| P-53C | Jim Bridger 1 & 2 Retire 2025, Jim Bridger 3-4 Retire 2028/2032 | P-31 |
| P-53J23C | Jim Bridger 1 & 2 Retire 2023 | P-53 |
| P-54C | Jim Bridger 2 Retire 2024 | P-31 |

**Figure 7.17 – C-Series Family Tree**




## CP-Series Cases

In the CP-series[7], top-performing portfolios informed by the C-series cases are examined with additional deterministic years covering 2023 through 2038. This provides a total of 16 years of hourly PaR reliability assessment, and fleshes out any granular variances driven by mapping results from a single reliability test year to multiple simulation years in the back-end of the study period.

Table 7.11 provides the CP-series portfolio definitions for this IRP. While the P-54C, P-54J23C, and P-31C cases were not evaluated in the CP-series, the family tree relationships for the cases in the table below are unchanged from the family tree relationships depicted for the C-series of cases.

[7] "CP" refers to "C-Prime", an expansion of the deterministic runs used for reliability assessment in the C-Series cases.

**Table 7.11 – CP-Series Case Definitions**

| Case | Description (Change from Parent Case) | Parent Case |
|---|---|---|
| P-36CP | Jim Bridger 1-2 Retire 2025 | P-46 |
| P-45CP | Jim Bridger 1-2 Retire 2023 and 2038 | P-31 |
| P-46CP | Jim Bridger 3 & 4 Retire 2025 | P-31 |
| P-46J23CP | Jim Bridger 3 & 4 Retire 2023 | P-46 |
| P-47CP | Jim Bridger 3 & 4 Retire 2035 | P-45 |
| P-48CP | Jim Bridger 3 & 4 Retire 2033 | P-45 |
| P-53CP | Jim Bridger 1 & 2 Retire 2025, Jim Bridger 3-4 Retire 2028/2032 | P-31 |

**Front Office Transaction (FOT) Portfolios**
PacifiCorp ran a series of FOT studies designed to quantify the impact and risk of market reliance for a given portfolio. These cases use an escalating scalar to elevate market prices during the peak months of July, August and December of every study year. As FOT prices are calculated as market price plus a premium, FOT prices are elevated with the market.

The scalar targets a maximum escalation based on the largest difference between each month's highest Mid-C forward price and the highest Mid-C historical price in the sample year of 2018. This yields a maximum peak scalar of 3.72 times higher than the forward price curve in the month of August; 3.70 times higher in the month of July; and 1.77 times higher in the month of December. The higher the original forward price in a given hour, the higher the scalar. This has the effect of increasing both the severity and frequency of high-price hours (increases upward volatility) while maintaining the shape of the underlying price curve.

Figure 7.18 illustrates the differences between the underlying forward price curve (FPC) and the escalating scaled price curve in each peak month in the sample year 2021.

**Figure 7.18 – Sample Year 2021 FOT MidC FPC and Scaled Price Curves**

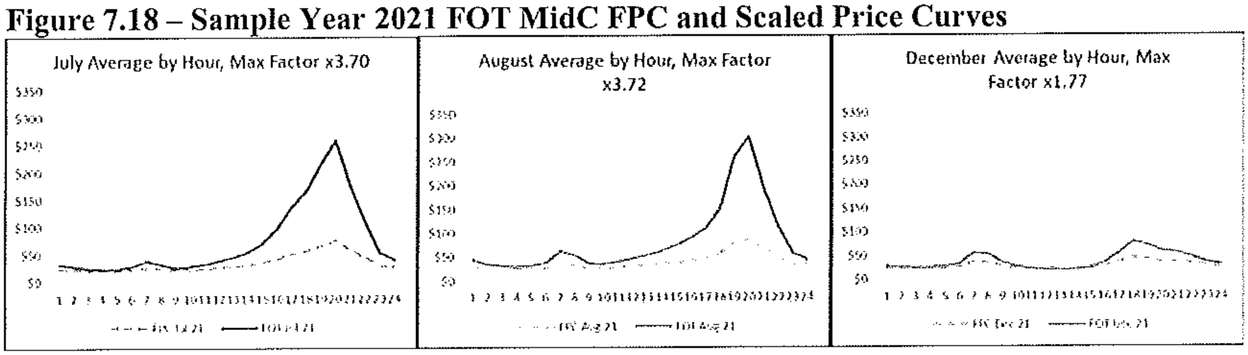



Table 7.12 lists the CP-series of cases where for which FOT scenarios were developed to evaluate market-reliance risk.

**Table 7.12 – Front Office Transaction (FOT) Case Definitions**

| Case | Description |
|---|---|
| P-45CP-FOT | P-45CP with FOT price curve |
| P-46CP-FOT | P-46CP with FOT price curve |
| P-47CP-FOT | P-47CP with FOT price curve |
| P-48CP-FOT | P-48CP with FOT price curve |
| P-53CP-FOT | P-53CP with FOT price curve |

### 2028-2029 Wyoming Wind Case

In reviewing CP-series case results, 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. Consequently, and considering it unreasonable to potentially include highly curtailed new wind in a leading candidate for the preferred portfolio, PacifiCorp produced an incremental 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.

## Preferred Portfolio Selection Cases

Certain additional cases were developed directly from the top-performing case (P-45CNW) based on analysis of portfolios from the initial cases through the CP-series of cases as described above to evaluate the impacts of specific future scenarios not considered elsewhere, but which may be adopted into the preferred portfolio if the analysis warrants their inclusion. In the 2019 IRP, there are two types of preferred portfolio selection cases:

- No Gas portfolios
- Gateway portfolios (excluding gateway south, which is modeled as an option in all cases)

### "No Gas" Cases

PacifiCorp ran two cases as variants of P-45CNW to evaluate portfolio impacts of excluding new natural gas capacity from the portfolio. 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 comes online in 2028 following retirement of the Dave Johnston plant. Table 7.13 provides the No-Gas case definitions for this IRP.

**Table 7.13 – No Gas Case Definitions**

| Case | Description | Parent Case |
|---|---|---|
| P-29 | P-45CNW, No New Gas Option | P-45CNW |
| P-29 PS | P-45CNW, No New Gas Option with pumped hydro storage | P-45CNW |

### Gateway 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. The Energy Gateway cases developed for the 2019 IRP are summarized in Table 7.14 and Table 7.15.

**Table 7.14 – Additional Gateway Case Definitions**

| Case | P-22 | P-23 | P-25 | P-26 |
|---|---|---|---|---|
| Base Case | P-45CNW | P-36CNW | P-45CNW | P-45CNW |
| Segments* | (D3), (F) | (D3), (E), (F), (H) | (D3), (E), (F), (H) | (F), (H) |

**Table 7.15 – Gateway Segment Definitions**

| Segment | Description | Incremental Capacity | Approximate Mileage | Build Year |
|---|---|---|---|---|
| (D3) Bridger/Anticline - Populus | 500 kV single circuit | 1700 MW + PathC 1000 MW | 200 mi | 2025 |
| (E) Populus - Hemingway | 500 kV single circuit | 1260 MW | 500 mi | 2025 |
| (F)* Aeolus - Clover | 500 kV single circuit | 1700 MW | 400 mi | 2023 |
| (H) Boardman - Hemingway | 500 kV single circuit | 600 MW | 290 mi | 2026 |

* Note: Energy Gateway South Segment F is modeled as an option, and is selected in each Energy Gateway case summarized above.

## Sensitivity Case Definitions

PacifiCorp initially identified 8 sensitivities based on prior IRP cycle experience, stakeholder feedback, and anticipated areas of interest. Each sensitivity is designed to highlight the impact of specific planning assumptions on future resource selections along with the associated impact on system costs and stochastic risks. These sensitivities were developed for informational purposes and serve to illustrate how the system behaves under a variety of conditions which helps inform the acquisition path analysis presented in Volume 1, Chapter 9 (Action Plan). All sensitivities, as summarized in Table 7.16, were run as a variant of case P-45CNW. Additional details on the sensitivity cases can be found in Volume II, Appendix M: Case Study Fact Sheets.

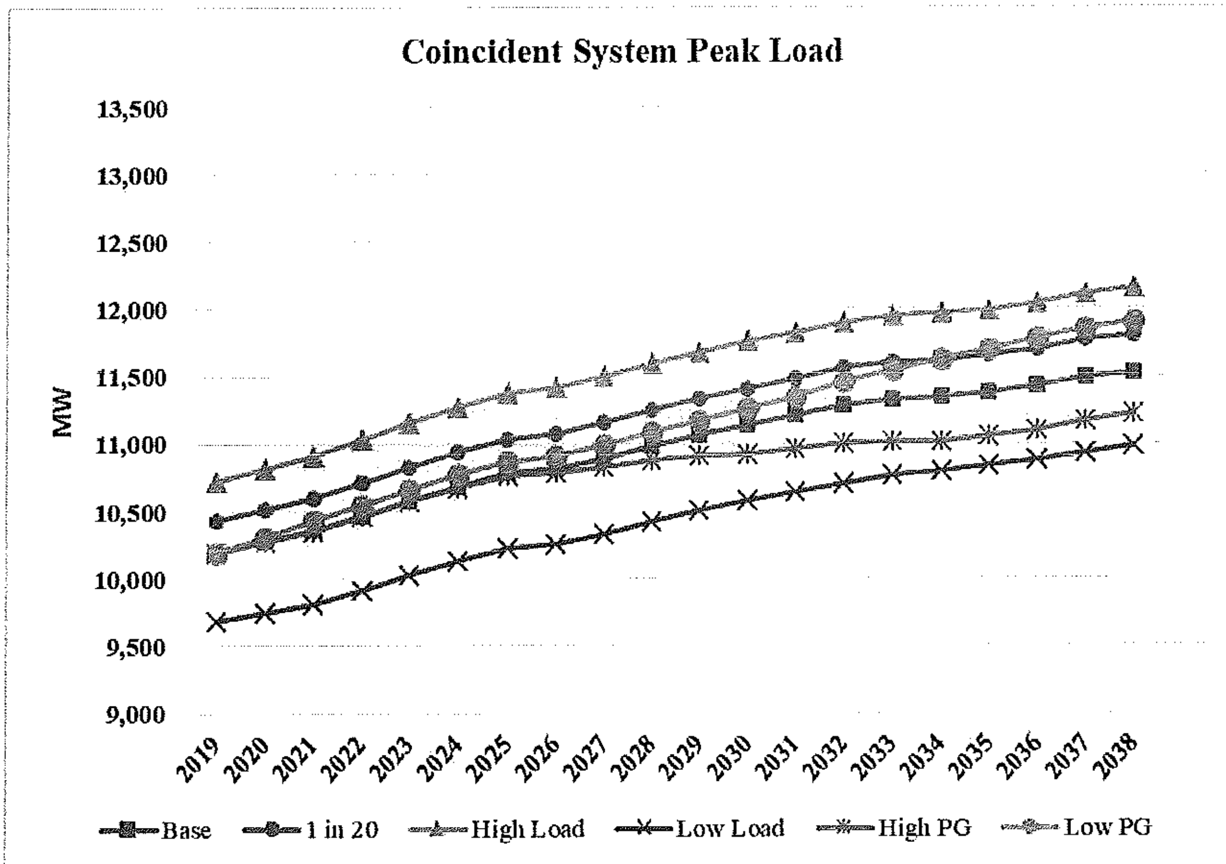
**Table 7.16 – Sensitivity Case Definitions**

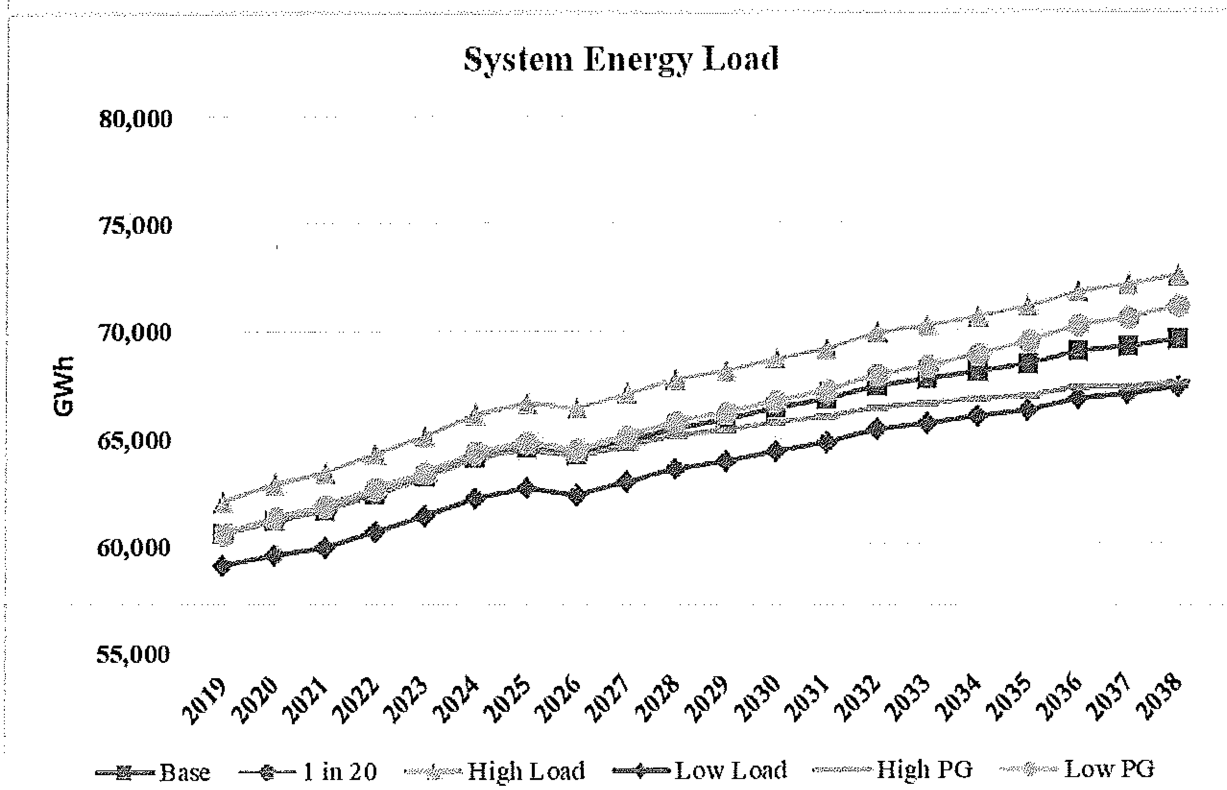
| Case | Description | Load Forecast | Private Generation | Resources | Customer Preference | SO Model CO2 Price |
|---|---|---|---|---|---|---|
| S-01 | Low Load | Low | Base | Optimized | Base | Base |
| S-02 | High Load | High | Base | Optimized | Base | Base |
| S-03 | 1 in 20 Load Growth | 1 in 20 | Base | Optimized | Base | Base |
| S-04 | Low Private Generation | Base | Low | Optimized | Base | Base |
| S-05 | High Private Generation | Base | High | Optimized | Base | Base |
| S-06 | Business Plan | Base | Base | Align first three years | Base | Base |
| S-07 | No Customer Preference | Base | Base | Optimized | No targeted renewables | Base |
| S-08 | High Customer Preference | Base | Base | Optimized | High | Base |

**Load Sensitivities**
PacifiCorp includes three different load forecast sensitivities. The low load forecast sensitivity (S-01) reflects pessimistic economic growth assumptions from IHS Global Insight and low Utah and Wyoming industrial loads. The high load forecast sensitivity (S-02) reflects optimistic economic growth assumptions from IHS Global Insight and high Utah and Wyoming industrial loads. The low and high industrial load forecasts focus on increased uncertainty in industrial loads further out in time. To capture this uncertainty, PacifiCorp modeled 1,000 possible annual loads for each year based on the standard error of the medium scenario regression equation. The low and high industrial load forecast is taken from $5^{th}$ and $95^{th}$ percentile.

The third load forecast sensitivity (S-03) is a 1-in-20 (5 percent probability) extreme weather scenario. The 1-in-20 peak weather scenario is defined as the year for which the peak has the chance of occurring once in 20 years. This sensitivity is based on 1-in-20 peak weather for July in each state. Figure 7.19 compares the low, high, and 1-in-20 load sensitivities, net of base case private generation levels, alongside the base case load forecast.

**Figure 7.19 - Load and Private Generation Sensitivity Assumptions**

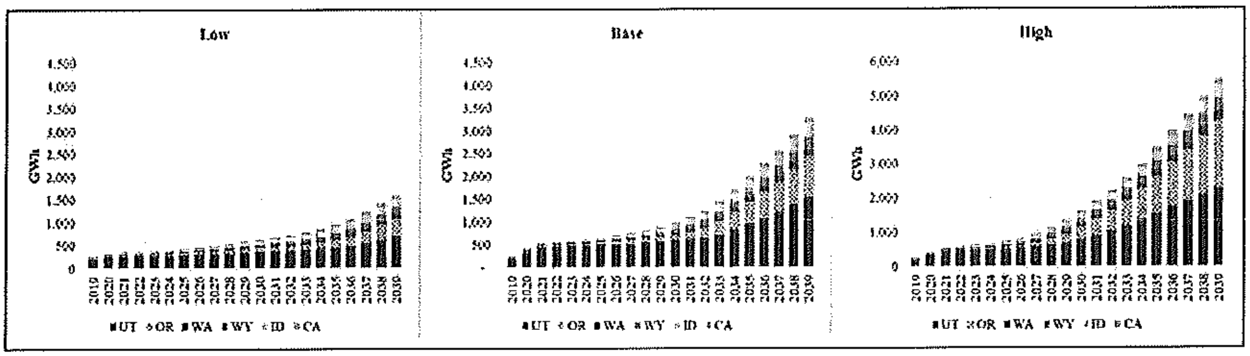


## Private Generation Sensitivities

Two private generation sensitivities are analyzed. As compared to base private generation penetration levels that incorporated annual reductions in technology costs, the low private generation sensitivity (S-04) reflects lesser reductions in technology costs, reduced technology performance levels, and lower retail electricity rates. In contrast, the high private generation sensitivity (S-05) reflects more aggressive technology cost reduction assumptions, greater technology performance levels, and higher retail electricity rates. Figure 7.20 summarizes private generation penetration levels for the low and high sensitivities alongside the base case.

**Figure 7.20 - Private Generation Sensitivity Assumptions**



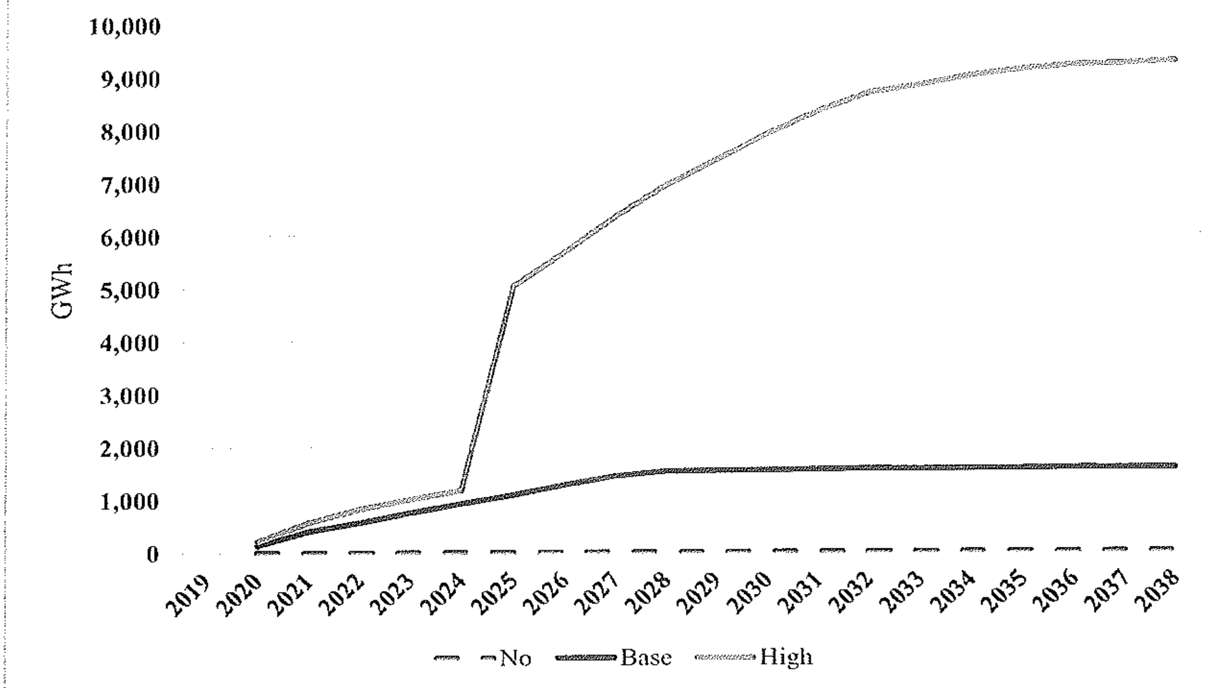

## Business Plan Sensitivity

Case S-06 complies with the Utah requirement to perform a business plan sensitivity consistent with the commission's order in Docket No. 15-035-04. Over the first three years, resources align with those assumed in PacifiCorp's December 2018 Business Plan. Beyond the first three years of the study period, unit retirement assumptions are aligned with those identified in the preferred portfolio. All other resource selections are optimized within the SO model simulation.

## Customer Preference Sensitivities

PacifiCorp includes two customer preference sensitivities. The first sensitivity is a no customer preference sensitivity (S-07) that assumes there are no customer preference resource requirements. The second sensitivity (S-08) is a high customer preference sensitivity that assumes proliferation of customer preference resources at higher levels than anticipated with close to 9,300 GWh of customer preference resources being added by the end of the twenty-year planning period. Figure 7.21 illustrates the relative customer preference generation requirements for these sensitivities.

**Figure 7.21 – Generation Requirements for Customer Preference Sensitivities**




**East/West Split**

Pursuant to a requirement by the Washington Utilities and Transportation Commission, PacifiCorp's IRP is to include a sensitivity that produces standalone resource portfolios for the west control area (WCA) compared to operation as part of PacifiCorp's integrated system. PacifiCorp will incorporate this sensitivity as part of its 2019 IRP Update pursuant to the Washington Utilities and Transportation Commission's July 26, 2019 order approving PacifiCorp's request for a waiver to WAC 480-100-238(4) in Docket UE-180259.

Ex. AA-S-5

# CHAPTER 8 – MODELING AND PORTFOLIO SELECTION RESULTS

## CHAPTER HIGHLIGHTS

- Using a range of cost and risk metrics to evaluate a wide range of resource portfolios, PacifiCorp selected a preferred portfolio reflecting a bold vision shared with our customers for a future where energy is delivered affordably, reliably and without greenhouse gas emissions.
- The 2019 Integrated Resource Plan (IRP) preferred portfolio includes accelerated coal retirements and investment in transmission infrastructure that will facilitate adding over 6,400 megawatt (MW) of new renewable resources by the end of 2023, with nearly 11,000 MW of new renewable resources over the 20-year planning period through 2038.[1]
- Near-term, by the end of 2023, the preferred portfolio includes nearly 3,000 MW of new solar resources, more than 3,500 MW of new wind resources, 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.[2]
- 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 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.
- Energy efficiency continues to play a key role in PacifiCorp's resource mix. In addition to continued investment in energy efficiency programs, the preferred portfolio continues to show a role for direct load control programs with total new capacity reaching 444 MW by the end of the planning period.
- 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. 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.
- 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 and 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 into the future.
- The preferred portfolio shows an overall decline in reliance on wholesale market firm purchases in the 2019 IRP preferred portfolio relative to the market purchases included in

[1] 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.
[2] *Id.*

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.

- 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. As compared to the 2017 IRP, projected carbon dioxide ($CO_2$) emissions in 2025, 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.

## Introduction

This chapter reports modeling and performance evaluation results for the resource portfolios developed with a broad range of input assumptions using the System Optimizer (SO) model and the Planning and Risk model (PaR). Using model data from the portfolio-development process and subsequent cost and risk analysis of unique portfolio alternatives, PacifiCorp steps through its preferred portfolio selection process and presents the 2019 IRP preferred portfolio.

The chapter is organized around the three modeling and evaluation steps identified in the previous chapter: (1) coal studies; (2) portfolio development; and (3) preferred portfolio selection. The final preferred portfolio selection is informed by all relevant case results and incorporates any refinements indicated by preceding results, recent relevant events and stakeholder feedback. This chapter also presents modeling results for additional 2019 IRP sensitivity cases that, while informative, were not considered for selection as the preferred portfolio.

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

## Coal Studies

The 2019 IRP included a thorough and robust economic analysis of PacifiCorp's coal units. The coal study analysis conducted in the 2019 IRP was initially prompted by the Public Utility Commission of Oregon (OPUC) as set forth in its 2017 IRP acknowledgement order, which administratively established certain modeling requirements. PacifiCorp met these requirements and then developed a more complete coal study. The coal study effort is comprised of the following three key phases:

- Phase One - Unit-by-unit coal studies.
- Phase Two - Stacked coal studies.
- Phase Three - Reliability coal studies.

The three phases of the coal studies are detailed in Volume II, Appendix R (Coal Studies).

## Coal Studies Conclusions

Each of the coal study phases show that early retirement of certain coal units has potential to reduce overall system costs. In particular, the coal studies showed that the greatest customer benefits were most likely to be realized with potential early retirement of coal units at the Naughton and Jim Bridger coal plants located in Wyoming.

The portfolio-development process considers other planning factors not fully evaluated in the coal studies (i.e., Regional Haze compliance, alternative retirement dates for jointly owned coal plants where PacifiCorp is a minority owner and not an operator, alternative timing of potential retirements when accounting for incremental capacity to maintain reliability). Consistent with the findings from the coal study, more than half of the cases developed in the initial phase of the portfolio-development process evaluated varying combinations of retirement dates for Naughton and Jim Bridger units.

## Portfolio Development

The following discussion begins with an examination of *initial portfolios* exploring variations in retirement timing for the Jim Bridger 1 & 2 and Naughton 1 & 2 units. The initial portfolios also explore potentially significant interactions with additional retirement options including possible Naughton 3 gas conversion, Gadsby gas unit retirements, and the timing of Cholla retirement.

Following the initial portfolios, PacifiCorp refines top-performing cases with two stages of additional reliability requirements, referred to as the C-series of cases and the CP-series of cases.

In the C-series of cases, top-performing portfolios are examined with a more granular assessment of reliability requirements through the production of hourly deterministic Planning and Risk Model (PaR) studies covering 2023 through 2030, plus 2038. This provides a total of nine years of hourly PaR reliability assessment rather than the three years (2023, 2030, and 2038) used to develop the initial portfolios. 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, which lowers the present-value revenue requirement (PVRR) in all cases.

Top-performing portfolios from the C-series of cases were further examined in the CP-series of cases with additional deterministic PaR studies covering 2023 through 2038. This provides a total of 16 years of hourly PaR reliability assessment, and fleshes out any granular variances in the back-end of the study period.

As discussed in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), PacifiCorp produced a variant of the top-performing CP-series case to eliminate Wyoming wind resources that were added in the 2028-2029 timeframe. This case, along with other cases from the CP-series, were further analyzed to quantify market reliance risk in a series of front office transaction (FOT) cases. Final selection cases were also developed to evaluate the impact of removing all new natural gas resource from the top-performing portfolio and to assess the impact of adding additional Energy Gateway transmission segments to the top-performing portfolio.