BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1729

In the Matter of PACIFICORP, dba PACIFIC POWER, Application to Update Schedule 37 Qualifying Facility Information	COMMENTS OF THE COMMUNITY RENEWABLE ENERGY ASSOCIATION, THE OREGON SOLAR + STORAGE INDUSTRIES ASSOCIATION, AND THE RENEWABLE ENERGY COALITION

I. INTRODUCTION

The Community Renewable Energy Association ("CREA"), the Oregon Solar + Storage Industries Association ("OSSIA"), and the Renewable Energy Coalition ("Coalition") (collectively, the "Joint QF Parties") file these comments regarding PacifiCorp's (or the "Company") application to update its Schedule 37 qualifying facility ("QF") information subsequent to acknowledgement of the Company's 2021 Integrated Resource Plan ("IRP"). There are a number of major issues presented in PacifiCorp's avoided cost update that require serious scrutiny from the Commission.

As explained in detail herein, the Joint QF Parties request that the Oregon Public Utility Commission ("OPUC" or "Commission") take the following actions:

- Renewable Solar Rates: Correct the Negative Capacity Rates and On-Peak Prices that are lower than Off-Peak Prices for Renewable Solar QFs by requiring the following adjustments:

- Require PacifiCorp to use a capacity allocation method that does not result in a negative capacity value for solar QFs, as Portland General Electric Company ("PGE") does;
- Impose a market price floor on the solar renewable on-peak rates to ensure that the negative capacity price PacifiCorp calculates does not deprive renewable solar QFs of at least the energy value they supply; and/or
- Require PacifiCorp to allocate some portion of capacity value to Off-Peak hours instead of allocating all capacity value to On-Peak hours;

- <u>Solar-plus-Storage:</u> Require PacifiCorp to offer a solar-plus-storage standard rate to enable small solar QFs to deliver and sell in the hours PacifiCorp appears to assert to be the hours of highest need and value;
- <u>Capacity Contribution Values:</u> Require PacifiCorp to recalculate its capacity contribution values based on PacifiCorp's existing portfolio of committed resources, *not* its Preferred Portfolio in 2030 with almost 1,900 megawatts ("MW") of hypothetical and uncommitted solar resources;
- <u>Non-Renewable Deficiency Rates</u>: For the non-renewable deficiency period rates, reject PacifiCorp's proposal to reduce its combined cycle combustion turbine ("CCCT") proxy's capital costs by 25 percent, and instead require PacifiCorp to use the same costs as the gas-fired proxy

resource that were approved from the 2019 IRP, which would restore PacifiCorp's non-renewable rates to a more reasonable level.

II. COMMENTS

A. Regulatory Background and Legal Standards

Congress enacted the Public Utility Regulatory Policies Act of 1978 ("PURPA") to address the energy crises of the 1970s, and Section 210 of PURPA remains the only federal law that directly mandates the purchase of renewable and cogenerated electric energy by monopoly electric utilities. In enacting PURPA, Congress found traditional electric utilities, as lone buyers of electric energy in a market with many potential producers, "were reluctant to purchase power from . . . nontraditional facilities."[1] Thus, to overcome this reluctance, PURPA directed the Federal Energy Regulatory Commission ("FERC") to promulgate regulations "to *encourage* cogeneration and small power production" including regulations that "require electric utilities to offer to . . . purchase electric energy from such facilities[,]" which are known as "qualifying facilities" or "QFs."[2] In effect, PURPA is the nation's bare minimum renewable energy standard.

PURPA still has significant importance in Oregon. Under the Oregon's Renewable Portfolio Standard ("RPS"), regulated electric utilities generally procure large-scale renewable energy facilities of at least 100 MW in capacity, but Oregon's RPS law also declares that small-scale and community-based facilities "are an essential

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[1] *FERC v. Mississippi*, 456 US 742, 750 (1982).
[2] 16 USC § 824a-3(a) (emphasis added).

element of this state's energy future" and requires that the utilities meet a significant portion of their capacity from such facilities.[3] For such small facilities, PURPA is as important today as it was in 1978. Additionally, QFs are an important element of Oregon's efforts to achieve zero carbon emissions through the recently enacted House Bill 2021.

At issue here is FERC's requirement that utilities pay QFs a price set at the utility's "full avoided cost."[4] Avoided costs are "the incremental cost to an electric utility of electric energy or energy and capacity that the utility would generate itself or purchase from another source but for the purchase from a qualifying facility."[5] Consistent with federal law, Oregon law mandates that the "price for such purchase shall not be less than the utility's avoided cost."[6] Oregon law also requires the Commission to follow state policies, which are to increase the marketability of QFs and to create a settled and uniform institutional climate for Oregon QFs.[7]

The Commission requires utilities to offer all QFs an avoided cost rate that is calculated based on the costs of the next major resource (in excess of 100 MW) planned in the utility's acknowledged IRP.[8] During periods of resource sufficiency prior to the planned acquisition of the major resource, the utility pays the QF the forecasted prices for

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3 ORS 469A.210(1).

4 *Am. Paper Inst., Inc. v. Am. Elec. Power Serv. Corp.*, 461 US 402, 406, 413-17 (1983); *see also* 18 CFR §§ 292.101(b)(6), 292.304(b).

5 ORS 758.505(1).

6 ORS 758.525(2).

7 ORS 758.515.

8 *In re Investigation Relating to Elec. Util. Purchases from QFs*, Docket No. UM 1129, Order No. 05-584 at 26-29 (May 13, 2005).

short-term market electricity sales.[9] Additionally, for QFs that are qualified as RPS-eligible facilities under Oregon law, the Commission requires the additional option for such QFs to sell both their electrical output and their renewable energy credits ("RECs") to PGE or PacifiCorp in exchange for renewable avoided cost rates calculated based on the costs of the next major renewable resource the utility will acquire.[10] Indeed, the Commission's administrative rules expressly provide: "Each public utility that is currently complying with Oregon's renewable portfolio standard *must offer* renewable and non-renewable avoided cost rates to eligible qualifying facilities."[11]

The starting place for the review of avoided cost rates is the purchasing utility's acknowledged IRP. The utility's avoided cost rates should include "inputs and assumptions taken from IRPs that are subject to stakeholder review."[12] The Commission therefore approves a major avoided cost update after acknowledgement of each utility's IRP, which typically occurs every two years.[13]

However, the IRP is not itself a litigated proceeding where the Commission resolves disputes over the critical inputs to the avoided costs. Thus, where, as here, the utility's filing relies on changes made in a recently acknowledged IRP or IRP Update,

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9 *Id.*

10 *In re Pub. Util. Comm'n of Or., Investigation Into Resource Sufficiency Pursuant to Order No. 06-538*, Docket No. UM 1396, Order No. 11-505, at 1-2, 4-5 (Dec. 13, 2011).

11 OAR 860-029-0040(6) (emphasis added).

12 *In re Commission Investigation Into QF Contracting and Pricing*, Docket No. UM 1610, Order No. 14-058 at 12 (Feb. 24, 2014).

13 *Id.* at 23-25.

Staff and QFs may challenge the utility's proposed calculation of its avoided cost rates.[14] This right to challenge the utility's proposed rates makes good sense–otherwise, the utility would unilaterally set the rates it must pay its competitor QFs.

In any rate filing, the utility has the burden of proof to demonstrate that the factual inputs and assumptions for its avoided cost rates are just and reasonable. The utility is charged with the statutory responsibility to "prepare, publish and file" its avoided cost prices, which "shall be reviewed and approved by the commission."[15] The Commission's administrative rules specifically state that the utility "has the burden of supporting and justifying" the underlying avoided cost data.[16] Placing the burden of proof on the party that developed the information is consistent with administrative legal principles, which almost universally place the burden of proof on the movant or proponent.[17] Likewise, the Commission's rules specifically state that "[s]tandard rates for purchases shall be implemented . . . [i]n the same manner as rates are published for electricity sales . . . ."[18] Therefore, the Commission's rules require modification to the utility's proposed avoided cost rates when necessary to ensure their reasonableness.

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14 Docket No. UM 1129, Order No. 05-584 at 36-37; Docket No. UM 1129, Order No. 06-538 at 44 (Sept. 20, 2006).

15 ORS 758.525(1).

16 OAR 860-029-0080(6).

17 ORS 757.210; 5 USC § 556(d); 16 USC § 824d(e).

18 OAR 860-029-0040(4); *see also* OAR 860-029-0080(6) (stating proposed avoided cost rates "shall be subject to suspension and modification by the Commission."); Docket No. UM 1129, Order No. 05-584 at 36-37 (stating same rule).

B. <u>Renewable Solar Rates</u>: The Commission Should Reject PacifiCorp's Negative Capacity Price and Order Correction of the Rate Calculation that Provides Unjustifiably Low On-Peak Prices for Solar QFs.

The Commission should correct the unjustifiably low renewable avoided cost rates PacifiCorp proposes to offer to solar QFs. The renewable wind proxy costs are increasing in PacifiCorp's rate filing, due to the wind proxy in the 2021 IRP being changed from a Wyoming plant to an Oregon plant with a lower capacity factor. However, despite the increase in cost of the avoided resource, PacifiCorp's proposed rates largely negate the value of the increased avoided cost for renewable solar QFs through an unreasonable on-peak/off-peak cost allocation.

For the first time for any Oregon utility, PacifiCorp's proposed avoided cost rates are drastically lower for on-peak hours than for off-peak hours across most of the deficiency period for solar QFs. Because solar QFs produce over 80 percent of their generation during on-peak hours when the sun shining, this aspect of PacifiCorp's avoided cost proposal severely harms solar development and deserves serious Commission scrutiny.[19]

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[19] PacifiCorp explains that in its filing: "LLH includes eight hours every night (10:00pm-6:00am), plus all hours on Sundays and holidays. HLH includes sixteen hours every day (6:00am-10:00pm), but only on Monday through Saturday when it is not a holiday." *See* Attachment A, PacifiCorp's Response to CREA Data Request No. 2.7. According to PacifiCorp's workpapers cited in the data request, 82.2% of a tracking solar QFs' generation is expected to occur during on-peak hours, and 84.1% of a fixed solar QF's generation is expected to occur during on-peak hours. *See* PacifiCorp's non-confidential workpapers, "1_OR Standard QF AC Study_2022 04 20" excel spreadsheet, "Profile" tab, cells C10 through M10.

To illustrate, the following tables show PacifiCorp's proposed renewable deficiency on-peak/off-peak solar rates:[20]

	Fixed Solar	
Year	On-Peak	Off-Peak
2026	$28.02	$43.59
2027	$27.24	$43.81
2028	$27.89	$45.11
2029	$28.82	$46.23
2030	$28.83	$47.24
2031	$28.63	$47.43
2032	$29.29	$48.58
2033	$29.05	$49.97
2034	$29.41	$51.30
2035	$29.56	$53.00
2036	$30.05	$54.35
2037	$30.58	$55.53
2038	$30.83	$57.28
2039	$31.35	$58.63
2040	$32.19	$59.22
2041	$32.25	$61.31
2042	$33.34	$62.22

	Tracking Solar	
Year	On-Peak	Off-Peak
2026	$31.40	$43.59
2027	$30.69	$43.81
2028	$31.42	$45.11
2029	$32.42	$46.23
2030	$32.51	$47.24
2031	$32.39	$47.43
2032	$33.13	$48.58
2033	$32.97	$49.97
2034	$33.42	$51.30
2035	$33.65	$53.00
2036	$34.23	$54.35

[20] PacifiCorp's non-confidential workpapers, "1_OR Standard QF AC Study_2022 04 20" excel spreadsheet, Exhibits 7 & 8 tabs.

2037	$34.85	$55.53
2038	$35.19	$57.28
2039	$35.81	$58.63
2040	$36.74	$59.22
2041	$36.91	$61.31
2042	$38.09	$62.22

The primary driver of this significant discount for on-peak prices is PacifiCorp's proposal to use a negative price for the capacity value of the renewable solar QFs and to allocate all such negative capacity dollars to the on-peak hours. The negative capacity price added (or deducted) from the on-peak renewable solar prices ranges from $15.84/MWh to $22.29/MWh for fixed solar and $12.46/MWh to $17.53/MWh for tracking solar.[21] This is explained by PacifiCorp in its response to CREA Data Request No. 2.7 as follows:

> Second, the approved methodology includes an adjustment for avoided firm capacity costs based on the difference in the capacity contribution of each qualifying facility (QF) relative to the renewable proxy resource. The fixed-tilt solar resource has a lower capacity contribution (11 percent) than the proxy renewable wind resource (41 percent), as shown in tab "Table 14". As a result, the capacity adjustment for the fixed-tilt solar resource is a negative value. Under the approved methodology, the capacity adder is allocated to on-peak hours, which traditionally had the greatest capacity need. This results in a reduction to on-peak pricing, and on-peak prices that are significantly lower than off-peak prices for solar resources.[22]

However, the Commission's Order No. 14-058 approving the capacity contribution calculation method is not to be blindly adhered to even when it leads to

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21 PacifiCorp's non-confidential workpapers, "1_OR Standard QF AC Study_2022 04 20" excel spreadsheet, Exhibits 7 & 8 tabs.

22 *See* Attachment A, PacifiCorp's Response to CREA Data Request 2.7.

unreasonable and unintended results, and it certainly never intended a significant *negative* capacity price for on-peak renewable solar rates. When it approved the method, the Commission specifically "direct[ed] the parties to address issues regarding calculation methodology in future utility IRPs."[23] Notably, the Commission's orders demonstrate no intent to create a *negative* capacity value, much less on-peak prices that would be lower than the off-peak prices.[24] The method was intended to "adjust[] the capacity component implicit in the renewable on-peak price by the incremental capacity contribution of the specific QF resource type relative to the avoided renewable resource."[25] The order noted that, under the renewable wind prices, the "on-peak price includes an implicit, small capacity contribution."[26] At the time it was adopted, the adjustment was essentially an encouragement through a capacity price *adder* for renewable baseload and solar QFs, which were understood to provide substantially superior capacity value compared to the avoided renewable wind proxy.

This adjustment was intended to counterbalance the utilities' complaints–at the time–that wind QFs provided insufficient capacity value and should receive lower non-renewable/standard pricing. Indeed, Order No. 14-058 stated: "For solar and baseload QFs, the price adjustment would result in a higher capacity component (and therefore a higher on-peak price) than in the current method."[27] Thus, the adjustment was clearly

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23 Docket No. UM 1610, Order No. 14-058 at 15 (requiring adjustments for capacity contribution in rate calculations).

24 *Id.*

25 *Id.*

26 *Id.* at 8; *see also* Docket No. UM 1610, Staff/100, Bless/22-28 (describing Staff's proposal, which the Commission ultimately adopted).

27 Docket No. UM 1610, Order No. 14-058 at 15.

never intended to take the "implicit, small capacity contribution" contained in the renewable wind proxy costs and convert it into a negative capacity price that results in unreasonably low on-peak solar prices below even the value of the solar energy alone. PacifiCorp's rate calculation flips this regime on its head.

Notably, Oregon's other utility that offers renewable rates, PGE, does not have a negative capacity price for renewable solar QFs or renewable on-peak solar prices that are lower than the off-peak prices, even though PGE also uses a lower contribution to peak capacity value for solar QFs relative to the wind proxy.[28] Thus, PacifiCorp is apparently using a significantly different rate calculation method than PGE, and PacifiCorp's method now leads to an unexpected and unreasonable result. The Commission should require changes to PacifiCorp's renewable capacity pricing allocation method to state the capacity value as an adder, not as a negative value that reduces the energy payments and results in unreasonably low on-peak renewable solar prices.

The end result of PacifiCorp's methodology is to deprive solar QFs of payment even for the energy value of they deliver because PacifiCorp's proposed on-peak renewable solar rates are even lower than PacifiCorp's forecasted Mid-C prices, as set forth below:

[28] *See generally In re PGE's Application to Update Schedule 201 Qualifying Facility Information*, Docket No. UM 1728, Application, Attachment A at 16, Attachment B at 3-4, 14-16 (.

Year	Renewable Fixed[29] Solar On-Peak Price	Annual Price Mid C HLH[30]
2026	$28.02	$39.99
2027	$27.24	$38.80
2028	$27.89	$39.98
2029	$28.82	$40.37
2030	$28.83	$39.14
2031	$28.63	$41.03
2032	$29.29	$41.41
2033	$29.05	$40.04
2034	$29.41	$41.29
2035	$29.56	$41.15
2036	$30.05	$39.51
2037	$30.58	$40.11
2038	$30.83	$41.67
2039	$31.35	$38.96
2040	$32.19	$35.23
2041	$32.25	$33.85
2042	$33.34	$33.12

Thus, at a minimum, the Commission should order that the forward market prices for on-peak hours are the floor for PacifiCorp's on-peak solar renewable prices to ensure the unexpected results of PacifiCorp's capacity valuation calculation do not deprive renewable solar QFs of at least the energy value they supply to PacifiCorp.

Additionally, aside from PacifiCorp's unique capacity valuation method, the Commission should consider altering the previous allocation of all capacity pricing to on-peak renewable prices. Allocating all of a negative capacity price to the on-peak hours suppresses the on-peak hours so that on-peak hours are lower than off-peak hours. That

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29 PacifiCorp's non-confidential work papers, "1_OR Standard QF AC Study_2022 04 20" excel spreadsheet, Exhibit 7 tab.

30 PacifiCorp's non-confidential work papers, "1_OR Standard QF AC Study_2022 04 20" excel spreadsheet, "OFPC Source" tab, column Q.

aspect of the method was not forever set in stone by Order No. 14-058. Instead, the allocation of the renewable capacity pricing to on-peak hours was premised on the assumption that all capacity value accrued to the on-peak hours. As PacifiCorp explained in discovery, "the capacity adder is allocated to on-peak hours, which traditionally had the greatest capacity need."[31] Since that time, however, the Commission has adopted new capacity calculation requirements that requires the utilities to evaluate capacity value of "all hours in a year."[32] In PacifiCorp's capacity contribution study in its 2021 IRP, PacifiCorp itself states that "planning for coincident peak loads is no longer sufficient to determine the necessary amount and timing of new resources[,]" and "a resource's capacity value (or contribution to ensuring reliable system operation) is also dependent on both its characteristics and the composition of the overall portfolio."[33] Accordingly, capacity value has potential relevance to all hours of the year, not just the on-peak hours.

Additionally, PacifiCorp asserts that the off-peak hours are at least as valuable as the on-peak hours in many years. In PacifiCorp's response to CREA Data Request 2.7, the other reason PacifiCorp provides for the lower on-peak solar prices than the off-peak prices is as follows:

> First, PacifiCorp's March 31, 2022 official forward price curve (OFPC) has higher off-peak (light load hour (LLH)) prices than on-peak (heavy load hour (HLH)) prices, starting in 2027, as shown on tab "OFPC Source". This is as a result of increasing penetration of solar resources in the resource mix across the west, which suppresses prices during daylight

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31 Attachment A, PacifiCorp's Response to CREA Data Request 2.7.

32 *In re Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity*, Docket No. UM 1719, Order No. 16-326, 5-6 (Aug. 26, 2016).

33 *See* Attachment B, PacifiCorp's 2021 IRP, Vol. II, App. K at 217.

> hours, which are more prevalent in on-peak. As shown in tab "Table 13", the renewable resource avoided cost is shaped to on-peak and off-peak values that reflect the ratio from the OFPC. This is the starting point for renewable pricing for all resource types.[34]

Given that PacifiCorp now apparently considers the off-peak hours of equal or higher value than on-peak hours, it no longer makes sense to allocate all of the capacity credit to the on-peak hours. The Commission should therefore order some reallocation of the capacity pricing to the off-peak hours in PacifiCorp's renewable rates.

In sum, PacifiCorp's renewable solar capacity calculation is broken and is resulting in upside down allocation between on-peak and off-peak prices with on-peak deficiency period renewable prices lower than even the market prices. The Commission should take some or all of the steps outlined above to prevent this unintended and unreasonable outcome.

C. <u>Solar-plus-Storage</u>: The Commission Should Require PacifiCorp to Offer a Solar-plus-Storage Standard Rate to Enable QFs to Deliver in Off-Peak Hours

In light of PacifiCorp's belief that solar QFs will not enable PacifiCorp to meet its capacity needs without storage, the Commission should require PacifiCorp to offer a higher standard rate for solar-plus-storage QFs. CREA in particular is aware of small-scale, community-based organizations and developers interested in pursuing solar-plus-storage projects, but the lack of a standard rate offering and the unreasonably low stand-alone-solar rates make such development unlikely to be successful without proactive action by the Commission.

34 Attachment A, PacifiCorp's Response to CREA Data Request 2.7.

The Commission's rules provide that the utility's "standard rate may differentiate among qualifying facilities using various technologies on the basis of supply characteristics of the different technologies."[35] Thus, it is appropriate to offer higher standard rates to new QF types that can supply higher capacity value.

At the time the Commission created capacity differentiation for resource types in Order No. 14-058, the only three resource types used were baseload, wind, and solar. However, in subsequent years, PacifiCorp added a new rate class for tracking solar, as opposed to just fixed solar, due to the ability to model the enhanced capacity value tracking solar offers and to encourage development of tracking solar. Now, in PacifiCorp's 2021 IRP, PacifiCorp has calculated the capacity contribution of Lakeview, Oregon-sited solar-plus-4-hour-storage to be 82 percent in summer and 93 percent in winter.[36] That is substantially higher than the corresponding measure for Lakeview, Oregon-sited solar without storage of just 13 percent in the summer and 18 percent in the winter, which is apparently used with some adjustment in the tracking solar and fixed solar QF avoided cost rates.[37]

PacifiCorp suggested in the workshop that a solar-plus-storage QF would need to be subject to certain dispatch or delivery conditions in its contract to be entitled to the higher capacity rate. Perhaps additional contractual commitments would be warranted for entitlement to a solar-plus-storage rate. But adoption and implementation of a contract addendum to address the delivery requirements of such a solar-plus-storage QF

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35 OAR 860-029-0040(4)(c).

36 Attachment B, PacifiCorp's 2021 IRP, Vol. II, App. K, Table K.2 at 221.

37 Attachment B, PacifiCorp's 2021 IRP, Vol. II, App. K, Table K.1 at 220.

could be implemented if there was a will to do so. The Commission is currently engaged in a contracting terms rulemaking, AR 631, and has recently approved a number of form contracts in utility request for proposals that contain specific provisions for dispatch of solar-plus-storage facilities. Thus, the Commission could approve rates at this time and make such rates available at such time as the Commission approves an addendum to PacifiCorp's standard contract to implement such rates. The Joint QF Parties stand ready to cooperate in good faith in development of any necessary contractual addendum.

In sum, the technology to develop small-scale, standard-rate-sized solar-plus-storage QFs exists today, and the impediment to development of such resources is the lack of a standard rate offering for such resources. Without a standard rate, small-scale solar-plus-storage will be deterred by the difficulty of attempting to negotiate a non-standard rate with PacifiCorp. Thus, given that PacifiCorp's IRP now supplies the necessary calculations to easily calculate a standard rate, the Commission should require PacifiCorp to offer such QFs a standard rate.

D. <u>Capacity Contribution Values</u>: The Commission Should Require PacifiCorp to Use Capacity Contribution Values Based on Its Existing Resource Portfolio, Not the Preferred Portfolio PacifiCorp Speculates Might Exist in 2030.

PacifiCorp's negative capacity credit for renewable solar QFs appears to be exacerbated by PacifiCorp's flawed capacity contribution calculation for Oregon solar resources. There are a number of flaws with the capacity contribution calculation used by PacifiCorp in its 2021 IRP and the proposed avoided cost rates.

The Commission requires the utilities to use either the effective load carrying capability ("ELCC") or the capacity factor ("CF") method to calculate contribution to peak capacity, but in doing so the Commission noted that the CF method becomes less accurate as renewable penetration increases.[38] Thus, the Commission directed that "as the utilities' renewable penetration level increases in the future (e.g., 20 - 25 percent of system mix), we will require the utilities to perform a one-time benchmark of the CF approximation method against an ELCC calculation."[39] Additionally, because contribution to peak capacity generally declines as incremental renewable resources, such as solar, are added to the existing portfolio, the utility should not assume the existence of uncommitted and unconstructed resources in the calculation of contribution to peak capacity values used for avoided cost rates. Otherwise, the QF would have no ability to allow the utility to avoid the costs and be compensated for the value of such uncommitted resources as PURPA requires.

The capacity contribution calculation in PacifiCorp's 2021 IRP appears to violate those two requirements. First, PacifiCorp's IRP relies solely on the CF method and does not describe or explain any ELCC benchmarking that was conducted even though PacifiCorp's existing renewable penetration level–including 3,811 MW of Company owned or contracted wind and 2,340 MW of contracted solar–would justify such ELCC benchmarking under existing Commission policy.[40] Second, PacifiCorp's IRP states that its CF calculations provide a "marginal capacity contribution values . . . applicable to small incremental or decremental changes *relative to the composition of the IRP*

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38 Docket No. UM 1719, Order No. 16-326 at 6.

39 *Id.*

40 *See* Attachment B, PacifiCorp's 2021 IRP, Vol. II, App. K; *see also* Attachment C, PacifiCorp's 2021 IRP, Vol. I at 138-142.

preferred portfolio in 2030 . . . ."[41] PacifiCorp's IRP acknowledges that "wind, solar, and energy storage have declining marginal capacity contribution values as the quantity of a given resource type increases."[42] Further, its IRP elsewhere explains that the 2030 preferred portfolio will include 1,902 MW of incremental solar not online at this time.[43] The incremental addition of 1,902 MW of solar is certain to drive down the CF value and is almost certainly responsible in significant part for the low capacity contribution values for solar resources in PacifiCorp's proposed avoided cost rates.

No information appears to be provided regarding the CF or ELCC values of solar, wind, or storage based on PacifiCorp's existing portfolio. Therefore, the Commission should order PacifiCorp to recalculate its capacity contribution values based on the portfolio as it exists today, not based on the preferred portfolio that it speculates will exist in 2030 with an additional 1,902 MW of solar. Otherwise, QFs are unable to meet PacifiCorp's capacity needs and will not be compensated for capacity value they would supply and allow PacifiCorp to avoid.

Finally, at a higher level, the Commission should also question how solar resources could suddenly be providing such lower capacity values. On its face, that aspect of PacifiCorp's IRP is highly suspect. As noted above, the utilities were each complaining not long ago that wind has a poor capacity value, but now that solar has become the predominant renewable QF type, both PacifiCorp and PGE have in recent

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41 Attachment B, PacifiCorp's 2021 IRP, Vol. II, App. K at 219-220 (emphasis added).

42 Attachment B, PacifiCorp's 2021 IRP, Vol. II, App. K at 219-220.

43 Attachment C, PacifiCorp's 2021 IRP, Vol. I at 10.

years begun offering far reduced solar avoided cost rates through drastically diminished capacity values for solar. Notably, due the availability of only the investment tax credit for solar resources, the utilities generally cannot justify owning and rate-basing solar facilities as easily as the utilities can justify owning and rate-basing wind facilities. The utilities are thus incentivized to undervalue the capacity contribution of solar resources, and the Commission should review such calculations with an appropriate level of skepticism. In addition to making the proposed changes to this rate filing, this subject deserves ongoing scrutiny from the Commission in Docket No. UM 2011 and other future avoided cost dockets.

E. <u>Non-Renewable Deficiency Period Rates</u>: The Commission Should Require Revisions to the Non-Renewable/Standard Rate Deficiency Period Gas Plant.

At a time when gas prices are soaring and supply-chain issues are inflating the costs of everything, PacifiCorp proposes that its deficiency period non-renewable avoided cost rates should significantly *decrease*–on the order of \$8.59/MWh to \$14.96/MWh depending on the year.[44] PacifiCorp explains that the primary cause of this decrease is PacifiCorp's proposal that the capital costs of a natural gas power plant proxy should plummet by approximately 25 percent.[45] However, the fact that PacifiCorp's natural gas price forecast is lower than other publicly available forecasts also contributes to this result. The Commission should order revisions to PacifiCorp's rate calculations to ensure the non-renewable deficiency period rates are not unreasonably low.

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44 *See* PacifiCorp's non-confidential work papers, "1_OR Standard QF AC Study_2022 04 20" excel spreadsheet, "Table 7 to 8 Comparison" tab, Table 7.1, column H.

45 Attachment D, PacifiCorp's Response to CREA Data Request No. 2.4.

1. The Commission Should Reject PacifiCorp's Proposed 25-Percent Reduction in the Capital Costs of its Combined Cycle Combustion Turbine Proxy.

Despite escalating costs in today's economy, PacifiCorp's avoided CCCT plant in its proposed rates has capital cost that are approximately 25 percent lower than the capital costs of the CCCT in the prior rate cycle from the 2019 IRP.[46]

In discovery and at the workshop, PacifiCorp explained that the reduced capital costs are primarily driven by the switch from the 2019 IRP rate's use of a "'H' size CT having a total CCCT net capacity of 447 megawatts" to the instant 2021 IRP rate proposal's use of a "'J' size CT having a total CCCT net capacity of 645 MW."[47] PacifiCorp explains that the "capital cost for the 'J' CCCT was spread over 44 percent more generating capacity resulting in a 22 percent lower costs per kilowatt ($/kW)."[48] In other words, PacifiCorp's new rates propose to achieve economy of scale and cost savings of a much larger gas-fired power plant and thus drive the avoided cost rates down.

The Commission should reject PacifiCorp's proposal to use an even larger CCCT in the rates because doing so has no bearing in reality. In the time since the 2019 IRP,

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[46] *Compare* PacifiCorp's non-confidential work papers, "1_OR Standard QF AC Study_2022 04 20" excel spreadsheet, Table 9 tab, column(a) (containing $1,054/kW as capital costs for 645 MW CCCT Dry "J" resource) *to* Docket No. UM 1729, PacifiCorp's Application (June 8, 2020) (containing existing rates with Table 9's CCCT capital costs of $1,429/kW for 447 MW CCCT Dry "G/H" resource); *see also* Attachment E, PacifiCorp's Response to CREA Data Request No. 2.5; *see also* Attachment F, PacifiCorp's Response to CREA Data Request No. 2.6.

[47] Attachment E, PacifiCorp's Response to CREA Data Request No. 2.5.

[48] Attachment E, PacifiCorp's Response to CREA Data Request No. 2.5.

House Bill 2021 has effectively barred construction of any new gas-fired power plants in Oregon. Thus, there is no basis to now propose to base the avoided cost rates on an even larger gas-fired power plant than previously assumed. PacifiCorp is more likely to build a stand-alone storage unit or some non-gas-fired resource than an even larger gas plant, but PacifiCorp has not proposed rates based on a storage unit.

Moreover, PacifiCorp agrees in discovery that the much lower capital costs it proposed from the 2021 IRP for the 645 MW CCCT do not take into account the impacts of recent supply chain issues, and therefore are not even a reasonable update of current costs. PacifiCorp explains that "recent supply chain shortages are not included in the calculation" because the 2021 IRP cost estimates "were prepared in the summer of 2020, prior to the start of supply chain shortages."[49] Thus, in addition to being inconsistent with Oregon law, the cost estimates PacifiCorp proposes are too low because they are not reasonably reflective of today's market conditions.

Although not entirely clear, PacifiCorp also appears to state in discovery that it neglected to include all fixed operation and maintenance costs aside from pipeline costs of the newly proposed CCCT proxy in its proposed rates.[50] According its discovery response, that omission arbitrarily reduces the avoided cost rates by approximately \$3.28/MWh.[51] But PacifiCorp has not proposed to update its filing to correct that error.

In light of all of the problems identified with PacifiCorp's proposed use of the 645 MW CCCT from the 2021 IRP, the Joint QF Parties recommend that the Commission

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49 Attachment F, PacifiCorp's Response to CREA Data Request No. 2.6.
50 Attachment E, PacifiCorp's Response to CREA Data Request No. 2.5.
51 Attachment E, PacifiCorp's Response to CREA Data Request No. 2.5.

require PacifiCorp to use the same capital costs of the CCCT proxy resource that were approved from the 2019 IRP, which would restore PacifiCorp's non-renewable rates to a more reasonable level.

2. PacifiCorp's Natural Gas Price Forecast Is Not Reasonable.

The Commission should also consider further scrutiny of PacifiCorp's unreasonably low natural gas price forecast. As everyone knows, natural gas prices are currently soaring, and one would naturally expect that fact to result in significant avoided cost rate increases. While PacifiCorp's natural gas price forecast does increase in several years compared to the forecast used in its existing rates, it also *decreases* in some years and is overall still quite low, ranging during the deficiency period beginning in 2026 from just $3.80/MMBtu to $6.14/MMBtu by 2040. While the Joint QF Parties are not recommending any changes at this time, it is important for the Commission to take note of PacifiCorp's low gas price forecast.

It is useful to compare the long-term gas forecast PacifiCorp proposes for use in its Oregon rates to the forecast used in the avoided cost rates recently approved for PacifiCorp in Idaho. PacifiCorp explains in discovery that the only other state that currently uses a gas-fired proxy method of avoided costs is Idaho, and that the Idaho Public Utilities Commission's ("IPUC") Staff controls the gas forecast used, which has long been the transparent and publicly available forecast published in the Energy Information Administration's ("EIA") Annual Energy forecast.[52] In contrast, Oregon has allowed the utilities to individually develop their own proprietary long-term gas forecasts.

[52] Attachment G, PacifiCorp's Response to CREA Data Request No. 2.3.

The result, predictably, is that the Oregon utilities have developed much lower gas price forecasts than the independent government agency relied upon in Oregon's neighboring state.

The following table shows the comparison between the EIA's gas price forecast used in PacifiCorp's Idaho rates, approved effective June 1, 2022, and the gas price forecast PacifiCorp proposes to use in Oregon:

Year	EIA (IPUC Approved) (nominal) ($/MMBtu)[53]	PacifiCorp (OPUC Proposed) (nominal) ($/MMBtu)[54]
2026	4.05	3.80
2027	4.32	3.84
2028	4.65	3.94
2029	4.95	4.01
2030	5.18	3.98
2031	5.37	4.14
2032	5.59	4.25
2033	5.81	4.43
2034	5.96	4.62
2035	6.06	4.71

53 EIA's Annual Energy Outlook 2022, Energy Prices: Nominal: Electric Power: Natural Gas, available at: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2022&region=1-8&cases=ref2022.

54 PacifiCorp's non-confidential work papers, "1_OR Standard QF AC Study_2022 04 20" excel spreadsheet, "Table 10" tab.

2036	6.20	4.88
2037	6.34	5.14
2038	6.50	5.47
2039	6.67	5.81
2040	6.88	6.14

As demonstrated in the table, PacifiCorp's natural gas price forecast is lower than that generated by the EIA in all years and significantly lower in several years.

The Joint QF Parties understand that the Commission has made a determination to allow the Oregon utilities to generate their own natural gas price forecasts, and we have not retained an expert to fully vet PacifiCorp's internal gas price forecast. Thus, we are not proposing that the Commission require use of the EIA or another forecast at this time. However, this issue deserves further scrutiny in the future. The utilities have an incentive to keep an internally generated gas price forecast low to suppress avoided cost rates, which is why the IPUC has required use of an independent and transparent price forecast. Additionally, the unreasonably low gas price forecast PacifiCorp has proposed further demonstrates that the Joint QF Parties' other rate adjustments would be justified to overcome certain elements of PacifiCorp's rate calculations that undervalue its avoided costs.

III. CONCLUSION

For the reasons stated above, the Joint QF Parties request that the Commission take the actions listed in the Introduction of these Comments.

Dated this 22nd day of June 2022.

Respectfully submitted,

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Attachment A

PacifiCorp's Response to CREA Data Request No. 2.7

CREA Data Request 2.7

Reference Exhibit 7. Please explain why the solar and wind renewable prices are lower during the on-peak hours in many years than during the off-peak hours in many years. In the explanation, please explain how PacifiCorp weights the on-peak and off-peak hours.

Response to CREA Data Request 2.7

Please refer to the work papers supporting PacifiCorp's April 28, 2022 filing, specifically file "1_OR Standard QF AC Study_2022 04 20.xlsx". Note: the work papers supporting PacifiCorp's April 28, 2022 filing are provided with the Company's response to CREA Data Request 2.1.

On-peak renewable pricing is lower than off-peak renewable pricing for two reasons:

First, PacifiCorp's March 31, 2022 official forward price curve (OFPC) has higher off-peak (light load hour (LLH)) prices than on-peak (heavy load hour (HLH)) prices, starting in 2027, as shown on tab "OFPC Source". This is as a result of increasing penetration of solar resources in the resource mix across the west, which suppresses prices during daylight hours, which are more prevalent in on-peak. As shown in tab "Table 13", the renewable resource avoided cost is shaped to on-peak and off-peak values that reflect the ratio from the OFPC. This is the starting point for renewable pricing for all resource types.

Second, the approved methodology includes an adjustment for avoided firm capacity costs based on the difference in the capacity contribution of each qualifying facility (QF) relative to the renewable proxy resource. The fixed-tilt solar resource has a lower capacity contribution (11 percent) than the proxy renewable wind resource (41 percent), as shown in tab "Table 14". As a result, the capacity adjustment for the fixed-tilt solar resource is a negative value. Under the approved methodology, the capacity adder is allocated to on-peak hours, which traditionally had the greatest capacity need. This results in a reduction to on-peak pricing, and on-peak prices that are significantly lower than off-peak prices for solar resources.

For details on the proportion of the generation output that is expected to occur during on-peak periods for each resource type, please refer to tab "Profile", specifically the calculations in cell C10 through M10. The calculation uses a 12-month by 24-hour generation profile specific to each resource type, and weights this output based on the relative frequency of HLH and LLH pricing in each hour. LLH includes eight hours every night (10:00pm-6:00am), plus all hours on Sundays and holidays. HLH includes sixteen hours every day (6:00am-10:00pm), but only on Monday through Saturday when it is not a holiday.

Attachment B

PacifiCorp's 2021 IRP, Volume II, Appendix K

APPENDIX K – CAPACITY CONTRIBUTION

Introduction

The capacity contribution of a resource is represented as a percentage of that resource's nameplate or maximum capacity and is a measure of the ability of a resource to reliably meet demand. This capacity contribution affects PacifiCorp's resource planning activities, which are intended to ensure there is sufficient capacity on its system to meet its load obligations inclusive of a planning reserve margin. Because of the increasing penetration of variable energy resources (such as wind and solar) and energy-limited resources (such as storage and demand response), planning for coincident peak loads is no longer sufficient to determine the necessary amount and timing of new resources. To ensure resource adequacy is maintained over time, all resource portfolios evaluated in the integrated resource plan (IRP) have sufficient capacity to meet PacifiCorp's load obligations and a planning reserve margin in all hours of each year. Because all resources provide both energy and capacity benefits, identifying the resource that can provide additional capacity at the lowest incremental cost to customers is not straightforward. A resource's energy value is dependent on its generation profile and location, as well as the composition of resources and transmission in the overall portfolio. Similarly, a resource's capacity value (or contribution to ensuring reliable system operation) is also dependent on both its characteristics and the composition of the overall portfolio. To further complicate the analysis, PacifiCorp's portfolio composition changes dramatically over time, as a result of retirements and expiring contracts.

In the 2019 IRP, PacifiCorp developed initial capacity contribution estimates for wind and solar capacity that accounted for expected declining contributions as the level of penetration increased. A key assumption in this analysis was that only a single variable was modified, for example, when evaluating solar penetration level, the capacity from wind and energy storage resources in the portfolio were held constant. As the preparation of the 2019 IRP continued, PacifiCorp identified that these initial estimates did not adequately account for the interactions between solar, wind, and energy storage and thus did not ensure that each portfolio was adequately reliable. Therefore, as part of the 2019 IRP PacifiCorp assessed each portfolio to verify that it would support reliable operation in each hour of the year.

At the conclusion of the 2019 IRP, PacifiCorp recalculated the capacity contribution values for wind and solar resources using the capacity factor approximation method (CF Method) as outlined in a 2012 report produced by the National Renewable Energy Laboratory (NREL Report)[1]. The CF Method calculates a capacity contribution based on a resource's expected availability during periods when the risk of loss of load events is highest, based on the loss of load probability (LOLP) in each hour. This final CF Method analysis was performed using a portfolio that was very similar to the 2019 IRP preferred portfolio. For the reasons discussed above, this final CF Method analysis provides a reasonable estimate of capacity contribution value so long as the changes relative to the preferred portfolio are small, since in effect, the CF Method calculates the marginal capacity contribution of a one megawatt resource addition. Changes to the locations and quantities of wind, solar, and energy storage are key drivers of the marginal capacity contribution results.

[1] Madaeni, S. H.; Sioshansi, R.; and Denholm, P. "Comparison of Capacity Value Methods for Photovoltaics in the Western United States." NREL/TP-6A20-54704, Denver, CO: National Renewable Energy Laboratory, July 2012 (NREL Report) at: www.nrel.gov/docs/fy12osti/54704.pdf

The capacity contribution analysis for the 2021 IRP is comparable to that in PacifiCorp's 2019 IRP in two key ways. First, rather than assigning a capacity contribution at the start of the analysis, the hourly reliability of portfolios was assessed to identify periods of shortfalls. Second, a final CF Method analysis was performed using a portfolio that is similar to the 2021 IRP preferred portfolio. The final CF Method analysis for the 2021 IRP is presented in this Appendix.

CF Methodology

The NREL Report summarizes several methods for estimating the capacity value of renewable resources that are broadly categorized into two classes: 1) reliability-based methods that are computationally intensive; and 2) approximation methods that use simplified calculations to approximate reliability-based results. The NREL Report references a study from Milligan and Parsons that evaluated capacity factor approximation methods, which use capacity factor data among varying sets of hours, relative to a more computationally intensive reliability-based metric. As discussed in the NREL Report, the CF Method was found to be the most dependable technique in deriving capacity contribution values that approximate those developed using a reliability-based metric.

As described in the NREL Report, the CF Method "considers the capacity factor of a generator over a subset of periods during which the system faces a high risk of an outage event." When using the CF Method, hourly LOLP is calculated and then weighting factors are obtained by dividing each hour's LOLP by the total LOLP over the period. These weighting factors are then applied to the contemporaneous hourly capacity factors to produce a capacity contribution value.

The weighting factors based on LOLP are defined as:

$$w_i = \frac{LOLP_i}{\sum_{j=1}^{T} LOLP_j}$$

where w_i is the weight in hour i, $LOLP_i$ is the LOLP in hour i, and T is the number of hours in the study period, which is 8,760 hours for the current study. These weights are then used to calculate the weighted average capacity factor as an approximation of the capacity contribution as:

$$CV = \sum_{i=1}^{T} w_i C_i,$$

where C_i is the capacity factor of the resource in hour i, and CV is the weighted capacity value of the resource.

For fixed profile resources, including wind, solar, and energy efficiency, the average LOLP values across all iterations are sufficient, as the output of these resources is the same in each iteration. To determine the capacity contribution of fixed profile resources using the CF Method, PacifiCorp implemented the following three steps:

1. A 50-iteration hourly Monte Carlo simulation of PacifiCorp's system was produced using the Plexos Short-Term (ST) model. The key stochastic variables assessed as part of this analysis are loads, thermal outages, and hydro conditions. The LOLP for each hour in the

year is calculated by counting the number of iterations in which system load and/or reserve obligations could not be met with available resources and dividing by the total number of iterations.[2] For example, if in hour 19 on December 22nd there are three iterations with shortfalls out of a total of 50 iterations, then the LOLP for that hour would be 6 percent.[3]

2. Weighting factors were determined based upon the LOLP in each hour divided by the sum of LOLP among all hours within the same summer or winter season. In the example noted above, the sum of LOLP among all winter hours is 58 percent.[4] The weighting factor for hour 19 on December 22nd would be 1.0417 percent.[5] This means that 1.0417 percent of all winter loss of load events occurred in hour 19 on December 22nd and that a resource delivering in only in that single hour would have a winter capacity contribution of 1.0417 percent.

3. The hourly weighting factors are then applied to the capacity factors of fixed profile resources in the corresponding hours to determine the weighted capacity contribution value in those hours. Extending the example noted, if a resource has a capacity factor of 41.0 percent in hour 19 on December 22nd, its weighted winter capacity contribution for that hour would be 0.4271 percent.[6]

For resources which are energy limited, such as energy storage or demand response programs, the LOLP values in each iteration must be examined independently, to ensure that the available storage or control hours are sufficient. Continuing the example of December 22nd described above, consider if hour 18 and hour 19 both have three hours with energy or reserve shortfalls out of 500 iterations. If all six shortfall hours are in different iterations, a 1-hour energy storage resource could cover all six hours. However, if the six shortfall hours are in the same three iterations in hour 18 and hour 19 (i.e. 2-hour duration events), then a 1-hour storage resource could only cover three of the six shortfall hours.

Additional considerations are also necessary for hybrid resources which share an interconnection and cannot generate their maximum potential output simultaneously.

Final CF Method Results

The final CF Method results described below provide a reasonable capacity contribution value so long as the changes relative to the preferred portfolio are small, since in effect, the CF Method calculates the marginal capacity contribution of a one-megawatt resource addition. Please note that marginal capacity contribution values reported herein are applicable to small incremental or

[2] In the past, PacifiCorp assumed that the first hour of any shortfall would be covered as part of its participation in the Northwest Power Pool (NWPP) reserve sharing agreement, which allows a participant to receive energy from other participants within the first hour of a contingency event. While this reserve sharing remains in effect, shortfalls in the 2021 IRP are much more likely to result from changes in load, renewable resource output, or energy storage limitations, and not in the first hour after a contingency event occurs. In light of this, PacifiCorp's 2021 IRP analysis no longer excludes the first hour of every shortfall event.

[3] 0.6 percent = 3 / 500.

[4] For each hour, the hourly LOLP is calculated as the number of iterations with ENS divided by the total of 500 iterations. There are 288 winter ENS iteration-hours out of total of 5,832 winter hours. As a result, the sum of LOLP for the winter is 288 / 500 = 58 percent. There are 579 summer ENS iteration-hours out of total of 2,928 summer hours. As a result, the sum of LOLP for the summer is 579 / 500 = 116 percent.

[5] 1.0417 percent = 0.6 percent / 58 percent, or simply 1.0417 percent = 3 / 288.

[6] 0.4271 percent = 1.0417 percent x 41.0 percent.

decremental changes relative to the composition of the IRP preferred portfolio in 2030 and do not represent the average capacity contribution for each of the megawatts of a given resource type included in the preferred portfolio. In general, wind, solar, and energy storage have declining marginal capacity contribution values as the quantity of a given resource type increases. This results in average capacity contribution values that exceed the marginal capacity contribution values reported herein.

Table K.1 – Final CF Method Capacity Contribution Values for Wind, Solar, and Storage

	Capacity Factor (%)	Capacity Contribution (%)	
Summer/Winter:	**Annual**	**S**	**W**
Solar			
Idaho Falls, ID	28%	14%	7%
Lakeview, OR	29%	13%	18%
Milford, UT	32%	15%	7%
Yakima, WA	25%	9%	4%
Rock Springs, WY	30%	14%	13%
Wind			
Pocatello, ID	37%	33%	39%
Arlington, OR	37%	46%	17%
Monticello, UT	29%	14%	42%
Goldendale, WA	37%	47%	21%
Medicine Bow, WY	44%	30%	32%
Stand-alone Storage			
2-hour duration		49%	75%
4-hour duration		74%	90%
9-hour duration		90%	96%

Table K.2 – Final CF Method Capacity Contribution Values for Solar Combined with Storage

	Capacity Factor (%)	Capacity Contribution (%)	
Summer/Winter:	**Annual**	**S**	**W**
Solar & 100% x 4-hour Storage			
Idaho Falls, ID	28%	81%	92%
Lakeview, OR	29%	82%	93%
Milford, UT	32%	80%	95%
Yakima, WA	25%	79%	91%
Rock Springs, WY	30%	80%	94%

The above CF Method results are from a one-year study period (2030) and shortfall events are identified separately for every hour in that period. The details of the wind and solar resource modeling in the study period are important for interpreting the results. The study includes specific wind and solar volumes by resource for each hour in the period, and includes the effects of calm and cloudy days on resource output. Where data was available, the modeled generation profiles for proxy resources are derived from calendar year 2018 hourly generation profiles of existing resources, adjusted to align with the expected annual output of each proxy resource.

The use of correlated hourly shapes produces variability across each month and a reasonable correlation between resources of the same type that are located in close proximity. It also results in days with higher generation and days with lower generation in each month. As one would expect, days with lower renewable generation are more likely to result in shortfall events. As a result, basing CF Method capacity contribution calculations on an average or 12-month by 24-hour forecast of renewable generation will tend to overstate capacity contribution, particularly if there is a significant quantity of similarly located resources of the same type already in the portfolio, or if an appreciable quantity of resource additions are being contemplated. Even if an hourly renewable generation forecast is used, capacity contributions can be overstated if the weather underlying the forecast is not consistent with that used for similarly located resources used to develop the CF Method results. Because similarly located resources of the same type would experience similar weather in actual operations, a mismatch in the underlying weather conditions used in renewable generation forecasting will create diversity in the generation supply than would not occur in actual operations.

Because they are both influenced by weather, a relationship between renewable output and load is expected. To assess this relationship, PacifiCorp gathered information on daily wind and solar output from 2016-2019, and compared it to the load data from that period, the same load data that was used to determine stochastic parameters.

Each of the days in the historical period was assigned to a tier based on the rank of its daily average load within that month. This was done independently for the east and west sides of the system. The seven tiers were defined as follows:

Tier 1: The peak load day

Tier 2: 2nd – 5th highest load days

Tier 3: Days 6-10

Tier 4: Days 11-15

Tier 5: Days 16-20

Tier 6: Days 21-25

Tier 7: Days 26-31

The average wind and solar generation on the days in each tier was then compared to the average wind and solar generation for the entire month. The results indicated that west-side wind is often below average during the highest load days in a month, and above average during the lowest load days in a month. The results for other resource types were less pronounced, but do exhibit some patterns, as shown in Figure K.1 and Figure K.2.

Figure K.1 – Renewable Resources vs. High Load Conditions

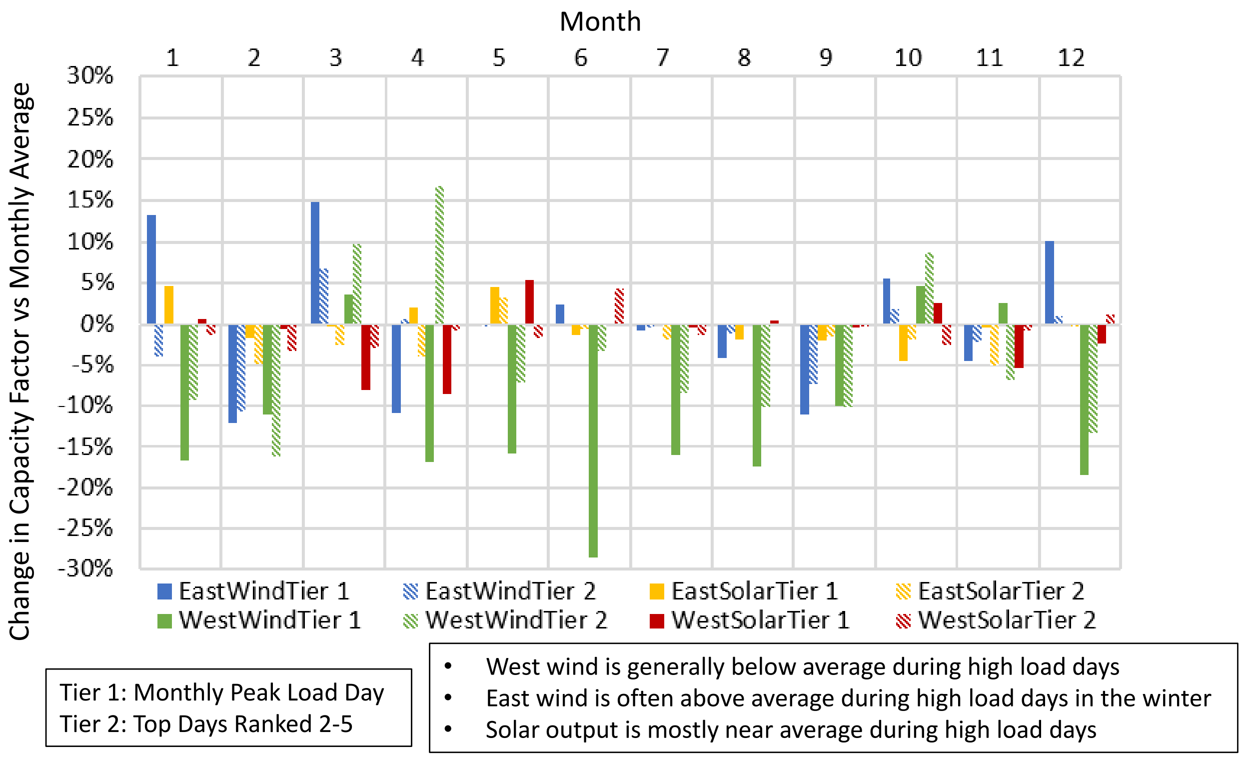
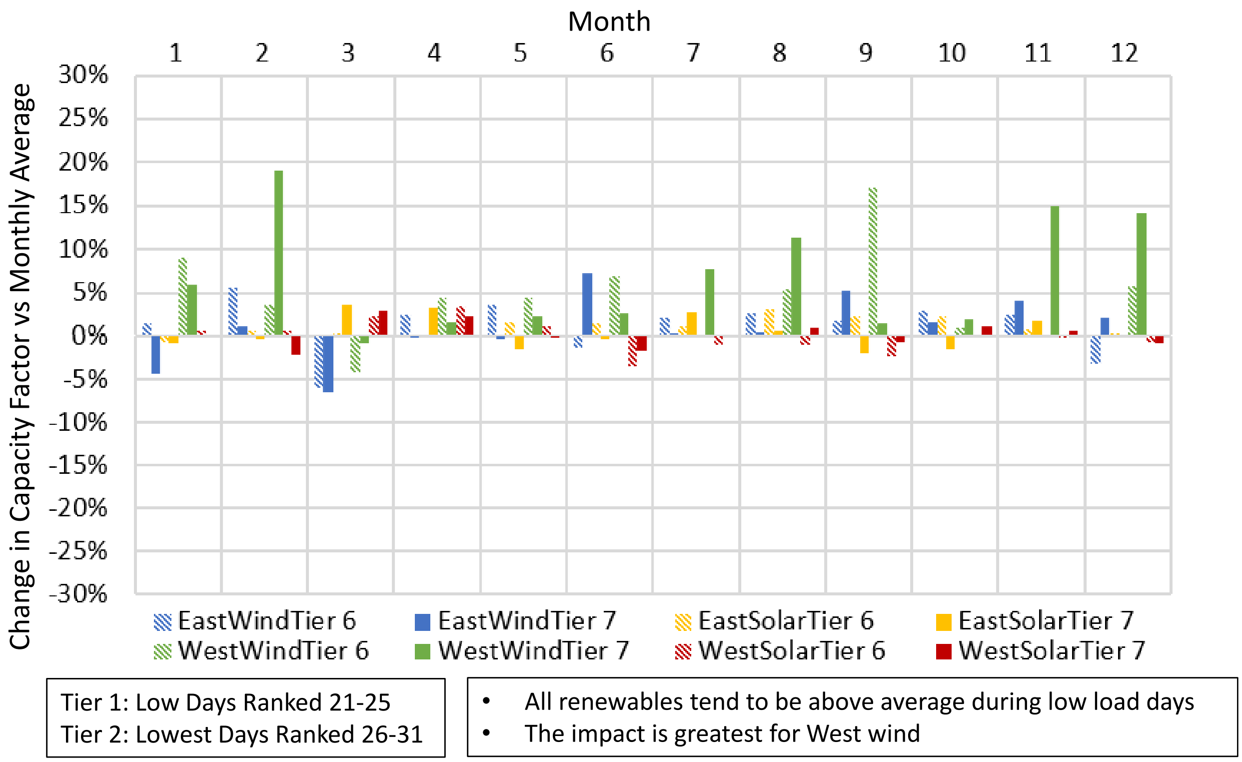


Figure K.2 – Renewable Resources vs. Low Load Conditions



Standard stochastic evaluation of prices, loads, etc. is based on standard deviations and mean reversion statistics. The results indicate that wind and solar output does exhibit relationships with load, but they are poorly represented by standard deviations – a different modeling technique is necessary.

Because of the complexity of the data, PacifiCorp did not attempt to develop wind and solar generation that varies by stochastic iteration for the 2021 IRP. Instead, PacifiCorp developed a technique using the existing input framework: a single 8760 profile for each wind and solar resource that repeats every year. Because the load forecast rotates with the calendar, such that the peak load day moves to different calendar days, this creates differences in the alignment of load and renewable output across the IRP study horizon.

The order of the 2018 historical days was rearranged so that the forecasted intra-month variation in renewable output was reasonably aligned with the intra-month variation observed in the historical period for the days in the same load tier. Each day of renewable resource output derived from the 2018 history is mapped to a specific day for modeling purposes – only the order of the days changes. To maintain correlations within wind and solar output, all wind and solar resources across the entire system are mapped using the same days.

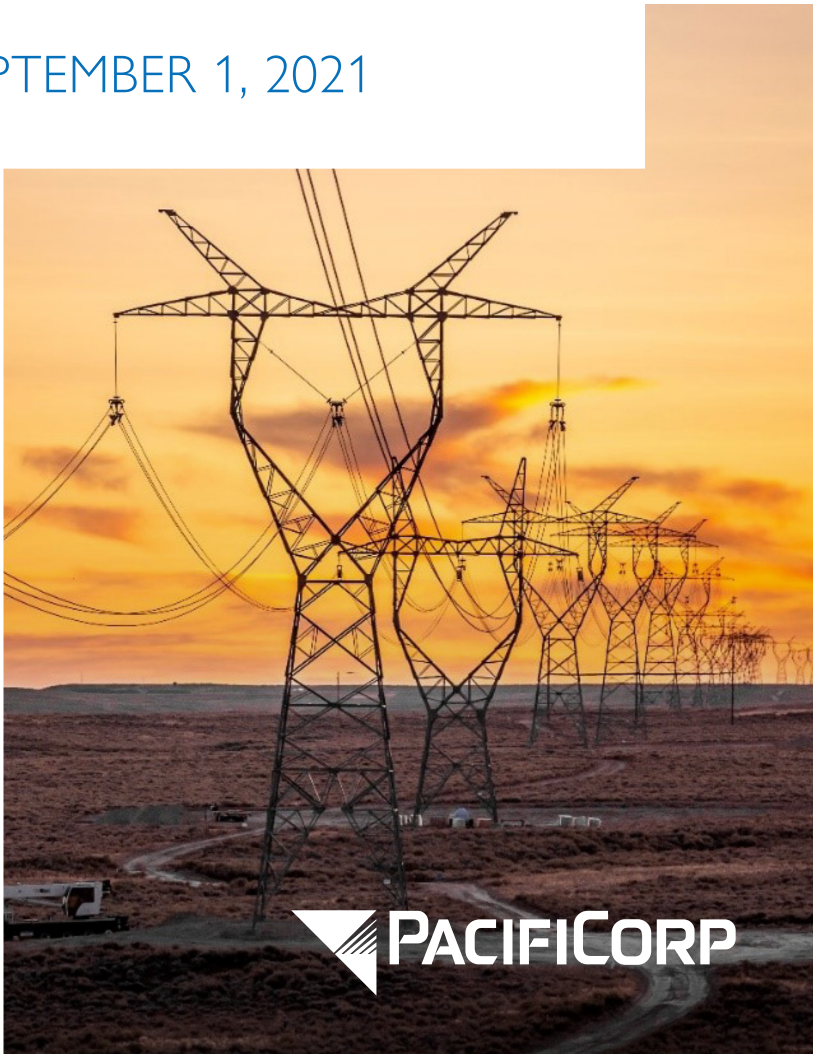
While this technique builds on previous modeling and produces a reasonable forecast that captures some of the relationships between wind, solar, and load, additional work is needed in future IRPs to explore the variation and diversity of solar and wind output and further relationships with load.

Attachment C

PacifiCorp's 2021 IRP, Volume I

2021 Integrated Resource Plan

VOLUME I | SEPTEMBER 1, 2021



PACIFICORP

This 2021 Integrated Resource Plan Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Top to Bottom):
Pavant III Solar Plant
Marengo Wind Project
Transmission Line - Wyoming
Panguitch Solar & Battery Storage

TABLE OF CONTENTS

CHAPTER 2 – INTRODUCTION

CHAPTER 3 – PLANNING ENVIRONMENT

CHAPTER 4 – TRANSMISSION

CHAPTER 5 – RELIABILITY AND RESILIENCY

CHAPTER 6 – LOAD AND RESOURCE BALANCE

CHAPTER 7 – RESOURCE OPTIONS

CHAPTER 8 – MODELING AND PORTFOLIO EVALUATION APPROACH

CHAPTER 9 – MODELING AND PORTFOLIO SELECTION RESULTS

CHAPTER 10 – ACTION PLAN

APPENDIX A – LOAD FORECAST DETAILS

APPENDIX B – REGULATORY COMPLIANCE

APPENDIX C – PUBLIC INPUT

APPENDIX D – DSM RESOURCES

APPENDIX E – SMART GRID

APPENDIX F – FLEXIBLE RESERVE STUDY

APPENDIX H – STOCHASTIC PARAMETERS

APPENDIX I – CAPACITY EXPANSION RESULTS 177

APPENDIX J – STOCHASTIC SIMULATION RESULTS 211

APPENDIX K – CAPACITY CONTRIBUTION

APPENDIX L – PRIVATE GENERATION STUDY 225

APPENDIX M – RENEWABLE RESOURCES ASSESSMENT 227

APPENDIX N – ENERGY STORAGE POTENTIAL EVALUATION

APPENDIX O – WASHINGTON CLEAN ENERGY ACTION PLAN

APPENDIX P – RFP OVERVIEW

INDEX OF TABLES

INDEX OF FIGURES

CHAPTER 1 – EXECUTIVE SUMMARY

PacifiCorp's 2021 Integrated Resource Plan (IRP) was developed through comprehensive analysis and an extensive public-input process spanning over a year and a half resulting in the selection of a least-cost, least-risk preferred portfolio. With accelerated coal retirements, no new fossil-fueled resources, continued growth in energy efficiency programs, and incremental renewable resources, the 2021 IRP preferred portfolio results in a greater reduction in greenhouse gas emissions relative to the 2019 IRP. Reliable service will be maintained with investment in transmission infrastructure, the conversion of two coal units to natural gas peaking units, growth in demand response programs, the addition of advanced nuclear resources, the addition of energy storage resources, and over the long term, the addition of non-emitting peaking resources.

PacifiCorp's Vision

The time is now

At PacifiCorp, we share a vision with our customers and communities in which clean energy from across the West powers jobs and innovation. This bold vision has guided our work for years. Most recently, it took shape in our 2017 and 2019 IRPs, in which we outlined an ambitious path to substantially increase our renewable energy capacity, evolving our existing portfolio and connecting supply with demand through an expanded, modernized transmission system.

Now is the time for further action.

Delivering on our promise

The power of the West lies in its diversity: windswept plains and high deserts, the sun-soaked Great Basin, and rivers fed by rain and mountain snow. Taken together, these reserves of wind, solar and hydro power can help meet the growing and changing needs of homes and businesses throughout the West, cleanly, reliably and affordably.

Yet, capturing this power alone is not enough. To unlock the full promise of these abundant resources, we must add transmission and storage capacity, unlock customer demand response resources with a modernized grid, and replace retiring thermal resources with non-emitting resources like advanced nuclear, to connect the West to its energy future—built on a resilient, hardened, adaptable grid that safely delivers power when and where it's needed.

PacifiCorp's 2021 IRP is a roadmap for action. It sets forth a path to build upon our significant progress toward the goals laid out in the 2017 and 2019 IRPs and identifies critical investments in expanded and modernized transmission, renewable energy, storage, demand response and advanced nuclear resources.

Our integrated system connects and brings new opportunities to the West, building on a foundation of infrastructure designed to handle extreme weather and enhance the energy resilience of communities from the Pacific Coast to the Rocky Mountains, all while continuing to deliver energy solutions for our customers at prices that are below national and regional averages.

As our 2021 IRP shows, this expanded, modernized transmission will connect supply with demand from east to west and from north to south, serving as the backbone of the West for the hundreds of energy providers that serve our region alongside PacifiCorp.

Putting our customers at the center of everything we do

At PacifiCorp, we're committed to meeting the demands of our customers and communities throughout the West to deliver safe, affordable, clean energy and a resilient, modern grid.

Together with the communities we serve and our regional partners, it is time to act, with targeted, strategic investments that will position us to continue delivering affordable, reliable power.

Our customer-centered vision embodies four core themes:

Reliable Power: We strive to deliver energy safely during all hours, and plan extensively to ensure that we have sufficient supply and ability to deliver to the communities we serve. We understand that electricity is an essential service, and work around the clock to ensure that we are dependable, and communities can rely on us.

Resilient Infrastructure: This is a time of rapid change, with more extreme weather and challenging conditions. We are working to minimize disruptions, implement strategies to recover quickly when they occur, and deploy upgrades that will strengthen our critical infrastructure.

Affordable Prices: PacifiCorp is proud to be one of the lowest-cost electricity providers in the nation and the region. As we plan for our next generation of resources, we are prioritizing resources that add value and keep customer prices low.

Clean Energy: Through strategic, customer-focused investments in a diversity of resources, PacifiCorp is on a path to reduce carbon emissions, system-wide, by 74 percent from 2005 levels by 2030. Our resource plan includes continued significant new renewable additions among other diverse, advanced technologies to keep us on that path and achieve even deeper decarbonization beyond 2030.

2021 IRP Roadmap

The 2021 IRP outlines PacifiCorp's bold vision for the West between now and 2040 and sets us on the path to achieve a clean, resilient and affordable energy future that leverages the abundant, diverse, clean energy resources that the West can offer through a modernized and expanded grid.

- **Continue our growth into a grid powered by clean energy (incremental to projects already online and projects with executed agreements that will come online through 2023)**:
    - 4,290 MW from energy efficiency programs
    - 5,628 MW of new solar resources (most paired with storage)
    - 3,628 MW of new wind resources
    - 6,181 MW of storage resources, including battery storage co-located with solar, standalone battery storage and pumped hydro storage resources
    - 2,448 MW of direct load control programs

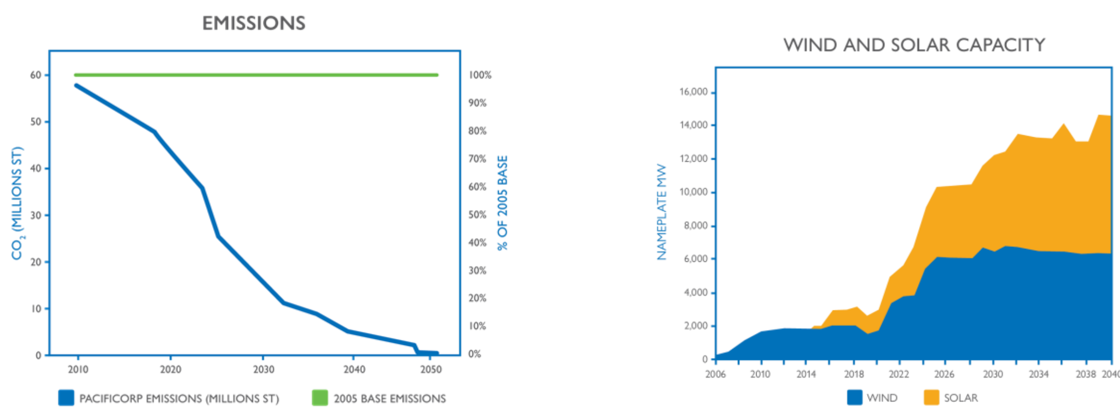
- 500 MW of advanced nuclear (the Natrium ™ reactor demonstration project) in 2028, with an additional 1,000 MW of advanced nuclear over the long-term

- **Connect and optimize these diverse, clean resources across the West with a strengthened and modernized transmission network that ensures resilient service, reduces costs and creates maximum opportunities for our communities to thrive (incremental to projects already online)**:
  - 416 miles of new transmission from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah (Energy Gateway South)
  - 59 miles of new transmission from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming (Energy Gateway West Sub-Segment D.1)
  - 290 miles of new transmission from the Boardman substation in north central Oregon to the Hemingway substation in south central Idaho

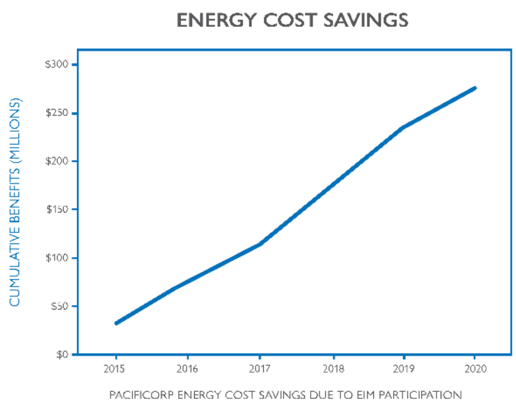
Meeting our goals. Accelerating our progress.

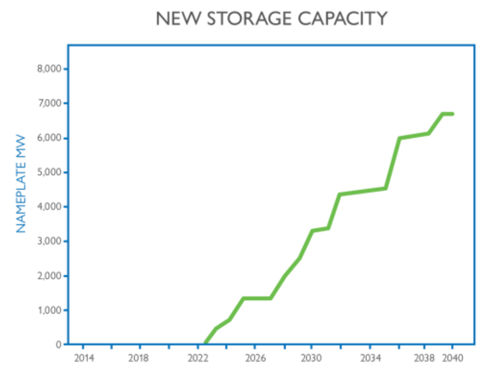
Our 2021 IRP positions PacifiCorp to rapidly expand its supply of clean energy while increasing our storage capacity and delivering cost savings to our customers.[1]

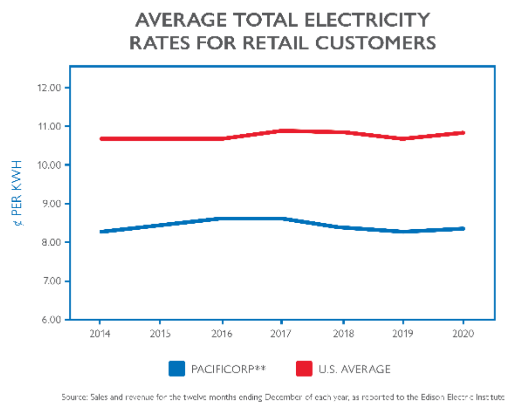
Figure 1.1 – IRP preferred portfolio metrics and trajectory



[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.







Evolving Our Portfolio

Working in close partnership with our communities, we are making significant progress in our evolution to an increasingly low-carbon portfolio. Over the past two years, our progress toward those goals has included:

- A completed coal-to-gas peaker conversion of Naughton Unit 3 in Kemmerer, Wyoming
- Retirement of the Cholla Unit 4 coal-fired generator in Joseph City, Arizona

Our resource strategy in the 2021 IRP continues that progress, and within the next four years will:

- Begin the process of retiring or divesting Colstrip Units 3 and 4 in Colstrip, Montana
- Begin the process of a coal-to-gas peaker conversion of Jim Bridger Units 1 and 2 in Rock Springs, Wyoming
- Begin the process of retirement or sale of Naughton Units 1 and 2

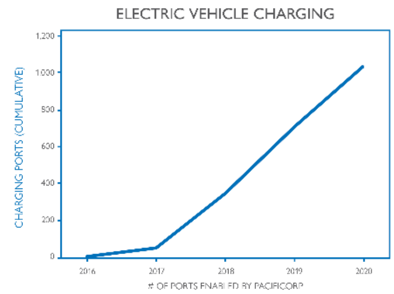
Throughout, we are collaborating closely with affected communities and with state leadership to support a successful transition for our employees and their communities.

Co-creating energy solutions with customers and communities

The communities PacifiCorp serves are why we exist, so we're working in close collaboration with them to build the opportunities and infrastructure that enables communities to thrive.

Clean transportation infrastructure

There are good things ahead for electric transportation in the West. In addition to the more than 2,100 new electric vehicle charging ports that we have already helped install, we're expanding workplace charging, supporting regional solutions to electrify interstates for cleaner freight transportation, and making electric vehicle ownership more accessible for rural and underserved communities.



Solar + Storage in our communities

PacifiCorp is partnering with the communities throughout its service area to leverage grid-scale battery storage and solar projects to help meet community energy needs. In Panguitch Utah, a one-megawatt peak capacity, five megawatt-hour energy storage system anticipates and responds to peak electricity consumption and levels demand on the local grid. This enables PacifiCorp to employ batteries as an alternative to traditional grid poles-and-wires infrastructure. The 650-kilowatt solar photovoltaic component of this project was funded through a grant from the company's Blue Sky renewable energy program.

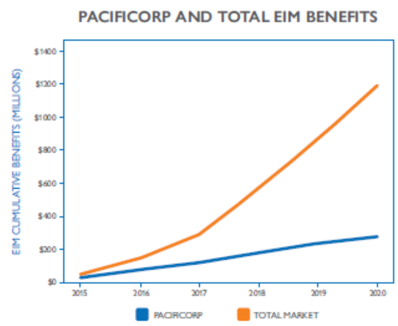
Similarly, through a partnership with the Oregon Institute of Technology in Klamath Falls, Oregon, PacifiCorp is installing a two-megawatt peak capacity, six megawatt-hour energy storage system that will partner with the existing geothermal and solar resources on the campus to provide increased local grid stability. PacifiCorp will also facilitate the interconnection of 64 megawatts of small community based solar systems over the next four years through the Oregon Community Solar Program. These projects are designed to provide an opportunity for residential and low-income customers to share in the benefits of local solar energy production.

Advanced nuclear demonstration project

A developer of an advanced nuclear reactor, TerraPower, has received support from the Department of Energy to construct a demonstration plant for its Natrium™ technology. TerraPower is investigating the opportunity to site Natrium at a retiring coal plant in Wyoming. The project promises many benefits to PacifiCorp including a 24/7 reliable source of clean energy with embedded storage, safety, cost and reduced spent fuel advantages while providing an employment transition opportunity for our existing coal employees and an economic boost to the community where they reside. Using safety features that take advantage of natural forces and do not require human intervention, this reactor will be able to shut down safely and independently, greatly reducing the risks associated with earlier nuclear reactors. TerraPower has not yet identified the specific site for this facility. For modeling purposes in the 2021 IRP, the Natrium™ demonstration project is placed at the Naughton facility. However, a modeling assumption does not equate to the selection of a site. Should TerraPower's site selection ultimately identify a different location than what was modeled in the 2021 IRP, updated analysis of portfolio implications will be made in a future IRP or IRP update.

Delivering resilience and reliability through a connected West

The diversity of the West's landscape—including its abundant clean energy resources—are the key to our strategy for delivering least-cost, least-risk, resilient power to our customers. We have already collaborated with utilities from across the region to form the Western Energy Imbalance Market (EIM),



which allows utilities to trade surplus power in near-real time. The EIM leverages diverse clean energy resources from across the West to dramatically lower greenhouse gas emissions, while increasing the grid's resilience and lowering costs for our customers.

In our 2019 IRP, we expanded our plans stemming from the 2017 IRP to significantly increase our transmission capacity to integrate new renewable resources more effectively into the grid and to deliver the full benefit of the EIM to our customers. We are on target with all benchmarks established by that IRP.

- Completed reinforcements of high-voltage transmission in the Utah Valley, northern Utah, southern Utah, and Yakima, Washington. These projects will allow the company to respond to interconnection requests and accommodate the renewable resources identified in the 2019 IRP.
- Continuing the regulatory process to construct Energy Gateway South and Energy Gateway West Sub-Segment D.1, which will connect eastern Wyoming to central Utah, enhance system reliability and provide access to more generation resources.

Expanded conservation measures

We're championing technical innovations that use fast-acting residential demand response resources to support the bulk power system. Our approach moves beyond peak-load management to create a grid-scale solution that turns demand response resources into frequency-responsive operating reserves. With over 100,000 customers participating in our program, more than 200 MW of operating reserve are available every day and can be dispatched in a matter of seconds. This reduces our need to buy reserve power on the market, and it's only used in emergencies, minimizing inconvenience to customers.

Our partnership with The Wasatch Group enabled us to develop and manage a first-of-its-kind battery demand response solution at an all-electric apartment building. That success has shaped a new battery demand response option for any Utah customer with on-site solar generation. The network of renewable energy stored in customer-owned batteries will enable greater use of renewable power, improves overall grid resiliency, and helps keep prices down.

In the coming years, our ongoing conservation and cost-effective demand-response initiatives will target to deliver:

- 603 MW of energy efficiency between 2021-2024
- 549 MW of demand response[2] between 2021-2024

Putting our shared vision to work for our customers

Our 2021 IRP is grounded in our commitment to deliver reliable, affordable power to all our customers through a dynamic, connected grid. It is the roadmap for a future of clean energy and strengthened infrastructure to support the delivery of this essential service. It's shaped by our customers and communities, and new technologies and programs, like demand response. And it's

[2] Capacity impacts for demand response include both summer and winter impacts within a year.

bolstered by innovations in power generation and storage that will help decarbonize our portfolio while lowering costs and increasing reliability.

This is the vision, with clear, measurable steps that will connect the region to its massive energy generating potential and leverage our transmission infrastructure across our six-state area to enhance reliability and resilience throughout the West.

By investing in resilience, through expanded and modernized transmission, a hardened grid, and a diverse, increasingly clean portfolio, we are delivering on our commitment to ensuring safe, reliable, affordable power for our customers, now and for generations to come.

PacifiCorp's Integrated Resource Plan Approach

PacifiCorp has been making progress in its efforts to bring the best of the West to its customers, and PacifiCorp's 2021 IRP presents the company's plans to continue to make significant advancements in this vision. The 2021 IRP sets forth a clear path to provide reliable and reasonably priced service to its customers. The analysis supporting this plan helps PacifiCorp, its customers, and its regulators understand the effect of both near-term and long-term resource decisions on customer bills, the reliability of electric service PacifiCorp customers receive, and changes to emissions from the generation sources used to serve customers. In the 2021 IRP, PacifiCorp presents a preferred portfolio that builds on its vision to deliver energy affordably, reliably and responsibly through near-term investments in transmission infrastructure that will facilitate continued growth in new renewable resource capacity while maintaining substantial investment in energy efficiency and demand response programs. All of this can be achieved by maintaining reliable service with incremental investments in transmission infrastructure and other non-emitting flexible resources capable of shaping and responding to changes in energy from an increasing supply of wind and solar resources.

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

The full planning process is completed every two years, with a review and update completed in the off years. Consequently, these plans, particularly the longer-range elements, can and do change over time. PacifiCorp's 2021 IRP was developed through an open and extensive public process, with input from an active and diverse group of stakeholders, including customer advocacy groups, community members, regulatory staff, and other interested parties. The public-input process began with the first public-input meeting in January 2020. Over the subsequent year and a half, PacifiCorp met with stakeholders and hosted eighteen public-input meetings. Throughout this effort, PacifiCorp received valuable input from stakeholders and presented findings from a broad range of studies and technical analyses that shaped and informed the 2021 IRP.

As depicted in Figure 1.2, PacifiCorp's 2021 IRP was developed by working through five fundamental planning steps that began with development of key inputs and assumptions to inform the modeling and portfolio-development process. The portfolio-development process is where PacifiCorp produced a range of different resource portfolios that meet projected gaps in the load and resource balance, each uniquely characterized by the type, timing, and location of new resources in PacifiCorp's system. The resource portfolios produced for the 2021 IRP were created considering a wide range of potential coal retirement dates, options to convert to gas or to retrofit for carbon capture utilization and sequestration for certain coal units, and other planning uncertainties.

PacifiCorp then developed variants of the top performing resource portfolio to further analyze impacts of specific resource actions within the top performing portfolio. In the resource portfolio analysis step, PacifiCorp conducted targeted reliability analysis to ensure portfolios had sufficient flexible capacity resources to meet reliability requirements. PacifiCorp then analyzed these different resource portfolios to measure the comparative cost, risk, reliability, and emission levels. This resource portfolio analysis ultimately informed selection of the least-cost and least-risk portfolio, the 2021 IRP preferred portfolio and development of the associated near-term resource action plan. Throughout this process, PacifiCorp considered a wide range of factors to develop key planning assumptions and to identify key planning uncertainties, with input from its stakeholder group. Supplemental studies were also done to produce specific modeling assumptions.

Figure 1.2 – Key Elements of PacifiCorp's 2021 IRP Approach

Preferred Portfolio Highlights

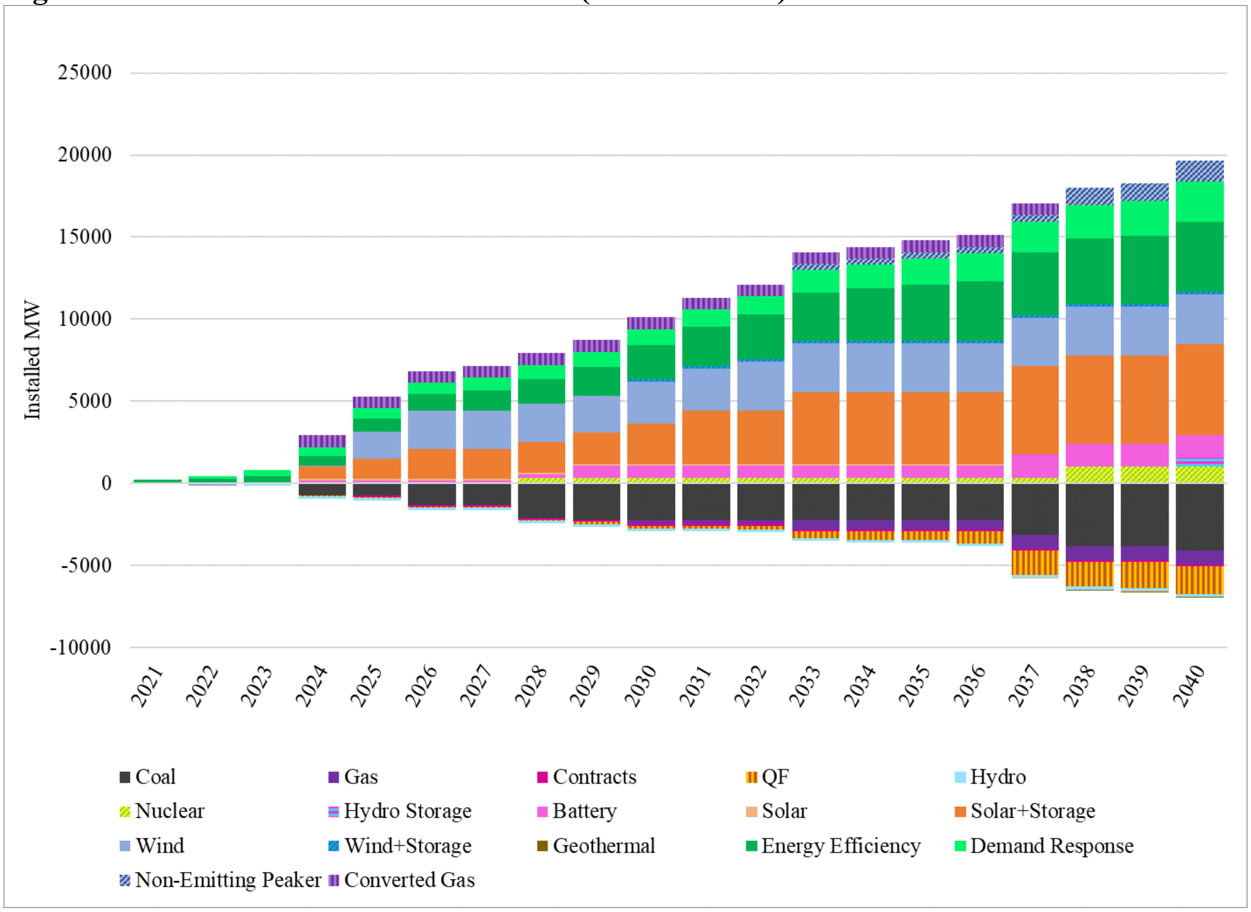
PacifiCorp's selection of the 2021 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process, described in the chapters that follow. Figure 1.3 shows that PacifiCorp's 2021 preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, and for the first time, advanced nuclear.

By the end of 2024, the 2021 IRP preferred portfolio includes the 2020 All-Source Request for Proposals (RFP) final shortlist resources. These projects include 1,792 MW of wind, 1,302 MW of solar additions, and 697 MW of battery storage capacity—497 MW paired with solar and a 200 MW standalone battery.[3] During this time, the preferred portfolio also includes the acquisition and repowering of Rock River I (49 MW) and Foote Creek II-IV (43 MW) wind projects located in Wyoming. Through the end of 2026, the 2021 IRP preferred portfolio includes an additional 745 MW of wind and an additional 600 MW solar co-located with storage. The 2021 IRP preferred portfolio includes the 500 MW advanced nuclear Natrium™ demonstration project, which will come online by summer 2028. Through 2040, the 2021 IRP preferred portfolio includes 1,000 MW of additional advanced nuclear resources and 1,226 MW of non-emitting peaking resources.

Over the 20-year planning horizon, the 2021 IRP preferred portfolio includes 3,628 MW of new wind and 5,628 MW of new solar co-located with storage.

[3] The reported capacity for RFP solar resources reflects their expected maximum output after degradation in their first full year of operation. The maximum solar capacity prior to degradation is 1,306 MW.

Figure 1.3 – 2021 IRP Preferred Portfolio (All Resources)



To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission investment. Specifically, the 2021 IRP preferred portfolio includes the Energy Gateway South transmission line - a new 416-mile high-voltage 500-kilovolt transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The 2021 preferred portfolio also includes the Energy Gateway West Subsegment D.1 project - a new 59-mile, high-voltage (230-kilovolt) transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. Both transmission lines will come online by the end of 2024.

The 2021 IRP preferred portfolio also includes a 290-mile high-voltage 500-kilovolt transmission line known as Boardman-to-Hemingway, which connects those respective substations in Oregon and Idaho, which will come online in 2026. Further, the 2021 IRP preferred portfolio further includes near-term and long-term transmission upgrades across the system that will facilitate continued and long-term growth in new resources needed to serve our customers. Table 1.1 summarizes the incremental transmission projects in the 2021 IRP preferred portfolio.

Table 1.1 – Transmission Projects Included in the 2021 IRP Preferred Portfolio[1,2,*]

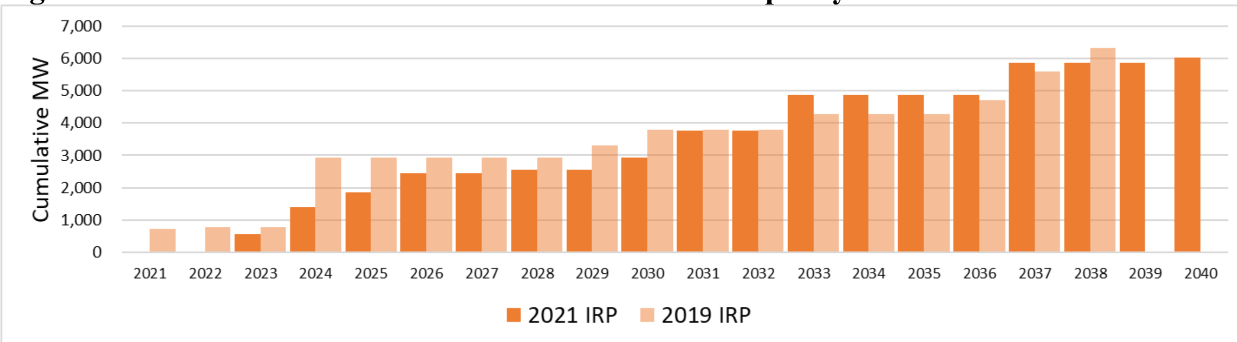
Year	Resource(s)	From	To	Description
2025	1,641 MW RFP Wind (2025)	Aeolus WY	Clover	Enables 1,930 MW of interconnection with 1700 MW of TTC: Energy Gateway South
2026	615 MW Wind (2026)	Within Willamette Valley OR Transmission Area		Enables 615 MW of interconnection: Albany OR area reinforcement
2026	130 MW Wind (2026) 450 MW Wind (2032) 650 MW Battery (2037)	Portland North Coast	Willamette Valley Southern Oregon	Enables 2080 MW of interconnection with 1950 MW TTC; Portland Coast area reinforcement, Willamette Valley and Southerm Oregon
2026	600 MW Solar+Storage (2026)	Borah-Populous	Hemingway	Enables 600 MW of interconnection with 600 MW of TTC: B2H Boardman-Hemingway
2028	41 MW Solar+Storage (2028) 377 MW Solar+Storage (2030)	Within Southern OR Transmission Area		Enables 460 MW of interconnection: Medford area reinforcement
2030	160 MW Solar+Wind+Storage (2030) 20 MW Solar+Storage (2030)	Yakima WA Transmission Area		Enables 180 MW of interconnection: Yakima local area reinforcement
2031	820 MW Solar+Storage (2031) 206 MW Non-Emitting Peaker (2033)	Northern UT Transmission Area		Enables 1040 MW of interconnection: Northern UT 345 kV reinforcement
2033	400 MW Non-Emitting Peaker (2033) 1100 MW Solar+Storage (2033)	Southern UT	Northern UT	Enables 1500 MW of interconnection with 800 MW TTC: Spanish Fork - Mercer 345 kV; New Emery – Clover 345 kV
2040	156 MW Solar+Storage (2040) 500 MW Pumped Storage (2040)	Central OR	Willamette Valley	Enables 980 MW of interconnection with 1500 MW of TTC
2028*	500 MW Adv Nuclear (2028)	Southwest Wyoming Transmission Area		Reclaimed transmission upon retirement of Naughton 1 & 2
2029*	549 MW Battery (2029)	Eastern Wyoming Transmission Area		Reclaimed transmission upon retirement of Dave Johnston Plant
2037	909 MW Solar+Storage (2037)	Southern Utah Transmission Area		Reclaimed transmission upon retirement of Huntington 1 & 2
2038	412 MW Non-Emitting Peaker (2038) 1000 MW Adv Nuclear (2038)	Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger Plant
2040	206 MW Non-Emitting Peaker (2040) 60 MW Wind (2040)	Eastern Wyoming Transmission Area		Reclaimed transmission upon retirement of Wyodak

1 - TTC = total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.
2 - Energy Gateway South is modeled in the 2021 IRP as a contingent option with bids in the 2020 All-Source Request for Proposals. Other transmission options prior to 2026 are not modeled as transmission requirements and costs are accounted for in the 2020 All-Source Request for Proposals transmission cluster study for all other resource bids.
* - Reclaimed transmission is committed with resources with a commercial operation date later than the date of retirement.

New Solar Resources

The 2021 IRP preferred portfolio includes 1,302 MW of new solar by the end of 2024 and 1,902 MW by the end of 2026. Through 2040, more than 5,600 MW of new solar is online as shown in Figure 1.4.

Figure 1.4 – 2021 IRP Preferred Portfolio New Solar Capacity*

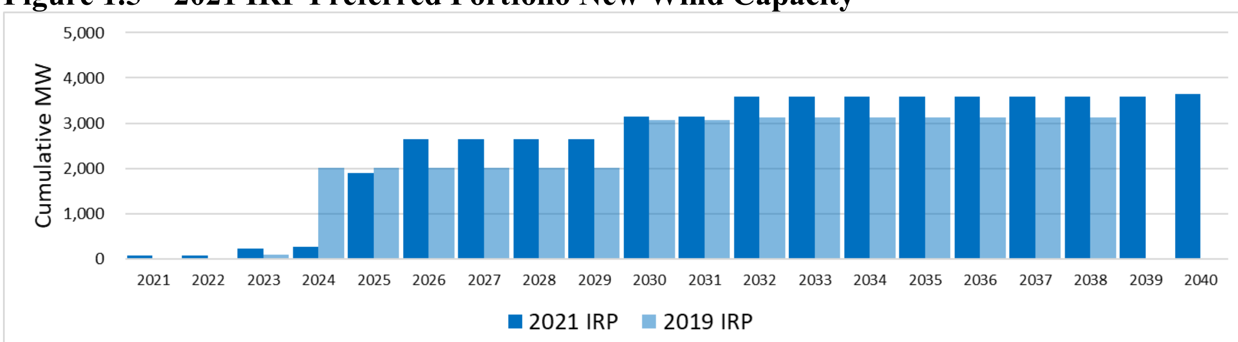


* 2021 IRP solar capacity shown in the figure includes solar resources coming via the 2020 All-Source Request for Proposals by the end of 2024. Resources are shown in the first full year of operation (the year after the year-online dates). The reported capacity for the 2020 All-Source Request for Proposals solar resources reflects their expected maximum output after degradation in their first full year of operation. The maximum solar capacity prior to degradation is 1,306 MW.

New Wind Resources

As shown in Figure 1.5, by the end of 2024, PacifiCorp's 2021 IRP preferred portfolio includes 1,792 MW of new wind generation resulting from the 2020 AS RFP and the acquisition and repowering of Rock River I (49 MW) and Foote Creek II-IV (43 MW). Through the end of 2026, the 2021 IRP preferred portfolio includes an additional 745 MW of new wind and more than 3,700 MW of new wind by 2040.

Figure 1.5 – 2021 IRP Preferred Portfolio New Wind Capacity*

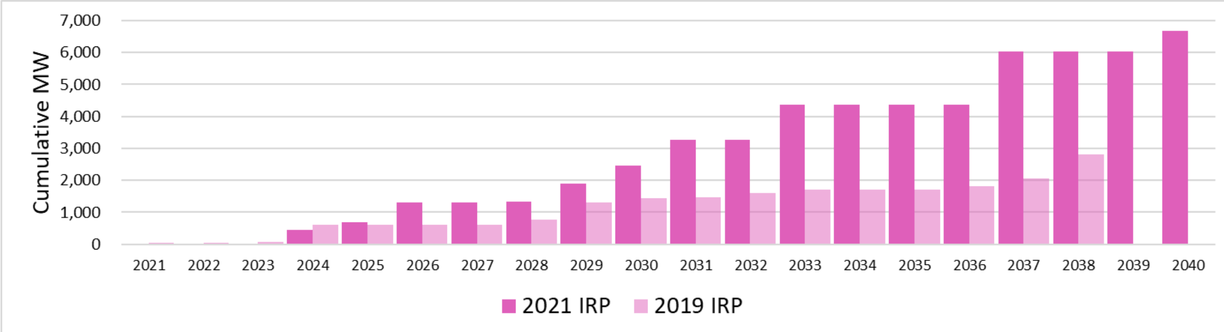


*Note: Wind additions shown are incremental to Energy Vision 2020 and other projects that have come online over the past few years. Resources are shown in the first full year of operation (the year after year-end online dates).

New Storage Resources

New storage resources in the 2021 IRP preferred portfolio are summarized in Figure 1.6. The 2021 IRP preferred portfolio includes nearly 700 MW of battery storage by the end of 2024 – 200 MW of which is a standalone battery and the remaining portion paired with solar resources resulting from the 2020 All-Source RFP. Through 2040, the 2021 IRP includes 4,781 MW of storage co-located with solar resources,1,400 MW of standalone battery, and 500 MW of pumped hydro.

Figure 1.6 – 2021 IRP Preferred Portfolio New Storage Capacity*

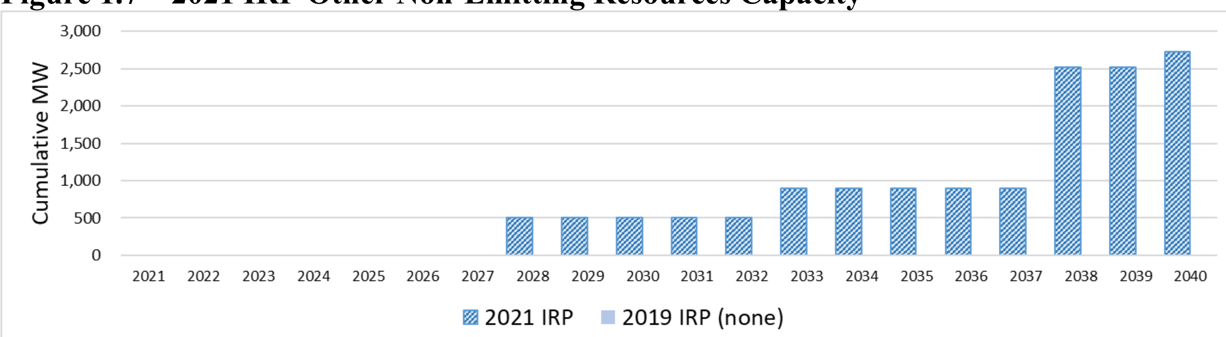


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Other Non-Emitting Resources

This is the first PacifiCorp IRP that includes new advanced nuclear and non-emitting peaking resources as part of its least-cost, least-risk preferred portfolio. As shown in Figure 1.7, the 500 MW advanced nuclear Natrium™ demonstration project will come online by summer 2028. Through 2040, the 2021 IRP preferred portfolio includes 1,000 MW of additional advanced nuclear resources and 1,226 MW of non-emitting peaking resources.

Figure 1.7 – 2021 IRP Other Non-Emitting Resources Capacity*

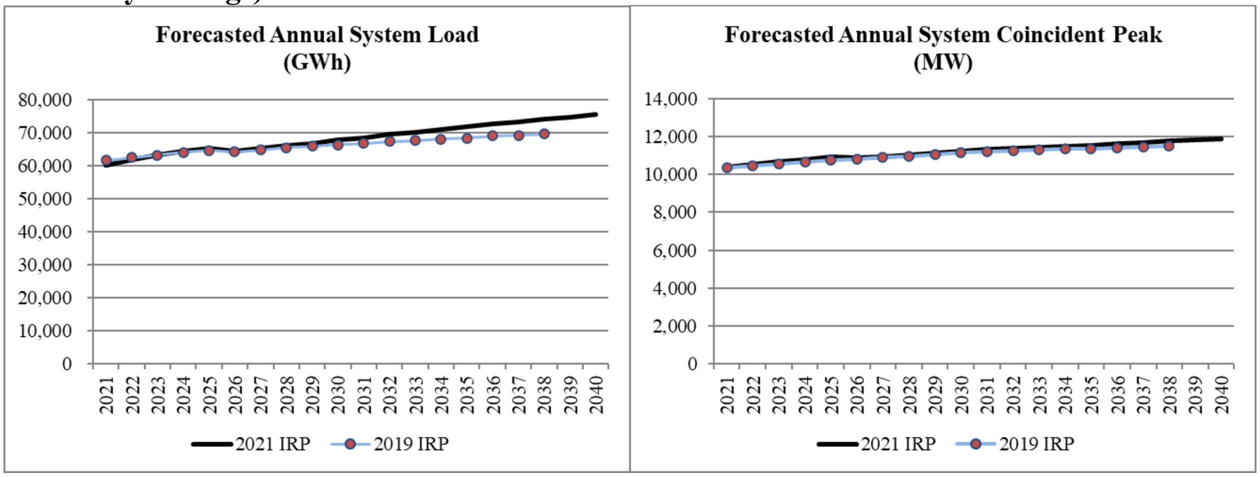


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Demand-Side Management

PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and direct load control programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP. Figure 1.8 shows that PacifiCorp's load forecast before incremental energy efficiency savings has increased relative to projected loads used in the 2019 IRP. On average, forecasted system load is up 2.2 percent and forecasted coincident system peak is up 1.1 percent when compared to the 2019 IRP. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 1.21 percent for load and 0.73 percent for peak. Changes to PacifiCorp's load forecast are driven by higher projected demand from data centers driving up the commercial forecast and an increased residential forecast.

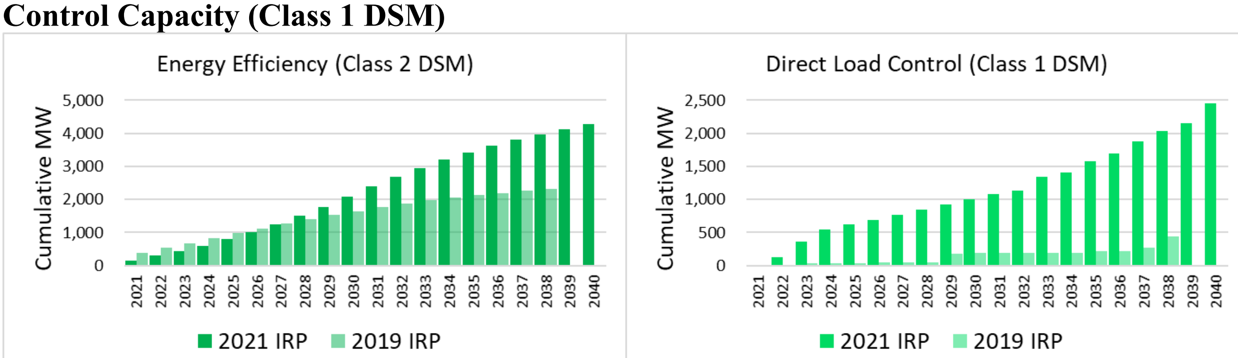
Figure 1.8 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)



DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 1.9 compares total energy efficiency capacity savings in the 2021 IRP preferred portfolio relative to the 2019 IRP preferred portfolio and includes 4,290 MW by the end of the planning period.

In addition to continued investment in energy efficiency programs, the preferred portfolio shows an increasing role for incremental direct load control programs. The chart to the right in Figure 1.9 compares cumulative capacity of direct load control program capacity in the 2021 IRP preferred portfolio relative to the 2019 IRP preferred portfolio and does not include capacity from existing programs. In the 2021 IRP, direct load control resources previously identified in the 2019 IRP and solicited via a demand response RFP, were modeled in addition to resources from the CPA assessing the upper limit of demand response opportunities and value within the IRP. This allowed for the evaluation of real-time resources as a substitute for front office transactions. The 2021 IRP has a cumulative capacity of direct load control programs reaching 2,448 MW by 2040 – an over 400% increase over the planning horizon from the 2019 IRP.

Figure 1.9 – 2021 IRP Preferred Portfolio Energy Efficiency (Class 2 DSM) and Direct Load Control Capacity (Class 1 DSM)



Wholesale Power Market Prices and Purchases

Figure 1.10 shows that the 2021 IRP's base case forecast for natural gas prices has decreased along with a decrease in wholesale power prices for most years relative to those in the 2019 IRP. These forecasts are based on prices observed in the forward market and on projections from third-party experts. The lower power prices observed in the 2021 IRP are primarily driven by the assumption of lower natural gas prices-than what was assumed in the 2019 IRP. Wholesale power prices are higher in 2027 to 2031 because of higher inflation impacting new resource costs. Moreover, the 2021 IRP assumed lower natural gas prices than the 2019 IRP as Henry Hub in particular, is softened by limited pipeline expansion lowering liquefied natural gas exports. While not shown in the figure below, the 2021 IRP also evaluated low and high price scenarios when evaluating the cost and risk of different resource portfolios.

Figure 1.10 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs

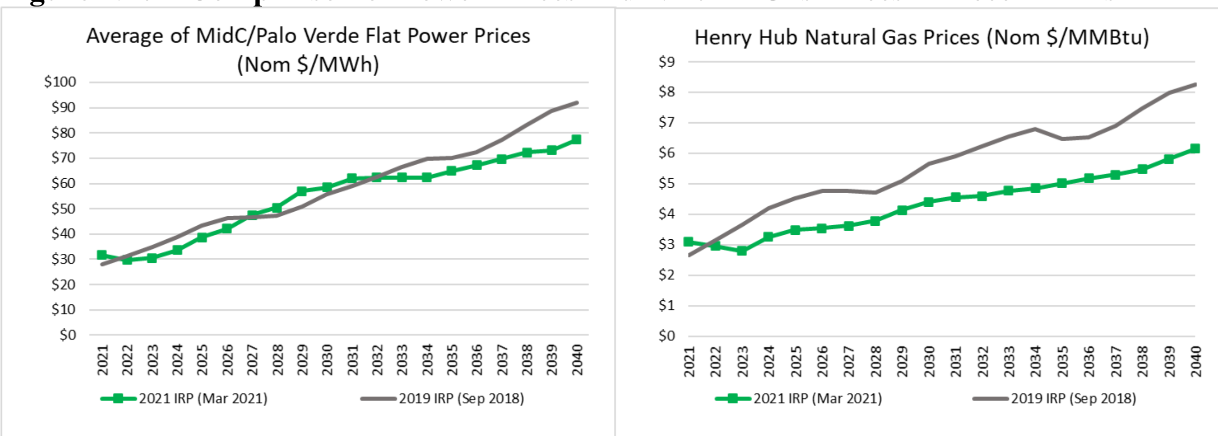
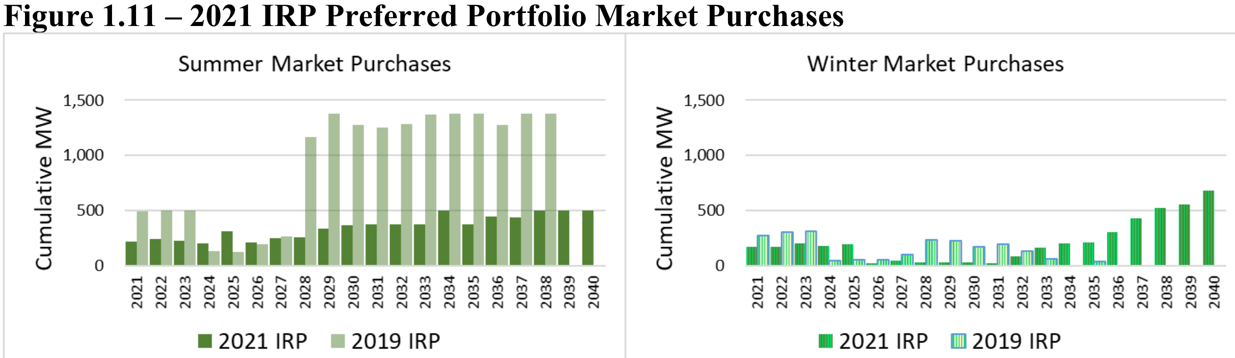


Figure 1.11 shows an overall decline in reliance on wholesale power market firm purchases in the 2021 IRP preferred portfolio relative to the wholesale power market purchases included in the 2019 IRP preferred portfolio. In particular, reliance on wholesale power market purchases during summer peak periods averages 366 MW per year over the 2020-2027 timeframe—down 60 percent from wholesale power market purchases identified in the 2019 IRP preferred portfolio. This reduction in wholesale power market purchases coincides with the period over which there are resource adequacy concerns in the region. While wholesale power market purchases increase beyond 2027, PacifiCorp is actively participating in regional efforts to develop day-ahead markets and a resource adequacy program that will help unlock regional diversity and facilitate market transactions over the long term.

Figure 1.11 – 2021 IRP Preferred Portfolio Market Purchases



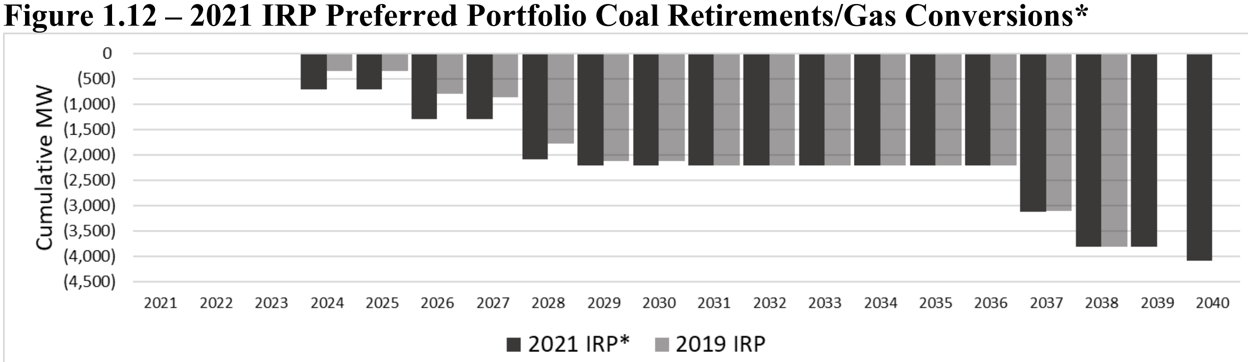
Coal and Gas Retirements/Gas Conversions

Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the EIM) that has enabled the company to reduce fuel consumption and associated costs and emissions, and instead buy increasingly low-cost, zero-emissions renewable energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy as the remaining coal units approach retirement dates. Driven in part by ongoing cost pressures on existing coal-fired facilities and dropping costs for new resource alternatives, of the 22 coal units currently serving PacifiCorp customers, the preferred portfolio includes retirement of 14 of the units by 2030 and 19 of the units by the end of the planning period in 2040. As shown in Figure 1.12, coal unit retirements/gas peaker conversions in the 2021 IRP preferred portfolio will reduce coal-fueled generation capacity by 1,300 MW by the end of 2025, over 2,200 MW by 2030, and over 4,000 MW by 2040.

Coal unit retirements scheduled under the preferred portfolio include:

- 2023 = Jim Bridger Units 1-2, converted to natural gas peakers in 2024 (same retirement year for Jim Bridger 1 in 2019 IRP and instead of 2028 for Jim Bridger 2 in the 2019 IRP).
- 2025 = Naughton Units 1-2 (same as 2019 IRP)
- 2025 = Craig Unit 1 (same as 2019 IRP)
- 2025 = Colstrip Units 3-4 (instead of 2027 in the 2019 IRP)
- 2027 = Dave Johnston Units 1-4 (same as 2019 IRP)
- 2027 = Hayden Unit 2 (instead of 2030 in the 2019 IRP)
- 2028 = Craig Unit 2 (instead of 2026 in the 2019 IRP)
- 2028 = Hayden Unit 1 (instead of 2030 in the 2019 IRP)
- 2036 = Huntington Units 1-2 (same as 2019 IRP)
- 2037 = Jim Bridger Units 3-4 (same as 2019 IRP)
- 2039 = Wyodak (same as 2019 IRP but outside of 2019 IRP planning horizon)

Figure 1.12 – 2021 IRP Preferred Portfolio Coal Retirements/Gas Conversions*



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

In addition to the coal unit retirements outlined above, the preferred portfolio reflects 1,554 MW natural gas retirements through 2040. This includes Naughton Unit 3 at the end of 2029, Gadsby at the end of 2032, Hermiston at the end of 2036, and Jim Bridger Units 1 and 2 at the end of 2037.

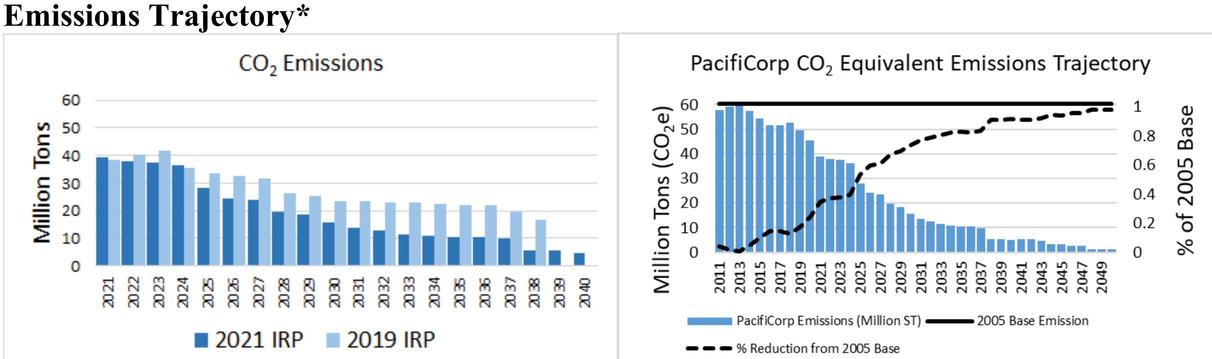
Carbon Dioxide Emissions

The 2021 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects a continued trajectory of declining carbon dioxide (CO_2) emissions. PacifiCorp's emissions have been declining and continue to decline related to several factors including PacifiCorp's participation in the EIM, which reduces customer costs and maximizes use of clean energy; PacifiCorp's on-going transition to clean-energy resources including new renewable resources, new advanced nuclear resources, new non-emitting resources, storage, transmission, and Regional Haze compliance that capitalizes on flexibility.

The chart on the left in Figure 1.13 compares projected annual CO_2 emissions between the 2021 IRP and 2019 IRP preferred portfolios. In this graph, emissions are not assigned to market purchases or sales, and in 2026, annual CO_2 emissions are down 26 percent relative to the 2019 IRP preferred portfolio. By 2030, average annual CO_2 emissions are down 34 percent relative to the 2019 IRP preferred portfolio, and down 52 percent in 2035. By the end of the planning horizon, system CO_2 emissions are projected to fall from 39.1 million tons in 2021 to 4.8 million tons in 2040—a reduction of 88 percent.

The chart on the right in Figure 1.13 includes historical data, assigns emissions at a rate of 0.4708 tons CO_2 equivalent per MWh to market purchases (with no credit to market sales), includes emissions associated with specified purchases, and extrapolates projections out through 2050. This graph demonstrates that relative to a 2005 baseline, system CO_2 equivalent emissions are down 53 percent in 2025, 74 percent in 2030, 83 percent in 2035, 92 percent in 2040, 94 percent in 2045, and 98 percent in 2050.

Figure 1.13 – 2021 IRP Preferred Portfolio CO_2 Emissions and PacifiCorp CO_2 Equivalent Emissions Trajectory*



*Note: PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2020 from owned facilities, specified sources and unspecified sources. From 2021 through the end of the twenty-year planning period in 2040, emissions reflect those from the 2021 IRP preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Market purchases are assigned a default emission factor (0.4708 short tons CO_2e/MWh) – emissions from sales are not removed. Beyond 2040, emissions reflect the rolling average emissions of each resource from the 2021 IRP preferred portfolio through the life of the resource. The emissions trajectory does not incorporate clean energy targets set forth in Oregon House Bill 2021 or any other state-specific emissions trajectories. PacifiCorp expects these targets, and an Oregon-specific emissions trajectory, to be incorporated following the 2023 integrated resource plan when PacifiCorp is required under the bill to file a Clean Energy Plan.

Renewable Portfolio Standards

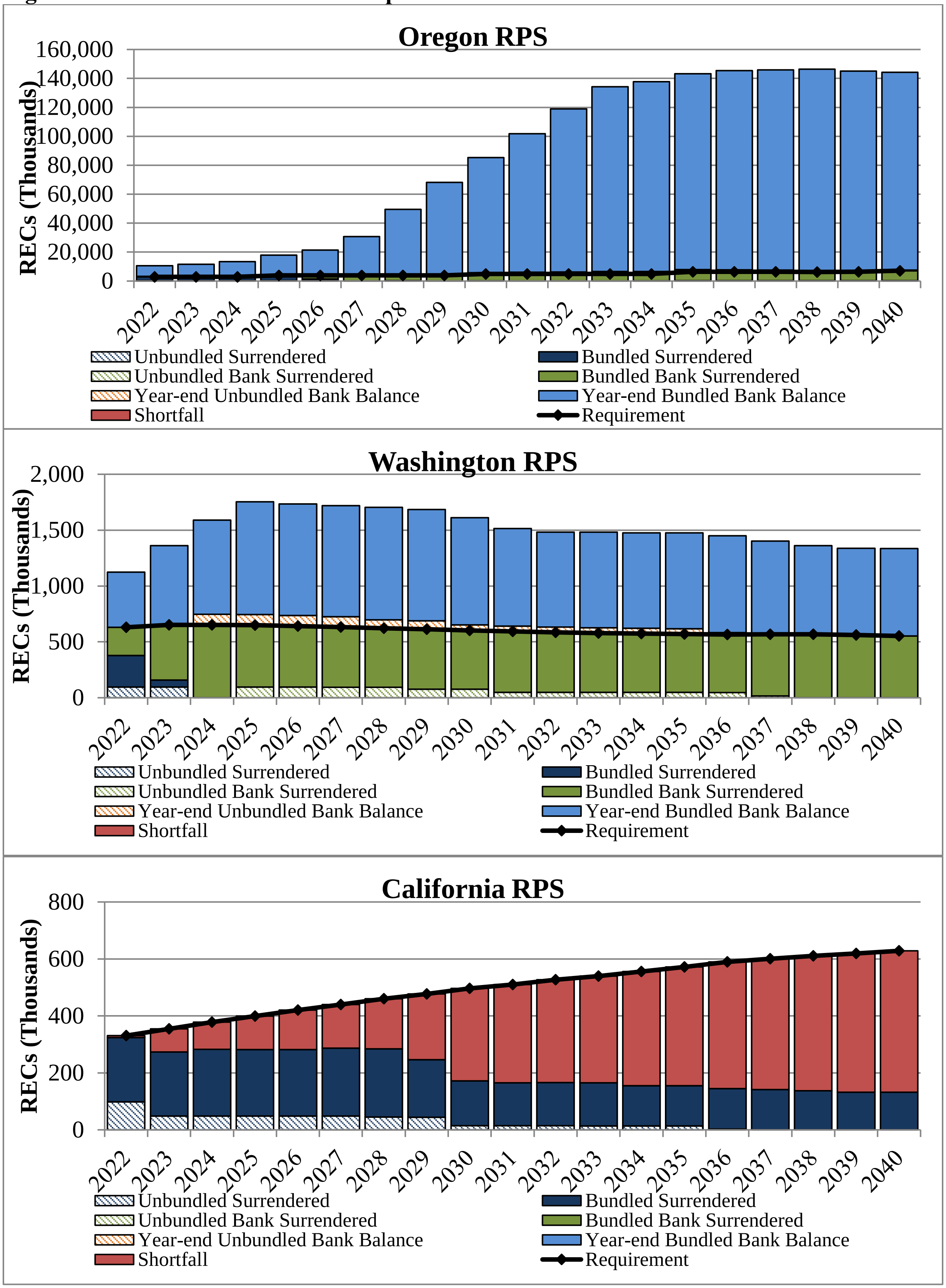
Figure 1.14 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for new renewable resources in the preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources and are not included to specifically meet RPS targets, they nonetheless contribute to meeting RPS targets in PacifiCorp's western states.

Oregon RPS compliance is achieved through 2040 with the addition of new renewable resources and transmission in the 2021 IRP preferred portfolio. Washington RPS compliance is achieved with the benefit of increased system renewable resources beginning 2021 as well as additional resources procured that meet the state's Clean Energy Transformation Act. Under PacifiCorp's 2020 Protocol, and the Washington Interjurisdictional Allocation Methodology, Washington's RPS position is improved by receiving a system share of renewable resources across the PacifiCorp's system.

The California RPS compliance position will be met with owned and contracted renewable resources, as well as REC purchases throughout the 2021 IRP study period. The ramping RPS requirement results in an increased need for unbundled REC purchases to meet the annual and compliance period targets in 2021-2040. New renewable resources and transmission in the 2021 IRP preferred portfolio mitigate that shortfall, but the company may need to purchase approximately 200,000 RECs in compliance periods 4 and 5, 2021-2024 and 2025-2028, respectively. Beyond 2028, the company may need to purchase 200,000-300,000 RECs per year to meet the ramping RPS.

While not shown in Figure 1.14, PacifiCorp meets the Utah 2025 state target to supply 20 percent of adjusted retail sales with eligible renewable resources with existing owned and contracted resources and new renewable resources and transmission in the 2021 IRP preferred portfolio.

Figure 1.14 – Annual State RPS Compliance Forecast



2021 IRP Advancements and Supplemental Studies

IRP Advancements

During each IRP planning cycle, PacifiCorp identifies and implements advancements to continuously improve the IRP for its customers, other stakeholders, and regulatory commissions. Some of the key advancements implemented in the 2021 IRP include:

- Implementation of Advanced Modeling System
  As part of its 2021 IRP, PacifiCorp implemented a new and more advanced third-party software to conduct its long-term capacity expansion modeling, hourly dispatch simulations of resource portfolios and stochastic modeling. PacifiCorp implemented the Plexos modeling system by Energy Exemplar. The three platforms of the Plexos tool (referred to as Long-term (LT), Medium-term (MT) and Short-term (ST)) work on an integrated basis to inform the optimal combination of resources by type, timing, size, and location over PacifiCorp's 20-year planning horizon. The Plexos tool also allows for improved endogenous modeling of resource options simultaneously, greatly reducing the volume of individual portfolios needed to evaluate impacts of varying resource decisions. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) for more information.

- Endogenous Modeling of Resources
  As part of it 2021 IRP, the Plexos model was able to endogenously consider coal retirement timing options along with other specified options such as gas conversion or carbon capture utilization and sequestration retrofit for a coal unit. In addition, the Plexos model had the ability to endogenously view costs and transmission capability associated with certain transmission upgrades that allowed for selection of specific transmission investments that coincide with new resource additions. Endogenous transmission modeling capabilities include the 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, and 4) transmission options that interact with multiple or complex elements of the IRP transmission topology. Endogenous modeling of standalone and co-located battery resources was also improved with the Plexos model over the 2019 IRP. In the 2019 IRP, optimization of dispatch, charging and reserves for batteries was modeled using an external tool, and the results brought back into the primary model. In the 2021 IRP, Plexos allows for the endogenous treatment of the entirety of battery optimization. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) for more information.

- Targeted Portfolio Reliability Analysis
  In the 2021 IRP, PacifiCorp further advanced its approach for assessing the reliability of resource portfolios and the ability of each unique resource portfolio to meet reliability requirements. This IRP incorporates operating reserves in the LT model for capacity expansion and optimizes available resources to meet requirements in all periods, not just the system peak. With significant levels of economic renewable resource being selected in every resource portfolio, PacifiCorp found that subsequent modeling of these resource portfolios using the Short-Term (ST) hourly dispatch model, which considers more granularity and an explicit accounting of operating reserve requirements, consistently identified capacity shortfalls needed to maintain reliable operation of the system. PacifiCorp ran 20-year ST studies to evaluate shortfalls on a portfolio-specific basis across each year of the 20-year planning horizon. From the results of these hourly deterministic ST runs PacifiCorp developed a process

to remedy the incremental need for reliability resources through cost-effective resource additions to a portfolio to ensure there is sufficient flexible capacity to meet reliability requirements. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) for more information.

- Improvements in Modeling Assumptions
  In the 2021 IRP, PacifiCorp improved several modeling assumptions including weather-adjusted energy efficiency, wind and solar to better align with the load forecast, re-bundling energy efficiency supply-side resource options on a net cost of capacity basis, optimizing battery dispatch that adheres to charging constraints within the Plexos model, and multipath endogenous transmission modeling options. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) for more information.

- Stakeholder Requests and Feedback
  In its 2021 IRP, in addition to PacifiCorp's stakeholder feedback form process of posting the forms received from stakeholders as well as PacifiCorp's response throughout the public-input process, PacifiCorp has also summarized the stakeholder feedback forms received and how feedback was considered as part of the 2021 IRP document. PacifiCorp received and responded to over 450 stakeholder feedback forms in the 2021 IRP. PacifiCorp was able to accommodate numerous stakeholder requests to develop additional scenarios and sensitivities during the public-input process. PacifiCorp and stakeholders collaborated to identify potential scenarios, and scenarios selected for inclusion included an analysis of accelerated coal retirements, variations of "business-as-usual" cases, alternate DSM bundling methodologies, and other updates to modeling inputs. A full summary of requests received and considered can be found in Volume II, Appendix C (Public Input Process).

- Public-Input Meetings
  PacifiCorp began its public-input process for the 2021 IRP development cycle much earlier than prior IRP development cycles with a series of three public-input meetings that were technical workshops on the Conservation Potential Assessment to inform development of PacifiCorp's demand-side management planning assumptions. In addition, due to the pandemic that emerged during the 2021 IRP development cycle, PacifiCorp was able to pivot and continue robust stakeholder participation throughout its public-input meeting process by holding the meetings via Microsoft Teams platform and phone conference. This enabled the option for video connectivity when available and simultaneous viewing of meeting material via the online platform. See Volume II, Appendix C (Public Input Process) for more information.

Supplemental Studies

PacifiCorp's 2021 IRP relies on numerous supplemental studies that support the derivation of specific modeling assumptions critical to development of its long-term resource plan. A description of these studies, discussed in more detail in 2021 IRP and appendices filed with the 2021 IRP, is provided below. Additional source files and information may also be located for some studies on PacifiCorp's IRP webpage at the following location:
www.pacificorp.com/energy/integrated-resource-plan.html

- Capacity Contribution
  The capacity contribution of a resource is dependent on the other components in a portfolio, and PacifiCorp's portfolio development process is based on achieving reliable system operation using the aggregate contributions of each resource in the portfolio, rather than focusing on an individual estimate. For reporting, the capacity factor approximation method (CF Method) was used to identify marginal capacity contribution values for individual resource options, based on a portfolio similar to the preferred portfolio.

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

- Energy Storage Potential Evaluation
  Energy storage resources can provide a variety of grid services since they are highly flexible, with the ability to respond to dispatch signals and act as both a load and a resource. This evaluation, refreshed for the 2021 IRP, provides details on these grid services and on how energy storage resources can be configured and sited to maximize the benefits they provide.

- Flexible Reserve Study
  This study, updated for the 2021 IRP, evaluates the need for flexible resources resulting from the variability and uncertainty in load, wind, solar, and other generation resources. The study produces an estimate of flexible reserve needs for each hour that accounts for the specific load, wind, and solar resources being evaluated. Reserve costs associated with meeting these flexible reserve needs are also estimated.

- Plant Water Consumption Study
  This study provides updated data on the water consumption of PacifiCorp-owned generating facilities by fuel type and by state in which the facility is located.

- Private Generation Resource Assessment
  This supplemental study, prepared by Guidehouse (formerly Navigant Consulting, Inc.), was refreshed for the 2021 IRP to produce updated private generation penetration forecasts for solar photovoltaic, small-scale wind, small-scale hydro, combined heat and power reciprocating engines, and combined heat and power micro-turbines specific to PacifiCorp's service territory. The private generation penetration forecasts from this study are applied as a reduction to forecasted load throughout the IRP modeling process and used in developing assumptions for the low private generation sensitivity and high generation sensitivity cases.

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

- Stochastic Parameter Update
  PacifiCorp's preferred portfolio-selection process relies, in part, on stochastic risk analysis using Monte Carlo random sampling of stochastic variables. Stochastic variables include natural gas and wholesale electricity prices, load, hydro generation, and unplanned thermal outages. For the 2021 IRP, PacifiCorp updated its stochastic parameter input assumptions with more current historical data.

- Renewable Resources Assessment
  A study on renewable resources and energy storage was commissioned to support PacifiCorp's 2021 Integrated Resource Plan (IRP). The 2020 Renewable Resources Assessment, prepared by Burns & McDonnell Engineering Company, Inc. (BMcD) is screening-level in nature and includes a comparison of technical capabilities, capital costs, and operations and maintenance costs that are representative of renewable energy and storage technologies. BMcD evaluated energy storage options of Pumped Hydro Energy Storage, Compressed Air Energy Storage, Lithium-Ion Battery, Flow Battery, as well as wind and solar and combinations of these resource types.

Action Plan

The 2021 IRP action plan identifies specific resource actions PacifiCorp will take over the next two-to-four years to deliver resources included in the preferred portfolio. Action items are based on the type and timing of resources in the preferred portfolio, findings from analysis completed during the development of the 2021 IRP, and other resource activities described in the 2021 IRP. Table 1.2 details specific 2021 IRP action items by category.

Table 1.2 – 2021 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	**Colstrip Units 3 and 4:** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2021 IRP preferred portfolio target exit date of December 31, 2025.
1b	**Craig Unit 1:** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2021 IRP preferred portfolio target exit date of December 31, 2025.
1b	**Naughton Units 1 and 2:** • PacifiCorp will initiate the process of retiring Naughton Units 1-2 by the end of December 2025, including completion of all required regulatory notices and filings. • By the end of Q2 2023, PacifiCorp will confirm transmission system reliability assessment and year-end 2025 retirement economics in 2023 IRP filing. • By the end of Q4 2023, PacifiCorp will initiate the process with the Wyoming Public Service Commission for approval of a reverse request for proposals for a potential sale of Naughton Units 1 and 2. • By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements.

1c	**<u>Jim Bridger Units 1 and 2 Gas Conversion:</u>** • PacifiCorp will initiate the process of ending coal-fueled operations and seeking permitting for a natural-gas conversion by 2024, including completion of all required regulatory notices and filings. • By the end of Q2 2022, PacifiCorp will finalize an employee transition plan. • By the end of Q2 2022, PacifiCorp will develop a community action plan in coordination with community leaders. • By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements. • By the end of Q4, 2023, PacifiCorp will remove units 1 and 2 from Washington's allocation of electricity.
1d	**<u>Carbon Capture, Utilization, and Sequestration/Wyoming House Bill 200 Compliance:</u>** • PacifiCorp issued a carbon capture, utilization, and sequestration (CCUS) request for expression of interest (REOI) on June 29, 2021. PacifiCorp will complete the 2021 CCUS REOI process and utilize any new relevant information. Additional model sensitivities will be run accordingly. • PacifiCorp will issue a CCUS Request for Proposals (RFP) in 2022. The 2021 CCUS REOI responses will inform the scope of the CCUS RFP. • A completed CCUS Front End Engineering & Design Study (FEED Study) based on a new CCUS technology was submitted to PacifiCorp in July 2021 for Dave Johnston Unit 2. Third-party review of the FEED Study will be completed by Q1 2022, and model sensitivities will subsequently be run as needed, with FEED Study assumptions and inputs as appropriate. • Subject to finalization of rules by the Wyoming Public Service Commission (WPSC) to implement House Bill 200 (HB 200), the Wyoming Low Carbon Energy Standard (anticipated by Q4 2021), by March 31, 2022, PacifiCorp will file with the WPSC an initial CCUS application to establish intermediate CCUS standards and requirements. • Subject to finalization of rules by the WPSC to implement HB 200, the Wyoming Low Carbon Energy Standard (anticipated by Q4 2021), PacifiCorp will submit for WPSC approval a final plan with its proposed energy portfolio standard for dispatchable and reliable low-carbon electricity, its plan for achieving the standard, and a target date of no later than July 1, 2030.
1e	**<u>Regional Haze Compliance:</u>** • Following the resolution of first planning period regional haze compliance disputes, and the submission of second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the Environmental Protection Agency, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.

Action Item	2. New Resource Actions
2a	**Customer Preference Request for Proposals:** • Consistent with Utah Community Renewable Energy Act, PacifiCorp continues to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp anticipates filing an application for approval of the program with the Utah Public Service Commission in 2022, which may necessitate issuance of a request for proposals to procure resources within the action plan window.
2b	**Acquisition and Repowering of Foote Creek II-IV and Rock River I:** • In Q3 2021, PacifiCorp will pursue necessary regulatory approvals to authorize the acquisition and repowering of Foote Creek II-IV in order to issue repowering contracts in Q1 2022 in support of a late 2023 in-service date. • In Q1 2022, PacifiCorp will pursue necessary regulatory approvals to authorize the acquisition and repowering of Rock River I following the expiration of the existing power purchase agreement in order to issue repowering contracts in Q3 2022 to support a late 2024 in-service date.
2c	**Natrium™ Demonstration Project:** • PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable. • By the end of 2022, PacifiCorp will finalize commercial agreements for the Natrium™ project. • Q1 2022, PacifiCorp will develop a community action plan in coordination with community leaders. • By 2025, PacifiCorp will begin training operators. • PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable, including, but not limited to, a request for the Oregon Public Utility Commission to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.

2d	**<u>2022 All-Source Request for Proposals:</u>** • PacifiCorp will issue an all-source Request for Proposals (RFP) to procure resources that can achieve commercial operations by the end of December 2026. • In September 2021, PacifiCorp will notify the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, of PacifiCorp's need for an independent evaluator. • In October 2021, PacifiCorp will file a draft all-source RFP with applicable state utility commissions. • In January 2022, PacifiCorp expects to receive approval of the all-source RFP from applicable state utility commissions and issue the RFP to the market. • In Q2 2022, PacifiCorp will identify an initial shortlist in advance of annual Cluster Request Window. • In Q1 2023, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon, file, certificate of public convenience and necessity (CPCN) applications, as applicable. • By Q2 2023 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • By Q4 2025-2026, winning bids from the all-source RFP are expected to achieve commercial operation. Resources must have commercial operation date of December 31, 2026, or earlier.
2e	**<u>2020 All-Source Request for Proposals:</u>** • PacifiCorp filed for approval of the final shortlist in Oregon in June 2021. • In September 2021, PacifiCorp will file CPCN applications in Wyoming, as applicable, for final shortlist. • In Q4 2021, PacifiCorp will make a filing in Utah for significant energy resources on final shortlist.
Action Item	**3. Transmission Action Items**
3a	**<u>Energy Gateway South Segment F (Aeolus-Clover 500 kV transmission line):</u>** • By Q2 2022, obtain Utah and Wyoming Certificates of Public Convenance and Necessity. • By the end of Q1 2022, Bureau of Land Management notice to proceed to construct Energy Gateway South. • In Q3 2024, construction of Energy Gateway South is expected to be completed and placed in service.
3b	**<u>Energy Gateway West, Segment D.1 (Windstar-Shirley Basin 230 kV transmission line):</u>** • By Q2 2022, obtain conditional Wyoming Certificate of Public Convenance and Necessity • By Q3 2022 complete ROW easement acquisition and option full Wyoming CPCN • In Q3 2024, construction of Energy Gateway West segment D.1 to be completed and placed in service.

3c	**<u>Boardman-to-Hemingway (500 kV transmission line):</u>** • Continue to support the project under the conditions of the Boardman-to-Hemingway Transmission Project (B2H) Joint Permit Funding Agreement. • Continue to participate in the development and negotiations of the construction agreement. • Continue to participate in "pre-construction" activities in support of the 2026 in-service date. • Continue negotiations for plan of service post B2H for parties to the permitting agreement.
3d	Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids
3e	Continue permitting support for Gateway West segments D.3 and E.
Action Item	**4. Demand-Side Management (DSM) Actions**

4a	**Energy Efficiency Targets:**

Energy Efficiency Targets:

- PacifiCorp will acquire cost-effective Class 2 DSM (energy efficiency) resources targeting annual system energy and capacity selections from the preferred portfolio as summarized below. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2021 IRP.
- PacifiCorp will pursue cost-effective energy efficiency resources as summarized in the table below:

Year	Annual 1st Year Energy (GWh)	Annual Incremental Capacity (MW)
2021	510	157
2022	492	138
2023	486	144
2024	529	164

- PacifiCorp will pursue cost-effective Class 1 (demand response) resources targeting annual system capacity[1] selections from the preferred portfolio[2] as summarized in the table below:

Year	Annual Incremental Capacity (MW)
2021	0
2022	123
2023	242
2024	184

[1] Capacity impacts for demand response include both summer and winter impacts within a year.
[2]A portion of cost-effective demand response resources identified in the 2021 preferred portfolio are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2019 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to resources subsequently procured under the previously issued RFP in compliance with state level procurement requirements.

Action Item	5. Market Purchases

5a	**Market Purchases:** • Acquire short-term firm market purchases for on-peak delivery from 2021-2023 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. • Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. • Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.
Action Item	**6. Renewable Energy Credit (REC) Actions**
6a	**Renewable Portfolio Standards (RPS):** • PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • As needed, issue RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting California RPS targets through 2024.
6b	**Renewable Energy Credit Sales:** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

CHAPTER 2 – INTRODUCTION

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

PacifiCorp's selection of the 2021 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process, described in the chapters that follow. PacifiCorp's 2021 preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, and for the first time, significant battery storage resources and advanced nuclear. By the end of 2024, the 2021 IRP preferred portfolio includes the 2020 All-Source RFP final shortlist resources including 1,792 MW of wind, 1,302 MW of solar additions, and 697 MW of battery storage capacity – 497 MW paired with solar and a 200 MW standalone battery. During this time, the preferred portfolio also includes the acquisition and repowering of Rock River 1 (49 MW) and Foote Creek II-IV (43 MW) wind projects. Through the end of 2026, the 2021 IRP preferred portfolio includes an additional 745 MW of wind and an additional solar co-located with storage.

To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes the construction of a 416-mile 500-kilovolt (kV) transmission line known as Gateway South connecting southeastern Wyoming and northern Utah, the 59-mile 230 kV transmission line in eastern Wyoming known as Gateway West Segment D.1, and the 500 kV, 290-mile transmission line across eastern Oregon and southwestern Idaho known as Boardman to Hemingway (B2H).

Other significant studies conducted to support analysis in the 2021 IRP include:

- An updated demand-side management resource conservation potential assessment;
- A private generation study for PacifiCorp's service territory;
- A renewable resources assessment;
- An assessment of smart grid technologies;
- Updated stochastic parameters; and
- An updated load and resource balance.

This chapter outlines the components of the 2021 IRP, summarizes the role of the IRP, and provides an overview of the public-input process.

2021 Integrated Resource Plan Components

The basic components of PacifiCorp's 2021 IRP include:

- Assessment of the planning environment, market trends and fundamentals, legislative and regulatory developments, and current procurement activities (Chapter 3).
- Description of PacifiCorp's transmission planning efforts and activities (Chapter 4).
- Discussion of PacifiCorp's commitment to serve customers reliably, and summary of the company's actions to ensure all-weather resource adequacy, wildfire mitigation planning, and transmission planning to support power flow reliability. (Chapter 5)
- Load and resource balance on a capacity and energy basis and determination of the load and energy positions for the front ten years of the twenty-year planning horizon (Chapter 6).
- Profile of resource options considered for addressing future capacity and energy needs (Chapter 7).
- Description of the IRP modeling, including a description of the portfolio development process, cost and risk analysis, and preferred portfolio selection process (Chapter 8).
- Presentation of IRP modeling results and selection of PacifiCorp's preferred portfolio (Chapter 9).
- Presentation of PacifiCorp's 2021 IRP action plan linking the company's preferred portfolio with specific implementation actions, including an accompanying resource acquisition path analysis and discussion of resource procurement risks (Chapter 10).

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

- Load Forecast Details (Volume II, Appendix A),
- IRP Regulatory Compliance (Volume II, Appendix B),
- Public Input (Volume II, Appendix C),
- Demand Side Management Resources (Volume II, Appendix D),
- Smart Grid (Volume II, Appendix E),
- Flexible Reserve Study (Volume II, Appendix F),
- Plant Water Consumption Study (Volume II, Appendix G),
- Stochastic Parameters (Volume II, Appendix H),
- Capacity Expansion Results (Volume II, Appendix I)
- Stochastic Simulation Results (Volume II, Appendix J),
- Capacity Contribution (Volume II, Appendix K),
- Private Generation Study (Volume II, Appendix L),
- Renewable Resources Assessment (Volume II, Appendix M),
- Energy Storage Potential Evaluation (Volume II, Appendix N),
- Washington Clean Energy Action Plan (Volume II, Appendix O),
- RFP Overview (Volume II, Appendix P); and
- Acronyms (Volume II, Appendix Q)

To promote transparency PacifiCorp is also providing data discs for the 2021 IRP. These discs support and provide additional details for the analysis described within the document. Data discs containing confidential information are provided separately under non-disclosure agreements, or specific protective orders in docketed proceedings.

The Role of PacifiCorp's Integrated Resource Planning

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

Public-Input Process

The IRP standards and guidelines for certain states require PacifiCorp to have a public-input process allowing stakeholder involvement in all phases of plan development. PacifiCorp organized five state meetings and held 18 public-input meetings, some of which spanned two days to facilitate information sharing, collaboration, and expectations for the 2021 IRP. The topics covered all facets of the IRP process, ranging from specific input assumptions to the portfolio modeling and risk analysis strategies employed.

Table 2.1 lists the public input meetings/conferences and highlights major agenda items covered. Volume II, Appendix C Public-Input Process provides more details concerning the public-input process.

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

Table 2.1 – IRP Public-Input Meetings

Meeting Type	Date	Main Agenda Items
State Meeting	7/22/20	Utah state stakeholder comments
State Meeting	7/22/20	Washington state stakeholder comments
State Meeting	7/23/20	Wyoming state stakeholder comments
State Meeting	7/24/20	Oregon state stakeholder comments
CPA Technical Workshop	1/21/20	Conservation Potential Assessment (CPA) Overview, Key Changes and Updates for the 2021 CPA, Market Characterization and Baseline Development, Measure Characterization and Potential Estimation, 2021 CPA Work Plan
CPA Technical Workshop	2/18/20	Energy Efficiency, Measure List Changes, Demand Response, Resource Options and Examples
CPA Technical Workshop	4/16/20	Conservation Potential Assessment Schedule and Milestones, Stakeholder Feedback, Recap of Key Discussion Topics From Prior Workshops, Drivers of difference in Forecasted Potential by State
General Meeting (2-Day)	6/18/20	Stakeholder Feedback Form Update, CPA Update, Optimization Modeling and Modeling Update, Modeling Energy Storage
	6/19/20	2019 IRP Highlights/ 2021 IRP Topics and Timeline, Request for Proposal Update, Transmission Overview and Update
General Meeting (2-Day)	7/30/20	Load Forecast Update, Distribution System Planning, Supply-side Resource Study Efforts, Coal Studies Discussion
	7/31/20	Environmental Policy, Renewable Portfolio Standards, DMS Bundling Portfolio Methodology, Private Generation Study, Stakeholder Feedback Form Recap
CPA Technical Workshop	8/28/20	2021 CPA Process Review, Energy Efficiency Potential Draft Results, Demand Response Potential Draft Results
General Meeting	9/17/20	Supply-side Resources, Portfolio Development Discussion, State Policy Update, Conservation Potential Assessment Update, Stakeholder Feedback Form Recap
General Meeting	10/22/20	General Updates, Summary of Oregon Energy Efficiency Analysis Results
General Meeting	11/16/20	Plexos Benchmark and Modeling Assumptions
General Meeting	12/3/20	Conservation Potential Assessment, DSM Bundling Methodology, Updated Portfolio Matrix and Analysis
General Meeting	1/29/21	Energy Efficiency Bundling Methodology, Renewable Shaping, Stakeholder Feedback Form Recap
General Meeting	2/10/21	Discussion of current status of IRP, proposed updates to schedule.
General Meeting	4/23/21	Portfolio Modeling process update, Stakeholder Feedback Form Recap
General Meeting	6/25/21	Update on Key Activities and Presentation of Indicative Case
General Meeting	7/30/21	Discussion of Portfolio Optimization and Modeling Discussion
General Meeting	8/6/21	Continued Discussion of Portfolio Results
General Meeting	8/27/21	Presentation of 2021 IRP results

In addition to the public-input meetings, PacifiCorp used other channels to facilitate resource planning-related information sharing and stakeholder input throughout the IRP process. The IRP webpage can be found at the following location: www.pacificorp.com/energy/integrated-resource-plan.html, an e-mail "mailbox" (irp@pacificorp.com), and a dedicated IRP phone line (503-813-5245) to support communications and inquiries among participants. Additionally, a stakeholder feedback form was used to provide opportunities for stakeholders to submit additional input and ask questions throughout the 2021 IRP public-input process. The submitted forms, as well as PacifiCorp's responses to these feedback forms are located on the PacifiCorp's IRP website: www.pacificorp.com/energy/integrated-resource-plan/comments.html. A summary of stakeholder feedback forms received, and company response was provided during the public-input meetings.

CHAPTER 3 – PLANNING ENVIRONMENT

CHAPTER HIGHLIGHTS

- In 2009 Appalachia (mostly Pennsylvania and West Virginia), produced almost no natural gas; by late 2013 it was producing almost 12 billion cubic feet per day (BCF/D) and by end-of-year 2020, Appalachia was producing over 35 BCF/D. In short, supply from Appalachia continues to grow as volumes and costs prove to be, respectively, higher and lower than anticipated. Today, Appalachia accounts for 34 percent of the nation's gas supply, and by 2040 is expected to account for 44 percent, spurred by increased drilling efficiencies and rising demand. Day-ahead 2020 Henry Hub prices averaged $2.03/Million British thermal units (MMBtu), down 77 percent from 2008 prices.
- Federal and state tax credits, declining capital costs, and improved technology performance have put wind and solar "in the money" in areas of high potential. As such, wind and solar will likely dominate U.S. capacity additions for the next decade. To better integrate these resources into the larger grid requires more flexible generation, transmission, new storage technologies, and market design changes.
- In 2019, the Washington Legislature approved the Clean Energy Transformation Act (CETA), which requires that 100% of electricity sales in Washington be 100% renewable and non-emitting by 2045. The Phase I rulemakings – governing the planning processes – were completed as of December 2020, and this IRP meets the requirements outlined in the law and subsequent rules.
- In 2021, Washington passed the Climate Commitment Act, which establishes a cap-and-trade program to be implemented by no later than 2023 through the regulatory rulemaking process. The Climate Commitment Act does not modify any of PacifiCorp's obligations under CETA, and utility allowances within the cap-and-trade program are aligned with the CETA renewable energy requirements. The legislation allows – but does not require – linkage with cap-and-trade programs in jurisdictions outside of Washington State.
- In 2021, Oregon passed House Bill 2021, which directs utilities to reduce emissions levels below 2010-2012 baseline levels by 80% by 2030, 90% by 2035, and 100% by 2040. Utilities will also convene a Community Benefits and Impacts Advisory Group. PacifiCorp's 2023 IRP will include modeling to support House Bill 2021.
- PacifiCorp and the California Independent System Operator Corporation (CAISO) launched the voluntary energy imbalance market (EIM) November 1, 2014, the first western energy market outside of California. The EIM has produced significant monetary benefits ($1.42 billion total footprint-wide benefits as of August 2, 2021). A significant contributor to EIM benefits is transfers across balancing authority areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations when energy is transferred into the CAISO balancing authority area.
- Beginning in early 2019, PacifiCorp along with other Northwest Power Pool (NWPP) member entities and the Northwest Power Pool itself engaged in the development and implementation of a regional Resource Adequacy (RA) Program as a mechanism to assure a high likelihood of adequate supply to meet customer demand under a wide array of scenarios. This program includes two components, a Forward Showing (FS) planning

mechanism and an Operational Program (Ops Program) to help Participants that are experiencing extreme events meet customer demand. The program is designed to be supplemental and complementary to those processes and requirements. Program planning is scheduled to continue throughout 2022, with a proposed implementation date in 2024.

- Near-term procurement activities focused on three areas—the purchase and sale of renewable energy credits, and the purchase or procurement of new renewable and battery resources, and the procurement of new demand response resources.

Introduction

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

Major issues in the power industry include resource adequacy and associated standards for the Western Electricity Coordinating Council (WECC). Future natural gas prices, the role of gas-fired generation, the roll of emerging technologies, and the declining net costs of renewables and battery technologies also play a role in the selection of the portfolio that best achieves least-cost, least-risk planning objectives.

On the government policy and regulatory front, a further significant issue in the power industry and facing PacifiCorp continues to be planning for eventual, but highly uncertain, climate change policies. This chapter provides discussion on climate change policies as well as a review of significant policy developments for currently regulated pollutants. This chapter also provides updates on the status of renewable portfolio standards and resource procurement activities.

Wholesale Electricity Markets

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

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

The benefits of access to an integrated wholesale market have grown with the increased penetration of intermittent generation such as solar and wind. Intermittent generation can come online and go offline abruptly in congruence with changing weather conditions. Federal and state (where applicable) tax credits, declining capital costs, and improved technology performance have put wind and solar "in the money" in areas of high potential. As such, wind and solar will continue to play a dominant role in power supply options over the next decade. To better integrate these resources into the larger grid requires more flexible generation, transmission, new storage technologies, and market design changes.

Regarding transmission, there are long-haul, renewable-driven transmission projects in advanced development in the U.S. WECC. These lines ultimately connect areas of high renewable potential and low population density to areas of high population density with less renewable potential. This includes PacifiCorp's proposed 416-mile high-voltage 500-kilovolt (kV) Gateway South project and the 59-mile high-voltage 230-kV Gateway West Segment D.1 project—both with an online date by the end of 2024. These transmission projects will provide greater system-wide flexibility and will provide east-west transfer capability.

Similarly, several transmission projects propose to provide east-to-west transfer capability to allow greater integration of intermittent resources. Gateway West – a series of transmission projects currently in the permitting process – would add east-to-west transfer capability on PacifiCorp's system.[1] Boardman-to-Hemingway (B2H), a joint effort with Idaho Power Company, a 290-mile high-voltage 500-kilovolt transmission between the Hemingway substation in southwestern Idaho and the Pacific Northwest with an online date by the end of 2026. Additionally, TransWest Express, a 730-mile line high-voltage 500-kilovolt transmission line from southwest Wyoming through Colorado and Utah to Nevada's Hoover Dam is anticipated to begin construction in once the Bureau of Land Management issues a notice to proceed, with a projected online date in the mid-2020s.

The intermittency of renewable generation has also given rise to a greater need for fast-responding and long-duration storage, which is essential for grid stability and resiliency. Pumped storage has been the traditional storage option and there are multiple projects being developed throughout the West. Of remaining mechanical, thermal, and chemical storage options, lithium-ion (Li-ion) batteries have shown the most promise in terms of cost and performance improvement. In 2013, the California Public Utility Commission (CPUC) required investor-owned utilities to procure 1,325 MW of storage by 2020; that requirement has been satisfied. Utility-scale four-hour battery storage modules have fallen considerably in price, and costs are expected to continue to decline as electric vehicle manufacturing drives further innovation. To date, nine states have implemented energy storage targets or mandates, with another one state seriously considering implementation.[2] In California, the world's largest Li-ion battery, 400 MW, is scheduled to go online at Pacific Gas & Electric (PG&E)'s Moss Landing Power Plant in 2021.[3] Hybrid co-located solar photovoltaic (SPV) and battery systems are now in Hawaii, Arizona, Nevada, California, and Texas. In March 2019, Florida Power & Light Company announced a plan to build the world's largest solar-powered battery system with 409 MW of capacity serving the customers in late 2021.

In 2018, the Federal Energy Regulatory Commission (FERC) directed regional transmission organizations (RTO) and independent system operators (ISO) to develop market rules for the

[1] Additional information on Gateway West projects can be found in Volume I, Chapter 4 (Transmission).

[2] California, New Jersey, New York, Massachusetts, Oregon, Nevada, Virginia, Connecticut, and Maine have either mandated or set energy storage targets, while Arizona is considering the implementation of targets.

[3] Phase II of Moss Landing is expected to reach a capacity of 1,600MWh/400MW in Fall 2021.

participation of energy storage in wholesale energy, capacity, and ancillary services markets[4]. The FERC gave operators nine months to file tariffs and another year to implement – essentially opening wholesale markets to energy storage. Operators' proposed tariffs have varied substantially among regions with PJM requiring a 10-hour continuous discharge capability while New England requires a continuous 2-hour capability. Later, in May 2019, the FERC issued an order generally affirming the earlier order to establish reforms to remove barrier to the participation of electric storage resources in certain organized wholesale markets. As part of its 2021 IRP, PacifiCorp is evaluating the cost effectiveness of several energy storage systems, including pumped storage, stand-alone li-on batteries, as well as co-located solar and co-located wind.[5]

Increased renewable generation has also contributed to the need for balancing sub-hourly demand and supply across a broader and more diverse market. For balancing purposes, PacifiCorp combined its resources with those of the CAISO through the creation of the EIM. The EIM became operational November 1, 2014, and as of August 2021 has seen NV Energy, Puget Sound Energy, Arizona Public Service, Portland General Electric, Powerex, Idaho Power, Balancing Authority of Northern California, Salt River Project, Seattle City Light, Los Angeles Department of Water and Power, Northwestern Energy, and Public Service Company of New Mexico join the EIM. Avista Utilities, Tucson Electric Power, Tacoma Power, and Bonneville Power Administration plan to join in 2022. The multi-service area footprint brings greater resource and geographical diversity allowing for increased reliability and cost savings in balancing generation with demand using 15-minute interchange scheduling and five-minute dispatch. CAISO's role is limited to the sub-hourly scheduling and dispatching of participating EIM generators. CAISO does not have any other grid operator responsibilities for PacifiCorp's service areas. As part of other EIM participant entities, PacifiCorp is also participating in the CAISO stakeholder process to establish and Expanded Day-Ahead Market (EDAM), tentatively targeted to go-live in 2022.

As with all markets, electricity markets are faced with a wide range of uncertainties. In February 2021, winter storm Uri caused an unprecedented decline in marketed natural gas production of 186.7 billion cubic feet (Bcf), or 24.1% in Texas, comparing with previous month. This decline contributed significantly to the largest monthly decline in natural gas production on record in the Lower 48 states. This weather event caused widespread disruptions in energy supply and demand, including extended electric power blackouts in Texas.

Market participants routinely study demand uncertainties driven by weather and overall economic conditions. The North American Electric Reliability Corporation (NERC) publishes an annual assessment of regional power reliability and any number of data services are available that track the status of new resource additions[6]. In its latest assessment, published December 2020, the NERC indicates that WECC region has adequate resources through 2030. However, the NERC's probabilistic studies indicate that in each of the WECC's sub-regions' (except Alberta), resource adequacy is at risk during off peak hours, starting as early as 2021.[7]

[4] 162 FERC ¶ 61,127 United States of American Federal Energy Regulatory Commission, 18 CFR Part 35 [Docket Nos. RM16-23-000; AD16-20-000; Order No. 841] *Electric Storage Participation in Markets Operated by Regional Transmission* Organizations and Independent System Operator (Issued February 15, 2018)

[5] Solar or wind resources coupled with battery storage.

[6] 2020 Long-term Reliability Assessment, December 2020, North American Electric Reliability Assessment

[7] A discussion of regional resource adequacy efforts can be found in Volume I, Chapter 5 (Reliability and Resiliency)

In addition to reliability planning, there are externalities that can heavily influence the direction of future prices. One such uncertainty is the evolution of natural gas prices over the course of the IRP planning horizon. Given the increased role of natural gas-fired generation, gas prices are a critical determinant of western electricity prices, and this trend is expected to continue over the term of this plan's decision horizon. Another critical uncertainty that weighs heavily on the 2021 IRP, as in past IRPs, is the uncertainty surrounding future greenhouse gas policies, both federal and/or state. PacifiCorp's official forward price curve (OFPC) does not assume a federal carbon dioxide (CO_2) policy, but other price scenarios developed for the IRP consider impacts of potential future federal CO_2 emission policies. However, PacifiCorp's OFPC does include enforceable state climate programs that have been signed into law[8].

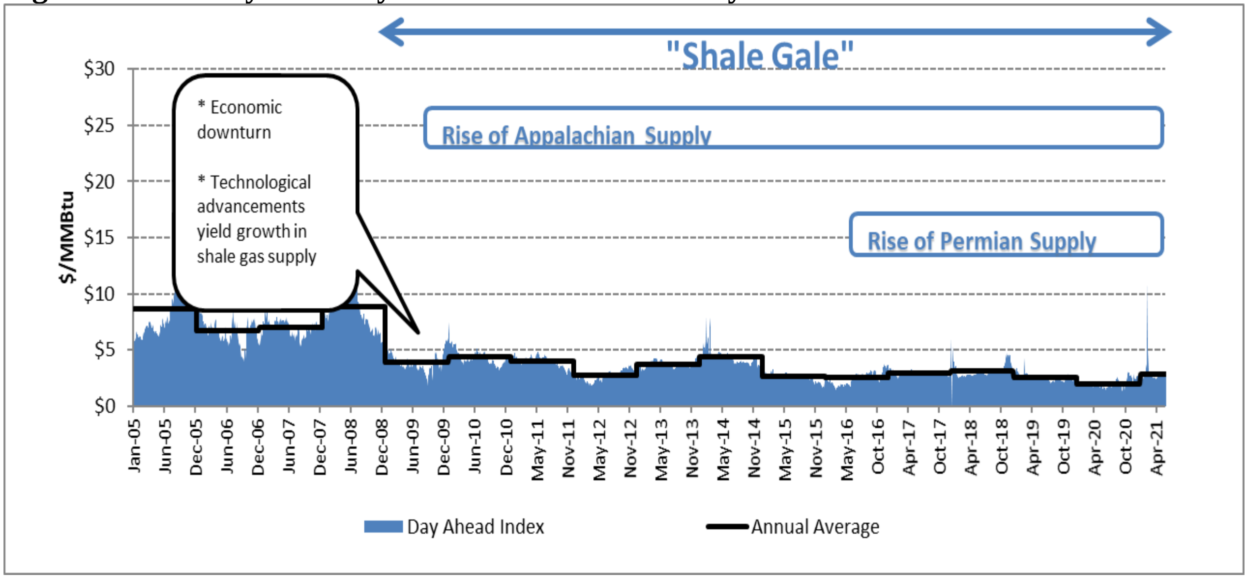
Natural Gas Uncertainty

Since 2008, North American natural gas markets have undergone a remarkable paradigm shift. As shown in Figure 3.1, Henry Hub day-ahead gas prices hit a high of $13.31/MMBtu on July 2, 2008 and a low of $1.49/MMBtu on March 4, 2016. Day-ahead prices averaged $8.86/MMBtu in 2008, dropped to $3.94 in 2009, and have averaged $2.72 since 2015. Day-ahead 2020 Henry Hub prices averaged $2.03/MMBtu, down 77 percent from 2008 prices. The relative price placidity since 2009, labeled the "Shale Gale", reflects a story of supply – mostly that of Appalachian and, later, Permian supply[9].

In 2009, Appalachia (mostly Pennsylvania and West Virginia), produced almost no natural gas; by late 2013 it was producing almost 12 BCF/D and by end-of-year 2020, Appalachia was producing over 35 BCF/D. In short, supply from Appalachia continues to grow as volumes and costs prove to be, respectively, higher and lower than anticipated. Today, Appalachia accounts for 34 percent of the nation's gas supply, and by 2040 is expected to account for 44 percent, spurred by increased drilling efficiencies and rising demand.

[8] A forecast of California carbon allowance prices is used as a proxy for future cap-and-trade allowance auction prices. Oregon's House Bill 2020, establishing a Climate Policy Office and directing it to adopt an Oregon Climate Action Program by rule is still in Committee and has not yet been signed into law.
[9] Other significant shale gas plays include: Eagle Ford (TX); Haynesville (LA/TX); Niobrara (CO/WY); and the Bakken (ND/MT).

Figure 3.1 – Henry Hub Day-Ahead Gas Price History



Source: Thomson Reuters as cited by the Energy Information Administration at: www.eia.gov/dnav/ng/hist/rngwhhdD.htm.

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

Figure 3.2 – U.S. Dry Natural Gas Production (Trillion Cubic Feet)

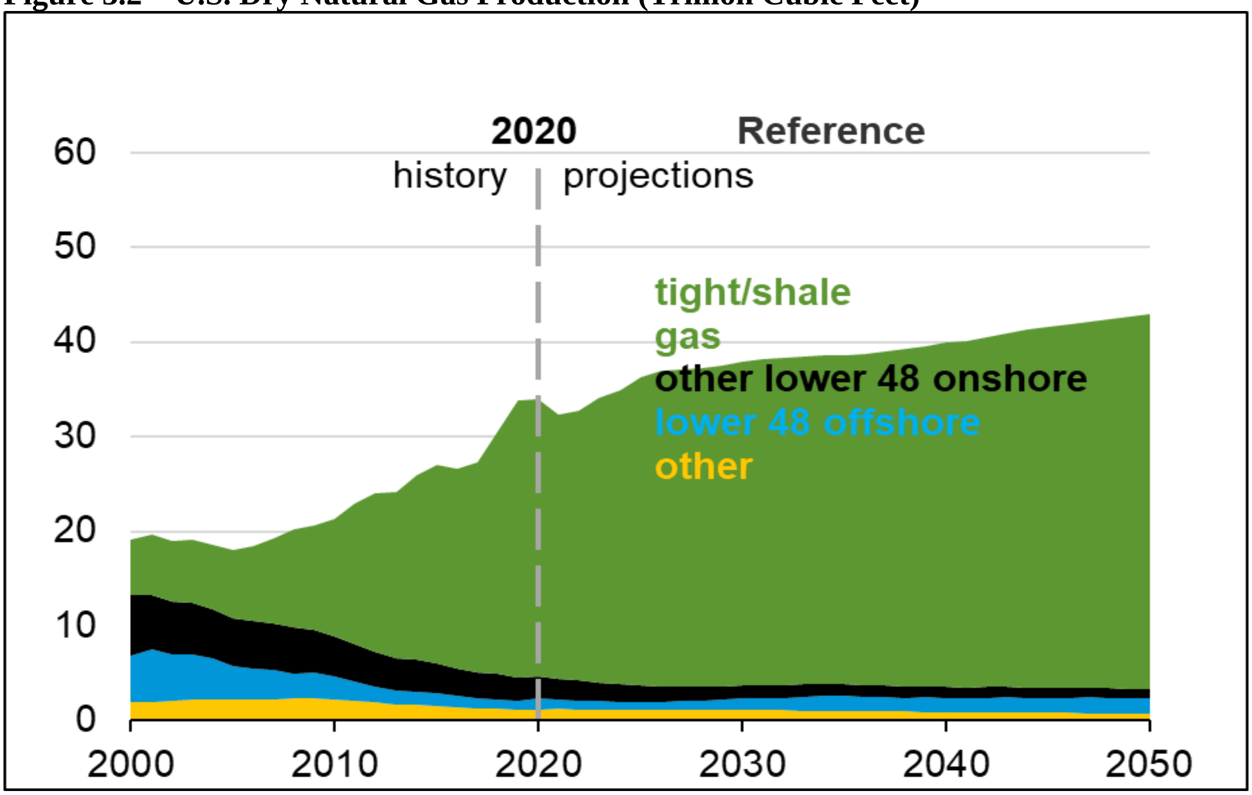
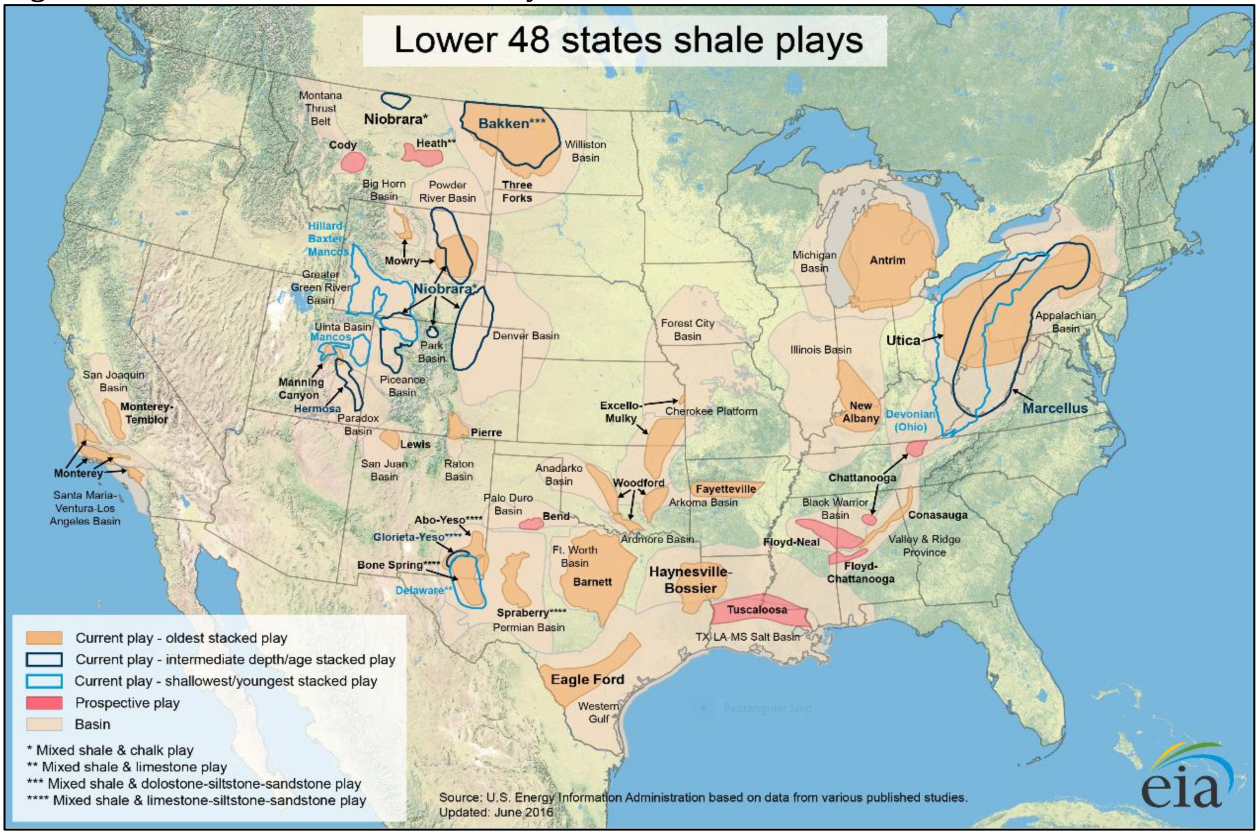
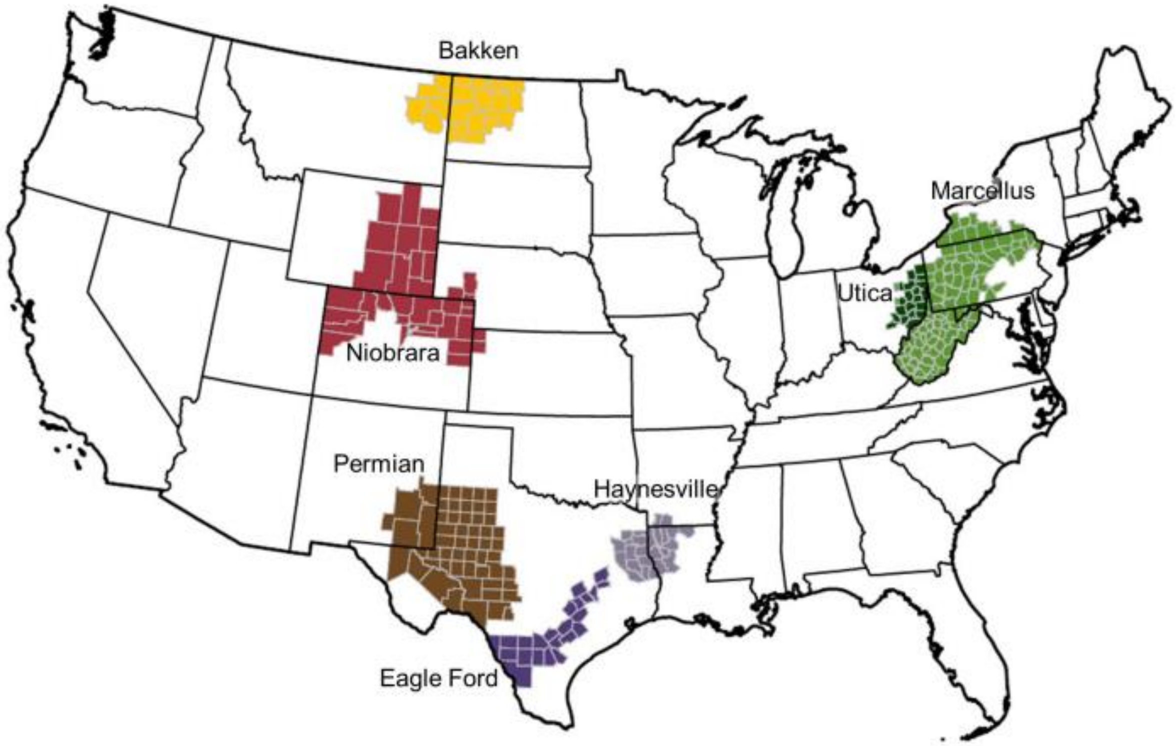


Figure 3.3 – Lower 48 States Shale Plays



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

Figure 3.4 – Plays Accounting for Natural Gas Production Growth 2011 -2020



Source: *Drilling Productivity Report*, May 17, 2021, U.S. Department of Energy, Energy Information Administration

Figure 3.5 shows Henry Hub NYMEX futures, as of June 30, 2021. Natural gas futures show a high price, $3.17/MMBtu in 2022, which offers the "signal-to-drill" to the natural gas producers. But as producers chase production efficiencies the "signal-to-drill" price becomes lower. While the futures decline in the short term to reflect the ramp-up in the natural gas production, the annual futures rise after 2024 due to export and domestic demand growth.

But, for the next decade low-cost natural gas will come from oil-targeted plays, especially in the Permian Basin. West Texas Intermediate two-year futures are currently hovering around $72/barrel, 68% more than 2020, reflecting the increasing demand as global economy continues to recover. It is more than enough to spur oil-targeted drilling in western Canada, the Permian, and Bakken. In the Bakken break even costs are below $50/barrel, while in the Permian, break-even costs range from $26/barrel to $50/barrel. Moreover, producers are "front-loading" oil production which releases a disproportionately large amount of associated gas. Front-loading involves drilling closely spaced "child" wells to quickly boost initial oil production but the resulting decrease in well pressure also releases inordinate quantities of associated gas.[10] This is especially true of Permian Basin oil wells, whose output naturally contains 20 to 50 percent natural gas. Permian Basin production had peaked at 12.8 Bcf/d in March 2020, following several years of rapid growth. Output from the basin then fell due to the oil price collapse and the onset of the COVID-19 pandemic in early 2020. Since then, production has started to rebound.

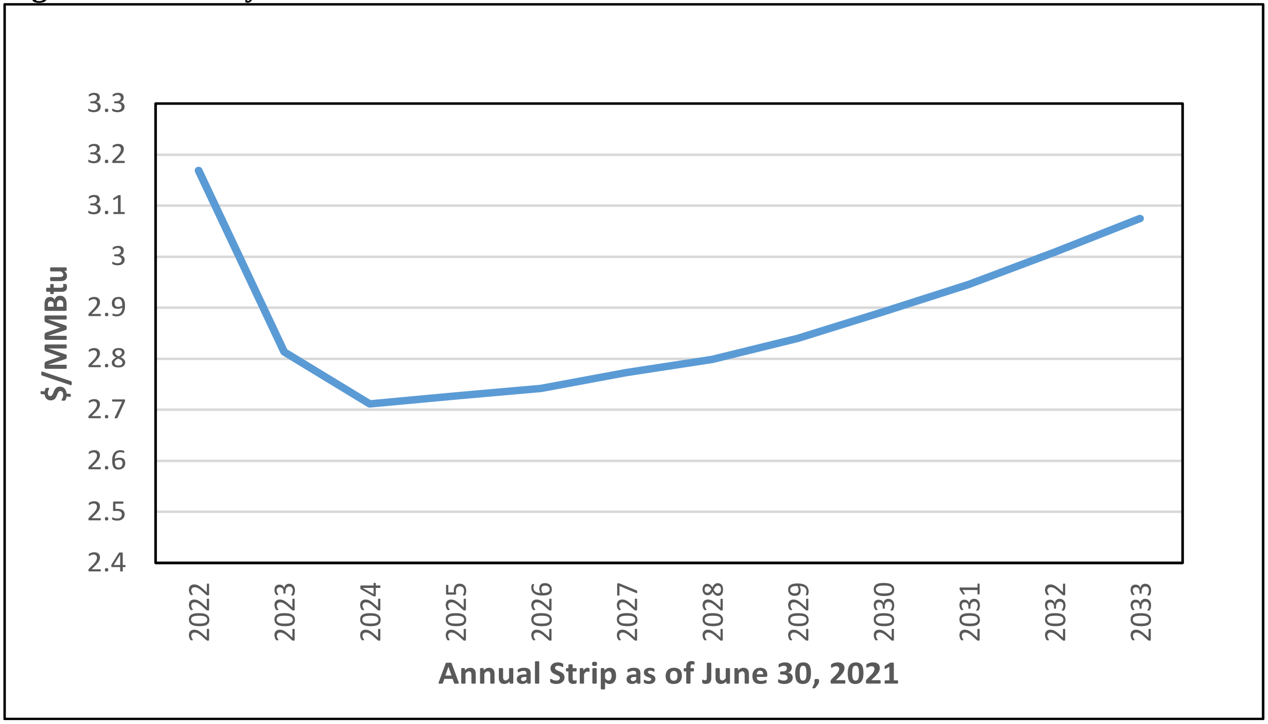
[10] Note that while front-loading increases initial production it often shortens productive well life.

In 2016, following crude's price collapse, U.S. production fell to 8.8 million barrels of oil per day (MMbpd[11]) from a high of 9.6 MMbpd in 2015. In 2018, U.S. production averaged 10.9 MMbpd, hitting an all-time high of 11.97 MMBpd in December 2018. In 2020, the COVID-19 pandemic triggered an unprecedented demand shock in the oil industry, leading to a historic market collapse in oil prices. In addition, an oil price war between Russia and Saudi Arabia erupted in March when the two nations failed to reach a consensus on oil production levels. The oversupply of oil led to an unprecedented collapse in oil prices in April 2020, forcing the contract futures price for West Texas Intermediate (WTI) to plummet from $18 a barrel to around -$37 a barrel. By the summer of 2020, oil prices began to rebound as nations emerged from lockdown and OPEC agreed to significant cuts in crude oil production. Since the end of 2020, as optimism over the possible rollout of multiple COVID-19 vaccines buoyed the market, the global demand recovery has led the oil prices increasing continuously, which led to the increased oil production. Moreover, the EIA estimated that as of May 2021, 6,521 wells remain drilled but uncompleted; these wells can be put into production quickly and represent a significant source of supply[12]. U.S. production can ramp up very quickly.

This resiliency of supply coupled with the flexibility to quickly ramp up production will shorten the length of asynchronous supply and demand cycles. Unexpected weather-induced demand spikes or supply disruptions will still whipsaw prices for short periods of time. But Liquefied Natural Gas (LNG) startups, outages or dial backs could swing prices for longer periods given the magnitude of volumes coupled with locational concentration[13]. US LNG exports have recovered from the summer 2020 weakness after global fundamentals tightened in winter 2020/21. Summer feed gas normally bound for liquefaction would then be diverted onto the U.S. market, depressing prices. The summer 2021 dial back will act to also moderate winter prices by increasing storage and the likelihood of entering winter with an overhang. Although U.S. LNG tends to be the marginal global supplier, buyers are interested in U.S. LNG due to its low-cost natural gas supply and contract flexibility. Of note, even oil-rich Saudi Arabia has entered into a 20-year supply agreement for U.S. LNG. The imported LNG is expected to be used to replace Saudi Arabia's oil-fired power generation, thereby freeing up oil for export. U.S. LNG exports are projected to increase in 2022 because of commissioning of additional LNG trains at Sabine Pass and Calcasieu Pass. To summarize, the key drivers of U.S. demand are: 1) LNG exports, 2) Mexican exports, and 3) power generation. Of the three, power generation is by far the largest, but exports (especially LNG) are the fastest growing.

[11] MMbpd: Million barrels per day.
[12] EIA does not distinguish between oil and gas wells since over 50 percent of wells produce both.
[13] Current and expected facilities are mostly concentrated in the Gulf Coast.

Figure 3.5 – Henry Hub NYMEX Futures



Stronger oil prices and a recovering economy should enable the natural gas production to return to strong growth in 2022-2023. Associated and Appalachian gas production rebounded faster than expected in late 2020, following price-induced shut-ins earlier that year. However, as pipeline projects become increasingly difficult to build in the Appalachian region, supply growth there will be constrained after 2026, with strong associated gas and Haynesville production growth keeping prices low. Rocky Mountain production gets squeezed by western Canadian, lower-48 associated gas, and Appalachian volumes. In the Northwest, where natural gas markets are influenced by production and imports from Canada, prices at Sumas have traded at a premium relative to AECO. This is likely to continue as AECO loses market share to Appalachia in serving AECO's Ontario and Midwest markets. In short, the challenge in gauging the uncertainty in natural gas markets will be one of timing. The North American natural gas supply curve continues to flatten as production efficiencies expose an ever-increasing resilient, flexible, and low-cost resource base. In such a world, managing long-term boom and bust cycles is not as crucial as managing shorter-term market perturbations.

PacifiCorp's Multi-State Process

PacifiCorp is a multi-state utility that provides retail electric service to nearly 2 million customers across six states. The costs of providing this retail electric service to customers is recovered through retail rates established in regulatory proceedings in each state. To ensure states receive the appropriate allocation of costs and benefits from PacifiCorp's integrated system, the collaborative multi-state process (MSP) has been used to address allocation issues. This collaborative process has led to the development and adoption of a series of inter-jurisdictional cost-allocation methods over time.

The underlying principle of each of the historic inter-jurisdictional cost-allocation methods has been the use of PacifiCorp's system as a single whole: except for distribution, all states are served from a common portfolio of assets, including generation assets, which enabled the company to leverage economies of scale to plan and operate in a way that resulted in cost savings for all customers. Recently, state energy policies across the states served by the company have challenged this principle. For example, requirements to remove coal-fired generation from rates in certain states will necessarily result in some states being allocated the costs and benefits of coal-fired generation while other states are not. Similarly, diverging state polices related to implementation of the Public Utilities Regulatory Policy Act of 1978, retail choice, private generation, and incorporation of societal externalities in resource planning challenge the long-standing practice of planning for a single, integrated system.

In December 2019, PacifiCorp filed the most recent inter-jurisdictional cost-allocation methodology, known as the 2020 Protocol. Five of PacifiCorp's six retail states agreed that the methodology outlined in the 2017 protocol should continue, with certain modifications.[14] The guiding principles underlying the 2020 Protocol are as follows:

- Provide a long-term, durable solution;
- Follow cost-causation principles;
- Minimize rate impacts at implementation;
- Allow for state autonomy for new resource portfolio selection;
- Maintain and optimize system-wide benefits and joint dispatch to the extent possible;
- Enable compliance with state policies;
- Ensure credit-supportive financial outcome; and
- Provide the company with a reasonable opportunity to recover its costs.

Under those principles, the 2020 Protocol represented a fundamental shift in how the company proposed to address inter-jurisdictional cost allocation, with the ultimate goal of moving away from the concept of a common generation resource portfolio with dynamic allocation factors and toward a cost-allocation protocol with fixed allocation factors for generation resources and state-specific resource portfolios. In support of that change, the 2020 Protocol used a gradual transition approach that relies on the continuation of historic protocols during an interim period (January 1, 2020 through December 31, 2023 or upon the resolution of all remaining cost-allocation issues), with a series of modifications:

- Cost-allocation procedures that will be implemented during the interim period (implemented issues);
- Cost-allocation procedures that are agreed to but that will not take effect until after the Interim Period (resolved issues); and
- Cost-allocation procedures that parties to the 2020 Protocol will continue to work to resolve during the interim period (framework issues).

Before the end of the interim period, assuming the resolution of all framework issues, a new cost allocation method – incorporating implemented issues, resolved issues and the final resolution of the framework issues – will be presented to state commissions for approval. This is anticipated to occur no later than year-end 2023.

[14] California, Idaho, Oregon, Utah, and Wyoming parties agreed to the extension of the methodology. As part of the agreement, Washington signed a Memorandum of Understanding that would continue negotiations toward Washington joining a common cost allocation methodology amongst all six states.

List of Implemented Issues

1. **States' Decisions to Exit Coal-Fueled Interim Period Resources:** including methodology regarding allocation of costs at closure, treatment of exit orders, exit dates, and common closures, as well as the process to establish exit dates for Hayden Units 1 and 2.

2. **Reassignment of Coal-Fueled Interim Period Resources:** Includes the process, methodology, and effects of commission decisions on the potential reassignment of coal-fueled resources from a state which has issued an exit order to states that do not have exit orders.

3. **Decommissioning Costs:** specifies the timing of a contractor-assisted engineering study of decommissioning costs and appropriate decommissioning cost reserve requirements for Jim Bridger, Dave Johnston, Hunter, Huntington, Naughton, Wyodak, Hayden, and Colstrip. This item also specifies the allocation of decommissioning costs.

4. **Qualifying Facilities:** outlines a superseding framework, in which existing qualifying facilities will remain system assigned and allocated – subject to any future limited realignment – until the end of 2029, after which time they will be assigned and allocated to the state that has jurisdiction over qualifying facility pricing. During the interim period, qualifying facilities will continue to be allocated, while after the interim period, qualifying facilities will be directly assigned to the state that has jurisdiction over qualifying facility pricing.

List of Resolved Issues

1. **Generation Costs:** including the share of resources assigned to serve load in each state. Interim resources will continue to have a fixed allocation, and new resources that begin operation before the end of the interim period will use the same methodology. New resources that begin operation after the interim period will be subject to future determination as part of the framework issues.

2. **Transmission Costs:** will continue to be allocated on the System Transmission factor, except as addressed as part of the "new resource assignment" framework issue.

3. **Distribution Costs:** will be directly allocated to states where distribution facilities are located.

4. **System Overhead Costs:** Will continue to be allocated based on the System Overhead factor but will also be subject to allocation based partially on the System Capacity, System Energy, and System Gross Plant Distribution factors.

5. **Administrative and General:** will be directly allocated to states, if possible.

6. **Other Allocation Issues:** modifies the allocation of certain existing miscellaneous issues.

7. **Demand-Side Management Programs:** will be allocated to the state in which the investment is made, and benefits will flow back to each state through net power costs or through reduced or delayed future capacity need.

8. **State-Specific Initiatives:** Will be allocated and assigned to the state adopting the initiative.

Update on 2020 Protocol and Status of Framework Issues

Following the filing of PacifiCorp's 2020 Protocol, Oregon, Idaho, Wyoming, Utah, and Washington have issued approval. Quarterly MSP meetings continue for parties to work through the framework issues in advance of the 2023 timeframe. The current framework issues as agreed upon in the 2020 Protocol are as follows:

1. **Resource Planning and New Resource Assignment –** The continued operation, planning, and dispatch of the Company's system as an integrated six-state system will likely be beneficial to PacifiCorp customers. However, as state energy policy continues to evolve, requiring the exclusion of certain generating resources, it appears infeasible to continue serving customers with a common generation portfolio and dynamically allocated system costs. As such, PacifiCorp will work to meet its legal requirements as a public utility in each state in a risk-adjusted, least-cost manner, while striving to mitigate cost impacts in other states. Parties to the MSP are working to develop a planning process that 1) optimizes risk-adjusted, least-cost resource portfolios on a system basis to the extent practicable while meeting individual state requirements and maintaining reliability; and 2) assigns benefits and allocates costs of specific new resources added to meet an individual state's needs. As of September 2021, these discussions are ongoing as part of the MSP framework process.

2. **Net Power Costs and Nodal Pricing Model** – The Nodal Pricing Model is a method to track the costs and benefits of resource portfolios which may differ for each state, and to maintain the benefits of system dispatch as much as practicable. After the interim period when states may no longer participate in a common resource portfolio, the Nodal Pricing Model may be used to track cost causation and receipt of benefits by each state for ratemaking purposes. PacifiCorp worked with a third-party vendor to implement the Nodal Pricing Model, and it is currently being used for day-ahead scheduling. Use of the Nodal Pricing Model for net power costs and other applicable ratemaking proceedings may be proposed after the interim period.

3. **Special Contracts** – PacifiCorp will work directly with special contract customers to develop one or more proposals for consideration of parties. PacifiCorp will make best efforts to present a proposal to parties by September 1, 2021, with the intention of incorporating a proposal into the post-interim period method.

4. **Limited Realignment** – During the interim period, parties have agreed to investigate the potential for limited realignment of interim period resources, primarily related to the transition of certain state energy policy away from coal-fueled resources. These discussions are ongoing as part of the MSP process.

5. **Post-Interim Period Capital Additions for Coal-Fueled Interim Period Resources** – For coal-fueled resources for which there are differing state exit dates or when exit dates differ from the depreciable life, this issue provides a process for determining the cost allocation for capital investments made subsequent to the interim period and prior to the state exit dates. PacifiCorp has provided a straw proposal as part of the 2020 Protocol filing, and discussions are ongoing.

Analysis of "Outstanding Material Disagreements"

In compliance with Wyoming Public Service Commission Order in Docket No. 9000-144-XI-19 (Record No. 15280), PacifiCorp includes this analysis of any material disagreements regarding cost allocation at the time of the preparation and filing of the 2021 IRP.

PacifiCorp has not identified any outstanding material disagreements, and notes that the framework issue discussions are proceeding as indicated in the executed agreement as part of the 2020 Protocol. If these discussions evolve into disagreements – or if there is no agreement by the end of the interim period on December 31, 2023 – PacifiCorp may quantify the risks and potential impacts to retail rates of such a disagreement as part of a future IRP or other regulatory filing.

The Future of Federal Environmental Regulation and Legislation

The inauguration of a new federal administration and the convening of the 117th U.S. Congress in January 2021 provides a backdrop of potentially changing federal energy policy within PacifiCorp's 2021 IRP cycle. Although the exact nature of these potential changes is not known at the time of filing, the company notes that changes to energy policy may impact the portfolio selection process in the 2021 IRP and in future IRPs. PacifiCorp actively monitors federal legislative requirements and participates in rulemaking processes by filing comments on various proposals, participating in scheduled hearings, and providing assessments of proposals.

Among potential federal legislative priorities under consideration, PacifiCorp notes that there have been some emerging themes:

- **The extension and/or expansion of production and investment tax credits:** In February 2021, California Representative Mike Thompson introduced the Growing Renewable Energy and Efficiency Now (GREEN) Act, which would increase the federal solar investment tax credit and provide investment tax credits for battery storage and electric vehicles.

  In April 2021, Oregon Senator Ron Wyden introduced the Clean Energy for America Act (CEAA), which proposed to provide tax incentives for clean electricity technologies and grid improvements, including transportation electrification and energy efficiency.

  In Spring 2021, the Biden Administration released the American Jobs Plan, a $2 trillion infrastructure plan that included proposals that would expand the investment tax credit to incentivize the buildout of high-voltage capacity power lines and potentially extend the investment and production tax credits for clean energy generation and storage.

- **A federal clean energy standard and/or renewable portfolio standard:** In addition to the potential expansion and extension of tax credits, the American Jobs Plan included provisions to set a national clean electricity standard, which would transition the electricity sector to be carbon-pollution free by 2035.

  In March 2021, the House Committee on Energy and Commerce introduced the Climate Leadership and Environmental Action for our Nation's (CLEAN) Future Act, which would require electricity suppliers to provide 100 percent clean energy by 2035 as part of a national clean electricity standard.

As of August 2021, these potential policy decisions continue to be discussed, details continue to evolve, and to date no new comprehensive federal energy policy requirements have been implemented. Most recently, the United States Congress has continued negotiations a bipartisan infrastructure bill, which may contain a federal clean energy standard, production and investment tax credits, or both. PacifiCorp will continue to closely monitor emerging federal legislation and requirements.

Federal Policy Update

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

New Source Performance Standards (NSPS) are established under the Clean Air Act for certain industrial sources of emissions determined to endanger public health and welfare. On August 3, 2015, the United States Environmental Protection Agency (EPA) issued a final rule limiting CO_2 emissions from coal-fueled and natural-gas-fueled power plants. New natural-gas-fueled power plants can emit no more than 1,000 pounds of CO_2 per megawatt-hour (MWh). New coal-fueled power plants can emit no more than 1,400 pounds of CO_2/MWh. The final rule largely exempts simple cycle combustion turbines from meeting the standards. On December 6, 2018, the EPA proposed to revise the NSPS for greenhouse gas emissions from new, modified, and reconstructed fossil fuel-fired power plants. EPA's proposal would replace EPA's 2015 determination that carbon capture and storage technology was the best system of emissions reduction for new coal units. The comment period for the proposed revisions closed in March 2019. In January 2021, the EPA issued the final rule. However, in April 2021, at the request of the EPA as directed by the Biden Administration, the D.C. Circuit vacated and remanded the January 2021 final rule.

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

On August 3, 2015, EPA issued a final rule, referred to as the Clean Power Plan (CPP), regulating CO_2 emissions from existing power plants.

On February 9, 2016, the U.S. Supreme Court issued a stay of the CPP suspending implementation of the rule pending the outcome of the merits of litigation before the D.C. Circuit Court of Appeals. On October 10, 2017, EPA proposed to repeal the CPP and on August 21, 2018, proposed the Affordable Clean Energy (ACE) rule to replace the CPP. The ACE rule sets forth a list of "candidate technologies" that states can use to reduce greenhouse gas emissions at coal-fueled power plants. The ACE rule was finalized June 19, 2019, replacing the CPP. On January 19, 2021, the D.C. Circuit vacated the ACE rule and directed the EPA to proceed with new rulemaking for the control of carbon emissions from electric utility coal-fired boilers.

Credit for Carbon Oxide Sequestration – Internal Revenue Service (IRS) § 45Q

In 2008, the Internal Revenue Service issued a tax credit for carbon oxide sequestration under section 45Q to incentivize carbon capture and sequestration (CCS) investments. The tax credit is computed per metric ton (tonne) of qualified carbon oxide captured and sequestered.[15] Carbon oxide can either be permanently disposed of in secure geological storage or the carbon oxide can be utilized – typically as a tertiary injectant in enhanced oil recovery (EOR).

The Bipartisan Budget Act of 2018 reformed 45Q for carbon capture equipment that is placed in service on or after February 9, 2018, increasing the credit amount from $10/tonne to $35/tonne for utilization and from $20/tonne to $50/tonne for storage.[16] This Act also removed the limit on the amount of tax credits that could be awarded for CCS, and, instead, requires a minimum amount of carbon oxide to be capture annually and is available for 12 years from the date the carbon capture equipment is originally placed into service.[17]

Clean Air Act Criteria Pollutants – National Ambient Air Quality Standards

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

In October 2015, EPA issued a final rule modifying the standards for ground-level ozone from 75 parts per billion (ppb) to 70 ppb. On November 16, 2017, the EPA designated all counties where PacifiCorp's coal facilities are located (Lincoln, Sweetwater, Converse and Campbell Counties in Wyoming; and Emery County in Utah) as "Attainment." On June 4, 2018, the EPA designated Salt Lake County and part of Utah County where the PacifiCorp Lake Side and Gadsby gas facilities are located as "Marginal Nonattainment." A marginal designation is the least stringent classification for a nonattainment area and does not require a formal State Implementation Plan (SIP).Utah submitted its strategy for meeting the standard to EPA in May of 2021.

In April 2017, the EPA Administrator signed a final action to reclassify the Salt Lake City and Provo $PM_{2.5}$ nonattainment area from moderate to serious. PacifiCorp's Lake Side and Gadsby facilities were identified as major sources subject to Utah's serious nonattainment area SIP for $PM_{2.5}$ and $PM_{2.5}$ precursors. On April 27, 2017, PacifiCorp submitted a best-available control

[15] Before February 9, 2018, the tax credit was strictly for CO_2.
[16] The tax credit reaches $35/tonne and $50/tonne in 2026.
[17] For an electric generating facility, a minimum of 500,000 tonnes of qualified carbon oxide must be captured per year to receive the 45Q tax credit. Construction of the qualified facility must begin before January 1, 2026.

measure technology analysis for Lake Side and Gadsby to the Utah Division of Air Quality for review. On January 2, 2019, the Utah Air Quality Board adopted source specific emission limits and operating practices in the SIP which incorporated the current emission and operating limits for the Lake Side and Gadsby facilities.

Regional Haze

EPA's regional haze rule, finalized in 1999, requires states to develop and implement plans to improve visibility in certain national park and wilderness areas. On June 15, 2005, EPA issued final amendments to its regional haze rule to require emission controls known as the Best Available Retrofit Technology (BART) for industrial facilities meeting certain regulatory criteria with emissions that have the potential to affect visibility. The regulated pollutants include fine particulate matter (PM), nitrogen oxide (NO_X), sulfur dioxide (SO_2), certain volatile organic compounds, and ammonia. The 2005 amendments included final guidelines, known as BART guidelines, for states to use in determining which facilities must install controls and the type of controls the facilities must use. States were given until December 2007 to develop their implementation plans, in which states were responsible for identifying the facilities that would have to reduce emissions under BART guidelines, as well as establishing BART emissions limits for those facilities. States are also required to periodically update or revise their implementation plans to reflect current visibility data and an effective long-term strategy for achieving reasonable progress toward visibility goals. In January 2017 EPA issued a final rule updating requirements for the first periodic update to the state implementation plans (SIP). EPA required states to submit their second periodic SIP update by July 31, 2021, unless granted an extension.

The regional haze rule is intended to achieve natural visibility conditions by 2064 in specific National Parks and Wilderness Areas, many of which are in the western United States where PacifiCorp owns and operates several coal-fired generating units (Utah, Wyoming, Colorado and Montana as well as Arizona, where a PacifiCorp-owned coal unit ceased operating in 2020).

On August 20, 2019, EPA issued a final guidance document on the technical aspects of developing regional haze SIPs for the second implementation period of the Regional Haze Program. EPA issued additional guidance through a memorandum on July 8, 2021, that emphasizes the 4-factor reasonable progress analysis for the second planning period and the reduced weight of visibility as a factor in the second planning period.

Utah Regional Haze

In May 2011, the state of Utah issued a regional haze SIP requiring the installation of SO2, NOx and PM controls on Hunter Units 1 and 2 and Huntington Units 1 and 2. In December 2012, the EPA approved the SO2 portion of the Utah regional haze SIP and disapproved the NOX and PM portions. EPA's approval of the SO2 SIP was appealed by environmental advocacy groups to the Tenth Circuit Court of Appeals (Tenth Circuit). In addition, PacifiCorp and the state of Utah appealed EPA's disapproval of the NOX and PM SIP. PacifiCorp and the state's appeals were dismissed, and the SO2 appeal was denied by the Tenth Circuit. In June 2015, the state of Utah submitted a revised SIP to EPA for approval with an alternative BART NOx analysis incorporating a requirement for PacifiCorp to retire Carbon Units 1 and 2, crediting NOX controls previously installed on Hunter Unit 3, and concluding that no incremental controls (beyond those included in the May 2011 SIP and already installed) were required at the Hunter and Huntington units. On June 1, 2016, EPA issued a final rule to partially approve and partially disapprove Utah's regional haze SIP and propose a federal implementation plan (FIP). The FIP required the installation of selective catalytic reduction (SCR) controls by August 4, 2021, at four of PacifiCorp's units in Utah, including Hunter Units 1 and 2 and Huntington Units 1 and 2. On September 2, 2016, the state of Utah and PacifiCorp filed petitions for administrative and judicial review of EPA's final rule, followed by a motion to stay the effective date of the final rule.

On June 30, 2017, Utah and PacifiCorp provided new information to EPA, again requesting reconsideration. EPA responded on July 14, 2017, indicating its intent to reconsider its FIP. EPA also filed a motion with the Tenth Circuit to stay EPA's FIP and hold the litigation in abeyance pending the rule's reconsideration. On September 11, 2017, the Tenth Circuit granted the petition for stay and the request for abatement. The compliance deadline of the FIP and the litigation were stayed pending EPA's reconsideration, and EPA was required to file periodic status reports with the Court.

Utah and PacifiCorp worked with EPA to develop a revised Utah Regional Haze SIP, based on the new CAMx modeling. The Utah Air Quality Board approved the revised SIP on June 24, 2019, and the SIP Revision was submitted to EPA for review on July 3, 2019. On December 3, 2019, Utah submitted a supplement to EPA with a minor SIP revision relating to PM 2.5.

On January 10, 2020, the EPA published its proposed approval of the Utah SIP Revision and withdrawal of the FIP requirements for the Hunter and Huntington plants to install SCR on Hunter Units 1 and 2 and Huntington Units 1 and 2. After receiving public comments and holding a public hearing in the Price area on February 12, 2020, EPA issued final approval of the Utah SIP Revision and FIP withdrawal on November 27, 2020. The final rule credits existing NOX emission controls at the Hunter and Huntington plants as well as NOX and PM emission reductions provided by the closure of the Carbon plant in 2015. Based on the newly approved plan, EPA also withdrew the 2016 FIP requirements to install selective catalytic reduction (SCR) control technology on Hunter Units 1 and 2 and Huntington Units 1 and 2. On January 11, 2021, the Tenth Circuit granted Utah, PacifiCorp, and EPA's motion to dismiss the Utah regional haze petitions.

Environmental advocacy groups filed a petition for review objecting to the revised Utah regional haze SIP on January 20, 2021, in the Tenth Circuit. At EPA's request, the Tenth Circuit abated the petition on February 4, 2021, while EPA considers the petition under the new Biden administration's guidelines. The state of Utah, PacifiCorp and co-owners of the Hunter plant filed motions to intervene, which remain under advisement until the abatement is lifted.

The Western Regional Air Partnership (WRAP) is currently developing the modeling that the state will use for the implementation of the second planning period. Utah will use a 'Q/d' screening level of 10 to determine which sources will be evaluated for reasonable progress controls under the rule. On April 21, 2020, PacifiCorp submitted a Regional Haze Reasonable Progress Analysis for the second planning period to the Utah Department of Environmental Quality for PacifiCorp's Huntington and Hunter plants. The analysis was requested by the State as part of its Second Planning Period SIP development process. PacifiCorp's analysis included a proposal to implement reasonable progress emission limits for NOx and SO2 on the Hunter and Huntington units to meet second planning period requirements. On October 20, 2020, PacifiCorp submitted a follow-up letter in response to questions from the Utah Department of Environmental Quality (Utah DEQ) about proposed emission reductions and costs for control technology. Utah DEQ and PacifiCorp are engaged in ongoing discussions regarding evaluations and requirements for emission reductions and control technologies.

Wyoming Regional Haze
On January 10, 2014, EPA issued a final rule partially approving and partially disapproving the Wyoming SIP. The final rule required installation of the following NO_X and PM controls at PacifiCorp facilities for regional haze first planning period:

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

Wyodak – PacifiCorp and the state of Wyoming petitioned EPA's final action several requiring SCR at Wyodak. PacifiCorp and other parties successfully requested a stay of EPA's final rule relating to the Wyoming SIP pending resolution of the petition. PacifiCorp subsequently submitted a request for reconsideration to EPA and is currently engaged in a settlement process with EPA and Wyoming. The EPA, state of Wyoming and PacifiCorp signed a Settlement Agreement for Wyodak on December 16, 2020. EPA published the Settlement Agreement in the Federal Register requesting public comment on January 4, 2021. PacifiCorp submitted formal comments to the EPA on March 5, 2021, in support of the Wyodak Settlement Agreement. The public comment period was extended through July 6, 2021. EPA did not proceed with final approval of the Settlement Agreement and has engaged Wyoming and PacifiCorp regarding paths for resolution.

Naughton - In its 2014 rule, EPA approved Wyoming's determination that BART for Units 1 and 2 was LNB/OFA. EPA also indicated support for the conversion of the Naughton Unit 3 to natural gas in lieu of retrofitting the unit with SCR and stated that it would expedite consideration of the gas conversion once the state of Wyoming submitted the requisite SIP amendment. Wyoming submitted its Regional Haze SIP amendment regarding Naughton Unit 3 to EPA on November 28, 2017. On March 7, 2017, Wyoming issued PacifiCorp a permit for Unit 3's conversion to natural gas, which allowed operation of Unit 3 on coal through January 30, 2019. PacifiCorp ceased coal operation on Unit 3 on January 30, 2019, as required by the permit. EPA's final rule approval of Wyoming's SIP revision for Naughton Unit 3 gas conversion was published in the *Federal Register* on March 21, 2019, with an effective date of April 22, 2019. Naughton Unit 3 currently operates on natural gas. Environmental groups petitioned EPA's approval of LNB/OFA as BART for Units 1 and 2 in the Tenth Circuit. Like the Wyodak petition, that petition was stayed by the court and remains stayed.

Jim Bridger - SCR was installed on Jim Bridger Units 3 and 4 by the dates required by Wyoming in state law and by EPA in the 2014 final rule. On February 5, 2019, PacifiCorp submitted to Wyoming an application and proposed SIP revision instituting plant-wide variable average monthly-block pound per hour NOx and SO_2 emission limits, in addition to an annual combined NOx and SO_2 limit, on all four Jim Bridger boilers in lieu of the requirement to install SCR on Units 1 and 2. The proposed SIP revision demonstrates that the proposed limits are more cost effective while leading to better modeled visibility than the SCR installation on Units 1 and 2 required in the federally approved SIP.

Wyoming's proposed approval of the SIP revision was published for public comment July 20, 2019, through August 23, 2019. On May 5, 2020, the Wyoming Department of Environmental Quality issued permit P0025809 with PacifiCorp's proposed monthly and annual NOx and SO_2 emission limits. Under the permit, the new emission limits become effective January 1, 2022. Wyoming submitted a corresponding regional haze SIP revision to EPA on May 14, 2020. EPA has not taken formal action responding to the SIP revision. Discussions between EPA, Wyoming, and PacifiCorp regarding the SIP revision and regional haze compliance at Jim Bridger are ongoing.

WRAP performed the modeling that the state will use for the implementation of the second planning period. On March 31, 2020, PacifiCorp submitted a four-factor reasonable progress analysis to Wyoming which analyzed PacifiCorp's Naughton, Jim Bridger, Dave Johnston, and Wyodak plants. The four-factor analyses will be used by the state in its development of the SIP for the regional haze second planning period.

Arizona Regional Haze

The state of Arizona issued a regional haze SIP requiring, among other things, the installation of SO_2, NO_X and PM controls on Cholla Unit 4, which is owned by PacifiCorp and operated by Arizona Public Service. EPA approved in part and disapproved in part the Arizona SIP and issued a FIP requiring the installation of SCR equipment on Cholla Unit 4. PacifiCorp filed an appeal regarding the FIP as it relates to Cholla Unit 4, and the Arizona Department of Environmental Quality and other affected Arizona utilities filed separate appeals of the FIP as related to their interests. For the Cholla FIP requirements, the court stayed the appeals while parties attempted to agree on an alternative compliance approach.

In July 2016, the EPA issued a proposed rule to approve an alternative Arizona SIP, which included the option to convert Cholla 4 to a natural gas-fired unit or retire the unit by in 2025. EPA approved the revised SIP on March 27, 2017. The final action allowed Cholla Unit 4 to utilize coal until April 30, 2025, with an option to convert to gas by July 31, 2025. Cholla Unit 4 was retired in December 2020.

Colorado Regional Haze

The Colorado regional haze SIP required SCR controls at Craig Unit 2 and Hayden Units 1 and 2. In addition, the SIP required the installation of selective non-catalytic reduction (SNCR) technology at Craig Unit 1 by 2018. Environmental groups appealed EPA's action, and PacifiCorp intervened in support of EPA. In July 2014, parties to the litigation other than PacifiCorp entered into a settlement agreement that requires installation of SCR equipment at Craig Unit 1 in 2021.

In February 2015, the State of Colorado submitted a revised SIP to EPA for approval. As part of a further agreement between the owners of Craig Unit 1, state and federal agencies, and parties to previous settlements, the owners of Craig agreed to retire Unit 1 by December 31, 2025, or, to convert the unit to natural gas by August 31, 2023. The Colorado Air Quality Board approved the agreement on December 15, 2016. Colorado submitted the corresponding SIP amendment to EPA Region 8 on May 17, 2017. EPA approved the SIP on July 5, 2018.

Mercury and Hazardous Air Pollutants

The Mercury and Air Toxics Standards (MATS) became effective April 16, 2012. The MATS rule required that new and existing coal-fueled facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources were required to comply with the new standards by April 16, 2015. However, individual sources may have been granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls or for transmission system reliability reasons. By April 2015, PacifiCorp had taken the required actions to comply with MATS across its generation facilities. On April 25, 2016, the EPA published a Supplemental Finding that determined that it is appropriate and necessary to regulate under the MATS rule which addressed the Supreme Court decision.

On February 7, 2019, the EPA published a reconsideration of the Supplemental Finding in which it proposed to find that it is not appropriate and necessary to regulate hazardous air pollutants, reversing the Agency’s prior determination. In May 2020, the EPA published its decision to repeal the appropriate and necessary findings in the MATS rule regarding regulation of electric utility steam generating units, and to retain the rule’s current emission standards. The rule took effect in July 2020. Several petitions for review were filed in the D.C. Circuit by parties challenging and supporting the EPA's decision to rescind the appropriate and necessary finding. Until litigation over the rule is exhausted, PacifiCorp cannot fully determine the potential impacts of the changes to the MATS rule.

Coal Combustion Residuals

In May 2010, the EPA released a proposed rule to regulate the management and disposal of coal combustion byproducts under the Resource Conservation and Recovery Act (RCRA). The final rule became effective October 19, 2015. The final rule regulates coal combustion byproducts as non-hazardous waste under RCRA Subtitle D and establishes minimum nationwide standards for the disposal of coal combustion residuals (CCR). Under the final rule, surface impoundments and landfills utilized for coal combustion byproducts may need to be closed unless they can meet the more stringent regulatory requirements. The final rule requires regulated entities to post annual groundwater monitoring and corrective action reports. The first of these reports was posted to PacifiCorp’s coal combustion rule compliance data and information websites in March 2018. Based on the results in those reports, additional action was required under the rule. At the time the rule was published in April 2015, PacifiCorp operated 18 surface impoundments and seven landfills that contained CCR. Before the effective date in October 2015, nine surface impoundments and three landfills were either closed or repurposed to no longer receive CCR and hence are not subject to the final rule.

Multiple parties filed challenges over various aspects of the final rule in 2015, resulting in settlement of some of the issues and subsequent regulatory action by the EPA, including subjecting inactive surface impoundments to regulation. In response to legal challenges and court actions, EPA, in March 2018, issued a proposal to address provisions of the final CCR rule that were remanded back to the agency. The proposal included provisions that establish alternative performance standards for owners and operators of CCR units located in states that have approved permit programs or are otherwise subject to oversight through a permit program administered by the EPA. The first phase of the CCR rule amendments was made effective in August 2018 (the "Phase 1, Part 1 rule"). In addition to adopting alternative performance standards and revising groundwater performance standards for certain constituents, the EPA extended the deadline by which facilities must initiate closure of unlined ash ponds exceeding a groundwater protection standard and impoundments that do not meet the rule's aquifer location restrictions to October 2020.

Following the March 2019 submittal of competing motions from environmental groups, EPA finalized its Holistic Approach to Closure: Part A rule ("Part A rule") in September 2020. The rule reclassified compacted-soil lined surface impoundments from "lined" to "unlined," established a deadline of April 11, 2021, by which all unlined surface impoundments must initiate closure, and revised the alternative closure provisions to grant facilities additional time to initiate closure in order to manage CCR and non-CCR waste streams either due to a lack of alternative capacity or due to a commitment to close the coal-fueled operating unit and complete closure of unlined impoundments by a date certain. The Part A rule also revised certain requirements regarding annual groundwater monitoring and corrective action reports and publicly accessible CCR internet sites. A provision in Part A allows demonstrations to be submitted to the EPA allowing for operation of unlined CCR ponds beyond the April 11, 2021, deadline for initiation of closure. PacifiCorp has submitted alternative closure demonstrations for the Naughton South Ash Pond and the Jim Bridger FGD Pond 2. PacifiCorp anticipates a response and determination from EPA on both demonstrations before the end of 2021.

On October 16, 2020, the EPA released the pre-publication version of the final Holistic Approach to Closure: Part B rule ("Part B rule"). The Part B rule finalizes a two-step process, as set forth in the March 2020 proposal, allowing facilities to request approval to continue operating an existing unlined CCR surface impoundment with an alternate liner system. The other provisions that were contained in the Part B proposal, including (1) options to use CCR during closure of a CCR unit, (2) an additional closure-by-removal option and (3) new requirements for annual closure progress reports, were not finalized with the Part B rule. These options will be addressed by the EPA in a subsequent rulemaking action. In addition to the Part A and Part B rules, the EPA has proposed the Phase II rule, the federal CCR permit program rule, and the advanced notice of proposed rulemaking for legacy impoundments. Until the proposals are finalized and fully litigated, PacifiCorp cannot determine whether additional action may be required.

Separately, on August 10, 2017, the EPA issued proposed permitting guidance on how states' coal combustion residuals permit programs should comply with the requirements of the final rule as authorized under the December 2016 Water Infrastructure Improvements for the Nation Act. To date, none of the states in which PacifiCorp operates has submitted an application to the EPA for approval of state permitting authority. The state of Utah adopted the federal final rule in September 2016, which required PacifiCorp to submit permit applications for two of its landfills by March 2017. It is anticipated that the state of Utah will submit an application to EPA for approval of its coal combustion residuals permit program prior to the end of 2022. In 2019, the state of Wyoming proposed to adopt state rules which incorporate the final federal rule by reference. Wyoming finalized its rule in late 2020 and is waiting on legislative approval, likely in 2022, before submitting an application to the EPA to implement a state permit program.

Water Quality Standards

Cooling Water Intake Structures

The federal Water Pollution Control Act ("Clean Water Act") establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among other things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact" to aquatic organisms. In May 2014, EPA issued a final rule, effective October 2014, under § 316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The final rule established requirements for electric generating facilities that withdraw more than two million gallons per day, based on total design intake capacity, of water from waters of the United States and use at least 25 percent of the withdrawn water exclusively for cooling purposes. PacifiCorp's Dave Johnston generating facility withdraws more than two million gallons per day of water from waters of the U.S. for once-through cooling applications. Jim Bridger, Naughton, Gadsby, Hunter, and Huntington generating facilities currently use closed-cycle cooling towers and withdraw more than two million but less than 125 million gallons of water per day. The rule includes impingement (i.e., when fish and other aquatic organisms are trapped against screens when water is drawn into a facility's cooling system) mortality standards and entrainment (i.e., when organisms are drawn into the facility) standards. The standards will be set on a case-by-case basis to be determined through site-specific studies and will be incorporated into each facility's discharge permit.

Rule-required permit application requirements (PARs) have been submitted to the appropriate permitting authorities for the Jim Bridger, Naughton, Gadsby, Hunter and Huntington plants. As the five facilities utilize closed-cycle recirculating cooling water systems (cooling towers) exclusively for equipment cooling, it is expected that state agencies will require no further action from PacifiCorp to comply with the rule-required standards.

Because Dave Johnston utilizes once-through cooling with withdrawal rates greater than 125 million gallons per day, the facility has been required to conduct more rigorous permit application requirements. The Dave Johnston permit application requirements were submitted to the Wyoming Water Quality Division on May 31, 2019. The application proposed that no modifications to the intake structure were required; however, upon review of the submittal and subsequent issuance of a draft permit for public notice, the Water Quality Division has indicated that PacifiCorp may be required to select and implement an approved 316(b) impingement mortality compliance option by December 31, 2023. As the final Dave Johnston Wyoming Pollutant Discharge Elimination System permit has yet to be issued which is expected to include 316(b) impingement mortality (IM) compliance requirements, it is anticipated that the December 31, 2023 IM technology implementation date will be adjusted to compensate for the actual permit issuance date.

Effluent Limit Guidelines

In November 2015, the EPA published final effluent limitation guidelines and standards for the steam electric power generating sector which, among other things, regulate the discharge of bottom ash transport water, fly ash transport water, combustion residual leachate and non-chemical metal cleaning wastes. These guidelines, which had not been revised since 1982, were revised in response to the EPA's concerns that the addition of controls for air emissions has changed the effluent discharged from coal- and natural gas-fueled generating facilities. Under the originally promulgated guidelines, permitting authorities were required to include the new limits in each impacted facility's National Pollutant Discharge Elimination System permit upon renewal with the new limits to be met as soon as possible, beginning November 1, 2018 and fully implemented by December 31, 2023.

On April 5, 2017, a request for reconsideration and administrative stay of the guidelines was filed with the EPA. EPA granted the request for reconsideration and extended certain compliance dates for flue gas desulfurization wastewater and bottom ash transport water limits until November 1, 2020.

On November 22, 2019, EPA proposed updates to the 2015 rule, specifically addressing flue gas desulfurization wastewater and bottom ash transport water. Those proposals were formalized in rule when the EPA administrator signed the Reconsideration Rule, and it was published in the Federal Register on October 13, 2020. The rule eases selenium limits on flue gas desulfurization wastewater, eases the zero-discharge requirements on bottom ash transport water associated with blowdown of ash handling systems, allows a two-year time extension to meet flue gas desulfurization wastewater requirements, and includes additional subcategories to both wastewater categories.

Most of the issues raised by this rule are already being addressed at PacifiCorp facilities through compliance with the coal combustion residuals rule and are not expected to impose significant additional requirements on the facilities. The Dave Johnston plant anticipates achieving compliance with the rule by issuing a notice of planned participation for subcategorization, or by installation and operation of a bottom ash recycle system that would enable long-term compliance with the Reconsideration Rule.

Renewable Generation Regulatory Framework

Regulatory and permitting requirements for renewable energy projects are addressed at federal, state, and local levels. All wind projects in the United States must comply with federal regulations for wildlife impacts, aviation safety, clean water, communication systems, and Department of Defense impacts. Eagle Incidental Take Permits (EITPs), including associated surveys, monitoring, and compensatory mitigation, are necessary for wind projects that may result in take of bald or golden eagles. State and county regulations often address localized topics such as road and traffic concerns, community economic impacts, viewshed requirements, sage-grouse stipulations, wind turbine location guidelines, and land use and zoning restrictions. Solar projects must comply with federal and state regulations that restrict disturbance of certain flora and fauna and are subject to local planning and zoning regulations for land use. Storm water pollution prevention plans for renewable projects are usually required on a state level to control sediment runoff during construction and all renewable projects must comply with the Clean Water Act rules which are controlled at the federal level. Renewable energy projects located on federally managed lands are subject to National Environmental Policy Act (NEPA) review, which may include cultural and biological resource surveys, assessment of potential impacts, public comment periods, and avoidance/minimization/mitigation efforts. Power lines associated with renewable energy projects, including collector lines at the project site and grid-connecting transmission lines, may also be subject to environmental regulations, review, stipulations, or permits.

The wind projects constructed as part of PacifiCorp's Energy Vision 2020 initiative for example, (TB Flats, Ekola Flats, and Cedar Springs) were required to obtain permits from the State of

Wyoming's Industrial Siting Division which required extensive studies of the conditions of the site, coordination with state agencies in the development process, and forecast of impacts from the project. Renewable energy projects in the State of Wyoming that meet the Industrial Siting Division's size or capital thresholds must obtain approval before they can begin construction. Most wind project developers coordinate with federal and/or state authorities to evaluate and mitigate potential impacts to birds or other wildlife species, particularly eagles, migratory birds, and bats, during the wind turbine siting process to minimize wildlife impacts and potential operational risks. Greater sage-grouse are currently managed by the states, and renewable energy projects and associated transmission lines would require state agency review; stipulations or mitigation requirements vary by state and project impacts. Because the generation capabilities of renewable energy projects are site specific and can vary greatly between different sites, understanding the specific permit requirements for each site is critical to developing a successful project.

Tax Extender Legislation

On Dec. 27, 2020, President Trump signed into law the Taxpayer Certainty and Disaster Relief Act of 2020. Among other things, the bill extended and expanded certain alternative energy tax credits. Notable as relating to the 2021 IRP, the renewable electricity production tax credit (PTC) was extended by one year for certain qualifying facilities; for wind facilities that begin construction during 2021, the credit continues to be equal to 60% of the full value of the PTC. The energy tax credit (ITC) was extended by two years for certain qualifying facilities; the bill extends the 26% ITC for solar energy property that begins construction during 2021 and 2022, before being phased down further.

The energy tax credit was expanded to cover offshore wind facilities; generally, any offshore wind project that on which construction after December 31, 2017, and before January 1, 2026, will qualify for a 30% ITC. And, finally, the credit for carbon dioxide sequestration was extended to cover facilities that begin construction by the end of 2025. Additional schedules detailing the phase-out of the wind PTC and solar ITC are provided as follows:

Table 3.1 – Tax Extender Legislation and Phaseout of PTC and ITC

Phaseout of Wind PTC		
Date Construction Begins	**In-Service Date***	**% of Full PTC Rate**
Before 12/31/2015	Before 01/01/2020	100%
01/01/2016 - 12/31/2016	Before 01/01/2022	100%
01/01/2017 - 12/31/2017	Before 01/01/2023	80%
01/01/2018 - 12/31/2018	Before 01/01/2023	60%
01/01/2019 - 12/31/2019	Before 01/01/2024	40%
01/01/2020 - 12/31/2020	Before 01/01/2025	60%
01/01/2021 - 12/31/2021	Before 01/01/2026	60%
On or After 01/01/2022	Any	0%

* In-Service date assumes the use of the Continuity Safe Harbor which is 4 years after the calendar year during which construction, 5 years for projects beginning construction in 2016 and 2017.

Phaseout of Solar ITC		
Date Construction Begins	**In-Service Date**	**ITC Rate**
Before 01/01/2020	Before 01/01/2026	30%
01/01/2020 - 12/31/2020	Before 01/01/2026	26%
01/01/2021 - 12/31/2021	Before 01/01/2026	26%
01/01/2022 - 12/31/2022	Before 01/01/2026	26%
01/01/2023 - 12/31/2023	Before 01/01/2026	22%
Before 01/01/2024	On or After 01/01/2026	10%
On or After 01/01/2024	Any	10%

State Policy Update

California

Under the authority of the Global Warming Solutions Act, the California Air Resources Board (CARB) adopted a greenhouse gas cap-and-trade program in October 2011, with an effective date of January 1, 2012; compliance obligations were imposed on regulated entities beginning in 2013. The first auction of greenhouse gas allowances was held in California in November 2012, and the second auction in February 2013. PacifiCorp is required to sell, through the auction process, its directly allocated allowances and purchase the required allowances necessary to meet its compliance obligations.

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

2030. CARB has subsequently been directed to update the AB 32 scoping plan to reflect the new interim 2030 target and previously established 2050 target.

In 2002, California established a RPS requiring investor-owned utilities to increase procurement from eligible renewable energy resources. California's RPS requirements have been accelerated and expanded a number of times since its inception. Most recently, in September 2018, Governor Jerry Brown signed into law the 100 Percent Clean Energy Act of 2018, Senate Bill (SB) 100, which requires utilities to procure 60 percent of their electricity from renewables by 2030 and enabled all the state's agencies to work toward a longer-term planning target for 100 percent of California's electricity to come from renewable and zero-carbon resources by December 31, 2045.

Oregon

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

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

On March 10, 2020, Oregon Governor Kate Brown issued Executive Order 20-04 (EO 20-04), which directs state agencies to take actions to reduce and regulate greenhouse gas emissions.

EO 20-04 establishes emissions reduction goals for Oregon and directs certain state agencies to take specific actions to reduce emissions and mitigate the impacts of climate change. EO 20-04 also provides overarching direction to state agencies to exercise their statutory authority to help achieve Oregon's climate goals.

In 2021, Oregon passed House Bill 2021, which directs utilities to reduce emissions levels below 2010-2012 baseline levels by 80% by 2030, 90% by 2035, and 100% by 2040. Utilities will also convene a Community Benefits and Impacts Advisory Group. PacifiCorp's 2023 IRP will include modeling to support House Bill 2021.

Washington

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

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

In July 2015, Governor Inslee released an executive order that directed the Washington Department of Ecology to develop new rules to reduce carbon emissions in the state. In December 2017, Washington's Superior Court concluded that the Department of Ecology did not have the authority to impose the Clean Air Rule without legislative approval. As a result, the Department of Ecology has suspended the rule's compliance requirements.

In 2019, the Washington Legislature approved the Clean Energy Transformation Act (CETA) which requires utilities to eliminate coal-fired resources from Washington rates by December 31, 2025, be carbon neutral by January 1, 2030, and establishes a target of 100 percent of its electricity from renewable and non-emitting resources by 2045.

In 2021, Washington passed the Climate Commitment Act, which establishes a cap-and-trade program to be implemented by no later than 2023 through the regulatory rulemaking process. The Climate Commitment Act does not modify any of PacifiCorp's obligations under CETA, and utility allowances within the cap-and-trade program are aligned with the CETA renewable energy requirements. The legislation allows – but does not require – linkage with cap-and-trade programs in jurisdictions outside of Washington State.

Utah

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

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

On March 11, 2020, the Utah Legislature passed HB 396, Electric Vehicle Charging Infrastructure Amendments, that enables PacifiCorp to create an Electrical Vehicle Infrastructure Program, with a maximum funding from customers of $50 million for all costs and expenses. The legislation allows PacifiCorp to own and operate electric vehicle charging stations and to provide investments in make-ready infrastructure to interested customers.

Wyoming

On March 8, 2019, Wyoming Senate File 0159 (SF 159) was passed into law. SF 159 limits the recovery costs for the retirement of coal fired electric generation facilities, provides a process for the sale of an otherwise retiring coal fired electric generation facility, exempts a person purchasing an otherwise retiring coal fired electric generation facility from regulation as a public utility; requires purchase of electricity generated from purchased retiring coal fired electric generation facility (as specified in final bill); and provides an effective date.

Cost recovery associated with electric generation built to replace a retiring coal fired generation facility shall not be allowed by the Wyoming Public Service Commission unless the Commission has determined that the public utility made a good faith effort to sell the facility to another person prior to its retirement and that the public utility did not refuse a reasonable offer to purchase the facility or the Commission determines that, if a reasonable offer was received, the sale was not completed for a reason beyond the reasonable control of the public utility.

Under SF 159 electric public utilities, other than cooperative electric utilities, shall be obligated to purchase electricity generated from a coal fired electric generation facility purchased under agreement approved by the Commission, provided the otherwise retiring coal fired electric generation facility offers to sell some or all of the electricity from the facility to an electric public utility, the electricity is sold at a price that is no greater than the purchasing electric utility's avoided cost, the electricity is sold under a power purchase agreement, and the Commission approves a 100 percent cost recovery in rates for the cost of the power purchase agreement and the agreement is 100 percent allocated to the public utility's Wyoming customers unless otherwise agreed to by the public utility.

In March 2020, the Wyoming legislature passed House Bill 200 (HB 200), Reliable and Dispatchable Low-Carbon Energy Standards. HB 200 requires the Wyoming Public Service Commission to put in place a standard for each public utility specifying a percentage of electricity to be generated from coal-fired generation utilizing carbon capture technology by 2030. The requirement would only apply to generation allocated to Wyoming customers. HB 200 will require each public utility to demonstrate in its IRP the steps taken to achieve the electricity generation standard established by the Commission and will allow rate recovery of costs incurred by a public utility that utilizes coal-fired generation with carbon capture technology installed.

Greenhouse Gas Emission Performance Standards

California, Oregon and Washington have greenhouse gas emission performance standards applicable to all electricity generated in the state or delivered from outside the state that is no higher than the greenhouse gas emission levels of a state-of-the-art combined cycle natural gas generation facility. The standards for Oregon and California are currently set at 1,100 lb CO_2/MWh, which is defined as a metric measure used to compare the emissions from various greenhouse gases based on their global warming potential. In September 2018, the Washington Department of Commerce issued a new rule lowering the emissions performance standard to 925 lb CO_2/MWh.

Renewable Portfolio Standards

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

RPS policies are currently implemented at the state level and vary considerably in their renewable targets (percentages), target dates, resource/technology eligibility, applicability of existing plants and contracts, arrangements for enforcement and penalties, and use of RECs.

In PacifiCorp's service territory, California, Oregon, and Washington have each adopted a mandatory RPS, and Utah has adopted a RPS goal. Each of these states' legislation and requirements are summarized in Table 3.2, with additional discussion below.

Table 3.2 – State RPS Requirements

	California	Oregon	Washington	Utah
Legislation	• Senate Bill 1078 (2002) • Assembly Bill 200 (2005) • Senate Bill 107 (2006) • Senate Bill 2 First Extraordinary Session (2011) • Senate Bill 350 (2015) • Senate Bill 100 (2018)	• Senate Bill 838 Oregon Renewable Energy Act (2007) • House Bill 3039 (2009) • House Bill 1547-B (2016)	• Initiative Measure No. 937 (2006) • SB 5400 (2013)	• Senate Bill 202 (2008)
Requirement or Goal	• 20% by December 31, 2013 • 25% by December 31, 2016 • 33% by December 31, 2020 • 44% by December 31, 2024 • 52% by December 31, 2027 • 60% by December 31, 2030 and beyond • Planning target of 100% renewable and zero-carbon by 2045 * Based on the retail load for a three-year compliance period	• 5% by December 31, 2011 • 15% by December 31, 2015 • 20% by December 31, 2020 • 27% by December 31, 2025 • 35% by December 31, 2030 • 45% by December 31, 2035 • 50% by December 31, 2040 * Based on the retail load for that year	• 3% by January 1, 2012 • 9% by January 1, 2016 • 15% by January 1, 2020 and beyond * Annual targets are based on the average of the utility's load for the previous two years	• Goal of 20% by 2025 (must be cost effective) • Annual targets are based on the adjusted[18] retail sales for the calendar year 36 months before the target year

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

California

California originally established its RPS program with passage of SB 1078 in 2002. Several bills that have since been passed into law to amend the program. In the 2011 First Extraordinary Special Session, the California Legislature passed SB 2 (1X) to increase California's RPS to 33 percent by 2020.[19] SB 2 (1X) also expanded the RPS requirements to all retail sellers of electricity and publicly owned utilities. In October 2015, SB 350, the Clean Energy and Pollution Reduction Act, was signed into law.[20] SB 350 established a greenhouse gas reduction target of 40 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050 and expanded the state's renewables portfolio standard to 50 percent by 2030. In September 2018, the signing of SB 100, the Clean Energy Act of 2018, further expanded and accelerated the California RPS to 60 percent by 2030 and directed the state's agencies to plan for a longer-term goal of 100 percent of total retail sales of electricity in California to come from eligible renewable and zero-carbon resources by December 31, 2045.

SB 2 (1X) created multi-year RPS compliance periods, which were expanded by SB 100. The California Public Utilities Commission approved compliance periods and corresponding RPS procurement requirements, which are shown in Table 3.3 below.

Table 3.3 – California Compliance Period Requirements

Compliance Period	Procurement Quantity Requirement Calculation
Compliance Period 1 (2011-2013)	(20% * 2011 Retail Sales) + (20% * 2012 Retail Sales) + (20% * 2013 Retail Sales)
Compliance Period 2 (2014-2016)	(21.7% * 2014 Retail Sales) + (23.3% * 2015 Retail Sales) + (25% * 2016 Retail Sales)
Compliance Period 3 (2017-2020)	(27% * 2017 Retail Sales) + (29% * 2018 Retail Sales) + (31% * 2019 Retail Sales) + (33% * 2020 Retail Sales)
Compliance Period 4 (2021-2024)	(35.8% * 2021 Retail Sales) + (38.5% * 2022 Retail Sales) + (41.3% * 2023 Retail Sales) + (44% * 2024 Retail Sales)
Compliance Period 5 (2025-2027)	(47% * 2025 Retail Sales) + (50% * 2026 Retail Sales) + (52% * 2027 Retail Sales)
Compliance Period 6 (2028-2030)	(54.7% * 2028 Retail Sales) + (57.3% * 2029 Retail Sales) + (60% * 2030 Retail Sales)

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

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

> Have a first point of interconnection with a California balancing authority, have a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area, or are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source;[11] or
>
> Have an agreement to dynamically transfer electricity to a California balancing

[19] www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf
[20] leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

authority.

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

Portfolio Content Category 3 includes eligible renewable energy resource electricity products, or any fraction of the electricity, including unbundled renewable energy credits that do not qualify under the criteria of Portfolio Content Category 1 or Portfolio Content Category 2.[21]

Additionally, the CPUC established the balanced portfolio requirements for contracts executed after June 1, 2010. The balanced portfolio requirements set minimum and maximum levels for the Procurement Content Category products that may be used in each compliance period as shown in Table 3.4.

Table 3.4 – California Balanced Portfolio Requirements

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

In December 2011, the CPUC confirmed that multi-jurisdictional utilities, such as PacifiCorp, are not subject to the percentage limits in the three portfolio content categories. PacifiCorp is required to file annual compliance reports with the CPUC and annual procurement reports with the California Energy Commission (CEC). Neither SB 350 nor SB 100 changed the portfolio content categories for eligible renewable energy resources or the portfolio balancing requirements exemption provided to PacifiCorp. For utilities subject to the portfolio balancing requirements, the CPUC extended the compliance period 3 requirements through 2030.

The full California RPS statute is listed under Public Utilities Code Section 399.11-399.32. Additional information on the California RPS can be found on the CPUC and CEC websites.
Qualifying renewable resources include solar thermal electric, photovoltaic, landfill gas, wind, biomass, geothermal, municipal solid waste, energy storage, anaerobic digestion, small hydroelectric, tidal energy, wave energy, ocean thermal, biodiesel, and fuel cells using renewable fuels. Renewable resources must be certified as eligible for the California RPS by the CEC and tracked in the Western Renewable Energy Generation Information System (WREGIS).

[21] A REC can be sold either "bundled" with the underlying energy or "unbundled" as a separate commodity from the energy itself into a separate REC trading market.

Oregon

Oregon established the Oregon RPS with passage of SB 838 in 2007. The law, called the Oregon Renewable Energy Act, was adopted in June 2007, and provides a comprehensive renewable energy policy for the state.[22] Subject to certain exemptions and cost limitations established in the Oregon Renewable Energy Act, PacifiCorp and other qualifying electric utilities must meet a target of at least 25 percent renewable energy by 2025. In March 2016, the Legislature passed SB 1547,[23] also referred to as Oregon's Clean Electricity and Coal Transition Act. In addition to requiring Oregon to transition off coal by 2030, the new law doubled Oregon's RPS requirements, which are to be staged at 27 percent by 2025, 35 percent by 2030, 45 percent by 2035, and 50 percent by 2040 and beyond. Other components of SB 1547 include:

- Development of a community solar program with at least 10 percent of the program capacity reserved for low-income customers.
- A requirement that by 2025, at least eight percent of the aggregate electric capacity of the state's investor-owned utilities must come from small-scale renewable projects under 20 megawatts.
- Creates new eligibility for pre-1995 biomass plants and associated thermal co-generation. Under the previous law, pre-1995 biomass was not eligible until 2026.
- Direction to the state's investor-owned utilities to propose plans encouraging greater reliance on electricity in all modes of transportation, to reduce carbon emissions.
- Removal of the Oregon Solar Initiative mandate.[24]

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

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

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

[22] www.leg.state.or.us/07reg/measpdf/sb0800.dir/sb0838.en.pdf
[23] olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled
[24] In 2009, Oregon passed House Bill 3039, also called the Oregon Solar Initiative, requiring that on or before January 1, 2020, the total solar photovoltaic generating nameplate capacity must be at least 20 megawatts from all electric companies in the state. The Public Utility Commission of Oregon determined that PacifiCorp's share of the Oregon Solar Initiative was 8.7 megawatts.

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

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

PacifiCorp files an annual RPS compliance report by June 1 of every year and a renewable implementation plan on or before January 1 of even-numbered years, unless otherwise directed by the Public Utility Commission of Oregon. These compliance reports and implementation plans are available on PacifiCorp's website.[25]

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

Utah

In March 2008, Utah's governor signed Utah SB 202, the Energy Resource and Carbon Emission Reduction Initiative.[26] The Energy Resource and Carbon Emission Reduction Initiative is codified in Utah Code Title 54 Chapter 17. Among other things, this law provides that, beginning in the year 2025, 20 percent of adjusted retail electric sales of all Utah utilities be supplied by renewable energy if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions and for sales avoided because of energy efficiency and demand side management programs. Qualifying renewable energy sources can be located anywhere in the Western Electricity Coordinating Council areas, and unbundled renewable energy credits can be used for up to 20 percent of the annual qualifying electricity target.

Eligible renewable resources include electricity from a facility or upgrade that becomes operational on or after January 1, 1995, that derives its energy from wind, solar photovoltaic, solar thermal electric, wave, tidal or ocean thermal, certain types of biomass and biomass products, landfill gas or municipal solid waste, geothermal, waste gas and waste heat capture or recovery, and efficiency upgrades to hydroelectric facilities if the upgrade occurred after January 1, 1995. Up to 50 average megawatts from a certified low-impact hydro facility and in-state geothermal

[25] www.pacificpower.net/ORrps
[26] le.utah.gov/~2008/bills/sbillenr/sb0202.pdf

and hydro generation without regard to operational online date may also be used toward the target. To assist solar development in Utah, solar facilities located in Utah receive credit for 2.4 kilowatt-hours of qualifying electricity for each kWh of generation.

Under the Carbon Reduction Initiative, PacifiCorp is required to file a progress report by January 1 of each of the years 2010, 2015, 2020 and 2024.

PacifiCorp filed its most recent progress report on December 31, 2019. This report showed that the company is positioned to meet its 20 percent target requirement of approximately 4.8 million megawatt-hours of renewable energy in 2025 from existing company-owned and contracted renewable energy sources.

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

Washington

In November 2006, Washington voters approved I-937, a ballot measure establishing the Energy Independence Act, which is an RPS and energy efficiency requirement applied to qualifying electric utilities, including PacifiCorp.[27] The law requires that qualifying utilities procure at least three percent of retail sales from eligible renewable resources or RECs by January 1, 2012 through 2015; nine percent of retail sales by January 1, 2016 through 2019; and 15 percent of retail sales by January 1, 2020, and every year thereafter.

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

PacifiCorp is required to file an annual RPS compliance report by June 1 of every year with the Washington Utilities and Transportation Commission (WUTC) demonstrating compliance with the Energy Independence Act. PacifiCorp's compliance reports are available on PacifiCorp's website.[28]

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

[27] www.secstate.wa.gov/elections/initiatives/text/I937.pdf
[28] www.pacificpower.net/report

REC Management Practices

PacifiCorp provides the following summary of REC management practices in compliance with Order 20-186 in Oregon. The company intends to maximize the value of RECs for customers either through retirement for compliance purposes or monetization through sales. As a multi-state utility, PacifiCorp has Renewable Portfolio Standards in Washington, Oregon, and California, and a Renewable Portfolio Goal in 2025 in Utah. PacifiCorp generally retains and retires RECs allocated to Washington, Oregon, and California for compliance purposes, but requests flexibility to manage its RECs based on opportunities it sees in the market, which may include selling RECs at a favorable price and acquiring RECs at a lower price. The company maximizes the sale of RECs allocated to Utah, Idaho, and Wyoming and allocates the revenue from those sales to those states.

Clean Energy Standards

Washington

In 2019, Governor Jay Inslee signed into law Senate Bill 5116, the Clean Energy Transformation Act. Under the law, Washington utilities are required to be carbon neutral by January 1, 2030 and institute a planning target of 100 percent clean electricity by 2045. The bill establishes four-year compliance periods beginning January 1, 2030 and requires utilities to use electricity from renewable resources and non-emitting electric generation in an amount equal to 100 percent of the retail electric load over each compliance period. Through December 31, 2044, an electric utility may satisfy up to 20 percent of its compliance obligation with an alternative compliance option such as the purchase of unbundled RECs.

Oregon

In July 2021, Oregon Governor Kate Brown signed into law House Bill 2021, which set emissions reduction targets for utilities and electricity providers. Under the law, retail electricity providers shall reduce greenhouse gas emissions by 80 percent below baseline emissions levels by 2030, by 90 percent below baseline emissions level by 2035, and by 100 percent below baseline emissions levels by 2040.

California

In 2018, California passed Senate Bill 100 – known as the "100 percent Clean Energy Act of 2018," which sets a 2045 goal of powering all retail electricity sold in California with renewable and zero-carbon resources. The law also updates the state's Renewables Portfolio Standard to ensure that by 2030 at least 60 percent of California's electricity is renewable.

Wyoming

In March 2020, the Wyoming governor signed House of Representatives Enrolled Act No. 79, which requires the WPSC to adopt a low-carbon standard to specify a percentage of an electric utility's electricity to be generated from coal-fueled generation utilizing carbon capture technology by no later than 2030. The bill allows electric utilities to implement a surcharge not to exceed 2% of customer bills to recover costs to comply with the standard. The WPSC is establishing the standard and requirements to implement the law through a rulemaking process expected to be completed before the end of 2021.

Transportation Electrification

The electric transportation market is in an emerging state,[29] and plug-in electric vehicles (EV) currently comprise a negligible share of PacifiCorp's load. This rapidly evolving market represents a potential driver of future load growth and those impacts managed proactively, provide an opportunity to increase the efficiency of the electrical system and provide benefits for all PacifiCorp customers. In addition, increased adoption of electric transportation has the ability to improve air quality, reduce noise pollution, reduce greenhouse gas emissions, improve public health and safety, and create financial benefits for drivers, which can be a particular benefit for low- and moderate-income populations.

To help manage and understand the potential future load growth impacts of electric transportation PacifiCorp is investing to support EV fast chargers along key corridors, develop workplace charging programs, research new rate designs and implement time-of-use pricing pilots, create partnerships for smart mobility programs and develop opportunities for customers in our rural communities. Our investments include the Oregon Clean Fuels programs as well as pilot programs approved and filed with the OPUC equaling over $12 million in TE investment. This includes infrastructure, education and outreach and innovative e mobility projects. As of the end of 2020, PacifiCorp had supported installation of over 2,100 EV ports throughout the territory

Electric vehicle load is reflected in the Company's load forecast. PacifiCorp continues to actively engage with local, regional, and national stakeholders and participate in state regulatory processes that can inform future planning and load forecasting efforts for electric vehicles

Hydroelectric Relicensing

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

The value of relicensing hydroelectric facilities is continued availability of energy, capacity, and ancillary services associated with hydroelectric generation. Hydroelectric projects can often provide unique operational flexibility because they can be called upon to meet peak customer demands almost instantaneously and back up intermittent renewable resources such as wind. In addition to operational flexibility, hydroelectric generation does not have the emissions concerns of thermal generation and can also often provide important ancillary services, such as spinning reserve and voltage support, to enhance the reliability of the transmission system.

On September 27, 2019, the FERC issued a new license order for the Prospect No. 3 Hydroelectric Project, a 7.2 MW project located in southern Oregon. The license period is 40 years. Conditions

[29] As of June 2019, the market share of plug-in electric vehicles was two percent: www.nada.org/WorkArea/DownloadAsset.aspx?id=21474858563

of the license are consistent with the Commission's previous environmental analysis. Pursuant to the new license, PacifiCorp will implement increased minimum flows downstream of the diversion dam, replace the project's wood-stave flowline and sag-pipe, upgrade and construct new wildlife crossings over the waterway, and prepare and implement various monitoring and management plans.

On March 19, 2021, the FERC issued a new license order for the Weber Hydroelectric Project, a 3.85 MW project located in north central Utah. The license period is 40 years. Conditions of the license are consistent with the Commission's previous environmental analysis and similar to previous license conditions. Pursuant to the new license, PacifiCorp will construct a new fish ladder at the diversion dam, complete recreation site improvements, annually provide four 4-hour whitewater boater flow releases and prepare and implement various monitoring and management plans.

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

FERC has sole jurisdiction under the Federal Power Act to issue new operating licenses for non-federal hydroelectric projects on navigable waterways, federal lands, and under other criteria. FERC must find that the project is in the broad public interest. This requires weighing, with "equal consideration," the impacts of the project on fish and wildlife, cultural resources, recreation, land use, and aesthetics against the project's energy production benefits. Because some of the responsible state and federal agencies have the ability to place mandatory conditions in the license, FERC is not always in a position to balance the energy and environmental equation. For example, the National Oceanic and Atmospheric Administration Fisheries agency and the U.S. Fish and Wildlife Service have the authority in the relicensing process to require installation of fish passage facilities (fish ladders and screens) and to specify their design. This is often the largest single capital investment that will be considered in relicensing and can significantly impact project economics. Also, because a myriad of other state and federal laws come into play in relicensing, most notably the Endangered Species Act and the Clean Water Act, agencies' interests may compete or conflict with each other, leading to potentially contrary or additive licensing requirements. PacifiCorp has generally taken a proactive approach towards achieving the best possible relicensing outcome for its customers by engaging in negotiations with stakeholders to resolve complex relicensing issues. In some cases, settlement agreements are achieved which are submitted to FERC for incorporation into a new license. FERC welcomes license applications that reflect broad stakeholder involvement or that incorporate measures agreed upon through multi-party settlement agreements. History demonstrates that with such support, FERC generally accepts proposed new license terms and conditions reflected in settlement agreements.

Potential Impact

Relicensing hydroelectric facilities involves significant process costs. The FERC relicensing process takes a minimum of five years and may take longer, depending on the characteristics of the project, the number of stakeholders, and issues that arise during the process. As of December 31, 2020, PacifiCorp had incurred approximately $5 million in costs for license implementation and ongoing hydroelectric relicensing, which are included in construction work- in-progress on PacifiCorp's Consolidated Balance Sheet. As current or upcoming relicensing and settlement efforts continue for the Cutler and other hydroelectric projects, additional process costs are being or will be incurred that will need to be recovered from customers. Hydroelectric relicensing costs have and will continue to have a significant impact on overall hydroelectric generation cost. Such costs include capital investments and related operations and maintenance costs associated with fish passage facilities, recreational facilities, wildlife protection, water quality, cultural and flood management measures. Project operational and flow-related changes, such as increased in-stream flow requirements to protect aquatic resources, can also directly result in lost generation. Much of these relicensing and settlement costs relate to PacifiCorp’s three largest hydroelectric projects: Lewis River, Klamath River, and North Umpqua.

Treatment in the IRP

The known or expected operational impacts related to FERC orders and settlement commitments are incorporated in the projection of existing hydroelectric resources discussed in Volume I, Chapter 7 (Resource Options).

PacifiCorp’s Approach to Hydroelectric Relicensing

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

Utah Rate Design Information

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

Residential Rate Design

Residential rates in Utah are comprised of a customer charge and energy charges. The customer charge is a monthly charge that provides limited recovery of customer-related costs incurred to serve customers regardless of usage. All other remaining costs are recovered through volumetric-based energy charges. Energy charges for residential customers are designed with an inclining-tier rate structure so high usage during a billing month is charged a higher rate. This gives customers a price signal to encourage reduced consumption. Additionally, energy charges are differentiated by season with higher rates in the summer when the costs to serve are higher. Residential customers also have an option for time-of-day rates. Time-of-day rates have a surcharge for usage during the on-peak periods and a credit for usage during the off-peak periods. This rate structure provides an additional price signal to encourage customers to use less energy during the daily on-peak periods when energy costs are higher. As of Spring 2021, less than one percent of customers have opted to participate in the time-of-day rate option.

Changes in residential rate design include a critical peak pricing program or an expansion of time-of-use rates. These types of rate designs will be discussed in more detail in Volume I, Chapter 7 (Resource Options). As part of the STEP legislation enacted in SB 115, the company developed a pilot time-of-use program to encourage off-peak charging of electric vehicles for residential customers. The results of this pilot may inform future rate design offerings. Any changes in standard residential rate design or institution of optional rate options to support energy efficiency or time-differentiated usage should be balanced with the recovery of fixed costs to ensure price signals are economically efficient and do not unduly shift costs to other customers.

With the growth in the number of customers adopting private distributed generation, rates have begun to evolve to address the change in usage requirements and ensure appropriate cost recovery from these customers. A deeper consideration of the implications of current rates and rate designs is necessary to address growing issues with private generation and ensure the appropriate price signals are set for the changing circumstances. As a result of a settlement in Docket No. 14-035-114, new customer generators in Utah receive export credits that are valued at a different rate than retail rates as part of a transition program.

Commercial and Industrial Rate Design

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

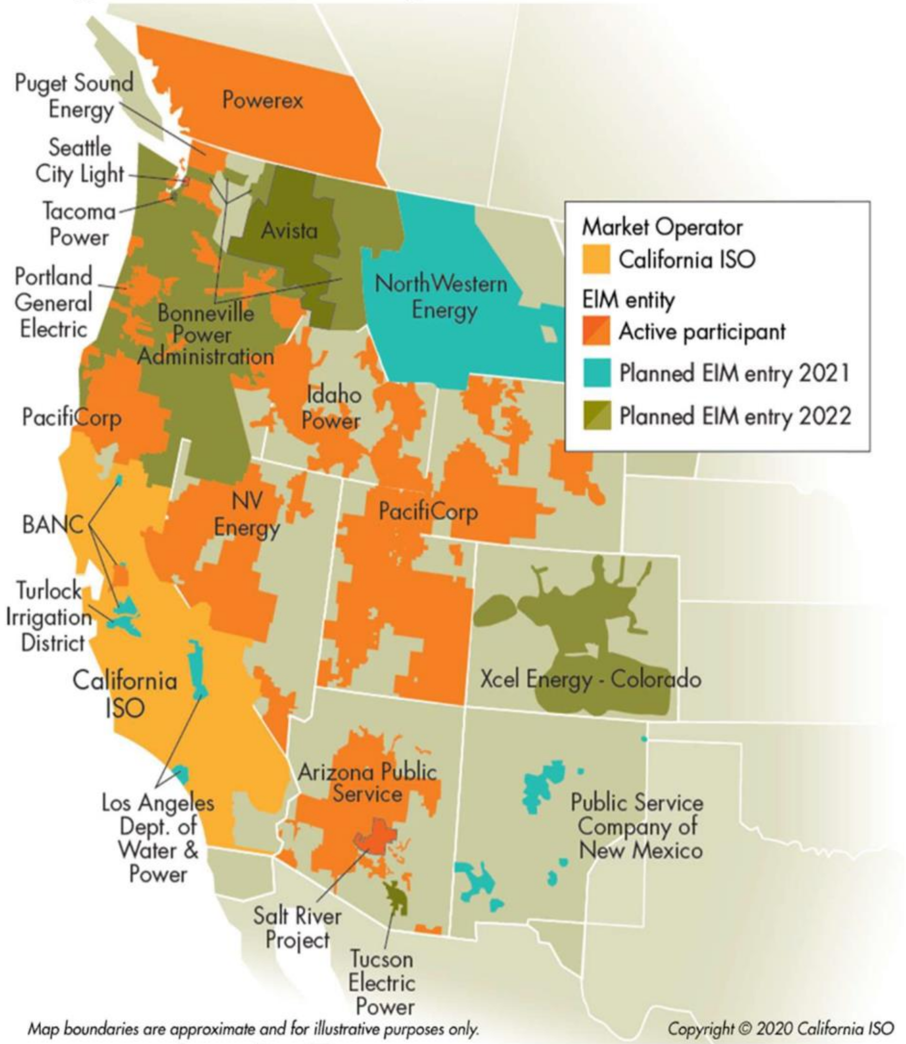
Irrigation Rate Design

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

Energy Imbalance Market

PacifiCorp and the CAISO launched the EIM November 1, 2014. The EIM is a voluntary market and the first western energy market outside of California. NV Energy began participating in December 2015, Arizona Public Service and Puget Sound Energy began participating in October 2016, and Portland General Electric began participating in October 2017. Idaho Power and Powerex began participating in April 2018, and the Balancing Authority of Northern California (BANC)[1] began participating in April 2019. Seattle City Light (SCL) and Salt River Project (SRP) began participating in April 2020, and 2021 saw the addition of NorthWestern Energy, Los Angeles Department of Water & Power, Public Service Company of New Mexico, and Turlock Irrigation District. The EIM footprint now includes portions of Arizona, California, Idaho, Nevada, Oregon, Utah, Washington, Wyoming, and extends to the border with Canada. PacifiCorp continues to work with the CAISO, existing and prospective EIM entities, and stakeholders to enhance market functionality and support market growth.

Figure 3.6 – Energy Imbalance Market Expansion



The EIM has produced significant monetary benefits ($1.42 billion total footprint-wide benefits as of August 2021), quantified in the following categories: (1) more efficient dispatch, both inter- and intra-regional, by automating dispatch every 15 minutes and every five minutes within and across the EIM footprint; (2) reduced renewable energy curtailment by allowing balancing authority areas to export or reduce imports of renewable generation that would otherwise need to be curtailed; and (3) reduced need for flexibility reserves in all EIM balancing authority areas, also referred to as diversity benefits, which reduces cost by aggregating load, wind, and solar variability and forecast errors of the EIM footprint.

A significant contributor to EIM benefits is transfers across balancing authority areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations when energy is transferred into the CAISO balancing authority area to serve California load. The transfer volumes are therefore a good indicator of a portion of the benefits attributed to the EIM. Transfers can take place in both the five and 15-minute market dispatch intervals.

After development and expansion of the EIM in the west, a natural next question is – are there continued opportunities to increase economic efficiency and renewable integration beyond the scope of EIM but short of a fully regional independent system operator? PacifiCorp believes the answer may be yes, but several items that are critical to its success will need creative solutions; resource sufficiency, transmission utilization, voluntary nature and governance. The concept of extending day-ahead market services is a current CAISO stakeholder initiative, which also aligns with the CAISO's day-ahead market enhancement stakeholder initiative. The Extended Day-Ahead Market (EDAM) stakeholder initiative is expected to continue working through transmission utilization, resource sufficiency, governance and congestion management in 2021.

Recent Resource Procurement Activities

PacifiCorp issued and will issue multiple requests for proposals (RFP) to secure resources or transact on various energy and environmental attribute products. Table 3.5 summarizes recent RFP activities.

Table 3.5 – PacifiCorp's Requests for Proposal Activity

RFP	RFP Objective	Status	Issued	Completed
2017 Renewable Energy Credits RFP	Purchase renewable energy credits for Oregon Schedule 272 participation	Closed	August 2017	September 2017
2017 Renewable RFP	Purchase new or repowered wind renewable energy	Closed	September 2017	November 2018
2017 Solar RFP	Purchase solar renewable energy	Closed	November 2017	March 2018
2017 Market Resource RFP	Purchase firm power for PacifiCorp's western balancing authority	Closed	November 2017	November 2017
2018 Oregon Community Solar RFP	Purchase solar energy or Oregon Community Solar	Ongoing	July 2018	On hold pending final program rules
2018 Renewable Energy Credits RFP	Purchase renewable energy credits for Oregon Schedule 272 participation	Closed	August 2018	September 2018
2019R Utah RFP	Purchase new renewable energy for specific customers under Utah Schedule 32 or 34	Ongoing	March 2019	Fall 2019
Renewable energy credits (Sale)	Excess system RECs	Ongoing	Based on specific need	Ongoing
2019 Capacity and Energy Supply RFP	Purchase capacity and energy supply	Ongoing	June 4, 2019	Ongoing
Renewable energy credits (Purchase)	Oregon compliance needs	Ongoing	Based on specific need	Ongoing
Renewable energy credits (Purchase)	Washington compliance needs	Ongoing	Based on specific need	Ongoing
Renewable energy credits (Purchase)	California compliance needs	Ongoing	Based on specific need	Ongoing
Short-term Market (Sales)	System balancing	Ongoing	Based on specific need	Ongoing
2020 All-Source RFP	Seeking resources consistent with the 2019 IRP's least cost resource portfolio	Ongoing	July 2020	Ongoing
2021 DR RFP	Oregon compliance and purchase of cost-effective flexible capacity	On-going	January 2021	Ongoing

2020 All-Source RFP

PacifiCorp's 2020 All Source RFP ("2020AS RFP") was filed for approval with the Utah PSC and the Oregon PUC in April 2020. In July 2020, the Utah PSC and the Oregon PUC approved the 2020AS RFP, and PacifiCorp issued the 2020AS RFP to market. The 2020AS RFP sought bids for resources capable of coming online by the end of 2024 up to the level of resources identified in PacifiCorp's 2019 IRP. Bids were submitted in August 2020. An initial shortlist was identified in October 2020. The initial shortlist includes a total of 6,982 MWs of new generation and storage capacity. Of the total, 5,652 MWs are new generation resources (represented by 3,173 MWs of solar generation and 2,479 MWs of wind generation) and an additional 1,330 MWs of new battery storage assets, which includes 1,130 MWs of solar collocated battery storage and 200 MWs of stand-alone battery storage.

The final shortlist of winning bids was identified by June 2021 and is comprised of 1,792 MW of wind generation, 95 MW of solar generation, 1,211 MW of solar generation collocated storage and 200 MW of stand-alone battery storage; 590 MW of wind generation is being contracted as a build and transfer to PacifiCorp with the balance of the generation contracted through long-term power purchase agreements.

PacifiCorp is finalizing both build and transfer and power purchase agreement updated drafts that will be forwarded to all final shortlisted participants prior to September 1, 2021. Contract negotiations are expected to proceed into early Q1 2022. All necessary final state regulatory approvals and proceedings are expected to be complete by Q2 2022.

2021 DR RFP

PacifiCorp’s 2019 IRP identified the addition of 178 MW of DR system wide by 2029 as resource additions of a least cost least risk long term resource plan. To acquire the DR resource needs identified in the 2019 IRP, the company issued a DR RFP for cost effective DR resources. Successful initial short list bids from this DR RFP joined final bids from the AS 2020 RFP for a combined analysis in the 2021 IRP to determine the optimal acquisition of resources to meet system needs. On February 8, 2021, PacifiCorp issued an RFP soliciting proposals from implementation contractors for Demand Response (DR) resources. Although a variety of programs were eligible for consideration, of most interest to PacifiCorp were programs located in Oregon and/or Washington with the following focus:

1) Non-Residential Curtailment
2) Residential and/or Small Commercial Smart Thermostat or Water Heaters
3) Irrigation load control

The final shortlist of bids was identified in June 2021 and includes over 600 MW of capacity during the planning horizon. PacifiCorp is finalizing the procurement and negotiation of demand response resources following the completion of 2021 IRP. Contract negotiations and program filings are expected to conclude in Q4 of 2021. All necessary state regulatory approvals and proceedings are expected to be complete in the winter and spring of 2022.

CHAPTER 4 – TRANSMISSION

CHAPTER HIGHLIGHTS

- PacifiCorp's planned transmission projects help facilitate a transitioning resource portfolio and comply with reliability requirements, while providing sufficient flexibility necessary to ensure existing and future resources can meet customer demand cost effectively and reliably.
- Given the long lead time needed to site, permit, and construct new transmission lines, these projects need to be planned well in advance of resource additions.
- PacifiCorp's transmission planning and benefits evaluation efforts adhere to regulatory and compliance requirements and respond to commission and stakeholder requests for a robust evaluation process and clear criteria for evaluating transmission additions.
- The 2021 IRP preferred portfolio includes the Energy Gateway South transmission line - a new 416-mile high-voltage 500-kilovolt transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The 2021 preferred portfolio also includes the Energy Gateway West Subsegment D.1 project - a new 59-mile high-voltage 230-kilovolt transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. Both transmission lines will come online by the end of 2024.
- The 2021 IRP preferred portfolio also includes the Boardman to Hemingway line - an approximately 290-mile high-voltage 500-kilovolt transmission line and associated infrastructure running from the proposed Longhorn substation near Boardman, Oregon and the Hemingway substation near Melba, Idaho, which will come online in 2026.
- Further, the 2021 IRP preferred portfolio 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 resources needed to serve our customers. While construction of the balance of future Energy Gateway segments (i.e., Gateway West segments D.3, and E is beyond the scope of acknowledgement for this IRP, these segments are expected to deliver future benefits for our customers and for the region. Thus, continued permitting of these segments is warranted to ensure that PacifiCorp is well positioned to advance these projects at the appropriate time.

Introduction

PacifiCorp's bulk transmission network is a high-value asset that is designed to reliably transport electric energy from a broad array of generation resources (owned or contracted generation including market purchases) to load centers. There are many benefits associated with a robust transmission network, some of which are set forth below:

1. Reliable delivery of diverse energy supply to continuously changing customer demands under a wide variety of system operating conditions.
2. Ability to always meet aggregate electrical demand and customers' energy requirements, taking into account scheduled outages and the ability to maintain reliability during unscheduled outages.
3. Ability to meet changing regulatory requirements as states move towards a renewable energy future.

4. Economic dispatch of resources within PacifiCorp's diverse system.
5. Economic transfer of electric power to and from other systems as facilitated by the company's participation in the market, which reduces net power costs and provides opportunities to maintain resource adequacy at a reasonable cost.
6. Access to some of the nation's best wind and solar resources, which provides opportunities to develop geographically diverse low-cost renewable assets.
7. Protection against market disruptions where limited transmission can otherwise constrain energy supply.
8. Ability to meet obligations and requirements of PacifiCorp's Open Access Transmission Tariff (OATT).

PacifiCorp's transmission network is highly integrated with other transmission systems in the west and provides the critical infrastructure needed to serve our customers cost effectively and reliably. Consequently, PacifiCorp's transmission network is a critical component of the IRP process. PacifiCorp has a long history of providing reliable service in meeting the bulk transmission needs of the region. This valued asset will become even more critical as the regional resource mix transitions to accommodate increasing levels of variable generation from renewable resources that will be used to serve the growing energy needs of our customers.

Regulatory Requirements

Open Access Transmission Tariff

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

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

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

Reliability Standards

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

This chapter provides:

- Justification supporting acknowledgement of PacifiCorp's plan to construct the Gateway South, Gateway West segment D.1 and Boardman-to-Hemingway transmission lines. Support for PacifiCorp's plan to continue permitting the balance of Gateway West;
- Key background information on the evolution of the Energy Gateway Transmission Expansion Plan; and
- An overview of PacifiCorp's investments in recent short-term system improvements that have improved reliability, helped to maximize efficient use of the existing system, and enabled the company to defer the need to invest in larger-scale transmission infrastructure.

Generation Interconnection Queue Reform

In 2019, PacifiCorp initiated a public stakeholder process to review possible generation interconnection tariff reform transitioning from a serial queue process to a cluster study process.

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

In May of 2020 the Federal Energy Regulatory Commission (FERC) issued an order approving the transition and in the same year PacifiCorp initiated the first cluster study process, the "transitional cluster study". The transitional study was initiated in October of 2020 and completed in March of 2021, the first annual cluster study process was initiated in April of 2021 and is planned to complete in November of 2021. Subsequent study processes will be initiated annually beginning in April.

PacifiCorp's serial queue interconnection process, based on the *pro forma* tariff generation interconnection procedures, presented significant challenges in meeting the goals of FERC Order No. 2003 due to a large number of Interconnection Requests in the company's queue competing to serve PacifiCorp load. There was additional concern at the state commission level that the serial process inhibited wholesale competition. The main feature the interconnection cluster approach is its prioritization of commercial readiness over queue position in the interconnection process—i.e., a change from a "first-come, first-served" to a "first-ready, first-served" approach. To do this, generator developers are required to demonstrate sufficient progress toward commercial operation before submitting a formal Interconnection Request and entering a Cluster. This process of increasing the requirements for obtaining a queue position in this way increases the likelihood that only projects that are likely to be commercially viable enter the interconnection process.

In the transition cluster study 56 requests totaling approximately 4260 megawatts were entered into the process and evaluated, of those 24 projects moved beyond the initial cluster study phase. These requests represented a mix of solar, hydro, solar and storage, battery storage, wind, geothermal and nuclear resources. In the first annual cluster study, under process now, 59 requests were received totaling approximately 12,037 megawatts with 52 currently remaining in the process. These requests represent a mix of solar, solar and storage, battery storage, pumped storage, wind, wind and storage and geothermal resources.

Aeolus to Bridger/Anticline

In 2018, PacifiCorp received the necessary state regulatory approvals, state and local permits, and private rights-of-way to construct the Aeolus-to-Bridger/Anticline sub-segment D.2 of Gateway West. Construction began in April 2019 and was completed in October 2020 and energized in November 2020.

Aeolus-to-Mona (Gateway South)

The 2021 PacifiCorp IRP preferred portfolio includes the Aeolus-to-Mona (Clover substation) transmission segment (Energy Gateway South or Segment F).

To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes significant transmission investment. Specifically, the 2021 IRP preferred portfolio includes the Energy Gateway South transmission line - a new 416-mile, high-voltage 500-kilovolt transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The 2021 preferred portfolio also includes the Energy Gateway West Subsegment D.1 project - a new 59 mile high-voltage 230-kilovolt transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. Both transmission lines come online by the end of 2024.

Timing of construction is driven by the phase-out schedule of federal production tax credits (PTCs), particularly the 2024 in-service requirements for 60 percent PTC eligibility, and potential risk associated with the termination of the BLM permit for non-use. In addition to supporting renewable resource additions in PacifiCorp's generation portfolio, qualifying them for PTCs, the new transmission segment will increase transfer capability out of eastern Wyoming.

Gateway West – Continued Permitting

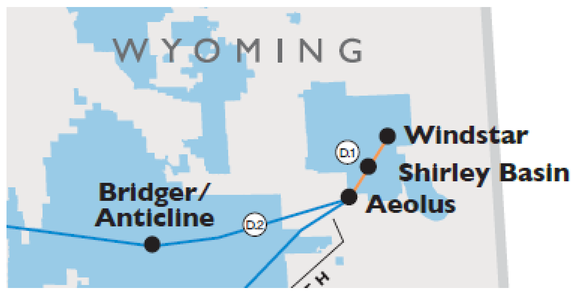
In addition to the Windstar-to-Populus line (Energy Gateway Segment D), the Gateway West transmission project also includes the Populus-to-Hemingway transmission segment (Energy Gateway Segment E). While PacifiCorp is not requesting acknowledgement of a plan to construct these segments in this IRP, the company will continue to permit the projects.

Windstar to Populus (Segment D)

The Windstar-to-Populus transmission project consists of three key sub-segments:

- D1—A single-circuit 230-kV line that will run approximately 59 miles between the existing Windstar substation in eastern Wyoming and the Aeolus substation near Medicine Bow, Wyoming, which includes a loop-in to the existing Shirley Basin 230-kV substation;

Figure 4.1 - Segment D

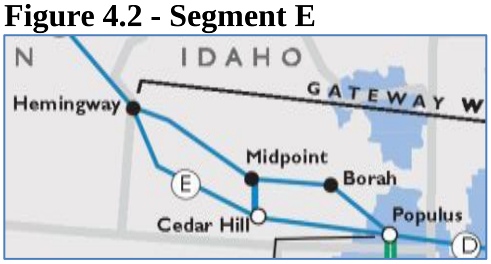


- D2—A single-circuit 500-kV line completed October 2020 and energized November 2020 and

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

Populus to Hemingway (Segment E)

Figure 4.2 - Segment E



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

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

Under the National Environmental Policy Act, the BLM has completed the EIS for the Gateway West project. The BLM released its final EIS on April 26, 2013, followed by the ROD on November 14, 2013, providing a right-of-way grant for all of Segment D and most of Segment E of the project. The BLM chose to defer its decision on the western-most portion of Segment E of the project located in Idaho in order to perform additional review of the Morley Nelson Snake

River Birds of Prey Conservation Area. Specifically, the sections of Gateway West that were deferred for a later ROD include the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway. A ROD for these final sections of Segment E was issued on January 19, 2017 and a right-of-way grant was issued on August 8, 2018.

Plan to Continue Permitting – Gateway West

The Gateway West transmission projects continue to offer benefits under multiple, future resource scenarios. To ensure the Company is well positioned to advance the projects, it is prudent for PacifiCorp to continue to permit the balance of Gateway West transmission projects. The Records of Decision and rights-of-way grants contain many conditions and stipulations that must be met and accepted before a project can move to construction. PacifiCorp will continue the work necessary to meet these requirements and will continue to meet regularly with the Bureau of Land Management to review progress.

Request for Acknowledgement for Boardman-to-Hemingway

The 2021 IRP preferred portfolio also includes an approximately 290-mile high-voltage 500-kilovolt transmission line known as Boardman-to-Hemingway to come online by 2026. Further, the 2021 IRP 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.

PacifiCorp continues to participate in the project under the Joint Funding Permitting Agreement with Idaho Power and BPA. In accordance with this agreement, PacifiCorp is responsible for its share of the costs associated with federal and state permitting activities and other pre-construction activities agreed to in the updated agreement.

Idaho Power’s 2019 IRP identifies the Boardman-to-Hemingway transmission line (B2H) as a preferred resource to meet its capacity needs, reflecting a need for the project in 2026 to avoid a deficit in load-serving capability in peak-load periods. Given the status of ongoing permitting activities and the construction period, Idaho Power expects the in-service date for the transmission line to be in 2026 or beyond.

The BLM released its ROD for B2H on November 17, 2017. The ROD allows BLM to grant right-of-way to Idaho Power for the construction, operation, and maintenance of the B2H Project on BLM-administered land. The BLM right-of-way grant was executed on January 9, 2018.

For all lands crossed in Oregon, Idaho Power must receive a site certificate from the Energy Facility Siting Council (EFSC) prior to constructing and operating the proposed transmission line. The Oregon Department of Energy (ODOE) serve as staff members to EFSC facilitating the review of the site certificate application process. ODOE and EFSC both review Idaho Power’s application to ensure compliance with state energy facility siting standards. The project has been issued a Proposed Order approving the project, with the next step the completion of the Contested Case proceeding, which is expected to conclude in 2022.

The U.S. Forest Service (USFS) issued a separate ROD on November 9, 2018 for lands administered by the USFS based on the analysis in the final EIS. The USFS ROD approves the issuance of a special-use authorization for a portion of the project that crosses the Wallowa-

Whitman National Forest. The U.S. Department of the Navy issued a ROD on September 25, 2019 in support of construction of a portion of the B2H project on 7.1 miles of the Naval Weapons Systems Training Facility in Boardman, Oregon.

Factors Supporting Acknowledgement

PacifiCorp's existing transmission path between the two balancing areas (PACW and PACE) consists of a single line (Midpoint Idaho to Summer Lake Oregon) fully used during key operating periods, including winter peak periods in the Pacific Northwest and summer peak in the Intermountain West. PacifiCorp has invested in the permitting of the B2H project because of the strategic value of connecting the two regions. As a potential owner in the project, PacifiCorp would be able to use its bidirectional capacity to increase reliability and to enable more efficient use of existing and future resources for its customers. The following lists additional B2H benefits:

- **Customers**: PacifiCorp continues to invest to meet customers' needs, making only critical investments now to ensure future reliability, security, and safety. The B2H project will bolster reliability, security, and safety for PacifiCorp customers as the regional supply mix transitions.
- **Renewables**: The B2H project has been identified as a strategic project that can facilitate the transfer of geographically diverse renewable resources, in addition to other resources, across PacifiCorp's two balancing authority areas. Transmission line infrastructure, like B2H, is needed to maintain a robust electrical grid while integrating clean, renewable energy resources across the Pacific Northwest and Mountain West states. The 2019 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 2030. Coupled with renewable additions 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. To support the addition of the new renewable resources typically located remotely from load centers and retirement of coal resources requires continued investment in a robust transmission system required to move resources across and between both PacifiCorp balancing areas.
- **Regional Benefit**: PacifiCorp, as a past member of the regional planning entity Northern Tier Transmission Group (NTTG), supported the inclusion of B2H in the NTTG 2018-2019 regional plan. PacifiCorp as a current member of the regional planning organization NorthernGrid has supported the inclusion of B2H into the 2020-2021 regional plan. From a regional perspective, the B2H project is a cost-effective investment that will provide regional solutions to identified regional needs. The project resolves possible system issues as identified in the NTTG 2018-2019 draft regional plan. This plan shows system issues depicted by heat maps, refer to figure 33, for the regional transmission line without B2H and with B2H, refer to figure 34 in the NTTG report. Figure 34 in the NTTG report shows the removal of system issues graphically.
- **Balancing Area Operating Efficiencies**: PacifiCorp operates and controls two balancing areas. After the addition of B2H and portions of Gateway West, more transmission capacity will exist between PacifiCorp's two balancing areas, providing the ability to increase operating efficiencies. B2H will provide PacifiCorp 300 MW of additional west-to-east capability and 600 MW of east-to-west capability to move resources between PacifiCorp's two balancing authority areas.

- **Regional Resource Adequacy**: PacifiCorp is participating in the ongoing effort to evaluate and develop a regional resource adequacy program with other utilities that are members of the Northwest Power Pool. The B2H project is anticipated to provide incremental transmission infrastructure that will broaden access to a more diverse resource base, which will provide opportunities to reduce the cost of maintaining adequate resource supplies in the region.
- **Grid Reliability and Resiliency**: The Midpoint-to-Summer Lake 500-kV transmission line is the only line connecting PacifiCorp's east and west control areas. The loss of this line has the potential to reduce transfers by 1,090 MW. When B2H is built, the new transmission line will provide redundancy by adding an additional 1,000 MW of capacity between the Hemingway substation and the Pacific Northwest. This additional asset would mitigate the impact when the existing line is lost.
- **Oregon and Washington Renewable Portfolio Standards and Other State Legislation**: New legislation and rules for recently passed legislation are being developed to meet state-specific policy objectives that are expected to drive the need for additional renewable resources. As these laws are enacted and rules are developed, PacifiCorp will evaluate how the B2H transmission line can help facilitate meeting state policy objectives by providing incremental access to geographically diverse renewable resources and other flexible capacity resources that will be needed to maintain reliability. PacifiCorp believes that investment in transmission infrastructure projects, like B2H and other Energy Gateway segments, are necessary to integrate and balance intermittent renewable resources cost effectively and reliably.
- **Energy Imbalance Market (EIM)**: PacifiCorp was a leader in implementing the western EIM. The real-time market helps optimize the electric grid, which lowers costs, enhances reliability, and more effectively integrates resources. PacifiCorp believes the B2H project could help advance the objectives of the EIM and has the potential of benefitting PacifiCorp customers and the broader region.
- **Grid Reliability**: The loss of the Hemingway–Summer Lake 500-kV transmission line, the only 500-kV connection between the Pacific Northwest and Idaho Power, during peak summer load is one of the most severe possible contingencies the Idaho Power transmission system can experience. Once Hemingway–Summer Lake 500-kV disconnects, the transfer capability of the Idaho to Northwest path is reduced by over 700 MW in the west-to-east direction. After the addition of B2H, there will be two major 500-kV connections between the Pacific Northwest and Idaho Power. The Hemingway–Summer Lake 500-kV outage would become much less severe to Idaho Power's transmission system. Additionally, loss of the Hemingway–Summer Lake 500-kV line with heavy east-to-west power transfer out of Idaho to the Pacific Northwest results in significant system impacts. In this disturbance, an existing remedial action scheme (power system logic used to protect power system equipment) will disconnect over 1,000 MW of generation at the Jim Bridger Power Plant to reduce path transfers and protect bulk transmission lines and apparatus. Due to the magnitude of the generation loss, recovery from this disturbance can be extremely difficult. After the addition of B2H, this enormous amount of generation shedding will no longer be required. With two 500-kV lines between Idaho and the Pacific Northwest, the loss of one can be absorbed by the other. Keeping 1,000 MW of generation on the system for major system outages is important for grid stability.

Next Steps

Given the extensive list of benefits noted above, PacifiCorp is committed to participating in the Boardman-to-Hemingway project in accordance with the terms of the Joint Funding Permitting Agreement through Oregon's permitting process and will continue to work with Idaho Power in the development and negotiations of the definitive agreement for the construction and ownership of the new line. PacifiCorp continues to evaluate the benefits to PacifiCorp's customers prior to commitment of entering into a project construction agreement. Additionally, PacifiCorp will continue to review possible benefits of the project as it continues to participate in project development activities, including moving forward with preliminary construction and construction agreement negotiations.

Energy Gateway Transmission Expansion Plan

Introduction

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

Background

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

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

Planning Initiatives

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

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

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

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

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

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

- ***Northern Tier Transmission Group Transmission Planning Reports***

In the 2018-2019 NTTG Draft Regional Transmission Plan, sub segments of Energy Gateway (both Gateway West and Gateway South) were listed as necessary to provide acceptable system performance. The study also established that the amount of new Wyoming wind generation that is added over time can impact the transmission system reliability west of Wyoming. Additionally, three interregional projects were included in the study the Southwest Inter-tie Project (SWIP North), Cross Tie and TransWest Express, which showed that all three projects relied on Energy Gateway to attain their full transfer capability rating.

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

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

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

Energy Gateway Configuration

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

Since Energy Gateway's initial announcement in 2007, this series of projects has continued to be vetted through multiple public transmission planning forums at the local, regional and Western Interconnection level. In accordance with the local planning requirements in PacifiCorp's OATT, Attachment K, PacifiCorp has conducted numerous public meetings on Energy Gateway and transmission planning in general. Meeting notices and materials are posted publicly on PacifiCorp's Attachment K Open Access Same-time Information System (OASIS) site. PacifiCorp is also a member of NorthernGrid regional planning organization and WECC's Reliability Assessment Committee and was a member of Northern Tier Transmission Group (NTTG) regional planning organization.

These groups continually evaluate PacifiCorp's transmission plan in their efforts to develop and refine the optimal regional and interconnection-wide plans. Please refer to PacifiCorp's OASIS site for information and materials related to these public processes.[2]

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

Energy Gateway's Continued Evolution

The Energy Gateway Transmission Expansion Plan is the product of years of ongoing local and regional transmission planning efforts with significant customer and stakeholder involvement. Since its announcement in May 2007, Energy Gateway's scope and scale have continued to evolve to meet the future needs of PacifiCorp customers and the requirements of mandatory transmission planning standards and criteria. Additionally, PacifiCorp has improved its ability to meet near-term customer needs through a limited number of smaller-scale investments that maximize efficient use of the current system and help defer, to some degree, the need for larger capital investments like Energy Gateway (see the following section titled "Efforts to Maximize Existing System Capability"). The IRP process, as compared to transmission planning, can result in frequent changes in the least-cost, least-risk resource plan driven by changes in the planning environment (i.e., market conditions, cost and performance of new resource technologies, etc.). Near-term fluctuations in the resource plan do not always support the longer-term development needs of transmission infrastructure, or the ability to invest in transmission assets in time to meet customer needs. Together, however, the IRP and transmission planning processes complement each other by helping PacifiCorp optimize the timing of its transmission and resource investments to deliver cost-effective and reliable energy to our customers.

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

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

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

in the Intermountain Region. Due to the significant upfront costs inherent in transmission investments, firm partnership commitments also failed to materialize, leading PacifiCorp to pursue the current configuration with the intent of only developing system capacity sufficient to meet the long-term needs of its customers.

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

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

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

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

In May 2013, PacifiCorp completed the Mona-to-Oquirrh project. In November 2013, the BLM issued a partial ROD providing a right-of-way grant for all of Segment D and most of Segment E of Energy Gateway. The agency chose to defer its decision on the western-most portion of Segment E of the project located in Idaho in order to perform additional review of the Morley Nelson Snake River Birds of Prey Conservation Area. Specifically, the sections of Gateway West that were deferred for a later ROD include the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway.

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

In December 2016, the BLM issued its ROD and right-of-way grant for the Gateway South project.

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

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

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

Figure 4.3 – Energy Gateway Transmission Expansion Plan

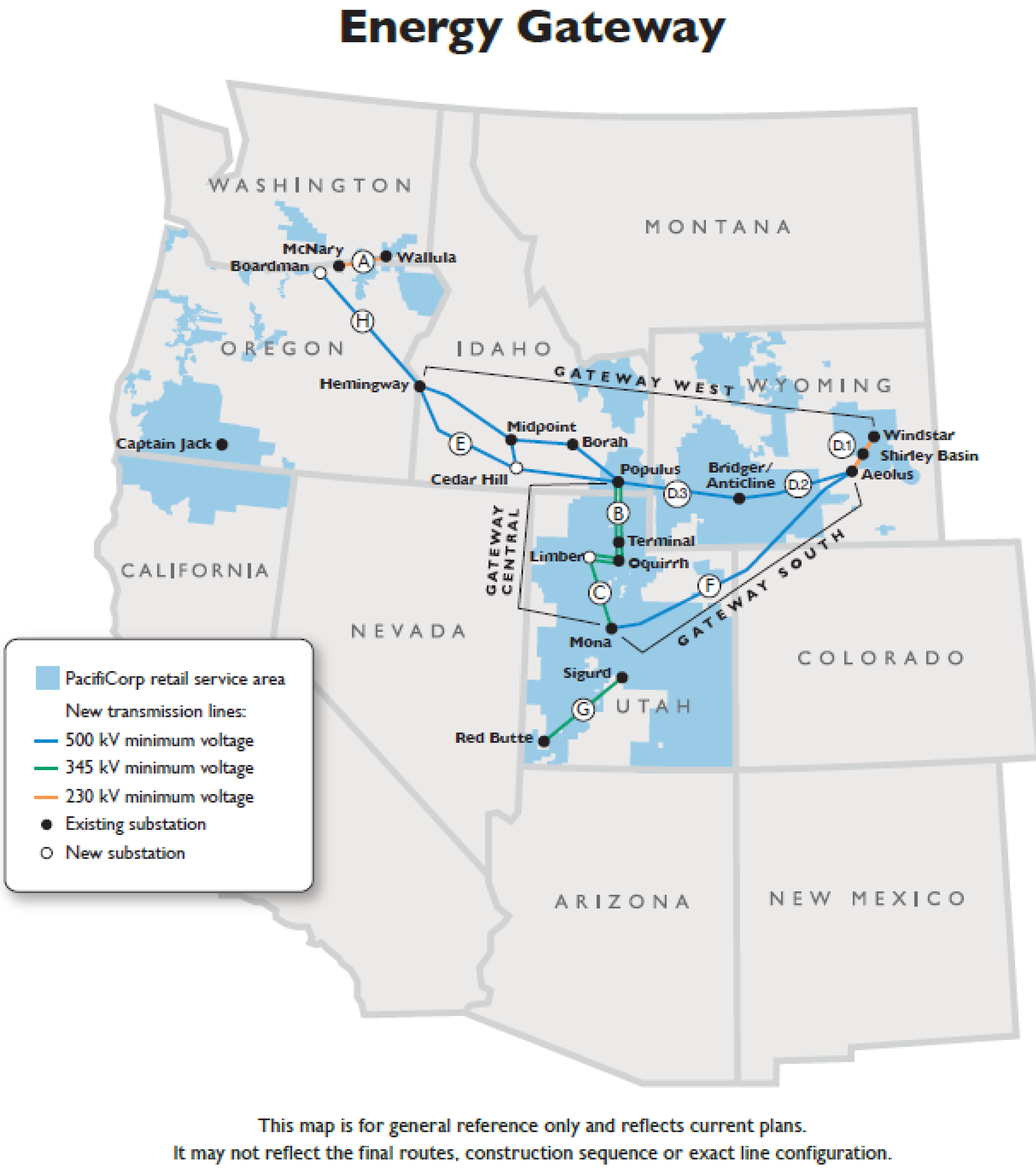


Table 4.1 – Energy Gateway Transmission Expansion Plan

Segment & Name	Description	Approximate Mileage	Status and Scheduled In-Service
(A) Wallula-McNary	230 kV, single circuit	30 mi	• Status: completed • Placed in-service: January 2019
(B) Populus-Terminal	345 kV, double circuit	135 mi	• Status: completed • Placed in-service: November 2010
(C) Mona-Oquirrh	500 kV single circuit 345 kV double circuit	100 mi	• Status: completed • Placed in-service: May 2013
Oquirrh-Terminal	345 kV double circuit	14 mi	• Status: rights-of-way acquisition underway • Scheduled in-service: 2026
(D1) Windstar-Aeolus	New 230 kV single circuit Re-built 230 kV single circuit	59 mi	• Status: permitting underway • Scheduled in-service: 2024
(D2) Aeolus-Bridger/Anticline	500 kV single circuit	140 mi	• Status: completed • Placed in-service: November 2020
(D3) Bridger/Anticline-Populus	500 kV single circuit	200 mi	• Status: permitting underway • Scheduled in-service: 2027 earliest
(E) Populus-Hemingway	500 kV single circuit	500 mi	• Status: permitting underway • Scheduled in service: 2030 earliest
(F) Aeolus-Mona	500 kV single circuit	416 mi	• Status: permitting underway • Scheduled in-service: 2024
(G) Sigurd-Red Butte	345 kV single circuit	170 mi	• Status: completed • Placed in-service: May 2015
(H) Boardman-Hemingway	500 kV single circuit	290 mi	• Status: pursuing joint-development and/or firm capacity opportunities with project sponsors • Scheduled in-service: 2026

Efforts to Maximize Existing System Capability

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

System-wide, PacifiCorp has instituted more than 155 grid operating procedures and 17 remedial action schemes to maximize the existing system capability while managing system risk. In addition, PacifiCorp has been an active participant in the Energy Imbalance Market since November 2014. By August 2021, 15 participants have joined the EIM. By broadening the pool of lower-cost resources that can be accessed to balance load system requirements, enhances reliability and reduces costs across the entire EIM Area. In addition, the automated system is able to identify and use available transmission capacity to transfer the dispatched resources, enabling more efficient use of the available transmission system.

Transmission System Improvements Placed In-Service Since the 2019 IRP

PacifiCorp East (PACE) Control Area

1. Salt Lake Valley Area
    - Install a new circuit switcher in series with the bus-tie circuit breaker at 90th South substation
        - Project driver is to correct NERC Standard TPL-001-4 Category P2-4 deficiency identified in PacifiCorp's 2017 NERC TPL Assessment for a bus tie breaker internal fault event that results in the loss of the entire 90th South 138-kV substation.
        - Benefits include mitigating the risk of thermal overloads and voltage issues and eliminating the potential loss of load at the entire 90th South 138-kV South substation for a bus tie failure event, and resolution of the NERC TPL-001-4 Category P2-4 deficiency.
2. Utah Valley Area
    - Upgrade the 345-138 kV transformer at Spanish Fork substation
        - Project driver is to correct NERC Standard TPL-001-4 Category P1 and P3 deficiencies identified in PacifiCorp's 2017 NERC TPL Assessment resulting from an outage of Spanish Fork 345-138 kV transformer #4 (N-1) and multiple double contingency outages (N-1-1) that result in thermal overloads on numerous substation transformers and transmission lines.
        - Benefits include mitigating the risk of thermal overloads and low voltage issues, additional capacity to address projected load growth, improved transmission reliability and resolution of the NERC TPL-001-4 Category P1 and P3 deficiencies.
3. Goshen Idaho Area
    - Install a new 161-kV line from Goshen to Sugarmill substations
        - Project driver is to address the single contingency (N-1) and multiple contingency (N-1-1) issues present in the Sugarmill-Rigby area and the large amount of load shedding risk identified in the 2016 Goshen Area Planning Study that proposed adding a new 161-kV line from Goshen to Sugarmill and then from Sugarmill to Rigby substation to allow a looped configuration during heavy summer load conditions.
        - Benefits include mitigating the risk of thermal overloads and voltage issues and eliminating the loss of up to 150 MW of load for N-1 outages and up to 300 MW for N-1-1 outages.
4. East Utah Area
    - Construct the new Naples 138-12.5 kV substation
        - Project driver is to correct NERC Standard TPL-001-4 Category P6 deficiencies identified in PacifiCorp's 2016 NERC TPL Assessment resulting in multiple double contingencies causing low 138-kV system voltages in the Vernal area.
        - Benefits include mitigating the risk of low voltage issues and resolution of the NERC Standard TPL-001-4 Category P6 deficiencies.

PacifiCorp West (PACW) Control Area

1. Yakima Washington Area

   - Construct a new 230-kV transmission line from BPA's Vantage substation to PacifiCorp's Pomona Heights substation
     - Project driver is to correct the NERC Standard TPL-002 deficiency identified in PacifiCorp's 2011 TPL Assessment for the loss of a single 230-kV line.
     - Benefits include mitigating the risk of thermal overloads and low voltage issues, adding additional capacity to address projected load growth, improving transmission reliability and resolution of the NERC TPL-002 deficiencies.

2. Yreka California Area

   - Install an additional 115-69 kV transformer at Yreka substation located
     - Project driver is to correct low voltage conditions under normal operating conditions during heavy summer loading periods due to inadequate voltage regulation on the 69-kV system served from Yreka substation, as identified in the 2013 Yreka-Mt Shasta Area Study.
     - Benefits include the ability to provide 69-kV voltage regulation by the new 115-69 kV transformers load tap changer, allows the use of load drop compensation feature to further improve the transmission voltage profile over the long term, and making the exiting non-LTC transformer available as an installed spare for immediate service restoration when needed.

3. Walla Walla Washington Area

   - Replace the existing 115-69 kV, 20 MVA transformer with a 115-69 kV, 50 MVA transformer at Dry Gulch substation
     - Project driver is to correct NERC Standard TPL-001-4 Category P2 deficiency identified in PacifiCorp's 2015 NERC TPL Assessment for a 115-kV bus fault at Dry Gulch substation.
     - Benefits include having 69-kV capacity and voltage regulation capability to operate in a normal open configuration to eliminate thermal overloads and low voltage conditions, eliminating the 69-kV loop in parallel with the 230-kV and 500-kV main grid system that impacted the 69-kV system for outages on the main grid system, removing the Tucannon 69-kV line from the WECC Path 6 definition, and resolving the NERC TPL-001-4 P2 deficiency.

Planned Transmission System Improvements

PacifiCorp East (PACE) Control Area

1. Central Wyoming Area

   - Upgrade the 345-230 #2 transformer at Jim Bridger substation
     - Project driver is to correct NERC Standard TPL-001-4 Category P1 and P3 deficiencies identified in PacifiCorp's 2017 NERC TPL Assessment resulting for a 345-kV or 230-kV bus fault (P1) and for the loss of a generator and both Jim Bridger 345-230 kV transformers #1 and #3 (P3) that will result in thermal overload of existing Jim Bridger 345-230 kV #2 transformer.

    - Benefits include mitigating the risk of thermal overloads and resolution of the NERC TPL-001-4 Category P1 and P3 deficiencies.

2. Goshen Idaho Area

   - Install a third 345-161 kV transformer at Goshen substation
     - Project driver is to correct NERC Standard TPL-001-4 Category P1 (N-1) deficiency identified in PacifiCorp's 2016 Goshen Area Study resulting in thermal overload of the remaining 345-161 kV transformer at Goshen substation.
     - Benefits include mitigating the risk of thermal overloads and resolution of the NERC Standard TPL-001-4 Category P1 deficiency.
   - Install a new 161-kV line from Sugarmill to Rigby substations located in Idaho
     - Project driver is to address the single contingency (N-1) and multiple contingency (N-1-1) issues present in the Sugarmill-Rigby area and the large amount of load shedding risk identified in the 2016 Goshen Area Planning Study that proposed adding a new 161-kV line from Goshen to Sugarmill (completed) and then from Sugarmill to Rigby substation (still to complete) to allow a looped configuration during heavy summer load conditions.
     - Benefits include mitigating the risk of thermal overloads and voltage issues and eliminating the loss of up to 150 MW of load for N-1 outages and up to 300 MW for N-1-1 outages.

3. Utah & Idaho – Upgrade Program – Backup Bus Differential Relays

   - Install backup bus differential relays at various substations located in Utah and Idaho
     - Project driver is to correct the NERC Standard TPL-001-4 Category P5-5 deficiencies identified in PacifiCorp's 2015 NERC TPL Assessments resulting in multiple contingencies for faults plus bus differential relays failure to operate that cause delayed fault clearing due to the failure of a non-redundant relay installation.
     - Benefits include mitigating the risk of delayed clearing of all transmission line connected to specific buses that would lead to thermal overloads and voltage issues, ensuring that critical differential bus protection has the required relay redundancy, improving reliability to the impacted substations and their connected transmission lines, and resolution of the NERC TPL-001-4 Category P5-5 deficiencies.

4. Utah, Idaho & Wyoming - Upgrade Program – Replace Over-dutied Circuit Breakers

   - Replace breakers identified as over-dutied with higher-capability breakers in various substations located in Idaho, Utah, and Wyoming
     - Project driver is to correct NERC Standard TPL-001-4 Requirement R2.3 deficiencies identified in PacifiCorp's 2015-2018 NERC TPL Assessment resulting in the identification of 13 over-dutied breakers.
     - Benefits include eliminating the risk of over-dutied breakers failing under fault interruption conditions that pose safety and reliability risks, and the resolution of the NERC TPL-001-4 Requirement R2.3 deficiencies.

5. Goshen Idaho Area

- Rebuild and convert an existing 69-kV line to 161-kV to establish a new 161-kV source at Rexburg substation in Idaho
    - Project driver is to improve 69-kV capacity and voltage regulation served from Rigby substation by converting an existing 69-kV line to 161 kV to create a 161-kV source at Rexburg substation through a new 161-69 kV transformer installation. The project also will include a new six breaker 69-kV ring bus at Rexburg substation that includes terminating two existing 69-kV lines and one new 69-kV line.
    - Benefits include establishing a new 161-kV source in the area, providing additional 69-kV capacity, improving 69-kV voltage regulation and reliability to customers served from the 69-kV system.

6. Park City Utah Area
    - Install a 9-mile, 138-kV transmission line between Midway and Jordanelle substations in Utah
        - Project drivers are projected load growth and reliability improvements which required of extension of the 138-kV line from Jordanelle-to-Midway substation.
        - Benefits are the established new 138-kV loop, additional capacity to address projected load growth and improved transmission reliability.

7. Salt Lake Valley Utah Area
    - Install two capacitor banks at Magna Substation and rebuild the Tooele – Pine Canyon 138 kV transmission line
        - Project driver is to correct N-1 contingency overload and low voltage issues at Magna substation and on the Tooele – Pine Canyon 138 kV line from consistent load growth and new block loads.
        - Benefits include mitigating the risk of thermal overloads and low voltage issues, adding additional capacity to address projected load growth and improve transmission reliability

PacifiCorp West (PACW) Control Area

1. Albany/Corvallis Oregon Area
    - Replace conductor on the 115-kV line between Hazelwood substation and BPA's Albany substation and construct a new 115-kV ring bus at Hazelwood substation.
        - Project driver is to correct NERC Standard TPL-001-4 Category P6 deficiencies for an outage on the transformers at Fry substation and reduce load loss exposure from various other N-1-1 contingencies.
        - Benefits include mitigating the risk of thermal overloads and voltage issues, improving transmission reliability, reducing the complexity of operating procedures for remaining N-1-1 contingencies and resolution of a number of NERC TPL-001-4 Category P6 deficiencies.
2. Medford Oregon Area
    - Construct one new 500-230 kV substation called Sams Valley
        - Project driver is to correct NERC Standard TPL-002-4 deficiencies for the loss of a single 230-kV line and for N-1-1 and N-2 outages to 230-kV lines that were initially identified in PacifiCorp's 2010 NERC TPL Assessment and supported

through subsequent NERC TPL Assessments, and to provide a second 500-kV source to address load growth in the Southern Oregon region.

  - Benefits include adding a second source of 500-kV capacity, adding a new 230-kV line, improving reliability of the 230-kV network, mitigates the risk of thermal overloads and low voltage, mitigates the risk of shedding load in preparation of the second contingency for N-1-1 outages, and resolves the NERC TPL-001-4 deficiencies.

- Expand the RAS at Meridian substation
  - Project driver is to expand the existing RAS to cover three additional N-1-1 contingencies on the southern Oregon 500-kV system and trip additional load as identified in the 2015 Meridian Area Load Tripping Assessment and the 2017 NERC TPL Assessment.
  - Benefit of expanding the RAS will be to avoid relying on the Southern Oregon Under-Voltage Load Shedding scheme as the primary mitigation for double contingencies on the 500-kV system.

3. Yakima Washington Area

- Construct a new 115-kV transmission line from Outlook substation to Punkin Center substation
  - Project driver is to correct NERC Standard TPL-001-4 Category P1 deficiencies identified in the 2016 NERC TPL Assessment for single contingency (N-1) outages on the 230-kV system serving the Yakima Upper Valley.
  - Benefits include mitigating the risk of thermal overloads, resolving an existing capacity limitation on the 115-kV line, improving transfer capability between the Upper Valley and the Lower Valley system, and resolution of the NERC TPL-001-4 Category P1 deficiency.

4. Oregon – Upgrade Program – Replace Over-dutied Circuit Breakers

- Replace breakers identified as over-dutied with higher-capability breakers at Lone Pine Substation
  - Project driver is to correct NERC Standard TPL-001-4 Requirement R2.3 deficiencies identified in PacifiCorp's 2015-2018 NERC TPL Assessment resulting in the identification of three over-dutied 115-kV breakers.
  - Benefits include eliminating the risk of over-dutied 115-kV breakers failing under fault interruption conditions that pose safety and reliability risks, and the resolution of the NERC TPL-001-4 Requirement R2.3 deficiencies.

These investments help maximize the existing system's capability, improve PacifiCorp's ability to serve growing customer loads, improve reliability, increase transfer capacity across WECC Paths, reduce the risk of voltage collapse and maintain compliance with North American Electric Reliability Corporation and Western Electricity Coordinating Council reliability standards.

CHAPTER 5 – RELIABILITY AND RESILIENCY

CHAPTER HIGHLIGHTS

- Regional resource adequacy assessments highlight that there are resource adequacy risks through the mid-2020s. The addition of variable energy resources replacing traditional "baseload" resources may act to tighten market supply.
- PacifiCorp's wildfire mitigation plans, which outline a risk-based, balanced and integrated approach, contain six critical focus areas of planning and execution for a reliable and resilient energy future: (1) Risk analysis and drivers, (2) Situational awareness, (3) Inspection and correction, (4) Vegetation management, (5) System hardening, and (6) Operational practices.
- The 2021 IRP preferred portfolio includes the Energy Gateway South (GWS), Energy Gateway West Subsegment D.1 (D.1), and Boardman-to-Hemingway (B2H) transmission lines. The preferred portfolio also includes other transmission upgrades that support the transition to renewable energy by providing access to low-cost, location-specific renewable resources, and additional transfer capability, which enables greater use of other low-cost resource options and relieves stress on current assets.

Introduction

Serving reliably (i.e., keeping the lights on for customers), as well as planning for a resilient system (i.e., operating through and recovering from a major disruption) is a primary focus for PacifiCorp. With the increasing retirement of thermal baseload resources, the incorporation of increasing numbers of intermittent renewable resources, and the impacts of climate change, planning for a reliable and resilient energy future is more crucial, and more complex, than ever. PacifiCorp continues to build on a strong track record of serving its customers safely, reliably, and affordably.

The focus on reliability and resiliency spans across several areas of the company: PacifiCorp's resource planning and energy supply teams work closely with regional peers and ensure that there is sufficient supply to serve customers, transmission and distribution teams work to mitigate the destructive impact of wildfire risk throughout the west and ensure that PacifiCorp is able to deliver power safely to customers now and in the future.

Supply-Based Reliability

Regional Resource Adequacy

As part of its 2021 IRP, PacifiCorp has conducted a review and evaluation of western resource adequacy studies and information, including evaluating the Western Electricity Coordinating Council (WECC) Power Supply Assessment (PSA) to glean trends and conclusions from the supporting analysis.

In 2020, WECC published and adopted the WECC Reliability Risk Priorities (WRRP), which outlined four priorities that were deemed to be the most significant to reliability in the western interconnection. Resource adequacy was identified as one of the four priorities, and in December 2020 WECC published the Western Assessment of Resource Adequacy (WARA), which will become an annual report in the future. PacifiCorp has reviewed the WARA, which serves as an interconnection-wide assessment of resource adequacy and uses that assessment as the basis of the following discussion. PacifiCorp also reviewed the 2020 North American Electric Reliability Council (NERC) Long-Term Reliability Assessment and the status of resource adequacy assessments prepared for the Pacific Northwest by the Pacific Northwest Resource Adequacy Forum.

WECC Western Assessment of Resource Adequacy Report

The WECC Western Assessment of Resource Adequacy was published on December 18, 2020 and was developed based on data collected from balancing authorities describing their own demand and supply projections over the next 10 years. The analysis is probabilistic and represents an hourly assessment of resource adequacy over the study period. The region-wide projections included in the study were categorized into two scenarios: one in which the region is required to meet its own demand without assumed reliance on imports, and a second scenario in which the region can assume that imports will help meet the demand needs of the future. Each scenario was further sub-divided into three variations:

- Variation 1: Existing Resources (EX) – Includes resources that are in-service and can be expected to run in future forecasts.
- Variation 2: Tier 1 Resources (T1) – Existing resources including those under construction and expected to be in-service in the forecasted year.
- Variation 3: Tier 1 and Tier 2 Resources (T12) – Existing and Tier 1 resources including those in licensing, siting, etc. but not yet in construction.

To inform the study, WECC has developed peaking assumptions and ramp need estimates on both an interconnection-wide basis, as well as for each planning subregion within the WECC. A summary of the planning regions and peak assumptions is shown in Table 5.1.

Table 5.1 – Planning Subregions and Peaking Assumptions underlying analysis

Designation	Subregion	Peaking Assumption	Ramp[1]	Peak Load
NWPP-NW[2]	Northwest Power Pool - Northwest	January	51%	39,300MW
NWPP-NE[3]	Northwest Power Pool – Northeast	February	30%	14,800MW
NWPP-C[4]	Northwest Power Pool – Central	July	104%	36,400MW
CAMX[5]	California and Mexico	August	81%	51,300MW
DSW[6]	Desert Southwest	July	100%	25,700MW

PacifiCorp serves load primarily in the NWPP-NW, NWPP-NE, and NWPP-C planning subregions.

[1] Represents needed resource ramp from lowest to highest demand hour of the peak demand day
[2] NWPP-NW covers Washington, Oregon, British Columbia, and portions of Montana and Idaho
[3] NWPP-NE covers portions of Idaho, Montana, Wyoming, South Dakota, Nebraska, and Alberta
[4] NWPP-C covers Nevada, Utah, Colorado, and portions of California, Idaho, and Wyoming
[5] CAMX covers the majority of California and Baja California
[6] DSW covers Arizona, New Mexico, and portions of Texas and California

NWPP-NW

- Expected availability of peak-hour resources in 2021: 44,000 MW to meet an expected peak of 39,300 MW. However, in low-availability scenarios (5% probability), the region could have only 29,200 MW of resources available to meet peak.

- One Day in Ten Years (ODITY) planning threshold: WECC determines that a planning reserve margin of 15%is likely sufficient to maintain the median ODITY resource adequacy threshold. However, as more variable resources continue to be added to the grid, a larger planning reserve margin may be needed to compensate. WECC estimates that in the spring, when variability in energy supply and demand is highest, a planning reserve margin of 40%+ may be appropriate.

- Scenario findings for NWPP-NW generally identify that the subregion may need imports to ensure system reliability as early as 2021, and the scenario outputs identify hours at risk of not being able to maintain ODITY threshold of resource adequacy:

  Stand-alone:
  - Existing Resources: 208 hours
  - T1: 195 hours
  - T2: 194 hours

  Imports:

  - Existing Resources: 0 hours
  - T1: 0 hours
  - T2: 0 hours

NWPP-NE

- Expected availability of peak-hour resources in 2021: 19,600 MW to meet an expected peak of 14,800 MW. However, in low-availability scenarios (5 percent probability), the region could have 16,700 MW available, which is still sufficient to meet peak demand.

- ODITY planning threshold: WECC determines that a planning reserve margin of 15% is likely sufficient to maintain the median ODITY resource adequacy threshold. WECC's highest reserve margin is estimated to be approximately 20% to account for potential limited availability in baseload resources.

- Scenario findings for NWPP-NE identifies that the subregion needs imports to maintain resource adequacy thresholds. From 2021-2024, WECC finds that in each stand-alone scenario there are over 4,000 hours per year in which 100+ MW of demand is at risk of being unserved. The number of hours increase as there is less baseload availability.

Stand-alone

- Existing Resources: 4,200 hours
- T1: 4,200 hours
- T2: 4,200 hours

Imports

- Existing Resources: 0 hours
- T1: 0 hours
- T2: 0 hours

NWPP-C

- Expected availability of peak-hour resources in 2021: 19,600 MW to meet an expected peak of 14,800 MW. However, in low-availability scenarios (5 percent probability), the region could have 16,700 MW available, which is still sufficient to meet peak demand.

- ODITY planning threshold: WECC determines that a planning reserve margin of 15% is likely sufficient to maintain the median ODITY resource adequacy threshold. WECC's highest reserve margin is estimated to be approximately 20% to account for potential limited availability in baseload resources.

- Scenario findings for NWPP-NE identifies that the subregion needs imports to maintain resource adequacy thresholds. From 2021-2024, WECC finds that in each stand-alone scenario there are over 4,000 hours per year in which 100+ MW of demand is at risk of being unserved. The number of hours increase as there is less baseload availability.

  Stand-alone

  - Existing Resources: 4,200 hours
  - T1: 4,200 hours
  - T2: 4,200 hours

  Imports

  - Existing Resources: 0 hours
  - T1: 0 hours
  - T2: 0 hours

Resource Assumptions

The WARA analysis includes all currently operating resource, with planned retirements included in the calculation.

The WECC Western Assessment of Resource Adequacy makes the following three recommendations. Details on how PacifiCorp has incorporated or is considering each recommendation are also provided.

Recommendation 1: *Planning entities and their regulatory authorities should consider moving away from a fixed planning reserve margin to a probabilistically determined margin. As variability grows, a dynamic planning reserve margin will better ensure resource adequacy for all hours.*

- PacifiCorp's 2019 IRP and its 2021 IRP both evaluate the performance of the selected portfolio of resources in all hours to ensure resource adequacy beyond the coincident peak.
- PacifiCorp's 2021 IRP calculates the planning reserve margin for every hour and identifies the lowest hourly margin by season and year, allowing for greater focus on the periods and types of conditions that lead to the greatest risk. As portfolios evolve over time, this automatically identifies the changing periods of risk.
- PacifiCorp's stochastic reliability modeling has identified that reliability risks exist in both the summer and the winter under a range of conditions.

Recommendation 2: *Planning entities should consider not only how much additional capacity is needed to mitigate variability, but also the expected availability of the resource. Understanding the differences in resource type availability is crucial to performing resource adequacy studies.*

- PacifiCorp recognizes that the conditions with the greatest risk can be addressed with targeted solutions, for instance solar combined with storage is very helpful for meeting summer requirements.
- PacifiCorp also recognizes that widespread adoption of a targeted solution will cause risks to evolve, and solutions will need evolve or change to target other conditions. To help retain flexibility for evolving needs, PacifiCorp increased the level of storage in its hybrid solar and storage resources to 100% of the solar nameplate with four-hour duration. But even this results in diminishing returns for winter needs.
- While four-hour storage provides significant flexibility, for instance to fill in gaps in typical renewable resource output, uncertainty remains about expected renewable resource availability under extreme conditions, which are relatively uncommon. To address this issue, additional analysis of renewable resource variability and correlation with load will be needed in future IRPs.

Recommendation 3: *Planning entities should coordinate their resource planning efforts on an interconnection-wide basis each year to help ensure they are not all relying on the* *same imports to maintain resource adequacy. This coordination will help subregions make assumptions about import availability in the context of the entire interconnection.*

- PacifiCorp evaluates its planning assumption around availability of markets and interconnection-wide imports, and has adjusted its forecasted maximum liquidity at the Mid-Columbia, California-Oregon Border, Nevada-Oregon Border, and Mona trading hubs as a result. Chapter 7 (Resource Options), as well as the section in this chapter addressing market availability, include a discussion of PacifiCorp's assumed maximum seasonal values for front-office transactions.

NERC Long-Term Resource Adequacy (LTRA)

Resources

As part of the regional reliability assessment to support the 2021 IRP, PacifiCorp reviewed and incorporated learnings from the NERC LTRA, published in December 2020. The NERC LTRA organizes resources into two broad categories in its 10-year WECC region reliability assessment:

<u>Anticipated Resources</u>

- Existing generating capacity able to serve peak hour load with firm transmission
- Capacity that is either under construction or has received approved planning requirements
- Firm net capacity transfers with firm contracts
- Less confirmed retirements

<u>Prospective Resources</u>

- Existing capacity that may be available to serve peak hour load, but lacks certainty associated with firm transmission, peak availability, etc.
- Capacity additions that have been requested but not received approval
- Non-firm net capacity transfers and transfers without firm contracts, but assessed to have a high probability of future implementation
- Less unconfirmed retirements

<u>Planning Reserve Margin</u>

The LTRA defines "planning reserve margin" as the difference between resources less demand, divided by demand, as a percentile.

Resources in this calculation are reduced by expected operating limits due to fuel availability, transmission and environmental limitations. Comparing the *anticipated* resource-based reserve margin to the reference planning margin yields one of three risk determinations:

- Adequate: Anticipated reserve margin exceeds the reference margin level
- Marginal: Anticipated reserve margin exceeds the reference margin level, but there are low expectations in meeting all forecast parameters; alternately, Anticipated reserve margin is below the reference margin level, but sufficient Tier 2 resources are projected to cover the shortfall

- Inadequate: Anticipated reserve margin is significantly less than reference margin level and load interruption is likely

WECC Subregions

Table 5.2 presents the WECC subregions used for the NERC LTRA. In the data that follows, the two subregions in Canada are not considered.

Table 5.2 – WECC Subregion Descriptions

Designation	Subregion	Country	Peaking Assumption
CAMX	California to Mexico	United States	Summer
NWPP	Northwest Power Pool	United States	Summer
RMRG	Rocky Mountain Reserve Group	United States	Summer
SRSG	Southwest Reserve Sharing Group	United States	Summer
AB	Alberta	Canada	Winter
BC	British Columbia	Canada	Winter

LTRA WECC Assessment

Table 5.3 through Table 5.5 represent the three types of reserve margins relevant to the WECC planning reserve margin calculation. In each table, the figures do not include WECC subregions outside of the United States.

Table 5.3 – NERC LTRA Anticipated Reserve Margin

Anticipated Reserve Margin											
U.S. WECC Subregion	Peaking Assumption	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NWPP/RMRG	Summer	25.9%	24.6%	23.4%	21.6%	20.8%	17.7%	16.5%	13.5%	11.7%	10.4%
SRSG	Summer	18.1%	17.3%	17.0%	14.7%	15.5%	16.8%	16.0%	15.4%	14.4%	13.6%
CAMX	Summer	21.4%	27.8%	27.3%	26.8%	22.5%	21.0%	20.6%	19.6%	19.2%	19.2%

Table 5.4 – NERC LTRA Prospective Reserve Margin

Prospective Reserve Margin											
U.S. WECC Subregion	Peaking Assumption	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NWPP/RMRG	Summer	25.9%	24.8%	24.0%	22.2%	21.5%	18.4%	17.2%	14.2%	12.3%	11.0%
SRSG	Summer	18.1%	18.1%	19.5%	17.2%	17.9%	19.2%	18.3%	17.6%	16.6%	15.7%
CAMX	Summer	21.4%	35.3%	40.8%	41.7%	37.3%	35.7%	35.2%	34.1%	33.6%	34.8%

Table 5.5 – NERC LTRA Reference Reserve Margin

Reference Planning Reserve Margin											
U.S. WECC Subregion	Peaking Assumption	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NWPP/RMRG	Summer	15.4%	16.1%	15.2%	15.1%	15.0%	14.9%	14.8%	15.6%	14.7%	14.5%
SRSG	Summer	10.9%	11.9%	11.0%	10.8%	10.7%	10.6%	10.5%	11.1%	10.4%	10.3%
CAMX	Summer	18.2%	15.8%	19.1%	19.1%	19.1%	19.0%	18.9%	15.7%	18.9%	19.0%

Using this data, a reserve margin position can be calculated to show project shortfalls, both with and without the inclusion of prospective resource additions. Table 5.6 reports the reserve margin differential based on anticipated resources, whereas Table 5.7 reports the reserve margin differential assuming prospective resources are achieved during the study period. In either table, a positive percentage represents a margin of overage where WECC is expected to have resources above the reference margin target; a negative number (highlighted for emphasis) represents a year where a given subregion is at risk of falling below the reference margin.

Based on this evaluation, potential shortfalls in planning reserve margin show up in the back three years of the study period and only in the NWPP/RMRG subregion of WECC.

Table 5.6 – Planning Reserve Margin Shortfalls by Subregion with Anticipated Resources

Shortfalls Assuming Anticipated Reserve Margin											
U.S. WECC Subregion	Peaking Assumption	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NWPP/RMRG	Summer	10.5%	8.5%	8.2%	6.5%	5.8%	2.8%	1.7%	**-2.1%**	**-3.0%**	**-4.1%**
SRSG	Summer	7.2%	5.4%	6.0%	3.9%	4.8%	6.2%	5.5%	4.3%	4.0%	3.3%
CAMX	Summer	3.2%	12.0%	8.2%	7.7%	3.4%	2.0%	1.7%	3.9%	0.3%	0.2%

Table 5.7 – Planning Reserve Margin Shortfalls by Subregion with Prospective Resources

Shortfalls Assuming Prospective Reserve Margin											
U.S. WECC Subregion	Peaking Assumption	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NWPP/RMRG	Summer	10.5%	8.7%	8.8%	7.1%	6.5%	3.5%	2.4%	**-1.4%**	**-2.4%**	**-3.5%**
SRSG	Summer	7.2%	6.2%	8.5%	6.4%	7.2%	8.6%	7.8%	6.5%	6.2%	5.4%
CAMX	Summer	3.2%	19.5%	21.7%	22.6%	18.2%	16.7%	16.3%	18.4%	14.7%	15.8%

Prior Measures

PacifiCorp's past assessments, relying on calculations incorporated into the WECC PSA, have reporting a rolling succession of power supply margins, where each year there is a downward trend in reserve margins extending into the future. The rolling nature of each year's outcome tells us that while declining reserve margins are important, the trend line is rarely followed from one year to the next. Rather, the trend line tends to be pushed forward like a wave, where the future shortage is not allowed to materialize because of cumulative actions taken within the WECC in recognition of future need.

Pacific Northwest Resource Adequacy Forum's Adequacy Assessment

As in the 2019 IRP, the Pacific Northwest Resource Adequacy Forum (later replaced by the Resource Adequacy Advisory Committee) issued resource adequacy standards in April 2008, which were subsequently adopted by the Northwest Power and Conservation Council. The standard calls for assessments three and five years out, conducted every year, and including only existing resources and planned resources that are already sited and licensed. The current assessment (issued October 2019) concludes that power supply is expected to be adequate through 2020, with energy and capacity surplus becoming a deficit in 2021 and 2022 at a loss of load probability of 10%. This deficit is primarily driven by the retirement of the Boardman and Centralia coal plants. The assessment includes approximately 550 MW of new capacity scheduled to come online in 2021.

2021 Northwest Power Plan

The Northwest Power and Conservation Council is currently in the process of finalizing the 2021 Northwest Power Plan, which is expected to be final in early 2022. Although preliminary, PacifiCorp has been actively participating in the planning process to date, and notes that the draft findings are similar to what the company has observed through the WECC Western Assessment of Resource Adequacy and the NERC LTRA, primarily:

- There is a resource adequacy need in the next few years, with up to 1,600 MW of capacity need by 2023;
- After 2023, even with additional coal-fired generation retirements, adequacy can be maintained through a high level of expected renewable resource buildout and the optimization of the existing hydro and gas-fired resource fleet; and
- There is inherent uncertainty driven by the possibility of accelerated loads due to electrification programs and the uncertainty of WECC-wide resource buildout.

NWPP Resource Adequacy Program

Beginning in early 2019, PacifiCorp along with other Northwest Power Pool (NWPP) member entities and the Northwest Power Pool itself engaged in the development of a regional Resource Adequacy (RA) Program as a mechanism to assure a high likelihood of adequate supply to meet customer demand under a wide array of scenarios.[7] This program includes two components, a forward showing (FS) planning mechanism and an operational program (Ops Program) to help participants that are experiencing extreme events meet customer demand. The program is intended to be a starting point and does not solve every issue facing the region, but is an incremental step toward increased regional coordination, which could better position the region to continue to tackle these big issues.

The program will focus on creating a capacity RA program with a demonstration of deliverability. Additional adequacy programs may also be necessary following the implementation of the capacity program. The region may also benefit from other forms of coordination, and while the structure and process associated with the program may serve as foundational building blocks to additional regional coordination, the NWPP and its participants are only working to implement the capacity RA program at this time. The proposed RA program does not replace or supplant the resource planning processes used by states or provinces or the regulatory requirements of the Federal Energy Regulatory Commission (FERC), North America Electric Reliability Corporation (NERC) or Western Electricity Coordinating Council (WECC). The program is designed to be supplemental and complementary to those processes and requirements. Program planning is scheduled to continue throughout 2022, with a proposed implementation date in 2024.

[7] https://www.nwpp.org/resources/2021-nwpp-ra-program-detailed-design

Reliable Service through Unpredictable Weather and Challenging Market Liquidity

As described in Volume I, Chapter 7 (Resource Options), PacifiCorp, other utilities, and power marketers who own and operate generation engage in market purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations. In addition to reflecting spot market purchase activity and existing long-term purchase contracts in the IRP portfolio analysis, PacifiCorp models front office transactions (FOT). FOTs are proxy resources, assumed to be firm, that represent procurement activity made on an on-going forward basis to help PacifiCorp cover short positions.

Solicitations for FOTs can be made years, quarters or months in advance, however, most transactions 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.

In developing FOT limits for the 2021 IRP, PacifiCorp reviewed the studies described in the sections above as part of its assessment of market reliance in addition to consideration of its active participation in wholesale power markets, its view of physical delivery constraints, and market liquidity and market depth. The 2021 IRP FOT limits are 1,000 MW in the winter, and 500 MW in the summer, reduced from 1,425 MW in the 2021 IRP. These reductions are due to an assumption of zero summer liquidity at COB, NOB, and Mona, as well as decreased liquidity at Mid-C in both Flat Annual and Heavy Load Hour. Table 5.8 details the assumed market availability limits.

Table 5.8 – Maximum Available Front Office Transactions by Market Hub

Market Hub/Proxy FOT Product Type	Availability Limit (MW)			
	2021		2019	
	Summer (July)	Winter (December)	Summer (July)	Winter (December)
Mid-Columbia (Mid-C)				
Flat Annual or Heavy Load Hour	350	350	Reduced from 400	
Heavy Load Hour	150	0	Reduced from 375	
California Oregon Border (COB)				
Flat Annual or Heavy Load Hour	0	250	Removed in summer only	
Nevada Oregon Border (NOB)				
Heavy Load Hour	0	100	Removed in summer only	
Mona				
Heavy Load Hour	0	300	Removed in summer only	
Total	**500**	**1,000**	**1,425**	**1,425**

PacifiCorp's historical market purchases at times exceeded its 2019 IRP FOT planning limits, indicating that it was able to find sellers in the market to meet capacity needs. While PacifiCorp expects to continue to use its transmission access to access markets whenever it is economic to do so, planning to rely exclusively on markets and imports at the same levels is becoming riskier as western resource mix evolves and there is greater reliance on variable and short-duration resources.

Aligned with review of the regional studies discussed above, and the historical market purchases and transactions, PacifiCorp has selected a peak-season FOT limit of 1,000 MW in the winter and 500 MW for the summer in the 2021 IRP. The company will continue to refine its assessments of market depth and liquidity for transactions, informed by actual operations, to quantify the risk associated with the level of market reliance. Several FOT studies are discussed and evaluated in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection Results).

Planning for Load Changes as a Result of Climate Change

Recent weather-based reliability events throughout the United States have underscored the need for utilities to consider the potential for increasingly extreme weather and the underlying reliability challenges that may be caused as part of its planning process. PacifiCorp has prepared a climate change scenario within the 2021 IRP to assess the ways in which climate change may impact planning assumptions (See Chapter 8, Volume I, Modeling and Portfolio Evaluation Approach). The following section provides an overview on the load assumptions associated with climate change projections.

PacifiCorp consulted with the Northwest Power and Conservation Council to collaboratively align on how to model future peak load need based on changing temperatures throughout PacifiCorp's service area. Further, a literature review of various climate change research was performed to determine a basis for temperatures informing the 2021 IRP climate change scenario. Ultimately, PacifiCorp's 2021 IRP climate change scenario relies on projected temperatures as determined by the United States Bureau of Reclamation (Reclamation) in the West-Wide Climate Risk Assessments: Hydroclimate Projections Study (Study).[8] In addition to temperature projections, the Reclamation study also provides hydrological projections for waterways throughout PacifiCorp's six-state service territory.

Table 5.9 below provides the projected range of temperature change for select sites within PacifiCorp's service territory, which were used to model projected temperatures in the 2021 IRP Washington-required scenario to include the effects of climate change.

[8] United States Bureau of Reclamation, March 2016, Managing Water in the West, Technical Memorandum No. 86-68210-2016-01, West-Wide Climate Risk Assessments: Hydroclimate Projections. https://www.usbr.gov/climate/secure/docs/2016secure/wwcra-hydroclimateprojections.pdf

Table 5.9 – Projected Range of Temperature Change in the 2020s and 2050s relative to the 1990s[9]

Bureau of Reclamation Site	PacifiCorp Jurisdiction Assumption	Projected Range of Temperature Change (°F)	
		2020s	2050s
Klamath River near Klamath	California	1.4 to 2.4	2.6 to 4.4
Snake River Near Heise	Idaho	1.6 to 3.1	3.1 to 5.6
Klamath River near Seiad Valley	Oregon	1.4 to 2.5	2.7 to 4.5
Green River near Greendale	Utah	1.7 to 3.1	3.1 to 5.7
Yakima River at Parker	Washington	1.5 to 2.6	2.7 to 5.0
Green River near Greendale	Wyoming	1.7 to 3.1	3.1 to 5.7

PacifiCorp used these temperature projections to calculate change in peak loads and energy driven by temperature change over the next three decades.[10]

As illustrated in Table 5.10, relative to the 2021 IRP forecast, the climate change scenario results in summer peaks being higher by approximately 50 MW (<1% higher) over the 2021-2025 timeframe. By 2040, summer peaks are projected to be 318 MW (2.7%) higher than the 2021 IRP Base.

As illustrated in Table 5.11, increasing winter temperatures results in less heating load, which drive lower winter peaks. By 2040, winter peaks are projected to be 259 MW (2.3%) lower than the 2021 IRP Base.

As illustrated in Table 5.12, increasing temperatures are driving a slightly lower energy forecast. This is driven by lower heating loads for Oregon, which is largely offset by increased loads in Utah.

[9] United States Bureau of Reclamation, March 2016, Managing Water in the West, Technical Memorandum No. 86-68210-2016-01, West-Wide Climate Risk Assessments: Hydroclimate Projections. https://www.usbr.gov/climate/secure/docs/2016secure/wwcra-hydroclimateprojections.pdf

[10] Additional information on methodology behind the peak-load calculation can be found in Volume I, Chapter 6 (Load and Resource Balance) of the 2021 IRP.

Table 5.10 – Change in Summer Coincident Peak Climate Change Scenario vs 2021 IRP Base (Megawatt-hours), at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2021	53	10	1	(0)	17	17	8
2022	53	11	1	(0)	17	17	8
2023	54	11	1	(0)	17	17	8
2024	55	11	1	(0)	17	17	8
2025	53	11	1	(0)	17	17	7
2026	71	16	3	(0)	26	18	8
2027	89	22	4	(0)	35	18	10
2028	107	28	5	(0)	44	19	11
2029	126	34	7	(0)	53	19	13
2030	139	41	8	-	63	14	14
2031	158	47	10	0	73	14	15
2032	178	54	11	0	82	14	16
2033	198	60	13	0	92	15	18
2034	218	67	14	0	103	15	19
2035	239	74	16	0	113	16	21
2036	245	80	17	0	119	16	14
2037	273	86	19	0	128	16	24
2038	291	91	20	0	137	17	26
2039	301	97	21	0	139	16	28
2040	318	103	22	0	146	16	30

Table 5.11 – Change in Winter Coincident Peak Climate Change Scenario vs 2021 IRP Base (Megawatt-hours), at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2021	(126)	(90)	(10)	(3)	(15)	(4)	(4)
2022	(127)	(90)	(10)	(3)	(16)	(4)	(4)
2023	(127)	(90)	(10)	(3)	(16)	(4)	(4)
2024	(128)	(90)	(10)	(3)	(16)	(4)	(4)
2025	(130)	(92)	(10)	(2)	(17)	(5)	(4)
2026	(137)	(95)	(12)	(3)	(18)	(5)	(4)
2027	(143)	(97)	(14)	(3)	(19)	(6)	(5)
2028	(150)	(101)	(15)	(3)	(20)	(6)	(5)
2029	(158)	(104)	(17)	(3)	(21)	(8)	(5)
2030	(162)	(107)	(19)	(3)	(22)	(6)	(5)
2031	(167)	(109)	(20)	(3)	(23)	(7)	(6)
2032	(175)	(112)	(22)	(3)	(24)	(8)	(6)
2033	(182)	(115)	(23)	(3)	(25)	(9)	(6)
2034	(189)	(118)	(25)	(3)	(26)	(10)	(6)
2035	(194)	(121)	(27)	(3)	(27)	(10)	(7)
2036	(201)	(124)	(28)	(4)	(28)	(12)	(7)
2037	(247)	(449)	(105)	(14)	290	24	7
2038	(256)	(461)	(106)	(14)	294	24	8
2039	(261)	(472)	(107)	(15)	300	25	8
2040	(259)	(484)	(109)	(15)	310	30	9

Table 5.12 – Change in Annual Energy Climate Change Scenario vs 2021 IRP Base (Megawatt-hours), at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2021	(129,280)	(171,850)	(38,220)	(13,050)	76,330	(16,180)	33,690
2022	(129,790)	(172,660)	(38,030)	(13,070)	76,800	(16,410)	33,580
2023	(131,060)	(173,320)	(37,820)	(13,050)	76,400	(16,710)	33,440
2024	(131,500)	(173,790)	(37,630)	(13,050)	76,560	(16,930)	33,340
2025	(131,870)	(174,200)	(37,470)	(13,060)	76,780	(17,130)	33,210
2026	(126,270)	(175,670)	(37,980)	(13,430)	83,670	(17,590)	34,730
2027	(120,520)	(177,100)	(38,480)	(13,790)	90,660	(18,060)	36,250
2028	(114,500)	(178,480)	(38,950)	(14,170)	97,840	(18,520)	37,780
2029	(107,870)	(179,490)	(39,360)	(14,550)	105,200	(18,950)	39,280
2030	(101,020)	(180,590)	(39,720)	(14,920)	112,780	(19,370)	40,800
2031	(93,880)	(181,720)	(40,060)	(15,310)	120,630	(19,750)	42,330
2032	(86,310)	(182,800)	(40,350)	(15,700)	128,740	(20,090)	43,890
2033	(78,250)	(183,760)	(40,570)	(16,080)	137,110	(20,380)	45,430
2034	(69,710)	(184,630)	(40,750)	(16,460)	145,750	(20,640)	47,020
2035	(60,710)	(185,420)	(40,880)	(16,850)	154,690	(20,850)	48,600
2036	(54,280)	(186,550)	(41,010)	(17,150)	161,400	(21,080)	50,110
2037	(47,420)	(187,620)	(41,090)	(17,450)	168,420	(21,280)	51,600
2038	(40,300)	(188,630)	(41,130)	(17,760)	175,600	(21,470)	53,090
2039	(32,870)	(189,600)	(41,140)	(18,070)	182,980	(21,640)	54,600
2040	(25,190)	(190,540)	(41,110)	(18,380)	190,520	(21,810)	56,130

Weather-Related Impacts to Variable Generation

The effect of extreme weather events associated with climate change is an evolving area of research that is growing in importance as renewable, intermittent resources dependent upon wind, solar, and hydrologic conditions comprise an increasing proportion of utility resource portfolios.

Wildfire Impacts

Increased wildfire frequency associated with climate change is expected to have a range of impacts to intermittent generation sources, including wind, solar, and hydro resources.

Wind generation sites in PacifiCorp's system are most likely to be subjected to fast moving range fires. Impacts at wind generation sites from range fires are likely to be limited and short in duration, as turbines and collector substations are surrounded by gravel surfaces that are fire resistant. Sensitive turbine equipment is located far above the ground away from damaging heat sources. Impacts to transmission lines and aboveground collector lines from range fires at wind generation sites is also anticipated to be minor due to the limited fuels available to cause ignition to wooden poles. Outage durations are likely to be short when operations staff is required to evacuate a site in advance of a fire and to curtail generation as a precautionary measure.

Climate change also poses fire risks at solar generation sites, which are also likely to manifest as range fires given solar projects are typically sited well away from substantial tree stands that could block solar panels. Impacts could be significant depending on the amount of vegetation at a site, as generating equipment is close to the ground close to potential fuel sources. If a range fire creates sufficient heat to impact equipment, resumption of generation will be dependent on the ability to obtain and install necessary replacement equipment.

Fire impacts at hydro generation sites will be driven primarily by impacts to transmission lines. Hydro generation sites are typically in heavily forested terrain and serviced by only one or two transmission lines. An intense forest fire can damage miles of transmission lines that can take weeks to months to restore to service. If a fire threatens a hydro generation site, the site will be proactively evacuated with generation units typically taken offline and the facility put into spill to avoid potential instream flow impacts that could occur with an unplanned unit shutdown resulting from impacts to local transmission lines. Generation units would be restarted as soon as possible when conditions permit safe re-entry to provide generation locally until transmission service, if interrupted, is restored. Fire damage to dams, water conveyance structures, and generating plants is expected to be minimal. Some damage to local distribution lines and communication infrastructure upon which hydro generation sources rely is also possible, which could impact generation restoration timelines.

PacifiCorp outlines its wildfire mitigation strategies later in this document.

Extreme Weather Impacts

Climate change also has the potential to result in increased frequency and magnitude of extreme weather events. Such changes can result in more frequent and intense precipitation events and flooding, which could impact hydropower generation and change historic operating practices to maintain flood control capabilities at projects where flood control benefits are part of project operations. Similar to wildfire events, increased flooding has the potential to impact access to remote hydro facilities. Increased precipitation and reduced snow water equivalent have the potential to modify runoff patterns impacting hydro generation but is not expected to impact dam safety at PacifiCorp hydro facilities, which are subject to FERC dam safety requirements that ensure they are able to safely pass probable maximum flood events. Increases in extreme weather that results in more frequent flood events has the potential to increase debris loading in river systems and reservoirs, potentially increasing generation downtime to remove debris that may reduce inflows to hydro units or reduce flows through fish screens.

Changes to wind patterns and wind speeds, and changes in extreme high and low air temperatures have the potential to impact wind and solar generation. Extreme high temperatures can raise ground temperatures, which has the potential to impact collector system capacities at wind and solar projects and reduce collector system carrying capacity, limiting output, similar to high temperature impacts to high voltage transmission lines. However, these impacts are not anticipated to be significant on wind energy resources given peak output is typically observed outside of summer months. Increasing air temperatures result in lower air densities, which could negatively impact wind energy output even if wind speeds are unchanged. Lower wind speeds in the summer relative to historic experience because of extreme high temperatures is also possible. Wind turbines in PacifiCorp's fleet generally are protected from extreme low temperatures given the conditions in which they currently operate, and low temperature protection features are installed in PacifiCorp turbines where weather conditions warrant their inclusion.

There is limited research on site-specific impacts from extreme weather events and thus how to plan to improve the resiliency of intermittent generation resources. Resiliency will be enhanced as planning to ensure site access occurs in response to observed changes in extreme weather events and as more research is available to locally forecast impacts of climate change and extreme weather so those impacts can be factored into the resource planning process.

Impacts on wind and solar energy

The impact on renewable energy generation due to extreme weather events and climate change is an evolving topic. For conclusive trends of climate change impact, data collection specific to geographic locations is critical. Climate impacts both the demand and supply side of energy. Due to daily or seasonal changes the demand for energy patterns is changing. On the supply side due to increasing temperatures and variability in climate parameters it impacts estimated energy outputs of projects as well as operational costs. However, there are limited studies in the North American region that quantitatively document the impact of a climate parameter on the future of wind and solar energy.[11] Some broad impacts anticipated from climate change are noted below:[12]

Wind Energy

- Changes to wind speed: could impact energy assessments
- Changes in temperature: with increased temperatures the air density could reduce energy outputs

[11] Climate change impacts on the energy system: a review of trends and gaps. Cronin, J., Anandarajah, G. & Dessens, O. Climatic Change volume 151, August 2018.
[12] Climate change impacts on renewable energy generation. A review of quantitative projections. Kepa Solaun, Emilio Cerdá. Renewable and Sustainable Energy Reviews

- Changes in seasonal or daily wind: could disrupt correlation between wind energy and grid load demand
- Rising sea levels: could damage offshore wind farm infrastructure

Solar Energy

- Changes in mean temperatures: increased global temperatures could reduce cell efficiency
- Changes in solar irradiation, dirt, snow, precipitation etc.: increase in these variables could reduce energy output

Integration of energy storage with wind and solar projects is a way to help make use of generated energy more efficiently.

Wildfire Risk Mitigation

Despite years of focus on wildfire prevention, wildfires continue to become more frequent and intense throughout the region. Continued growth of the wildland urban interface and the impacts of climate change mean that it is imperative that utilities continue to lead the way in implementing innovative strategies to keep customers and communities safe.

As a leading provider of safe and reliable electricity throughout the west, PacifiCorp has worked closely with stakeholders and experts to develop wildfire mitigation plans that ensure safe and reliable service and prioritize customer and community safety. PacifiCorp's wildfire mitigation plans, which describe the investments and protocols needed to construct, maintain, and operate electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire, are guided by the following core principles:

- Frequency of ignition events related to electric facilities can be reduced by engineering more resilient systems that experience fewer fault events.
- When a fault event does occur, the impact of the event can be minimized using equipment and personnel to shorten the duration to isolate the fault event.
- Systems that facilitate situational awareness and operational readiness are central to mitigating fire risk and its impacts.
- A successful plan must also consider the impact on customers and communities, in the overall imperative to provide safe, reliable, and affordable electric service.

PacifiCorp's plans, which outline a risk-based, balanced, and integrated approach, contain six critical focus areas of planning and execution for a reliable and resilient energy future: (1) Risk analysis and drivers, (2) Situational awareness, (3) Inspection and correction, (4) Vegetation management, (5) System hardening, and (6) Operational practices.

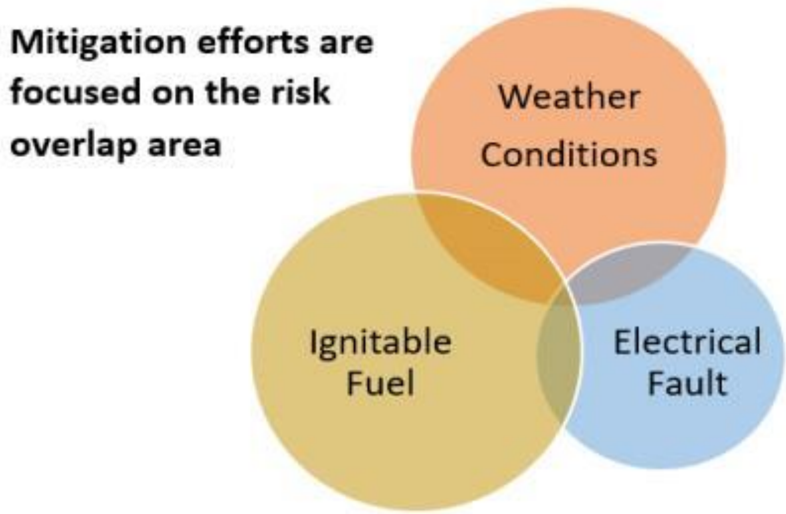
The company continues to build on over a century of wildfire mitigation experience and three decades of information gathering and analysis. PacifiCorp's planning focus areas above are intended to ensure that we continue to serve customers safely and reliably. As new analyses, technologies, practices, network changes, environmental influence or risks are identified, changes to address them may be incorporated into future iterations of the plans.

Risk Analysis and Drivers

PacifiCorp's risk evaluation process employs the concept that the risk is essentially the product of the likelihood of a specific risk event multiplied by the impact of the event. The likelihood, or probability, of an event is an estimate of a particular event occurring within a given time frame. The impact of event is an estimate of the effect when an event occurs. Impact can be evaluated using a variety of factors, including considerations centered on health and safety, the environment, customer satisfaction, system reliability, the company's image and reputation, and financial implications.

A disruption of normal operations on the electrical network, called a "fault" in the industry, could be a possible ignition source for wildfire. Under certain weather conditions and in the vicinity of wildland fuels, an ignition can grow into a harmful wildfire, potentially even growing into a catastrophic fire causing great harm to people and property. This general relationship is shown in the Figure 5.1.

Figure 5.1 – Wildfire Risk Mitigation Focus Areas



Therefore, PacifiCorp's risk analysis first concentrates on weather conditions and ignitable fuels, to identify the geographic areas at the greatest risk of catastrophic fire. The analysis also explores location specific fire history, recorded causes, the acreage impact of the fires, and the seasonality of fires. The analysis further considers historical outage data, reflecting the best available data regarding the potential for faults on the electrical system.

These faults, when experienced during fire risk time periods in locations with the greatest risk for catastrophic fire, reflect the best available data to utilities to correlate an identifiable event on the electric network to the risk of utility-related wildfire. There is a logical physical relationship, when a fault occurs it could result in a spark, thus there is a risk of fire, therefore these events are classified as ignition risk drivers. An unplanned outage, which is when a line is unintentionally de-energized, is most often rooted in a fault. Accordingly, the company has closely analyzed the causes and frequency of outages. This analysis is designed to determine which mitigation strategies are best suited to minimize fault events, thereby reducing the risk of fire. Additionally, this analysis highlights geographic locations that present the greatest risk, allowing PacifiCorp to focus efforts.

Situational Awareness

Situational awareness involves knowledge of the conditions that impact the potential for wildfire ignition and spread. Increasing its situational awareness of such conditions helps an electric utility implement operational strategies, respond to local conditions, and minimize the wildfire risk by making mitigation strategies more effective.

Weather Stations

PacifiCorp obtains data regarding local conditions from many sources and uses the data to adjust its operations in both the short and long term. Local weather data remains a key input to this process and PacifiCorp's overall situational awareness capability. To supplement existing local weather data and conditions, PacifiCorp installs and operates weather stations in high--risk locations. Additionally, PacifiCorp continues to evaluate the need for additional micro weather data in areas with a high risk of wildfires that could threaten the public and property to obtain more granular local weather data. As the company's overall plan and situational evolves, PacifiCorp intends to evaluate this program for future expansion should additional or different data be needed.

Meteorology

The ability to gather, interpret, and translate data into an assessment of utility specific risk and inform decision making protocols is another key component of PacifiCorp's situational awareness capability. To support this effort, PacifiCorp has developed a meteorology department within the company's broader emergency management department. The objectives of this department are to supplement the company's longer term risk analysis capabilities with a real time risk assessment and forecasting tool, identify and close any forecasting data gaps, manage day to day threats and risks, and recommend changes to operational protocols during periods of elevated risk.

Inspection and Correction

Inspection and correction programs are the cornerstone of a resilient system. These programs are tailored to identify conditions that could result in premature failure or potential fault scenarios, including situations in which the infrastructure may no longer be able to operate per code or engineered design, or may become susceptible to external factors, such as weather conditions.

PacifiCorp performs inspections on a routine basis as dictated by both state-specific regulatory requirements and PacifiCorp-specific policies. When an inspection is performed on a PacifiCorp asset, inspectors use a predetermined list of condition codes and priority levels to describe any noteworthy observations or potential noncompliance discovered during the inspection. Once recorded, PacifiCorp uses condition codes to establish the scope of and timeline for corrective action to make sure that the asset is in conformance with National Electric Safety Code (NESC) requirements, state-specific code requirements and/or PacifiCorp specific policies. This process is designed to correct conditions while reducing impact to normal operations.

The historic inspection and correction programs are effective at maintaining regulatory compliance and managing routine operational risk. They also mitigate some wildfire risk by identifying and correcting conditions which, if uncorrected, could ignite a fire. Recognizing the growing risk of wildfire, PacifiCorp plans to supplement its existing programs, in collaboration with state regulators and stakeholders, to further mitigate the growing wildfire specific operational risks and create greater resiliency against wildfires. These changes include the creation of a fire threat classification for specific conditions, an increase of inspection frequencies in high-risk locations, and the reduction of correction timeframes for fire threat conditions.

Vegetation Management

Vegetation management is generally recognized as a significant strategy in any Wildfire Mitigation Plan. Vegetation coming into contact with a power line could be a source of fire ignition. Thus, reducing vegetation contacts reduces the potential of an ignition originating from electrical facilities. While it is impossible to eliminate vegetation contacts completely, at least without radically altering the landscape near power lines, a primary objective of PacifiCorp's existing vegetation management program is to minimize contact between vegetation and power lines. This objective is in alignment with core Wildfire Mitigation Plan efforts, and continuing dedication to administering existing programs is a solid foundation for PacifiCorp's Wildfire Mitigation Plan efforts. To supplement the existing program, PacifiCorp vegetation management implements additional Wildfire Mitigation Plan strategies such as annual vegetation patrols, extended clearances, and radial pole clearing in high-risk locations.

System Hardening

PacifiCorp's electrical infrastructure is engineered, designed and operated in a manner consistent with prudent utility practice, enabling the delivery of safe, reliable power to all customers. When installing new assets, PacifiCorp is committed to incorporating the latest technology and engineered solutions. When conditions warrant, PacifiCorp may engage in strategic system hardening, which means replacing existing assets (or, in some circumstances, modifying existing assets using a new design and additional equipment) to make the assets more resilient. Recognizing the growing risk of wildfire, PacifiCorp plans to supplement existing asset replacement projects with system hardening programs designed to mitigate specific operational risks associated with wildfire.

System hardening programs are designed in reference to the equipment on the electrical network that could be involved in the ignition of a wildfire or be subject to an existing wildfire event. In general, system hardening programs attempt to reduce the occurrence of events involving the emission of sparks (or other forms of heat) from electrical facilities or reduce the impact of an existing wildfire on utility infrastructure. System hardening programs represent the greatest long-term mitigation tool available for use by electric utilities. The phasing and prioritization of such programs is therefore focused on locations that present the greatest risk through the line rebuild program.

Additionally, no single system hardening program mitigates all wildfire risk related to all types of equipment. Therefore, different system hardening components are grouped together as part of PacifiCorp's line rebuild program to address different factors, different circumstances and different geographic areas. Each project included in the line rebuild program described below, however, shares the common objective of reducing overall wildfire risk associated with the design and type of equipment used to construct electrical facilities.

It must be emphasized, however, that system hardening cannot prevent all ignitions, no matter how much is invested in the electrical network. Equipment does not always work perfectly and, even when manufactured and maintained properly, can age and fail; in addition, there are external forces and factors impacting equipment, including from third parties and natural conditions. Therefore, PacifiCorp cannot guarantee that a spark or heat coming from equipment owned and operated by PacifiCorp will never ignite a wildfire. Instead, PacifiCorp seeks to reduce the potential of an ignition associated with any electrical equipment. To this end, PacifiCorp plans to make investments with targeted system hardening programs.

Line Rebuild Program

PacifiCorp has evaluated specific areas for system hardening work based on the company's risk assessment methodology where bare overhead wire may be replaced with covered conductor. Where appropriate, poles will either be replaced or made more fire resilient (by fire protective treatment methods). Additionally, where conductor diameters do not support fault current properly (due to the limited arc energy they can tolerate), they will be replaced, generally with covered conductor. In all, the end effect will be more tolerant to incidental contact, while also being certain to tolerate fault event arc energy levels.

<u>Covered Conductor</u>

Historically, the vast majority of high voltage power lines in the United States, and in PacifiCorp's service territory, were installed with bare overhead conductor. As the name "bare" suggests, the wire is all metal and exposed to the air. For purposes of wildfire mitigation, a new conductor design has emerged as an industry best practice. Most of the projects in the Line Rebuild Program will involve the installation of covered conductor. Sometimes, with some variations in products, covered conductor is also called spacer cable, aerial cable, or tree cable.

The dominant characteristic of covered conductor is that the metal conductor which carries electricity is sheathed in a plastic covering. As a comparison for the lay person, covered conductor is like an extension power cord that you might use in your garage. The plastic coating provides insulation for the energized metal conductor inside the plastic coating. To be clear, covered conductor is not insulated enough for people to directly handle an energized high voltage power line (as discussed below). But the principle is the same. The plastic sheathing provides an insulating effect. It is this insulating effect which reduces the risk of wildfire, by greatly reducing the number of faults that would have occurred had bare conductor been used.

Variations in covered conductor products have been used in the industry for decades. Due to many operating constraints, however, use of covered conductor tended to be limited to locations with extremely dense vegetation where traditional vegetation management was not feasible or efficient. Recent technological developments, however, have markedly improved covered conductor products, reducing the operating constraints historically associated with the design. These advances have improved the durability of the project and reduced the impact of thermal insulation (i.e. because bare wires are exposed to air, bare wires can cool easier). There are still logistical challenges with covered conductor. Above all, the wire is heavier, especially when carrying snow or ice, meaning that more and/or stronger poles may be required when using covered conductor. And the product itself is more expensive than bare conductor.

The wildfire mitigation benefits of covered conductor are significant. As discussed in the risk assessment section, a disruption on the electrical network, a fault, can result in emission of spark or heat that could be a potential source of ignition. Covered conductor greatly reduces the potential of many kinds of faults. For example, contact from object is major category of real-world faults which can cause a spark. Whether it is a tree branch falling into a line or a Mylar balloon carried by the wind drifting into a line, contact from those objects with energized bare conductor causes the emission of sparks. If those same objects contact covered conductor, the wire is insulated enough that there are no sparks. Likewise, many equipment failures are a wildfire risk because the equipment failure then allows a bare conductor to contact a grounded object. Consequently, covered conductor greatly reduces the risk of ignition associated with most types of equipment failure. For example, if a cross arm breaks, the wire held up by the cross arm often falls to the ground (or low and out of position, so that the wire might be contacting vegetation on the ground or the pole itself). In those circumstances, a bare conductor can emit sparks (or heat) that can cause an ignition. The use of covered conductor, in those exact same circumstances, would almost certainly not lead to an ignition, because the insulation around the wire is sufficient to prevent any sparks and limit energy flow, even when there is contact with an object.

Covered conductor is especially well suited to reduce the occurrence of faults reasonably linked with the worst wildfire events. Dry and windy conditions pose the greatest wildfire risks. Wind is the driving force behind catastrophic wildfire spread. At the same time, wind has distinct and negative impacts on a power line. The wind blows objects into lines; a strong wind can cause equipment failure; and even parallel lines slapping in the wind can cause sparks. Covered conductor specifically reduces the potential of a catastrophic ignition event, because covered conductor is especially effective at limiting the kinds of faults that occur when it is windy. Taken together, these substantial benefits warrant the use of covered conductor in areas with a high wildfire risk.

In sum, at a very basic level, covered conductor is safer overall compared to bare conductor. Not only does covered conductor reduce the risk of wildfire, it is less dangerous to contact a covered conductor compared to a similar voltage bare conductor. Combined with the substantial wildfire mitigation benefits, covered conductor is the preferred design for rebuild projects. There are, however, unique challenges implicated in making it harder to spot a low-hanging or downed line.

PacifiCorp also evaluated the costs and benefits of underground design for the rebuild projects. The potential wildfire mitigation benefits are undeniable. While an underground design does not completely eliminate every ignition potential (i.e., because of above-ground junctions), it is the most effective design to most dramatically reduce the risk of any utility-related ignition. Unfortunately, because of cost and operational constraints, the functional realities of underground construction prevent widespread application as a wildfire mitigation strategy. Nonetheless, PacifiCorp is using an underground design as part of the rebuild projects when functional and cost-effective. Through the design process, each rebuild project is assessed to determine whether sections of the rebuild should be completed with underground construction. As a practical matter, the great majority of the rebuilds will be covered conductor. This outcome is consistent with emerging best practices. Utilities in geographic areas with extreme wildfire risk, including in California and Australia, are trending heavily towards use of covered conductor, with limited applications of underground construction where appropriate. Indeed, sourcing material for the planned projects is challenging because of the industry trend towards use of covered conductor as a primary wildfire mitigation strategy. On a related note, the company remains willing to consider additional underground applications. Some communities and landowners may prefer, for aesthetic reasons, to pursue a higher cost underground alternative. Consistent with governing electric service regulations, PacifiCorp will work with communities or individual landowners who are willing to pay the incremental cost and obtain the necessary legal entitlements for underground construction, if covered conductor is the least cost option for a rebuild project.

Non-Wooden Poles

Traditionally, overhead poles are replaced or reinforced within PacifiCorp's service territory consistent with state specific requirements and prudent utility practice. When a pole is identified for replacement, typically through routine inspections and testing, major weather events, or joint use accommodation projects, a new pole consistent with engineering specifications suitable for the intended use and design is installed in its place. Engineering specifications typically reflect the use of wooden poles which is consistent with prudent utility practice and considered safe and structurally sufficient to support overhead electrical facilities during standard operating conditions. However, the use of alternate non-wooden construction, such as steel or fiberglass, can provide additional structural resilience in high-risk locations during wildfire events and, therefore, aid in restoration efforts.

In addition to the installation of non-wooden solutions as a part of standard replacement programs or mechanisms in priority locations with increased risk, certain wooden poles may also be replaced with non-wooden solutions in conjunction with other wildfire mitigation system hardening programs. For example, as a part of covered conductor installation, the strength of existing poles is evaluated. In many cases, the strength of existing poles may not be sufficient to accommodate the additional weight of covered conductor. In these instances, the existing wooden pole is upgraded to support the increased strength requirements and, when present in high priority locations, replaced with a non-wooden solution for added resilience.

Non-Expulsion Fuses

Overhead expulsion fuses serve as one of the primary system protection devices on the overhead system. The expulsion fuse has a small metal element within the fuse body that is designed to melt when excessive current passes through the fuse body, interrupting the flow of electricity to the downstream distribution system. Under certain conditions, the melting action and interruption technique will expel an arc out of the bottom of the fuse tab. To reduce the potential for ignition resulting from fuse operation, PacifiCorp has identified alternate methodologies and equipment that do not expel an arc for installation within high-risk locations. PacifiCorp plans to replace expulsion fuses with non-expulsion fuses as a part of the high-risk locations line rebuild program in conjunction with the installation of covered conductor.

Operational Practices

System Operations

The manner in which an electrical system is operated can also help mitigate wildfire risk. PacifiCorp has specific procedures addressing system operations during fire season. These procedures are designed to reduce the potential for ignition of a fire from sparks emitted when a line is re-energized with a disturbance still on the line. Recognizing the increasing magnitude of the wildfire risk, PacifiCorp significantly augmented operating procedures in June 2018 to incorporate a more conservative approach designed to reduce the potential of fault-based ignitions on PacifiCorp's electrical network. From a practical perspective, the procedures implicate two primary subject areas: (a) settings for automatic reclosers and (b) line testing after lock-out.

Automatic reclosers are currently deployed on various transmission lines and distribution circuits throughout PacifiCorp's service territory. When a line trips open, an automatic recloser may operate to close the circuit very quickly, so long as the cause of a momentary trip has cleared. The reclosing function allows PacifiCorp to maintain service on a line that had tripped, rather than opening the circuit and de-energizing the line. In general, automatic recloser operation is beneficial because it reduces outages and improves customer reliability. The actual operation of recloser equipment does not directly present wildfire risk, as the recloser equipment itself does not emit sparks or otherwise pose an ignition risk.

The operation of automatic reclosers, however, indirectly implicates some degree of ignition risk. When a fault is detected on the line, a recloser will trip and reclose based on predetermined settings in an attempt to re-energize the line. If the cause of the fault is no longer present when the device recloses, the line will re-energize resulting in limited impact to customers. If the cause of the original fault still remains when the device recloses, however, the original fault may persist and, depending on the circumstances, potentially result in arcing or an emission of sparks. As a result, in some limited circumstances, the second fault scenario could lead to a fire ignition. Accordingly, automatic recloser settings can have a significant impact on wildfire mitigation.

The risk associated with line-testing on overhead lines is very similar. If a breaker has "locked-out", meaning that it has opened and no longer conducts electricity, a system operator will sometimes "test" the line. To test the line, the system operator will close the device, thereby allowing the line to be re-energized. If the fault has cleared, then the system will run normally. If the fault has not cleared, the device will lock out again. If the device locks out again, the system operator then knows that additional investigation or work will be required before the line can be successfully re-energized. Because faults are often temporary, line-testing can be an efficient tool to maintain customer reliability. At the same time, line-testing can result in the emission of sparks if a fault has not yet cleared when the line is tested. Accordingly, a "no-test" policy reduces the risk of ignition, and a "no-test" policy is applicable in certain circumstances during fire season.

In general, these system operating procedures are more restrictive when wildfire conditions are elevated. The specific circumstances in which automatic reclosers are disabled and no-test applies, on both transmission and distribution lines, are fully detailed in the procedures.

Field Operations

During fire season, PacifiCorp modifies the way it operates in the field to further mitigate wildfire risk. In particular, field operations consider the local weather and geographic conditions that may create an elevated risk of wildfire. These practices are targeted to reduce the potential of direct or indirect causes of ignition during planned work activities, fault response and outage restoration.

PacifiCorp personnel working in the field during fire season mitigate wildfire risk through a variety of tactics. Routine work, such as condition correction and outage response, poses some degree of ignition risk, and, in certain circumstances, crews modify their work practices and equipment to decrease this risk. In the extremely unlikely event that a fire ignition occurs while field crews or other PacifiCorp personnel are working in the field (collectively "field personnel"), such field personnel are equipped with basic tools to extinguish small fires.

<u>Work Restrictions</u>

PacifiCorp field operations can mitigate some wildfire risk by managing the way that field work is scheduled and performed. To effectively manage work during fire season, area managers regularly review local fire conditions and weather forecasts provided to them as part of PacifiCorp's monitoring program – discussed in the situational awareness section below.

During fire season generally, field operations managers are encouraged to defer any nonessential work at locations with dense and dry wildland vegetation, especially during periods of heightened fire weather conditions. If essential work needs to be performed in high-risk locations and other areas with appreciable wildland vegetation, certain restrictions may apply, including:

- **Hot Work Restrictions.** Field operations managers are encouraged to evaluate whether work should be performed during a planned interruption, rather than while a line is energized.
- **Time of Day Restrictions.** Field operations managers are encouraged to consider using alternate work hours to accommodate evening and night work when there may be less risk of ignition.
- **Wind Restrictions.** Field personnel are encouraged to defer work, if feasible, when there are windy conditions at a particular work site.
- **Driving Restrictions.** Field personnel are encouraged to keep vehicles on designated roads whenever operationally feasible.

Worksite Preparation

If wildland vegetation posing an ignition risk is prevalent at a worksite, and the work to be performed involves the potential emission of sparks from electrical equipment, field personnel working during fire season are encouraged to remove vegetation at the work site where allowed in accordance with land management/agency permit requirements, especially when there is dry or tall wildland grass. In addition to clearing work, the water truck resources, discussed below, are strategically assigned to sometimes accompany field personnel working in a wildland area during fire season, especially in high-risk locations. Depending on local conditions, dry vegetation in the immediate vicinity may be sprayed with water before work as a preventative measure.

Vehicles

Vehicles can be a source of ignition. As discussed above, field operations personnel are instructed to stay on designated roads during fire season, as feasible, and to avoid vegetation which could contact the undercarriage of parked vehicle. To further mitigate any wildfire risk associated with the use of vehicles, field operations plan to convert, over time, the vehicle exhaust configuration of work trucks. To accomplish this objective, field operations will strategically convert some vehicles in districts with the greatest amount of FHCA. Long term, when new vehicles are purchased, PacifiCorp plans to purchase trucks with a vehicle exhaust configuration which minimizes ignition risk.

Additional Labor Resources

Some wildfire mitigation activities require the time of field personnel, including in two key areas: (a) supporting system operations in administering the procedures discussed above and (b) responding to outages during fire season.

Under normal operating procedures, system operators and field personnel work together daily to manage the electrical network. In many situations, system operators depend on field personnel to gather information and assess local conditions. As discussed above, there are system operations procedures during wildfire season for disabling automatic recloser functions and limiting line-testing. Consequently, system operators need field personnel to gather information and assess local conditions during fire season more frequently than would otherwise be required under normal operating procedures. The requests from system operators may be varied, ranging from a simple phone call to confirm that it is raining in a particular area, to a much more time-intensive request, such as a full line patrol on a circuit.

Field personnel may also spend some additional time when responding to an outage during fire season. After a fault results in an outage, all or part of a circuit might remain de-energized while restoration work is performed, depending on the design, loading conditions and sectionalizing capability of the circuit experiencing the outage. Occasionally, additional foreign objects, such as tree limbs or other debris, can come into contact with the de-energized line and remain undetected throughout the duration of restoration efforts. Under normal operating procedures and consistent with prudent utility practices, a line is typically re-energized as soon as restoration work is complete. Consequently, a re-energized line could immediately experience a new fault if some contact between the line and foreign object had occurred while restoration work was being performed. The new fault would, of course, present additional wildfire risk, because of the potential of a spark being emitted as a result of a fault occurring when the line was re-energized. To mitigate this risk, field operations may perform some amount of line patrol on certain de-energized sections of the circuit, notably during fire season and particularly in high-risk locations dependent on current conditions at the work site and the duration of the restoration work. Depending on the circumstances, this extra patrol might be done just before or just after re-energizing the line. Typically, this type of line patrol does not involve a close inspection of any particular facility; instead, it is a quick visual assessment specifically targeted to identify obvious foreign objects that may have fallen into the line during restoration work.

Basic Personal Suppression Equipment

Personal safety is the first priority, and PacifiCorp field personnel are encouraged to evacuate and call 911 if necessary. Field personnel working in high-risk locations maintain the capability to extinguish a small fire that ignited while they are working in the field. Field personnel should attempt suppression only if the fire is small enough so that one person can effectively fight the fire while maintaining their personal safety. All field personnel working in high-risk locations during fire season will have basic suppression equipment available onsite, because field utility trucks typically carry the following equipment: (1) fire extinguisher; (2) shovel; (3) Pulaski; (4) water container; and (5) dust mask. The water container should hold at least five gallons and may be a pressurized container or a backpack with a manual pump (or other).

Mobile Generators

PacifiCorp has a mobile generator to assist with emergency response efforts. In short, when power on the electrical network is lost, either proactively or as the result of wildfire damage, a mobile generator unit can be dispatched to provide power. The generator is transported via tractor trailer to a specific location based on real-time circumstances. For example, a mobile generator may be dispatched by the Emergency Operations Center to mitigate the impact of a proactive de-energization, as discussed in greater detail in the Public Safety Power Shutoff section below. There are constraints in connecting the generator, and each deployment is examined on a case-by-case basis.

Water Truck Resources

PacifiCorp has water trucks that field operations use to mitigate against wildfire risk. For clarity, these resources are not dispatched to reported fires (i.e., like a fire truck). Instead, PacifiCorp resources are strategically assigned to accompany field personnel if conditions warrant. For example, if it is necessary to perform work in high-risk locations during a period in which there is a Red Flag Warning, PacifiCorp field operations may schedule a water truck to join field personnel working in the field. As discussed above, the water truck can be used to help prep the site for work. By watering down dry vegetation in the work area, any chance of an ignition can be minimized. In the extremely unlikely event there was an ignition, the water truck could be used to assist in the suppression of a small fire. Field operations currently has eight water trucks for use in such applications. In addition, the company plans to purchase two water trucks and one trailer.

Transmission-Based Reliability

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

With the increasing number of variable resources added to the grid throughout the west, PacifiCorp's ability to meet federal reliability directives depends increasingly on an interconnected transmission system across the western states and on the ability to move electricity throughout the six states served by the company. PacifiCorp's planning process ensures that the company is developing a portfolio that balances sufficient supply to serve all PacifiCorp customers with sufficient resources and transmission to ensure that electricity can be moved from generation sources to the communities served.

PacifiCorp's interconnection to other balancing authority areas and participation in the Energy Imbalance Market provide access to markets and promote affordable and reliable service to PacifiCorp's customers. Further, PacifiCorp's transmission capacity provides benefits to customers by increasing reliability and allowing additional generation to interconnect to serve customer load, as well as allowing PacifiCorp flexibility in designing generating resources for reserve capacity to comply with mandatory reliability standards.

Federal Reliability Standards

The Energy policy Act of 2005 included expanded reliability-related elements of the federal regulatory structure and directed the FERC to institute mandatory reliability standards that all users of the bulk electric system (BES) must follow.

FERC delegated the authority to NERC to develop reliability standards to ensure the safe and reliable operation of the BES in the United States under a variety of operating conditions. These standards are a federal requirement and are subject to oversight and enforcement by the WECC, NERC, and FERC. PacifiCorp is subject to compliance audits every three years and may be required to prove compliance during other reliability initiatives or investigations.

The transmission planning standards (TPL Standards), found within the NERC transmission reliability standards, specify that transmission system planning performance requirements to develop a BES that will operate reliably over a broad spectrum of system conditions. They also require study of a wide range of probable contingencies in both short-term (1-2 years) and long-term (10 year) scenarios to ensure system reliability. Together with regional planning criteria, such as those established by the NERC/WECC, and utility-specific planning criteria, the TPL Standards define the minimum transmission system requirements to safely and reliably serve customers.

In addition to the TPL Standards, PacifiCorp is also required to comply with FERC Order 1000 and completed per Attachment K of the Open Access Transmission Tariff (OATT) which requires PacifiCorp to participate in regional transmission planning processes that satisfy the transmission planning principles of FERC Order 890 and produces a regional transmission plan. To meet this requirement PacifiCorp is a member of the NorthernGrid regional planning association. The development of the regional transmission plan ensures the regional reliability is maintained and/or enhanced with the addition of new planned generation and transmission projects while reliably serving PacifiCorp customers.

Power Flow Analyses and Planning for Generator Retirements

PacifiCorp transmission planning has performed various coal unit retirement assessments analyzing potential impacts to the transmission system. These studies are performed outside of the IRP process under PacifiCorp's OATT processes which includes either 1) a customer request to perform a consulting study; or 2) a customer request to un-designate a network resource which then triggers a system impact and facilities study.

Past studies have found that a number of factors are critical in determining transmission system impacts and necessary mitigation, if any. These factors include: 1) location of the unit(s) to be retired, 2) the number of units being retired, 3) the size of the units being retired, 4) year of retirement, and 5) location, size, and type of replacement resources, if any. Based on the location, number of units, and size of the retired unit/s, studies can identify if the retirement results in either thermal or voltage issues on the transmission system. A retirement of a coal unit may result in voltage issues due to lack of reactive support that was previously provided by the retired unit/s. A retirement may also result in thermal overload of the transmission system due to changes in the flows post unit retirement. As such, until official notification to PacifiCorp transmission of coal unit undesignation/retirement is received, all such coal retirement analysis is considered preliminary.

Transmission Investment to Support Reliability, Resiliency and Ongoing Investment in Renewables

The 2021 IRP includes the 416-mile long 500-kV GWS transmission line from the Aeolus substation near Medicine Bow, WY to Clover substation near Mona, Utah. The construction of GWS directly connects eastern Wyoming to central Utah while enhancing the reliability throughout the PacifiCorp-served regions. Connecting into the Mona/Clover market hub provides additional flexibility in the use of least-cost resources from eastern Wyoming or southern Utah to serve customer load.

The addition of GWS improves reliability in PacifiCorp served regions by relieving the stress on the transmission system in the respective areas due to additional transmission in the area. For example, the addition of the GWS line in Wyoming relieves the stress on the underlying 230-kV transmission system while improving the reliability in that region. Similarly, the addition of the GWS line in the central Utah area unloads the underlying 345-kV transmission system improving reliability in that region. Essentially the 500-kV line brings two distant areas close to each other while maintaining the regional reliability. Utah and the surrounding system will benefit from both completion of the Gateway Central transmission projects as with increased transfer capability and increased resilience during outage conditions.

In addition to the GWS, PacifiCorp is also planning to construct the 56-mile-long 230-kV D.1 transmission line from Windstar substation near Glen Rock, WY to Shirley Basin substation near Medicine Bow, WY. This line provides a new transmission path allowing for renewable resources development in the area. The addition of this line improves the reliability of the transmission system during certain identified outage conditions (Dave Johnston to Amasa 230-kV outage or Amasa – Shirley Basin 230-kV outage). Current generation interconnections with large generator interconnection agreements (LGIA) in eastern Wyoming show that the D.1 is a prerequisite for connecting these new resources. Information for those resources can be found on PacifiCorp's OASIS web site, under queue numbers; Q0713, 0783, 0784, 0785, 0801, 0802, 0807, 0835 and 0836.

CHAPTER 6 – LOAD AND RESOURCE BALANCE

CHAPTER HIGHLIGHTS

- On both a capacity and energy basis, PacifiCorp calculates load and resource balances from existing resources, forecasted loads and sales, and reserve requirements. The capacity balance compares existing resource capability across all hours in both the summer and winter.
- Capacity assessment across more than the coincident peak is necessary due to the evolution of the company's portfolio to include more wind, solar, and storage resources. Solar in particular provides significant output during the summer coincident peak, but no output in many other summer hours. As a result, summer risks cannot easily be identified by looking at load alone. Instead, PacifiCorp evaluated the resources available relative to the expected load in every hour, and the hour with the lowest resources as a percentage of the hourly load in each season determines the planning reserve margin (PRM) achieved for that season in that year.
- The company's load obligation is calculated based on projected load less private generation, energy efficiency savings, and demand response, including interruptible load.
- A 2020 Private Generation Long-Term Resource Assessment (2021-2040) study prepared by Guidehouse Consulting, Inc. produced estimates on private generation penetration levels specific to PacifiCorp's six-state territory. The study provided expected penetration levels by resource type, along with high and low penetration sensitivities. PacifiCorp's 2021 IRP load and resource balance treats base case private generation penetration levels as a reduction in load.
- After accounting for a minimum 13 percent PRM target, load growth, coal unit retirements from the preferred portfolio, plus accounting for the level of potential market purchases (front office transactions, or FOTs) assumed in the 2021 IRP, and after incorporating future energy efficiency savings from the preferred portfolio, PacifiCorp's system is capacity deficient (before adding proxy resources) over both the summer and winter peaks throughout the twenty-year planning period.
- The uncertainty in the company's load and resource balance is increasing as PacifiCorp's resource portfolio and customer demand evolve over time. While PacifiCorp took steps to better reflect the relationship between renewable resources and load in the 2021 IRP, uncertainty remains, particularly with regard to the frequency and characteristics of the relatively extreme conditions that are most likely to trigger reliability shortfalls.

Introduction

This chapter presents PacifiCorp's assessment of its load and resource balance. PacifiCorp's long-term load forecasts (both energy and coincident peak load) for each state and the system as a whole are summarized in Volume II, Appendix A (Load Forecast Details). The summary-level system coincident peak is presented first, followed by a profile of PacifiCorp's existing resources. Finally, load and resource balances for capacity and energy are presented. These balances are composed of a year-by-year comparison of projected loads against the existing resource base, with and without available FOTs, assumed coal unit retirements and incremental new energy efficiency savings from the 2021 IRP preferred portfolio, before adding new generating resources.

System Coincident Peak Load Forecast

The system coincident peak load is the annual maximum hourly load on the system. The 2021 IRP relies on PacifiCorp's June 2020 load forecast. Table 6.1 shows the annual summer coincident peak load stated in megawatts (MW) as reported in the capacity load and resource balance before any load reductions from energy efficiency and private generation. The system summer peak load grows at a compound growth rate (CAGR) of 0.85 percent over the period 2021 through 2040.

Table 6.1 – Forecasted System Summer Coincident Peak Load in Megawatts, Before Energy Efficiency and Private Generation (MW)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
System	10,447	10,646	10,824	10,947	11,089	11,022	11,107	11,227	11,338	11,470
	2031	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
System	11,615	11,748	11,879	12,005	12,141	12,094	12,206	12,345	12,148	12,270

Existing Resources

Thermal Plants

Table 6.2 lists PacifiCorp's existing coal-fueled plants and Table 6.3 lists existing natural-gas-fueled plants. The "Retirement Year" reflects the year a resource retires or converts to natural gas as reflected in the preferred portfolio.

Table 6.2 – Coal-Fueled Plants

Plant	PacifiCorp Percentage Share (%)	State	Gas Conversion/ Retirement Year	Nameplate Capacity (MW)
Colstrip 3	10	Montana	2025	74
Colstrip 4	10	Montana	2025	74
Craig 1	19	Colorado	2025	82
Craig 2	19	Colorado	2028	79
Dave Johnston 1	100	Wyoming	2027	99
Dave Johnston 2	100	Wyoming	2027	106
Dave Johnston 3	100	Wyoming	2027	220
Dave Johnston 4	100	Wyoming	2027	330
Hayden 1	24	Colorado	2028	44
Hayden 2	13	Colorado	2027	33
Hunter 1	94	Utah	2042	418
Hunter 2	60	Utah	2042	269
Hunter 3	100	Utah	2042	471
Huntington 1	100	Utah	2036	459
Huntington 2	100	Utah	2036	450
Jim Bridger 1	67	Wyoming	2024/2037	354
Jim Bridger 2	67	Wyoming	2024/2037	359
Jim Bridger 3	67	Wyoming	2037	349
Jim Bridger 4	67	Wyoming	2037	351
Naughton 1	100	Wyoming	2025	156
Naughton 2	100	Wyoming	2025	201
Wyodak	80	Wyoming	2039	268
TOTAL – Coal				**5,246**

Table 6.3 – Natural-Gas-Fueled Plants

Natural Gas -fueled	PacifiCorp Percentage Share (%)	State	Assumed End of Life Year	Nameplate Capacity (MW)
Chehalis	100	Washington	2043	491
Currant Creek	100	Utah	2045	545
Gadsby 1	100	Utah	2032	64
Gadsby 2	100	Utah	2032	69
Gadsby 3	100	Utah	2032	105
Gadsby 4	100	Utah	2032	40
Gadsby 5	100	Utah	2032	40
Gadsby 6	100	Utah	2032	40
Hermiston	100	Oregon	2036	234
Lake Side 1	100	Utah	2047	551
Lake Side 2	100	Utah	2054	644
Naughton 3	100	Wyoming	2029	247
TOTAL – Natural Gas				**3,070**

Renewable Resources

Wind

PacifiCorp either owns or purchases under contract 3,811 MW of wind resources.
Table 6.4 shows existing wind facilities owned by PacifiCorp, while Table 6.5 shows existing wind power-purchase agreements (PPAs).

Table 6.4 – Owned Wind Resources

Utility-Owned Wind Projects	State	Capacity (MW)
Cedar Springs II	WY	200
Dunlap 1	WY	111
Ekola Flats 1	WY	250
Foote Creek I	WY	41
Glenrock I	WY	99
Glenrock III	WY	39
Goodnoe Hills East	WA	94
High Plains	WY	99
Leaning Juniper	OR	101
Marengo I	WA	156
Marengo II	WA	78
McFadden Ridge 1	WY	29
Pryor Mountain	MT	240
Rolling Hills	WY	99
Seven Mile Hill	WY	99
Seven Mile Hill II	WY	20
TB Flats	WY	500
TOTAL – Owned Wind		**2,255**

Table 6.5 – Non-Owned Wind Resources

Power Purchase Agreements / Exchanges	PPA or QF	State	Capacity (MW)
Big Top ORWF	QF	OR	2.0
BLM Rawlins	QF	WY	0.1
Butter Creek Power ORWF	QF	OR	5.0
Cedar Springs III	PPA	WY	133.0
Cedar Springs PPA	PPA	WY	199.0
Chopin	QF	OR	10.0
Combine Hills	PPA	OR	41.0
Four Corners ORWF	QF	OR	10.0
Four Mile Canyon ORWF	QF	OR	10.0
J Bar Ranch	QF	WY	0.1
Latigo	QF	UT	60.0
Meadow Creek Project - North Point	QF	ID	80.0
Meadow Creek Project Five Pine	QF	ID	40.0
Mountain Power I	QF	WY	61.0
Mountain Power II	QF	WY	80.0
Orchard Wind 1	QF	OR	10.0
Orchard Wind 2	QF	OR	10.0
Orchard Wind 3	QF	OR	10.0
Orchard Wind 4	QF	OR	10.0
Oregon Trail ORWF	QF	OR	10.0
Pacific Canyon ORWF	QF	OR	8.0
Pioneer Park I	QF	WY	80.0
Power County Park North	QF	ID	23.0
Power County Park South	QF	ID	23.0
Rock River I	PPA	WY	50.0
Sand Ranch ORWF	QF	OR	10.0
Spanish Fork Park 2	QF	UT	19.0
Stateline	Exchange	WA	175.0
Three Buttes Power (Duke)	PPA	WY	99.0
Three Mile Canyon	QF	OR	10.0
Tooele	QF	UT	1.5
Tooele	QF	UT	1.7
Top of the World	PPA	WY	200.0
Wagon Trail ORWF	QF	OR	3.0
Ward Butte ORWF	QF	OR	7.0
Wolverine Creek	PPA	ID	65.0
TOTAL - Purchased Wind			**1,556.4**

Solar

PacifiCorp has a total of 73 solar projects under contract representing 2,340 MW of nameplate capacity.

Table 6.6 – Non-Owned Solar Resources

Power Purchase Agreements / Exchanges	PPA or QF	State	Capacity (MW)
Adams	QF	OR	10.0
Appaloosa Solar IA	PPA	UT	120.0
Appaloosa Solar IB	PPA	UT	80.0
BC Solar	QF	OR	8.0
Bear Creek	QF	OR	10.0
Beryl	QF	UT	3.0
Black Cap	PPA	OR	2.0
Bly	QF	OR	8.0
Buckhorn	QF	UT	3.0
Captain Jack	QF	OR	3.0
Castle Solar (Retail 1)	PPA	UT	20.0
Castle Solar (Retail 2)	PPA	UT	20.0
Cedar Valley	QF	UT	3.0
Chiloquin	QF	OR	10.0
Cove Mountain	PPA	UT	58.0
Cove Mtn II	PPA	UT	122.0
eBay	QF	UT	0.5
Elbe	QF	OR	10.0
Elektron Solar 20Yr	PPA	UT	10.0
Elektron Solar 25Yr	PPA	UT	70.0
Enterprise	QF	UT	80.0
Escalante I	QF	UT	80.0
Escalante II	QF	UT	80.0
Escalante III	QF	UT	80.0
Granite Mountain - East	QF	UT	80.0
Granite Mountain - West	QF	UT	50.0
Granite Peak	QF	UT	3.0
Graphite	PPA	UT	80.0
Greenville	QF	UT	2.0
Horseshoe Solar	PPA	UT	75.0
Hunter	PPA	UT	100.0
Iron Springs	QF	UT	80.0
Klamath Falls Solar 1	QF	UT	1.0
Klamath Falls Solar 2	QF	UT	3.0
Laho	QF	UT	3.0
Milford	PPA	UT	99.0
Milford2	QF	UT	3.0
Milford Flat	QF	UT	3.0
Millican Solar Energy, LLC	PPA	OR	60.0
NW2_Neff	QF	OR	10.0
NW4_Bonanza	QF	OR	6.0
NW7_EaglePoint	QF	OR	10.0
NW9_Pendleton	QF	OR	6.0
Old Mill	PPA	OR	5.0
OR2_AgateBay	QF	OR	10.0
OR3_TurkeyHill	QF	OR	10.0

Power Purchase Agreements / Exchanges	PPA or QF	State	Capacity (MW)
OR5_Merrill	QF	OR	8.0
OR6_Lakeview	QF	OR	10.0
OR8_Dairy	QF	OR	10.0
OSLH Collier	QF	OR	10.0
Pavant	QF	UT	50.0
Pavant II LLC	QF	UT	50.0
Pavant III LLC	PPA	UT	20.0
Prineville	PPA	OR	40.0
Quichapa I	QF	UT	3.0
Quichapa II	QF	UT	3.0
Quichapa III	QF	UT	3.0
Red Hills	QF	UT	80.0
Rocket	PPA	UT	80.0
Sage I	QF	WY	20.0
Sage II	QF	WY	20.0
Sage III	QF	WY	18.0
Sigurd	PPA	UT	80.0
Skysol	QF	OR	55.0
Solarize Rogue LLC (OR Community Solar)	QF	OR	0.1
South Milford	QF	UT	3.0
SunE1	QF	UT	3.0
SunE2	QF	UT	3.0
SunE3	QF	UT	3.0
Sweetwater	QF	WY	80.0
Three Peaks	QF	UT	80.0
Tumbleweed	QF	OR	10.0
Woodline	QF	OR	8.0
TOTAL – Purchased Solar			**2339.6**

Geothermal

PacifiCorp owns and operates the Blundell geothermal plant in Utah, which uses naturally created steam to generate electricity. The plant has a net generation capacity of 34 MW. Blundell is a fully renewable, zero-discharge facility. The bottoming cycle, which increased the output by 11 MW, was completed at the end of 2007. The Oregon Institute of Technology added a new small qualifying facility (QF) using geothermal technologies to produce renewable power for the campus that is rated at 0.28 MW. PacifiCorp also has a power purchase agreement with the 20 MW Soda Lake geothermal project located in Nevada, which became operational in November 2019.

Biomass/Biogas

PacifiCorp has biomass/biogas agreements with 12 projects totaling approximately 80 MW of nameplate capacity.

Renewables Net Metering

Table 6.7 provides a breakdown of net metered capacity and customer counts from data collected as of August 16, 2021.

Table 6.7 – Net Metering Customers and Capacity

Fuel	Solar	Wind	Gas[1/]	Hydro	Mixed[2/]
Nameplate (kW)	570,106	853	884	965	1,217
Capacity (percentage of total)	99.32%	0.15%	0.15%	0.17%	0.21%
Number of customers	65,582	194	4	21	62
Customer (percentage of total)	99.57%	0.29%	0.01%	0.03%	0.09%

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

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

Hydroelectric Generation

PacifiCorp owns 1,135 MW of hydroelectric generation capacity and purchases the output from 89 MW of other hydroelectric resources. These resources provide operational benefits such as flexible generation, spinning reserves and voltage control. PacifiCorp-owned hydroelectric plants are located in California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah.

The amount of electricity PacifiCorp is able to generate or purchase from hydroelectric plants is dependent upon a number of factors, including the water content of snowpack accumulations in the mountains upstream of its hydroelectric facilities and the amount of precipitation that falls in its watershed. Operational limitations of the hydroelectric facilities are affected by varying water levels, licensing requirements for fish and aquatic habitat, and flood control, which lead to load and resource balance capacity values that are different from net facility capacity ratings.

Hydroelectric purchases are categorized into two groups, as shown in Table 6.8.

Table 6.8 – Hydroelectric Contracts

Hydroelectric Contracts by Load and Resource Balance Category		L&R Balance Capacity at System Peak (MW)
Hydroelectric		193
Qualifying Facilities - Hydroelectric		88
Total Contracted Hydroelectric Resources		**280**

Table 6.9 provides the capacity for each of PacifiCorp's owned hydroelectric generation facilities.

Table 6.9 – PacifiCorp Owned Hydroelectric Generation Facilities –Capacities

Plant	River System	State	Capacity (MW)
East			
Ashton	Bear	UT	8
Cutler	Bear	UT	30
Grace	Bear	UT	33
Lifton	Bear	UT	1
Oneida	Bear	UT	30
Soda	Bear	UT	14
PCM - North*	-	UT	9
PCM - South**	-	UT	1
West			
Bend	-	OR	4
Bigfork	Lewis	MT	4
Swift 1	Lewis	WA	240
Swift 2	Lewis	WA	70
Yale	Lewis	WA	134
Merwin	Lewis	WA	136
Copco 1	Klamath	OR/CA	20
Copco 2	Klamath	OR/CA	27
Iron Gate	Klamath	OR/CA	18
JC Boyle	Klamath	OR/CA	98
Clear Water 1	Umpqua	OR	15
Clear Water 2	Umpqua	OR	26
Fish Creek	Umpqua	OR	11
Lemolo 1	Umpqua	OR	29
Lemolo 2	Umpqua	OR	33
Slide Creek	Umpqua	OR	18
Soda Springs	Umpqua	OR	11
Toketee	Rogue	OR	43
Eagle Point	Rogue	OR	3
Prospect 1	Rogue	OR	5
Prospect 2	Rogue	OR	36
Prospect 3	Rogue	OR	7
Prospect 4	Rogue	OR	1
Fall Creek	-	OR	4
Wallowa Falls	-	OR	1
TOTAL – Hydroelectric before contracts			**1118**
Hydroelectric Contracts			**280**
TOTAL – Hydroelectric			**1398**

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

2/ Includes Bend, Fall Creek, and Wallowa Falls

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

Demand-Side Management

For resource planning purposes, PacifiCorp classifies demand-side management (DSM) resources into four categories. These resources are captured through programmatic efforts that promote efficient electricity use through various intervention strategies, aimed at changing energy use during peak periods (load control), timing (price response and load shifting), intensity (energy efficiency), or behaviors (education and information). The four categories include:

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

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

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

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

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

Table 6.10 summarizes PacifiCorp's existing DSM programs, their assumed impact, and how they are treated for purposes of incremental resource planning. Note that since incremental energy efficiency is determined as an outcome of resource portfolio modeling and is characterized as a new resource in the preferred portfolio, existing energy efficiency in Table 6.10 is shown as having zero MW.[1] For a summary of current DSM program offerings in each state, refer to Volume II, Appendix D (Demand-Side Management Resources).

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

Table 6.10 – Existing DSM Resource Summary

Program Class	Description	Energy Savings or Capacity at Generator	Included as Existing Resources for 2021-2040 Period
1	Residential/small commercial air conditioner load control	124 MW summer peak	Yes.
	Irrigation load management	205 MW summer peak	Yes.
	Interruptible contracts	191 MW summer peak	Yes.
2	PacifiCorp and Energy Trust of Oregon programs	0 MW[1/]	No. Class 2 DSM programs are modeled as resource options in the portfolio development process and included in the preferred portfolio.
3	Time-based pricing	Energy and capacity impacts are not available/measured	No. Historical savings from customer responses to pricing signals are reflected in the load forecast.
	Inverted rate pricing	Energy and capacity impacts are not available/measured	No. Historical savings from customer response to pricing structure is reflected in load forecast.
4	Energy education	Energy and capacity impacts are not available/measured	No. Historical savings from customer participation are reflected in the load forecast.

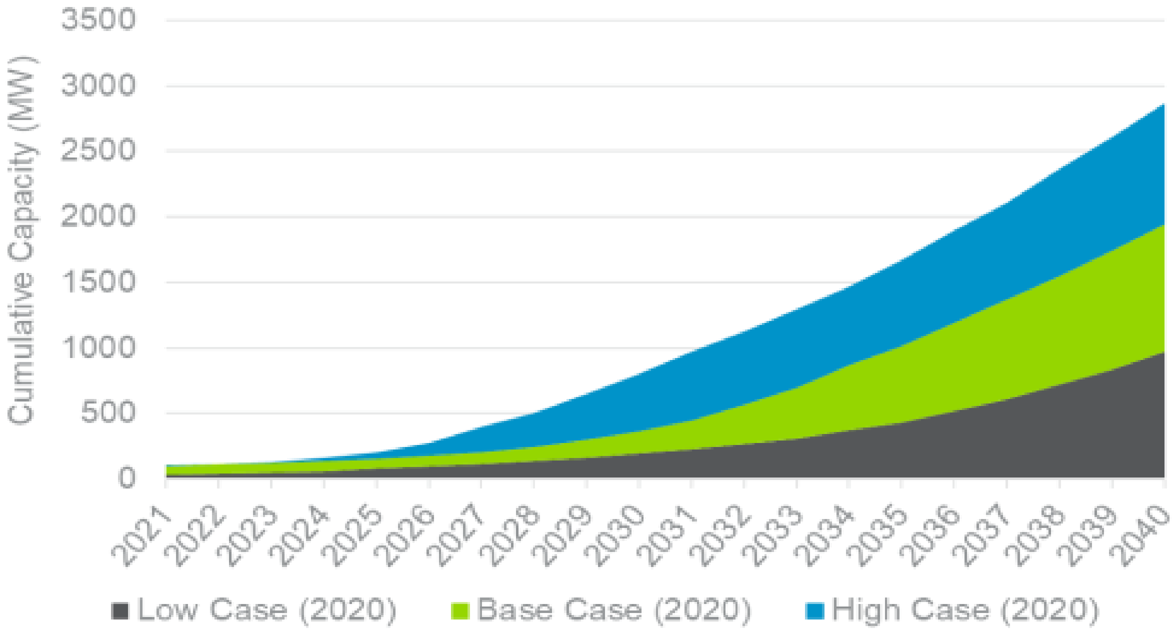
[1/] Due to the timing of the 2021 IRP load forecast, there is a small amount (68 MW) of existing Class 2 DSM in Table 6.12 (System Capacity Loads and Resources without Resource Additions).

Private Generation

For the 2021 IRP, PacifiCorp contracted with Guidehouse to update the assessment of private generation (PG) penetration performed for the 2021 IRP with new market and incentive developments. The study provided a forecast of adoption for each private generation resource in each of the six states served by PacifiCorp. Specific technologies studied included solar photovoltaic, small-scale wind, small-scale hydro, and combined heat and power (CHP) for both reciprocating engines and micro-turbines.

Guidehouse estimates approximately 1.74 gigawatts (GW) of PG capacity will be installed in PacifiCorp's territory from 2021-2040 in the base case scenario. As shown in **Figure 6.1**, the low and high scenarios project a cumulative installed capacity of 0.82 GW and 2.66 GW by 2040, respectively. The main drivers between the different scenarios include variation in technology costs, system performance, and electricity rate assumptions. The Guidehouse study identifies expected levels of customer-sited private generation, which is applied as a reduction to PacifiCorp's forecasted load for IRP modeling purposes.

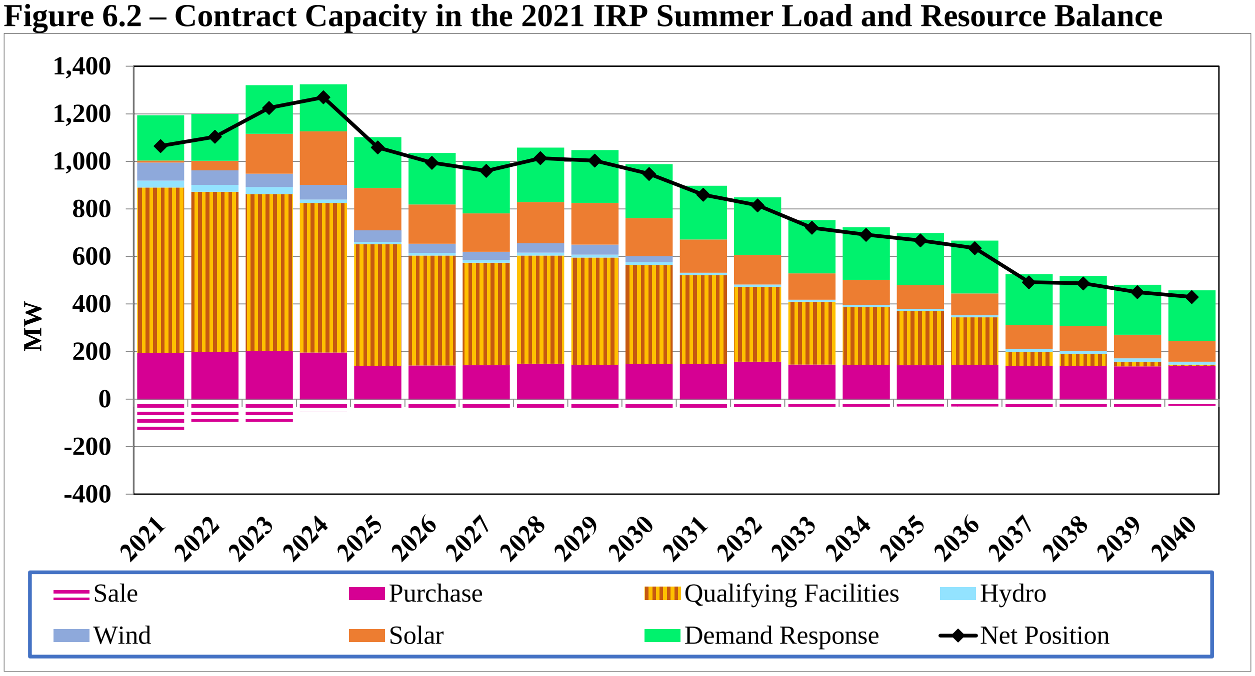
Figure 6.1 – Private Generation Market Penetration (MWAC), 2021-2040



Power-Purchase Agreements

PacifiCorp obtains the remainder of its capacity and energy requirements through long-term firm contracts, short-term firm contracts, and spot market purchases. Figure 6.2 presents the contract capacity in place for 2021 through 2040. As shown, major capacity reductions in wind purchases and QF contracts occur. For planning purposes, PacifiCorp assumes interruptible load contracts are extended through the end of the IRP study period. The renewable wind contracts are shown at their capacity contribution levels.

Figure 6.2 – Contract Capacity in the 2021 IRP Summer Load and Resource Balance



Load and Resource Balance

Capacity and Energy Balance Overview

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

The capacity balance compares generating capability to load obligations across both summer and winter. In the past, the coincident peak load hour was almost always the hour with the lowest margin, because the available resource output was comparable in the peak load hour and in other hours. With the significant penetration of solar resource in PacifiCorp's portfolio, the hour with the lowest margin is no longer readily identifiable from load alone, as solar resources have high availability during the peak load hour but no availability a few hours later when loads are slightly lower. Wind, storage, hydro, and other resources further complicate the calculation. In light of this, for the 2021 IRP, PacifiCorp evaluated the balance of generating capability and load obligations not just during the coincident peak load hour, but across all hours, to identify the winter and summer hours in each year with the lowest margin as a percentage of load. Under this method, the reported planning reserve margin is necessarily met in the coincident peak load hour, but the hour with the lowest margin generally coincides with a period of relatively high load and relatively low renewable resource output.

For reporting purposes, the capacity balance summarized in this chapter is developed by first reducing the hourly system load by hourly private generation projections to determine the net system coincident peak load for each of the first ten years (2021-2030) of the planning horizon. Interruptible load programs, existing load reduction DSM programs, and new load reduction DSM programs from the preferred portfolio at the time of the net system coincident peak are further netted from the peak load forecast to compute the annual peak-hour obligation. Then the annual firm capacity availability of the existing resources, reflecting assumed coal unit retirements from the preferred portfolio, is determined. The annual resource deficit or surplus is then computed by multiplying the obligation by the capacity reserve margin (13% for the 2021 IRP) and then subtracting the result from existing resources. This view is presented both without and with uncommitted FOTs.

The energy balance shows the average monthly surplus or deficit of energy over the first ten years of the planning horizon (2021-2030). The average obligation (load less existing DSM programs, new DSM programs from the preferred portfolio, and projected private generation) is computed and subtracted from the average existing resource availability for each month. The usefulness of the energy balance is limited because it does not address the cost of the available energy. The economics of adding resources to the system to meet both capacity and energy needs are addressed during the resource portfolio development process described in Chapter 8 (Modeling and Portfolio Evaluation Approach).

Load and Resource Balance Components

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

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

Existing Resources

A description of the resource categories follows:

Thermal

This category includes all thermal plants that are wholly owned or partially owned by PacifiCorp. The capacity balance counts these plants at their expected availability (after derating for forced outages and maintenance) weighted based on the expected timing of resource shortfalls during summer or winter periods. The energy balance also counts them at expected availability but includes all hours in the year. This includes the existing fleet of coal-fueled units, and six natural-gas-fueled plants. Presently, these thermal resources account for roughly two thirds of the firm capacity available in the PacifiCorp system.

All Other Resources

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. During the 2021 IRP, PacifiCorp identified that capacity contribution values for wind and solar would vary based on the penetration levels of these resources, as well as the composition of the rest of a portfolio, in particular the level of storage capability. To account for these effects, PacifiCorp performed a reliability analysis on every portfolio that was developed to ensure that the combination of resources achieved a targeted level of reliability. PacifiCorp also recognizes that other resources whose expected output varies over the course of each year are also impacted by portfolio changes.

For the purpose of reporting the capacity contribution of all other resources in the load and resource balance, PacifiCorp first calculated the contribution of long-duration dispatchable resources in the portfolio, using the methodologies described above. The remaining capacity in the load and resource balance, up to PacifiCorp's thirteen percent planning reserve margin, is attributable to the rest of the resources in PacifiCorp's portfolio. This remaining capacity was allocated based on each resource's hourly available generation during the hours in each winter or summer season when load exceeded the availability of long-duration dispatchable resources, and was allocated pro-rata among all resources delivering during such hours. It should be noted that while allocation of capacity among resources as described in this section is helpful for presenting a load and resource balance, the allocation to specific resources has no bearing on the reliability or economics of the preferred portfolio, which reflects the coordinated dispatch of all available resources in every hour of the year. The economics of resource additions are more closely aligned with marginal or "last-in" capacity contribution estimates, which are generally lower for resources whose output is positively correlated with other resources already present in the portfolio. For estimates of marginal capacity contribution values, please refer to Volume II, Appendix K (Capacity Contribution).

Sales

Contracts for the sale of firm capacity and energy are treated the same as all other resources, except that they have a negative capacity value. The energy balance counts them by expected model dispatch.

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, existing demand response, and interruptible contracts. The following are descriptions of each of these components:

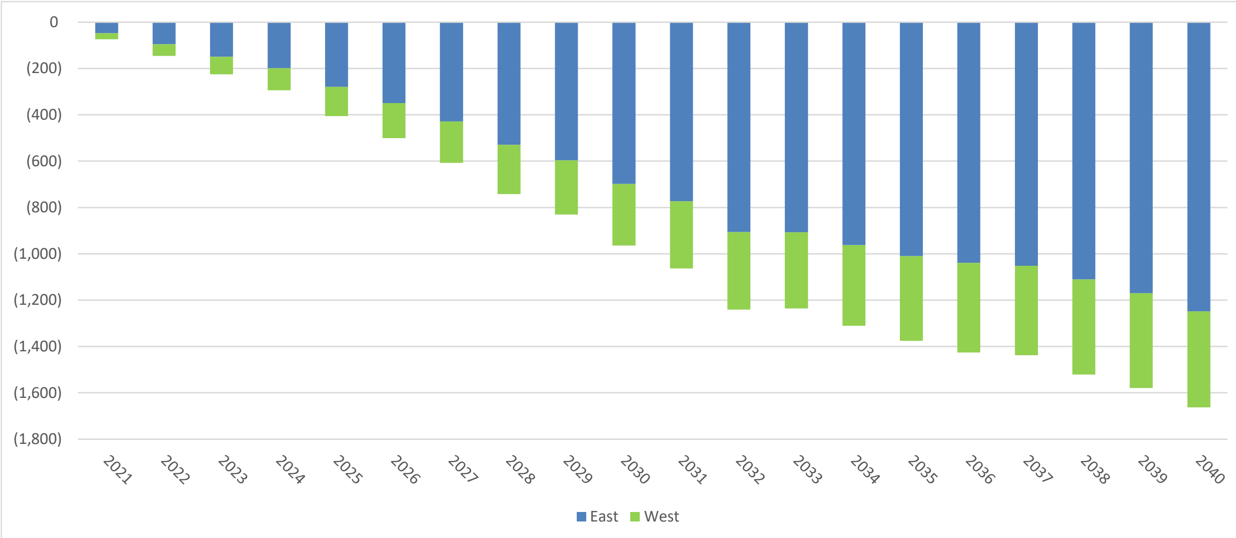
Load Net of Private Generation

The largest component of the obligation is retail load. In the 2021 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 and season. Loads reported by east and west BAAs thus reflect loads at the time of PacifiCorp's coincident system summer and winter peaks. The energy balance counts the average load on a monthly basis. For simplicity, load net of private generation is referred to as load in the following sections.

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 2020 energy efficiency that is not incorporated in the forecast. The 2020 energy efficiency forecast (73 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 2021 IRP preferred portfolio. Figure 6.3 shows the energy efficiency for the east and west control areas in the 2021 IRP preferred portfolio.

Figure 6.3 – Energy Efficiency Peak Contribution in Summer Capacity Load and Resource Balance (reduction to load, in MW)



Demand Response (Class 1 DSM)
Existing demand response program capacity is categorized as a reduction to peak load. Also included in the demand response category are interruptible contracts. PacifiCorp has had interruptible contracts for approximately 177 MW of load interruption capability for many years. These contracts are a key aspect of the retail service provided to the associated customers, and absent these contracts their demand would likely be different from that included in the load forecast. To maintain an alignment with the load forecast, these contracts are assumed to continue indefinitely under their current structure.

Planning Reserve Margin
Planning reserve margin (PRM) represents an incremental capacity 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 – Firm Sales

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 – Demand Response – 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 PRM adopted for the 2021 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 + Planning Reserves)

Capacity Balance Results

Table 6.11 and Table 6.12 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 6.11 -- Summer Peak – System Capacity Loads and Resources without Resource Additions

East	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Thermal	5,478	5,466	5,429	5,425	5,459	5,044	5,002	4,293	4,182	3,953
Hydroelectric	86	86	85	69	56	52	51	56	57	52
Renewable	668	690	815	912	709	676	661	718	743	676
Purchase	193	197	202	195	138	141	142	148	143	147
Qualifying Facilities	537	521	515	488	396	357	344	364	372	346
Sale	(20)	(20)	(20)	0	0	0	0	0	0	0
East Existing Resources	**6,943**	**6,940**	**7,026**	**7,090**	**6,758**	**6,271**	**6,201**	**5,580**	**5,498**	**5,174**
Load	7,096	7,246	7,380	7,475	7,583	7,492	7,550	7,643	7,728	7,833
Private Generation	(51)	(72)	(81)	(84)	(87)	(90)	(96)	(106)	(119)	(136)
Existing - Demand Response	(520)	(538)	(558)	(538)	(583)	(592)	(598)	(623)	(604)	(619)
Existing - Energy Efficiency	(43)	(45)	(46)	(45)	(49)	(49)	(50)	(52)	(50)	(52)
New Energy Efficiency	(48)	(95)	(149)	(199)	(280)	(349)	(429)	(529)	(597)	(698)
East Total obligation	**6,434**	**6,495**	**6,546**	**6,609**	**6,586**	**6,411**	**6,377**	**6,333**	**6,358**	**6,328**
Capacity Reserve Margin (13%)	836	844	851	859	856	833	829	823	827	823
East Obligation + Reserves	7,271	7,340	7,397	7,468	7,442	7,244	7,206	7,157	7,185	7,151
East Position	(327)	(400)	(371)	(378)	(684)	(974)	(1,005)	(1,577)	(1,687)	(1,977)
Available Front Office Transactions	0	0	0	0	0	0	0	0	0	0
West										
Thermal	2,139	2,165	2,168	2,144	2,149	2,019	2,015	2,014	2,036	2,035
Hydroelectric	577	567	521	508	407	386	380	420	423	390
Renewable	194	177	185	184	148	139	140	144	144	134
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	158	153	145	141	116	105	87	91	79	71
Sale	(109)	(76)	(76)	(54)	(44)	(42)	(41)	(44)	(44)	(41)
West Existing Resources	**2,961**	**2,986**	**2,945**	**2,924**	**2,777**	**2,608**	**2,582**	**2,626**	**2,638**	**2,591**
Load	3,351	3,400	3,443	3,472	3,506	3,530	3,557	3,584	3,610	3,638
Private Generation	(23)	(39)	(51)	(56)	(60)	(65)	(71)	(78)	(86)	(96)
Existing - Demand Response	0	0	0	0	0	0	0	0	0	0
Existing - Energy Efficiency	(24)	(25)	(26)	(25)	(27)	(28)	(28)	(29)	(28)	(29)
New Energy Efficiency	(26)	(51)	(76)	(95)	(126)	(152)	(178)	(213)	(234)	(266)
West Total obligation	**3,278**	**3,286**	**3,290**	**3,297**	**3,293**	**3,286**	**3,280**	**3,264**	**3,262**	**3,247**
Capacity Reserve Margin (13%)	426	427	428	429	428	427	426	424	424	422
West Obligation + Reserves	3,704	3,713	3,718	3,725	3,721	3,713	3,707	3,689	3,686	3,669
West Position	(743)	(726)	(773)	(801)	(943)	(1,105)	(1,125)	(1,063)	(1,048)	(1,078)
Available Front Office Transactions	500	500	500	500	500	500	500	500	500	500
System										
Total Resources	9,904	9,927	9,971	10,014	9,535	8,879	8,783	8,206	8,136	7,764
Obligation	9,712	9,781	9,836	9,906	9,878	9,697	9,657	9,598	9,620	9,575
Planning Reserves (13%)	1,263	1,272	1,279	1,288	1,284	1,261	1,255	1,248	1,251	1,245
Obligation + Reserves	10,975	11,053	11,115	11,193	11,162	10,958	10,912	10,845	10,871	10,820
System Position	(1,071)	(1,126)	(1,144)	(1,179)	(1,627)	(2,079)	(2,130)	(2,639)	(2,735)	(3,056)
Available Front Office Transactions	500	500	500	500	500	500	500	500	500	500
Uncomitted FOTs to meet remaining Need	1,071	1,126	1,144	500	500	500	500	500	500	500
Net Surplus/(Deficit)	0	0	0	(679)	(1,127)	(1,579)	(1,630)	(2,139)	(2,235)	(2,556)

Table 6.11 (cont.) – Summer Peak System Capacity Loads and Resources without Resource Additions

East	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Thermal	3,945	3,955	3,629	3,607	3,613	3,613	2,765	2,759	2,757	2,491
Hydroelectric	47	43	40	40	40	40	57	63	64	58
Renewable	582	525	471	465	465	465	587	595	586	539
Purchase	146	157	145	144	142	144	138	137	136	138
Qualifying Facilities	310	266	220	204	192	162	34	29	12	0
Sale	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**5,031**	**4,947**	**4,505**	**4,459**	**4,452**	**4,424**	**3,582**	**3,583**	**3,555**	**3,226**
Load	7,938	8,041	8,138	8,232	8,336	8,343	8,413	8,520	8,390	8,488
Private Generation	(160)	(189)	(218)	(251)	(291)	(181)	(205)	(230)	(119)	(132)
Existing - Demand Response	(615)	(660)	(609)	(604)	(598)	(607)	(582)	(579)	(574)	(581)
Existing - Energy Efficiency	(51)	(55)	(51)	(50)	(50)	(51)	(48)	(48)	(48)	(48)
New Energy Efficiency	(773)	(906)	(907)	(962)	(1,009)	(1,039)	(1,052)	(1,111)	(1,170)	(1,248)
East Total obligation	**6,339**	**6,231**	**6,353**	**6,364**	**6,388**	**6,465**	**6,526**	**6,552**	**6,478**	**6,478**
Capacity Reserve Margin (13%)	824	810	826	827	830	840	848	852	842	842
East Obligation + Reserves	7,163	7,041	7,179	7,192	7,219	7,306	7,374	7,404	7,320	7,321
East Position	(2,132)	(2,094)	(2,674)	(2,732)	(2,767)	(2,882)	(3,792)	(3,821)	(3,766)	(4,094)
Available Front Office Transactions	0	0	0	0	0	0	0	0	0	0
West										
Thermal	2,027	2,021	2,024	2,023	2,023	2,031	1,807	456	456	456
Hydroelectric	355	323	301	299	296	298	435	483	485	446
Renewable	117	108	105	92	92	100	129	142	143	128
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	64	49	45	39	37	38	25	22	9	6
Sale	(38)	(34)	(32)	(32)	(32)	(31)	(34)	(32)	(32)	(28)
West Existing Resources	**2,527**	**2,468**	**2,443**	**2,422**	**2,417**	**2,435**	**2,364**	**1,072**	**1,061**	**1,009**
Load	3,676	3,707	3,740	3,773	3,805	3,752	3,793	3,825	3,758	3,782
Private Generation	(118)	(158)	(205)	(258)	(316)	(263)	(305)	(351)	(195)	(225)
Existing - Demand Response	0	0	0	0	0	0	0	0	0	0
Existing - Energy Efficiency	(29)	(31)	(28)	(28)	(28)	(28)	(27)	(27)	(27)	(27)
New Energy Efficiency	(289)	(334)	(329)	(348)	(366)	(388)	(386)	(410)	(409)	(414)
West Total obligation	**3,241**	**3,184**	**3,178**	**3,138**	**3,095**	**3,073**	**3,075**	**3,038**	**3,127**	**3,115**
Capacity Reserve Margin (13%)	421	414	413	408	402	399	400	395	407	405
East Obligation + Reserves	132	80	84	60	36	12	14	(15)	(2)	(9)
East Position	2,395	2,388	2,359	2,362	2,381	2,423	2,350	1,087	1,064	1,018
Available Front Office Transactions	500	500	500	500	500	500	500	500	500	500
System										
Total Resources	7,558	7,415	6,948	6,881	6,869	6,859	5,946	4,655	4,616	4,235
Obligation	9,580	9,415	9,531	9,502	9,483	9,538	9,601	9,590	9,606	9,593
Planning Reserves (13%)	1,245	1,224	1,239	1,235	1,233	1,240	1,248	1,247	1,249	1,247
Obligation + Reserves	10,825	10,639	10,770	10,737	10,716	10,778	10,849	10,836	10,854	10,841
System Position	(3,267)	(3,225)	(3,821)	(3,856)	(3,847)	(3,919)	(4,903)	(6,182)	(6,239)	(6,606)
Available Front Office Transactions	500	500	500	500	500	500	500	500	500	500
Uncomitted FOTs to meet remaining Need	500	500	500	500	500	500	500	500	500	500
Net Surplus/(Deficit)	(2,767)	(2,725)	(3,321)	(3,356)	(3,347)	(3,419)	(4,403)	(5,682)	(5,739)	(6,106)

Table 6.12 – Winter Peak System Capacity Loads and Resources without Resource Additions

East	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Thermal	5,478	5,383	5,540	5,364	5,550	5,057	5,143	4,229	4,140	3,835
Hydroelectric	50	52	46	43	30	31	29	39	42	42
Renewable	765	929	885	860	546	676	639	796	843	802
Purchase	173	169	167	158	115	116	120	125	110	113
Qualifying Facilities	204	225	192	213	105	136	123	208	227	233
Sale	(16)	(17)	(15)	0	0	0	0	0	0	0
East Existing Resources	**6,654**	**6,741**	**6,815**	**6,638**	**6,346**	**6,016**	**6,054**	**5,397**	**5,362**	**5,025**
Load	5,538	5,678	5,800	5,860	5,943	5,874	5,915	6,008	6,081	6,161
Private Generation	(0)	(1)	(2)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Existing - Demand Response	(239)	(251)	(255)	(252)	(255)	(258)	(267)	(277)	(246)	(251)
Existing - Energy Efficiency	(32)	(33)	(34)	(33)	(34)	(34)	(35)	(37)	(33)	(33)
New Energy Efficiency	(39)	(74)	(109)	(143)	(181)	(213)	(259)	(309)	(308)	(356)
East Total obligation	**5,229**	**5,320**	**5,400**	**5,429**	**5,470**	**5,366**	**5,349**	**5,379**	**5,488**	**5,512**
Capacity Reserve Margin (13%)	680	692	702	706	711	698	695	699	713	717
East Obligation + Reserves	5,908	6,011	6,102	6,135	6,181	6,064	6,045	6,079	6,202	6,229
East Position	746	730	713	504	165	(48)	10	(682)	(839)	(1,203)
Available Front Office Transactions	300	300	300	300	300	300	300	300	300	300
West										
Thermal	2,205	2,211	2,186	1,930	2,203	2,064	2,060	1,982	2,010	1,991
Hydroelectric	497	518	434	456	320	330	317	410	439	439
Renewable	105	75	69	86	56	63	52	84	92	95
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	53	50	45	54	37	36	19	39	36	33
Sale	(88)	(71)	(59)	(45)	(32)	(33)	(32)	(38)	(41)	(40)
West Existing Resources	**2,773**	**2,784**	**2,675**	**2,482**	**2,585**	**2,461**	**2,418**	**2,478**	**2,536**	**2,519**
Load	3,318	3,358	3,397	3,421	3,449	3,479	3,516	3,550	3,585	3,615
Private Generation	(0)	(0)	(1)	(1)	(1)	(1)	(2)	(2)	(3)	(3)
Existing - Demand Response	0	0	0	0	0	0	0	0	0	0
Existing - Energy Efficiency	(23)	(24)	(24)	(24)	(24)	(24)	(25)	(26)	(23)	(24)
New Energy Efficiency	(25)	(48)	(69)	(86)	(105)	(124)	(149)	(176)	(176)	(200)
West Total obligation	**3,270**	**3,286**	**3,304**	**3,311**	**3,319**	**3,329**	**3,340**	**3,345**	**3,384**	**3,387**
Capacity Reserve Margin (13%)	425	427	430	430	431	433	434	435	440	440
West Obligation + Reserves	400	379	3,734	3,741	3,750	3,761	3,774	3,780	3,824	3,828
West Position	2,373	2,404	(1,058)	(1,260)	(1,165)	(1,301)	(1,356)	(1,302)	(1,287)	(1,309)
Available Front Office Transactions	700	700	700	700	700	700	700	700	700	700
System										
Total Resources	9,427	9,525	9,490	9,120	8,930	8,477	8,472	7,875	7,898	7,544
Obligation	8,498	8,605	8,704	8,740	8,789	8,695	8,689	8,725	8,872	8,900
Planning Reserves (13%)	1,105	1,119	1,132	1,136	1,143	1,130	1,130	1,134	1,153	1,157
Obligation + Reserves	9,603	9,724	9,836	9,876	9,931	9,825	9,819	9,859	10,025	10,056
System Position	(176)	(199)	(345)	(756)	(1,001)	(1,348)	(1,347)	(1,984)	(2,127)	(2,512)
Available Front Office Transactions	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Uncomitted FOTs to meet remaining Need	176	199	345	756	1,000	1,000	1,000	1,000	1,000	1,000
Net Surplus/(Deficit)	0	0	0	0	(1)	(348)	(347)	(984)	(1,127)	(1,512)

Table 6.12 (cont.) – Winter Peak System Capacity Loads and Resources without Resource Additions

East	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Thermal	3,901	3,947	3,646	3,554	3,677	3,411	2,830	2,643	2,783	2,421
Hydroelectric	36	36	34	37	38	43	47	48	52	49
Renewable	665	662	620	668	703	752	782	756	832	778
Purchase	129	129	131	119	109	111	136	133	134	119
Qualifying Facilities	186	178	133	124	119	80	15	13	4	0
Sale	0	0	0	0	0	0	0	0	0	(0)
East Existing Resources	**4,917**	**4,952**	**4,563**	**4,501**	**4,647**	**4,397**	**3,811**	**3,592**	**3,806**	**3,368**
Load	6,240	6,328	6,415	6,517	6,595	6,672	6,407	6,504	6,589	6,682
Private Generation	(9)	(10)	(12)	(13)	(14)	(16)	(33)	(37)	(41)	(45)
Existing - Demand Response	(288)	(287)	(291)	(264)	(243)	(247)	(303)	(295)	(299)	(267)
Existing - Energy Efficiency	(38)	(38)	(39)	(35)	(32)	(33)	(40)	(39)	(40)	(35)
New Energy Efficiency	(446)	(480)	(513)	(494)	(481)	(504)	(659)	(695)	(758)	(726)
East Total obligation	**5,459**	**5,513**	**5,560**	**5,711**	**5,824**	**5,872**	**5,372**	**5,438**	**5,451**	**5,609**
Capacity Reserve Margin (13%)	710	717	723	742	757	763	698	707	709	729
East Obligation + Reserves	6,169	6,230	6,283	6,453	6,581	6,636	6,070	6,145	6,160	6,338
East Position	(1,252)	(1,277)	(1,720)	(1,952)	(1,935)	(2,239)	(2,260)	(2,553)	(2,354)	(2,970)
Available Front Office Transactions	300	300	300	300	300	300	300	300	300	300
West										
Thermal	2,076	2,053	2,032	2,080	2,072	2,025	1,808	489	490	490
Hydroelectric	373	374	351	388	406	448	481	487	536	503
Renewable	79	79	70	78	78	91	101	104	111	107
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	25	23	19	19	19	19	17	16	13	8
Sale	(35)	(34)	(32)	(34)	(36)	(38)	(32)	(29)	(32)	(30)
West Existing Resources	**2,519**	**2,496**	**2,442**	**2,531**	**2,540**	**2,545**	**2,376**	**1,068**	**1,119**	**1,078**
Load	3,643	3,681	3,721	3,760	3,797	3,826	4,271	4,322	4,375	4,425
Private Generation	(4)	(4)	(5)	(6)	(7)	(8)	(9)	(11)	(12)	(13)
Existing - Demand Response	0	0	0	0	0	0	0	0	0	0
Existing - Energy Efficiency	(27)	(27)	(28)	(25)	(23)	(23)	(29)	(28)	(28)	(25)
New Energy Efficiency	(252)	(271)	(293)	(283)	(276)	(293)	(372)	(385)	(409)	(369)
West Total obligation	**3,360**	**3,378**	**3,395**	**3,446**	**3,491**	**3,502**	**3,861**	**3,898**	**3,925**	**4,018**
Capacity Reserve Margin (13%)	437	439	441	448	454	455	502	507	510	522
East Obligation + Reserves	185	168	148	165	178	163	130	121	101	153
East Position	2,334	2,328	2,294	2,366	2,362	2,382	2,246	947	1,018	925
Available Front Office Transactions	700	700	700	700	700	700	700	700	700	700
System										
Total Resources	7,436	7,449	7,005	7,033	7,186	6,942	6,187	4,660	4,925	4,445
Obligation	8,819	8,891	8,955	9,157	9,315	9,374	9,234	9,336	9,377	9,627
Planning Reserves (13%)	1,146	1,156	1,164	1,190	1,211	1,219	1,200	1,214	1,219	1,251
Obligation + Reserves	9,966	10,047	10,119	10,347	10,526	10,593	10,434	10,550	10,595	10,878
System Position	(2,530)	(2,599)	(3,115)	(3,314)	(3,340)	(3,651)	(4,247)	(5,889)	(5,670)	(6,433)
Available Front Office Transactions	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Uncomitted FOTs to meet remaining Need	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Net Surplus/(Deficit)	(1,530)	(1,599)	(2,115)	(2,314)	(2,340)	(2,651)	(3,247)	(4,889)	(4,670)	(5,433)

Figure 6.4 through Figure 6.7 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 7 (Resource Options).

Figure 6.4 – Summer System Capacity Position Trend

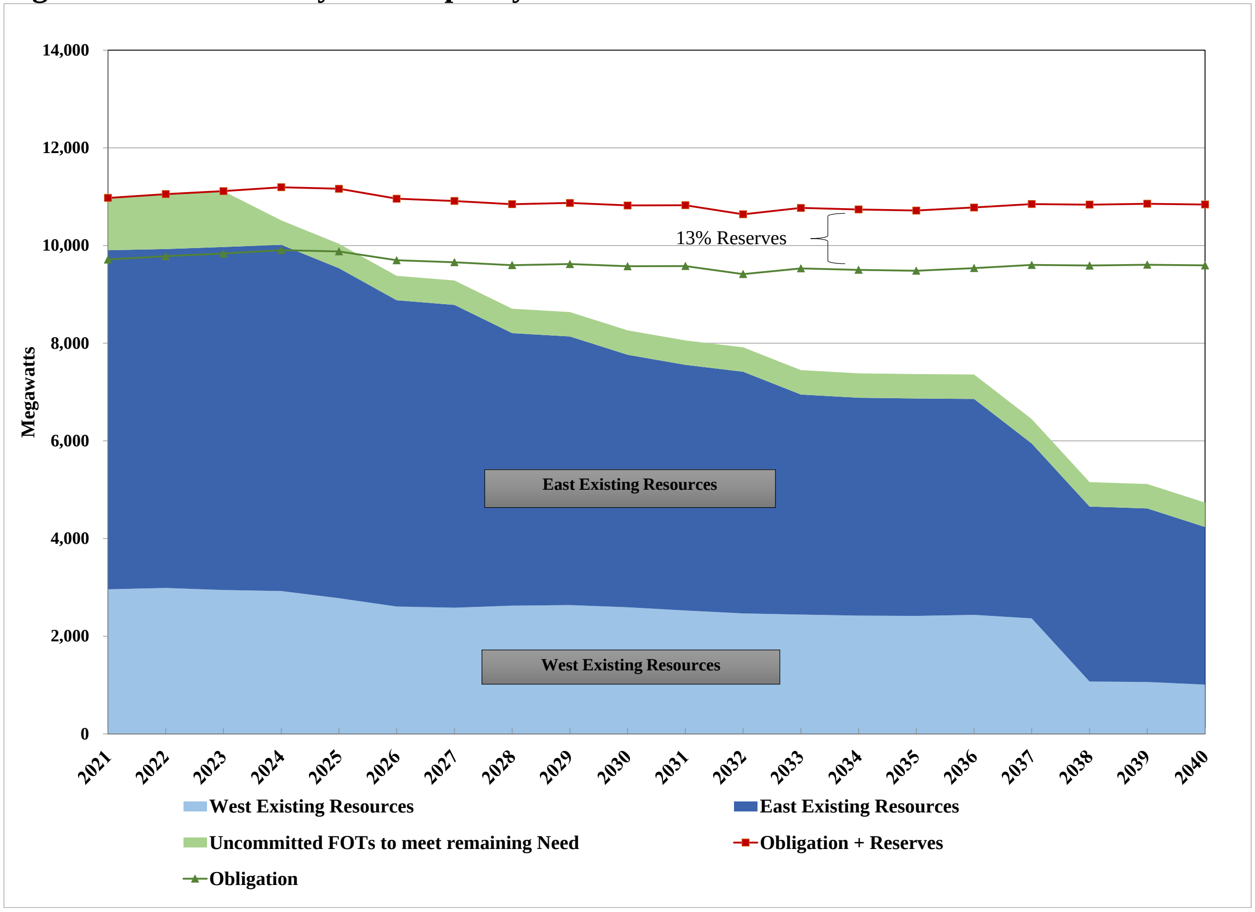


Figure 6.5 – Winter System Capacity Position Trend

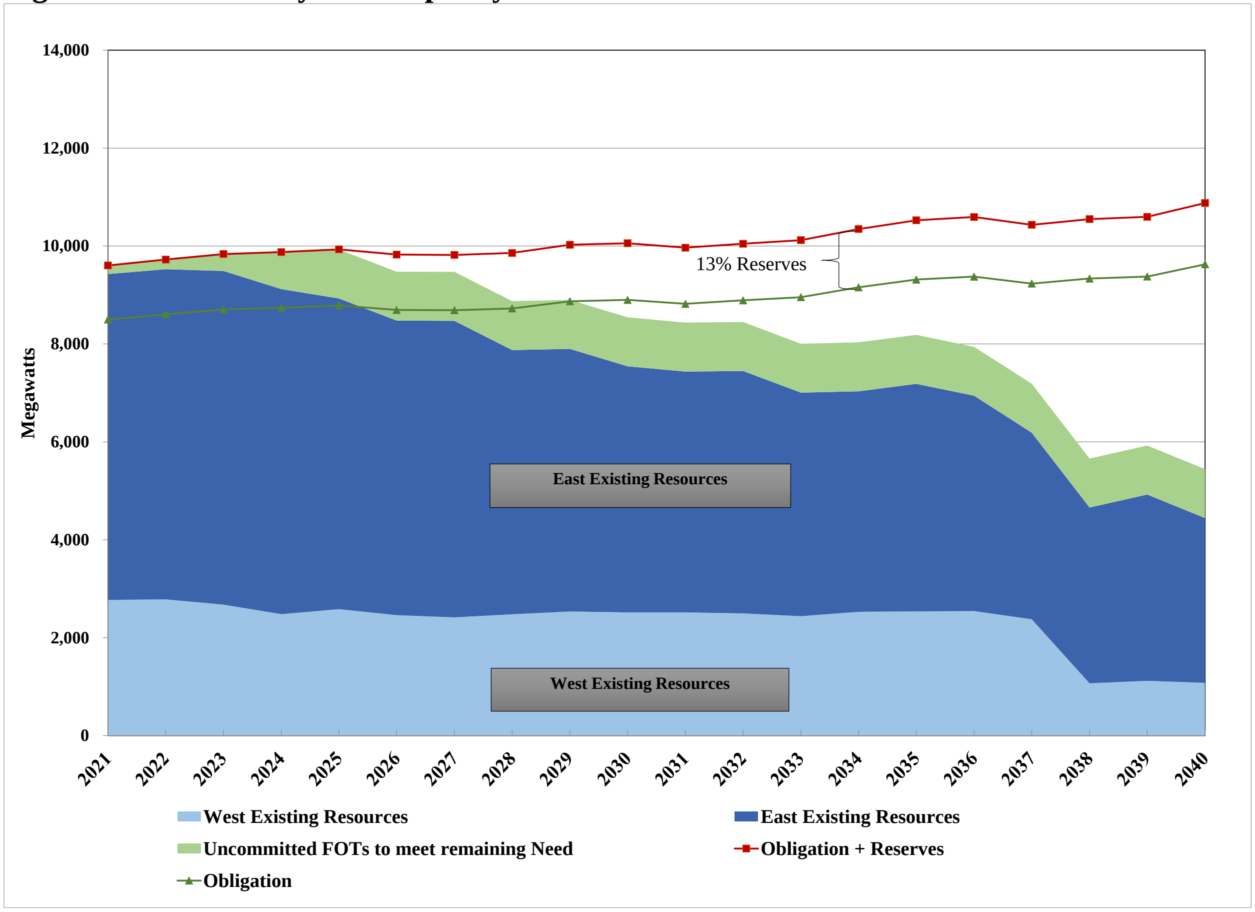


Figure 6.6 – East Summer Capacity Position Trend

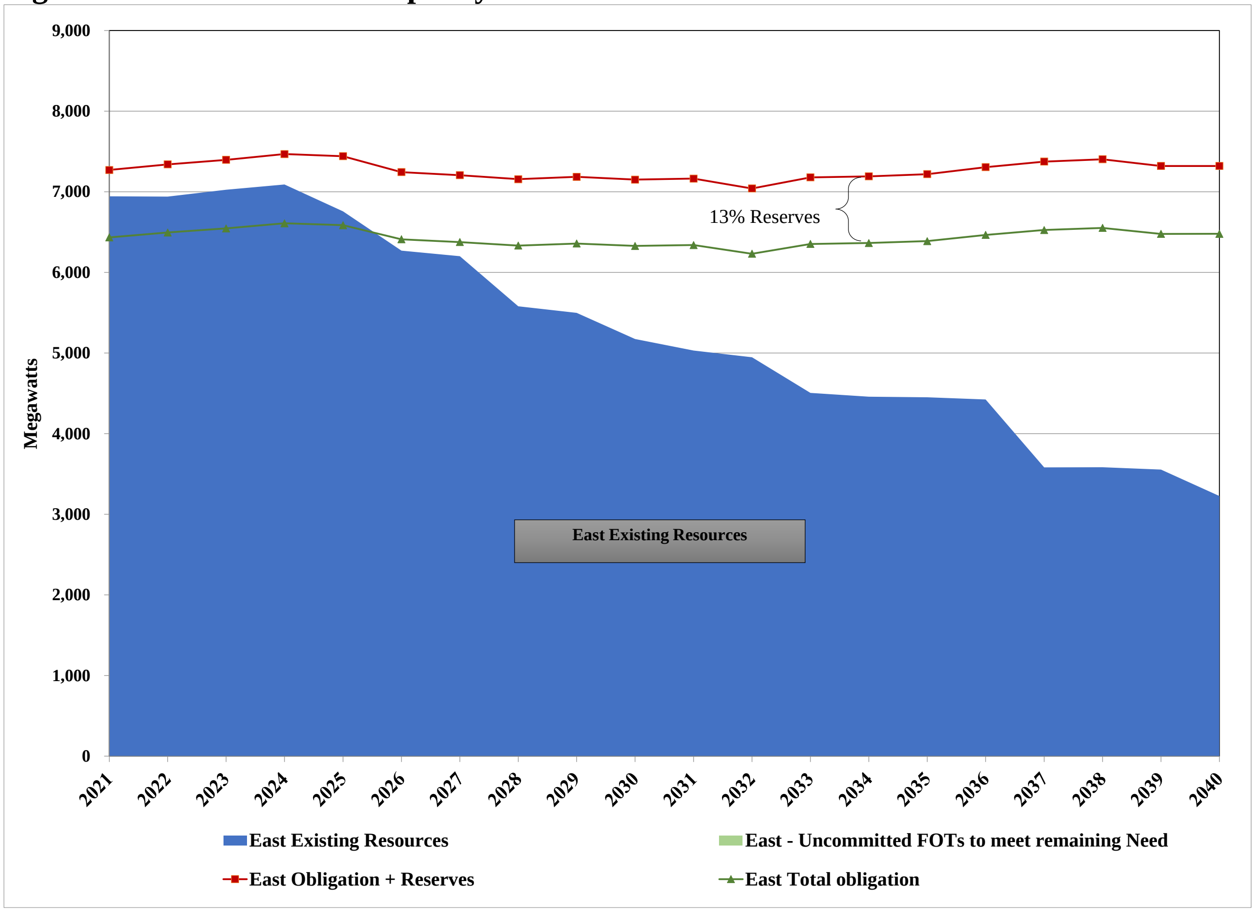
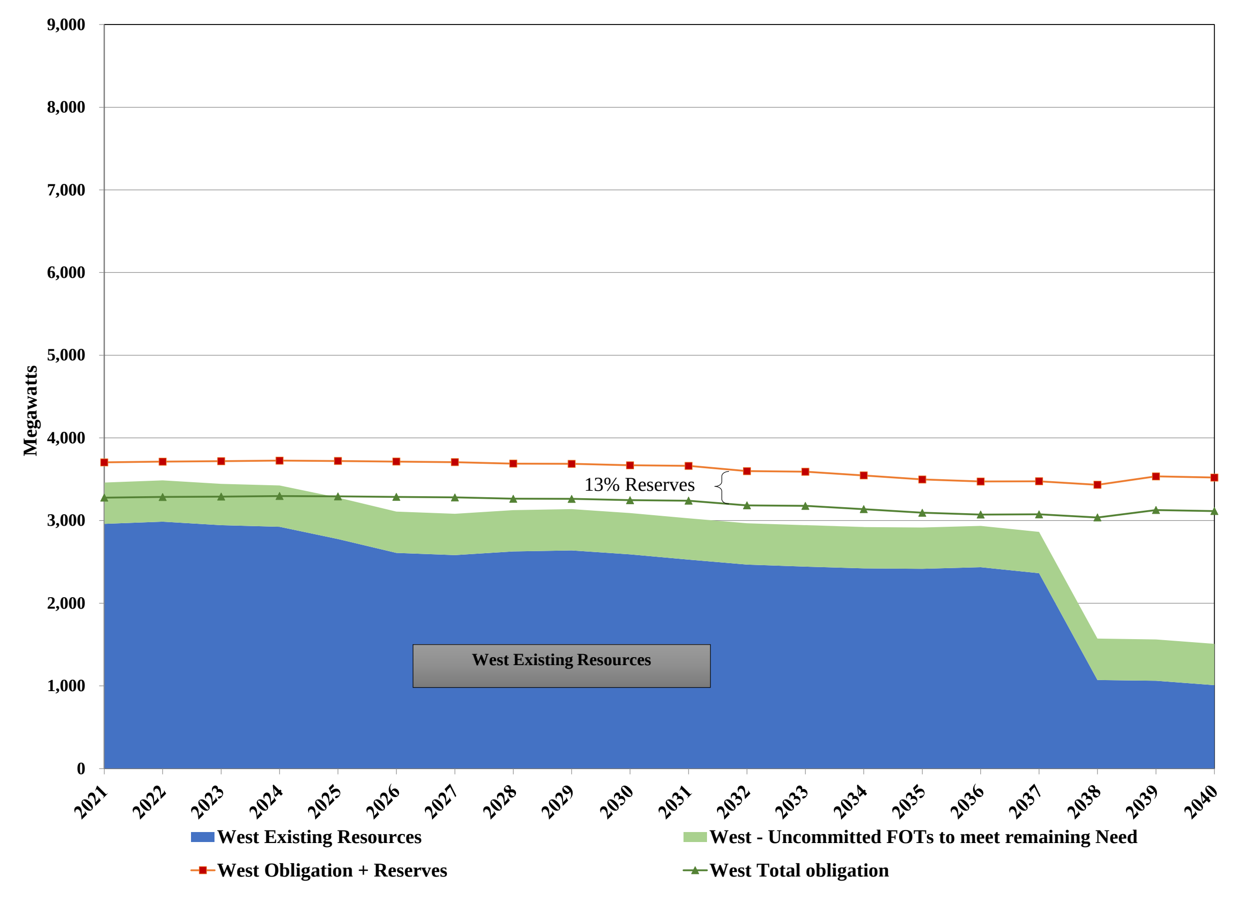


Figure 6.7 – West Summer Capacity Position Trend



Energy Balance Determination

Methodology

The energy balance shows the monthly surplus or (deficit) of energy. 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 + Renewable + Firm Purchases + QF – Sales

The average obligation is computed using the following formula:

Obligation = Load + Firm Sales

The energy position by month is then computed as follows:

Energy Position = Existing Resources – Obligation – Operating Reserve Requirements

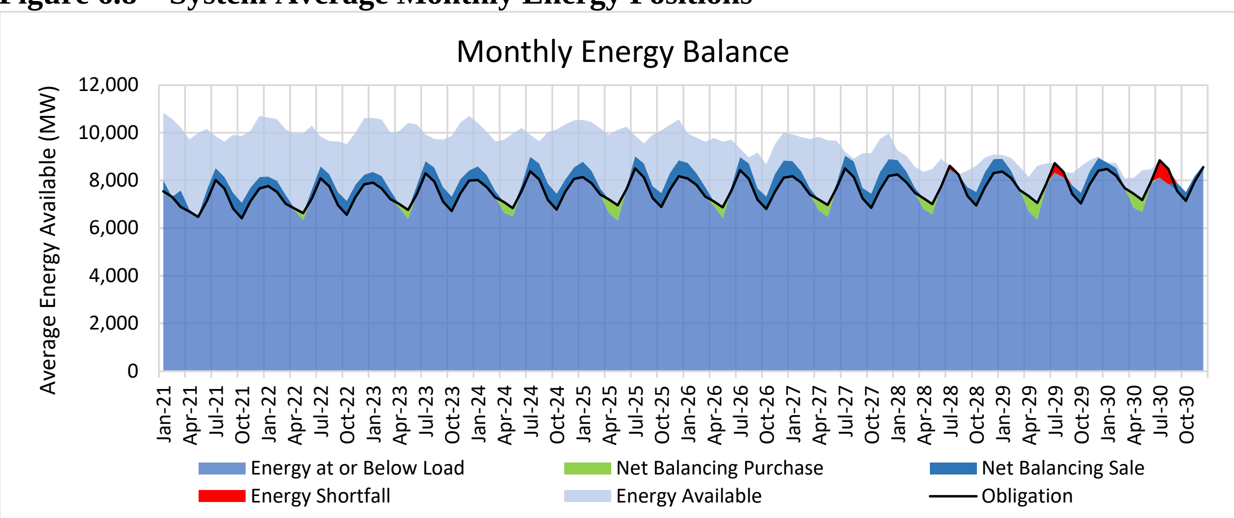
Operating Reserve Requirements include spinning and non-spinning reserves, but not regulation reserves, which are expected to be close to energy neutral over time. As duration-limited resources such as batteries become a larger portion of the Company's portfolio, less of the potential output of thermal resources is likely to be needed to meet Operating Reserve requirements. In addition, energy storage resources represent a net load, due to their roundtrip efficiency. For the 2021 IRP, storage resources are not included in the energy balance.

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 6.8 provides a snapshot of how existing system resources could be used to meet forecasted load across on-peak and off-peak periods given the assumptions about resource availability and wholesale power and natural gas prices. At times, resources are economically dispatched above load levels facilitating net system balancing sales. At other times, economic conditions result in net system balancing purchases, which occur more often during on-peak periods. Figure 6.8 also shows how much energy is available from existing resources at any given point in time. Those periods where all available resource energy falls below forecasted loads are highlighted in red, and indicate short energy positions without the addition of incremental resources to the portfolio.

Figure 6.8 – System Average Monthly Energy Positions



CHAPTER 7 – 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.
- 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.
- The Plexos model is able to endogenously model transmission upgrades.
- 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 reflects 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 2019 IRP. Wind and transmission resources were updated based upon market and performance data gained from construction of the Energy Vision 2020 project that came out of the 2017 IRP. 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 were updated to include 100 MW and 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. Combustion turbine types and configurations remained unchanged 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.[1] carbon capture and sequestration (CCS) retrofit costs were updated using cost data from existing carbon capture facilities, studies and CCS developers. New super critical pulverized coal-fueled 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 2019 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 (2020) third-party engineering cost and performance estimates;
- Original equipment manufacturers operation and maintenance estimates;
- Developer 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; and
- Projected PacifiCorp or electric utility industry installations, providing projected construction/maintenance costs and performance data of similar or identical resource options.

Black and Veatch and original equipment manufacturers provided estimated capital costs, operating and maintenance costs, performance, operating characteristics and planned outage cycles for simple cycle and combined cycle resources. Carbon capture, utilization and sequestration (CCUS) costs, revenues, and performance were estimated from existing carbon capture facilities, studies and CCUS developers. For this IRP cycle, Burns & McDonnell provided information for solar, wind, and energy storage resources. The Burns & McDonnell study builds upon prior 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

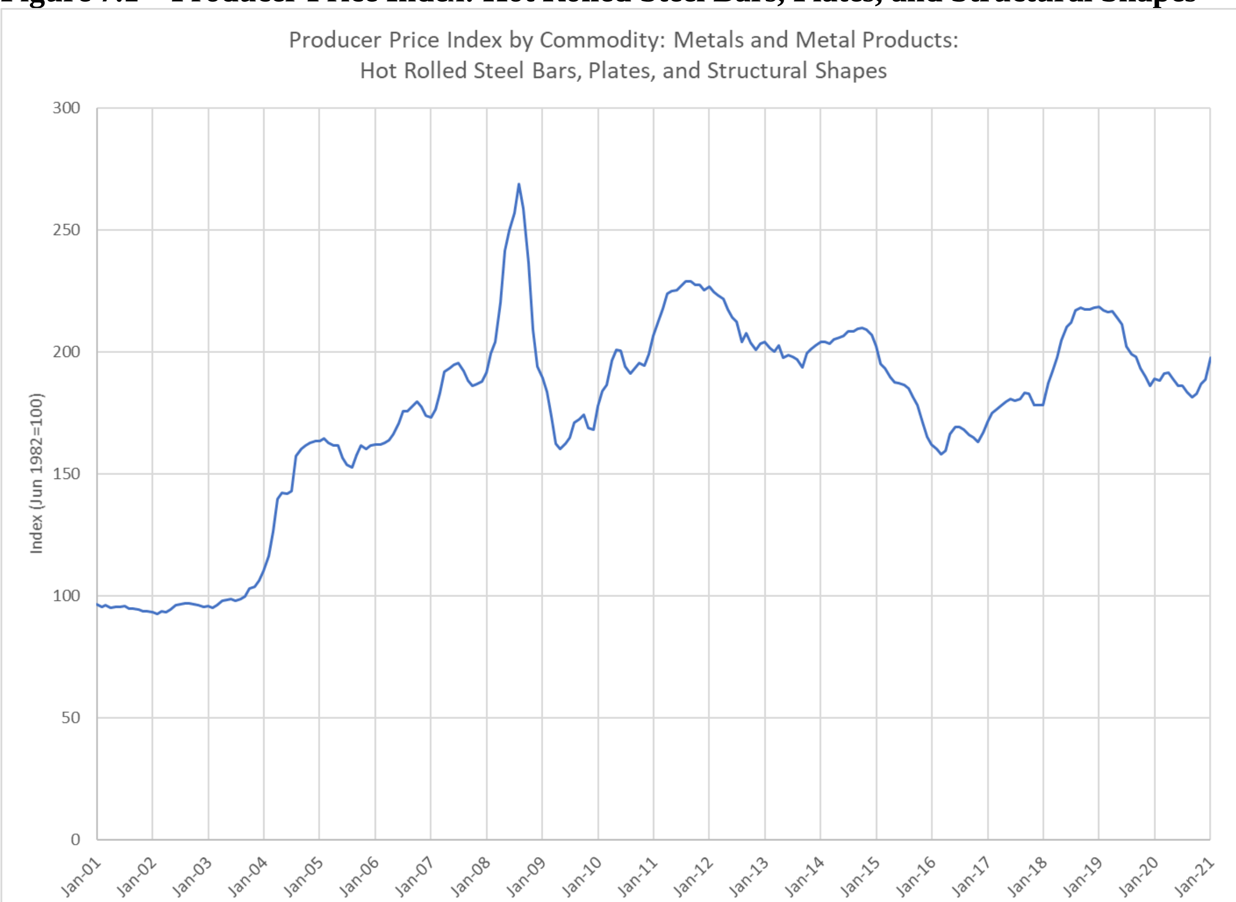
[1] While cost-and-performance metrics for gas-fired resources are presented in this chapter, PacifiCorp ultimately did not allow new gas-fired resources in its portfolio selection process. Please refer to Chapter 8 for a discussion of the risks PacifiCorp considered when making this planning assumption. A sensitivity case will be developed that enables new gas-fired proxy resources.

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.

Handling of Technology Improvement Trends and Cost Uncertainties

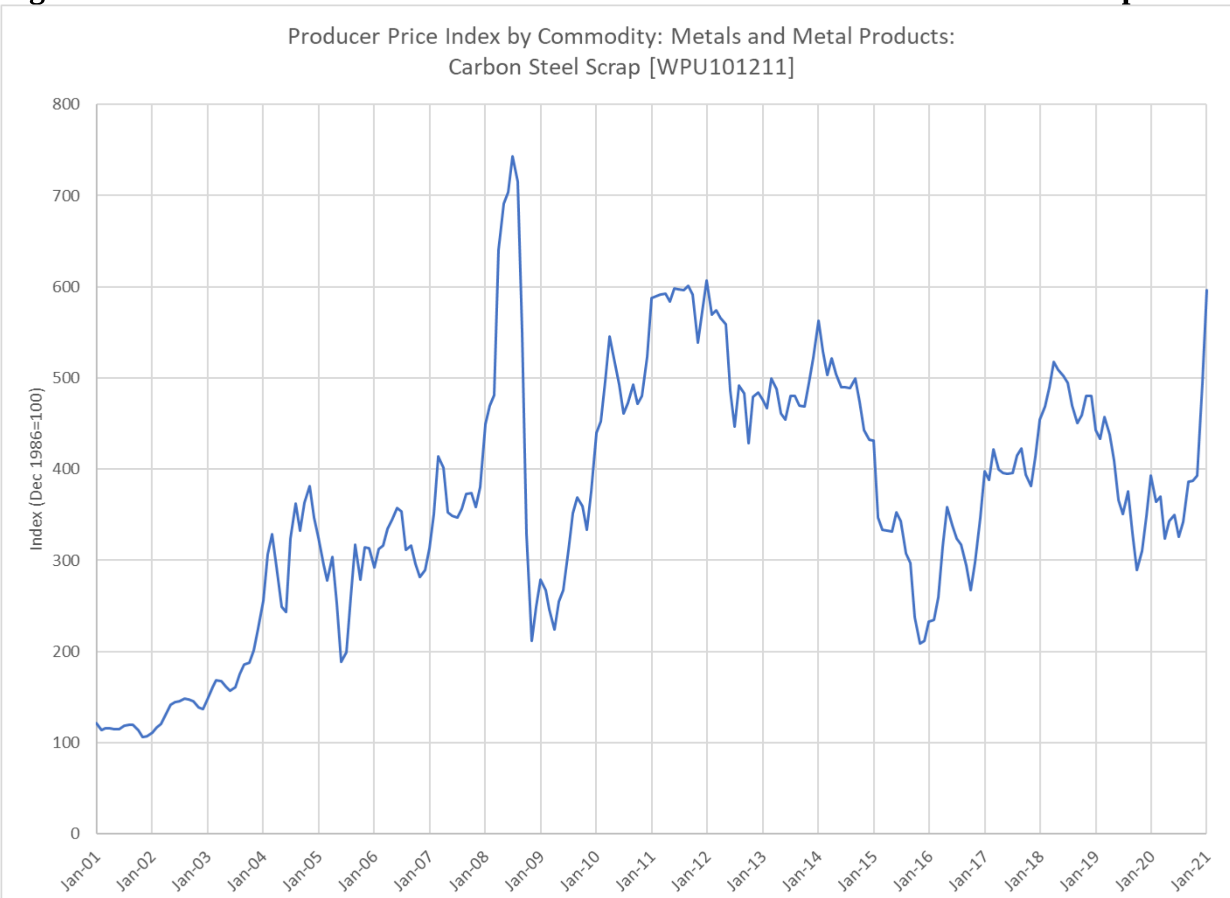
The capital cost uncertainty for some generation technologies is relatively high. Various factors contribute to this uncertainty including limited quantity and quality of data sets for new and emerging technologies that have been demonstrated at utility scale. Despite this uncertainty, the cost profile between the 2019 IRP and the 2021 IRP has not changed significantly. For example, Figure 7.1 shows the trend in U.S. steel prices over the period from January 2001 through January 2021. This figure illustrates changes in capital costs of generation resources. The 2021 IRP includes demolition costs for the first time. Demolition costs are impacted by the salvage of metals, including steel. Figure 7.2 shows the trend in U.S. carbon steel scrap and illustrates the uncertainty in demolition costs.

Figure 7.1 – Producer Price Index: Hot Rolled Steel Bars, Plates, and Structural Shapes[2]



[2] U.S. Bureau of Labor Statistics, Producer Price Index by Commodity: Metals and Metal Products: Hot Rolled Steel Bars, Plates, and Structural Shapes [WPU101704], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/WPU101704, June 13, 2021.

Figure 7.2 – Producer Price Index: Metals and Metal Products: Carbon Steel Scrap[3]



Prices for solar PV modules and balance of plant costs have been re-baselined since the 2019 IRP as described later in this chapter. 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 2021 IRP anticipates the cost of new solar projects to decline approximately five percent per year during next ten 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), as well as CCUS technologies, have shown significant cost uncertainty because only a few units have been built and operated. For example, experience with 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. Where carbon capture is dependent on revenues from enhanced oil recovery (EOR) to offset costs, the volatility in the price of oil adds an additional level of uncertainty. For example, declining oil prices caused NRG Energy's Petra Nova carbon capture facility to cease operation. The loss of revenue at Petra Nova illustrates the added uncertainty of recovering costs through carbon dioxide sales. As these technologies mature and more facilities are proven at commercial scale, the associated costs may decrease.

[3] U.S. Bureau of Labor Statistics, Producer Price Index by Commodity: Metals and Metal Products: Carbon Steel Scrap [WPU101211], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/WPU101211, June 14, 2021.

The potential to provide reduced, reliable capital and operating cost estimates is limited by the number of installed and successfully operated resources. Reliable cost and performance estimates are not expected to be realized until the next generation of new plants are built and successfully operated. 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.

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 recent RFPs.

Wind annual capital cost escalation rates are based on estimates provided by Burns and McDonnell and costs and market information obtained by PacifiCorp during the development and construction of recent wind projects. All other resources are assumed to escalate at inflation.

Resource Options and Attributes

Table 7.1 lists the cost-and-performance attributes for supply-side resource options designated by generic, elevation-specific regions where resources could potentially be located:

- 0 feet elevation: 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.

Table 7.2 and Table 7.3 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 2020 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, and 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 7.4 and Table 7.5.

Table 7.1 – 2021 Supply-Side Resource Table (2020$)

Description		Resource Characteristics				Costs				Operating Characteristics				Environmental			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Demolition Cost ($/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	0	169	2025	30	$ 1,463	$ 10	$ 7.44	$ -	9350	2.6	3.9	43.6234	0.0006	0.0090	0.2550	117.0000
Natural Gas	Intercooled SCCT Aero x2	0	227	2025	30	$ 1,126	$ 10	$ 5.03	$ -	8800	2.9	3.9	27.0223	0.0006	0.0090	0.2550	117.0000
Natural Gas	SCCT Frame "F" x1	0	239	2025	35	$ 699	$ 10	$ 14.16	$ -	9913	2.7	3.9	28.4484	0.0006	0.0090	0.2550	117.0000
Natural Gas	Brownfield SCCT Frame "F" x1	0	239	2025	35	$ 674	$ 10	$ 14.16	$ -	9913	2.7	3.9	28.4484	0.0006	0.0090	0.2550	117.0000
Natural Gas	IC Recips x 6	0	111	2026	40	$ 1,938	$ 12	$ 10.39	$ -	8286	2.5	5.0	27.1363	0.0006	0.0288	0.2550	117.0000
Natural Gas	CCCT Dry "H", 1x1	0	422	2026	40	$ 1,396	$ 10	$ 1.77	$ -	6343	2.5	3.8	23.5973	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", DF, 1x1	0	51	2026	40	$ 470	$ -	$ 0.05	$ -	8838	2.5	3.8	22.9547	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", 2x1	0	842	2027	40	$ 1,019	$ 10	$ 1.71	$ -	6361	2.5	3.8	20.1038	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", DF, 2x1	0	102	2027	40	$ 357	$ -	$ 0.05	$ -	8665	2.5	3.8	19.7926	0.0006	0.0072	0.2550	117.0000
Natural Gas	Brownfield CCCT Dry "H", DF, 2x1	0	842	2027	40	$ 1,019	$ 10	$ 1.08	$ -	6610	2.5	3.8	19.7926	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", 1x1	0	615	2026	40	$ 1,065	$ 10	$ 1.48	$ -	6264	2.5	3.8	20.3774	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", DF, 1x1	0	63	2026	40	$ 397	$ -	$ 0.06	$ -	8769	2.5	3.8	20.1033	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", 2x1	0	1,232	2027	40	$ 787	$ 10	$ 1.43	$ -	6251	2.5	3.8	17.8997	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", DF, 2x1	0	126	2027	40	$ 309	$ -	$ 0.06	$ -	8704	2.5	3.8	17.8427	0.0006	0.0072	0.2550	117.0000
Natural Gas	SCCT Aero x3	1,500	159	2025	30	$ 1,551	$ 14	$ 7.89	$ -	9362	2.6	3.9	43.6234	0.0006	0.0090	0.2550	117.0000
Natural Gas	Intercooled SCCT Aero x2	1,500	215	2025	30	$ 1,188	$ 14	$ 5.31	$ -	8802	2.9	3.9	27.0223	0.0006	0.0090	0.2550	117.0000
Natural Gas	SCCT Frame "F" x1	1,500	227	2025	35	$ 738	$ 14	$ 14.94	$ -	9916	2.7	3.9	28.4484	0.0006	0.0090	0.2550	117.0000
Natural Gas	Brownfield SCCT Frame "F" x1	1,500	227	2025	35	$ 711	$ 14	$ 14.94	$ -	9916	2.7	3.9	28.4484	0.0006	0.0090	0.2550	117.0000
Natural Gas	IC Recips x 6	1,500	111	2026	40	$ 1,938	$ 12	$ 10.39	$ -	8286	2.5	5.0	27.1363	0.0006	0.0288	0.2550	117.0000
Natural Gas	CCCT Dry "H", 1x1	1,500	397	2026	40	$ 1,484	$ 14	$ 1.88	$ -	6384	2.5	3.8	23.5973	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", DF, 1x1	1,500	51	2027	40	$ 470	$ -	$ 0.05	$ -	8789	2.5	3.8	22.9547	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", 2x1	1,500	797	2027	40	$ 1,077	$ 14	$ 1.81	$ -	6367	2.5	3.8	20.1038	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", DF, 2x1	1,500	102	2026	40	$ 357	$ -	$ 0.05	$ -	8713	2.5	3.8	19.7926	0.0006	0.0072	0.2550	117.0000
Natural Gas	Brownfield CCCT Dry "H", DF, 2x1	1,500	797	2026	40	$ 1,077	$ 14	$ 1.14	$ -	6633	2.5	3.8	19.7926	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", 1x1	1,500	582	2027	40	$ 1,125	$ 14	$ 1.57	$ -	6264	2.5	3.8	20.3774	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", DF, 1x1	1,500	63	2027	40	$ 397	$ -	$ 0.06	$ -	8816	2.5	3.8	20.1033	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", 2x1	1,500	1,166	2026	40	$ 832	$ 14	$ 1.51	$ -	6249	2.5	3.8	17.8997	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", DF, 2x1	1,500	126	2026	40	$ 309	$ -	$ 0.06	$ -	8742	2.5	3.8	17.8427	0.0006	0.0072	0.2550	117.0000
Natural Gas	SCCT Aero x3	3,000	150	2025	30	$ 1,645	$ 11	$ 8.37	$ -	9380	2.6	3.9	43.6234	0.0006	0.0090	0.2550	117.0000
Natural Gas	Intercooled SCCT Aero x2	3,000	203	2025	30	$ 1,260	$ 11	$ 5.63	$ -	8811	2.9	3.9	27.0223	0.0006	0.0090	0.2550	117.0000
Natural Gas	SCCT Frame "F" x1	3,000	214	2025	35	$ 779	$ 11	$ 15.79	$ -	9928	2.7	3.9	28.4484	0.0006	0.0090	0.2550	117.0000
Natural Gas	Brownfield SCCT Frame "F" x1	3,000	214	2025	35	$ 751	$ 11	$ 15.78	$ -	9928	2.7	3.9	28.4484	0.0006	0.0090	0.2550	117.0000
Natural Gas	IC Recips x 6	3,000	111	2026	40	$ 1,938	$ 12	$ 10.39	$ -	8286	2.5	5.0	27.1363	0.0006	0.0288	0.2550	117.0000
Natural Gas	CCCT Dry "H", 1x1	3,000	376	2026	40	$ 1,569	$ 11	$ 1.99	$ -	6387	2.5	3.8	23.5973	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", DF, 1x1	3,000	51	2027	40	$ 470	$ -	$ 0.05	$ -	8816	2.5	3.8	22.9547	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", 2x1	3,000	750	2027	40	$ 1,144	$ 11	$ 1.92	$ -	6400	2.5	3.8	20.1038	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", DF, 2x1	3,000	102	2026	40	$ 357	$ -	$ 0.05	$ -	8756	2.5	3.8	19.7926	0.0006	0.0072	0.2550	117.0000
Natural Gas	Brownfield CCCT Dry "H", DF, 2x1	3,000	750	2026	40	$ 1,144	$ 11	$ 1.21	$ -	6682	2.5	3.8	19.7926	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", 1x1	3,000	550	2027	40	$ 1,189	$ 11	$ 1.66	$ -	6270	2.5	3.8	20.3774	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", DF, 1x1	3,000	63	2027	40	$ 397	$ -	$ 0.06	$ -	8837	2.5	3.8	20.1033	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", 2x1	3,000	1,103	2026	40	$ 879	$ 11	$ 1.60	$ -	6256	2.5	3.8	17.8997	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", DF, 2x1	3,000	126	2026	40	$ 309	$ -	$ 0.06	$ -	8763	2.5	3.8	17.8427	0.0006	0.0072	0.2550	117.0000
Natural Gas	SCCT Aero x3	5,050	139	2025	30	$ 1,777	$ 12	$ 9.04	$ -	9400	2.6	3.9	43.6234	0.0006	0.0090	0.2550	117.0000
Natural Gas	Intercooled SCCT Aero x2	5,050	187	2025	30	$ 1,363	$ 12	$ 6.09	$ -	8816	2.9	3.9	27.0223	0.0006	0.0090	0.2550	117.0000
Natural Gas	SCCT Frame "F" x1	5,050	199	2025	35	$ 841	$ 12	$ 17.04	$ -	9936	2.7	3.9	28.4484	0.0006	0.0090	0.2550	117.0000
Natural Gas	Brownfield SCCT Frame "F" x1	5,050	199	2025	35	$ 811	$ 12	$ 17.03	$ -	9936	2.7	3.9	28.4484	0.0006	0.0090	0.2550	117.0000
Natural Gas	IC Recips x 6	5,050	111	2026	40	$ 1,938	$ 12	$ 10.39	$ -	8292	2.5	5.0	27.1363	0.0006	0.0288	0.2550	117.0000
Natural Gas	CCCT Dry "H", 1x1	5,050	350	2026	40	$ 1,687	$ 12	$ 2.14	$ -	6362	2.5	3.8	23.5973	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", DF, 1x1	5,050	51	2026	40	$ 470	$ -	$ 0.05	$ -	8545	2.5	3.8	22.9547	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", 2x1	5,050	686	2027	40	$ 1,252	$ 12	$ 2.10	$ -	6487	2.5	3.8	20.1038	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", DF, 2x1	5,050	102	2027	40	$ 358	$ -	$ 0.05	$ -	9470	2.5	3.8	19.7926	0.0006	0.0072	0.2550	117.0000
Natural Gas	Brownfield CCCT Dry "H", DF, 2x1	5,050	686	2027	40	$ 1,251	$ 12	$ 1.33	$ -	6874	2.5	3.8	19.7926	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", 1x1	5,050	504	2026	40	$ 1,299	$ 12	$ 1.81	$ -	6352	2.5	3.8	20.3774	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", DF, 1x1	5,050	63	2026	40	$ 397	$ -	$ 0.06	$ -	9452	2.5	3.8	20.1033	0.0006	0.0072	0.2550	117.0000

Table 7.1 – 2021 Supply-Side Resource Table (2020$) (Continued)

Description		Resource Characteristics				Costs				Operating Characteristics				Environmental			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Demolition Cost ($/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	CCCT Dry "J", 2x1	5,050	1,004	2027	40	$ 966	$ 12	$ 1.76	$ -	6373	2.5	3.8	17.8997	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", DF, 2x1	5,050	126	2027	40	$ 309	$ -	$ 0.06	$ -	9456	2.5	3.8	17.8427	0.0006	0.0072	0.2550	117.0000
Natural Gas	SCCT Aero x3	6,500	126	2025	30	$ 1,957	$ 13	$ 9.96	$ -	9314	2.6	3.9	43.6234	0.0006	0.0090	0.2550	117.0000
Natural Gas	Intercooled SCCT Aero x2	6,500	179	2025	30	$ 1,427	$ 13	$ 6.37	$ -	8786	2.9	3.9	27.0223	0.0006	0.0090	0.2550	117.0000
Natural Gas	SCCT Frame "F" x1	6,500	189	2025	35	$ 886	$ 13	$ 17.95	$ -	9930	2.7	3.9	28.4484	0.0006	0.0090	0.2550	117.0000
Natural Gas	Brownfield SCCT Frame "F" x1	6,500	189	2025	35	$ 854	$ 13	$ 17.95	$ -	9930	2.7	5.0	28.4484	0.0006	0.0090	0.2550	117.0000
Natural Gas	IC Recips x 6	6,500	111	2026	40	$ 1,937	$ 12	$ 10.39	$ -	8333	2.5	3.8	27.1363	0.0006	0.0288	0.2550	117.0000
Natural Gas	CCCT Dry "H", 1x1	6,500	335	2026	40	$ 1,761	$ 13	$ 2.23	$ -	6390	2.5	3.8	23.5973	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", DF, 1x1	6,500	51	2027	40	$ 470	$ -	$ 0.05	$ -	8857	2.5	3.8	22.9547	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", 2x1	6,500	669	2027	40	$ 1,283	$ 12	$ 2.15	$ -	6399	2.5	3.8	20.1038	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", DF, 2x1	6,500	102	2026	40	$ 357	$ -	$ 0.05	$ -	8852	2.5	4.8	19.7926	0.0006	0.0072	0.2550	117.0000
Natural Gas	Brownfield CCCT Dry "H", DF, 2x1	6,500	669	2026	40	$ 1,283	$ 12	$ 1.36	$ -	6724	2.5	5.8	19.7926	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", 1x1	6,500	490	2027	40	$ 1,337	$ 12	$ 1.86	$ -	6273	2.5	6.8	20.3774	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", DF, 1x1	6,500	63	2027	40	$ 397	$ -	$ 0.06	$ -	8864	2.5	7.8	20.1033	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", 2x1	6,500	981	2026	40	$ 988	$ 12	$ 1.80	$ -	6259	2.5	8.8	17.8997	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", DF, 2x1	6,500	126	2026	40	$ 309	$ -	$ 0.06	$ -	8789	2.5	9.8	17.8427	0.0006	0.0072	0.2550	117.0000
Coal	SCPC with CCS	4,500	526	2028	40	$ 6,488	$ 127	$ 7.00	$ 72.22	13087	5.0	5.0	1,004.2373	0.0085	0.0700	0.0222	20.5352
Coal	IGCC with CCS	4,500	466	2028	40	$ 6,282	$ 60	$ 11.77	$ 58.20	10823	8.0	7.0	394.0678	0.0085	0.0500	0.3333	20.5352
Coal	PC CCS retrofit @ 500 MW pre-retrofit basis	4,500	-115	2026	20	$ 2,971	$ 37	$ 3.29	$ 28.18	14372	5.0	5.0	450.0000	0.0050	0.0700	1.2000	20.5352
Coal	SCPC with CCS	6,500	692	2028	40	$ 7,348	$ 127	$ 7.58	$ 67.09	13242	5.0	5.0	1,004.2373	0.0085	0.0700	0.0222	20.5352
Coal	IGCC with CCS	6,500	456	2028	40	$ 7,113	$ 60	$ 14.11	$ 63.40	11047	8.0	7.0	394.0678	0.0085	0.0500	0.3333	20.5352
Coal	PC CCS retrofit @ 500 MW pre-retrofit basis	6,500	-115	2026	20	$ 2,971	$ 37	$ 3.29	$ 28.18	14372	5.0	5.0	450.0000	0.0050	0.0700	1.2000	20.5352
Geothermal	Blundell Dual Flash 90% CF	4,500	35	2021	40	$ 5,708	$ 127	$ 1.16	$ 103.85	N/A	5.0	5.0	10.0000	n/a	n/a	n/a	n/a
Geothermal	Greenfield Binary 90% CF	4,500	43	2023	40	$ 5,973	$ 127	$ 1.16	$ 103.85	N/A	5.0	5.0	270.0000	n/a	n/a	n/a	n/a
Geothermal	Generic Geothermal PPA 90% CF	4,500	30	2021	20	$ -	$ -	$ 77.34	$ -	N/A	5.0	5.0	270.0000	n/a	n/a	n/a	n/a
Wind	Pocatello, ID, 200 MW Wind, CF: 37.1% (100% PTC)	4,500	200	2024	30	$ 1,365	$ 13	$ -	$ 24.74	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind	Arlington, OR, 200 MW Wind, CF: 37.1% (100% PTC)	1,500	200	2024	30	$ 1,315	$ 13	$ -	$ 24.74	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind	Monticello, UT, 200 MW Wind, CF: 29.5% (100% PTC)	4,500	200	2024	30	$ 1,306	$ 13	$ -	$ 24.74	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind	Medicine Bow, WY, 200 MW Wind, CF: 43.6% (100%PTC)	6,500	200	2024	30	$ 1,356	$ 13	$ -	$ 24.74	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind	Goldendale, WA, 200 MW Wind, CF: 37.1% (100% PTC)	1,500	200	2024	30	$ 1,390	$ 13	$ -	$ 24.74	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind	Pocatello, ID, 200 MW Wind, CF: 37.1% (60% PTC)	4,500	200	2024	30	$ 1,365	$ 13	$ -	$ 24.74	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind	Arlington, OR, 200 MW Wind, CF: 37.1% (60% PTC)	1,500	200	2024	30	$ 1,315	$ 13	$ -	$ 24.74	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind	Monticello, UT, 200 MW Wind, CF: 29.5% (60% PTC)	4,500	200	2024	30	$ 1,306	$ 13	$ -	$ 24.74	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind	Medicine Bow, WY, 200 MW Wind, CF: 43.6% (60% PTC)	6,500	200	2024	30	$ 1,356	$ 13	$ 0.65	$ 24.74	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind	Goldendale, WA, 200 MW Wnd, CF: 37.1% (60% PTC)	1,500	200	2024	30	$ 1,390	$ 13	$ -	$ 24.74	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Pocatello, ID, 200 MW Wind, CF: 37.1% + BESS: 50% pwr, 4 hours	4,500	200	2024	30	$ 2,152	$ 233	$ -	$ 37.59	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Arlington, OR, 200 MW Wind, CF: 37.1% + BESS: 50% pwr, 4 hours	1,500	200	2024	30	$ 2,086	$ 233	$ -	$ 37.59	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Monticello, UT, 200 MW Wind, CF: 29.5% + BESS: 50% pwr, 4 hours	4,500	200	2024	30	$ 2,061	$ 233	$ -	$ 37.59	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Medicine Bow, WY, 200 MW Wind, CF: 43.6% + BESS: 50% pwr, 4 hours	6,500	200	2024	30	$ 2,136	$ 233	$ 0.65	$ 37.59	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Goldendale, WA, 200 MW Wind, CF: 37.1% + BESS: 50% pwr, 4 hours	1,500	200	2024	30	$ 2,211	$ 233	$ -	$ 37.59	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Idaho Falls, ID, 100 MW Solar, CF: 26.1% (30% ITC)	4,700	100	2023	25	$ 1,429	$ 35	$ -	$ 16.20	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Idaho Falls, ID, 200 MW Solar, CF: 26.1% (30% ITC)	4,700	200	2023	25	$ 1,302	$ 35	$ -	$ 16.10	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Lakeview, OR, 100 MW Solar, CF: 27.6% (30% ITC)	4,800	100	2023	25	$ 1,444	$ 35	$ -	$ 16.20	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Lakeview, OR, 200 MW Solar, CF: 27.6% (30% ITC)	4,800	200	2023	25	$ 1,330	$ 35	$ -	$ 16.10	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a

Table 7.1 – 2021 Supply-Side Resource Table (2020$) (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)
Solar	Milford, UT, 100 MW Solar, CF: 30.2% (30% ITC)	5,000	100	2023	25	$ 1,422	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Milford, UT, 200 MW Solar, CF: 30.2% (30% ITC)	5,000	200	2023	25	$ 1,297	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Rock Springs, WY, 100 MW Solar, CF: 27.9% (30% ITC)	6,400	100	2023	25	$ 1,423	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Rock Springs, WY, 200 MW Solar, CF: 27.9% (30% ITC)	6,400	200	2023	25	$ 1,297	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Yakima, WA, 100 MW Solar, CF: 24.2% (30% ITC)	1,000	100	2023	25	$ 1,486	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Yakima, WA, 200 MW Solar, CF: 24.2% (30% ITC)	1,000	200	2023	25	$ 1,357	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Idaho Falls, ID, 100 MW Solar, CF: 26.1% (10% ITC)	4,700	100	2023	25	$ 1,429	$ 35	$ -	$ 16.20	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Idaho Falls, ID, 200 MW Solar, CF: 26.1% (10% ITC)	4,700	200	2023	25	$ 1,302	$ 35	$ -	$ 16.10	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Lakeview, OR, 100 MW Solar, CF: 27.6% (10% ITC)	4,800	100	2023	25	$ 1,444	$ 35	$ -	$ 16.20	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Lakeview, OR, 200 MW Solar, CF: 27.6% (10% ITC)	4,800	200	2023	25	$ 1,330	$ 35	$ -	$ 16.10	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Milford, UT, 100 MW Solar, CF: 30.2% (10% ITC)	5,000	100	2023	25	$ 1,422	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Milford, UT, 200 MW Solar, CF: 30.2% (10% ITC)	5,000	200	2023	25	$ 1,297	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Rock Springs, WY, 100 MW Solar, CF: 27.9% (10% ITC)	6,400	100	2023	25	$ 1,423	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Rock Springs, WY, 200 MW Solar, CF: 27.9% (10% ITC)	6,400	200	2023	25	$ 1,297	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Yakima, WA, 100 MW Solar, CF: 24.2% (10% ITC)	1,000	100	2023	25	$ 1,486	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Yakima, WA, 200 MW Solar, CF: 24.2% (10% ITC)	1,000	200	2023	25	$ 1,357	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Idaho Falls, ID, 100 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours (30% ITC)	4,700	100	2023	25	$ 2,351	$ 255	$ -	$ 30.00	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Idaho Falls, ID, 200 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours (30% ITC)	4,700	200	2023	25	$ 2,161	$ 255	$ -	$ 28.95	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Lakeview, OR, 100 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours (30% ITC)	4,800	100	2023	25	$ 2,329	$ 255	$ -	$ 30.00	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Lakeview, OR, 200 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours (30% ITC)	4,800	200	2023	25	$ 2,154	$ 255	$ -	$ 28.95	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Milford, UT, 100 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (30% ITC)	5,000	100	2023	25	$ 2,283	$ 255	$ -	$ 31.40	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (30% ITC)	5,000	200	2023	25	$ 2,102	$ 255	$ -	$ 30.45	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Rock Springs, WY, 100 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (30% ITC)	6,400	100	2023	25	$ 2,312	$ 255	$ -	$ 31.40	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (30% ITC)	6,400	200	2023	25	$ 2,128	$ 255	$ -	$ 30.45	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Yakima, WA, 100 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours (30% ITC)	1,000	100	2023	25	$ 2,405	$ 255	$ -	$ 31.40	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Yakima, WA, 200 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours (30% ITC)	1,000	200	2023	25	$ 2,217	$ 255	$ -	$ 30.45	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage + Wind	Idah Falls, ID, 200 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours + 200 MW Wind	4,700	200	2023	25	$ 3,395	$ 268	$ -	$ 82.95	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage + Wind	Lakeview, OR, 200 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours + 200 MW Wind	4,800	200	2023	25	$ 3,424	$ 268	$ -	$ 82.95	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a

Table 7.1 – 2021 Supply-Side Resource Table (2020$) (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)
Solar + Storage + Wind	Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours + 200 MW Wind	5,000	200	2023	25	$ 3,364	$ 268	$ -	$ 81.45	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage + Wind	Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours + 200 MW Wind	6,400	200	2023	25	$ 3,364	$ 268	$ -	$ 81.45	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage + Wind	Yakima, WA, 200 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours + 200 MW Wind	1,000	200	2023	25	$ 3,424	$ 268	$ -	$ 81.45	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Storage	Pumped Hydro, Swan Lake. 3600 MWh	N/A	400	2027	60	$ 3,095	$ 485	$ -	$ 12.50	78%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Goldendale, 14400 MWh	N/A	1,200	2028	60	$ 2,833	$ 485	$ -	$ 12.50	78%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Seminoe, 7500 MWh	N/A	750	2029	80	$ 3,461	$ 485	$ 0.37	$ 16.00	80%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Badger Mountain, 4000 MWh	N/A	500	2027	80	$ 2,621	$ 485	$ 0.37	$ 28.00	80%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Owyhee, 4800 MWh	N/A	600	2029	80	$ 3,203	$ 485	$ 0.37	$ 20.00	80%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Flat Canyon, 1800 MWh	N/A	300	2029	80	$ 4,046	$ 485	$ 0.37	$ 53.33	80%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Utah PS2, 4000 MWh	N/A	500	2027	80	$ 3,237	$ 485	$ 0.37	$ 28.00	80%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Utah PS3, 4800 MWh	N/A	600	2029	80	$ 3,371	$ 485	$ 0.37	$ 20.00	80%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Banner Mountain, 3400 MWh	N/A	400	2028	50	$ 3,276	$ 485	$ 0.00	$ 28.50	81%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, Hydrostor, 150 MW, 600 MWh	N/A	150	2024	50	$ 1,954	$ 12	$ 6.50	$ 12.67	60%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, Hydrostor, 150 MW, 1200 MWh	N/A	150	2024	50	$ 2,189	$ 12	$ 6.50	$ 12.67	60%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, Hydrostor, 150 MW, 1800 MWh	N/A	150	2024	50	$ 2,445	$ 12	$ 6.50	$ 12.67	60%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, Hydrostor, 300 MW, 1200 MWh	N/A	300	2024	50	$ 1,557	$ 12	$ 6.50	$ 9.33	60%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, Hydrostor, 300 MW, 2400 MWh	N/A	300	2024	50	$ 1,692	$ 12	$ 6.50	$ 9.33	60%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, Hydrostor, 300 MW, 3600 MWh	N/A	300	2024	50	$ 2,016	$ 12	$ 6.50	$ 9.33	60%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, Hydrostor, 500 MW, 2000 MWh	N/A	500	2024	50	$ 1,549	$ 12	$ 6.50	$ 6.60	60%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, Hydrostor, 500 MW, 4000 MWh	N/A	500	2025	50	$ 1,762	$ 12	$ 6.50	$ 6.60	60%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, Hydrostor, 500 MW, 6000 MWh	N/A	500	2025	50	$ 2,010	$ 12	$ 6.50	$ 6.60	60%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Li-Ion Battery, , 1 MW, 0.5 MWh	N/A	1	2023	20	$ 1,948	$ 55	(a)	$ 40.00	85%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Li-Ion Battery, , 1 MW, 1 MWh	N/A	1	2023	20	$ 2,058	$ 110	(a)	$ 50.00	85%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Li-Ion Battery, , 1 MW, 4 MWh	N/A	1	2023	20	$ 3,167	$ 440	(a)	$ 70.00	85%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Li-Ion Battery, , 1 MW, 8 MWh	N/A	1	2023	20	$ 4,622	$ 880	(a)	$ 100.00	85%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Li-Ion Battery, , 50 MW, 200 MWh	N/A	50	2023	20	$ 1,820	$ 440	(a)	$ 27.60	85%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Flow Battery, , 1 MW, 1 MWh	N/A	1	2023	20	$ 4,719	$ 12	(a)	$ 13.00	70%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Flow Battery, , 1 MW, 4 MWh	N/A	1	2023	20	$ 5,051	$ 12	(a)	$ 13.00	70%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Flow Battery, , 1 MW, 8 MWh	N/A	1	2023	20	$ 7,291	$ 12	(a)	$ 27.00	70%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Flow Battery, , 20 MW, 160 MWh	N/A	20	2023	20	$ 4,190	$ 12	(a)	$ 30.50	70%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Nuclear	Small Modular Reactor	5,000	854	2028	60	$ 5,396	$ 722	$ 6.72	$ 65.03	N/A	5.0	5.0	N/A	0.0000	0.0000	0.0000	0.0000
Hydrogen	Non-Emitting Peaker	5,050	206	2030	30	$ 959	$ 2,414	$ 21.29	$ -	9936	2.7	3.9	218.0000	0.0000	0.0000	0.0000	0.0000

Table 7.1 – 2021 Supply-Side Resource Table (2020$) (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)
CCUS for Coal Plants	Naughton 2 PC CCUS Retrofit	6,500	155	2026	20	$ 3,930	$ 37	$ 7.30	$ 39.90	1437200%	5.0	5.0	450.0000	0.0050	0.0700	1.2000	20.5352
CCUS for Coal Plants	Johnston 2 PC CCUS Retrofit	6,500	82	2026	20	$ 5,314	$ 37	$ 6.10	$ 40.58	1437200%	5.0	5.0	450.0000	0.0050	0.0700	1.2000	20.5352
CCUS for Coal Plants	Johnston 4 PC CCUS Retrofit	6,500	254	2026	20	$ 3,877	$ 37	$ 5.69	$ 37.88	1437200%	5.0	5.0	450.0000	0.0050	0.0700	1.2000	20.5352
CCUS for Coal Plants	Wyodak PC CCUS Retrofit	6,500	206	2026	20	$ 3,935	$ 37	$ 7.31	$ 39.95	1437200%	5.0	5.0	450.0000	0.0050	0.0700	1.2000	20.5352
CCUS for Coal Plants	Bridger 1 PC CCUS Retrofit	6,500	273	2026	20	$ 3,934	$ 37	$ 7.31	$ 39.94	1437200%	5.0	5.0	450.0000	0.0050	0.0700	1.2000	20.5352
CCUS for Coal Plants	Bridger 3 PC CCUS Retrofit	6,500	269	2026	20	$ 3,873	$ 37	$ 5.69	$ 37.83	1437200%	5.0	5.0	450.0000	0.0050	0.0700	1.2000	20.5352
CCUS for Coal Plants	Bridger 4 PC CCUS Retrofit	6,500	270	2026	20	$ 3,876	$ 37	$ 5.69	$ 37.86	1437200%	5.0	5.0	450.0000	0.0050	0.0700	1.2000	20.5352

Table 7.2 - Total Resource Cost for Supply-Side Resource Options

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)			Capital Cost $/kW				Fixed Cost					
							Fixed O&M $/kW-Yr					
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital Cost 1/	Demolition Cost	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
SCCT Aero x3	No	0	$1,463	$10	7.497%	$110.43	$0.00	1.262%	$0.00	$31.94	$31.94	$142.37
Intercooled SCCT Aero x2	No	0	$1,126	$10	7.497%	$85.14	$0.00	1.135%	$0.00	$30.03	$30.03	$115.17
SCCT Frame "F" x1	No	0	$699	$10	7.049%	$49.97	$0.00	0.273%	$0.00	$33.77	$33.77	$83.74
Brownfield SCCT Frame "F" x1	No	0	$674	$10	7.049%	$48.20	$0.00	0.273%	$0.00	$33.77	$33.77	$81.97
IC Recips x 6	No	0	$1,938	$12	7.049%	$137.45	$0.00	0.136%	$0.00	$28.47	$28.47	$165.92
CCCT Dry "H", 1x1	No	0	$1,396	$10	6.886%	$96.84	$0.00	0.146%	$0.00	$23.57	$23.57	$120.41
CCCT Dry "H", DF, 1x1	No	0	$470	$0	6.886%	$32.34	$0.00	0.000%	$0.00	$23.57	$23.57	$55.91
CCCT Dry "H", 2x1	No	0	$1,019	$10	6.886%	$70.86	$0.00	0.146%	$0.00	$23.62	$23.62	$94.48
CCCT Dry "H", DF, 2x1	No	0	$357	$0	6.886%	$24.60	$0.00	0.000%	$0.00	$23.62	$23.62	$48.22
Brownfield CCCT Dry "H", DF, 2x1	No	0	$1,019	$10	6.886%	$70.83	$0.00	0.000%	$0.00	$23.36	$23.36	$94.19
CCCT Dry "J", 1x1	No	0	$1,065	$10	6.886%	$73.99	$0.00	0.000%	$0.00	$23.36	$23.36	$97.35
CCCT Dry "J", DF, 1x1	No	0	$397	$0	6.886%	$27.36	$0.00	0.000%	$0.00	$23.36	$23.36	$50.73
CCCT Dry "J", 2x1	No	0	$787	$10	6.886%	$54.88	$0.00	0.146%	$0.00	$23.36	$23.36	$78.25
CCCT Dry "J", DF, 2x1	No	0	$309	$0	6.886%	$21.30	$0.00	0.000%	$0.00	$23.36	$23.36	$44.66
SCCT Aero x3	No	1,500	$1,551	$14	7.497%	$117.36	$0.00	1.262%	$0.00	$31.76	$31.76	$149.12
Intercooled SCCT Aero x2	No	1,500	$1,188	$14	7.497%	$90.12	$0.00	1.135%	$0.00	$29.91	$29.91	$120.03
SCCT Frame "F" x1	No	1,500	$738	$14	7.049%	$52.98	$0.00	0.273%	$0.00	$33.71	$33.71	$86.68
Brownfield SCCT Frame "F" x1	No	1,500	$711	$14	7.049%	$51.11	$0.00	0.273%	$0.00	$33.71	$33.71	$84.82
IC Recips x 6	No	1,500	$1,938	$12	7.049%	$137.45	$0.00	0.136%	$0.00	$28.47	$28.47	$165.92
CCCT Dry "H", 1x1	No	1,500	$1,484	$14	6.886%	$103.13	$0.00	0.146%	$0.00	$23.37	$23.37	$126.49
CCCT Dry "H", DF, 1x1	No	1,500	$470	$0	6.886%	$32.35	$0.00	0.000%	$0.00	$23.37	$23.37	$55.71
CCCT Dry "H", 2x1	No	1,500	$1,077	$14	6.886%	$75.15	$0.00	0.146%	$0.00	$23.41	$23.41	$98.56
CCCT Dry "H", DF, 2x1	No	1,500	$357	$0	6.886%	$24.60	$0.00	0.000%	$0.00	$23.41	$23.41	$48.01
Brownfield CCCT Dry "H", DF, 2x1	No	1,500	$1,077	$14	6.886%	$75.11	$0.00	0.000%	$0.00	$23.17	$23.17	$98.29
CCCT Dry "J", 1x1	No	1,500	$1,125	$14	6.886%	$78.43	$0.00	0.000%	$0.00	$23.17	$23.17	$101.61
CCCT Dry "J", DF, 1x1	No	1,500	$397	$0	6.886%	$27.37	$0.00	0.000%	$0.00	$23.17	$23.17	$50.54
CCCT Dry "J", 2x1	No	1,500	$832	$14	6.886%	$58.24	$0.00	0.146%	$0.00	$23.17	$23.17	$81.41
CCCT Dry "J", DF, 2x1	No	1,500	$309	$0	6.886%	$21.30	$0.00	0.000%	$0.00	$23.17	$23.17	$44.47
SCCT Aero x3	No	3,000	$1,645	$11	7.497%	$124	$0.00	1.262%	$0.00	$16.94	$16.94	$141.12
Intercooled SCCT Aero x2	No	3,000	$1,260	$11	7.497%	$95	$0.00	1.135%	$0.00	$15.94	$15.94	$111.26
SCCT Frame "F" x1	No	3,000	$779	$11	7.049%	$56	$0.00	0.273%	$0.00	$17.98	$17.98	$73.70
Brownfield SCCT Frame "F" x1	No	3,000	$751	$11	7.049%	$54	$0.00	0.273%	$0.00	$17.98	$17.98	$71.73

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)			Capital Cost $/kW				Fixed Cost					
							Fixed O&M $/kW-Yr					
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital Cost 1/	Demolition Cost	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
IC Recips x 6	No	3,000	$1,938	$12	7.049%	$137.45	$0.00	0.136%	$0.00	$15.18	$15.18	$152.62
CCCT Dry "H", 1x1	No	3,000	$1,569	$11	6.886%	$108.80	$0.00	0.146%	$0.00	$23.28	$23.28	$132.08
CCCT Dry "H", DF, 1x1	No	3,000	$470	$0	6.886%	$32.35	$0.00	0.000%	$0.00	$23.28	$23.28	$55.62
CCCT Dry "H", 2x1	No	3,000	$1,144	$11	6.886%	$79.55	$0.00	0.146%	$0.00	$12.43	$12.43	$91.98
CCCT Dry "H", DF, 2x1	No	3,000	$357	$0	6.886%	$24.60	$0.00	0.000%	$0.00	$12.43	$12.43	$37.03
Brownfield CCCT Dry "H", DF, 2x1	No	3,000	$1,144	$11	6.886%	$79.51	$0.00	0.000%	$0.00	$12.27	$12.27	$91.78
CCCT Dry "J", 1x1	No	3,000	$1,189	$11	6.886%	$82.65	$0.00	0.000%	$0.00	$12.27	$12.27	$94.92
CCCT Dry "J", DF, 1x1	No	3,000	$397	$0	6.886%	$27.37	$0.00	0.000%	$0.00	$12.27	$12.27	$39.64
CCCT Dry "J", 2x1	No	3,000	$879	$11	6.886%	$61.29	$0.00	0.146%	$0.00	$12.28	$12.28	$73.57
CCCT Dry "J", DF, 2x1	No	3,000	$309	$0	6.886%	$21.30	$0.00	0.000%	$0.00	$12.28	$12.28	$33.58
SCCT Aero x3	No	5,050	$1,777	$12	7.497%	$134.18	$0.00	1.262%	$0.00	$14.06	$14.06	$148.23
Intercooled SCCT Aero x2	Yes	5,050	$1,363	$12	7.497%	$103.10	$0.00	1.135%	$0.00	$13.22	$13.22	$116.32
SCCT Frame "F" x1	Yes	5,050	$841	$12	7.049%	$60.13	$0.00	0.273%	$0.00	$14.93	$14.93	$75.07
Brownfield SCCT Frame "F" x1	Yes	5,050	$811	$12	7.049%	$58.00	$0.00	0.273%	$0.00	$14.93	$14.93	$72.94
IC Recips x 6	Yes	5,050	$1,938	$12	7.049%	$137.45	$0.00	0.136%	$0.00	$12.61	$12.61	$150.06
CCCT Dry "H", 1x1	Yes	5,050	$1,687	$12	6.886%	$116.98	$0.00	0.146%	$0.00	$9.91	$9.91	$126.89
CCCT Dry "H", DF, 1x1	Yes	5,050	$470	$0	6.886%	$32.35	$0.00	0.000%	$0.00	$9.91	$9.91	$42.26
CCCT Dry "H", 2x1	No	5,050	$1,252	$12	6.886%	$87.04	$0.00	0.146%	$0.00	$9.93	$9.93	$96.97
CCCT Dry "H", DF, 2x1	No	5,050	$358	$0	6.886%	$24.63	$0.00	0.000%	$0.00	$9.93	$9.93	$34.56
Brownfield CCCT Dry "H", DF, 2x1	Yes	5,050	$1,251	$12	6.886%	$87.00	$0.00	0.000%	$0.00	$9.84	$9.84	$96.84
CCCT Dry "J", 1x1	Yes	5,050	$1,299	$12	6.886%	$90.28	$0.00	0.000%	$0.00	$9.84	$9.84	$100.13
CCCT Dry "J", DF, 1x1	Yes	5,050	$397	$0	6.886%	$27.36	$0.00	0.000%	$0.00	$9.84	$9.84	$37.21
CCCT Dry "J", 2x1	No	5,050	$966	$12	6.886%	$67.34	$0.00	0.146%	$0.00	$9.85	$9.85	$77.19
CCCT Dry "J", DF, 2x1	No	5,050	$309	$0	6.886%	$21.29	$0.00	0.000%	$0.00	$9.85	$9.85	$31.15
SCCT Aero x3	No	6,500	$1,957	$13	7.497%	$147.74	$0.00	1.262%	$0.00	$9.13	$9.13	$156.86
Intercooled SCCT Aero x2	Yes	6,500	$1,427	$13	7.497%	$107.96	$0.00	1.135%	$0.00	$8.62	$8.62	$116.58
SCCT Frame "F" x1	Yes	6,500	$886	$13	7.049%	$63.37	$0.00	0.273%	$0.00	$9.70	$9.70	$73.06
Brownfield SCCT Frame "F" x1	Yes	6,500	$854	$13	7.049%	$61.12	$0.00	0.273%	$0.00	$9.70	$9.70	$70.82
IC Recips x 6	Yes	6,500	$1,937	$12	7.049%	$137.42	$0.00	0.136%	$0.00	$8.24	$8.24	$145.66
CCCT Dry "H", 1x1	Yes	6,500	$1,761	$13	6.886%	$122.11	$0.00	0.146%	$0.00	$20.66	$20.66	$142.77

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)			Capital Cost $/kW				Fixed Cost					
							Fixed O&M $/kW-Yr					
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital Cost 1/	Demolition Cost	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
CCCT Dry "H", DF, 1x1	Yes	6,500	$470	$0	6.886%	$32.35	$0.00	0.000%	$0.00	$20.66	$20.66	$53.01
CCCT Dry "H", 2x1	No	6,500	$1,283	$12	6.886%	$89.23	$0.00	0.146%	$0.00	$6.71	$6.71	$95.94
CCCT Dry "H", DF, 2x1	No	6,500	$357	$0	6.886%	$24.61	$0.00	0.000%	$0.00	$6.71	$6.71	$31.32
Brownfield CCCT Dry "H", DF, 2x1	Yes	6,500	$1,283	$12	6.886%	$89.18	$0.00	0.000%	$0.00	$6.62	$6.62	$95.80
CCCT Dry "J", 1x1	Yes	6,500	$1,337	$12	6.886%	$92.91	$0.00	0.000%	$0.00	$6.62	$6.62	$99.53
CCCT Dry "J", DF, 1x1	Yes	6,500	$397	$0	6.886%	$27.36	$0.00	0.000%	$0.00	$6.62	$6.62	$33.98
CCCT Dry "J", 2x1	No	6,500	$988	$12	6.886%	$68.90	$0.00	0.146%	$0.00	$6.62	$6.62	$75.53
CCCT Dry "J", DF, 2x1	No	6,500	$309	$0	6.886%	$21.30	$0.00	0.000%	$0.00	$6.62	$6.62	$27.92
SCPC with CCS	No	4,500	$6,488	$127	6.822%	$451.29	$72.22	5.541%	$4.00	$0.00	$76.23	$527.52
IGCC with CCS	No	4,500	$6,282	$60	7.389%	$468.60	$58.20	0.000%	$0.00	$0.00	$58.20	$526.80
PC CCS retrofit @ 500 MW pre-retrofit basis	Yes	4,500	$2,971	$37	6.822%	$205.19	$28.18	5.541%	$1.56	$0.00	$29.74	$234.92
SCPC with CCS	No	6,500	$7,348	$127	6.822%	$509.92	$67.09	5.541%	$3.72	$0.00	$70.80	$580.72
IGCC with CCS	No	6,500	$7,113	$60	7.389%	$530.01	$63.40	0.000%	$0.00	$0.00	$63.40	$593.41
PC CCS retrofit @ 500 MW pre-retrofit basis	Yes	6,500	$2,971	$37	6.822%	$205.19	$28.18	5.541%	$1.56	$0.00	$29.74	$234.92
Blundell Dual Flash 90% CF	Yes	4,500	$5,708	$127	6.273%	$366.02	$103.85	0.875%	$0.91	$0.00	$104.76	$470.77
Greenfield Binary 90% CF	Yes	4,500	$5,973	$127	6.273%	$382.70	$103.85	0.000%	$0.00	$0.00	$103.85	$486.55
Generic Geothermal PPA 90% CF	Yes	4,500	$0	$0	6.273%	$0.00	$0.00	0.000%	$0.00	$0.00	$0.00	$0.00
Pocatello, ID, 200 MW Wind, CF: 37.1% (100% PTC)	Yes	4,500	$1,365	$13	6.979%	$96.14	$24.74	0.000%	$0.00	$0.00	$24.74	$120.88
Arlington, OR, 200 MW Wind, CF: 37.1% (100% PTC)	Yes	1,500	$1,315	$13	6.979%	$92.67	$24.74	0.000%	$0.00	$0.00	$24.74	$117.41
Monticello, UT, 200 MW Wind, CF: 29.5% (100% PTC)	Yes	4,500	$1,306	$13	6.979%	$92.05	$24.74	0.000%	$0.00	$0.00	$24.74	$116.79
Medicine Bow, WY, 200 MW Wind, CF: 43.6% (100%PTC)	Yes	6,500	$1,356	$13	6.979%	$95.54	$24.74	0.000%	$0.00	$0.00	$24.74	$120.28
Goldendale, WA, 200 MW Wind, CF: 37.1% (100% PTC)	Yes	1,500	$1,390	$13	6.979%	$97.89	$24.74	0.000%	$0.00	$0.00	$24.74	$122.63
Pocatello, ID, 200 MW Wind, CF: 37.1% (60% PTC)	Yes	4,500	$1,365	$13	6.979%	$96.14	$24.74	0.000%	$0.00	$0.00	$24.74	$120.88
Arlington, OR, 200 MW Wind, CF: 37.1% (60% PTC)	Yes	1,500	$1,315	$13	6.979%	$92.67	$24.74	0.000%	$0.00	$0.00	$24.74	$117.41
Monticello, UT, 200 MW Wind, CF: 29.5% (60% PTC)	Yes	4,500	$1,306	$13	6.979%	$92.05	$24.74	0.000%	$0.00	$0.00	$24.74	$116.79
Medicine Bow, WY, 200 MW Wind, CF: 43.6% (60% PTC)	Yes	6,500	$1,356	$13	6.979%	$95.54	$24.74	0.000%	$0.00	$0.00	$24.74	$120.28
Goldendale, WA, 200 MW Wnd, CF: 37.1% (60% PTC)	Yes	1,500	$1,390	$13	6.979%	$97.89	$24.74	0.000%	$0.00	$0.00	$24.74	$122.63
Pocatello, ID, 200 MW Wind, CF: 37.1% + BESS: 50% pwr, 4 hours	Yes	4,500	$2,152	$233	6.979%	$166.45	$37.59	2.902%	$1.09	$0.00	$38.68	$205.13
Arlington, OR, 200 MW Wind, CF: 37.1% + BESS: 50% pwr, 4 hours	Yes	1,500	$2,086	$233	6.979%	$161.82	$37.59	2.902%	$1.09	$0.00	$38.68	$200.50
Monticello, UT, 200 MW Wind, CF: 29.5% + BESS: 50% pwr, 4 hours	Yes	4,500	$2,061	$233	6.979%	$160.06	$37.59	2.902%	$1.09	$0.00	$38.68	$198.74
Medicine Bow, WY, 200 MW Wind, CF: 43.6% + BESS: 50% pwr, 4 hours	Yes	6,500	$2,136	$233	6.979%	$165.29	$37.59	2.902%	$1.09	$0.00	$38.68	$203.97
Goldendale, WA, 200 MW Wind, CF: 37.1% + BESS: 50% pwr, 4 hours	Yes	1,500	$2,211	$233	6.979%	$170.52	$37.59	2.902%	$1.09	$0.00	$38.68	$209.20
Idaho Falls, ID, 100 MW Solar, CF: 26.1% (30% ITC)	Yes	4,700	$1,429	$35	6.839%	$100.09	$16.20	1.379%	$0.22	$0.00	$16.42	$116.52
Idaho Falls, ID, 200 MW Solar, CF: 26.1% (30% ITC)	Yes	4,700	$1,302	$35	6.839%	$91.44	$16.10	1.379%	$0.22	$0.00	$16.32	$107.77
Lakeview, OR, 100 MW Solar, CF: 27.6% (30% ITC)	Yes	4,800	$1,444	$35	6.839%	$101.18	$16.20	1.379%	$0.22	$0.00	$16.42	$117.61
Lakeview, OR, 200 MW Solar, CF: 27.6% (30% ITC)	Yes	4,800	$1,330	$35	6.839%	$93.38	$16.10	1.379%	$0.22	$0.00	$16.32	$109.70
Milford, UT, 100 MW Solar, CF: 30.2% (30% ITC)	Yes	5,000	$1,422	$35	6.839%	$99.67	$17.60	1.379%	$0.24	$0.00	$17.84	$117.51
Milford, UT, 200 MW Solar, CF: 30.2% (30% ITC)	Yes	5,000	$1,297	$35	6.839%	$91.11	$17.60	1.379%	$0.24	$0.00	$17.84	$108.95
Rock Springs, WY, 100 MW Solar, CF: 27.9% (30% ITC)	Yes	6,400	$1,423	$35	6.839%	$99.70	$17.60	1.379%	$0.24	$0.00	$17.84	$117.55
Rock Springs, WY, 200 MW Solar, CF: 27.9% (30% ITC)	Yes	6,400	$1,297	$35	6.839%	$91.07	$17.60	1.379%	$0.24	$0.00	$17.84	$108.91
Yakima, WA, 100 MW Solar, CF: 24.2% (30% ITC)	Yes	1,000	$1,486	$35	6.839%	$104.04	$17.60	1.379%	$0.24	$0.00	$17.84	$121.88
Yakima, WA, 200 MW Solar, CF: 24.2% (30% ITC)	Yes	1,000	$1,357	$35	6.839%	$95.20	$17.60	1.379%	$0.24	$0.00	$17.84	$113.04
Idaho Falls, ID, 100 MW Solar, CF: 26.1% (10% ITC)	Yes	4,700	$1,429	$35	6.839%	$100.09	$16.20	1.379%	$0.22	$0.00	$16.42	$116.52
Idaho Falls, ID, 200 MW Solar, CF: 26.1% (10% ITC)	Yes	4,700	$1,302	$35	6.839%	$91.44	$16.10	1.379%	$0.22	$0.00	$16.32	$107.77
Lakeview, OR, 100 MW Solar, CF: 27.6% (10% ITC)	Yes	4,800	$1,444	$35	6.839%	$101.18	$16.20	1.379%	$0.22	$0.00	$16.42	$117.61
Lakeview, OR, 200 MW Solar, CF: 27.6% (10% ITC)	Yes	4,800	$1,330	$35	6.839%	$93.38	$16.10	1.379%	$0.22	$0.00	$16.32	$109.70
Milford, UT, 100 MW Solar, CF: 30.2% (10% ITC)	Yes	5,000	$1,422	$35	6.839%	$99.67	$17.60	1.379%	$0.24	$0.00	$17.84	$117.51
Milford, UT, 200 MW Solar, CF: 30.2% (10% ITC)	Yes	5,000	$1,297	$35	6.839%	$91.11	$17.60	1.379%	$0.24	$0.00	$17.84	$108.95
Rock Springs, WY, 100 MW Solar, CF: 27.9% (10% ITC)	Yes	6,400	$1,423	$35	6.839%	$99.70	$17.60	1.379%	$0.24	$0.00	$17.84	$117.55
Rock Springs, WY, 200 MW Solar, CF: 27.9% (10% ITC)	Yes	6,400	$1,297	$35	6.839%	$91.07	$17.60	1.379%	$0.24	$0.00	$17.84	$108.91

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)			Capital Cost $/kW				Fixed Cost					
							Fixed O&M $/kW-Yr					
Resource Description	No	Elevation (AFSL)	Total Capital Cost 1/	Demolition Cost	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
Idaho Falls, ID, 100 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	4,700	$2,351	$255	6.839%	$178.25	$30.00	1.379%	$0.41	$0.00	$30.41	$208.66
Idaho Falls, ID, 200 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	4,700	$2,161	$255	6.839%	$165.25	$28.95	1.379%	$0.40	$0.00	$29.35	$194.60
Yakima, WA, 100 MW Solar, CF: 24.2% (10% ITC)	Yes	1,000	$1,486	$35	6.839%	$104.04	$17.60	1.379%	$0.24	$0.00	$17.84	$121.88
Yakima, WA, 200 MW Solar, CF: 24.2% (10% ITC)	Yes	1,000	$1,357	$35	6.839%	$95.20	$17.60	1.379%	$0.24	$0.00	$17.84	$113.04
Lakeview, OR, 100 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	4,800	$2,329	$255	6.839%	$176.71	$30.00	1.379%	$0.41	$0.00	$30.41	$207.12
Lakeview, OR, 200 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	4,800	$2,154	$255	6.839%	$164.74	$28.95	1.379%	$0.40	$0.00	$29.35	$194.09
Milford, UT, 100 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	5,000	$2,283	$255	6.839%	$173.58	$31.40	1.379%	$0.43	$0.00	$31.83	$205.41
Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	5,000	$2,102	$255	6.839%	$161.21	$30.45	1.379%	$0.42	$0.00	$30.87	$192.08
Rock Springs, WY, 100 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	6,400	$2,312	$255	6.839%	$175.57	$31.40	1.379%	$0.43	$0.00	$31.83	$207.40
Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	6,400	$2,128	$255	6.839%	$163.01	$30.45	1.379%	$0.42	$0.00	$30.87	$193.88
Yakima, WA, 100 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	1,000	$2,405	$255	6.839%	$181.91	$31.40	1.379%	$0.43	$0.00	$31.83	$213.74
Yakima, WA, 200 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	1,000	$2,217	$255	6.839%	$169.05	$30.45	1.379%	$0.42	$0.00	$30.87	$199.92
Idaho Falls, ID, 100 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours (10% ITC)	Yes	4,700	$2,351	$255	6.839%	$178.25	$30.00	1.379%	$0.41	$0.00	$30.41	$208.66
Idaho Falls, ID, 200 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours (10% ITC)	Yes	4,700	$2,161	$255	6.839%	$165.25	$28.95	1.379%	$0.40	$0.00	$29.35	$194.60
Lakeview, OR, 100 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours (10% ITC)	Yes	4,800	$2,329	$255	6.839%	$176.71	$30.00	1.379%	$0.41	$0.00	$30.41	$207.12
Lakeview, OR, 200 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours (10% ITC)	Yes	4,800	$2,154	$255	6.839%	$164.74	$28.95	1.379%	$0.40	$0.00	$29.35	$194.09
Milford, UT, 100 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (10% ITC)	Yes	5,000	$2,283	$255	6.839%	$173.58	$31.40	1.379%	$0.43	$0.00	$31.83	$205.41
Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (10% ITC)	Yes	5,000	$2,102	$255	6.839%	$161.21	$30.45	1.379%	$0.42	$0.00	$30.87	$192.08
Rock Springs, WY, 100 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (10% ITC)	Yes	6,400	$2,312	$255	6.839%	$175.57	$31.40	1.379%	$0.43	$0.00	$31.83	$207.40
Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (10% ITC)	Yes	6,400	$2,128	$255	6.839%	$163.01	$30.45	1.379%	$0.42	$0.00	$30.87	$193.88
Yakima, WA, 100 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours (10% ITC)	Yes	1,000	$2,405	$255	6.839%	$181.91	$31.40	1.379%	$0.43	$0.00	$31.83	$213.74
Yakima, WA, 200 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours (10% ITC)	Yes	1,000	$2,217	$255	6.839%	$169.05	$30.45	1.379%	$0.42	$0.00	$30.87	$199.92
Idah Falls, ID, 200 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours + 200 MW Wind	No	4,700	$3,395	$268	6.839%	$250.50	$82.95	1.379%	$1.14	$0.00	$84.09	$334.59
Lakeview, OR, 200 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours + 200 MW Wind	No	4,800	$3,424	$268	6.839%	$252.44	$82.95	1.379%	$1.14	$0.00	$84.09	$336.53
Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours + 200 MW Wind	No	5,000	$3,364	$268	6.839%	$248.37	$81.45	1.379%	$1.12	$0.00	$82.57	$330.95
Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours + 200 MW Wind	No	6,400	$3,364	$268	6.839%	$248.33	$81.45	1.379%	$1.12	$0.00	$82.57	$330.90
Yakima, WA, 200 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours + 200 MW Wind	No	1,000	$3,424	$268	6.839%	$252.46	$81.45	1.379%	$1.12	$0.00	$82.57	$335.04
Pumped Hydro, Swan Lake. 3600 MWh	Yes	N/A	$3,095	$485	6.251%	$223.78	$12.50	0.000%	$0.00	$0.00	$12.50	$236.28
Pumped Hydro, Goldendale, 14400 MWh	Yes	N/A	$2,833	$485	6.251%	$207.43	$12.50	0.000%	$0.00	$0.00	$12.50	$219.93
Pumped Hydro, Seminoe, 7500 MWh	Yes	N/A	$3,461	$485	6.111%	$241.13	$16.00	0.000%	$0.00	$0.00	$16.00	$257.13
Pumped Hydro, Badger Mountain, 4000 MWh	Yes	N/A	$2,621	$485	6.111%	$189.78	$28.00	0.000%	$0.00	$0.00	$28.00	$217.78
Pumped Hydro, Owyhee, 4800 MWh	Yes	N/A	$3,203	$485	6.111%	$225.33	$20.00	0.000%	$0.00	$0.00	$20.00	$245.33
Pumped Hydro, Flat Canyon, 1800 MWh	Yes	N/A	$4,046	$485	6.111%	$276.88	$53.33	0.000%	$0.00	$0.00	$53.33	$330.22
Pumped Hydro, Utah PS2, 4000 MWh	Yes	N/A	$3,237	$485	6.111%	$227.44	$28.00	0.000%	$0.00	$0.00	$28.00	$255.44
Pumped Hydro, Utah PS3, 4800 MWh	Yes	N/A	$3,371	$485	6.111%	$235.63	$20.00	0.000%	$0.00	$0.00	$20.00	$255.63
Pumped Hydro, Banner Mountain, 3400 MWh	Yes	N/A	$3,276	$485	6.479%	$243.64	$28.50	0.000%	$0.00	$0.00	$28.50	$272.14
Adiabatic CAES, Hydrostor, 150 MW, 600 MWh	No	N/A	$1,954	$12	7.497%	$147.40	$12.67	0.000%	$0.00	$0.00	$12.67	$160.06
Adiabatic CAES, Hydrostor, 150 MW, 1200 MWh	No	N/A	$2,189	$12	7.497%	$165.01	$12.67	0.000%	$0.00	$0.00	$12.67	$177.67
Adiabatic CAES, Hydrostor, 150 MW, 1800 MWh	No	N/A	$2,445	$12	7.497%	$184.22	$12.67	0.000%	$0.00	$0.00	$12.67	$196.89
Adiabatic CAES, Hydrostor, 300 MW, 1200 MWh	No	N/A	$1,557	$12	7.497%	$117.65	$9.33	0.000%	$0.00	$0.00	$9.33	$126.98
Adiabatic CAES, Hydrostor, 300 MW, 2400 MWh	No	N/A	$1,692	$12	7.497%	$127.79	$9.33	0.000%	$0.00	$0.00	$9.33	$137.12
Adiabatic CAES, Hydrostor, 300 MW, 3600 MWh	No	N/A	$2,016	$12	7.497%	$152.05	$9.33	0.000%	$0.00	$0.00	$9.33	$161.38
Adiabatic CAES, Hydrostor, 500 MW, 2000 MWh	Yes	N/A	$1,549	$12	7.497%	$117.06	$6.60	0.000%	$0.00	$0.00	$6.60	$123.66
Adiabatic CAES, Hydrostor, 500 MW, 4000 MWh	Yes	N/A	$1,762	$12	7.497%	$132.99	$6.60	0.000%	$0.00	$0.00	$6.60	$139.59
Adiabatic CAES, Hydrostor, 500 MW, 6000 MWh	Yes	N/A	$2,010	$12	7.497%	$151.61	$6.60	0.000%	$0.00	$0.00	$6.60	$158.21
Li-Ion Battery, , 1 MW, 0.5 MWh	No	N/A	$1,948	$55	8.676%	$173.74	$40.00	0.000%	$0.00	$0.00	$40.00	$213.74
Li-Ion Battery, , 1 MW, 1 MWh	No	N/A	$2,058	$110	8.676%	$188.13	$50.00	0.000%	$0.00	$0.00	$50.00	$238.13
Non-Emitting Peaker	Yes	5,050	$959	$2,414	7.497%	$252.85	$0.00	0.000%	$0.00	$0.00	$0.00	$252.85
Li-Ion Battery, , 50 MW, 200 MWh	Yes	N/A	$1,820	$440	8.676%	$196.05	$27.60	0.000%	$0.00	$0.00	$27.60	$223.65
Flow Battery, , 1 MW, 1 MWh	No	N/A	$4,719	$12	8.676%	$410.44	$13.00	0.000%	$0.00	$0.00	$13.00	$423.44
Flow Battery, , 1 MW, 4 MWh	No	N/A	$5,051	$12	8.676%	$439.29	$13.00	0.000%	$0.00	$0.00	$13.00	$452.29
Flow Battery, , 1 MW, 8 MWh	No	N/A	$7,291	$12	8.676%	$633.58	$27.00	0.000%	$0.00	$0.00	$27.00	$660.58
Flow Battery, , 20 MW, 160 MWh	Yes	N/A	$4,190	$12	8.676%	$364.59	$30.50	0.000%	$0.00	$0.00	$30.50	$395.09
Small Modular Reactor	Yes	5,000	$5,396	$722	6.733%	$411.88	$65.03	5.687%	$3.70	$0.00	$68.73	$480.61
Non-Emitting Peaker	Yes	5,050	$959	$2,414	7.497%	$252.85	$0.00	0.000%	$0.00	$0.00	$0.00	$252.85

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)			Capital Cost $/kW				Fixed Cost					
							Fixed O&M $/kW-Yr					
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital and Environmental Cost 1/	Demolition Cost	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
Brownfield Site												
Utah (Hunter, Huntington)												
Brownfield SCCT Frame "F" x1	Yes	5,050	$811	$12	7.049%	$58.00	0.00	0.273%	$0.00	$14.93	$14.93	$72.94
Intercooled SCCT Aero x2	Yes	5,050	$1,363	$12	7.497%	$103.10	0.00	1.135%	$0.00	$13.22	$13.22	$116.32
Brownfield CCCT Dry "H", DF, 2x1	Yes	5,050	$1,251	$12	6.886%	$87.00	0.00	0.000%	$0.00	$9.84	$9.84	$96.84
CCCT Dry "J", 1x1	Yes	5,050	$1,299	$12	6.886%	$90.28	0.00	0.000%	$0.00	$9.84	$9.84	$100.13
Milford, UT, 200 MW Solar, CF: 30.2% (10% ITC)	Yes	5,000	$1,297	$35	6.839%	$91.11	17.60	1.379%	$0.24	$0.00	$17.84	$108.95
Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	5,000	$2,102	$255	6.839%	$161.21	30.45	1.379%	$0.42	$0.00	$30.87	$192.08
Wyoming (Bridger, Johnston, Wyodak)						0						
Brownfield SCCT Frame "F" x1	Yes	6,500	$854	$13	7.049%	$61.12	0.00	0.273%	$0.00	$9.70	$9.70	$70.82
Intercooled SCCT Aero x2	Yes	6,500	$1,427	$13	7.497%	$107.96	0.00	1.135%	$0.00	$8.62	$8.62	$116.58
Brownfield CCCT Dry "H", DF, 2x1	Yes	6,500	$1,283	$12	6.886%	$89.18	0.00	0.000%	$0.00	$6.62	$6.62	$95.80
CCCT Dry "J", 1x1	Yes	6,500	$1,337	$12	6.886%	$92.91	0.00	0.000%	$0.00	$6.62	$6.62	$99.53
Medicine Bow, WY, 200 MW Wind, CF: 43.6% (60% PTC)	Yes	6,500	$1,356	$13	6.979%	$95.54	24.74	0.000%	$0.00	$0.00	$24.74	$120.28
Medicine Bow, WY, 200 MW Wind, CF: 43.6% + BESS: 50% pwr, 4 hours	Yes	6,500	$2,136	$233	6.979%	$165.29	37.59	2.902%	$1.09	$0.00	$38.68	$203.97
Rock Springs, WY, 200 MW Solar, CF: 27.9% (10% ITC)	Yes	6,400	$1,297	$35	6.839%	$91.07	17.60	1.379%	$0.24	$0.00	$17.84	$108.91
Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	6,400	$2,128	$255	6.839%	$163.01	30.45	1.379%	$0.42	$0.00	$30.87	$193.88
Naughton 1 PC CCUS Retrofit	Yes	6,500	$3,939	$37	8.920%	$354.70	39.99	5.541%	$2.22	$0.00	$42.21	$396.91
Naughton 2 PC CCUS Retrofit	Yes	6,500	$3,930	$37	8.920%	$353.83	39.90	5.541%	$2.21	$0.00	$42.11	$395.94
Johnston 2 PC CCUS Retrofit	Yes	6,500	$5,314	$37	8.920%	$477.27	40.58	5.541%	$2.25	$0.00	$42.83	$520.10
Johnston 4 PC CCUS Retrofit	Yes	6,500	$3,877	$37	8.920%	$349.16	37.88	5.541%	$2.10	$0.00	$39.97	$389.13
Wyodak PC CCUS Retrofit	Yes	6,500	$3,935	$37	9.010%	$357.86	39.95	5.541%	$2.21	$0.00	$42.16	$400.02
Bridger 1 PC CCUS Retrofit	Yes	6,500	$3,934	$37	8.920%	$354.24	39.94	5.541%	$2.21	$0.00	$42.15	$396.39
Bridger 3 PC CCUS Retrofit	Yes	6,500	$3,873	$37	9.010%	$352.29	37.83	5.541%	$2.10	$0.00	$39.93	$392.22
Bridger 4 PC CCUS Retrofit	Yes	6,500	$3,876	$37	9.010%	$352.56	37.86	5.541%	$2.10	$0.00	$39.96	$392.52

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)		Convert to $/MWh											
					Levelized Fuel							Credits	
Resource Description	Elevation (AFSL)	Capacity Factor 2/	l Fixed($/MW	Storage Efficiency	$/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Total Resource Cost	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
SCCT Aero x3	0	33%	$49.25	N/A	$ 2.97	$ 27.77	$ 7.44	11.48%	$ 0.85	$ -	$85.32	$ -	$85.32
Intercooled SCCT Aero x2	0	33%	$39.84	N/A	$ 2.97	$ 26.13	$ 5.03	11.48%	$ 0.58	$ -	$71.58	$ -	$71.58
SCCT Frame "F" x1	0	33%	$28.97	N/A	$ 2.97	$ 29.44	$ 14.16	13.23%	$ 1.87	$ -	$74.44	$ -	$74.44
Brownfield SCCT Frame "F" x1	0	33%	$28.36	N/A	$ 2.97	$ 29.44	$ 14.16	13.23%	$ 1.87	$ -	$73.83	$ -	$73.83
IC Recips x 6	0	33%	$57.40	N/A	$ 2.97	$ 24.61	$ 10.39	8.73%	$ 0.91	$ -	$93.30	$ -	$93.30
CCCT Dry "H", 1x1	0	78%	$17.62	N/A	$ 2.97	$ 18.84	$ 1.77	10.21%	$ 0.18	$ -	$38.41	$ -	$38.41
CCCT Dry "H", DF, 1x1	0	12%	$53.19	N/A	$ 2.97	$ 26.25	$ 0.05	0.00%	$ -	$ -	$79.49	$ -	$79.49
CCCT Dry "H", 2x1	0	78%	$13.83	N/A	$ 2.97	$ 18.89	$ 1.71	10.79%	$ 0.18	$ -	$34.61	$ -	$34.61
CCCT Dry "H", DF, 2x1	0	12%	$45.87	N/A	$ 2.97	$ 25.73	$ 0.05	0.00%	$ -	$ -	$71.65	$ -	$71.65
Brownfield CCCT Dry "H", DF, 2x1	0	78%	$13.78	N/A	$ 2.97	$ 19.63	$ 1.08	10.21%	$ 0.11	$ -	$34.61	$ -	$34.61
CCCT Dry "J", 1x1	0	78%	$14.25	N/A	$ 2.97	$ 18.60	$ 1.48	10.21%	$ 0.15	$ -	$34.49	$ -	$34.49
CCCT Dry "J", DF, 1x1	0	12%	$48.26	N/A	$ 2.97	$ 26.05	$ 0.06	0.00%	$ -	$ -	$74.36	$ -	$74.36
CCCT Dry "J", 2x1	0	78%	$11.45	N/A	$ 2.97	$ 18.57	$ 1.43	10.79%	$ 0.15	$ -	$31.60	$ -	$31.60
CCCT Dry "J", DF, 2x1	0	12%	$42.48	N/A	$ 2.97	$ 25.85	$ 0.06	0.00%	$ -	$ -	$68.39	$ -	$68.39
SCCT Aero x3	1,500	33%	$51.59	N/A	$ 2.97	$ 27.81	$ 7.89	11.48%	$ 0.91	$ -	$88.19	$ -	$88.19
Intercooled SCCT Aero x2	1,500	33%	$41.52	N/A	$ 2.97	$ 26.14	$ 5.31	11.48%	$ 0.61	$ -	$73.58	$ -	$73.58
SCCT Frame "F" x1	1,500	33%	$29.99	N/A	$ 2.97	$ 29.45	$ 14.94	13.23%	$ 1.98	$ -	$76.36	$ -	$76.36
Brownfield SCCT Frame "F" x1	1,500	33%	$29.34	N/A	$ 2.97	$ 29.45	$ 14.94	13.23%	$ 1.98	$ -	$75.71	$ -	$75.71
IC Recips x 6	1,500	33%	$57.40	N/A	$ 2.97	$ 24.61	$ 10.39	8.73%	$ 0.91	$ -	$93.30	$ -	$93.30
CCCT Dry "H", 1x1	1,500	78%	$18.51	N/A	$ 2.97	$ 18.96	$ 1.88	10.21%	$ 0.19	$ -	$39.54	$ -	$39.54
CCCT Dry "H", DF, 1x1	1,500	12%	$53.00	N/A	$ 2.97	$ 26.10	$ 0.05	0.00%	$ -	$ -	$79.15	$ -	$79.15
CCCT Dry "H", 2x1	1,500	78%	$14.42	N/A	$ 2.97	$ 18.91	$ 1.81	10.79%	$ 0.19	$ -	$35.34	$ -	$35.34
CCCT Dry "H", DF, 2x1	1,500	12%	$45.67	N/A	$ 2.97	$ 25.88	$ 0.05	0.00%	$ -	$ -	$71.60	$ -	$71.60
Brownfield CCCT Dry "H", DF, 2x1	1,500	78%	$14.38	N/A	$ 2.97	$ 19.70	$ 1.14	10.21%	$ 0.12	$ -	$35.35	$ -	$35.35
CCCT Dry "J", 1x1	1,500	78%	$14.87	N/A	$ 2.97	$ 18.60	$ 1.57	10.21%	$ 0.16	$ -	$35.20	$ -	$35.20
CCCT Dry "J", DF, 1x1	1,500	12%	$48.08	N/A	$ 2.97	$ 26.18	$ 0.06	0.00%	$ -	$ -	$74.32	$ -	$74.32
CCCT Dry "J", 2x1	1,500	78%	$11.91	N/A	$ 2.97	$ 18.56	$ 1.51	10.79%	$ 0.16	$ -	$32.15	$ -	$32.15
CCCT Dry "J", DF, 2x1	1,500	12%	$42.30	N/A	$ 2.97	$ 25.96	$ 0.06	0.00%	$ -	$ -	$68.32	$ -	$68.32
SCCT Aero x3	3,000	33%	$48.82	N/A	$ 3.21	$ 30.11	$ 8.37	11.48%	$ 0.96	$ -	$88.26	$ -	$88.26
Intercooled SCCT Aero x2	3,000	33%	$38.49	N/A	$ 3.21	$ 28.28	$ 5.63	11.48%	$ 0.65	$ -	$73.05	$ -	$73.05
SCCT Frame "F" x1	3,000	33%	$25.49	N/A	$ 3.21	$ 31.87	$ 15.79	13.23%	$ 2.09	$ -	$75.24	$ -	$75.24
Brownfield SCCT Frame "F" x1	3,000	33%	$24.81	N/A	$ 3.21	$ 31.87	$ 15.78	13.23%	$ 2.09	$ -	$74.55	$ -	$74.55

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)*

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)		Convert to $/MWh			Levelized Fuel							Credits	
Resource Description	Elevation (AFSL)	Capacity Factor 3/	Total Fixed ($/MWh)	Storage Efficiency	$/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Total Resource Cost	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
IC Recips x 6	3,000	33%	$52.80	N/A	$ 3.21	$ 26.60	$ 10.39	8.73%	$ 0.91	$ -	$90.69	$ -	$90.69
CCCT Dry "H", 1x1	3,000	78%	$19.33	N/A	$ 3.21	$ 20.50	$ 1.99	10.21%	$ 0.20	$ -	$42.02	$ -	$42.02
CCCT Dry "H", DF, 1x1	3,000	12%	$52.92	N/A	$ 3.21	$ 28.30	$ 0.05	0.00%	$ -	$ -	$81.26	$ -	$81.26
CCCT Dry "H", 2x1	3,000	78%	$13.46	N/A	$ 3.21	$ 20.55	$ 1.92	10.79%	$ 0.21	$ -	$36.13	$ -	$36.13
CCCT Dry "H", DF, 2x1	3,000	12%	$35.23	N/A	$ 3.21	$ 28.11	$ 0.05	0.00%	$ -	$ -	$63.39	$ -	$63.39
Brownfield CCCT Dry "H", DF, 2x1	3,000	78%	$13.43	N/A	$ 3.21	$ 21.45	$ 1.21	10.21%	$ 0.12	$ -	$36.22	$ -	$36.22
CCCT Dry "J", 1x1	3,000	78%	$13.89	N/A	$ 3.21	$ 20.13	$ 1.66	10.21%	$ 0.17	$ -	$35.84	$ -	$35.84
CCCT Dry "J", DF, 1x1	3,000	12%	$37.71	N/A	$ 3.21	$ 28.37	$ 0.06	0.00%	$ -	$ -	$66.14	$ -	$66.14
CCCT Dry "J", 2x1	3,000	78%	$10.77	N/A	$ 3.21	$ 20.08	$ 1.60	10.79%	$ 0.17	$ -	$32.62	$ -	$32.62
CCCT Dry "J", DF, 2x1	3,000	12%	$31.94	N/A	$ 3.21	$ 28.13	$ 0.06	0.00%	$ -	$ -	$60.13	$ -	$60.13
SCCT Aero x3	5,050	33%	$51.28	N/A	$ 3.13	$ 29.42	$ 9.04	11.48%	$ 1.04	$ -	$90.78	$ -	$90.78
Intercooled SCCT Aero x2	5,050	33%	$40.24	N/A	$ 3.13	$ 27.59	$ 6.09	11.48%	$ 0.70	$ -	$74.62	$ -	$74.62
SCCT Frame "F" x1	5,050	33%	$25.97	N/A	$ 3.13	$ 31.10	$ 17.04	13.23%	$ 2.25	$ -	$76.36	$ -	$76.36
Brownfield SCCT Frame "F" x1	5,050	33%	$25.23	N/A	$ 3.13	$ 31.10	$ 17.03	13.23%	$ 2.25	$ -	$75.62	$ -	$75.62
IC Recips x 6	5,050	33%	$51.91	N/A	$ 3.13	$ 25.95	$ 10.39	8.73%	$ 0.91	$ -	$89.16	$ -	$89.16
CCCT Dry "H", 1x1	5,050	78%	$18.57	N/A	$ 3.13	$ 19.91	$ 2.14	10.21%	$ 0.22	$ -	$40.84	$ -	$40.84
CCCT Dry "H", DF, 1x1	5,050	12%	$40.21	N/A	$ 3.13	$ 26.75	$ 0.05	0.00%	$ -	$ -	$67.00	$ -	$67.00
CCCT Dry "H", 2x1	5,050	78%	$14.19	N/A	$ 3.13	$ 20.31	$ 2.10	10.79%	$ 0.23	$ -	$36.82	$ -	$36.82
CCCT Dry "H", DF, 2x1	5,050	12%	$32.88	N/A	$ 3.13	$ 29.64	$ 0.05	0.00%	$ -	$ -	$62.57	$ -	$62.57
Brownfield CCCT Dry "H", DF, 2x1	5,050	78%	$14.17	N/A	$ 3.13	$ 21.51	$ 1.33	10.21%	$ 0.14	$ -	$37.15	$ -	$37.15
CCCT Dry "J", 1x1	5,050	78%	$14.65	N/A	$ 3.13	$ 19.88	$ 1.81	10.21%	$ 0.18	$ -	$36.53	$ -	$36.53
CCCT Dry "J", DF, 1x1	5,050	12%	$35.39	N/A	$ 3.13	$ 29.58	$ 0.06	0.00%	$ -	$ -	$65.03	$ -	$65.03
CCCT Dry "J", 2x1	5,050	78%	$11.30	N/A	$ 3.13	$ 19.95	$ 1.76	10.79%	$ 0.19	$ -	$33.19	$ -	$33.19
CCCT Dry "J", DF, 2x1	5,050	12%	$29.63	N/A	$ 3.13	$ 29.60	$ 0.06	0.00%	$ -	$ -	$59.28	$ -	$59.28
SCCT Aero x3	6,500	33%	$54.26	N/A	$ 3.09	$ 28.78	$ 9.96	11.48%	$ 1.14	$ -	$94.14	$ -	$94.14
Intercooled SCCT Aero x2	6,500	33%	$40.33	N/A	$ 3.09	$ 27.15	$ 6.37	11.48%	$ 0.73	$ -	$74.58	$ -	$74.58
SCCT Frame "F" x1	6,500	33%	$25.27	N/A	$ 3.09	$ 30.68	$ 17.95	13.23%	$ 2.38	$ -	$76.29	$ -	$76.29
Brownfield SCCT Frame "F" x1	6,500	33%	$24.50	N/A	$ 3.09	$ 30.68	$ 17.95	13.23%	$ 2.38	$ -	$75.51	$ -	$75.51
IC Recips x 6	6,500	33%	$50.39	N/A	$ 3.09	$ 25.75	$ 10.39	8.73%	$ 0.91	$ -	$87.43	$ -	$87.43
CCCT Dry "H", 1x1	6,500	78%	$20.89	N/A	$ 3.09	$ 19.75	$ 2.23	10.21%	$ 0.23	$ -	$43.10	$ -	$43.10
CCCT Dry "H", DF, 1x1	6,500	12%	$50.43	N/A	$ 3.09	$ 27.37	$ 0.05	0.00%	$ -	$ -	$77.85	$ -	$77.85

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)		Convert to $/MWh			Levelized Fuel							Credits	
Resource Description	Elevation (AFSL)	Capacity Factor 3/	l Fixed($/MW	Storage Efficiency	$/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Total Resource Cost	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
CCCT Dry "H", 2x1	6,500	78%	$14.04	N/A	$ 3.09	$ 19.77	$ 2.15	10.79%	$ 0.23	$ -	$36.20	$ -	$36.20
CCCT Dry "H", DF, 2x1	6,500	12%	$29.79	N/A	$ 3.09	$ 27.35	$ 0.05	0.00%	$ -	$ -	$57.20	$ -	$57.20
Brownfield CCCT Dry "H", DF, 2x1	6,500	78%	$14.02	N/A	$ 3.09	$ 20.78	$ 1.36	10.21%	$ 0.14	$ -	$36.30	$ -	$36.30
CCCT Dry "J", 1x1	6,500	78%	$14.57	N/A	$ 3.09	$ 19.38	$ 1.86	10.21%	$ 0.19	$ -	$36.00	$ -	$36.00
CCCT Dry "J", DF, 1x1	6,500	12%	$32.32	N/A	$ 3.09	$ 27.39	$ 0.06	0.00%	$ -	$ -	$59.77	$ -	$59.77
CCCT Dry "J", 2x1	6,500	78%	$11.05	N/A	$ 3.09	$ 19.34	$ 1.80	10.79%	$ 0.19	$ -	$32.38	$ -	$32.38
CCCT Dry "J", DF, 2x1	6,500	12%	$26.56	N/A	$ 3.09	$ 27.16	$ 0.06	0.00%	$ -	$ -	$53.78	$ -	$53.78
SCPC with CCS	4,500	90%	$66.91	N/A	$ 1.96	$ 25.65	$ 7.00	0.00%	$ -	$ -	$99.56	$ -	$99.56
IGCC with CCS	4,500	86%	$69.93	N/A	$ 1.96	$ 21.21	$ 11.77	11.52%	$ 1.36	$ -	$104.27	$ -	$104.27
PC CCS retrofit @ 500 MW pre-retrofit basis	4,500	90%	$29.80	N/A	$ 1.96	$ 28.17	$ 3.29	0.00%	$ -	$ -	$61.26	$ -	$61.26
SCPC with CCS	6,500	90%	$73.66	N/A	$ 1.96	$ 25.95	$ 7.58	0.00%	$ -	$ -	$107.19	$ -	$107.19
IGCC with CCS	6,500	86%	$78.77	N/A	$ 1.96	$ 21.65	$ 14.11	11.52%	$ 1.63	$ -	$116.15	$ -	$116.15
PC CCS retrofit @ 500 MW pre-retrofit basis	6,500	90%	$29.80	N/A	$ 1.96	$ 28.17	$ 3.29	0.00%	$ -	$ -	$61.26	$ -	$61.26
Blundell Dual Flash 90% CF	4,500	90%	$59.71	N/A	$ -	$ -	$ 1.16	0.00%	$ -	$ -	$60.87	$ (16.12)	$44.75
Greenfield Binary 90% CF	4,500	90%	$61.71	N/A	$ -	$ -	$ 1.16	0.00%	$ -	$ -	$62.88	$ (16.12)	$46.75
Generic Geothermal PPA 90% CF	4,500	90%	$0.00	N/A	$ -	$ -	$ 77.34	0.00%	$ -	$ -	$77.34	$ (16.12)	$61.22
Pocatello, ID, 200 MW Wind, CF: 37.1% (100% PTC)	4,500	37%	$37.19	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$38.12	$ (16.12)	$22.00
Arlington, OR, 200 MW Wind, CF: 37.1% (100% PTC)	1,500	37%	$36.13	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$37.05	$ (16.12)	$20.93
Monticello, UT, 200 MW Wind, CF: 29.5% (100% PTC)	4,500	30%	$45.20	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$46.13	$ (16.12)	$30.00
Medicine Bow, WY, 200 MW Wind, CF: 43.6% (100%PTC)	6,500	44%	$31.49	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$32.42	$ (16.12)	$16.30
Goldendale, WA, 200 MW Wind, CF: 37.1% (100% PTC)	1,500	37%	$37.73	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$38.66	$ (16.12)	$22.54
Pocatello, ID, 200 MW Wind, CF: 37.1% (60% PTC)	4,500	37%	$37.19	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$38.12	$ (9.67)	$28.45
Arlington, OR, 200 MW Wind, CF: 37.1% (60% PTC)	1,500	37%	$36.13	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$37.05	$ (9.67)	$27.38
Monticello, UT, 200 MW Wind, CF: 29.5% (60% PTC)	4,500	30%	$45.20	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$46.13	$ (9.67)	$36.45
Medicine Bow, WY, 200 MW Wind, CF: 43.6% (60% PTC)	6,500	44%	$31.49	N/A	$ -	$ -	$ 0.65	0.00%	$ -	$ 0.93	$33.07	$ (9.67)	$23.40
Goldendale, WA, 200 MW Wnd, CF: 37.1% (60% PTC)	1,500	37%	$37.73	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$38.66	$ (9.67)	$28.99
Pocatello, ID, 200 MW Wind, CF: 37.1% + BESS: 50% pwr, 4 hours	4,500	37%	$63.12	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$64.05	$ (16.12)	$47.92
Arlington, OR, 200 MW Wind, CF: 37.1% + BESS: 50% pwr, 4 hours	1,500	37%	$61.69	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$62.62	$ (16.12)	$46.50
Monticello, UT, 200 MW Wind, CF: 29.5% + BESS: 50% pwr, 4 hours	4,500	30%	$76.90	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$77.83	$ (16.12)	$61.71
Medicine Bow, WY, 200 MW Wind, CF: 43.6% + BESS: 50% pwr, 4 hours	6,500	44%	$53.40	85%	$ -	$ -	$ 0.65	0.00%	$ -	$ 0.93	$54.98	$ (16.12)	$38.86
Goldendale, WA, 200 MW Wind, CF: 37.1% + BESS: 50% pwr, 4 hours	1,500	37%	$64.37	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$65.30	$ (16.12)	$49.18
Idaho Falls, ID, 100 MW Solar, CF: 26.1% (30% ITC)	4,700	26%	$50.96	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$51.67	$ (10.96)	$40.70
Idaho Falls, ID, 200 MW Solar, CF: 26.1% (30% ITC)	4,700	26%	$47.13	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$47.84	$ (9.99)	$37.85
Lakeview, OR, 100 MW Solar, CF: 27.6% (30% ITC)	4,800	28%	$48.64	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$49.35	$ (10.48)	$38.86
Lakeview, OR, 200 MW Solar, CF: 27.6% (30% ITC)	4,800	28%	$45.37	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$46.08	$ (9.66)	$36.42
Milford, UT, 100 MW Solar, CF: 30.2% (30% ITC)	5,000	30%	$44.42	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$45.12	$ (9.43)	$35.69
Milford, UT, 200 MW Solar, CF: 30.2% (30% ITC)	5,000	30%	$41.18	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$41.89	$ (8.60)	$33.28
Rock Springs, WY, 100 MW Solar, CF: 27.9% (30% ITC)	6,400	28%	$48.10	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$48.80	$ (10.21)	$38.58
Rock Springs, WY, 200 MW Solar, CF: 27.9% (30% ITC)	6,400	28%	$44.56	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$45.27	$ (9.31)	$35.96
Yakima, WA, 100 MW Solar, CF: 24.2% (30% ITC)	1,000	24%	$57.49	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$58.20	$ (12.30)	$45.90
Yakima, WA, 200 MW Solar, CF: 24.2% (30% ITC)	1,000	24%	$53.32	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$54.03	$ (11.23)	$42.80
Idaho Falls, ID, 100 MW Solar, CF: 26.1% (10% ITC)	4,700	26%	$50.96	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$51.67	$ (0.52)	$51.15
Idaho Falls, ID, 200 MW Solar, CF: 26.1% (10% ITC)	4,700	26%	$47.13	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$47.84	$ (0.47)	$47.36
Lakeview, OR, 100 MW Solar, CF: 27.6% (10% ITC)	4,800	28%	$48.64	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$49.35	$ (0.50)	$48.85
Lakeview, OR, 200 MW Solar, CF: 27.6% (10% ITC)	4,800	28%	$45.37	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$46.08	$ (0.46)	$45.62
Milford, UT, 100 MW Solar, CF: 30.2% (10% ITC)	5,000	30%	$44.42	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$45.12	$ (0.45)	$44.67
Milford, UT, 200 MW Solar, CF: 30.2% (10% ITC)	5,000	30%	$41.18	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$41.89	$ (0.41)	$41.48
Rock Springs, WY, 100 MW Solar, CF: 27.9% (10% ITC)	6,400	28%	$48.10	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$48.80	$ (0.48)	$48.31
Rock Springs, WY, 200 MW Solar, CF: 27.9% (10% ITC)	6,400	28%	$44.56	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$45.27	$ (0.44)	$44.82
Idaho Falls, ID, 100 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours (30% ITC)	4,700	26%	$91.26	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$91.97	$ (18.04)	$73.92

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)		Convert to $/MWh											
					Levelized Fuel							Credits	
Resource Description	Elevation (AFSL)	Capacity Factor 3/	l Fixed($/MW	Storage Efficiency	$/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Total Resource Cost	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
Idaho Falls, ID, 200 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours (30% ITC)	4,700	26%	$85.11	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$85.82	$ (16.59)	$69.23
Yakima, WA, 100 MW Solar, CF: 24.2% (10% ITC)	1,000	24%	$57.49	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$58.20	$ (0.58)	$57.61
Yakima, WA, 200 MW Solar, CF: 24.2% (10% ITC)	1,000	24%	$53.32	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$54.03	$ (0.53)	$53.50
Lakeview, OR, 100 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours (30% ITC)	4,800	28%	$85.67	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$86.37	$ (16.90)	$69.47
Lakeview, OR, 200 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours (30% ITC)	4,800	28%	$80.28	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$80.98	$ (15.63)	$65.35
Milford, UT, 100 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (30% ITC)	5,000	30%	$77.65	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$78.35	$ (15.14)	$63.21
Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (30% ITC)	5,000	30%	$72.60	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$73.31	$ (13.94)	$59.37
Rock Springs, WY, 100 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (30% ITC)	6,400	28%	$84.86	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$85.56	$ (16.60)	$68.96
Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (30% ITC)	6,400	28%	$79.33	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$80.03	$ (15.28)	$64.75
Yakima, WA, 100 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours (30% ITC)	1,000	24%	$100.83	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$101.53	$ (19.90)	$81.62
Yakima, WA, 200 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours (30% ITC)	1,000	24%	$94.31	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$95.01	$ (18.35)	$76.66
Idaho Falls, ID, 100 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours (10% ITC)	4,700	26%	$91.26	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$91.97	$ (0.86)	$91.11
Idaho Falls, ID, 200 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours (10% ITC)	4,700	26%	$85.11	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$85.82	$ (0.79)	$85.03
Lakeview, OR, 100 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours (10% ITC)	4,800	28%	$85.67	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$86.37	$ (0.80)	$85.57
Lakeview, OR, 200 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours (10% ITC)	4,800	28%	$80.28	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$80.98	$ (0.74)	$80.24
Milford, UT, 100 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (10% ITC)	5,000	30%	$77.65	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$78.35	$ (0.72)	$77.63
Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (10% ITC)	5,000	30%	$72.60	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$73.31	$ (0.66)	$72.65
Rock Springs, WY, 100 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (10% ITC)	6,400	28%	$84.86	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$85.56	$ (0.79)	$84.78
Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (10% ITC)	6,400	28%	$79.33	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$80.03	$ (0.73)	$79.31
Yakima, WA, 100 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours (10% ITC)	1,000	24%	$100.83	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$101.53	$ (0.94)	$100.59
Yakima, WA, 200 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours (10% ITC)	1,000	24%	$94.31	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$95.01	$ (0.87)	$94.14
Idah Falls, ID, 200 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours + 200 MW Wind	4,700	26%	$146.34	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$147.05	$ -	$147.05
Lakeview, OR, 200 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours + 200 MW Wind	4,800	28%	$139.19	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$139.90	$ -	$139.90
Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours + 200 MW Wind	5,000	30%	$125.10	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$125.80	$ -	$125.80
Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours + 200 MW Wind	6,400	28%	$135.39	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$136.10	$ -	$136.10
Yakima, WA, 200 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours + 200 MW Wind	1,000	24%	$158.04	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$158.75	$ -	$158.75
Pumped Hydro, Swan Lake. 3600 MWh	N/A	38%	$71.93	78%	$ -	$ -	$ -	0.00%	$ -	$ -	$71.93	$ -	$71.93
Pumped Hydro, Goldendale, 14400 MWh	N/A	50%	$50.21	78%	$ -	$ -	$ -	0.00%	$ -	$ -	$50.21	$ -	$50.21
Pumped Hydro, Seminoe, 7500 MWh	N/A	42%	$70.45	80%	$ -	$ -	$ 0.37	0.00%	$ -	$ -	$70.82	$ -	$70.82
Pumped Hydro, Badger Mountain, 4000 MWh	N/A	33%	$74.58	80%	$ -	$ -	$ 0.37	0.00%	$ -	$ -	$74.95	$ -	$74.95
Pumped Hydro, Owyhee, 4800 MWh	N/A	33%	$84.02	80%	$ -	$ -	$ 0.37	0.00%	$ -	$ -	$84.39	$ -	$84.39
Pumped Hydro, Flat Canyon, 1800 MWh	N/A	25%	$150.78	80%	$ -	$ -	$ 0.37	0.00%	$ -	$ -	$151.15	$ -	$151.15
Pumped Hydro, Utah PS2, 4000 MWh	N/A	33%	$87.48	80%	$ -	$ -	$ 0.37	0.00%	$ -	$ -	$87.85	$ -	$87.85
Pumped Hydro, Utah PS3, 4800 MWh	N/A	33%	$87.54	80%	$ -	$ -	$ 0.37	0.00%	$ -	$ -	$87.91	$ -	$87.91
Pumped Hydro, Banner Mountain, 3400 MWh	N/A	35%	$87.72	81%	$ -	$ -	$ 0.00	0.00%	$ -	$ -	$87.72	$ -	$87.72
Adiabatic CAES, Hydrostor, 150 MW, 600 MWh	N/A	17%	$109.63	60%	$ -	$ -	$ 6.50	0.00%	$ -	$ -	$116.13	$ -	$116.13
Adiabatic CAES, Hydrostor, 150 MW, 1200 MWh	N/A	33%	$60.85	60%	$ -	$ -	$ 6.50	0.00%	$ -	$ -	$67.35	$ -	$67.35
Adiabatic CAES, Hydrostor, 150 MW, 1800 MWh	N/A	50%	$44.95	60%	$ -	$ -	$ 6.50	0.00%	$ -	$ -	$51.45	$ -	$51.45
Adiabatic CAES, Hydrostor, 300 MW, 1200 MWh	N/A	17%	$86.97	60%	$ -	$ -	$ 6.50	0.00%	$ -	$ -	$93.47	$ -	$93.47
Adiabatic CAES, Hydrostor, 300 MW, 2400 MWh	N/A	33%	$46.96	60%	$ -	$ -	$ 6.50	0.00%	$ -	$ -	$53.46	$ -	$53.46
Adiabatic CAES, Hydrostor, 300 MW, 3600 MWh	N/A	50%	$36.84	60%	$ -	$ -	$ 6.50	0.00%	$ -	$ -	$43.34	$ -	$43.34
Adiabatic CAES, Hydrostor, 500 MW, 2000 MWh	N/A	17%	$84.70	60%	$ -	$ -	$ 6.50	0.00%	$ -	$ -	$91.20	$ -	$91.20
Adiabatic CAES, Hydrostor, 500 MW, 4000 MWh	N/A	33%	$47.81	60%	$ -	$ -	$ 6.50	0.00%	$ -	$ -	$54.31	$ -	$54.31
Adiabatic CAES, Hydrostor, 500 MW, 6000 MWh	N/A	50%	$36.12	60%	$ -	$ -	$ 6.50	0.00%	$ -	$ -	$42.62	$ -	$42.62

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)		Convert to $/MWh											
					Levelized Fuel							Credits	
Resource Description	Elevation (AFSL)	Capacity Factor 3/	l Fixed($/MW	Storage Efficiency	$/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Total Resource Cost	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
Li-Ion Battery, , 1 MW, 0.5 MWh	N/A	2%	$1,171.19	85%	$ -	$ -	cluded in FO	0.00%	$ -	$ -	$1,171.19	$ -	$1,171.19
Li-Ion Battery, , 1 MW, 1 MWh	N/A	4%	$652.41	85%	$ -	$ -	cluded in FO	0.00%	$ -	$ -	$652.41	$ -	$652.41
Li-Ion Battery, , 1 MW, 4 MWh	N/A	17%	$262.28	85%	$ -	$ -	cluded in FO	0.00%	$ -	$ -	$262.28	$ -	$262.28
Li-Ion Battery, , 1 MW, 8 MWh	N/A	33%	$197.73	85%	$ -	$ -	cluded in FO	0.00%	$ -	$ -	$197.73	$ -	$197.73
Li-Ion Battery, , 50 MW, 200 MWh	N/A	17%	$153.19	85%	$ -	$ -	cluded in FO	0.00%	$ -	$ -	$153.19	$ -	$153.19
Flow Battery, , 1 MW, 1 MWh	N/A	4%	$1,160.11	70%	$ -	$ -	cluded in FO	0.00%	$ -	$ -	$1,160.11	$ -	$1,160.11
Non-Emitting Peaker	5,050	33%	$87.47	0%	$ 26.72	$ 265.54	$ 21.29	0.00%	$ -	$ -	$374.30	$ -	$374.30
Flow Battery, , 20 MW, 160 MWh	N/A	33%	$135.30	70%	$ -	$ -	cluded in FO	0.00%	$ -	$ -	$135.30	$ -	$135.30
Small Modular Reactor	5000	86%	$ 64.12	N/A	$ -	$ -	$ 6.72	0.00%	$ -	$ -	$70.84	$ -	$70.84
Non-Emitting Peaker	5050	33%	$ 87.47	0%	$ 26.72	$ 265.54	$ 21.29	0.00%	$ -	$ -	$374.30	$ -	$374.30

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($) Resource Description	Elevation (AFSL)	Convert to $/MWh Capacity Factor 3/	Total Fixed ($/MWh)	Storage Efficiency	Levelized Fuel ¢/mmBtu	$/MWh	Variable Costs ($/MWh) O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost / CO2 Revenues	Total Resource Cost	Credits PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
Brownfield Site													
Utah													
Brownfield SCCT Frame "F" x1	5050	33%	$25.23	N/A	$ 3.13	$ 31.10	$ 17.03	13.23%	$ 2.25	$ -	$75.62	$ -	$75.62
Intercooled SCCT Aero x2	5050	33%	$40.24	N/A	$ 3.13	$ 27.59	$ 6.09	11.48%	$ 0.70	$ -	$74.62	$ -	$74.62
Brownfield CCCT Dry "H", DF, 2x1	5050	78%	$14.17	N/A	$ 3.13	$ 21.51	$ 1.33	10.21%	$ 0.14	$ -	$37.15	$ -	$37.15
CCCT Dry "J", 1x1	5050	78%	$14.65	N/A	$ 3.13	$ 19.88	$ 1.81	10.21%	$ 0.18	$ -	$36.53	$ -	$36.53
Milford, UT, 200 MW Solar, CF: 30.2% (10% ITC)	5000	30%	$41.18	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$41.89	$ (0.41)	$41.48
Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (30% ITC)	5,000	30%	$72.60	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$73.31	$ (13.94)	$59.37
Wyoming													
Brownfield SCCT Frame "F" x1	6500	33%	$24.50	N/A	$ 3.09	$ 30.68	$ 17.95	13.23%	$ 2.38	$ -	$75.51	$ -	$75.51
Intercooled SCCT Aero x2	6500	33%	$40.33	N/A	$ 3.09	$ 27.15	$ 6.37	11.48%	$ 0.73	$ -	$74.58	$ -	$74.58
Brownfield CCCT Dry "H", DF, 2x1	6500	78%	$14.02	N/A	$ 3.09	$ 20.78	$ 1.36	10.21%	$ 0.14	$ -	$36.30	$ -	$36.30
CCCT Dry "J", 1x1	6500	78%	$14.57	N/A	$ 3.09	$ 19.38	$ 1.86	10.21%	$ 0.19	$ -	$36.00	$ -	$36.00
Medicine Bow, WY, 200 MW Wind, CF: 43.6% (60% PTC)	6,500	44%	$31.49	N/A	$ -	$ -	$ 0.65	0.00%	$ -	$ 0.93	$33.07		$33.07
Medicine Bow, WY, 200 MW Wind, CF: 43.6% + BESS: 50% pwr, 4 hours	6,500	44%	$53.40	85%	$ -	$ -	$ 0.65	0.00%	$ -	$ 0.93	$54.98		$54.98
Rock Springs, WY, 200 MW Solar, CF: 27.9% (10% ITC)	6400	28%	$44.56	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$45.27	$ (0.44)	$44.82
Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (30% ITC)	6,400	28%	$79.33	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$80.03	$ (15.28)	$64.75
Naughton 1 PC CCUS Retrofit	6,500	85%	$53.31	0%	$ 2.28	$ 32.77	$ 7.32	0.00%	$ -	$ (12.28)	$81.12	$ (25.79)	$55.33
Naughton 2 PC CCUS Retrofit	6,500	85%	$53.17	0%	$ 2.28	$ 32.77	$ 7.30	0.00%	$ -	$ (12.28)	$80.97	$ (25.79)	$55.18
Johnston 2 PC CCUS Retrofit	6,500	85%	$69.85	0%	$ 0.99	$ 14.23	$ 6.10	0.00%	$ -	$ (12.28)	$77.90	$ (25.79)	$52.11
Johnston 4 PC CCUS Retrofit	6,500	85%	$52.26	0%	$ 0.99	$ 14.23	$ 5.69	0.00%	$ -	$ (12.28)	$59.91	$ (25.79)	$34.12
Wyodak PC CCUS Retrofit	6,500	85%	$53.72	0%	$ 1.14	$ 16.38	$ 7.31	0.00%	$ -	$ (12.28)	$65.14	$ (25.79)	$39.35
Bridger 1 PC CCUS Retrofit	6,500	85%	$53.24	0%	$ 2.12	$ 30.47	$ 7.31	0.00%	$ -	$ (12.28)	$78.74	$ (25.79)	$52.95
Bridger 3 PC CCUS Retrofit	6,500	85%	$52.68	0%	$ 2.12	$ 30.47	$ 5.69	0.00%	$ -	$ (12.28)	$76.56	$ (25.79)	$50.77
Bridger 4 PC CCUS Retrofit	6,500	85%	$52.72	0%	$ 2.12	$ 30.47	$ 5.69	0.00%	$ -	$ (12.28)	$76.60	$ (25.79)	$50.81

Additionally, total resource costs were prepared for five natural gas-fired combined cycle combustion turbine resource options at an elevation of 3,000 feet at varying capacity factors to show how these costs are affected by dispatch. Table 7.3 shows the total resource cost results for this analysis.

Table 7.3 - Total Resource Cost, for various Capacity Factors ($/MWh, 2020)

Total Resource Cost ($/MWh)			
Capacity Factor CCCT	**40%**	**78%**	**94%**
Capacity Factor Duct Fire	**10%**	**12%**	**22%**
CCCT Dry "H", 1x1	$60.39	$42.02	$38.73
CCCT Dry "H", DF, 1x1	$91.85	$81.26	$57.21
CCCT Dry "H", 2x1	$48.92	$36.13	$33.84
CCCT Dry "H", DF, 2x1	$70.43	$63.39	$47.37
Brownfield CCCT Dry "H", DF, 2x1	$48.98	$36.22	$33.94
CCCT Dry "J", 1x1	$49.04	$35.84	$33.48
CCCT Dry "J", DF, 1x1	$73.68	$66.14	$48.99
CCCT Dry "J", 2x1	$42.85	$32.62	$30.79
CCCT Dry "J", DF, 2x1	$66.52	$60.13	$45.61

Table 7.4 - Glossary of Terms from the Supply-Side Resource Table

Term	Description
Fuel	Primary fuel used for electricity generation or storage.
Resource	Primary technology used for electricity generation or storage.
Elevation (afsl)	Average feet above sea level for the proxy site for the given resource.
Net Capacity (MW)	For natural gas-fired generation resources, the Net Capacity is the net dependable capacity (net electrical output) for a given technology, at the given elevation, at the annual average ambient temperature in a "new and clean" condition.
Commercial Operation Year	The resource availability year is the earliest year the technology associated with the given generating resource is commercially available for procurement and installation. The total implementation time is the number of years necessary to implement all phases of resource development and construction: site selection, permitting, maintenance contracts, IRP approval, RFP process, owner's engineering, construction, commissioning and grid interconnection.
Design Life (years)	Average number of years the resource is expected to be "used and useful," based on various factors such as manufacturer's guarantees, fuel availability and environmental regulations.
Base Capital ($/kW)	Total capital expenditure in dollars per kilowatt-hour ($/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

Term	Description
	costs, owner's contingency), and financial costs (allowance for funds used during construction (AFUDC), capital surcharge, property taxes and escalation during construction, if applicable).
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 ($/kW-year)	Includes labor costs, combustion turbine fixed maintenance fees, contracted services fees, office equipment and training.
Demolition Cost ($/kW)	Total cost to decommission and demolish the generating unit at the end of life in dollars per kilowatt ($/kW).
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 7.5 - 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
CCUS	Carbon Capture Utilization 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 7.1.

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.

Brownfield SCCT Frame “F” x1 - a resource located at an existing generating facility 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 "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 "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 7.1: CCCT Dry "G/H", DF, 2x1; CCCT Dry "J/HA.02", DF, 1x1; CCCT Dry "J/HA.02", DF, 2x1.

Natural Gas, CCCT Dry "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.

Brownfield CCCT Dry "H", DF, 2X1 - a resource located at an existing generating facility based on a combined cycle resource using two frame-type General Electric 7HA.01 combustion turbines, two 3-pressure heat recovery steam generators with duct firing 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", 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", 2x1 - a combined cycle resource based on two frame-type General Electric 7HA.02 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 CCUS – 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 CCUS to reduce carbon dioxide emissions by 90 percent.

Coal, PC CCUS pre-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 CCUS – an advanced IGCC resource to facilitate lower CCUS 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 SCR 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, 4.0 MW turbine 37 percent Net Capacity Factor (NCF) WA/OR/ID – a wind resource based on 4.0 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, 4.0 MW turbine 29 percent NCF UT – a wind resource based on 4.0 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, 4.0 MW turbine 43 percent NCF WY – a wind resource based on 4.0 MW wind turbines located in Wyoming with an estimated annual net capacity factor of 43 percent.

Wind + Energy Storage – a wind resource as described above paired with a 4-hour battery with 50% of the power capacity of the wind resource. The batteries paired with wind resources in the previous IRP had 25% of the power of the wind resources.

Solar, PV Single Axis Tracking in ID, OR, UT, WA, and WY with NCF between 24.2 and 30.2 percent depending upon location (1.30 MWdc/MWac) – a large utility scale (100 MW or 200 MW) solar photovoltaic resource using crystalline silica solar panels in a single axis tracking system located in Idaho Falls, Idaho; Lakeview, Oregon; Milford, Utah; Rock Springs, WY; and Yakima, Washington.

Solar + Energy Storage – a solar resource as described above paired with a 4-hour battery with 50% of the power capacity of the solar resource. The batteries paired with solar resources in the previous IRP had 25% of the power of the solar resources.

Storage, Pumped Hydro Storage – a range (300 - 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 8 to 12 hours. Total development time is estimated at 6 –to 8 years due to various progress on permitting. The recharge ratio for this resource is 78 to 81 percent. Actual pumped hydro storage projects within PacifiCorp's territory were analyzed.

Storage, Lithium Ion Battery – a battery technology of lithium ion batteries located on PacifiCorp owned property. 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 85 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 70 percent.

Storage, CAES – compressed air energy storage (CAES) system consists of air storage reservoir pressurized by a compressor similar to a conventional gas turbine compression section but driven by an electric motor coupled with an adiabatic power generation turbine. The compressed air powers the adiabatic turbine. Off-peak energy is used to compress air into the storage reservoir. A system size of 500 MW is assumed. The air storage reservoir is assumed to be solution mined to size. No natural gas is required to generate power. The recharge ratio for this storage resource is 55 percent . The CAES resource modeled in the 2019 and prior IRP's was a diabatic system which differed from this resource in that it required burning fuel in the power generation turbine similar to a gas turbine engine.

Nuclear, Advanced Fission – removed from the list of resource options due to lack of progress by the developers.

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 884 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 7 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 2021 IRP and associated resource acquisition portfolios and/or products. The 2020 Renewable Resources Assessment and Summary Tables (Assessment) (See Volume II, Appendix M) 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 during procurement proposal evaluation 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 PacifiCorp:

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

Solar

The BMcD Assessment includes 100 MW, and 200 MW single axis tracking (SAT), PV options evaluated at five locations within the PacifiCorp services area. The 2021 IRP differs from the previous IRP in the following ways:

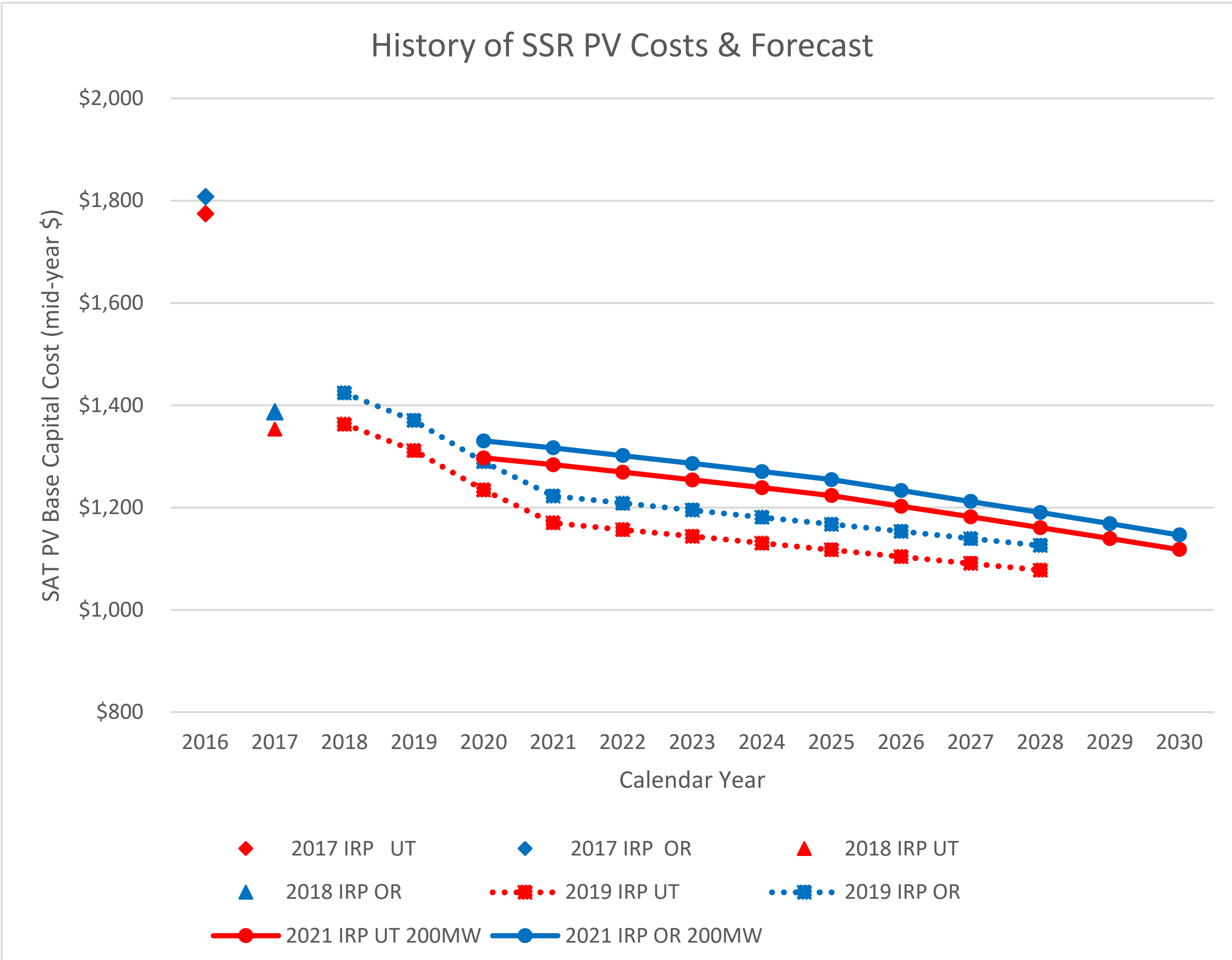
- Idaho, Washington and Wyoming solar resource costs were extrapolated from the previous IRP to scale similarly to the Oregon and Utah solar resource cost changes.
- The 5 MW option was removed and the 50 MW option for each of the five locations was increased to 100 MW based upon industry trends of building larger solar facilities.
- The DC to AC ratio was reduced from 1.46 to 1.30 based upon industry trends.

Solar costs (including forecasted costs) used for the 2021 IRP closely match the forecasted costs from the 2019 IRP through 2024 at which point the new linear forecast indicates costs may continue to decrease more rapidly than forecasted in the 2019 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 7.3 shows a history of capital cost forecasts used in the SSR for PV resources in Utah and Oregon. The 2021 IRP Capital cost estimates for solar resources are based upon a combination of information sources including the Burns & McDonnell study, recent studies from NREL and others, and from PacifiCorp's experience with active projects. The dotted lines show the forecast from the 2019 IRP. The data from prior IRP's was based on a 50 MW scale; however, the 50 MW scale is no longer included as a resource option. The solid line indicates the 2021 IRP price forecast at the 200 MW scale. It appears that the economy of scale has shifted to the larger (200 MW) scale plants.

Figure 7.3 – History of SSR PV Cost & Forecast



Wind

Wind energy has been one of the most cost-effective new generation resources for PacifiCorp's customers in recent IRPs and led to PacifiCorp's Energy Vision 2020 initiative. Energy Vision 2020 included the repowering of existing wind facilities, 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 added 1,150 MW of new wind power to PacifiCorp's generation resources. The wind market knowledge gained by PacifiCorp during the construction of the Energy Vision 2020 wind projects has been combined with the information in the BMcD Assessment to inform the wind costs in the 2021 IRP. Changes in the federal production tax credits (PTCs) for wind projects will also impact the market conditions for wind project in the coming years.

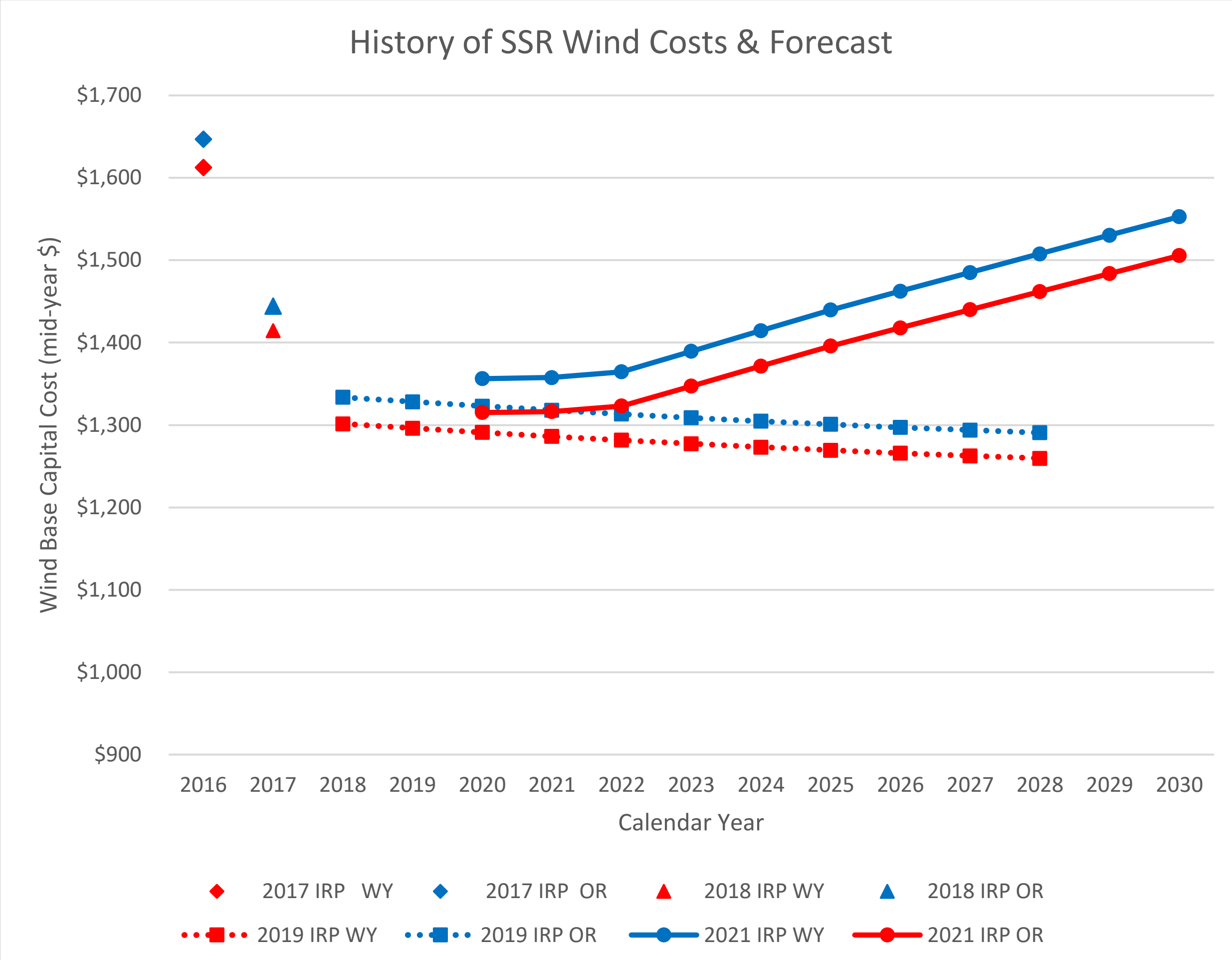
The BMcD Assessment uses a 200 MW project size that can be realized within most wind development areas in PacifiCorp's service territory and large enough to achieve economies of scale. Multiple 200 MW projects can be selected within the IRP models to meet larger generation needs. The net capacity factors for onshore wind generating facilities in the states of Idaho, Oregon, Utah, Washington, and Wyoming reflect strong wind resources that are achievable 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. Although the size of wind turbines in the SSR has increased from 3.6 MW to 4.0 MW the cost for utility scale wind farms in the 2021 IRP is very similar to the costs in the 2019 IRP. All wind resources are specified in 200 MW blocks, but the model can choose multiple blocks or a fractional amount of a block.

Federal PTCs were extended in December 2020 to allow wind projects that begin construction in 2021 and complete construction before December 31, 2024 to qualify for a 60% of the full tax credit amount. Wind projects that started construction in 2016 and 2017 were granted an extra year to complete construction and qualify for production tax credits due to Covid 19. The 2016 and 2017 projects must now be completed by 2021 and 2022 respectively. Wind construction activity is expected to remain strong through 2024 due to the PTC extensions. Capital cost estimates for wind resources in the IRP are projected to increase at less than the rate of inflation, based upon a combination of information sources including the Burns & McDonnell study, recent studies from NREL and others, communications with wind equipment suppliers and construction companies, and from PacifiCorp's experience with active and recently completed wind construction projects as shown in Figure 7.4, while other estimates indicate the levelized cost of energy for wind production could decline as much as 20 percent over the next ten years. The progressive national goals for renewable energy being put in place by the Biden administration could help sustain growth in the wind industry over the next decade and beyond.

Offshore Wind

Offshore wind holds the promise of high production capacity but faces various risks and costs that are higher than onshore wind projects. The most promising offshore wind regimes are located approximately 10 to 20 miles from the coast and will require underwater electric transmission lines to connect to the shore. New offshore wind projects will have to bear the cost of underwater transmission lines and any land-based transmission upgrades that are required to interconnect the project to the grid. Offshore wind turbines along the Pacific coast will need to be built on floating bases due to water depths that are hundreds of meters deep, as compared to offshore wind developments in shallower waters along the Atlantic coast. Floating offshore wind turbines are much less common than seabed-mounted offshore wind turbines that can be built in ocean waters up to 60 meters deep. Interest in offshore wind along the Pacific coast has increased during the past year and the advancement of two areas for offshore wind development along the coast of California by the US Department of the Interior was a significant step forward in the development process. PacifiCorp is reviewing offshore wind studies and reports and may include offshore wind as a resource in the SSR for the 2023 IRP.

Figure 7.4 – History of SSR Wind Costs & Forecast



Solar and 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 values for solar resources are 24% in Washington, 26% in Idaho, 27% in Oregon and Wyoming, and 30% in Utah. 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 energy used in IRP modeling. The hourly generation shape reflects average hourly resource variability. The hourly generation shape is repeated for each year of the simulation.

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, publicly available capital costs from the Geothermal Resources Council and publicly available prices for energy supplied under power purchase agreements.

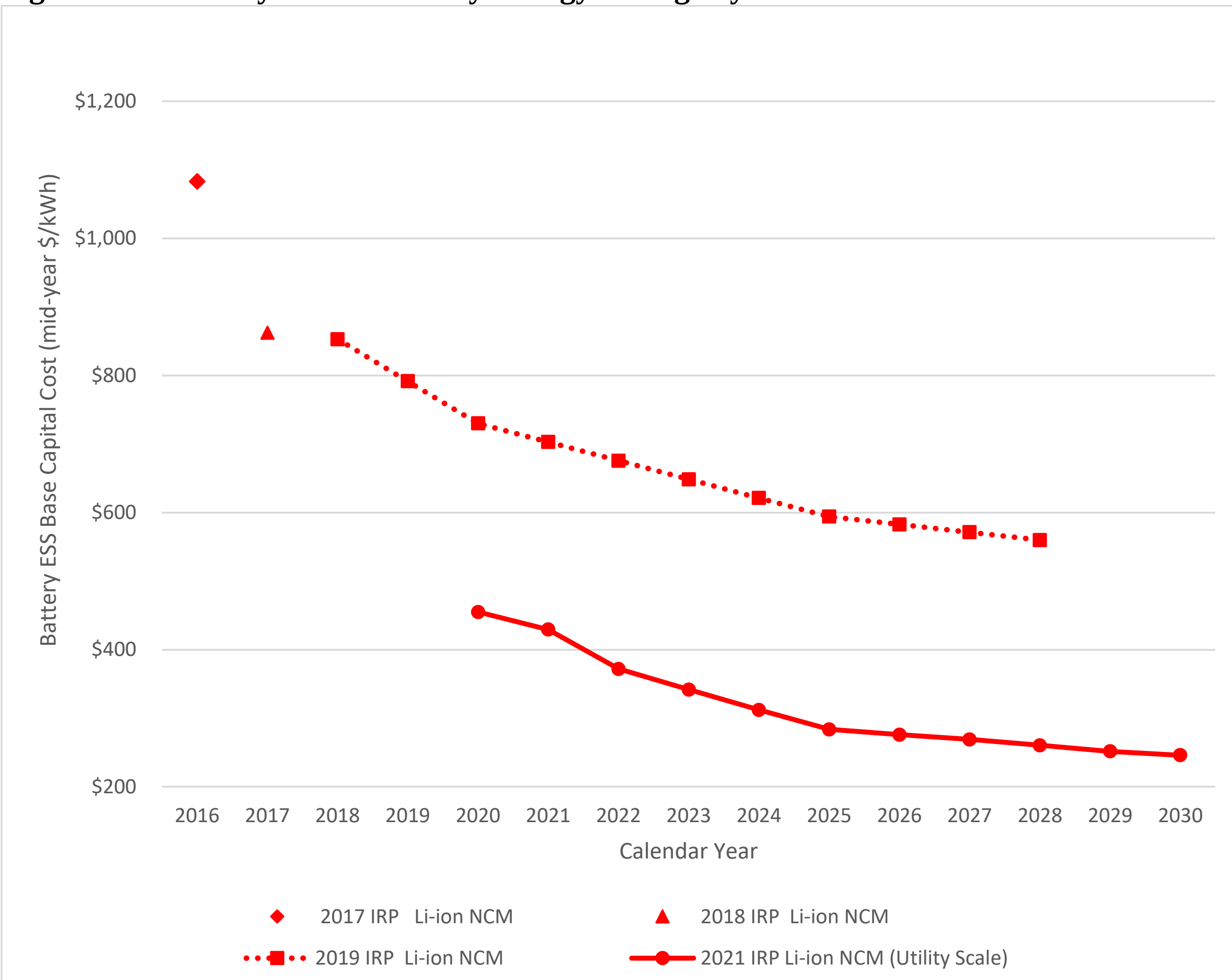
The cost recovery mechanisms currently available to PacifiCorp as a regulated electric utility are not compatible with the inherent risks associated with the development of geothermal resources for power generation. The primary risks of geothermal development are dry holes, well integrity and insufficient 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 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 Burns and McDonnell 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, despite the change technology change from an adiabatic system to a diabatic system. 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 7.5 shows a history of capital costs and a forecast used in the SSR for Li-Ion battery resources. The solid line indicates the 2020 price forecast at the 50 MW scale considered for the 2021 IRP, and part of the change from prior IRPs is due to economy-of-scale benefits. 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.

Figure 7.5 – History of SSR Battery Energy Storage System Costs & Forecast



PacifiCorp and its Berkshire Hathaway Energy affiliates continuously monitor and evaluate technical developments in the utility power industry, including energy storage technologies (lithium-ion and flow batteries, pumped storage hydro and hybrid energy-storage solutions), nuclear and carbon capture technologies. With the ever-advancing technological developments, market conditions, and regulatory environment, it is critical that PacifiCorp understand when developing technologies and other opportunities become sufficiently established in the marketplace that they can be implemented with minimal risk to PacifiCorp's system customers.

Fortune Business Insights estimates the global battery energy storage market size stood at $7.06 billion in 2019 and is anticipated to reach $19.74 billion by 2027, at a CAGR of 20.4%. The growth and technological advancements in lithium-ion batteries for the electric vehicle markets have resulted in technological advancements and cost reductions that also stand to benefit the electric utility market. PacifiCorp has monitored the use of lithium-ion battery storage in the electric utility market and believes based on its analysis and experience that the technology is mature enough for large scale deployment.

PacifiCorp has experience in all aspects of battery storage project development and execution including, budgeting, proforma, tax credits, siting, permitting, interconnection, engineering, equipment procurement, construction, project controls, quality assurance, commissioning, operation, and maintenance. PacifiCorp has utilized this expertise in 1) the development of proxy resources for the integrated resource plans since 2009, 2) the development of the use cases and specifications outlined in the 2020 all source request for proposal and 3) in the execution and construction of two battery storage demonstration projects and a third of which is in design development.

PacifiCorp has included consideration of battery storage in its IRP as a system resource since 2009. Since then, PacifiCorp actively monitored developments in battery storage and its cost, use, and application to our system resource planning. By 2015 battery storage became a more viable resource alternative, and PacifiCorp assigned an internal subject matter expert to track, review and evaluate ongoing and emerging developments in the battery storage market and the value that energy storage could provide to our customers.

PacifiCorp also leverages the broader Berkshire Hathaway Energy platform of companies including NV Energy and MidAmerican Energy to collaborate and share experiences and lessons learned regarding battery energy storage technology and capturing the value of energy storage. NV Energy has been a leader in battery storage implementation having signed contracts for more than 1 gigawatt of solar and 100 MW of storage in 2018 and an additional 1.2 gigawatts of solar and 590 MW of batteries contracted in 2019, and having further implemented residential, small and large commercial and industrial energy storage customer programs,[1] and having installed several transmission and distribution pilot projects.

In addition to leveraging the experience of its peer utilities, PacifiCorp has engaged the expertise of market-leading 3rd party technical experts including WSP, Black & Veatch, Power Engineers, FlexGen, Tesla and other leading battery consultants and suppliers to develop its proxy resource assumptions, develop its procurement specifications, evaluate bidders and design and construct utility-owned transmission and distribution facilities.

In 2019, PacifiCorp's IRP process identified approximately 700 megawatts of battery storage as a part of its least-cost portfolio and 2019 IRP action plan and worked to incorporate battery storage resources into the resulting 2020 all-source request for proposal. Leading up to the inclusion of battery storage in the 2020 all-source request for proposal, PacifiCorp developed a preferred supplier list, standard specifications, and system control schemes for battery storage facilities. In the request for proposal, PacifiCorp outlined battery storage use cases and required functionality to ensure battery storage proposals value was captured through battery energy storage bids. Finally, PacifiCorp engaged outside legal expertise in the structuring of contracting terms and conditions to mitigate any remaining delivery risk to its customers. Such outside legal expertise brings in battery storage contracting knowledge and experience from both within and outside the Berkshire Hathaway Energy.

PacifiCorp procurement and operational experience with battery storage projects

PacifiCorp completed the Panguitch Solar and Battery Storage project in Utah in 2020 as a utility-owned and operated transmission and distribution upgrade deferral project. In 2019-2020,

[1] https://www.nvenergy.com/cleanenergy/energy-storage/storage-faqs

PacifiCorp partnered with Sonnen, Inc. and the Wasatch Group to complete The Soleil Lofts Residential Apartment Project, a network of solar powered battery storage systems for the benefit of the apartment community and PacifiCorp's customers. PacifiCorp is currently completing the development and design for a second transmission and distribution upgrade deferral project in Oregon to install a battery storage project at the Oregon Institute of Technology in Klamath Falls, which is scheduled for completion in 2022. These three projects demonstrate the capability and validate the value battery storage provides to the electrical grid through peak shifting in order to defer the cost to upgrade regional transmission and distribution lines. PacifiCorp had complete turnkey responsibility for the Panguitch Solar and Battery Storage facility and will similarly be responsible for the Oregon Institute of Technology facility. The Soleil Lofts facilities were developed, constructed and owned by a 3rd party, but are being dispatched by PacifiCorp's Energy Supply Management Group for the benefit of PacifiCorp's system.

Panguitch Solar and Battery Storage Project

To correct voltage issues experienced during peak loading conditions on a portion of PacifiCorp's system in southern Utah, a stationary battery system and photovoltaic solar array was installed on a distribution circuit out of the Panguitch substation located in Garfield County, Utah. This project will alleviate peak loading on the power transformer, improve voltage conditions, and defer costs associated with upgrading the upstream 69-kV sub-transmission system under a traditional poles and wires build-out. The Panguitch project was a 650-kilowatt photovoltaic solar field and one megawatt, five-hour battery system in central Utah. PacifiCorp with Black & Veatch and battery supplier FlexGen developed multiple operating modes to demonstrate the full range and capabilities of 684 Samsung lithium-ion batteries and how different control modes affect energy system operation.

The Utah Public Service Commission approved the Panguitch battery storage project (1 MW, 5 MWh) under the Sustainable Transportation and Energy Plan/Utah Innovative Technologies (STEP/UIT) program December 29, 2016. The solar photovoltaic component (650 kW) of the project was separately funded by the company's Blue Sky program. PacifiCorp completed the purchase of a ten-acre project site in October 2017. Construction began in July 2019 and was completed in late 2019. Commercial operations began in 2020.

Since commercial operations began, the company has worked with the battery provider to refine the control algorithms to enable charging of the battery only from the on-site solar generation facility. The company is currently collecting solar and battery charge/discharge data from the site to further optimize operational performance.

Soleil Lofts Residential Apartment Project

Soleil Lofts, located in Herriman, Utah is an all-electric, net-zero development, that will generate as much electricity as it uses through rooftop solar panels backed up with battery storage. PacifiCorp collaborated with the Soleil Lofts residential apartment project to develop a behind the meter application of battery systems. This project is the largest utility-managed residential battery demand response solution in the United States. PacifiCorp with Sonnen, Inc. and the Wasatch Group completed a network of solar powered battery storage systems for the benefit of the apartment community and PacifiCorp's customers. The project features over 630 individuals Sonnen ecoLinx batteries, totaling 12.6 MWh of solar energy storage that is managed by PacifiCorp. The batteries provide emergency back-up power, daily management of peak energy use, and demand response for the overall management of the electric grid and demonstrating a way to expand residential renewable power capacity.

Oregon Institute of Technology

Oregon House Bill (HB) 2193, passed in June of 2015 directed electric companies in Oregon to identify and evaluate potential energy storage technologies. PacifiCorp has commenced a project to engineer, design, procure, interconnect, and commission a 2 MW (6 MWh) battery storage project on the campus of the Oregon Institute of Technology ("OIT") in Klamath Falls, Oregon. Design and procurement activities are underway in parallel with the generation interconnection review process. The project is expected to go into service in early 2023. PacifiCorp has contracted Kiewit Engineering as the Owner's engineer, Power Engineers as the Engineer of Record, and is working with supply vendors to secure a final purchase agreement. Once the design is complete a construction contractor will be selected via competitive bid. PacifiCorp's engineering and management team are also working with OIT to provide a student learning experience by partnering with OIT student groups who will be working with the project team during the design and construction of the project.

Outside Engineering Support for Battery Storage Procurement and Operations

In preparation for the 2020 all-source request for proposal which resulted from the resource need action items in the 2019 IRP process, PacifiCorp engaged WSP to 1) develop preferred use case and technical specifications for collocated and stand-alone storage resource bids, 2) evaluate the technical bid responses, and 3) update the generating-resource power purchase agreements to include battery storage terms and conditions and relevant exhibits needed for a collocated resource and storage power purchase agreement.

WSP is a globally recognized professional services firm with a 130-year history. WSP's primary inputs have been in a supporting role, assisting in the development of revised specification specific to wind and solar farm equipment and installations including accompanying battery storage facilities. Specific to battery storage, WSP has been influential in assisting PacifiCorp in the development of Li-battery specifications and has participated in the development of operating and contractual parameters that will become part of our revised power purchase agreement contract template in the 2020AS RFP contracting process.

A summary of WSP team members, their role and years of experience is provided in Table 7.6.

Table 7.6 – WSP Team Roles and Years of Experience

Role	# Years of Experience
Principal-In-Charge	19
Project Manager	27
BESS / SCADA Expert	7
BESS Constructability and Operations	29
BESS / Electrical Engineering (US)	9
BESS / Electrical Engineering (CAN)	7
BESS Systems Engineer	6

As stated above, PacifiCorp has been actively monitoring developments in battery storage since 2009 with support through the broader Berkshire Hathaway Energy platform of companies including NV Energy and MidAmerican Energy and through the engagement of market-leading companies like WSP, Black & Veatch, Power Engineers, FlexGen, Tesla. Further, PacifiCorp is actively evaluating and pursuing new control systems that will both integrate and optimize battery storage, and other electronically controlled distributed assets, to further assure both maximum customer benefit and improved system flexibility and stability for years to come. With each new battery storage resource added to on our system, we gain additional depth and experience that we then apply to the next cycle of integrated resource planning and subsequent resource procurement.

Natural Gas

A variety of natural gas-fueled generating resources 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. 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 zero feet above mean sea level and 59 °F (ISO conditions) as a reference. The essential services provided by the resource are firming for variable energy resources, intermediate and base generation.

Three simple cycle combustion turbine options and one reciprocating engine option could 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 firming and 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 9,936 Btu/kW-hr for the SCCT Frame “F” to 8,286 Btu/kW-hr for the 18V50SG engines. Installation of high temperature oxidation catalysts for carbon monoxide (CO) control and a selective catalytic reduction (SCR) system for NOx control would be available for these resources.

Eight combined cycle combustion turbine options could provide firming, intermediate and base generating service. Firming generating service requires resources that can increase and decrease generation to replace decreases and increases in generation from variable energy resources. 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 “H” size was represented by a GE HA.01. The “J” 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 6,352 to 6,487 Btu/kW-hr. Installation of oxidation catalysts for CO control and SCR systems for 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 SSR 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 SSR 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 SSR table, more than one manufacturer produces these types 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.

Coal

Coal resources are shown in the SSR table as new supercritical pulverized coal (PC) boilers and IGCC located in Utah and Wyoming at an existing site. Both resource types include CO_2 capture and compression needed for transportation. The standard design technology for PC boilers is supercritical technology (compared to subcritical). Supercritical technology is generally more cost-effective because it has a higher efficiency (resulting in a lower overall emissions intensity), has better load following capability, faster ramp rates, uses less water and requires less steel for construction. As such, there is a greater competitive marketplace for large supercritical boilers than for subcritical boilers, and large boiler manufacturers only offer supercritical boilers in the 500-plus MW sizes. A new coal-fueled generating facility would be subject to carbon dioxide emissions limits (1,400 lbs per megawatt-hour gross) under the Federal New Source Performance Standards

(NSPS) for Greenhouse Gases (GHG). These emission limits are only achievable if a coal-fueled generating facility is equipped with CCUS technology; however, this imposes a significant cost for both new and existing coal resources. Based on this requirement, only coal resource options that include CCUS technology are included in the SSR table. The capital and O&M costs for new coal-fuel generation options were updated by escalating corresponding costs used in the 2019 IRP. The CCUS retrofit costs were updated using information from existing carbon capture facilities, relevant studies and CCUS developers.

Carbon Capture Utilization and Sequestration

There are a limited number of commercial-scale carbon capture projects in operation around the world. Most have been installed in conjunction with a planned carbon dioxide end use of injection for EOR. There are only two major utility-scale CCUS retrofit projects on coal plants in North America that have been operated commercially. SaskPower's Boundary Dam Power Station Unit 3 (115 MW net), located in Saskatchewan, Canada, was retrofitted with an amine-based carbon capture system and entered commercial operation in October 2014. The captured carbon dioxide is piped 41 miles to the Weyburn field to be used for EOR. Any carbon dioxide not used for EOR is sequestered at the Aquistore research project. The total cost of the project was approximately $1.24 billion (including approximately $200 million through federal grants). In July 2016, the plant reached a major milestone when it demonstrated that over 1,100,000 tons of carbon dioxide had been captured.

NRG Energy installed a 240 MW equivalent flue gas slipstream amine-based carbon capture system on W.A. Parish Generating Station Unit 8 that went into commercial operation in January 2017. The project, named the Petra Nova Project, was a joint venture between NRG Energy and JX Nippon Oil & Gas Exploration, and cost approximately $1 billion. Approximately $195 million of federal funding in grants was awarded to the project as part of the Clean Coal Power Initiative Program (CCPI), a cost-shared collaboration between the federal government and private industry. The Petra Nova Project included a retrofit of an existing coal-fueled plant using amine-based system and captured approximately 5,200 short tons per day when operating at full capacity.[4] Captured carbon dioxide was 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 carbon capture retrofit of a pulverized coal plant in the world. The amine-based capture system utilizes Mitsubishi's proprietary KM CDR Process® and uses its KS-1™ amine solvent. Due to low demand for and price of oil in 2020, NRG Energy announced Petra Nova would be placed in a reserve shutdown effective May 1, 2020.[5] In January 2021, the Electric Reliability Council of Texas received a Notification of Suspension of Operations (NSO) for Petra Nova Power.[6] The NSO stated the resource would be mothballed indefinitely as of June 26, 2021.[7]

To address the availability and viability of commercial sequestration near PacifiCorp coal generation resources, three PacifiCorp power plants participated in federally funded research to conduct a Phase I pre-feasibility study, which was awarded in 2016, for carbon capture and storage.

[4] W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project Final Scientific/Technical Report; March 31, 2020.

[5] Petra Nova status update | NRG Energy

[6] W-A012721-01 Notification of Suspension of Operations (NSO) for Petra Nova Power I LLC (PNPI_GT2) (ercot.com)

[7] A March 2021 notice was issued, moving up the date to suspend operations to June 1, 2021. W-A012721-03 Date of suspension of operations changed - Indefinite Mothball Status of Petra Nova Power I LLC (PNPI_GT2) (ercot.com)

A grant from the U.S. Department of Energy (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 projects showed that geological formations exist near the plants that may support carbon sequestration, though further studies would be required. Neither site was selected by the U.S. DOE for an advanced study in the Phase II of the grant program.

PacifiCorp issued a request for expression of interest to potential CCUS counterparties on September 7, 2018. The request focused on possible deployment of CCUS technologies at PacifiCorp's Dave Johnston generating facility, including utilization of EOR. On February 28, 2019, PacifiCorp received Phase I feasibility studies from three respondent parties. On April 23, 2019, the participants were notified they could opt to progress to a Phase II front-end engineering and design (FEED) study at their discretion. Only one of the parties expressed intent to complete a FEED study. No participants received DOE funds to support Phase II studies. PacifiCorp remains open to evaluate any CCUS project proposal that may arise from these efforts. As part of its ongoing CCUS evaluation, PacifiCorp issued a new request for expression of interest (REOI) for CCUS on June 29, 2021 to identify and engage with any interested parties to explore the feasibility and design of CCUS facilities to remove carbon dioxide from exhaust gases for PacifiCorp's Wyoming coal-fueled generation, and subsequently utilize and/or sequester all removed carbon dioxide. Responses to the REOI will be a precursor to a PacifiCorp issuing a request for proposal (RFP) for CCUS projects.

PacifiCorp continues to monitor and evaluate current and emerging CCUS 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 carbon dioxide at an existing coal-fired unit has been included in the SSR. Due to the high capital cost of implementing CCUS on coal-fueled generation (both on a retrofit basis and for new resources) and applicable tax credits, CCUS was not considered viable in previous IRPs. Capital cost, transportation infrastructure, availability of commercial sequestration (non-EOR) sites, long-term liabilities for sequestration, and the lack of availability of federal funding continue to contribute to the risk and uncertainty of CCUS.

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 the NuScale Small Modular Reactor (SMR), but used nth-of-a-kind pricing rather than the 1st-of-a-kind pricing previously used for the plant being developed for construction at the Idaho National Lab site. 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. Blue Castle Holdings (BCH) again did not provide updated pricing, therefore the advanced reactor option based on the AP1000 design was eliminated from the resource options.

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 lack of maturity for the technology. 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 NuScale resource.

PacifiCorp's 2021 IRP includes the Natrium™ advanced nuclear demonstration project: a molten sodium-cooled nuclear reactor paired with a molten salt thermal energy storage tank. Both the reactor and the molten salt energy storage generate power through a single steam turbine.

At this time, the specific cost and performance assumptions for the Natrium™ advanced nuclear demonstration project are confidential and are not summarized in the SSR. The demonstration project has three primary elements: a nuclear reactor that produces heat, a steam generator to convert heat to electricity, and a molten salt tank to store heat. Operating characteristics of this facility are summarized as follows:

- 345 MW of baseload energy production at a 92.5% capacity factor
- Maximum output of 500 MW
- Minimum output of 100 MW
- A ramp rate of approximately 40 MW per minute from min to max
- Molten salt storage supports maximum output of 500 MW for a 5.5-hour duration (max output then drops to 345 MW until output is reduced and more heat can be stored)
- Maximum storage efficiency is 99%

Demand-Side Resources

Resource Options and Attributes

Source of Demand-Side Management Resource Data
PacifiCorp conducted a Conservation Potential Assessment (CPA) with for 2021-2040, which provided DSM resource opportunity estimates for the 2021 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.[8] 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 2021 IRP planning and modeling, PacifiCorp had established, funded and begun acquiring 2021 DSM program acquisition targets. To ensure that the 2021 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 2021. Beyond 2021, 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.

<u>Demand Response: DSM Capacity Supply Curves</u>
The potential and costs for demand response resources were provided at the state level, with impacts specified separately for summer and winter peak periods. To acquire resource needs identified in the 2019 IRP, the company issued the All Source (AS) 2020 RFP for large scale resources and subsequently issued a demand response (DR) RFP for DR resources. Successful initial short list bids from this DR RFP joined final bids from the AS 2020 RFP for a combined analysis in the 2021 IRP to determine the optimal acquisition of resources to meet system needs.

[8] The 2021 Conservation Potential Study is available on PacifiCorp's demand-side management web page. www.pacificorp.com/energy/integrated-resource-plan/support.html.

In 2022, where competitive bids overlapped with measures in the conservation potential assessment (CPA), competitive bids were substituted for demand response measures identified in the CPA to avoid double counting of demand response resources in the IRP and reflect resource characteristics and current pricing. In 2023 and beyond RFP and CPA resources were modeled together to assess the upper limit on demand response opportunities and value within the IRP given limitations on front office transactions. 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.

Table 7.7 and Table 7.8 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 2021 CPA.[9] Potential shown is incremental to the existing DSM resources identified in Table 7.7 For existing program offerings, it is assumed that the PacifiCorp could begin acquiring incremental potential in 2021. For resources representing new product offerings, it is assumed PacifiCorp could begin acquiring potential in 2022, accounting for the time required for program design, regulatory approval, vendor selection, etc.

Table 7.7 – Demand Response Program Attributes West Control Area[10],*

	Summer		Winter	
Product	20-Year Potential (MW)	Average Levelized Cost ($/kW-yr)	20-Year Potential (MW)	Average Levelized Cost ($/kW-yr)
Res - EV DLC	14	$144	15	$145
Res - Home Energy Management System	14	$84	5	$166
Res – HVAC DLC	11	$181	58	$61
Res – Pool Pump DLC	0.3	$521	0.3	$524
Res – Water Heater DLC	1	$62	2	$29
Res – Smart Thermostat	63	$31	23	$65
Res – Grid Interactive Water Heaters	18	$141	60	$61
Res –Battery DLC	50	$69	50	$69
C&I –Battery DLC	47	$48	47	$48
C&I – Grid Interactive Water Heaters	4	$93	8	$51
C&I – HVAC DLC	4	$141	8	$51
C&I – Pool Pump DLC	4	$330	2	$364
C&I – Smart Thermostats	0	$20	0	$301
C&I – Water Heater DLC	8	$48	5	$43
C&I – Third Party	62	$273	56	$335
Ag – Irrigation DLC	8	$51	0	$0

* Average levelized cost weighted by the 20-year cumulative potential in each state

[9] The CPA can be found at: www.pacificorp.com/energy/integrated-resource-plan/support.html.
[10] Demand response resources derived from the demand response RFP are not included to protect confidential 3rd party pricing information.

Table 7.8 – Demand Response Program Attributes East Control Area[11]

Product	Summer		Winter	
	20-Year Potential (MW)	Levelized Cost ($/kW-yr)	20-Year Potential (MW)	Levelized Cost ($/kW-yr)
Res - EV DLC	210	$62	210	$62
Res - Home Energy Management System	1	$971	1	$1,020
Res – HVAC DLC	42	$94	63	$192
Res – Pool Pump DLC	0.3	$585	0.3	$585
Res – Water Heater DLC	2	$142	6	$63
Res – Grid Interactive Water Heaters	16	$288	54	$124
Res –Battery DLC	210	$62	210	$62
C&I –Battery DLC	92	$61	92	$61
C&I – Grid Interactive Water Heaters	7	$201	12	$140
C&I – HVAC DLC	4	$313	9	$355
C&I – Pool Pump DLC	0	$247	0	$225
C&I – Smart Thermostats	9	$50	5	$177
C&I – Water Heater DLC	1	$92	1	$65
C&I – Third Party	146	$217	117	$304
Ag – Irrigation DLC	13	$65	0	$0

Average levelized cost weighted by the 20-year cumulative potential in each state

Energy Efficiency DSM, Energy Supply Curves

The 2021 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[12]
- **Measure:**
  - 98 residential measures
  - 138 commercial measures
  - 96 industrial measures
  - 25 irrigation measures

[11] Demand response resources derived from the demand response RFP are not included to protect confidential 3rd party pricing information.
[12] Oregon's DSM potential was assessed in a separate study commissioned by the Energy Trust of Oregon.

- **Facility type:**[13]
  - Six residential facility types
  - 28 commercial facility types
  - 34 industrial facility types
  - Two irrigation facility type

The 2021 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 15.1 million MWh.[14] 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 10.8 million MWh for all five states. The technical achievable potential for all six states for modeling consideration is 13.8 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 by building type and state generated almost 30,000 separate permutations or distinct measures that could be modeled using the supply curve methodology. To reduce the resource options for consideration without losing the overall resource quantity available or its relative cost, resources were consolidated into bundles, using ranges of levelized costs and net cost of capacity to reduce the number of combinations to a more manageable number.

Bundle development began with the energy efficiency technical potential identified by the 2021 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 achievability assumptions in the Draft 2021 Power Plan as, which typically assume that 85% of the technical potential could be acquired over the 20-year period.[15]

[13] Facility type includes such attributes as existing or new construction, single or multi-family. Facility types represent a combination of market segment and vintage and are more fully described in in the Analysis Approach in Volume 1, Chapter 2, of the2021 CPA.
[14] 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.
[15] 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.

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 2021 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 7.9 shows the 20-year MWh potential for DSM energy efficiency levelized cost bundles, designated by ranges of $/MWh.

Table 7.9 – 20-Year Total Incremental Energy Efficiency Potential by Cost Bundle (MWh)

Bundle	California	Idaho	Oregon	Utah	Washington	Wyoming
Annual Measures 1 (Best)	14,907	117,483	663,976	3,046,586	257,744	953,035
Annual Measures 2	4,243	44,907	505,973	433,935	48,147	111,397
Annual Measures 3 - Weather	1,719	24,887	52,257	119,916	30,747	17,654
Annual Measures 3 - Non-Weather	536	15,254	72,949	60,729	7,632	18,527
Annual Measures 4 - Weather	8,277	17,602	-	292,054	52,506	20,573
Annual Measures 4 - Non-Weather	1,342	3,696	54,515	69,006	10,602	11,610
Annual Measures 5 - Weather	3,011	22,106	22,753	42,323	26,355	4,037
Annual Measures 5 - Non-Weather	2,199	5,247	82,199	32,067	16,103	7,847
Annual Measures 6 - Weather	1,009	10,212	-	258,334	16,538	10,418
Annual Measures 6 - Non-Weather	141	1,251	18,600	37,860	57,595	20,163
Summer Measures 7 - Weather	2,894	16,837	121,477	150,336	26,229	8,448
Summer Measures 7 - Non-Weather	255	3,401	64,074	11,160	3,073	7,642
Summer Measures 8 - Weather	7,927	18,140	22,924	256,041	37,761	10,953
Summer Measures 8 - Non-Weather	2,519	5,038	120,418	98,283	11,727	24,612
Summer Measures 9 - Weather	10,299	11,455	6,642	267,252	31,988	8,213
Summer Measures 9 - Non-Weather	3,025	2,590	25,851	24,055	21,127	17,602
Summer Measures 10 - Weather	6,237	11,849	48,133	185,206	37,902	9,705
Summer Measures 10 - Non-Weather	796	1,013	35,465	57,507	10,818	12,551
Summer Measures 11 - Weather	7,184	9,700	12,889	237,866	26,380	12,295
Summer Measures 11 - Non-Weather	1,967	9,487	12,737	173,013	59,880	43,670
Highest Cost Measures	76,185	162,172	270,159	1,196,598	320,867	279,849
Winter Measures 6	3,170	12,130	166,645	96,308	16,389	6,885
Winter Measures 5	4,291	2,895	215,250	111,172	21,021	24,665
Winter Measures 4	15,298	2,583	195,188	35,337	7,507	7,734
Winter Measures 3	550	5,466	79,514	77,771	5,149	15,857
Winter Measures 2	105	7,864	106,755	45,286	6,320	19,939
Winter Measures 1 (Best)	-	3,215	33,265	34,164	406	5,647

Cost credits afforded to DSM energy efficiency resources include the following:

- A state-specific transmission and distribution investment deferral cost credit (Table 7.10)
- Stochastic risk reduction credit of $3.59/MWh[16]
- Northwest Power Act 10-percent credit (Oregon and Washington resources only)[17]

Table 7.10 – State-specific Transmission and Distribution Credits

State	Transmission Deferral Value ($/KW-year)	Distribution Deferral Value ($/KW-year)	Total
California	$6.34	$11.06	$17.40
Oregon	$6.34	$13.38	$19.72
Washington	$6.34	$16.86	$23.20
Idaho	$6.34	$16.72	$23.06
Utah	$6.34	$13.20	$19.54
Wyoming	$6.34	$7.48	$13.82

The bundle is split by weather dependent and non-weather dependent measures and their net cost of capacity ($/kw-yr) cost for the group of measures in the cost bins. 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.

PacifiCorp relies on simulated load shapes tied to weather stations in PacifiCorp's service territory. Weather is a major driver of PacifiCorp's load and in any given month weather results in a range of high and low load conditions. Weather also impacts the hourly timing of energy efficiency savings particularly for measures that are weather dependent. For the 2021 IRP, PacifiCorp chose to reshape daily energy efficiency volumes to better align with seasonal variations in the load forecast. The highest demand for weather-sensitive end use loads is expected to occur at the time of the winter and summer peaks in PacifiCorp's service territory. For weather dependent measures, the highest daily simulated savings were mapped to the highest to lowest load days to align with the load forecast. To capture the time-varying impacts of energy efficiency resources, each bundle uses 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.

[16] 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.

[17] The formula for calculating the $/MWh Power Act 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.

Distribution Efficiency

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.

This distribution energy efficiency activities were not modeled as potential resources in this IRP.

Transmission Resources

In developing resource portfolios for the 2021 IRP, PacifiCorp included 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 information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).

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 2021 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 7.11 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 I, Chapter 5 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 8 (Modeling and Portfolio Evaluation Approach).

Table 7.11 - 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")	350	350
Heavy Load Hour ("6X16")	150	0
California Oregon Border (COB)		
Flat Annual ("7x24") or Heavy Load Hour ("6X16")	0	250
Nevada Oregon Border (NOB) Heavy Load Hour ("6X16")	0	100
Mona Heavy Load Hour ("6X16")	0	300

CHAPTER 8 – 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.
- PacifiCorp used the Plexos Long-Term planning model (LT model) to produce unique resource portfolios across a range of different planning cases. Informed by the public-input process, PacifiCorp identified case assumptions that were used to produce optimized resource portfolios, each one unique regarding the type, timing, location, and amount of new resources that could be pursued to serve customers over the next 20 years.
- PacifiCorp used the Plexos Medium-Term schedule (MT model) to perform stochastic risk analysis of the portfolios. Each portfolio was evaluated for 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 CO_2 policy scenario was developed to evaluate performance assuming a price signal that aligns with the social cost of greenhouse gases (SC-GHG). Taken together, there are five distinct price-policy scenarios (medium gas/medium CO_2, medium gas/zero CO_2, high gas/high CO_2, low gas/zero CO_2, and the social cost of greenhouse gases).
- A primary function of the MT model is to calculate an optimized risk-adjustment, representing the relative risk of a portfolio under unfavorable stochastic conditions for that portfolio.
- Each portfolio was evaluated in the Short-Term model (ST model) to establish system costs for each portfolio over the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes as well as a present-value revenue requirement (PVRR) which serves as the basis for selecting least-cost least-risk portfolios.
- The MT model risk-adjustment was added to the system cost determined by the ST model to calculate a final "risk-adjusted" PVRR measure of system cost.
- A selection of portfolios were analyzed using the other four price-policy scenarios in the ST and MT models to evaluate how each portfolio performs under differing market/policy conditions.
- Taking into consideration stakeholder comments and regulatory requirements, PacifiCorp produced additional studies that examine the potential impact of portfolio options on the system.
- Informed by comprehensive modeling, PacifiCorp's preferred portfolio selection process involves evaluating cost and risk metrics reported from the ST and MT models, comparing resource portfolios based on expected costs, low-probability high-cost outcomes, reliability, CO_2 emissions and other criteria.

Introduction

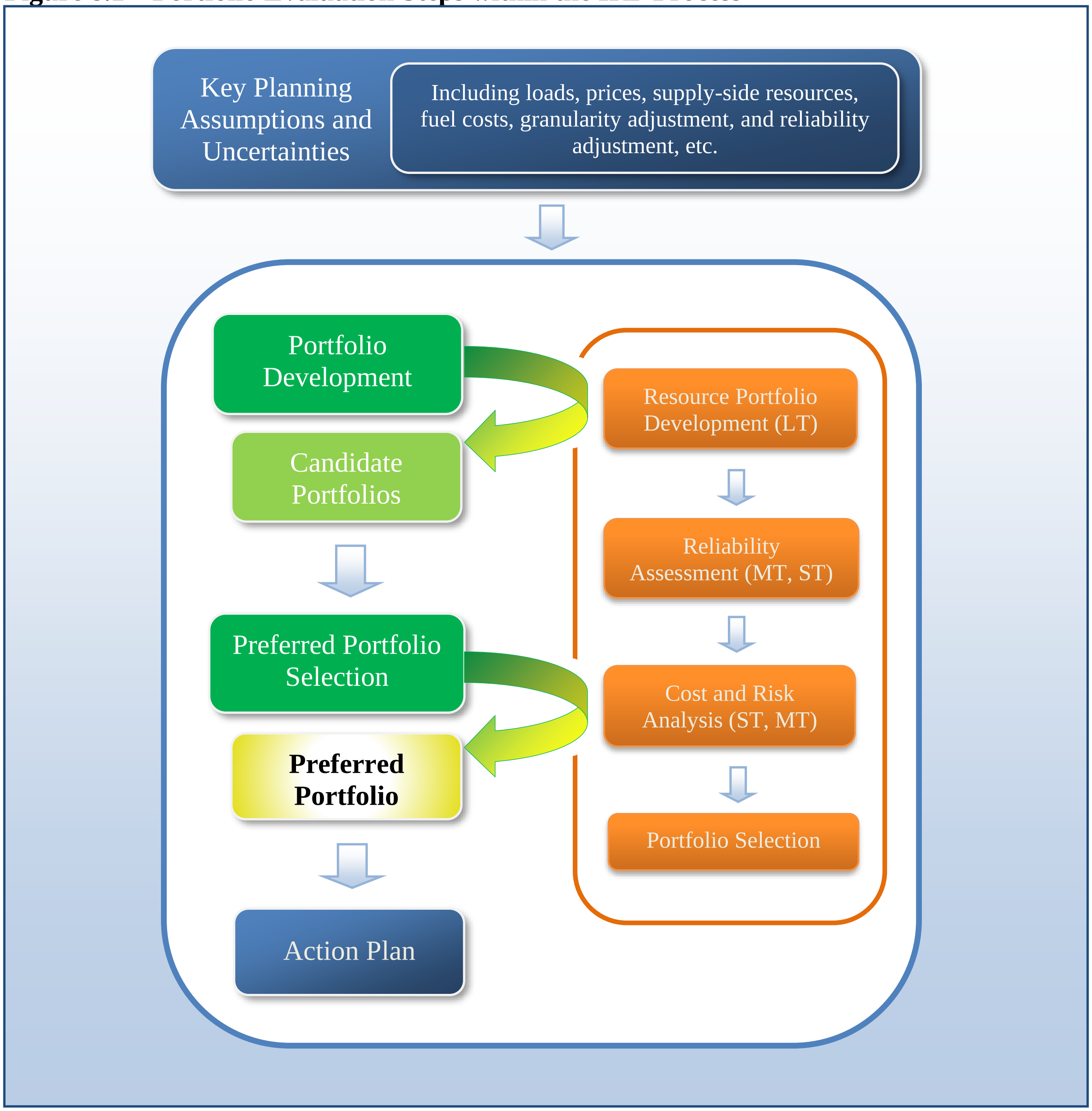
IRP modeling is used to assess the comparative cost, risk, and reliability attributes of different resource portfolios, each meeting reliability requirements. These portfolio attributes form the basis of an overall quantitative portfolio performance evaluation.

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 Volume I, Chapter 9 – Modeling and Portfolio Selection Results.

Modeling and Evaluation Steps

Figure 8.1 summarizes the modeling and evaluation steps for the 2021 IRP, highlighted in green. The steps are (1) portfolio development, and (2) portfolio screening. The result of the final screening step is selection of the preferred portfolio.

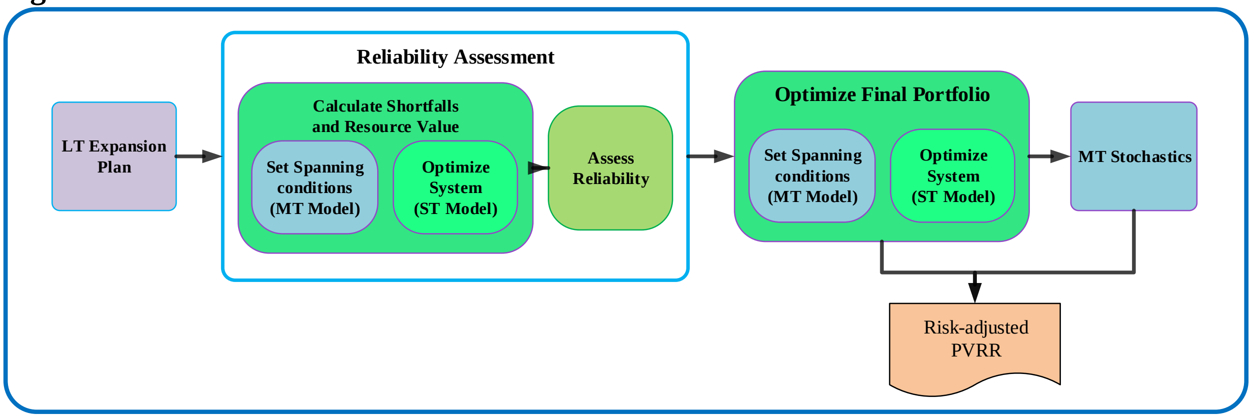
Figure 8.1 – Portfolio Evaluation Steps within the IRP Process



For each modeling and evaluation step, PacifiCorp developed unique resource portfolios, analyzed deterministic 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.

Figure 8.2 provides additional process detail regarding these portfolio processing elements, followed by descriptions of each element.

Figure 8.2 – Portfolio Production Process



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 LT model, which is used to produce resource portfolios with sufficient capacity to be reliable on a 20-year aggregated granularity basis.

Reliability Assessment

Resource portfolios developed by the LT model are simulated in the ST model to quantify reliability shortfalls at an hourly level. The ST model also supports the assessment of each resource's net system value, inclusive of resources that are not part of the specific portfolio being examined. This allows for the refinement of each portfolio according to a highly granular view of its needs and at the same time provides the data necessary to optimally select additional resources when needed to resolve shortfalls. The reliability-adjusted portfolio is then rerun through the ST model to create an optimal dispatch which considers all resource availability and system requirements at an hourly level, inclusive of individual resource operations and market purchases.

Cost and Risk Analysis

Resource portfolios developed by the LT model and adjusted for reliability by the ST model are simulated in the MT model 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. The MT results are used to calculate a risk adjustment which is combined with ST model system costs to achieve a final risk-adjusted PVRR to guide portfolio selection.

Portfolio Selection

The portfolio selection process is based on modeling results from the resource portfolio development and cost and risk analysis steps. The screening criteria are based on the PVRR of system costs, assessed across a range of price-policy scenarios on a deterministic basis and on an upper-tail stochastic risk basis. Portfolios are ranked using a risk-adjusted PVRR metric, a metric that combines the deterministic 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 as an indicator of risks associated with greenhouse gas emissions.

Resource Portfolio Development

Resource expansion plan modeling, performed with the LT model, is used to produce resource portfolios with sufficient capacity to achieve reliability over the 20-year study horizon. Each resource portfolio is refined for reliability at an hourly granularity during the reliability assessment development step. Each subsequent 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 management (DSM) resources. Changes to these input variables cause changes to the resource mix, which influences system costs and risks. New to this IRP is using the LT model to consider the retirement of coal endogenously.

Long-Term (LT) Capacity Expansion Model

In the 2021 IRP, the LT model is used to establish an initial portfolio under expected conditions (medium gas, medium CO_2), and then modified for each case, based on study parameters, to eliminate shortfalls and maintain reliability. The LT model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability, and other constraints.[1] Over the 20-year planning horizon, the model optimizes resource additions subject to resource costs and load constraints. These constraints include seasonal loads, operating reserves and regulation reserves plus a minimum capacity reserve margin for each load area represented in the model.

The initial resource portfolio developed with the LT model is appropriately reliable to its granularity and performance limitations. Operating reserve requirements include contingency reserves, which are calculated as 3% of load and 3% of generation. The capacity reserve margin in the 2021 IRP is set at a "floor" of 13% at each load area in the topology, as provided in Figure 8.3.

In the event that an early retirement of an existing generating resource is assumed or selected for a given planning scenario, the LT model will select additional resources as required to meet loads plus reliability requirement in each period and location.

To accomplish these optimization objectives, the LT model performs a 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 representative data blocks for each of the 12 months of every 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

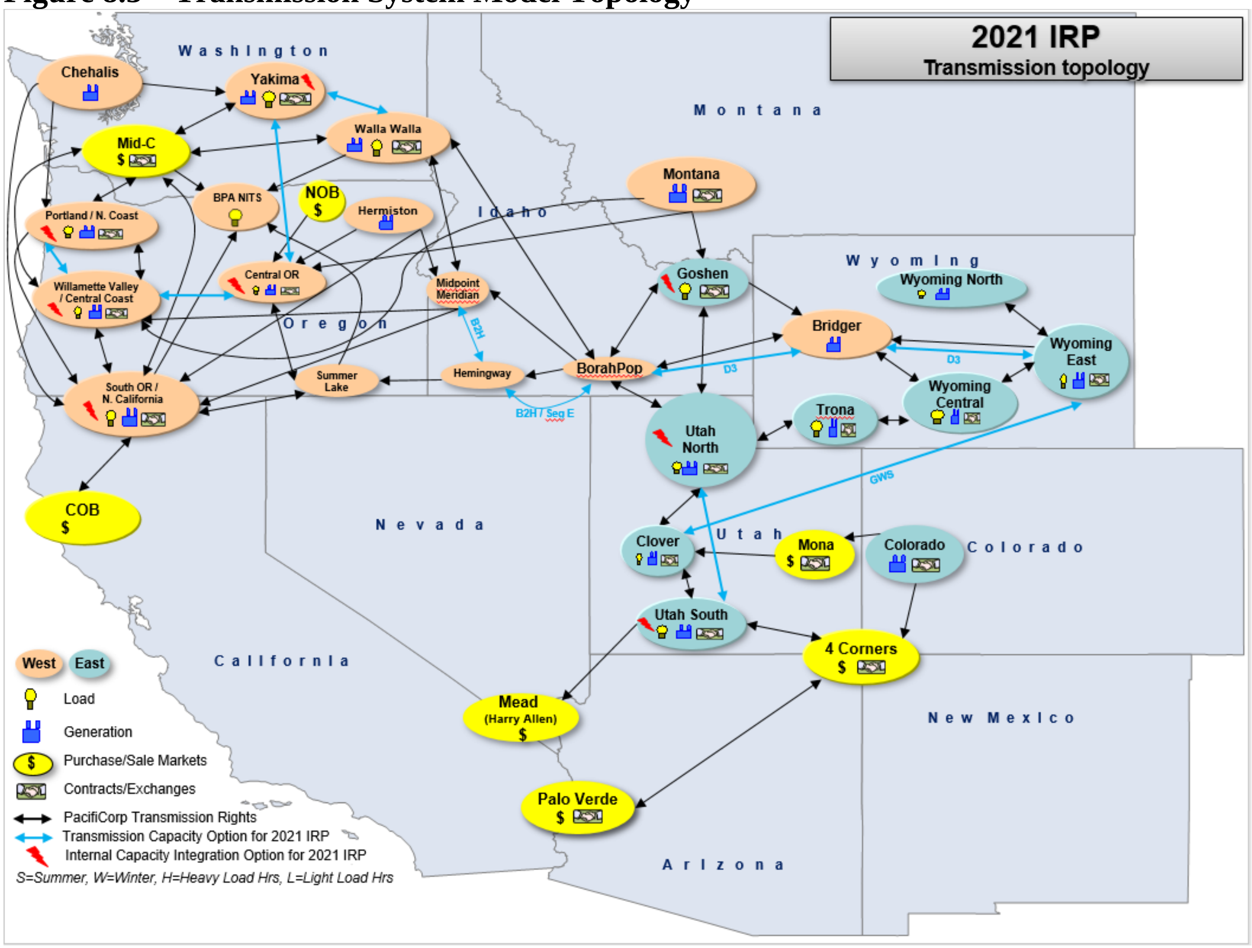
[1] LT model performance limits the granularity at which the model can be run. For the 2021 IRP there is an additional reliability assessment performed in the ST model to ensure that final portfolios meet reliability requirements.

cost of existing contracts, market purchase costs, 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.

Key modeling elements and inputs for the LT capacity expansion model include the following:

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 8.3 – Transmission System Model Topology



Transmission Costs
In developing resource portfolios for the 2021 IRP, PacifiCorp included 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.

Resource Adequacy

In its 2021 IRP, Pacificorp established a 13% hourly capacity reserve margin requirement for each topology location containing load in the LT model. The capacity reserve margin applies in all periods and must be met by available resources within that area or imports from adjacent areas with excess resources available, subject to transmission constraints. This treatment is an improvement on a traditional planning reserve margin which accounts only for peak load capacity met by an estimated firm capacity contribution. Additionally, the 2021 IRP directly modeled operating reserve requirements in expansion plan model runs, which ensures that expansion resources selected to CRM requirements will also meet operating contingency spin and non-spin reserve requirements. Taken together, these reliability requirements ensure that PacifiCorp has sufficient resources to meet load in all periods, recognizing the uncertainty 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.

Granularity and Reliability Adjustments

As detailed during the 2021 IRP public-input process, the granularity adjustment reflects the difference in economic value between an hourly 8760 cost calculation in ST modeling, and the four-block per month representation used in the LT model.

This adjustment is needed because resources with high variable costs that are rarely dispatched may provide a large value in a few intervals in the ST study, while not dispatching in any of the 4 LT model blocks. Also, storage resources allow for arbitrage among high value and low value hours in each day; however, the four-block granularity smooths out many of the storage arbitrage opportunities.

In parallel with the granularity adjustment, the reliability adjustment addresses unmet capacity needs by hour in the LT model portfolio selection. Much of the peak load hour requirements in mid-afternoon in the summer are adequately met by solar resources. However, resource requirements are driven by portfolio-dependent *net* load peaks (load less renewable resource output), which are harder for the LT model to identify.

While the granularity and reliability adjustments help direct the LT model to more cost-effective resources and a more reliable portfolio, the LT model cannot guarantee reliability at an hourly operational level. Marginal benefits decline as any resource type becomes a larger share of a portfolio, as it saturates the need in the hours it is available. A similar effect occurs with storage, where each incremental MW of system storage capacity must cover a longer duration.

As a consequence of the performance limitations of capacity expansion optimization, the ST model is leveraged to refine the portfolio to achieve a final balanced and reliable mix of resources, as described under the Cost and Risk Analysis section of this analysis, further below.

New Resource Options

<u>Demand-Side Management</u>

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). Operating characteristics include variables such as total number of hours per year and hours per event that the demand response resource is available.

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 represent expected monthly generation levels such that half of the time actual monthly generation would fall below expected levels, and half of the time actual monthly generation would be above expected levels assuming no curtailments.

The ability for wind and solar resources, to reliably meet demand over time is impacted by the forecasted profiles, along with mix of other resources in the portfolio. The use of resource availability to meet requirements in all periods allows the model to endogenously account for declining capacity contribution due to the increasing penetration of resources with similar dispatch patterns.

Non-Emitting Resources

Two non-CO_2-emitting thermal resources are considered: advanced nuclear projects and non-emitting peaking units. Advanced nuclear resources are characterized by continuous operation and substantial storage in the form of heat stored as molten salt. In contrast, non-emitting peaking resources are designed to run infrequently to support system reliability by dispatching only when needed to meet shortfalls. The non-emitting peaking resource is assumed to use a non-CO_2 emitting fuel such as hydrogen.

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 for a specified period;
- 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 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 variable costs (for example, the cost of natural gas for expanding air with gas turbine expanders).

Market Purchases

Market purchases are transactions by the company's front office represent short-term firm agreements 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., future months or quarters, 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 contribution of short-term firm market purchases is accounted for in the portfolio-development process. For capacity expansion optimization modeling, market purchases contribute capacity toward meeting the 2021 IRP's capacity reserve margin and supply energy to meet system needs.

Capital Costs

Annual capital recovery factors are used to convert capital investment dollars into nominal levelized revenue requirement costs. All capital costs evaluated in the IRP are converted to nominal levelized revenue requirement costs. Use of nominal levelized revenue requirement costs is an established 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 nominal 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 remains constant such that the PVRR is identical to the PVRR of the nominal requirement when using the same nominal discount rate.

General Assumptions

Study Period and Date Conventions

PacifiCorp executes its 2021 IRP models for a 20-year period beginning January 1, 2021 and ending December 31, 2040. Future IRP resources reflected in model simulations are given an in-service date of January 1st of a given year, except for 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 2029 IRP simulations and cost data reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. A single annual escalation rate value of 2.155 percent is assumed. This escalation rate reflects the average of annual inflation rate projections for the period 2021 through 2040, using PacifiCorp's September 2020 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 2021 IRP is 6.88 percent. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.[2] PVRR figures reported in the 2021 IRP are reported in 2021 dollars.

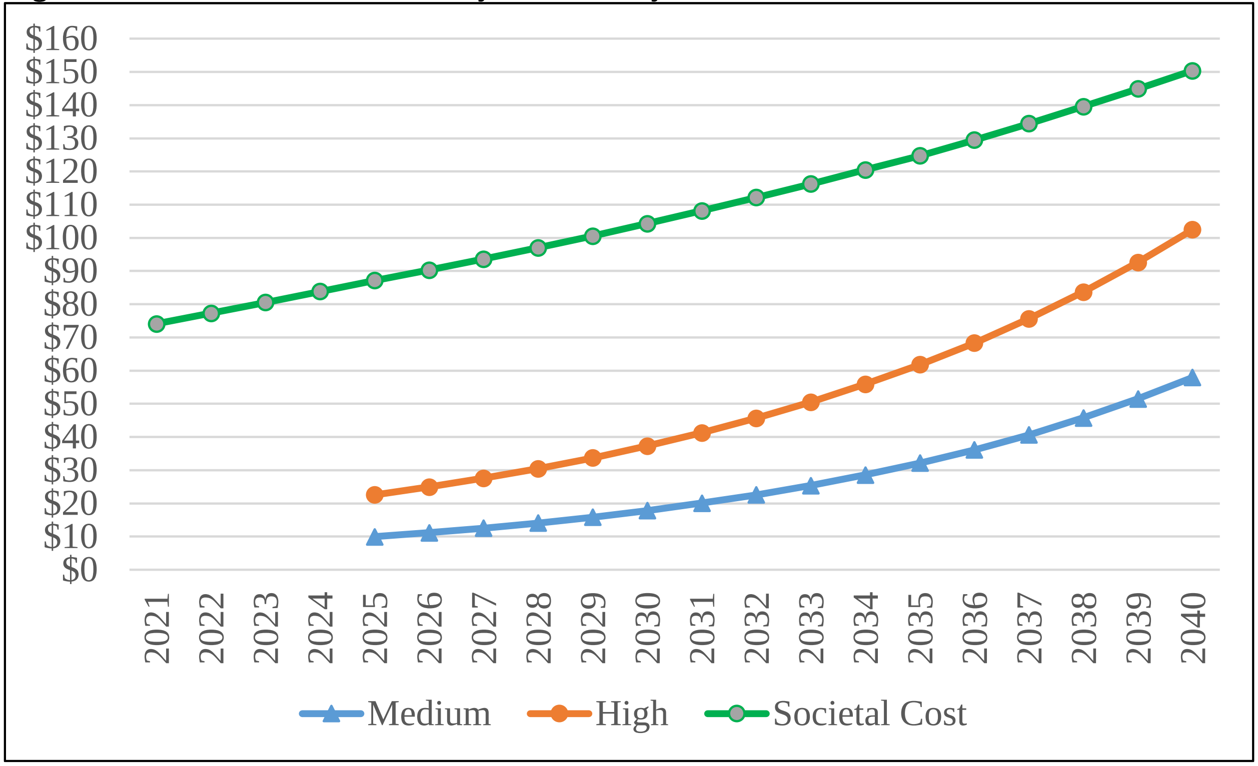
CO_2 Price Scenarios

PacifiCorp used four different CO_2 price scenarios in the 2021 IRP—zero, medium, high, and a price forecast that aligns with the social cost of greenhouse gases. The medium and high scenario are derived from expert third-party multi-client "off-the-shelf" subscription services. Both scenarios apply a CO_2 price as a tax beginning 2025.

PacifiCorp also incorporated the social cost of greenhouse gas in compliance with RCW 19.280.030. Social cost of greenhouse gas emissions are assumed to start in 2021. The social cost of greenhouse gases is applied such that the price for the SC-GHG is reflected in market prices and dispatch costs for the purposes of developing each portfolio (i.e., incorporated into capacity expansion optimization modeling). Aligned with Washington staff suggested treatment, system operations also include the SC-GHG once the portfolios are determined, presenting the risk that this operational assumption will not be aligned with actual market forces (i.e., market transactions at the Mid-Columbia market do not reflect the social cost of greenhouse gases and PacifiCorp does not directly incur emission costs at the price assumed for the social cost of greenhouse gases).

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

Figure 8.4 – CO_2 Prices Modeled by Price-Policy Scenarios



<u>Wholesale Electricity and Natural Gas Forward Prices</u>

For 2021 IRP modeling purposes, five electricity price forecasts were used: the official forward price curve (OFPC) and four 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 2021 IRP modeling inputs were prepared, the March 2021 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.[3] As such, these 36 months are market forwards as of March 2021. 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[4] (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.

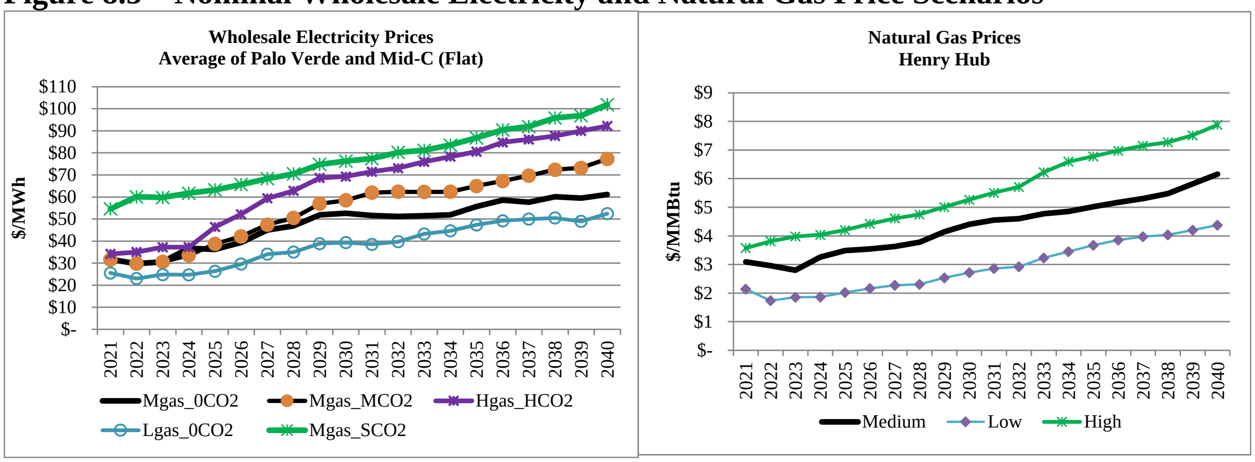
[3] The March 2021 OFPC prompt month is May 2021; April 2021 would be traded as "balance of month" when the OFPC is released.
[4] AURORAXMP is a proprietary production cost simulation model, developed by Energy Exemplar, LLC.

Scenarios pairing medium gas prices with alternative CO_2 price assumptions reflect OFPC forwards through April 2024 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 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 five 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.[5] The OFPC used in the 2021 IRP does not assume any CO_2 policy or tax in conjunction with its medium gas price forecast. However, PacifiCorp's 2021 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 2021 IRP medium case differs from that of the March 2021 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.

Figure 8.5 summarizes the five wholesale electricity price forecasts and three natural gas price forecasts used in the base and scenario cases for the 2021 IRP.

Figure 8.5 – Nominal Wholesale Electricity and Natural Gas Price Scenarios



Cost and Risk Analysis

Short-Term (ST) Schedule Model

The ST model uses the same common input assumptions described for the LT model with additional data provided by two other Plexos models. The LT model results provide the initial capacity expansion plan, and the MT model provides an optimized set of spanning conditions.

Spanning conditions are constraints that must be observed across periods of time that extend beyond the ST model's ability to "see" as it chronologically optimizes several days of hourly data

[5]Zero CO2, medium CO2 price, high CO2 price, and a social based cost of CO2.

at a time (e.g., an annual emissions limit). The MT model is able to determine for each month how each spanning condition is allocated for the ST model's use. The result is that even though the ST model is focused on hourly details and cannot simultaneously account for limitations that span across every hour in a year, the model will nonetheless appropriately adhere to an annual constraint.

Reliability Assessment and System Cost

The ST model begins with an portfolio from the LT model that has not yet been refined to reflect the reliability needs of a particular study (e.g., a particular sensitivity or price-policy scenario). The ST model is first run at an hourly level for 20 years in order to retrieve two critical pieces of data: 1) shortfalls by hour, and 2) the value of every potential resource to the system.

This information is used to determine the most cost-effective resource additions needed to meet reliability shortfalls, leading to a reliability-modified portfolio. The ST model is then run again with the modified portfolio to calculate an initial PVRR which is risk-adjust by outcomes of MT model stochastics.

<u>Resource Value</u>

Plexos calculates a locational marginal price (LMP) specific to each area in each hour that is based on supply and demand in that area and available imports and exports on transmission links to adjacent areas. This is also known as a shadow price. Plexos also calculates the marginal price specific to ancillary services (i.e., operating reserves) in each hour. Plexos then multiplies these prices by a generator's energy and operating reserve provision for each hour and reports the total as a resource's estimated revenue. In an organized market, this would represent the expected payments based on market-clearing prices.

When variable costs (such as fuel, emissions, and VOM) are subtracted out, the result is a resource's "net revenue". Net revenue provides a clear model-optimized assessment of every resource's value to the system, which is then used to assess resource additions needed to preserve reliable operation of the system.

While the net revenue approach is demonstrably superior to past resource value measures, especially as it is evaluated simultaneously for all potential resources, modeling capabilities, net revenue has limitations that should be acknowledged. Net revenue represents the value of the last MW of capacity from a given resource – as resources grow larger, the average value from the first MW of capacity to the last MW of capacity will tend to be somewhat higher than the reported marginal value. Conversely, adding more of a particular resource will result in declining values. While marginal prices will be very high in hours with supply shortfalls, this only indirectly contributes to reliable operation by helping to identify beneficial replacement resources. Once sufficient resources are added, shortfalls will mostly be eliminated and marginal prices will again reflect the variable cost of an available resource.

<u>Portfolio Refinements</u>

While a large number of resource options are evaluated, new generation resources are mostly restricted to two circumstances: replacement resources at retiring generators, and new resources at locations with interconnection or transmission upgrade options.

These interconnection and transmission upgrade options are limited and can be expensive. Replacing existing thermal generators with resources that provide only a portion of their interconnection capacity in "firm" capacity creates a need for additional interconnection capacity elsewhere, and a key strategy is maximizing the "firmness" of each MW of interconnection capacity to provide greater value. For this reason, the modeling of combined solar and storage resources now reflects storage with capacity equal to 100% of solar nameplate, and four-hour duration—up from 25% of solar capacity in the 2019 IRP, and 50% of capacity as discussed early in the 2021 IRP public-input process. This allows a collocated solar resource to shift more energy accumulated during periods of high solar radiance, increasing its effective capacity contribution.

Portfolio Cost

The second run of the ST model optimizes the reliability-adjusted portfolio to reflect least-cost operations while meeting all requirements and adhering to modeled constraints. The ST model's hourly granularity means that this system cost will be highly accurate, taking into account operational nuances that are obscured in the less granular LT and MT models. This in turn means that when evaluating the constellation of all competitive portfolios, the comparison will be based on appropriate relationships among all system components to yield an accurate PVRR.

Additional Measures

- Annual and energy not served (ENS)
- Annual CO_2 emissions.

Medium-Term (MT) Schedule Model

The MT model uses the same common input assumptions described for LT and ST models with additional data provided by the LT and ST model results (e.g., the capacity expansion portfolio). While the LT and ST models supply an optimized portfolio for each case, the MT model is able to bring the advantages of stochastic-driven risk metrics to the evaluation of the studies. While deterministic ST system cost results are the most precise available due the hourly granularity, the MT model provides the necessary data to calculate a stochastic risk metric for each case, which is then added to the ST system cost outcomes to produce the risk-adjusted PVRR for each case.

Cost and Risk Analysis

Once unique resource portfolios are developed using the LT and ST models, 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 the MT model.

The stochastic simulation in the MT model produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The MT 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.

The stochastic parameters used in the MT model for the 2021 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 for developing the stochastic parameters for the 2021 IRP.

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. 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 7 – Resource Options. Table 8.1 through Table 8.8 summarize updated stochastic parameters and seasonal price correlations for the 2021 IRP.

Table 8.1 – Short-Term Load Stochastic Parameters

Short-Term Volatility	CA/OR without Portland	Portland	ID	UT	WA	WY
Winter 2021 IRP	0.045	0.041	0.038	0.023	0.052	0.016
Spring 2021 IRP	0.039	0.038	0.066	0.030	0.039	0.018
Summer 2021 IRP	0.043	0.059	0.057	0.051	0.053	0.017
Fall 2021 IRP	0.041	0.037	0.045	0.033	0.042	0.018
Short-Term Mean Reversion	**CA/OR without Portland**	**Portland**	**ID**	**UT**	**WA**	**WY**
Winter 2021 IRP	0.154	0.165	0.177	0.281	0.147	0.226
Spring 2021 IRP	0.214	0.242	0.258	0.519	0.157	0.272
Summer 2021 IRP	0.197	0.265	0.148	0.307	0.212	0.234
Fall 2021 IRP	0.290	0.277	0.198	0.202	0.234	0.241

Table 8.2 – Short-Term Gas Price Parameters

Short-Term Volatility	East Gas	West Gas
Winter 2021 IRP	0.115	0.166
Spring 2021 IRP	0.091	0.203
Summer 2021 IRP	0.099	0.131
Fall 2021 IRP	0.101	0.171
Short-Term Mean Reversion	**East Gas**	**West Gas**
Winter 2021 IRP	0.061	0.031
Spring 2021 IRP	0.160	0.140
Summer 2021 IRP	0.503	0.287
Fall 2021 IRP	0.046	0.022

Table 8.3 – Short-Term Electricity Price Parameters

Short-Term Volatility	Four Corners	COB	Mid-Columbia	Palo Verde
Winter 2021 IRP	0.132	0.163	0.198	0.121
Spring 2021 IRP	0.172	0.288	0.630	0.138
Summer 2021 IRP	0.220	0.339	0.260	0.202
Fall 2021 IRP	0.174	0.173	0.160	0.150
Short-Term Mean Reversion	**Four Corners**	**COB**	**Mid-Columbia**	**Palo Verde**
Winter 2021 IRP	0.089	0.070	0.090	0.086
Spring 2021 IRP	0.180	0.258	0.461	0.151
Summer 2021 IRP	0.312	0.395	0.196	0.146
Fall 2021 IRP	0.197	0.178	0.120	0.163

Table 8.4 – Winter Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.413	1.000				
COB	0.377	0.620	1.000			
Mid - Columbia	0.320	0.540	0.757	1.000		
Palo Verde	0.492	0.791	0.586	0.564	1.000	
Natural Gas West	0.344	0.235	0.302	0.288	0.248	1.000

Table 8.5 – Spring Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.197	1.000				
COB	0.141	0.339	1.000			
Mid - Columbia	0.102	0.424	0.638	1.000		
Palo Verde	0.223	0.630	0.327	0.276	1.000	
Natural Gas West	0.563	0.195	0.215	0.168	0.097	1.000

Table 8.6 – Summer Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.066	1.000				
COB	0.161	0.224	1.000			
Mid - Columbia	0.116	0.233	0.797	1.000		
Palo Verde	0.056	0.440	0.453	0.542	1.000	
Natural Gas West	0.674	0.035	0.103	0.075	-0.003	1.000

Table 8.7 – Fall Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.207	1.000				
COB	0.251	0.289	1.000			
Mid - Columbia	0.225	0.279	0.596	1.000		
Palo Verde	0.165	0.609	0.401	0.435	1.000	
Natural Gas West	0.359	0.129	0.203	0.226	0.160	1.000

Table 8.8 – Hydro Short-Term Stochastic

	Short Term Volatility	Short-Term Mean Reversion
Winter 2021 IRP	0.274	0.722
Spring 2021 IRP	0.189	0.433
Summer 2021 IRP	0.210	1.149
Fall 2021 IRP	0.298	0.368

Figure 8.78.7 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 \$27.18/MWh to \$69.57/MWh during the 20-year study

period. For Palo Verde electricity prices, the difference between the first and 99th percentiles range from \$31.08/MWh to \$88.59/MWh.

Figure 8.6 – Simulated Annual Mid-C Electricity Market Prices

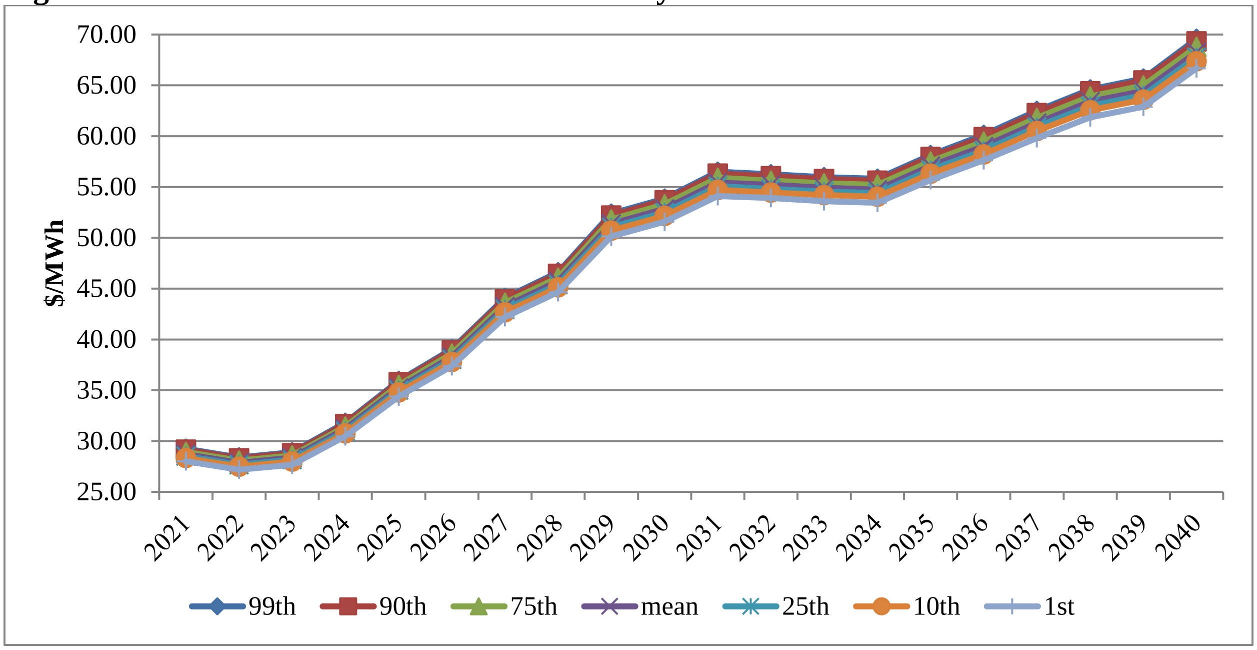


Figure 8.7 – Simulated Annual Palo Verde Electricity Market Prices

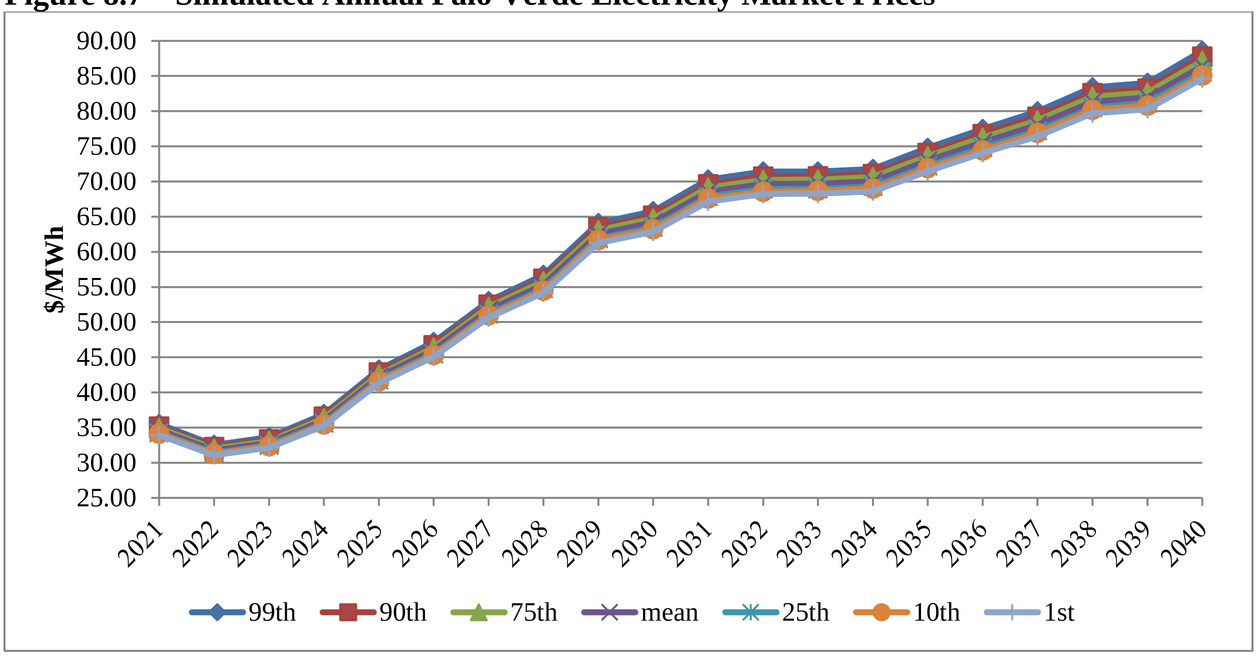


Figure **8.8** and Figure 8.9 show annual electricity prices at the first, 10^{th}, 25^{th}, 50^{th}, 75^{th}, 90^{th}, and 99^{th} percentiles for west and east natural gas prices. For west natural gas prices, differences between the first and 99^{th} percentiles range from \$2.71/ Million British thermal units (MMBtu) to

$5.25/MMBtu during the 20-year study period. For east natural gas prices, differences between the first and 99th percentiles range from $2.61/MMBtu to $6.01/MMBtu.

Figure 8.8 – Simulated Annual Western Natural Gas Market Prices

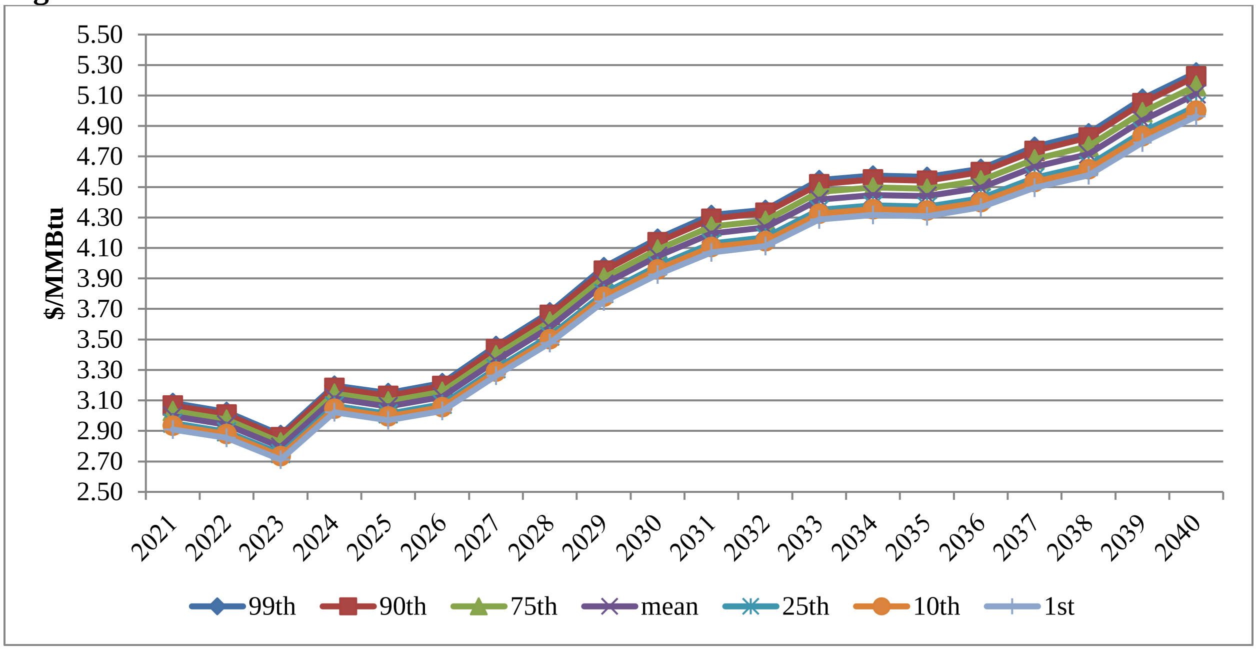
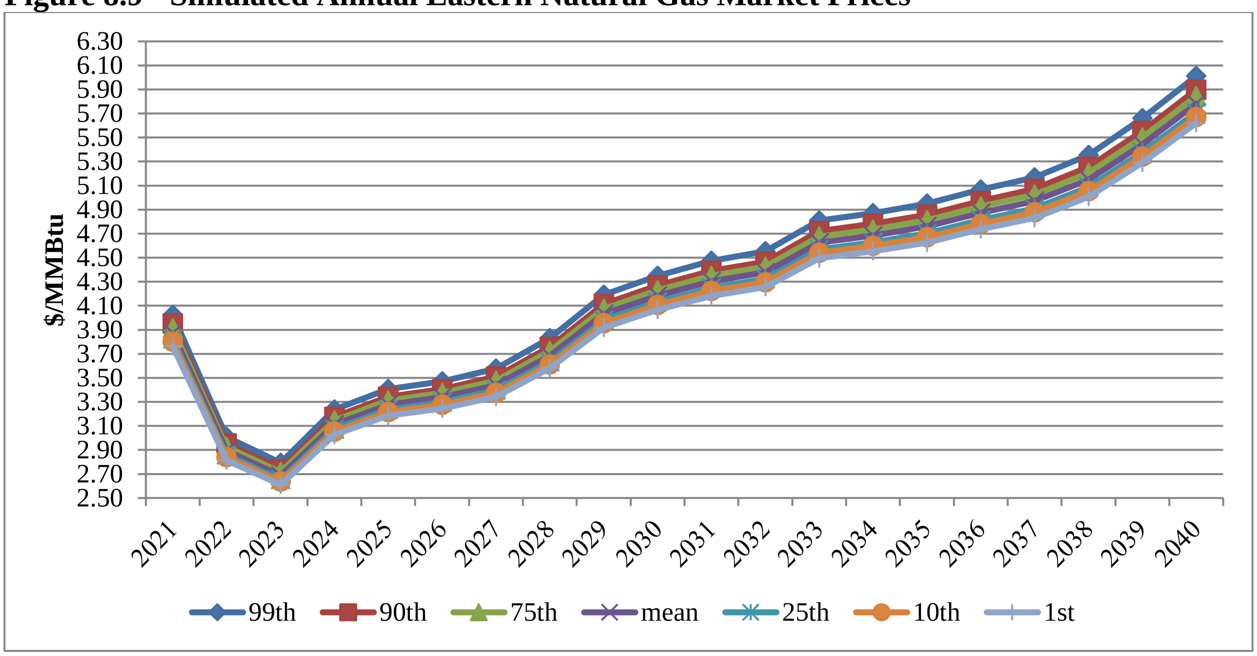


Figure 8.9 - Simulated Annual Eastern Natural Gas Market Prices



Figures 8.10 through 8.16 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 load, the annual differences between the first and 99th percentiles range from 154 gigawatt-hours (GWh) to 165 GWh. For Utah load, the annual difference ranges from 830 GWh to 1,069 GWh. For Wyoming load, the annual difference

ranges from 150 GWh to 177 GWh. For Oregon load, annual differences range from 423 GWh to 545 GWh. California load, annual differences range from 27 GWh to 29 GWh For Washington load, the annual difference ranges from 160 GWh to 187 GWh. For PacifiCorp's system load, the annual difference ranges from 1,430 GWh to 1,731 GWh.

Figure 8.10 - Simulated Annual Idaho Load

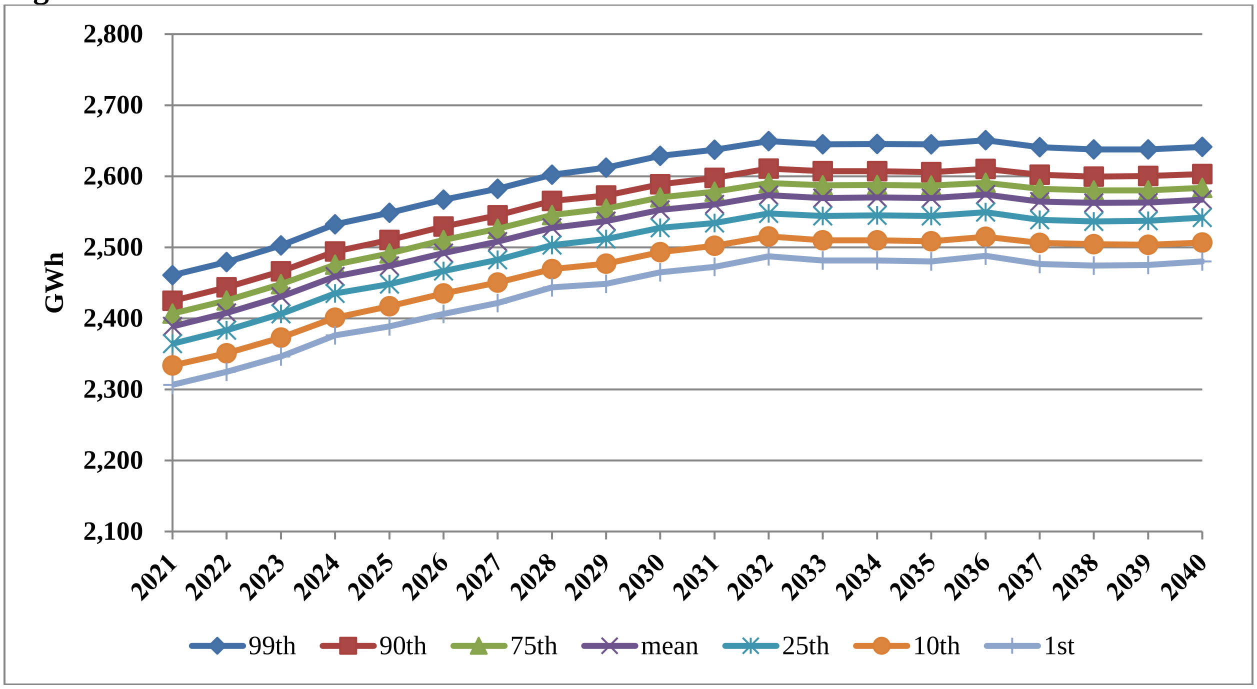


Figure 8.11 - Simulated Annual Utah Load

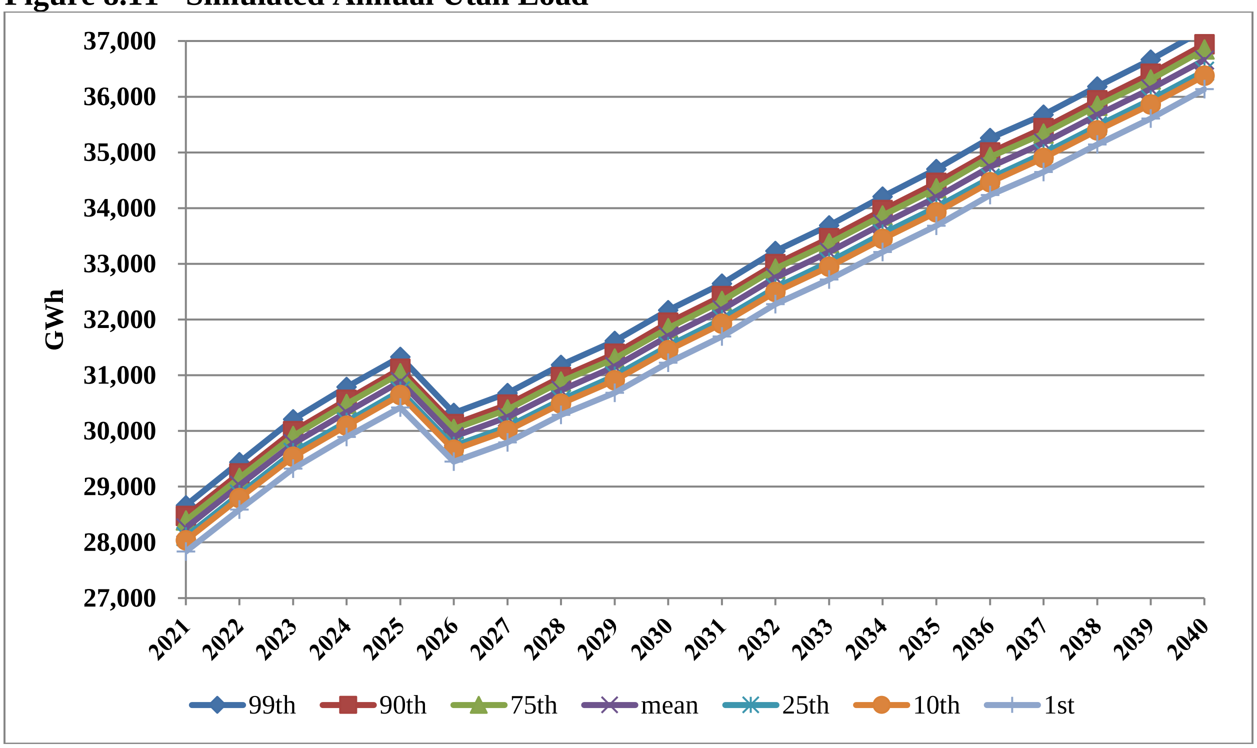


Figure 8.12 - Simulated Annual Wyoming Load

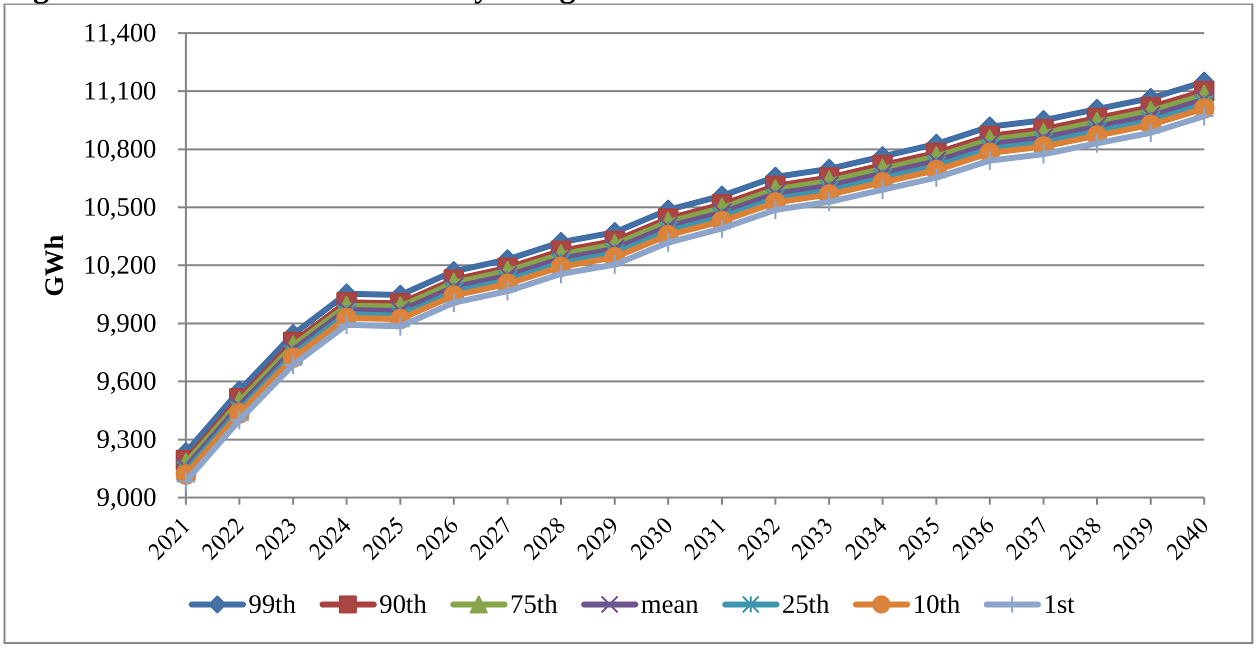


Figure 8.13 - Simulated Annual Oregon Load

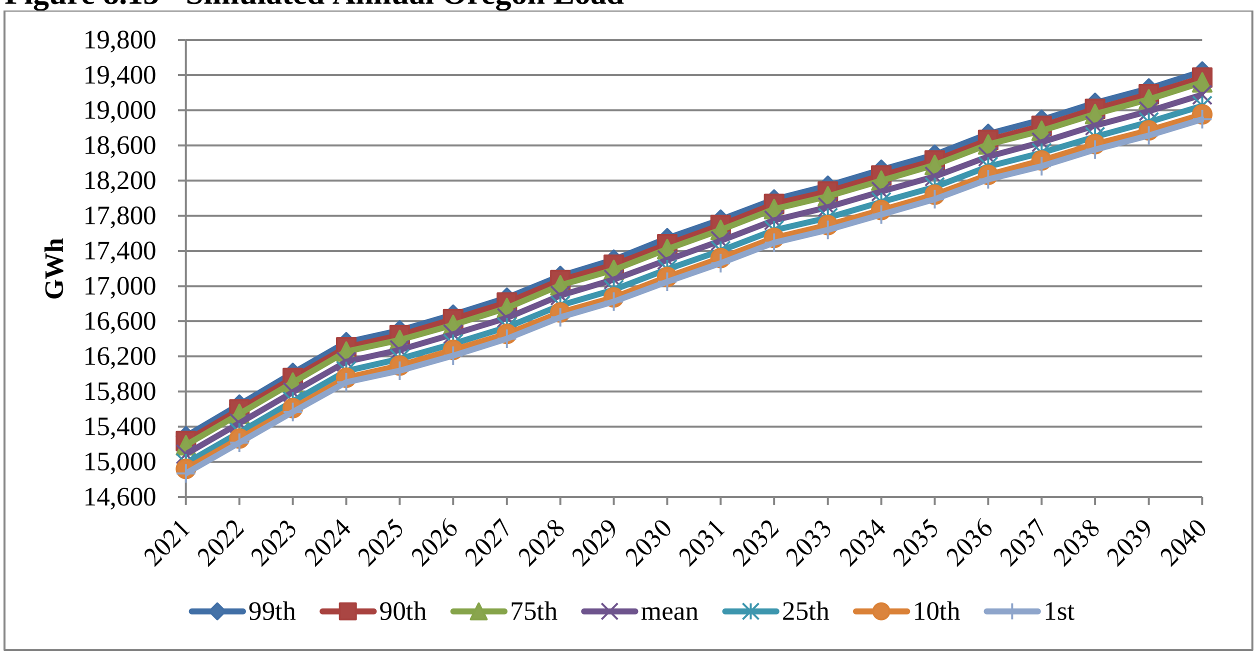


Figure 8.14 - Simulated Annual Washington Load

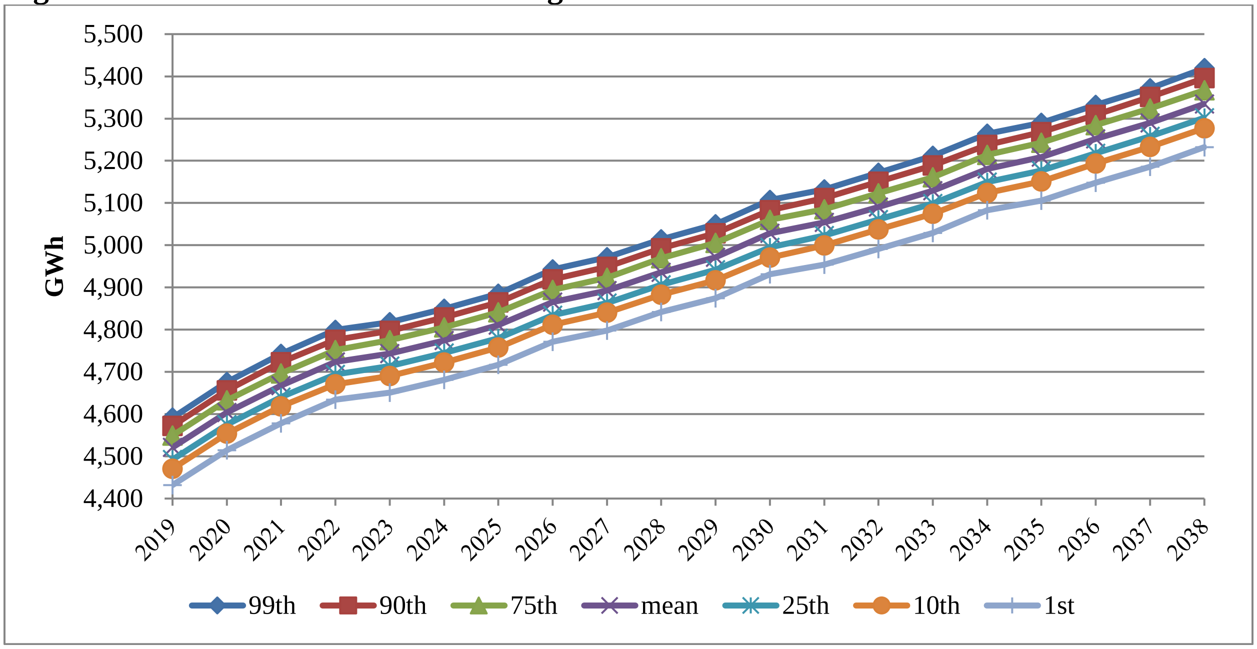


Figure 8.15 - Simulated Annual California Load

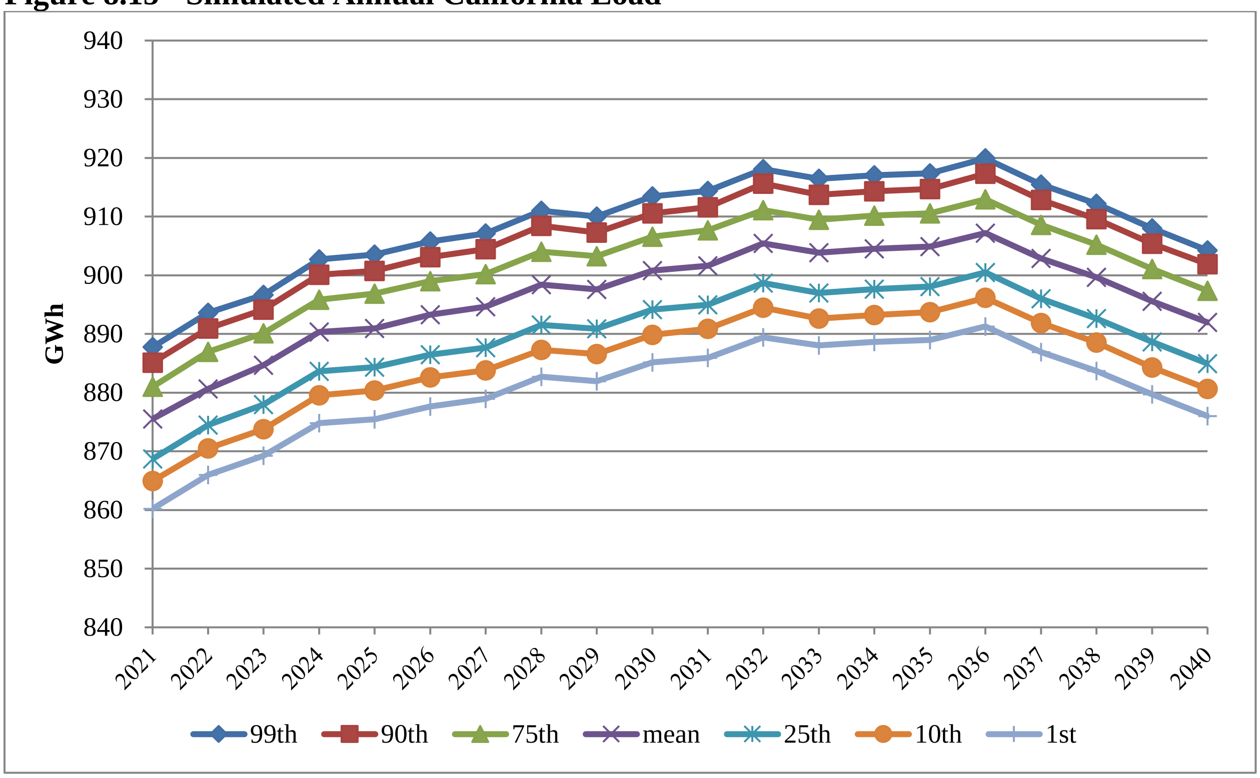


Figure 8.16 - Simulated Annual System Load

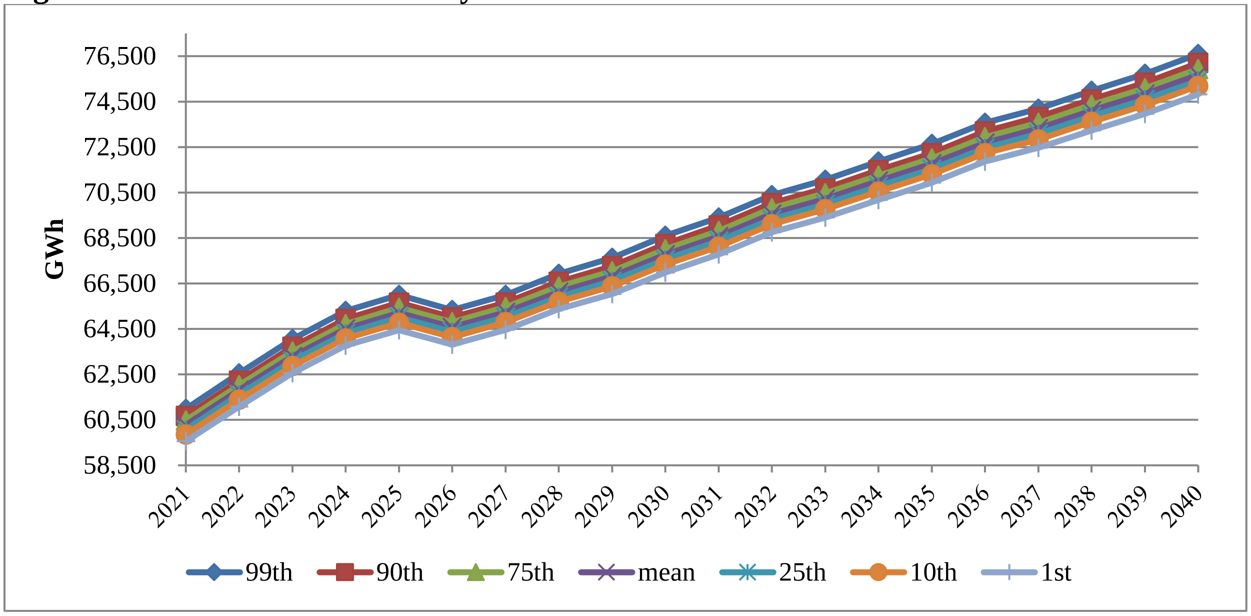
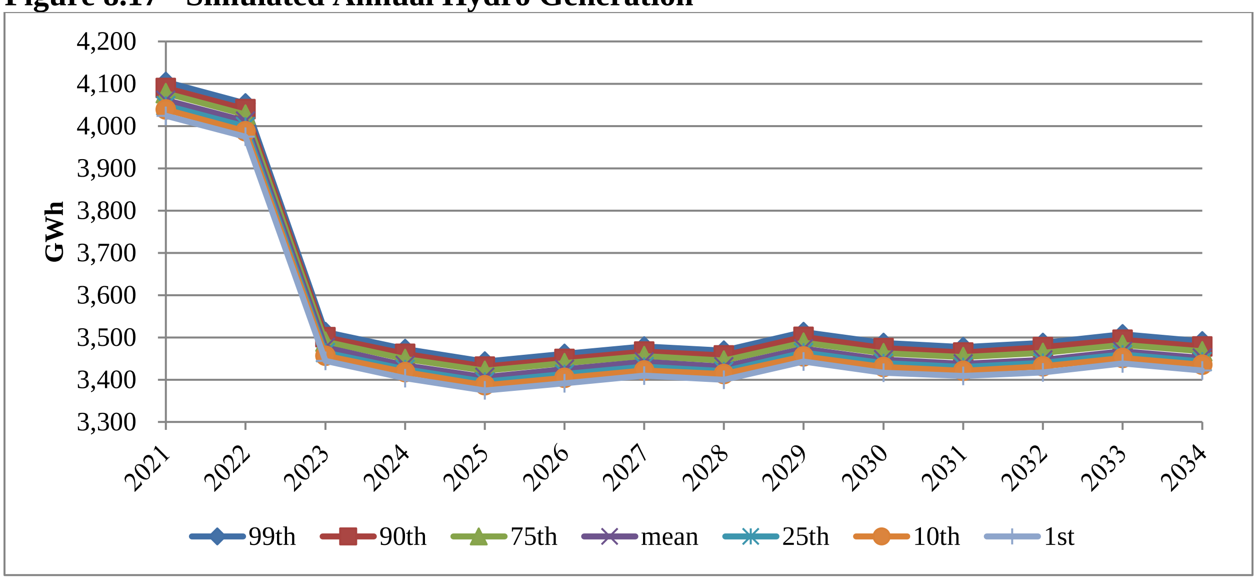


Figure 8.177 shows hydro generation at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. PacifiCorp can dispatch its hydro generation on a limited basis to meet load and reserve obligations. The parameters 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 68 GWh to 80 GWh.

Figure 8.17 - Simulated Annual Hydro Generation



Monte Carlo Simulation

During model execution, the MT 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 resource portfolios being analyzed. In the case of natural gas prices, electricity prices, and regional loads, the MT model applies Monte Carlo draws on a daily basis. In the case of hydroelectric generation, Monte Carlo draws are applied on a weekly basis.

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 the MT model include:

- Stochastic mean PVRR
- Upper-tail Mean PVRR
- 5th, 90th and 95th percentile PVRR
- Standard deviation
- Risk-adjustment (5% of the 95th percentile)

<u>Stochastic Mean PVRR</u>

The stochastic mean PVRR is the average of system net variable operating costs among 50 iterations, combined with the nominal levelized capital costs and fixed costs corresponding to the LT model for any given resource portfolio. The net variable cost from stochastic simulations, expressed as a net present value, includes system costs for fuel, variable O&M, long term contracts, system balancing market purchase expenses and sales revenues, reserve deficiency costs, and ENS costs applicable when available resources fall short of load obligations. Capital costs for new and existing resources are calculated on a nominal-levelized basis. Other components in the stochastic mean PVRR include CO_2 emission costs for any scenarios that include a CO_2 price assumption. The stochastic mean PVRR, limited by performance constraints of the MT model, is not used directly in portfolio selection; instead, the more granular ST PVRR serves as the base measure of net system cost, modified appropriately by stochastic risk.

<u>Upper-Tail Mean PVRR</u>

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 fixed costs, taken from the LT model, are added to these three production costs, and the arithmetic average of the resulting PVRRs is computed.

<u>5th and 95th Percentile PVRR</u>

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

<u>Production Cost Standard Deviation</u>

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 2021 through 2040. 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.

Risk-Adjustment

The MT model outcomes of the 50 stochastic samples are used to calculate a risk-adjustment measuring the relative risk of low-probability, high-cost outcomes. This measure is calculated as five percent of system variable costs from the 95th percentile. This metric expresses a low-probability portfolio cost outcome as a risk premium based on 50 Monte Carlo simulations for each resource portfolio and applied to the hourly-granularity deterministic PVRR. The rationale behind the risk-adjusted PVRR is to have a consolidated cost indicator for portfolio ranking, combining the most precise available system cost and high-end cost-risk concepts.

Forward Price Curve Scenarios

Preferred portfolio variants developed during the portfolio-development process are analyzed in the MT model with up to five price-policy scenarios. Price assumptions for each of these scenarios are subject to short-term volatility and mean reversion stochastic parameters when used in the MT model. The approach for producing wholesale electricity and natural gas price scenarios used for MT model simulations is identical to the approach used to develop price scenarios for the portfolio-development process.

Other Plexos Modeling Methods and Assumptions

Transmission System

The base transmission topology shown in Figure 8.3 is used in each of the three Plexos models, LT, ST and MT. Any transmission upgrades selected by LT and ST model processes that provide incremental transfer capability among bubbles in this topology are part of the portfolio and thus included in the MT stochastics and final ST optimizations.

Resource Adequacy

The CRM is a portfolio selection driver adequate to the capabilities of the LT model. Consistent with past IRPs use of a PRM, the CRM is not used once the initial portfolio is established. This is because ST reliability modifications to the portfolio rely on hourly resource availability and system requirements to directly determine reliability shortfalls and any additional resource need at the hourly level. MT stochastic model runs optimize unit commitment and dispatch logic on the resulting fixed portfolio to meet all requirements, including operating reserve and regulation reserves.

Energy Storage Resources

Storage resources such as battery energy storage systems (BESS), compressed air energy storage (CAES), and flow storage have many potential advantages, including storage for frequency regulation, grid stabilization, transmission loss reduction, reduced transmission congestion, renewable energy smoothing, spinning reserve, peak-shaving, load-levelling, transmission and distribution deferral, and asset utilization.

Each of the Plexos models (LT/MT/ST) dispatch storage resources endogenously, subject to their constraints, for example requirements to charge from onsite solar or for the combined solar and storage output and reserves to remain within a single interconnection limit. The model can deploy energy storage for the most cost-effective uses, including any combination of load ramping and leveling, reserve carrying, and to complement the benefits of renewable resource additions, particularly co-located renewables.

Other Cost and Risk Considerations

In addition to reviewing the risk-adjustment, ENS, and CO_2 emissions data, 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 market purchases.

Customer Rate Impacts

To derive a rate impact measure, PacifiCorp computes the 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 risk adjusted PVRR results from the models and capital costs on a nominal levelized basis. 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 quantifies market purchases for each portfolio allowing comparisons among cases in Chapter 9 – modeling and Portfolio Selection Results. In the 2021 IRP market purchase become increasingly constricted compared to past IRPs, as described in Volume I, Chapter 7 – Resource Options.

Portfolio Selection

Portfolios are measured for relative performance with regard to system costs, risk-adjusted system costs, ENS and CO_2 emissions. The risk adjusted PVRR accounts for relative upper tail stochastic risk among portfolios.

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

Additional quantitative analysis can be performed to further assess the relative differences among top-performing portfolios; qualitative analysis can also be considered where appropriate during portfolio selection on the basis of known factors that could not be readily captured in models.

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 2021 IRP this includes additional analysis to assess the impacts of new natural gas resources, and energy efficiency methodologies based on levelized cost of energy (LCOE) bundling as compared to capacity contribution bundling.

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

Case Definitions

Case definitions specify a combination of planning assumptions used to develop each unique resource portfolio analyzed in the 2021 IRP, organized here into major development categories:

- Initial Portfolios
    - P02 (optimized coal retirements)
    - P03 (coal retired by 2030)
    - BAU1 (end-of-life coal retirements)
    - BAU2 (2019 IRP coal retirements)
- Preferred Portfolio Selection
    - Top Performing Portfolio
    - Preferred Portfolio Variants
- Washington Required Portfolios and Sensitivities[6]

Additional portfolio detail can be found in Volume II, Appendix I – Capacity Expansion Results.

Initial Portfolios

Informed by the public-input process, these cases build diversity around varying key retirement dates. These portfolios explore potentially significant interactions among retirement options

[6] Informational portfolios that are not eligible for selection as the preferred portfolio.

including the potential to convert coal units to natural gas operations, retire units prior to end-of-life, install carbon-capture equipment on coal-fired facilities, retire units at end-of-life, or cease all coal-fired operations by year 2030. Potential trade-offs among these options are captured in the relative strengths of each unique portfolio in how it interacts with the optimized selection of proxy resources throughout the planning horizon. 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 rely on the combined capabilities of three optimization models within Plexos, the LT model, MT model and ST model, new to PacifiCorp in the 2021 IRP cycle.

There are considerable stranded-cost risks associated with planning a system that is reliant on new natural gas resources with depreciable lives ranging between 30 to 40 years (i.e., a new gas-fired resource placed in service in 2030 would be depreciated as late as 2070). Further, when considering current state policies, it is not feasible to assume new natural gas resources can obtain the permits needed to site and operate such a facility in many parts of PacifiCorp's service territory. Finally, PacifiCorp has observed that there is very limited development activity for new natural gas facilities. This was most recently evident in the 2020AS RFP, which did not result in a single bid for new natural gas resources. Therefore, new natural gas proxy resources were not made available for selection in any of Initial Portfolios.

Portfolios generated with SCGHG price-policy assumptions are consistent with RCW19.280.030 in Washington.

Table 8.9 provides the initial portfolio definitions for this IRP. Additional information, including coal unit retirement assumptions, are provided for each case in Volume II, Appendix I – Capacity Expansion Results.

Table 8.9 – Initial Portfolio Case Definitions

Case Type[a]	Price-Policy	Existing Coal[b]	Existing Gas[b]	Other Existing Resources[b]	Proxy Resources[c]
P02	MM	Optimized	End of Life	End of Life	No New Gas
P02	MN	Optimized	End of Life	End of Life	No New Gas
P02	LN	Optimized	End of Life	End of Life	No New Gas
P02	HH	Optimized	End of Life	End of Life	No New Gas
P02	SCGHG	Optimized	End of Life	End of Life	No New Gas
P03	MM	Retired by 2030	End of Life	End of Life	No New Gas
P03	MN	Retired by 2030	End of Life	End of Life	No New Gas
P03	LN	Retired by 2030	End of Life	End of Life	No New Gas
P03	HH	Retired by 2030	End of Life	End of Life	No New Gas
P03	SCGHG	Retired by 2030	End of Life	End of Life	No New Gas
BAU1	MM	End of Life	End of Life	End of Life	No New Gas
BAU1	MN	End of Life	End of Life	End of Life	No New Gas
BAU1	LN	End of Life	End of Life	End of Life	No New Gas
BAU1	HH	End of Life	End of Life	End of Life	No New Gas
BAU1	SCGHG	End of Life	End of Life	End of Life	No New Gas
BAU2	MM	2019 IRP	2019 IRP	2019 IRP	No New Gas
BAU2	MN	2019 IRP	2019 IRP	2019 IRP	No New Gas
BAU2	LN	2019 IRP	2019 IRP	2019 IRP	No New Gas
BAU2	HH	2019 IRP	2019 IRP	2019 IRP	No New Gas
BAU2	SCGHG	2019 IRP	2019 IRP	2019 IRP	No New Gas

(a) "P" refers generically to "portfolio"; "BAU" refers to "business as usual", a designation derived from stakeholder feedback recommending the BAU1 and BAU2 series of cases.
(b) Aligned with the intent of the BAU2 study requests, the designation "2019 IRP" means that existing resources maintain 2019 retirement assumption except where updated information has changed known planning.
(c) Optimized proxy portfolio selections exclude new gas proxy resources except for gas-conversion of specific existing coal resources.

All initial portfolios consider variations in retirement timing, the impact of regional haze compliance operating limits and options for gas conversion or CCUS retrofit for certain units. The initial portfolios differ based on planning assumptions around coal unit retirement options and retirement timing.

P02 (optimized coal retirements)

P02 portfolios are fully optimized using the best available input data and assumptions regarding requirements and constraints. The P02-MM case represents a reasonably likely future that assumes medium gas prices and a medium CO_2 price proxy for future federal policy. In this series, coal retirement timing is optimized, whereas other existing resources are assumed to operate through end of life; contracts expire at the end of their term. Proxy resource selections exclude new gas-fueled additions except in the case of a coal-to-gas conversion of an existing resource. Based on the logic of optimization modeling, P02 cases are expected to perform well compared to other case types within the same price-policy environment assumptions given that the models will have the most latitude to find a low-cost portfolio solution. The P02 series of cases includes a unique portfolio developed under each of the five price-policy scenarios.

P03 (coal retired by 2030)

These P03 cases feature the retirement of all coal resources by 2030 using an optimized retirement strategy within the first nine years of the planning horizon. Other existing resources are assumed to operate through end of life; contracts expire at the end of their term. Proxy resource selections exclude new gas-fueled additions except in the case of a coal-to-gas conversion of an existing coal resource. In contrast to the P02 series, described above, the P03 series is expected to be relatively costly as the pre-2030 retirement strategy prevents the models from optimizing coal retirements in the last half of the planning horizon. The P03 series of cases includes a unique portfolio developed under each of the five price-policy scenarios.

Business as Usual Cases

During the 2021 IRP public input process, four stakeholder feedback forms requested specific “Business as Usual” (BAU) Cases:

Table 8.10 – Business as Usual Study Requests

Requesting Party	Requested Case Summary
Wyoming Office of Consumer Advocate (Form 037)	Begin with current generation and transmission portfolio and reflect analysis on customer impacts of changes to portfolio to accommodate load growth and environmental compliance obligations. Exclude early coal retirement as that is analyzed elsewhere in the IRP.
Wyoming Public Service Commission (Form 045)	Carry forward the 2019 IRP preferred portfolio, with updates due to regulatory changes, no additional assumed early retirements, and exclude externalities that are not currently required by law to be evaluated.
Renewable Northwest (Form 046)	Include a BAU case that incorporates reliability issues in California, Front Office Transaction assumptions and state energy policy.
Joint Parties (Utah Association of Energy Users, Utah Division of Public Utilities, Wyoming Industrial Energy Consumers, and Wyoming Office of Consumer Advocate (Form 058)	Two BAU cases – one based on the 2019 IRP preferred portfolio and one based on the 2017 IRP Update preferred portfolio with all commitments since the 2019 IRP included in BAU case.

Based on this feedback, PacifiCorp planned to develop two stakeholder-defined BAU case series, termed “BAU1” and “BAU2”.

<u>BAU1 (end-of-life coal retirements)</u>

The retirement strategy for BAU1 cases assumes existing assets will operate through the end of their life operating life (no early retirement), including coal and non-coal resources; contracts expire at the end of their term. Proxy resource selections exclude new gas-fueled additions except in the case of a coal-to-gas conversion of an existing coal resource. The BAU1 series of cases includes a unique portfolio developed under each of the five price-policy scenarios.

BAU2 (2019 IRP coal retirements)

BAU2 cases target portfolios that are reasonably aligned with the 2019 IRP preferred portfolio. Existing resource assumptions will differ from the 2019 IRP retirement assumption only where required to align with updated information, such as anticipated retirement dates for the minority-owned Colstrip and Hayden facilities. Proxy resources can change to optimally meet load, ensuring sufficient capacity and energy to accommodate changes in load from the 2019 IRP. Such proxy resource selections exclude new gas-fueled additions and new coal-to-gas conversions are disallowed. The BAU2 series of cases includes a unique portfolio developed under each of the five price-policy scenarios.

Preferred Portfolio Selection Cases

Certain additional cases were developed directly from the top-performing case (P02-MM) based on analysis of portfolios from the twenty initial 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 2021 IRP, there are eight preferred portfolio selection cases referred to as the "P02 Variants" as shown in Table 8.11:

Table 8.11 – Preferred Portfolio Variants

Portfolio	Description
P02a-JB1-2 GC	Excludes gas conversion of Jim Bridger Units 1 and 2
P02b-No B2H	Excludes Boardman-to-Hemingway transmission segment
P02c-No GWS	Excludes the Energy Gateway South transmission segment
P02d-No RFP	Excludes 2020 All-Source Request for Proposals Final Shortlist and the Energy Gateway South transmission segment
P02e-No NUC	Excludes the Natrium™ advanced nuclear demonstration project
P02f-No NAU25	Excludes the early retirement of Naughton Units 1 and 2
P02g-CCUS	Includes Carbon Capture Utilization and Sequestration (CCUS) retrofit of Dave Johnston Unit 4 in response to Wyoming House Bill 200
P02h-JB3-4 RET	Includes early retirement of Jim Bridger Units 3 and 4 in response to stakeholder feedback

Each variant case begins with inputs and assumptions identical to the preferred portfolio (P02-MM-CETA), which is the top performing portfolio (P02-MM) with adjustments required for Washington's Clean Energy Transformation Act (CETA).

P02a-JB1-2 GC
Starting with the assumption of the P02-MM-CETA portfolio, this portfolio is re-optimized with added assumption that coal-to-gas conversions are disallowed, requiring an alternate strategy to maintain system reliability.

P02b-No B2H
In this sensitivity the transmission segments associated with the Boardman-to-Hemingway project are removed along with 600 MW (nameplate) of enabled resources. The portfolio is re-optimized in the absence of these projects, requiring an alternate strategy to maintain system reliability.

P02c-No GWS

The Energy Gateway South and associated D.1[7] projects enable 1,930 MW (nameplate) of interconnected resources; approximately 1,641 MW of this interconnection capability is occupied by projects identified in the All-Source 2020 RFP. In the P02c-No GWS case, both the transmission project and enabled final shortlist wind bids from the All-source 2020 RFP are removed. The portfolio is re-optimized in the absence of these projects, requiring an alternate strategy to maintain system reliability.

P02d-No RFP

Similar to P02c-No GWS, the 'No RFP' case eliminates the Energy Gateway South and D.1 transmission projects, but also removes all final shortlist bids from the All-source 2020 RFP (not just the wind bids enabled by GWS and D.1). The portfolio is re-optimized in the absence of these projects, requiring an alternate strategy to maintain system reliability.

P02e-No NUC

The 'No Nuc' case removes the Natrium™ demonstration project in 2028 from the preferred portfolio and re-optimizes proxy resources to maintain reliability. As the purpose of the sensitivity is evaluate the system value of the Natrium™ demonstration project, proxy nuclear resources are still allowed in the later years of the planning horizon in order to meet load and reliability requirements at a reasonable cost. This results in a portfolio that targets the system value contribution of the individual demonstration project.

P02f-No NAU25

The retirements of Naughton unit 1 and Naughton unit 2 in 2025 are assumed in the preferred portfolio. This sensitivity evaluates the cost and risk merits of this strategy by disallowing these two early retirements, re-optimizing the portfolio, and comparing outcomes.

P02g-CCUS

In response to Wyoming House Bill 200, this sensitivity includes the CCUS retrofit of Dave Johnston Unit 4. The CCUS installation is assumed to occur in 2026 and also assumes the life of Dave Johnston Unit 4 could be extended beyond the end of the planning horizon.

P02h-JB3-4 RET

The P02h-JB3-4 RET sensitivity tests the potential system cost or benefit of retiring Jim Bridger unit 3 and Jim Bridger unit 4 prior to end-of-life. Based on the selected early retirement dates, the portfolio is re-optimized in the absence of these projects, requiring an alternate strategy to maintain system reliability.

Washington Required Portfolios

Washington's CETA legislation requires utilities to conduct three scenarios:

- **Alternative Lowest Reasonable Cost** - WAC 480-100-620(10)(a) instructs utilities to "describe the alternative lowest reasonable cost and reasonably available portfolio that the

[7] Refer to Volume I, Chapter 4 – Transmission for details regarding these projects.

utility would have implemented if not for the requirement to comply" with CETA's Clean Energy Transformation Standards. This sensitivity including the requirement to use the social cost of greenhouse gases (SCGHG) price-policy assumption in the resource acquisition decision. In Chapter 9 – Modeling and Portfolio Selection Results, the company will analyze this portfolio in the context of both CETA and non-CETA complaint outcomes.

- **Climate Change** - WAC 480-100-620(10)(b) instructs utilities to "incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change." Please see Appendix A for additional detail regarding the climate change scenario.

- **Maximum Customer Benefit** - WAC 480-100-620(10)(c) instructs utilities to "model the maximum amount of customer benefits described in RCW 19.405.040(8) prior to balancing against other goals." The maximum customer benefit scenario focuses on adding distributed generation, demand response, and energy efficiency in Washington, as well as avoiding high-voltage transmission upgrades in PacifiCorp's Yakima and Walla Walla communities to minimize burdens and maximize benefits to Washington customers. Washington load forecast reflects the high private generation forecast. The portfolio assumes the social cost of greenhouse gas price-policy scenario and includes all available Washington energy efficiency and demand response.

Sensitivity Case Definitions

PacifiCorp identified eight sensitivities outlined in Table 8.12 and discussed further in Volume I, Chapter 9 – Modeling and Portfolio Selection Results.

Table 8.12 – Sensitivity Case Definitions

Case	Description	Load Forecast	Private Generation	Resources	CO_2 Policy
S-01	High Load	High	Base	Optimized	Medium gas / Medium CO_2
S-02	Low Load	Low	Base	Optimized	Medium gas / Medium CO_2
S-03	1 in 20 Load Growth	1 in 20	Base	Optimized	Medium gas / Medium CO_2
S-04	New Proxy Gas Allowed	Base	Base	Optimized	Medium gas / Medium CO_2
S-05	Business Plan	Base	Base	Align first three years	Medium gas / Medium CO_2
S-06	Levelized Cost of Energy Efficiency Bundles	Base	Base	Optimized	Medium gas / Medium CO_2
S-07	High Private Generation	Base	High	Optimized	Medium gas / Medium CO_2
S-08	Low Private Generation	Base	Low	Optimized	Medium gas / Medium CO_2

Load Sensitivities (S01, S02, S03)

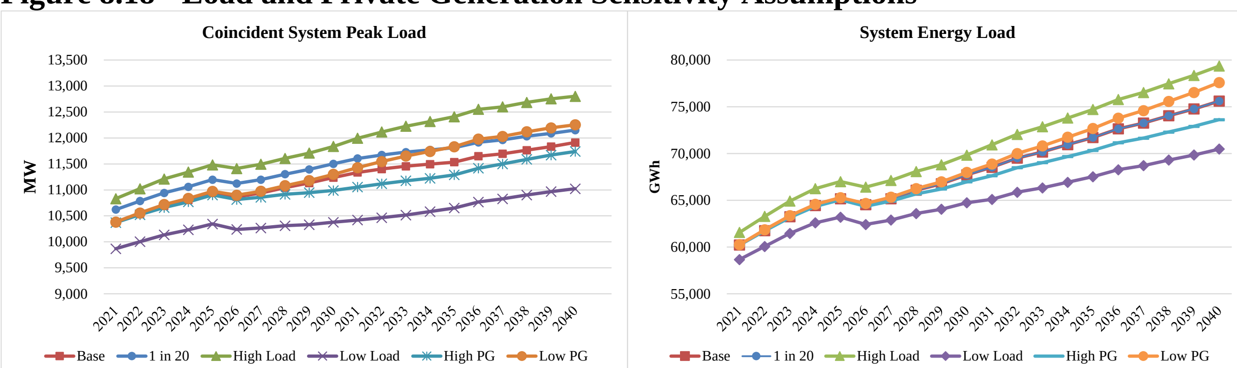
PacifiCorp includes three different load forecast sensitivities. The high load forecast sensitivity (S01) reflects optimistic economic growth assumptions from IHS Global Insight and high Utah and Wyoming industrial loads. The low load forecast sensitivity (S02) reflects pessimistic economic growth assumptions from IHS Global Insight and low Utah and Wyoming industrial loads. The low and high industrial load forecasts focus on increased uncertainty in industrial loads further out in time. To capture this uncertainty, PacifiCorp modeled 1,000 possible annual loads for each year based on the standard error of the medium scenario regression equation. The low and high industrial load forecast is taken from 5th and 95th percentile.

The third load forecast sensitivity (S03) 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 8.18 compares the low, high, and 1-in-20 load sensitivities, net of base case private generation levels, alongside the base case load forecast.

New Proxy Gas (S04)
In this sensitivity, new gas peaking resources replace non-emitting peaking resources and new combined cycle combustion turbines replace advanced nuclear resources.

Business Plan Sensitivity (S05)
Case S05 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 2020 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 using the Plexos models.

Figure 8.18 - Load and Private Generation Sensitivity Assumptions



Levelized Cost of Energy Efficiency Bundles (S06)
For the 2021 IRP, PacifiCorp reshaped the daily volumes from energy efficiency to better align with the load forecast. This creates a realistic representation of the relationship between load and weather-sensitive energy efficiency resource options. This sensitivity tests the effectiveness of this methodology change in terms of efficiency and as measured by cost and risk metrics.

Private Generation Sensitivities (S07, S08)
Two private generation sensitivities are analyzed. As compared to base private generation penetration levels that incorporated annual reductions in technology costs, the high private generation sensitivity (S07) reflects more aggressive technology cost reduction assumptions, greater technology performance levels, and higher retail electricity rates. In contrast, the low private generation sensitivity (S08) reflects lesser reductions in technology costs, reduced technology performance levels, and lower retail electricity rates.

CHAPTER 9 – MODELING AND PORTFOLIO SELECTION RESULTS

CHAPTER HIGHLIGHTS

- Using 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 with increasingly reduced greenhouse gas emissions.
- By the end of 2024, the 2021 IRP preferred portfolio includes the 2020 All-Source RFP final shortlist resources including 1,792 MW of wind, 1,302 MW of solar additions, and 697 MW of battery storage capacity – 497 MW paired with solar and a 200 MW standalone battery. During this time, the preferred portfolio also includes the acquisition and repowering of Rock River 1 (49 MW) and Foote Creek II-IV (43 MW) wind projects. and 4,290 MW of incremental energy efficiency and 2,448 MW of new direct load control resources.
- To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes significant transmission investments. Specifically, the 2021 IRP preferred portfolio includes the Energy Gateway South (GWS) transmission line—a new 416-mile, high-voltage 500-kilovolt transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The 2021 preferred portfolio also includes the Energy Gateway West Subsegment D.1 project (D.1)—a new 59-mile high-voltage 230-kilovolt transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. Both transmission lines come online by the end of 2024.
- The 2021 IRP preferred portfolio also includes a 290-mile high-voltage 500-kilovolt transmission line known as Boardman-to-Hemingway (B2H) to come online in 2026.
- Further, the 2021 IRP preferred portfolio includes near-term and long-term transmission upgrades across the system that will facilitate continued and long-term growth in new resources needed to reliably serve our customers.
- This is the first PacifiCorp IRP that includes new advanced nuclear and non-emitting peaking resources as part of its least-cost, least-risk preferred portfolio. The 500 MW advanced nuclear Natrium™ demonstration project will come online by summer 2028. Through 2040, the 2021 IRP preferred portfolio includes 1,000 MW of additional advanced nuclear resources and 1,226 MW of non-emitting peaking resources.
- Driven in part by ongoing cost pressures on existing coal-fired facilities and dropping costs for new resource alternatives, of the 22 coal units currently serving PacifiCorp customers, the preferred portfolio includes retirement of 14 of the units by 2030 and 19 of the units by the end of the planning period in 2040. Coal-fueled generation capacity is reduced by 1,300 MW by the end of 2025, 2,211 MW by 2030, and over 4,000 MW by 2040. The preferred portfolio also reflects 1,554 MW of natural gas retirements through 2040.
- In the 2021 IRP preferred portfolio, Jim Bridger Units 1 and 2 are converted to natural gas-fueled peaking units in 2024, providing a low-cost reliable resource for meeting load and reliability requirements. There are no new natural gas resources in the preferred portfolio.
- The preferred portfolio shows an overall decline in reliance on wholesale market firm purchases in the 2021 IRP preferred portfolio relative to the market purchases included in the 2019 IRP preferred portfolio.

- The 2021 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 2019 IRP, projected CO_2 emissions in 2026 are down 26 percent. By 2030, average annual CO_2 emissions are down 34 percent relative to the 2019 IRP preferred portfolio, and down 52 percent in 2035. By the end of the planning horizon, system CO_2 emissions are projected to fall from 39.1 million tons in 2021 to 4.8 million tons in 2040—a reduction of 88 percent.

Introduction

This chapter reports modeling and portfolio selection results for the resource portfolios developed with a broad range of input assumptions informed by the Plexos modeling. Using model data from the portfolio-development process and subsequent cost and risk analysis of unique portfolio alternatives, the following discussion describes PacifiCorp's preferred portfolio selection process and presents the 2021 IRP preferred portfolio.

This chapter is organized around the portfolio development, modeling and evaluation steps identified in the previous chapter and covers the portfolio, cost and risk analysis for the: (1) initial portfolios; (2) the variants of the top performing initial portfolio and (3) the preferred portfolio selection. The final preferred portfolio selection is informed by all relevant modeling results. This chapter also presents modeling results for additional scenarios required under Washington's Clean Energy Transformation Act (CETA) that, while informative, were not considered eligible for selection as the preferred portfolio.

Results of resource portfolio cost and risk analysis from each step are presented in the following discussion of PacifiCorp's portfolio evaluation processes. Stochastic modeling results are also summarized in Volume II, Appendix J – Stochastic Simulation Results.

Initial Portfolio Development

The following discussion begins with an examination of initial portfolios exploring variations in retirement timing, the impact of regional haze compliance operating limits and options for gas conversion or carbon capture utilization and sequestration (CCUS) retrofit for certain units. The initial portfolios differ based on planning assumptions around coal unit retirement options and retirement timing. This includes a fully optimized view of potential retirements (P02), a partially optimized view of early retirements that requires all coal units to be retired by 2030 (P03), fixed retirements based on end-of-life operating assumptions (BAU1) and forced retirements consistent with the 2019 IRP preferred portfolio (BAU2).

Following the initial portfolios, PacifiCorp examined variants of the top-performing case with eight additional portfolios referred to as the P02-MM variants. All portfolios are examined with a granular assessment of reliability requirements through the production of hourly deterministic ST studies for every year over the 20-year planning horizon. Similar to the initial portfolios, this provides twenty years of hourly ST reliability assessment data used to inform the portfolios and ensure they are reliable.

As discussed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach), PacifiCorp evaluated eight variants of the top-performing P02-MM initial portfolio. Final selection of the top-performing portfolio and preferred portfolio selection also included an assessment of compliance with CETA.

Initial Portfolio Development

The following tables and figures present resource additions and system costs for the initial portfolios. Additional information is provided for all cases in Volume II, Appendix I (Capacity Expansion Results), including resource portfolio results showing new resource capacity and changes to existing resource capacity by year.

Initial Portfolios Thermal Retirements

Figure 9.1 summarizes the cumulative nameplate coal and gas retirements, including retirement of units converted or converting to gas-fueled peaking resources by case over the near-term, mid-term, and long-term among the initial portfolio cases. Note, in reporting cumulative capacity in this figure, the mid-term results include capacity retired in the near-term, and similarly, the long-term results include capacity retired in the near-term and in the mid-term. Unit-specific retirement dates for each case can be found in Volume II, Appendix I (Capacity Expansion Results).

Through 2026, coal unit retirement capacity ranges from 230 MW (BAU1 portfolios which assume end-of-life retirements) to 2,909 MW (P03 that assumes all coal units retire by 2030 and specifically, the P03-HH and P03-SCGHG portfolios). By the end of the planning horizon, coal retirements are similar among nearly all cases with exception of P03 which includes the early retirement of Hunter Units 1-3 as part of the planning assumption to retire all units by 2030. There is slight variation in timing of coal retirements among P02 and P03. Coal retirement timing assumptions with the BAU1 and BAU2 cases are fixed based on the planning assumption end-of-life (BAU1) and the 2019 IRP preferred portfolio retirement timing (BAU2). By the end of the planning horizon, coal retirements are the same among P02, BAU1 and BAU2 cases with a total of over 4,000 MW retired by 2040 (19 of PacifiCorp's 22 units). P03 includes retirement of Hunter Units 1-3 that are accelerated from end-of-life in 2042 to a 2029 retirement.

Not shown on the chart below, gas retirements are the same among all cases and include retirement of the gas-fueled Naughton Unit 3 at the end of 2029, Gadsby Units 1-6 at the end of 2032, Hermiston at the end of 2036, and the gas-fueled Jim Bridger Units 1 and 2 at the end of 2037. This represents a total of 1,554 MW of gas retirements through 2040.

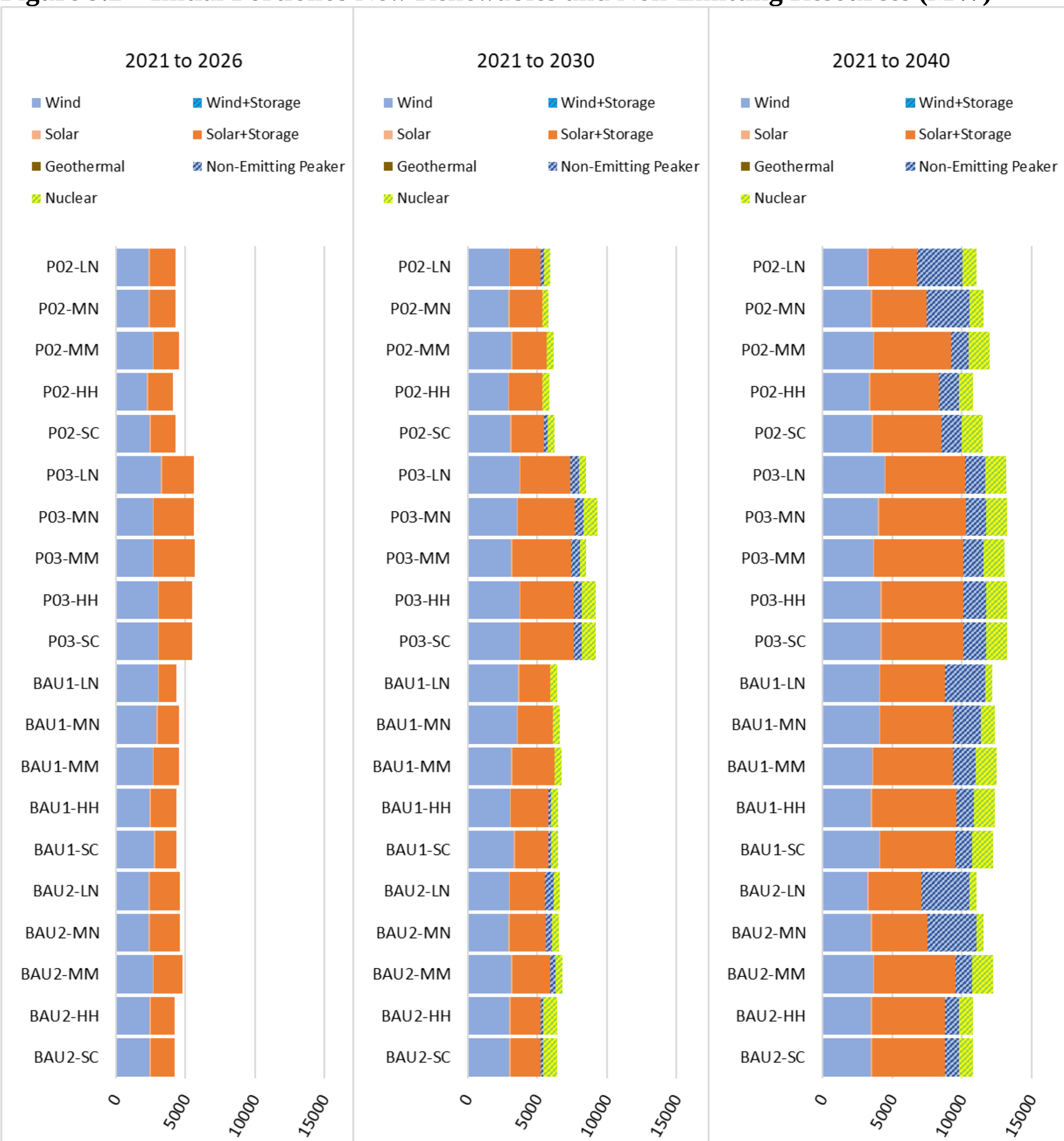
Figure 9.1 – Initial Portfolios Thermal Retirements (MW)

Initial Portfolios New Renewables and Non-Emitting Resources

Figure 9.2 reports the nameplate capacity of new renewables and non-emitting resource additions for each initial portfolio. Through 2025, all portfolios include the 2020 All-Source RFP final shortlist resources including 1,792 MW of wind, 1,302 MW of solar additions, and 697 MW of battery storage capacity – 497 MW paired with solar and a 200 MW standalone battery. They also include the acquisition and repowering of Rock River 1 (49MW) and Foote Creek II-IV (43 MW) wind projects. In 2026, all cases include an additional 745 MW of wind and additional solar and storage ranging from 600 MW up to 1,090 MW. All cases include GWS and D.1 in 2024 along with 1,641 MW of new wind in eastern Wyoming.

All cases include B2H in 2026 along with 600 MW of new co-located solar and storage. All cases include the 500 MW Natrium™ demonstration project in 2028. Through 2040, total new renewable capacity including new wind, new solar and new solar collocated with storage ranges between 6,794 MW and 10,306 MW. Through 2040, total new nuclear and non-emitting peaking resource capacity ranges between 2,010 MW and 4,277 MW.

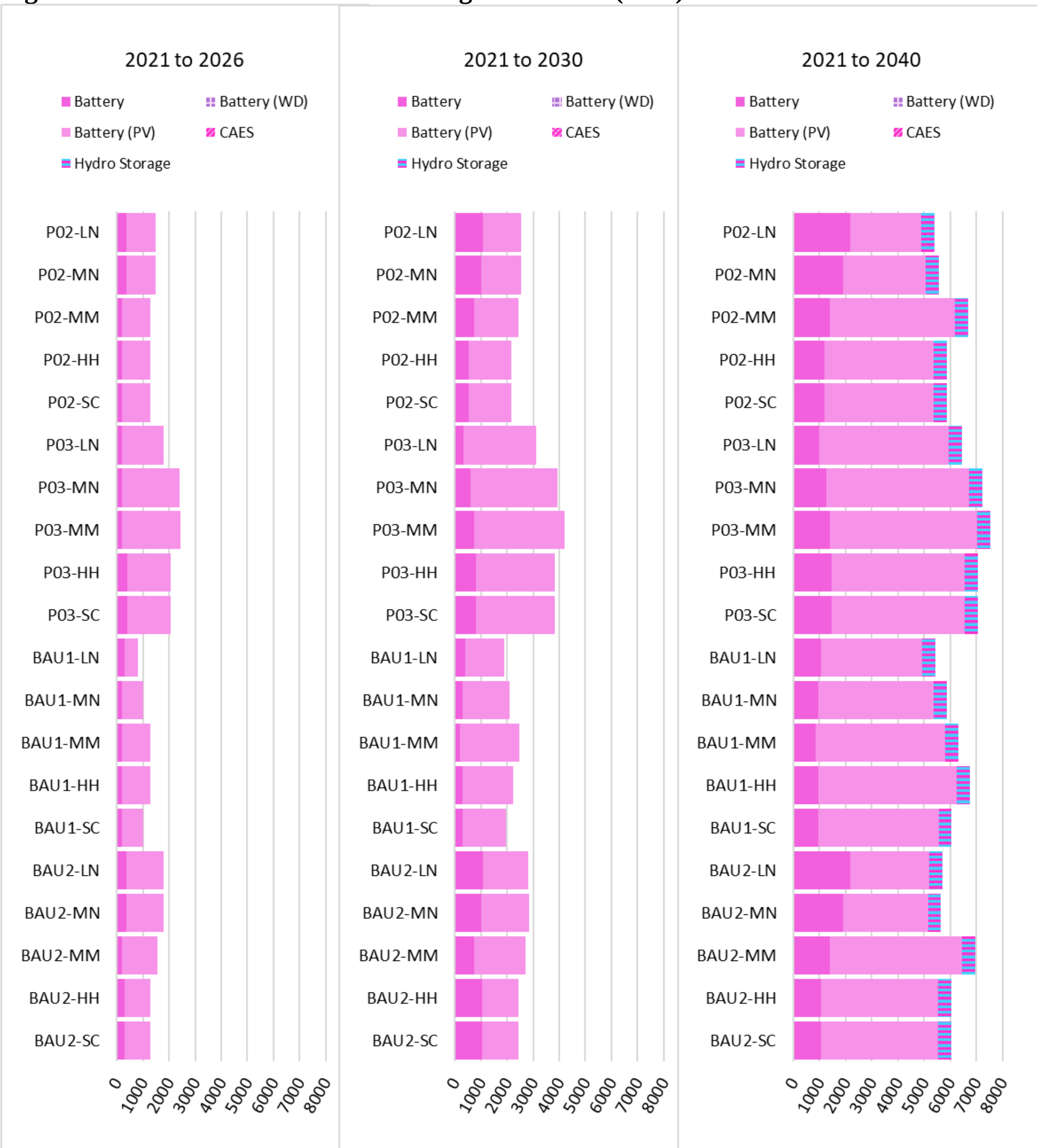
Figure 9.2 – Initial Portfolios New Renewables and Non-Emitting Resources (MW)



Initial Portfolios New Storage Resources

Figure 9.3 summarizes cumulative nameplate capacity of new storage resources for each initial portfolio. Through 2025, all cases include the 2020 All-Source RFP final shortlist resources including 697 MW of battery storage capacity – 497 MW paired with solar and a 200 MW standalone battery. More storage resources are accelerated into the mid-term among those cases that have higher levels of accelerated coal and gas retirements. Through 2040, total storage selections range between 5,404 MW (P02-LN) and 7,531 MW (P03-MM) including storage co-located with solar, standalone battery and a 500 MW pumped storage project selected in all cases in 2040.

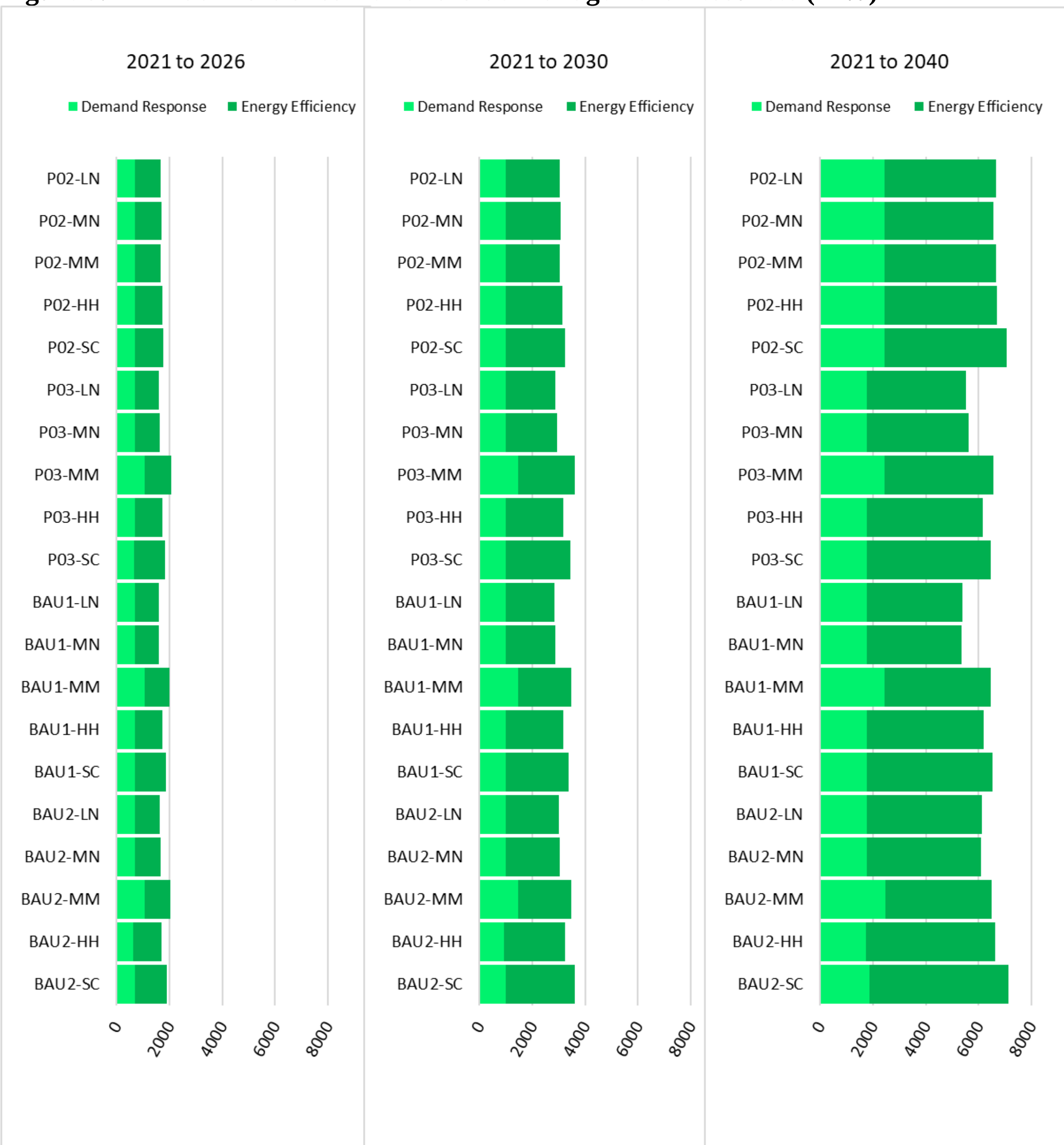
Figure 9.3 – Initial Portfolios New Storage Resources (MW)



Initial Portfolios Demand-Side Management (DSM) Resources

Figure 9.4 summarizes aggregated Demand-Side Management (DSM) selections by case. DSM selections continue to be relatively stable among all cases however, variations do occur among price-policy assumptions relative to CO_2. Through 2030, energy efficiency selections range between 1,845 MW (Case BAU1-LN) and 2,589 (Case BAU2-SC); demand response selections range between 918 MW (Case BAU2-HH) and 1,469 MW (Cases BAU-1 MM, BAU-2 MM, P-03 MM). More demand response resources are accelerated into the mid-term among those cases that have higher levels of accelerated coal and gas retirements. Through 2040, energy efficiency selections range between 3,605 MW (Case BAU1-MN) and 5,249 (Case BAU2-SC); demand response selections range between 1,752 MW (Case BAU2-HH) and 2,458 MW (Case BAU2-MM).

Figure 9.4 – Initial Portfolios Demand-Side Management Resources (MW)



CO_2 Emissions

Figure 9.5 reports cumulative CO_2 emissions for each initial portfolio. Total CO_2 emissions across the initial portfolios are stable under the medium gas, medium CO_2 (MM) price policy conditions, averaging 372 million tons over the 20-year planning period. Emissions are generally higher in cases with no CO_2 price, averaging 427 million tons in low gas, no CO_2 (LN) and medium gas, no CO_2 (MN) price-policy conditions. Under high gas, high CO_2 (HH) price environments, emissions average 323 million tons. The lowest emissions are reported under the social cost of greenhouse gas (SCGHG) price-policy portfolios, averaging 195 million tons. Emissions across all cases range from 171 million tons (P03-SCGHG) to 550 million tons (P02-MN).

Figure 9.5 – Initial Portfolios CO_2 Emissions (Million Tons)

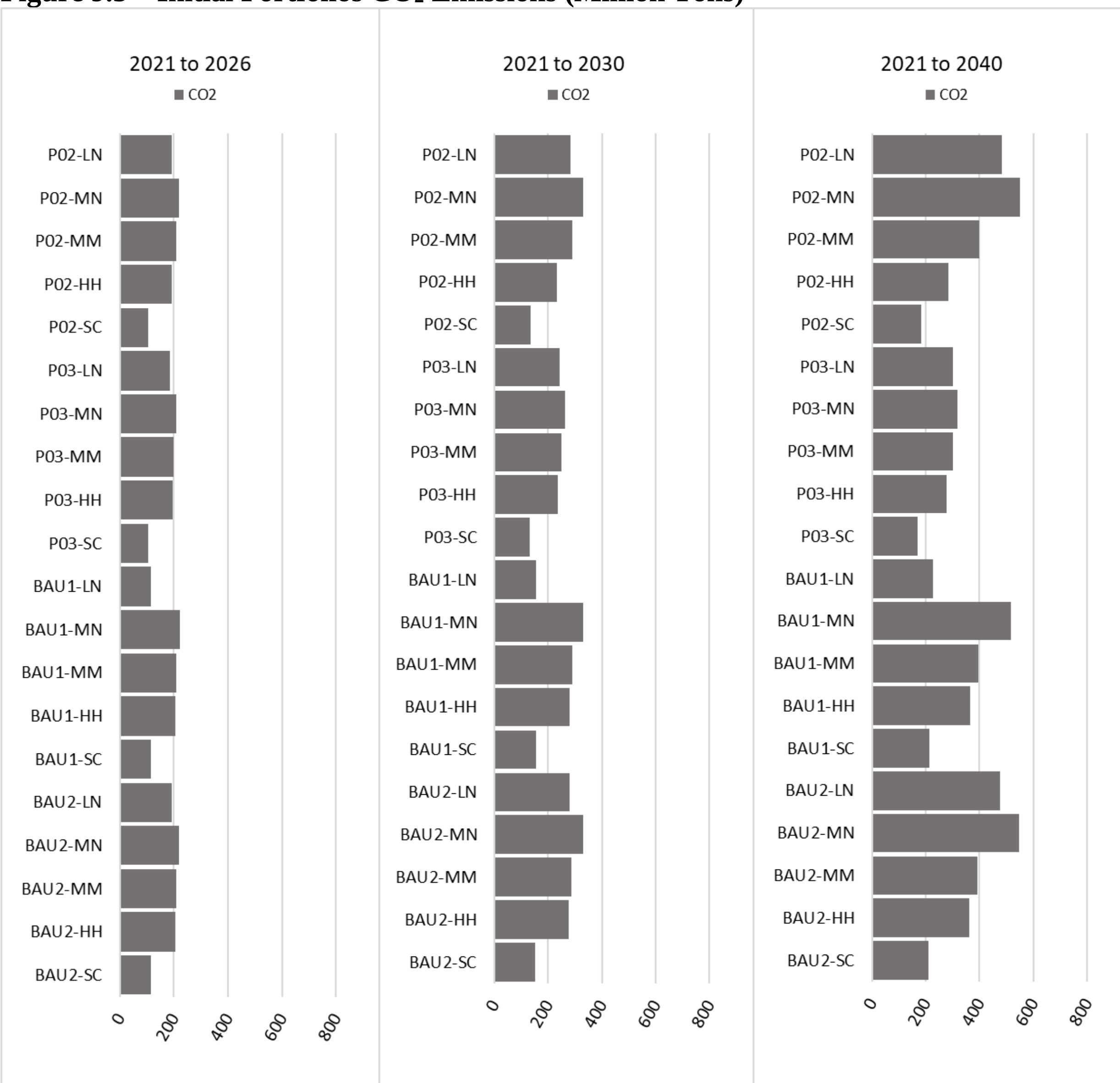


Table 9.1 to Table 9.**5** present cost and risk results for the initial portfolios across five price-policy scenarios, including the deterministic present value revenue requirement (PVRR), the risk-adjusted PVRR, the amount of energy not served (ENS) as a percentage of load, and total CO_2 emissions.

As shown in Table 9.1, the medium gas/medium CO_2 price-policy scenario, P02 outperforms other cases on a PVRR basis, risk-adjusted PVRR, and ENS. While P02 has higher cumulative CO_2 emissions, P03 has a risk-adjusted cost that is \$1.7b higher than P02. Emissions levels are similar among the P02, BAU1, and BAU2 portfolios.

Table 9.1 – Initial Portfolios Cost and Risk Results Summary (Medium Gas/Medium CO_2)

	ST Value			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case - MM	PVRR (\$m)	Change from Lowest Cost Portfolio (\$m)	Rank	ST PVRR plus 5% of 95th Stochastic (\$m)	Change from Lowest Cost Portfolio (\$m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P02	25,822	\$0	1	26,179	\$0	1	0.0049%	0.00000%	1	398,953	97,568	4
P03	27,594	\$1,772	4	27,876	\$1,696	4	0.0051%	0.00021%	2	301,385	0	1
BAU1	26,867	\$1,045	3	27,200	\$1,021	3	0.0051%	0.00021%	3	395,123	93,738	3
BAU2	26,719	\$897	2	27,054	\$875	2	0.0053%	0.00037%	4	391,900	90,515	2

As shown in Table 9.2, In the low gas/no CO_2 price-policy scenario, P02 outperforms other cases on cost and ENS and has comparable emissions to BAU1 and BAU2. P02 cumulative CO_2 emissions are higher than in P03, driven by P03 retirement assumptions of retiring all coal by 2030, which has a risk-adjusted cost that is \$2.5b higher than P02. Emissions levels are similar among the P02, BAU1, and BAU2 portfolios.

Table 9.2 – Initial Portfolios Cost and Risk Results Summary (Low Gas/No CO_2)

	ST Value			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case - LN	PVRR (\$m)	Change from Lowest Cost Portfolio (\$m)	Rank	ST PVRR plus 5% of 95th Stochastic (\$m)	Change from Lowest Cost Portfolio (\$m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P02	22,001	\$0	1	22,252	\$0	1	0.0053%	\$0	1	472,867	172,908	4
P03	24,610	\$2,609	4	24,772	\$2,520	4	0.0055%	\$0	2	299,959	0	1
BAU1	22,454	\$453	2	22,663	\$411	2	0.0058%	\$0	4	447,378	147,419	2
BAU2	22,480	\$479	3	22,735	\$483	3	0.0057%	\$0	3	466,064	166,105	3

As shown in Table 9.3, In the medium gas/no CO_2 price-policy scenario, P02 outperforms other cases on costs and ENS and has comparable emissions to BAU1 and BAU2. P02 cumulative CO_2 emissions are higher than in P03, driven by P03 retirement assumptions of retiring all coal by 2030, which has a risk-adjusted cost that is \$3.5b higher than P02.

Table 9.3 – Initial Portfolios Cost and Risk Results Summary (Medium Gas/No CO_2)

	ST Value			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case - MN	PVRR (\$m)	Change from Lowest Cost Portfolio (\$m)	Rank	ST PVRR plus 5% of 95th Stochastic (\$m)	Change from Lowest Cost Portfolio (\$m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P02	22,022	\$0	1	22,256	\$0	1	0.0049%	\$0	1	540,688	224,270	4
P03	25,616	\$3,594	4	25,780	\$3,523	4	0.0053%	\$0	3	316,418	0	1
BAU1	22,499	\$477	3	22,677	\$420	2	0.0052%	\$0	2	517,882	201,464	2
BAU2	22,460	\$439	2	22,702	\$445	3	0.0055%	\$0	4	537,670	221,252	3

As shown in Table 9.4, In the high gas/high CO_2 price-policy scenario, P02 outperforms other cases on costs and ENS and has comparable emissions to P03, the case with lowest emissions, which has a risk-adjusted cost that is \$1.0b higher than P02.

Table 9.4 – Initial Portfolios Cost and Risk Results Summary (High Gas/High CO_2)

	ST Value			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case - HH	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P02	27,492	$0	1	27,993	$0	1	0.0056%	$0	1	283,845	5,527	2
P03	28,671	$1,179	2	29,030	$1,037	2	0.0059%	$0	3	278,317	0	1
BAU1	29,308	$1,815	4	29,804	$1,810	4	0.0056%	$0	2	365,205	86,888	4
BAU2	28,884	$1,391	3	29,384	$1,391	3	0.0060%	$0	4	363,367	85,050	3

In the medium gas/social cost of greenhouse gas scenario, P02 outperforms other cases on cost except for P03, outperforms P03 and BAU2 on ENS, and ties BAU1 on ENS. P02 emissions are comparable to P03 emissions, the case with lowest emissions. P03 retires all coal by 2030 and has a risk-adjusted cost that is $178m lower than P02.

Table 9.5 – Initial Portfolios Cost and Risk Results Summary (Med Gas/Social Cost and Greenhouse Gas)

	ST Value			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case - SCGHG	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P02	38,399	$80	2	39,318	$178	2	0.0068%	$0	1	184,121	13,417	2
P03	38,319	$0	1	39,140	$0	1	0.0110%	$0	3	170,704	0	1
BAU1	40,383	$2,065	4	41,421	$2,281	4	0.0102%	$0	2	214,365	43,662	4
BAU2	40,182	$1,863	3	41,224	$2,084	3	0.0137%	$0	4	209,299	38,595	3

Based on these findings, PacifiCorp identified P02-MM as the top-performing portfolio at this stage of the portfolio-development process. PacifiCorp developed and analyzed additional portfolios as variants of P02-MM, as described in the following section.

P02 Variant Portfolios

Eight P02 variant portfolios were developed from the top-performing P02-MM portfolio to analyze key resources and in response to stakeholder interest. The P02 variant portfolios are summarized in the Table 9.6.

Table 9.6 – P02 Variant Portfolios

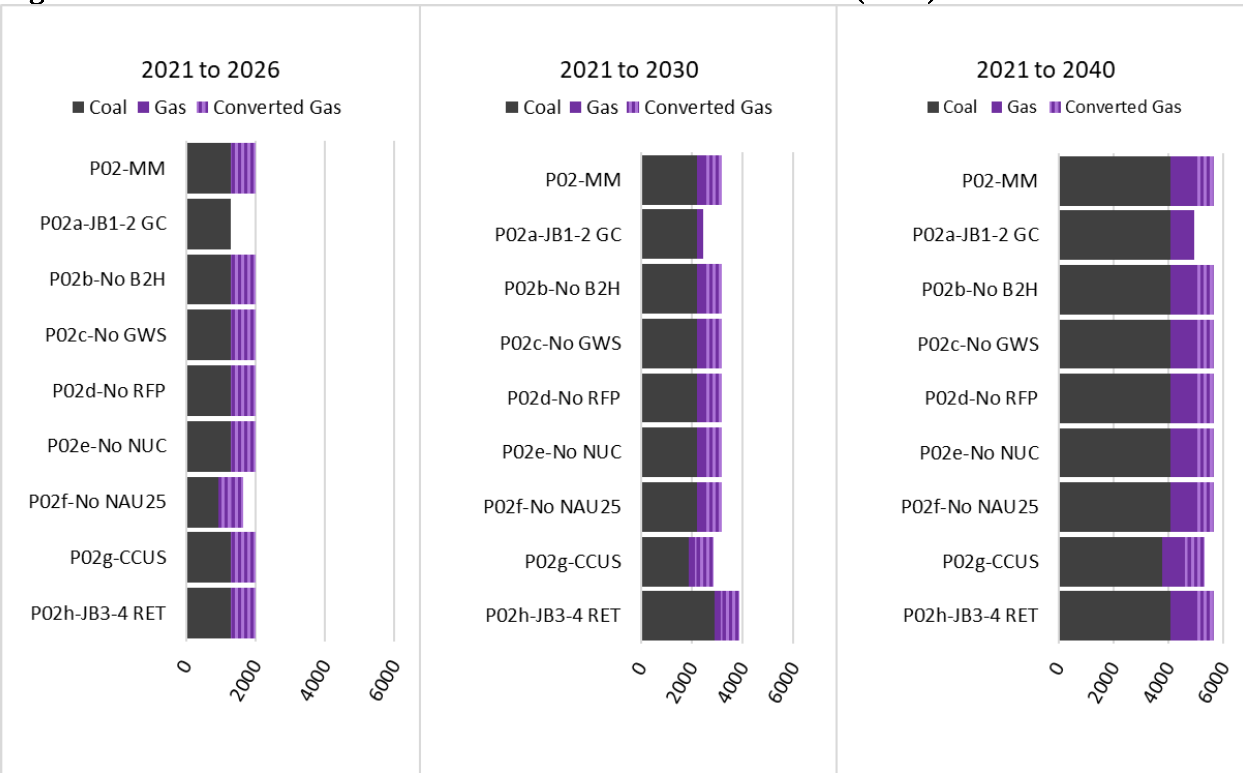
Case	Description
P02a – JB1-2 No GC	Excludes gas conversion of Jim Bridger Units 1 and 2
P02b – No B2H	Excludes Boardman-to-Hemingway transmission segment
P02c – No GWS	Excludes the Energy Gateway South transmission segment
P02d – No RFP	Excludes 2020 All-Source Request for Proposals Final Shortlist and the Energy Gateway South transmission segment
P02e – No Nuc	Excludes the Natrium™ advanced nuclear demonstration project
P02f – No Nau 25	Excludes the early retirement of Naughton Units 1 and 2
P02g – CCUS	Includes Carbon Capture Utilization and Sequestration (CCUS) retrofit of Dave Johnston Unit 4 in response to Wyoming House Bill 200
P02h – JB 3-4 Retire	Includes early retirement of Jim Bridger Units 3 and 4 in response to stakeholder feedback

P02 Variant Portfolios Portfolio Summary

Coal and Gas Retirements

Figure 9.6 summarizes cumulative nameplate coal and gas retirements for the P02 variant portfolios over the near-term, mid-term, and long-term. Note, in reporting cumulative capacity in this figure and the similar figures that follow, the mid-term results include capacity retired in the near-term, and similarly, the long-term results include capacity retired in the near-term and in the mid-term. Unit-specific retirement dates for each case can be found in Volume II, Appendix I (Capacity Expansion Results). Through 2026, total coal retirements range between 944 MW (P02e – No Nau 25) and 1,302 MW (P02-MM and all other P02 variant portfolios). Through the end of 2030, coal retirements range between 1,882 MW (P02g – CCUS) and 2,911 MW (P02h – JB 3-4 Retire). Through 2040, total coal retirements are 4,088 MW in each case with exception of P02g – CCUS, which totals 3,758 MW resulting from the CCUS retrofit of Dave Johnston Unit 4.

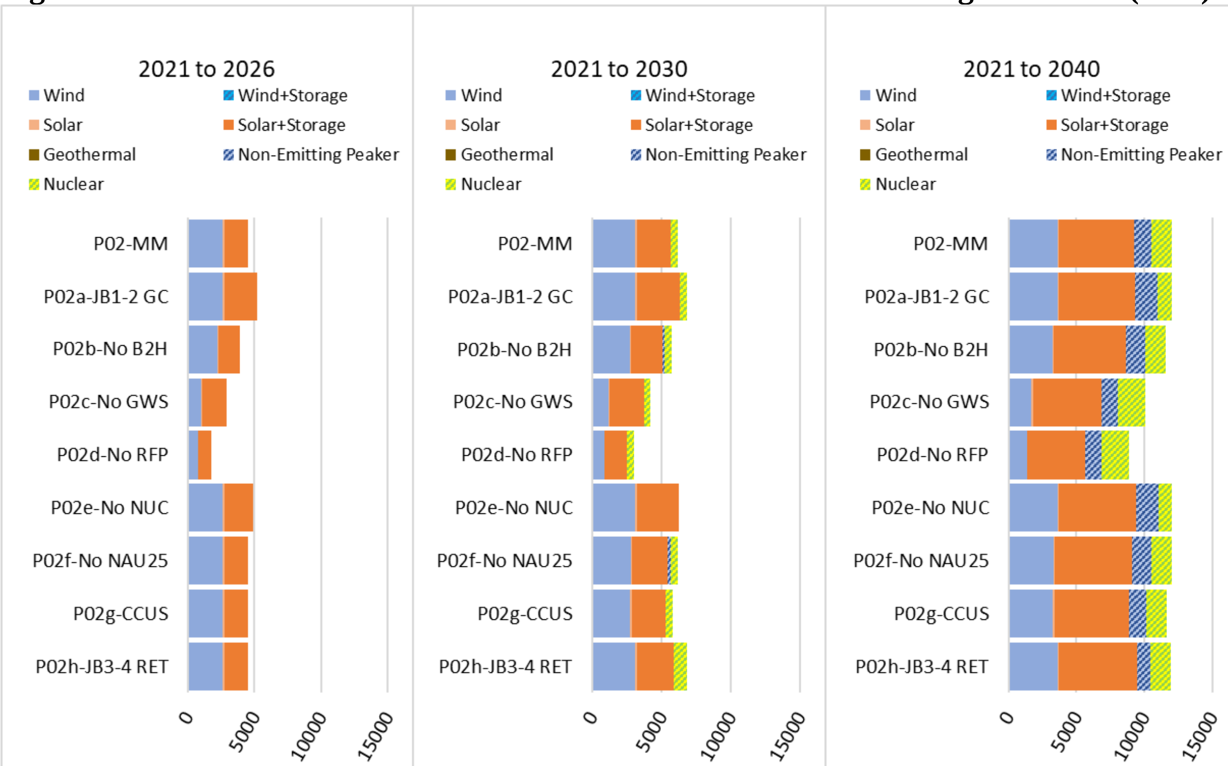
Figure 9.6 – P02 Variant Portfolios Coal and Gas Retirements (MW)



New Renewable and Non-Emitting Resources

Figure 9.7 summarizes the capacity of new renewables and non-emitting resource additions for each of the P02 variant portfolios. P02b excludes B2H in 2026 along with 600 MW of new co-located solar and storage. P02c (no GWS or D.1) excludes 1,641 MW of new wind in eastern Wyoming. P02d (no RFP bids, no GWS, and no D.1) results in the lowest new renewable additions, excluding 1,792 MW of wind, 1,302 MW of solar additions, and 697 MW of battery storage capacity. P02e excludes the 500 MW Natrium™ demonstration project in 2028, resulting in the lowest nuclear resource additions across the horizon at 1,000 MW in 2038; P02e also has the highest non-emitting peaking additions, at 1,638 MW.

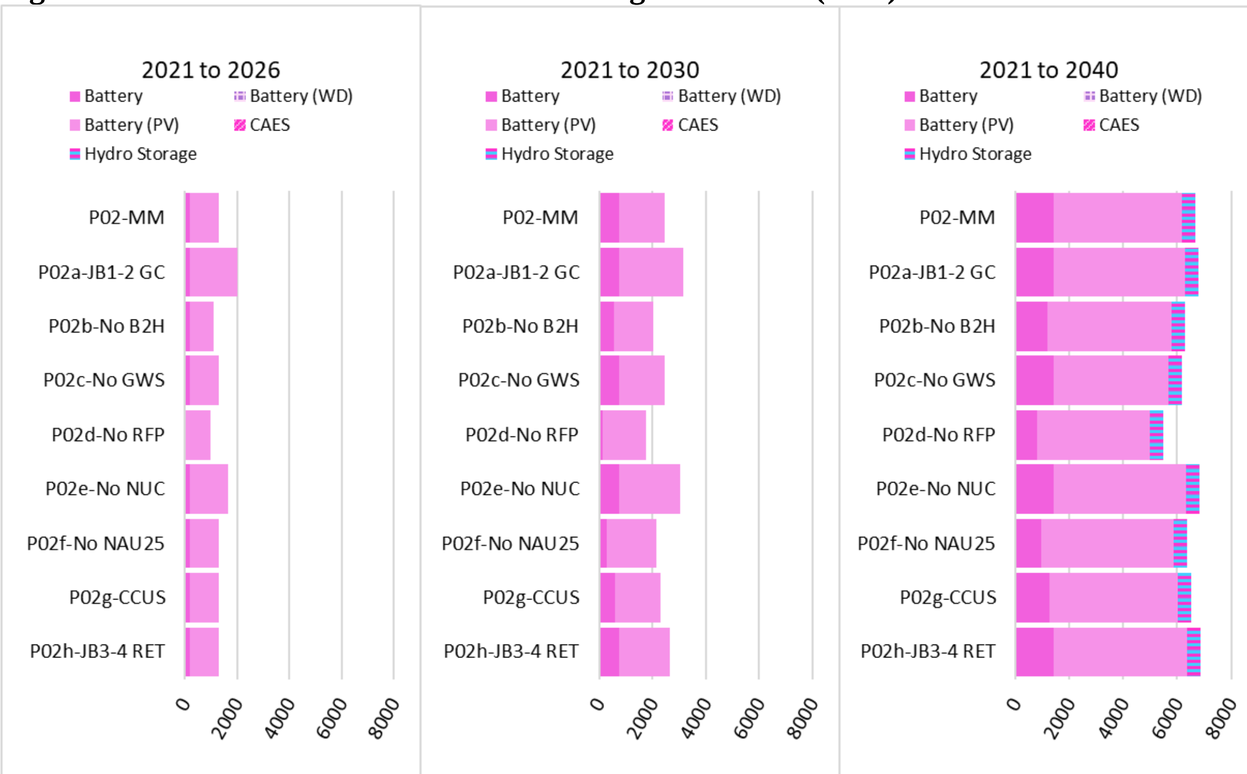
Figure 9.7 – P02 Variant Portfolios New Renewables and Non-Emitting Resources (MW)



New Storage Resources

Figure 9.8 summarizes the capacity of new storage resource additions for each of the P02 variant portfolios. P02d-No RFP adds the least total battery resource in the absence of the All-Source RFP resources, and the GWS and D.1 transmission lines. This is due to larger additions of advance nuclear and non-emitting peaking units needed to meet system requirements. With the removal of large dispatchable resources, such as the Natrium™ demonstration project (P02e-No Nuc) or the Jim Bridger plant (P02h-JB 3-4 Retire), there are higher selections of storage to maximize the value of renewable additions.

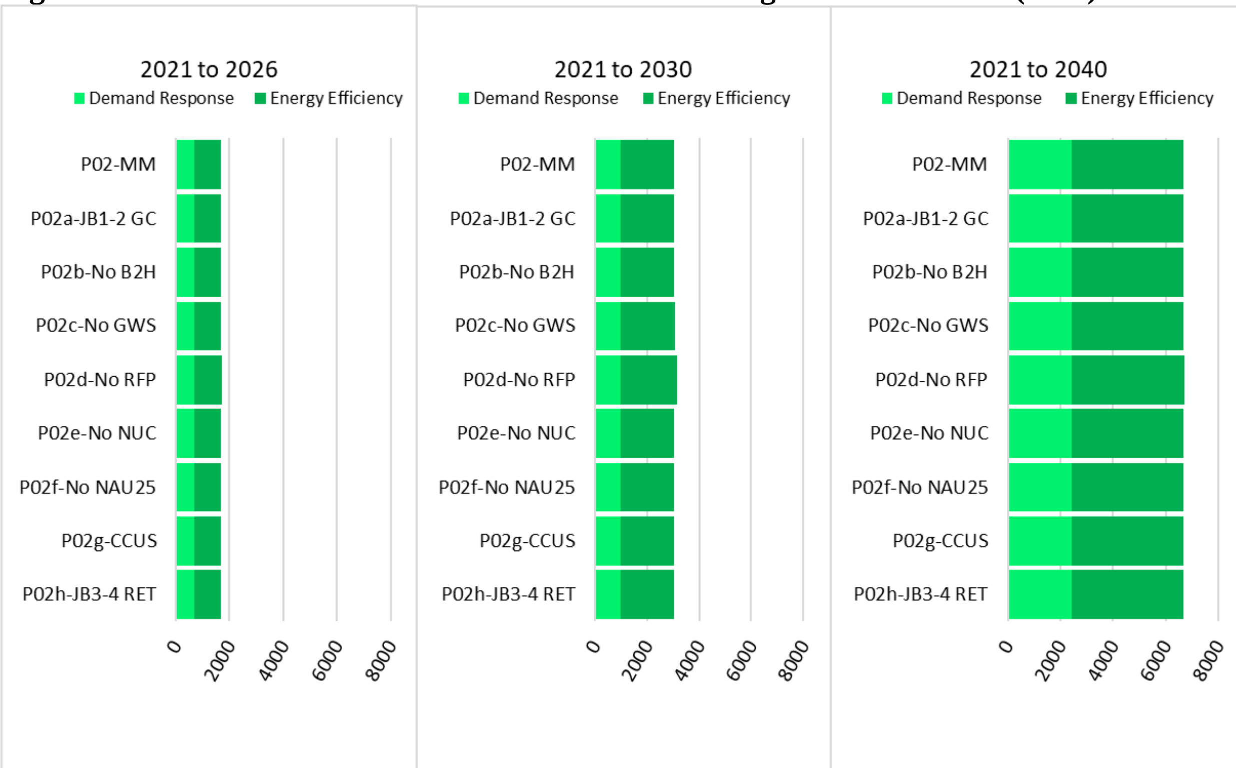
Figure 9.8 – P02 Variant Portfolios New Storage Resources (MW)



P02 Variant Portfolios Demand-Side Management Resources

Figure 9.9 summarizes aggregated DSM selections by case. DSM selections remain relatively consistent among P02 variants and range between 1,669 MW and 1,709 MW through 2026. Through 2040, energy efficiency selections and demand response total investments are consistent among the P02 variant portfolios.

Figure 9.9 – P02 Variant Portfolios Demand-Side Management Resources (MW)



CO_2 Emissions

Figure 9.10 reports cumulative CO_2 emissions for each of the P02 variant portfolios. Total CO_2 emissions through 2026 are very stable, ranging between 205 million tons (P02a-JB1-2 GC) and 220 million tons (P02d-No RFP). Through 2040, cumulative CO_2 emissions range between 369 million tons (P02h-JB3-4 Retire) and 476 (P02d-No RFP GWS) million tons.

Figure 9.10 – P02 Variant Portfolios CO_2 Emissions Summary (Million Tons)

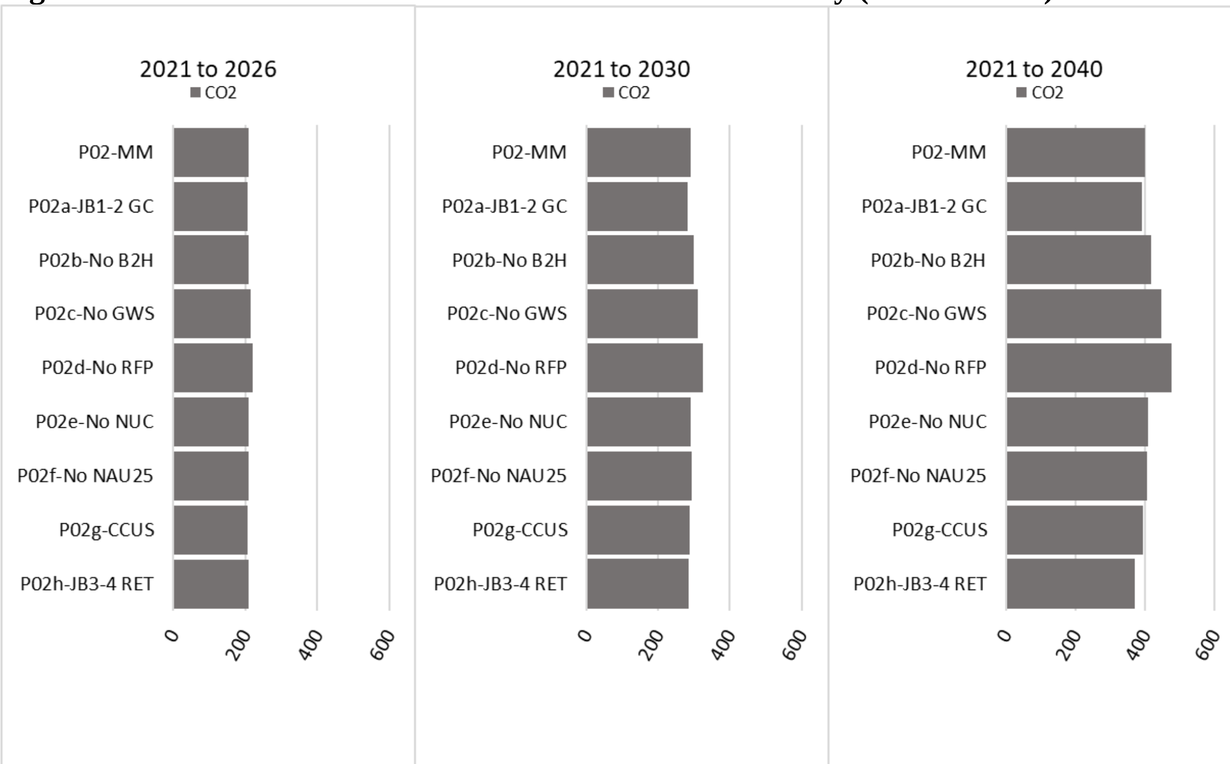
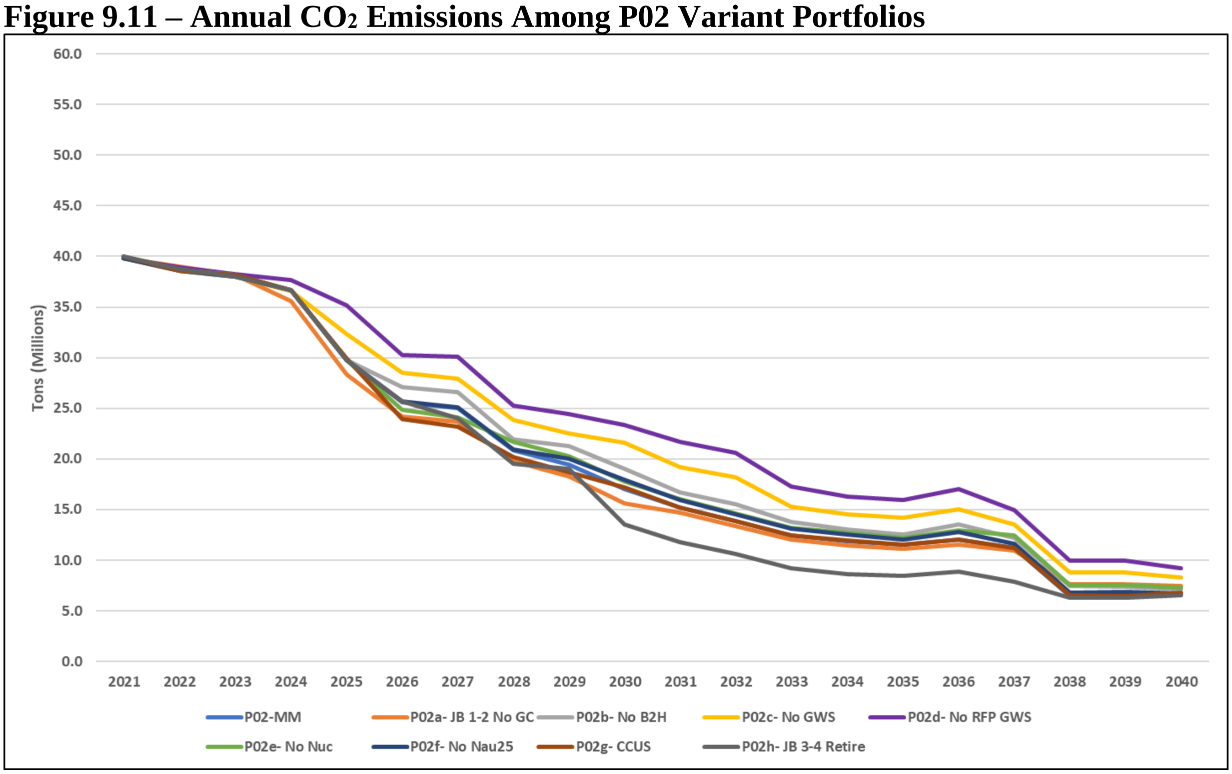


Figure 9.11 shows the annual emissions profile for the P02-MM portfolio and the eight P02 variant portfolios through the end of the planning period in 2040.

Figure 9.11 – Annual CO_2 Emissions Among P02 Variant Portfolios



P02 Variants Portfolio Discussion

Jim Bridger Unit 1 and Unit 2 Gas Conversion Variant (P02a-JB 1-2 GC)

The P02a-JB 1-2 No GC portfolio is a variant of the P02-MM portfolio that eliminates the gas conversion of Jim Bridger Units 1 and 2. When this variant is compared to the P02-MM portfolio, changes in proxy resources and system costs driven by the gas conversion of Jim Bridger Units 1 and 2 can be isolated.

Figure 9.12 shows the cumulative (at left) and incremental (at right) portfolio changes when the gas conversion of Jim Bridger Units 1 and 2 is eliminated from the P02-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the conversion is eliminated. Without the gas conversion, the model optimizes the next-best selection and indicates that Jim Bridger Units 1 and 2 retire at the end of 2023 and an additional 700 MW of solar co-located with storage is added in 2024. Over 600 MW of non-emitting peakers displace a similar amount of solar co-located with storage over the 2031-2037 timeframe. In 2038, considering Jim Bridger Units 1 and 2 were already retired at the end of 2023, the case without gas conversion avoids an advanced nuclear resource and non-emitting peaker resources that are required in the P02-MM portfolio when the converted units would have otherwise retired.

Figure 9.12 – Increase/(Decrease) in Proxy Resources when the Jim Bridger Gas Conversion is Eliminated from the P02-MM portfolio.

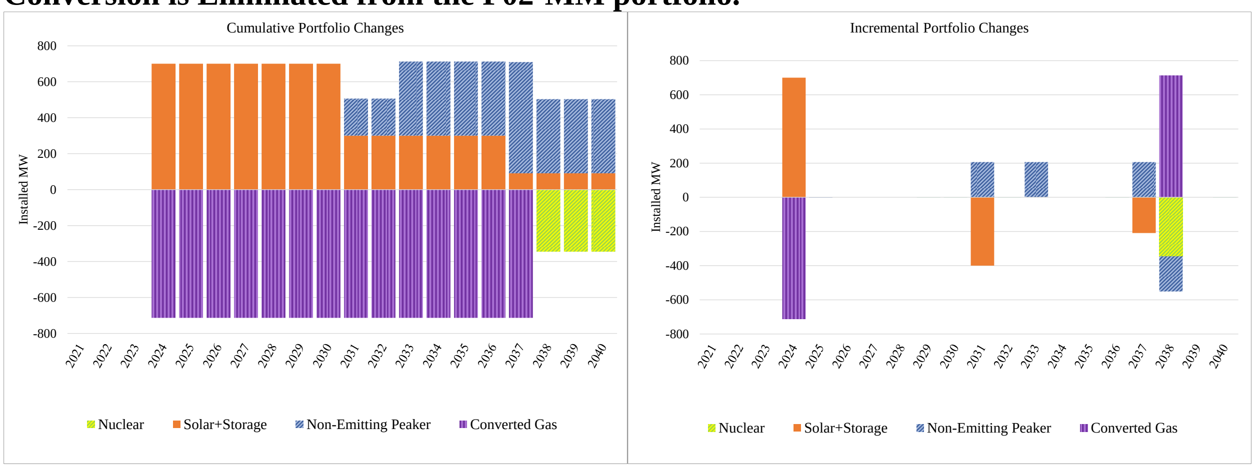


Figure 9.13 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when the gas conversion of Jim Bridger Units 1 and 2 is eliminated from the P02-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative present-value revenue requirement differential (PVRR(d)) over time (the dashed black line).[1] Through 2040, the PVRR(d) shows that the portfolio without gas conversion of Jim Bridger Units 1 and 2 is $477 million higher cost than the P02-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without gas conversion is $469 million higher cost than the P02-MM portfolio.

The key drivers to this result are consistent with changes in resources between the two portfolios. The portfolio without gas conversion retires Jim Bridger Units 1 and 2 at the end of 2023 (the next

[1] The PVRR(d) represents the differential in revenue requirement costs relative to the P02-MM portfolio.

best alternative to gas conversion), which triggers the addition of 700 MW of solar co-located with storage in 2024. The initial capital associated with the 700 MW solar resource paired with 700 MW of 4-hour storage is $2,890/kW. The initial capital required to convert Jim Bridger Units 1 and 2 to natural gas is about $25/kW.

Figure 9.13 – Increase/(Decrease) in System Costs when the Jim Bridger Gas Conversion is Eliminated from the P02-MM portfolio.

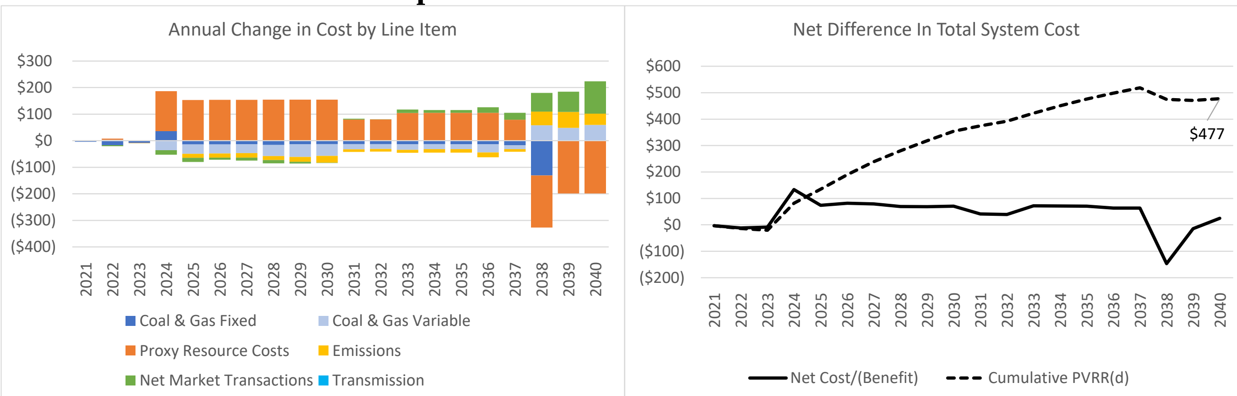


Table 9.7 summarizes the PVRR(d) of the P02a-JB 1-2 No GC portfolio relative to the P02-MM portfolio under a range of different price-policy scenarios. The portfolio that eliminates gas conversion for Jim Bridger Units 1 and 2 is significantly higher cost than the P02-MM portfolio across each of the price-policy scenarios. This trend holds true for both the ST PVRR and the risk-adjusted PVRR results. Both portfolios, as measured by ENS, are very reliable among all price-policy scenarios. Emissions are slightly higher when Jim Bridger Units 1 and 2 are converted to natural gas (approximately 1-2 percent relative to the case without gas conversion). In aggregate, these results support the inclusion of the Jim Bridger Unit 1 and 2 gas conversion in the preferred portfolio.

Table 9.7 – PVRR(d) of the P02a-JB 1-2 No GC Portfolio Relative to the P02-MM Portfolio Under Varying Price-Policy Scenarios.

	PVRR ($m)	ST PVRR + 5% of 95th Stochastic ($m)	ENS Average % of Load	CO2 Emissions 2021-2040 (Thousand Tons)
P02-MM-MM	$25,822	$26,179	0.0049%	398,953
P02-MM-LN	$22,620	$22,821	0.0054%	436,134
P02-MM-MN	$22,449	$22,637	0.0049%	511,369
P02-MM-HH	$28,807	$29,308	0.0049%	368,551
P02-MM-SCGHG	$39,667	$40,693	0.0094%	208,650
P02a-MM-MM	$26,299	$26,648	0.0049%	390,206
P02a-MM-LN	$23,154	$23,350	0.0051%	427,277
P02a-MM-MN	$22,944	$23,123	0.0049%	504,386
P02a-MM-HH	$29,226	$29,712	0.0050%	360,636
P02a-MM-SCGHG	$40,019	$41,028	0.0097%	206,732
Change from P02-MM-MM	$477	$469	0.0000%	(8,747)
Change from P02-MM-LN	$534	$529	-0.0003%	(8,857)
Change from P02-MM-MN	$495	$486	0.0000%	(6,982)
Change from P02-MM-HH	$418	$404	0.0001%	(7,915)
Change from P02-MM-SCGHG	$353	$335	0.0003%	(1,918)

Boardman-to-Hemingway Variant (P02b-No B2H)

The P02b-No B2H portfolio is a variant of the P02-MM portfolio that eliminates the B2H transmission line. When this variant is compared to the P02-MM portfolio, changes in proxy resources and system costs driven by the removal of the B2H transmission line can be isolated. Figure 9.14 shows the cumulative (at left) and incremental (at right) portfolio changes when the B2H transmission line is eliminated from the P02-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the transmission line is eliminated. Without B2H, 405 MW of wind and 200 MW of solar co-located with storage is removed from the portfolio in 2026. Approximately 200 MW of storage capacity is removed from eastern Wyoming in 2029, which must be replaced by just over 200 MW of non-emitting peaking capacity in 2030.

Figure 9.14 – Increase/(Decrease) in Proxy Resources when the B2H Transmission Line is Eliminated from the P02-MM portfolio.

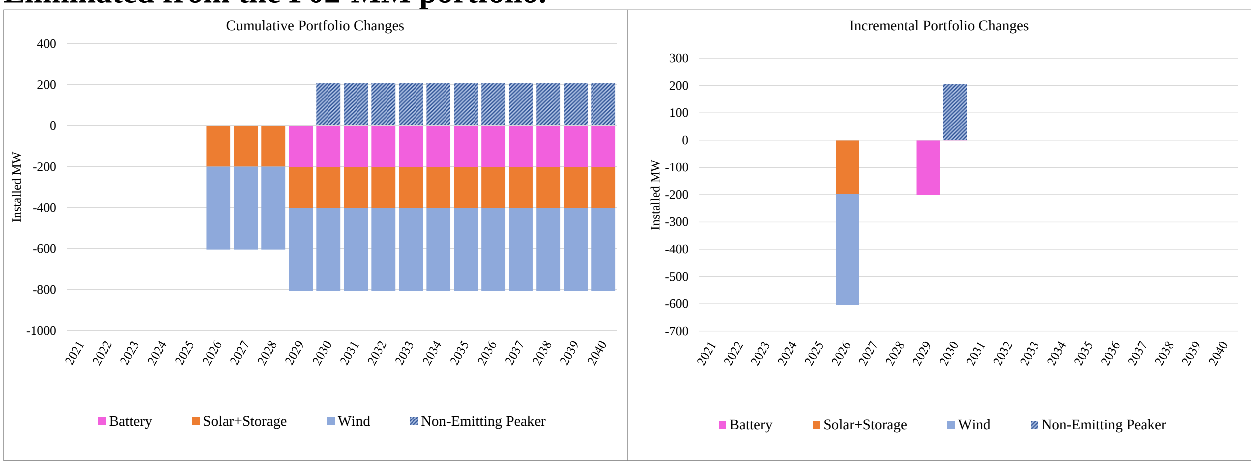


Figure 9.15 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when the B2H transmission line is eliminated from the P02-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio without the B2H transmission line is $388 million higher cost than the P02-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without B2H is $453 million higher cost than the P02-MM portfolio.

Without the B2H transmission line, the cost for proxy resources is reduced consistent with the changes in the resource portfolio. However, the reduction in resources results in an increase in net market costs, indicating that without the B2H transmission line, the system would be more dependent on the market. With fewer renewable resources, output from coal and gas resources increase, emissions increase, and the associated costs from higher fossil-fueled generation and emissions also increase. The increase in transmission costs is driven by the incremental costs to reliably serve increasing load in central Oregon. The B2H transmission line provides more flexibility and increased load-serving capability on the 500-kV transmission system into the central Oregon load pocket. Without the B2H transmission line, additional resources would need to be sited in southern Oregon that could be called upon to maintain reliable operations of the broader transmission system in the region. The analysis assumes that 725 MW of incremental 4hour battery resources and other transmission upgrades would be needed in southern Oregon if the B2H transmission line is not built. The transmission cost savings reflect the fact that these investments would be avoided if B2H is built.

Figure 9.15 – Increase/(Decrease) in System Costs when the B2H Transmission Line is Eliminated from the P02-MM portfolio.

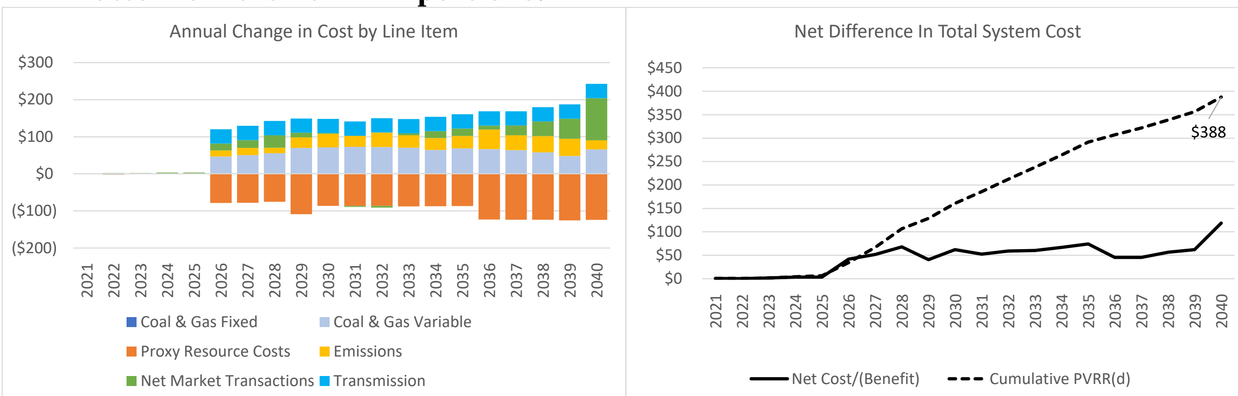


Table 9.8 summarizes the PVRR(d) of the P02b-No B2H portfolio relative to the P02-MM portfolio under a range of different price-policy scenarios. Eliminating the B2H transmission line increases the ST PVRR and the risk-adjusted PVRR all price-policy scenarios Removal of B2H also results in higher emissions (emissions increase by approximately 5 percent in the MM price-policy scenario). Note, that both portfolios, as measured by ENS results, are very reliable among all price-policy scenarios. While the cost increase from B2H in the LN price-policy scenario is low relative to other price-policy scenarios, it is more likely than not that there will be some form of policy that will impute a cost on greenhouse gas emissions. It is also unlikely that gas prices will remain low for decades to come. In aggregate, these results support the inclusion of the B2H transmission line in the preferred portfolio.

Table 9.8 – PVRR(d) of the P02b-No B2H Portfolio Relative to the P02-MM Portfolio Under Varying Price-Policy Scenarios.

	PVRR ($m)	ST PVRR + 5% of 95th Stochastic ($m)	ENS Average % of Load	CO2 Emissions 2021-2040 (Thousand Tons)
P02-MM-MM	$25,822	$26,179	0.0049%	398,953
P02-MM-LN	$22,620	$22,821	0.0054%	436,134
P02-MM-MN	$22,449	$22,637	0.0049%	511,369
P02-MM-HH	$28,807	$29,308	0.0049%	368,551
P02-MM-SCGHG	$39,667	$40,693	0.0094%	208,650
P02b-MM-MM	$26,209	$26,633	0.0050%	418,015
P02b-MM-LN	$22,650	$22,902	0.0054%	456,553
P02b-MM-MN	$22,603	$22,850	0.0050%	527,710
P02b-MM-HH	$29,549	$30,130	0.0050%	387,960
P02b-MM-SCGHG	$41,117	$42,251	0.0117%	228,728
Change from P02-MM-MM	$388	$453	0.0001%	19,062
Change from P02-MM-LN	$30	$81	0.0001%	20,419
Change from P02-MM-MN	$154	$213	0.0000%	16,342
Change from P02-MM-HH	$742	$822	0.0001%	19,408
Change from P02-MM-SCGHG	$1,450	$1,557	0.0023%	20,078

Energy Gateway South and Sub-Segment D.1 Variant (P02c-No GWS)

The P02c-No GWS portfolio is a variant of the P02-MM portfolio that eliminates the GWS and D.1 transmission lines. Because wind bids selected to the 2020AS RFP final shortlist that are located in eastern Wyoming cannot interconnect without these two transmission lines,[2] these resources are also eliminated from the P02c-No GWS portfolio. When this variant is compared to the P02-MM portfolio, changes in proxy resources and system costs driven by the removal of the GWS and D.1 transmission lines can be isolated.

Figure 9.16 shows the cumulative (at left) and incremental (at right) portfolio changes when the GWS and D.1 transmission line are eliminated from the P02-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the transmission lines are eliminated. Without GWS and D.1, 2020AS RFP wind resources are removed from the portfolio in 2024 (shown as a reduction in 2025, the first full year these resources would be online). An additional 289 MW of wind is eliminated in 2030. In 2034, the absence of the new wind resources triggers the addition of an additional advanced nuclear plant that displaces solar co-located with storage resources. The lack of resource additions with the removal of wind resources in the portfolio without GWS and D.1 signals an increase in market reliance.

Figure 9.16 – Increase/(Decrease) in Proxy Resources when the GWS and D.1 Transmission Lines are Eliminated from the P02-MM portfolio.

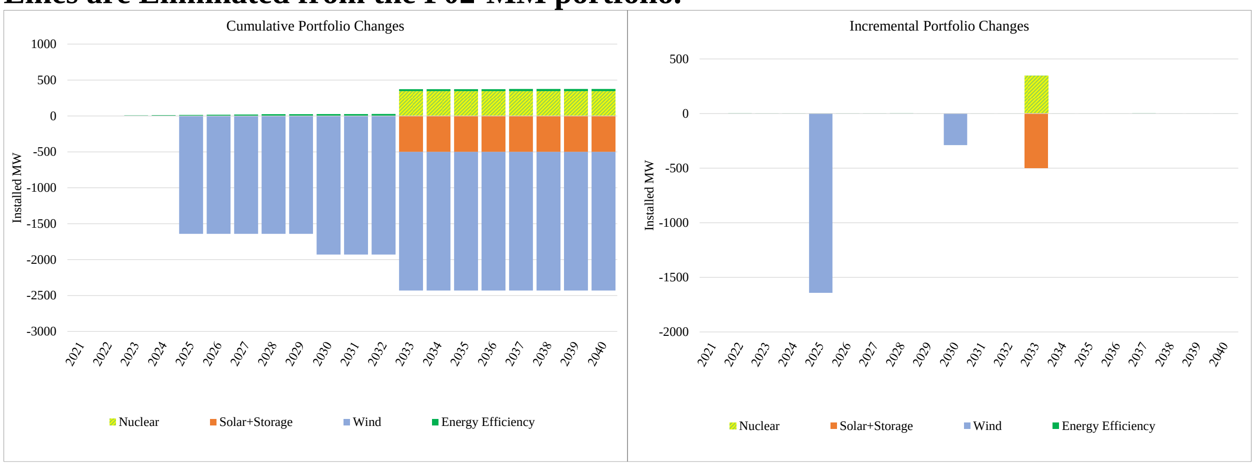
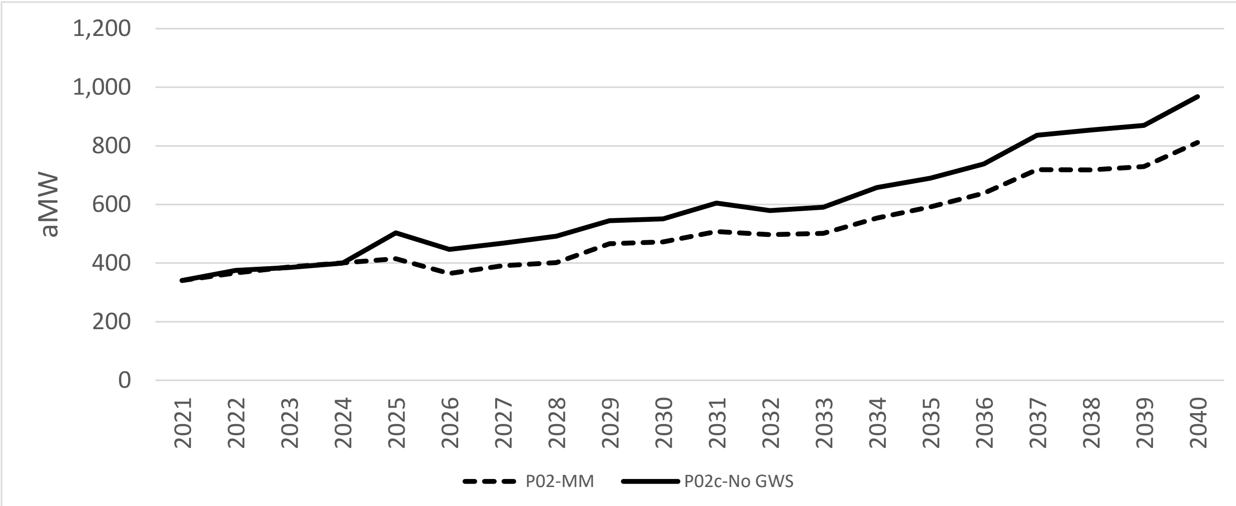


Figure 9.17 shows how market purchases change when the GWS and D.1 transmission lines are removed from the portfolio. With fewer resources, market purchases on an annual basis increase by nearly 20% if GWS and D.1 are removed from the portfolio. Consequently, there is elevated market-reliance risk if the GWS and D.1 transmission lines are not built.

[2] Examination of this variant focuses on the estimated impacts to resource procurement, market purchases, and system costs, but ignores the elimination of GWS and D.1 transmission lines would interfere with PacifiCorp transmission's ability to provide nearly 2,500 MW of requests for transmission and interconnection service governed by multiple FERC-jurisdictional executed contracts.

Figure 9.17 – Increase/(Decrease) Market Purchases in the P02-MM and P02c-No GWS Portfolios.



When GWS, D.1, and the associated 2020AS RFP wind resources are removed from the portfolio, the costs associated with new resources decline. The cost for transmission is also reduced. This reduction in transmission cost is net of the cost required to build a new 230-kV line to accommodate PacifiCorp's obligation to provide firm point-to-point transmission service to a third-party transmission customer. The 230-kV alternative is not avoidable if GWS is not built. Further, the $1.4 billion cost assumed for this alternative is the minimum cost for the alternative considering that it includes only the upgrades required to grant a single transmission service request. Additional costs would be incurred to accommodate additional requests for interconnection service. To accommodate all of these requests, it is likely the alternative would be to construct GWS.

When the GWS and D.1 transmission lines are removed from the portfolio, coal and gas generation is increased, which increases variable costs for existing fossil-fired resources and the associated cost for increased emissions. Further, the system becomes more reliant on the market as shown by increased market costs. As noted above, this not only increases costs to the system, but it also introduces incremental market-reliance risk, which is not captured in PVRR results. The increase in system costs that occurs in 2034 coincides with the period where production tax credits associated with new wind in the P02-MM portfolio roll off and when there is a shift in the resource mix between the two cases (without GWS, D.1, and the associated 2020AS RFP wind, an additional advanced nuclear facility is required).

Figure 9.18 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when the GWS and D.1 transmission lines are eliminated from the P02-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio without the GWS and D.1 transmission lines is $128 million higher cost than the P02-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without the GWS and D.1 transmission lines is $260 million higher cost than the P02-MM portfolio. The risk-adjusted results indicate that the GWS and D.1 transmission lines add significant risk mitigation benefits associated with volatility in market prices, loads, hydro generation, and unplanned outages.

Figure 9.18 – Increase/(Decrease) in System Costs when the GWS and D.1 Transmission Lines are Eliminated from the P02-MM portfolio.

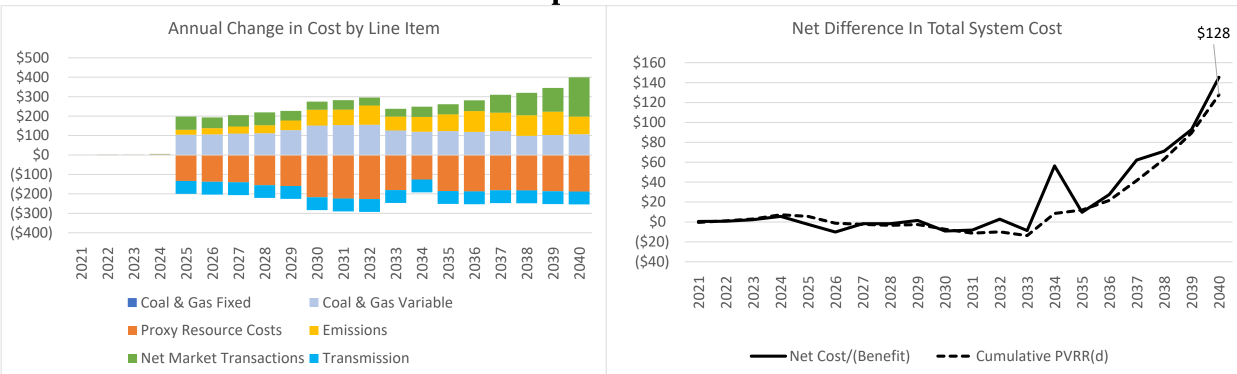


Table 9.9 summarizes the PVRR(d) of the P02c-No GWS portfolio relative to the P02-MM portfolio under a range of different price-policy scenarios. System costs increase when GWS and D.1 are removed from the portfolio in MM, HH, and SCGG price-policy scenarios. Conversely, costs decrease in the LN and MN price-policy scenarios. Without GWS and D.1, emissions from PacifiCorp's fossil-fueled resources increase considerably—ranging from 8.4% in the MN price-policy scenario to 17.8% in the SCGG price-policy scenario. As discussed earlier, it is more likely than not that there will be some form of policy action taken to impute a cost or penalty on greenhouse gas emissions. It is also unlikely gas prices will be suppressed for many decades to come, as assumed in the LN price-policy scenario. Further, cost-and-risk results indicate that there is a tremendous opportunity cost of not building these transmission lines should policies develop that impose costs on greenhouse gas emissions. This is seen with the disproportionate increase in costs under HH and SCGG price-policy scenarios relative to the size of cost reductions in the unlikely LN and MN price-policy scenarios. Considering the removal of GWS and D.1 increases system costs among the MM, HH, and SCGG price-policy scenarios, significantly increases emissions and associated costs and risks, and significantly increases market-reliance risk, this analysis supports including GWS, D.1, and the associated 2020AS RFP wind resources in the preferred portfolio.

Table 9.9 – PVRR(d) of the P02c-No GWS Portfolio Relative to the P02-MM Portfolio Under Varying Price-Policy Scenarios.

	PVRR ($m)	ST PVRR + 5% of 95th Stochastic ($m)	ENS Average % of Load	CO2 Emissions 2021-2040 (Thousand Tons)
P02-MM-MM	$25,822	$26,179	0.0049%	398,953
P02-MM-LN	$22,620	$22,821	0.0054%	436,134
P02-MM-MN	$22,449	$22,637	0.0049%	511,369
P02-MM-HH	$28,807	$29,308	0.0049%	368,551
P02-MM-SCGHG	$39,667	$40,693	0.0094%	208,650
P02c-MM-MM	$25,949	$26,439	0.0052%	445,607
P02c-MM-LN	$21,864	$22,151	0.0005%	484,784
P02c-MM-MN	$22,056	$22,349	0.0051%	554,193
P02c-MM-HH	$29,739	$30,408	0.0051%	413,739
P02c-MM-SCGHG	$42,235	$43,512	0.0157%	245,883
Change from P02-MM-MM	$128	$260	0.0002%	46,654
Change from P02-MM-LN	($755)	($670)	-0.0048%	48,650
Change from P02-MM-MN	($393)	($289)	0.0002%	42,825
Change from P02-MM-HH	$932	$1,100	0.0002%	45,187
Change from P02-MM-SCGHG	$2,568	$2,819	0.0063%	37,233

2020AS RFP Variant (P02d-No RFP)

The P02d-No RFP GWS portfolio is a variant of the P02-MM portfolio that eliminates all 2020AS RFP resources, including the GWS and D.1 transmission lines. When this variant is compared to the P02-MM portfolio, changes in proxy resources and system costs driven by the removal of the 2020AS RFP resources can be isolated.

Figure 9.19 shows the cumulative (at left) and incremental (at right) portfolio changes when the 2020AS RFP resources are eliminated from the P02-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the 2020AS RFP resources and the GWS and D.1 transmission lines are eliminated. Without 2020AS RFP resources, an additional 400 MW of solar co-located with storage is added to the portfolio in 2026. In 2029, 549 MW of storage is removed. In 2030, 149 MW of storage is added concurrent with the removal of 389 MW of wind. In 2033, an additional advanced nuclear resource displaces 500 MW of solar co-located with storage. The lack of resource additions with the removal of 2020AS RFP resources signals an increase in market reliance.

Figure 9.19 – Increase/(Decrease) in Proxy Resources when 2020AS RFP Resources are Eliminated from the P02-MM portfolio.

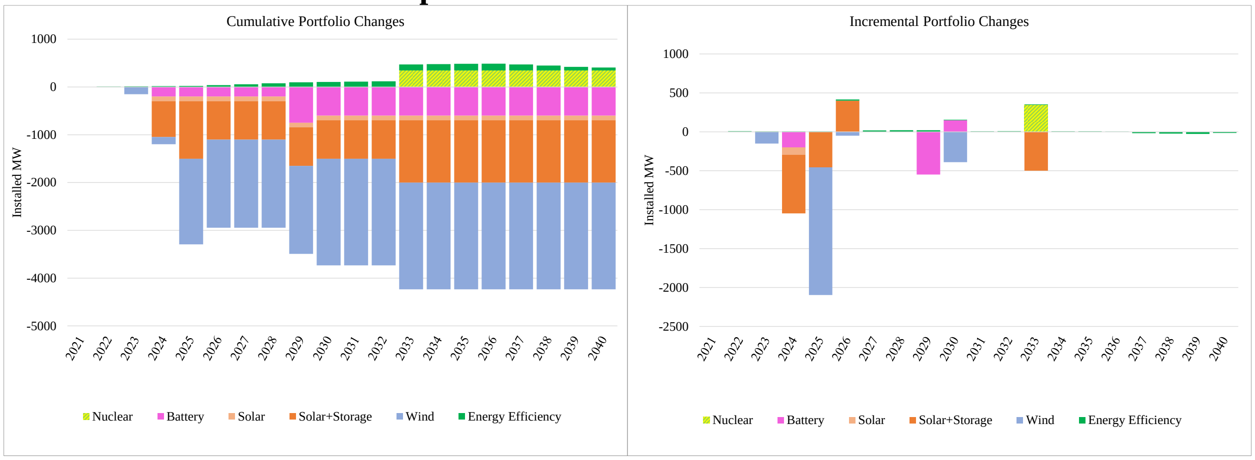


Figure 9.20 shows how market purchases change when the 2020AS RFP resources are removed from the portfolio. With fewer resources, market purchases on an annual basis increase by as much as 45% in 2025. From 2025 through 2040, market purchase volumes are, on average, 30% higher than the market purchases in the P02-MM portfolio. Consequently, there is elevated market-reliance risk without the 2020AS RFP resources.

Figure 9.20 – Increase/(Decrease) Market Purchases in the P02-MM and P02d-No RFP Portfolios.

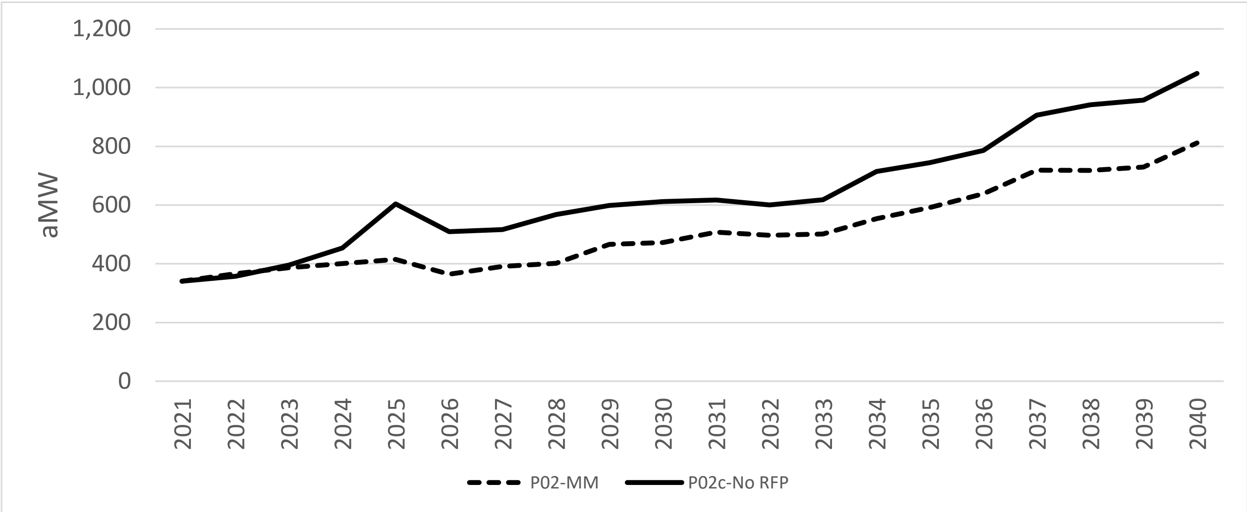


Figure 9.21 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when 2020AS RFP resources are eliminated from the P02-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio without 2020AS RFP resources is $1,036 billion higher cost than the P02-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without the 2020AS RFP resources is $1,265 billion higher cost than the P02-MM portfolio.

When the 2020AS RFP resources are removed from the portfolio, the costs associated with new resources decline. The cost for transmission is also reduced. As is the case in the portfolio that removes GWS and D.1 (but retains all 2020AS RFP resources not dependent upon these transmission lines), this reduction in transmission cost is net of the cost required to build a new 230-kV line to accommodate PacifiCorp's obligation to provide firm point-to-point transmission service to a third-party transmission customer. The 230-kV alternative is not avoidable if GWS is not built, and the $1.4 billion cost assumed for this alternative is the minimum cost considering that it focuses on the upgrades required to grant a single transmission service request. Additional costs would be incurred to accommodate additional requests for interconnection service. To accommodate all of these requests, it is likely the alternative would be to construct GWS.

When the 2020AS RFP bids are removed from the portfolio, coal and gas generation is increased, which increases variable costs for existing fossil-fired resources and the associated cost for increased emissions. Further, the system becomes more reliant on the market as shown by increased market costs. As noted above, this not only increases costs to the system, but it also introduces incremental market-reliance risk, which is not captured in PVRR results. The increase in costs in 2025 reflect a sizeable deficiency that would need to be covered with additional market purchases. The deficiency cost is grouped with the proxy resource costs in the chart at left, which essentially offsets new resource cost savings in that year.

Figure 9.21 – Increase/(Decrease) in System Costs when 2020AS RFP Resources are Eliminated from the P02-MM portfolio.

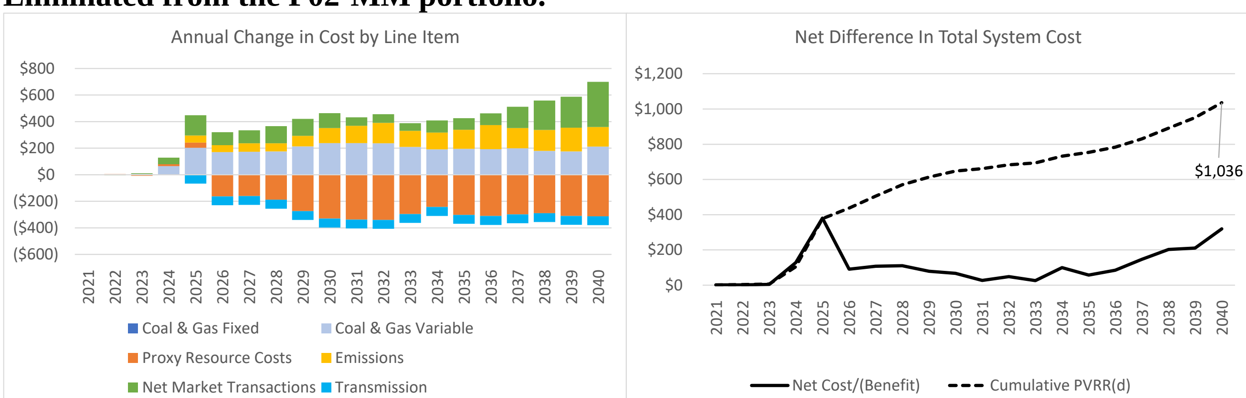


Table 9.10 summarizes the PVRR(d) of the P02d-No RFP GWS portfolio relative to the P02-MM portfolio under a range of different price-policy scenarios. System costs increase significantly when 2020AS RFP resources are removed from the portfolio in all but the LN price-policy scenario. Without the RFP resources, emissions from PacifiCorp's fossil-fueled resources increase considerably—ranging from 12.5% in the MN price-policy scenario to 34.7% in the SCGG price-policy scenario. As discussed earlier, it is more likely than not that there will be policy actions taken to impute a cost or penalty on greenhouse gas emissions. It is also unlikely that gas prices will be suppressed for many decades to come, as assumed in the LN price-policy scenario. Further, cost-and-risk results indicate that there is a tremendous opportunity cost of not pursuing the RFP resources along with the associated investments in the GWS and D.1 transmission lines should policies develop impose costs on greenhouse gas emissions. This is seen with the disproportionate increase in costs under HH and SCGG price-policy scenarios relative to the size of cost reductions in the unlikely LN price-policy scenario. Further, each of cases that remove 2020AS RFP resources show a more notable decline in reliability, as measured by the ENS metric. Considering the removal of 2020AS RFP bids and the associated investment in the GWS and D.1 transmission

lines increases system costs among all but the LN price-policy scenario, significantly increases emissions and associated costs, and significantly increases market-reliance risk, this analysis supports including 2020AS RFP resources in the preferred portfolio.

Table 9.10 – PVRR(d) of the P02d-No RFP GWS Portfolio Relative to the P02-MM Portfolio Under Varying Price-Policy Scenarios.

	PVRR ($m)	ST PVRR + 5% of 95th Stochastic ($m)	ENS Average % of Load	CO2 Emissions 2021-2040 (Thousand Tons)
P02-MM-MM	$25,822	$26,179	0.0049%	398,953
P02-MM-LN	$22,620	$22,821	0.0054%	436,134
P02-MM-MN	$22,449	$22,637	0.0049%	511,369
P02-MM-HH	$28,807	$29,308	0.0049%	368,551
P02-MM-SCGHG	$39,667	$40,693	0.0094%	208,650
P02d-MM-MM	$26,857	$27,445	0.0208%	476,318
P02d-MM-LN	$22,246	$22,605	0.0265%	515,934
P02d-MM-MN	$22,655	$23,036	0.0208%	575,308
P02d-MM-HH	$31,178	$31,973	0.0206%	445,220
P02d-MM-SCGHG	$45,770	$47,228	0.0537%	281,014
Change from P02-MM-MM	$1,036	$1,265	0.0159%	77,364
Change from P02-MM-LN	($374)	($216)	0.0211%	79,800
Change from P02-MM-MN	$206	$398	0.0159%	63,939
Change from P02-MM-HH	$2,371	$2,665	0.0157%	76,669
Change from P02-MM-SCGHG	$6,103	$6,535	0.0443%	72,364

Natrium™ Demonstration Project Variant (P02e-No Nuc)

The P02e-No Nuc portfolio is a variant of the P02-MM portfolio that eliminates the Natrium™ advanced nuclear demonstration project. When this variant is compared to the P02-MM portfolio, changes in proxy resources and system costs driven by the removal of the demonstration project can be isolated.

Figure 9.22 shows the cumulative (at left) and incremental (at right) portfolio changes when the Natrium™ demonstration project is eliminated from the P02-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. Without the Natrium™ demonstration project, 348 MW of solar co-located with storage is added to the portfolio in 2026 and an additional 240 MW is added in 2030. In 2037, a non-emitting peaker displaces solar+battery resource capacity.

Figure 9.22 – Increase/(Decrease) in Proxy Resources when the Natrium™ Demonstration Project is Eliminated from the P02-MM portfolio.

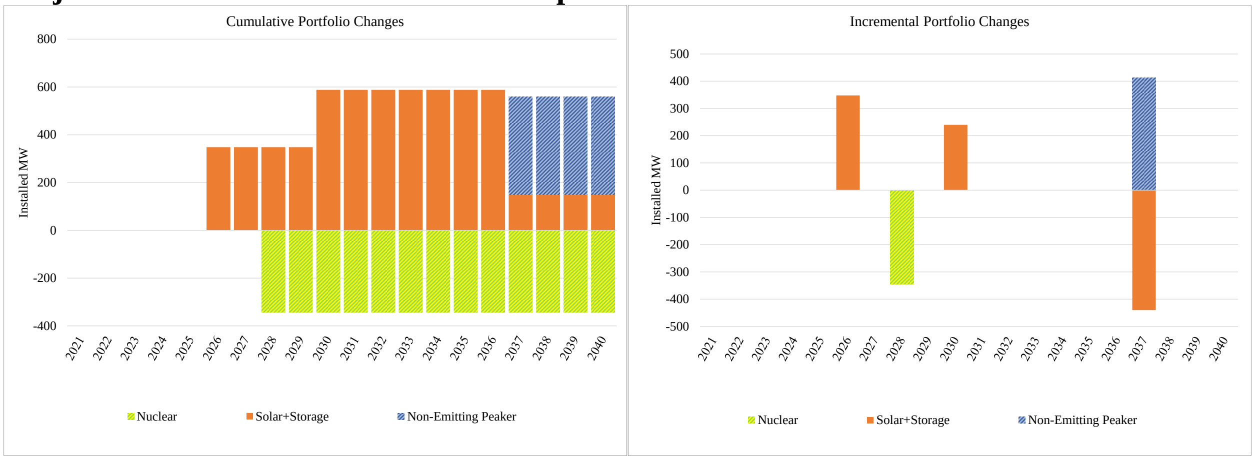


Figure 9.23 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when the Natrium™ demonstration project eliminated from the P02-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio without the demonstration project is $133 million higher cost than the P02-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without the demonstration project is $158 million higher cost than the P02-MM portfolio.

When the Natrium™ advanced nuclear demonstration project is removed from the portfolio, the cost for new proxy resources increases in 2026 with the addition of more solar+battery resources. Over this period, fossil-fueled generation decreases, which reduced operating costs and emissions costs. Beginning 2028, removing the Natrium™ demonstration project reduces new proxy resource costs. More than offsetting these cost savings are increased costs from fossil-fueled generation, emissions, and net market transactions.

Figure 9.23 – Increase/(Decrease) in System Costs when the Natrium™ Demonstration Project is Eliminated from the P02-MM portfolio.

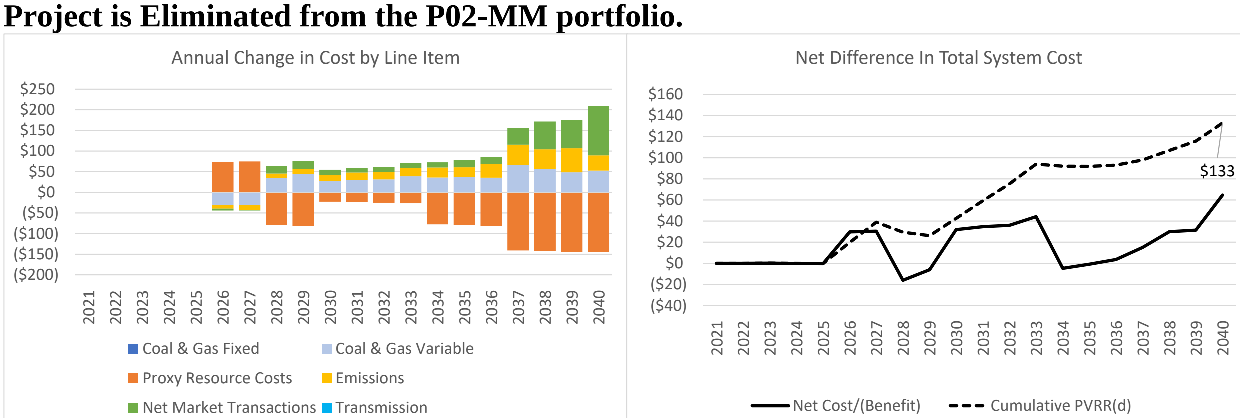


Table 9.11 summarizes the PVRR(d) of the P02e-No Nuc portfolio relative to the P02-MM portfolio under a range of different price-policy scenarios. System costs increase when the

Natrium™ demonstration project is removed from the portfolio in all but the LN and MN price-policy scenarios, which show an incremental reduction in costs on a deterministic basis. The cost reduction for the LN price-policy erodes by $12 million on a risk-adjusted basis, while the MN price-policy scenario breaks even with P02-MM when adjusted for risk. Without the demonstration project, emissions from PacifiCorp's fossil-fueled resources increase by about 2% to 3%, depending upon the price-policy scenario. Both portfolios, as measured by ENS results, are very reliable among all price-policy scenarios. In aggregate, these results support the inclusion of the Natrium™ advanced nuclear demonstration project in the preferred portfolio.

Table 9.11 – PVRR(d) of the P02e-No Nuc Portfolio Relative to the P02-MM Portfolio Under Varying Price-Policy Scenarios.

	PVRR ($m)	ST PVRR + 5% of 95th Stochastic ($m)	ENS Average % of Load	CO2 Emissions 2021-2040 (Thousand Tons)
P02-MM-MM	$25,822	$26,179	0.0049%	398,953
P02-MM-LN	$22,620	$22,821	0.0054%	436,134
P02-MM-MN	$22,449	$22,637	0.0049%	511,369
P02-MM-HH	$28,807	$29,308	0.0049%	368,551
P02-MM-SCGHG	$39,667	$40,693	0.0094%	208,650
P02e-MM-MM	$25,955	$26,337	0.0049%	408,473
P02e-MM-LN	$22,538	$22,751	0.0054%	446,547
P02e-MM-MN	$22,432	$22,637	0.0049%	521,098
P02e-MM-HH	$29,140	$29,672	0.0049%	377,010
P02e-MM-SCGHG	$40,167	$41,231	0.0090%	215,640
Change from P02-MM-MM	$133	$158	0.0000%	9,520
Change from P02-MM-LN	($82)	($70)	0.0000%	10,413
Change from P02-MM-MN	($17)	($0)	0.0000%	9,730
Change from P02-MM-HH	$333	$364	0.0000%	8,459
Change from P02-MM-SCGHG	$501	$537	-0.0004%	6,990

Naughton Units 1 and 2 Retirement Variant (P02f-No Nau 25)

The P02f-No Nau 25 portfolio is a variant of the P02-MM portfolio that maintains continued coal-fueled operation of Naughton Units 1 and 2 through the end of 2029. When this variant is compared to the P02-MM portfolio, changes in proxy resources and system costs driven by the removal of the demonstration project can be isolated.

Figure 9.24 shows the cumulative (at left) and incremental (at right) portfolio changes when Naughton Units 1 and 2 continue operating as coal-fueled resources through 2029. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. With continued coal-fueled operations at Naughton Units 1 and 2, 549 MW of 4-hour storage capacity is removed from the portfolio in 2029. When Naughton Units 1 and 2 subsequently retire at the end of 2029, 339 MW of wind is removed from the portfolio, a non-emitting peaker is added to the portfolio along with additional solar co-located with storage and standalone storage.

Figure 9.24 – Increase/(Decrease) in Proxy Resources when Naughton Units 1 and 2 Continue Operating as Coal-Fueled Resources through 2029.

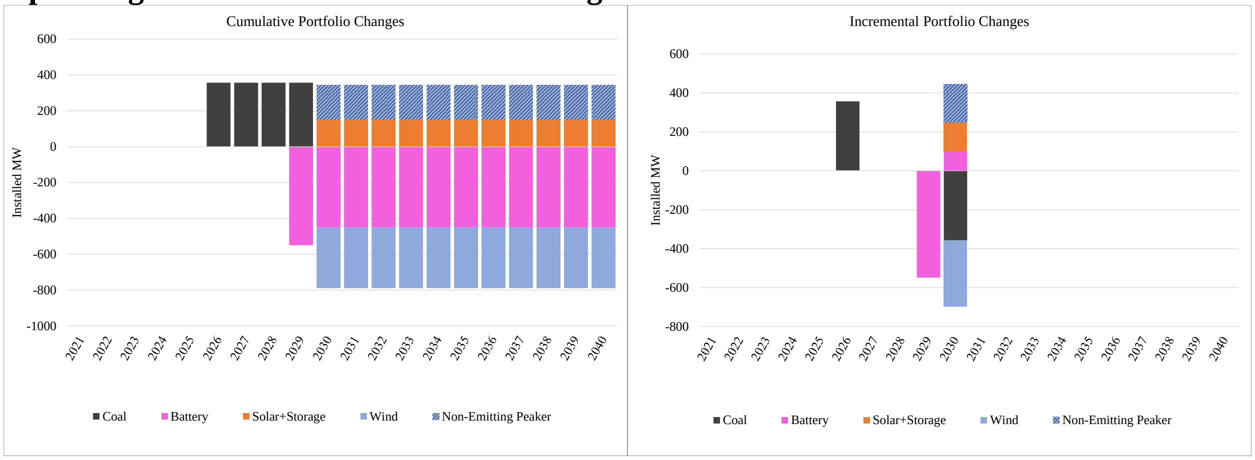


Figure 9.25 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when Naughton Units 1 and 2 continue operating as coal-fueled resources through 2029. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio that operates Naughton Units 1 and 2 through 2029 is $54 million higher cost than the P02-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio that operates Naughton Units 1 and 2 through 2029 is $66 million higher cost than the P02-MM portfolio.

When Naughton Units 1 and 2 continue operating as coal-fueled resources through 2029, changes in system costs are largely tied to changes in the operating cost of these two units through 2028. In 2029, the reduction in proxy resource costs is caused by the displacement of incremental solar co-located with storage. This is partially offset by increased costs from fossil-fueled resources and emissions. Beyond 2030, changes in the resource mix lead to reduced proxy resource costs. However, over this time, fossil-fueled resource costs increase, emissions costs increase, and the net cost of market transactions increase.

Figure 9.25 – Increase/(Decrease) in System Costs when Naughton Units 1 and 2 Continue Operating as Coal-Fueled Resources through 2029.

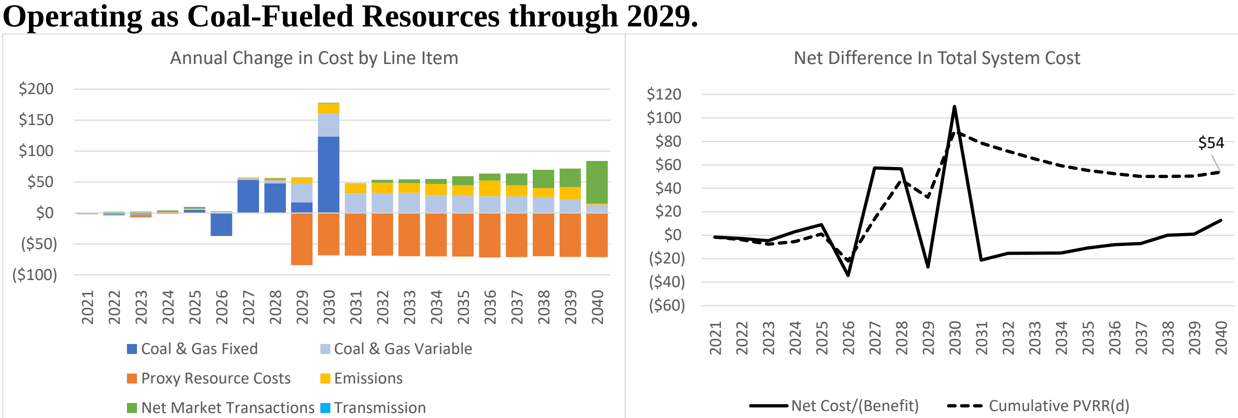


Table 9.12 summarizes the PVRR(d) of the P02f-No Nau 25 portfolio relative to the P02-MM portfolio under a range of different price-policy scenarios. System costs increase when Naughton Units 1 and 2 continue to operate as coal-fueled resources through 2029 in the MM, HH, and SCGG price-policy scenarios. Conversely, costs decrease in the LN and MN price-policy scenarios. If Naughton Units 1 and 2 do not retire at the end of 2025, emissions from PacifiCorp's fossil-fueled resources increase by about 2%. It is more likely than not that there will be some form of policy action taken to impute a cost or penalty on greenhouse gas emissions, even when considered through the 2029 time frame. It is also unlikely gas prices will be suppressed for the next decade, as assumed in the LN price-policy scenario. Further, cost-and-risk results indicate that there is a tremendous opportunity cost of continuing to operate Naughton Units 1 and 2 as coal-fueled resources should policies develop that impose costs on greenhouse gas emissions. This is seen with the disproportionate increase in costs under HH and SCGG price-policy scenarios relative to the size of cost reductions in the unlikely LN and MN price-policy scenarios. Considering the continued coal operations of Naughton Units 1 and 2 increases system costs among the MM, HH, and SCGG price-policy scenarios, significantly increases emissions and associated costs and risks, this analysis supports retiring Naughton Units 1 and 2 at the end of 2025.

Table 9.12 – PVRR(d) of the P02f-No Nau Portfolio Relative to the P02-MM Portfolio Under Varying Price-Policy Scenarios.

	PVRR ($m)	ST PVRR + 5% of 95th Stochastic ($m)	ENS Average % of Load	CO2 Emissions 2021-2040 (Thousand Tons)
P02-MM-MM	$25,822	$26,179	0.0049%	398,953
P02-MM-LN	$22,620	$22,821	0.0054%	436,134
P02-MM-MN	$22,449	$22,637	0.0049%	511,369
P02-MM-HH	$28,807	$29,308	0.0049%	368,551
P02-MM-SCGHG	$39,667	$40,693	0.0094%	208,650
P02f-MM-MM	$25,875	$26,245	0.0050%	405,395
P02f-MM-LN	$22,531	$22,738	0.0054%	442,821
P02f-MM-MN	$22,400	$22,593	0.0049%	518,642
P02f-MM-HH	$28,996	$29,512	0.0049%	374,781
P02f-MM-SCGHG	$40,045	$41,096	0.0098%	213,910
Change from P02-MM-MM	$54	$66	0.0001%	6,442
Change from P02-MM-LN	($89)	($83)	0.0001%	6,687
Change from P02-MM-MN	($49)	($45)	0.0000%	7,274
Change from P02-MM-HH	$189	$204	0.0000%	6,230
Change from P02-MM-SCGHG	$378	$402	0.0004%	5,260

Dave Johnston Unit 4 CCUS Variant (P02g-CCUS)

The P02g-CCUS portfolio is a variant of the P02-MM portfolio that forces a CCUS retrofit on Dave Johnston Unit 4 in 2026 to enable the project to qualify for existing tax credits. When this variant is compared to the P02-MM portfolio, changes in proxy resources and system costs driven by the CCUS retrofit can be isolated. Because CCUS was not selected as a least-cost resource option in the P02-MM portfolio, this variant was produced to evaluate a means to comply with Wyoming House Bill 200 (HB 200). HB 200 was passed by the Wyoming Legislature in March 2020, and it requires the Wyoming Public Service Commission to establish a standard that specifies a percentage of electricity that must be generated from coal-fired generation using carbon capture technology by 2030, subject to an incremental cost limitation of 2% of Wyoming customers' total bill to comply with the standard.

For modeling purposes, PacifiCorp chose to force a CCUS retrofit (amine based post-combustion + enhanced oil recovery) at Dave Johnston Unit 4 for the following reasons:

- There are no complications with co-ownership as would be the case with Wyodak or the Jim Bridger units
- CCUS at Dave Johnston Unit 4 would not require a new lined coalcombustion residual impoundment as would be the case at the Naughton coal units
- Expectation of lower costs associated with necessary inlet NO_X and SO_2 controls relative to Dave Johnston Units 1 and 2
- Dave Johnston Unit 3 has a federal closure commitment under EPA's regional haze rule. Installation of CCUS at Dave Johnston Unit 4 would be expected to meet preliminary HB 200 targets

This modeling assumption does not mean PacifiCorp has determined Dave Johnston Unit 4 is the only site for a CCUS retrofit. As described in the 2021 IRP action plan, PacifiCorp is engaged in a request for expressions of interest process and will soon be issuing a request for proposals that will help identify candidates for potential CCUS retrofits and help refine cost-and-performance assumptions.

Figure 9.26 shows the cumulative (at left) and incremental (at right) portfolio changes when the CCUS retrofit is installed on Dave Johnston Unit 4 relative to the P02-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the CCUS retrofit is installed. With the installation of CCUS in 2026, there is a net reduction of capacity due to the parasitic load associated with the carbon capture equipment.[3] Beyond 2027, when Dave Johnston is retired in the P02-MM portfolio, there is an increase in coal capacity through the remainder of the study period. The extended life of Dave Johnston Unit 4, with a CCUS retrofit installed, displaces 149 MW of standalone storage in 2029 and 359 MW of wind in 2030.

[3] Upon installation of the carbon capture equipment, Dave Johnston Unit 4's rating is 254 MW. As a coal-fired facility without carbon capture equipment, Dave Johnston Unit 4's rating is 330 MW.

Figure 9.26 – Increase/(Decrease) in Proxy Resources when CCUS is Installed on Dave Johnston Unit 4 in 2026.

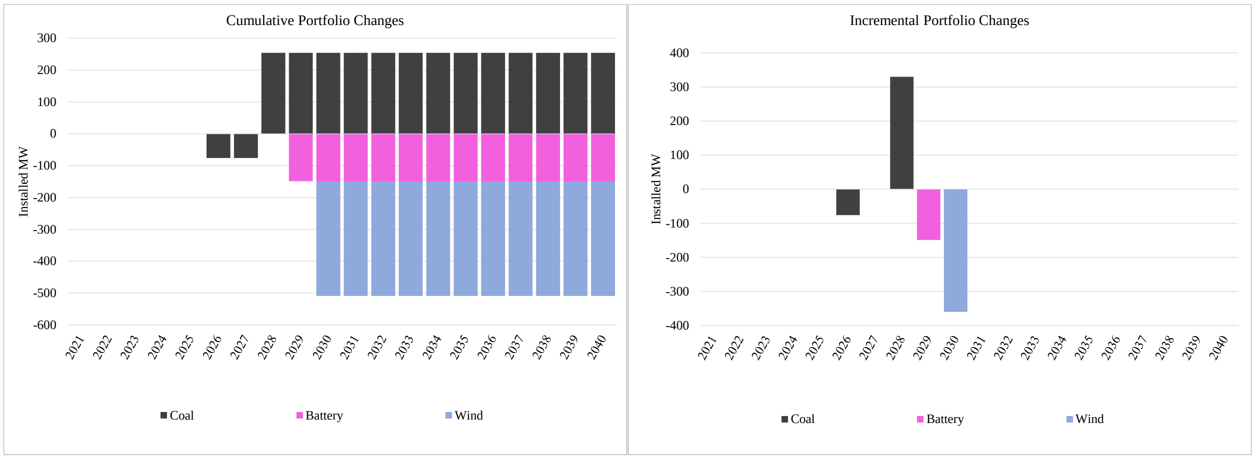


Figure 9.27 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when CCUS is installed on Dave Johnston Unit 4 in 2026. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio with CCUS installed on Dave Johnston Unit 4 project is $271 million higher cost than the P02-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio with the Dave Johnston Unit 4 CCUS retrofit is $235 million higher cost than the P02-MM portfolio.

On an ST PVRR basis, capital cost assumptions for the CCUS retrofit at Dave Johnston Unit 4 would need to decrease by approximately 33% to achieve break-even economics in the MM price-policy scenario—initial capital would need to drop from $1.14 billion to $761 million. Alternatively, the enhanced-oil recovery revenue stream assumed in this analysis (from a credit-worthy counterparty) would need to increase by approximately 84% to achieve break-even economics under the MM price-policy scenario. Prices for enhanced-oil recovery in the company's analysis start at $19.25/ton in 2026 and grow to $27.51 by 2040.

When the CCUS retrofit is installed in 2026, the carbon capture technology increases the costs associated with Dave Johnston Unit 4. This shows up as increased fixed costs for coal and gas resources in the chart at left. This is partially offset by reduced emissions costs. Beginning in the 2029-to-2030-time frame, avoided proxy resource costs add to the emissions cost savings.

Figure 9.27 – Increase/(Decrease) in System Costs when CCUS is Installed on Dave Johnston Unit 4 in 2026.

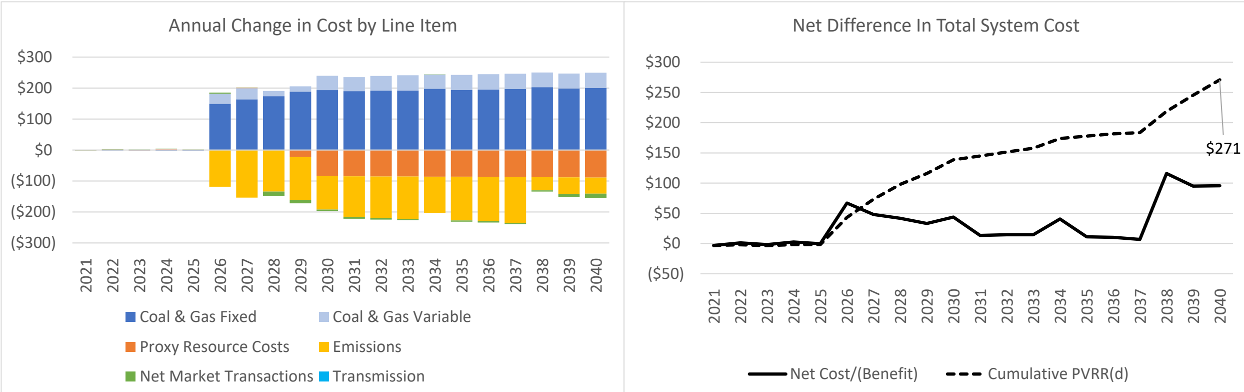


Table 9.13 summarizes the PVRR(d) of the P02g-CCUS portfolio relative to the P02-MM portfolio under a range of different price-policy scenarios. The portfolio that includes the CCUS retrofit at Dave Johnston Unit 4 is higher cost than the P02-MM portfolio across each of the price-policy scenarios. This trend holds true for both the ST PVRR and the risk-adjusted PVRR results. Both portfolios, as measured by ENS, are very reliable among all price-policy scenarios. Emissions are slightly lower when CCUS is installed on Dave Johnston Unit 4 (approximately 1% relative to the P02-MM portfolio). The magnitude of the increased cost in the portfolio that includes a CCUS retrofit on Dave Johnston Unit 4 in 2026, which would be situs-assigned to Wyoming customers, is expected to exceed the cost containment language set forth in HB 200, and for this reason, it is not included in the preferred portfolio. Nonetheless, PacifiCorp recognizes that this analysis is driven by a wide range of assumptions specific to the cost and commercial structure of CCUS opportunities. Consequently, PacifiCorp has established an action plan with a CCUS action item to continue with the on-going request for expressions of interest process initiated this year and to proceed with a request for proposals process that will help identify potential sites, costs, and commercial structures that will allow us to update this analysis in the 2023 IRP.

Table 9.13 – PVRR(d) of the P02g-CCUS Portfolio Relative to the P02-MM Portfolio Under Varying Price-Policy Scenarios.

	PVRR ($m)	ST PVRR + 5% of 95th Stochastic ($m)	ENS Average % of Load	CO2 Emissions 2021-2040 (Thousand Tons)
P02-MM-MM	$25,822	$26,179	0.0049%	398,953
P02-MM-LN	$22,620	$22,821	0.0054%	436,134
P02-MM-MN	$22,449	$22,637	0.0049%	511,369
P02-MM-HH	$28,807	$29,308	0.0049%	368,551
P02-MM-SCGHG	$39,667	$40,693	0.0094%	208,650
P02g-MM-MM	$26,093	$26,415	0.0048%	394,448
P02g-MM-LN	$22,888	$23,053	0.0054%	431,634
P02g-MM-MN	$22,769	$22,922	0.0048%	506,715
P02g-MM-HH	$28,960	$29,417	0.0049%	364,436
P02g-MM-SCGHG	$39,790	$40,772	0.0091%	207,527
Change from P02-MM-MM	$271	$235	-0.0001%	(4,506)
Change from P02-MM-LN	$269	$232	0.0000%	(4,500)
Change from P02-MM-MN	$320	$285	-0.0001%	(4,654)
Change from P02-MM-HH	$153	$109	0.0000%	(4,115)
Change from P02-MM-SCGHG	$124	$79	-0.0003%	(1,122)

Jim Bridger Units 3 and 4 Retirement Variant (P02h-JB3-4 Retire)

The P02h-JB3-4 Retire portfolio is a variant of the P02-MM portfolio that forces Jim Bridger Units 3 and 4 to retire before 2030 with the most optimal timing as determined by the Plexos model. When this variant is compared to the P02-MM portfolio, changes in proxy resources and system costs driven by the early retirement of Jim Bridger Units 3 and 4 can be isolated.

Figure 9.28 shows the cumulative (at left) and incremental (at right) portfolio changes when Jim Bridger Units 3 and 4 are retired early. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. When required to choose the most economic retirement date before 2030 for Jim Bridger Units 3 and 4, the portfolio with the early retirements retires Jim Bridger Unit 3 at the end of 2026 and retires Jim Bridger Unit 4 at the end of 2029. When Jim Bridger Unit 3 retires, 200 MW of solar co-located with storage is added to the portfolio. When Jim Bridger Unit 4 retires, an additional advanced nuclear resource is added in 2030. These additions displace a 2038 advanced nuclear resource and a 2038 non-emitting peaker, which are included in the P02-MM portfolio. Note, the chart at right does not indicate there is an increase in coal capacity. This bar indicates that the loss of coal capacity that would otherwise occur in the P02-MM portfolio with the retirement of Jim Bridger Units 3 and 4 at the end of 2037 does not occur in the P02h-JB3-4 Retire portfolio because those retirements already occurred at the end of 2026 and 2029.

Figure 9.28 – Increase/(Decrease) in Proxy Resources when Jim Bridger Units 3 and 4 are Forced to Retire before 2030.

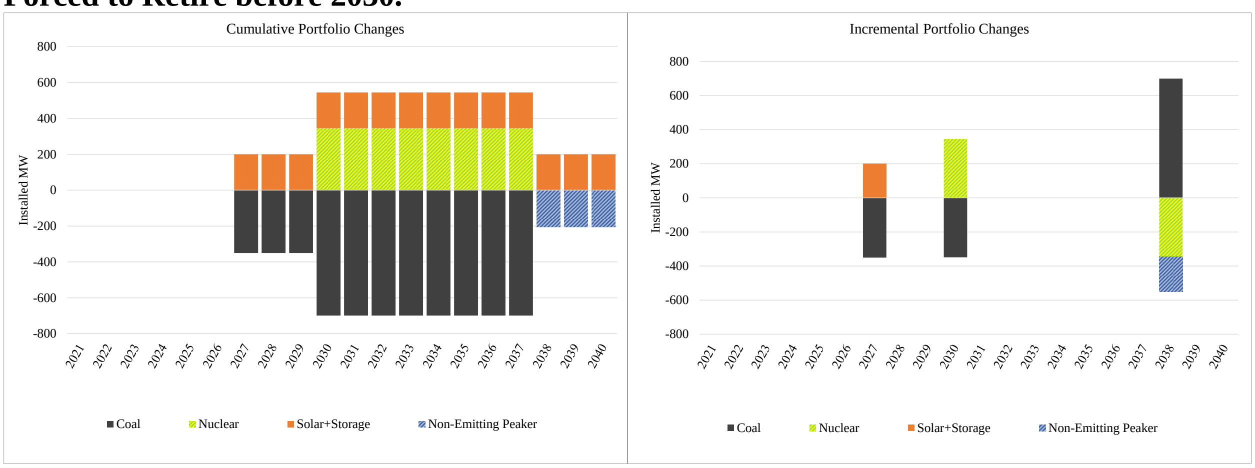


Figure 9.29 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when Jim Bridger Units 3 and 4 are forced to retire before 2030. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio with the accelerated retirement of Jim Bridger Units 3 and 4 is $95 million higher cost than the P02-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio with the early retirement of Jim Bridger Units 3 and 4 is $60 million higher cost than the P02-MM portfolio.

When Jim Bridger Units 3 and 4 retire early, there is a reduction in system costs associated with reduced fixed and variable expenses from fossil-fueled generation and reduced emissions expenses. These cost savings are more than offset by higher proxy resource costs from incremental solar co-located with storage and incremental advanced nuclear resources.

Figure 9.29 – Increase/(Decrease) in System Costs when Jim Bridger Units 3 and 4 are Forced to Retire Before 2030.

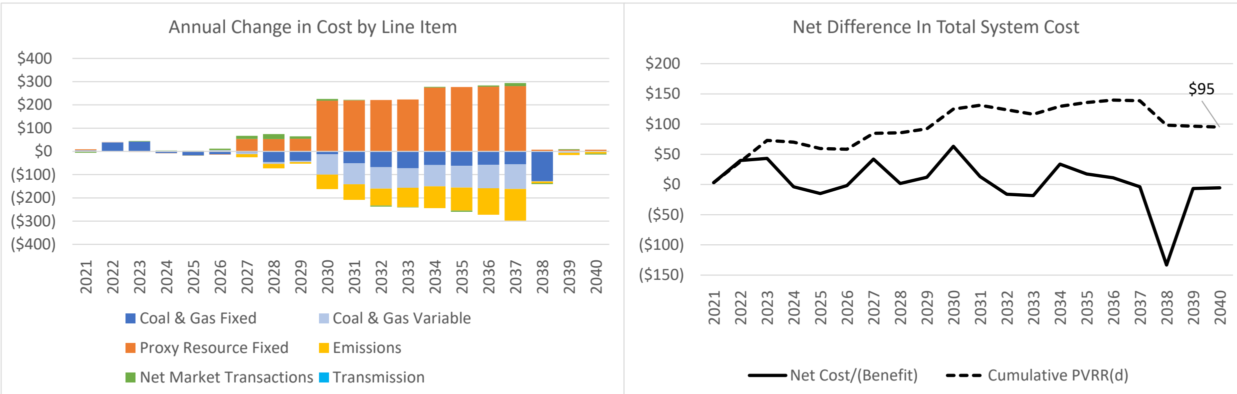


Table 9.14 summarizes the PVRR(d) of the P02h-JB3-4 Retire portfolio relative to the P02-MM portfolio under a range of different price-policy scenarios. System costs increase when Jim Bridger Units 3 and 4 retire early in the MM, LN, and MN price-policy scenarios. Conversely, costs decrease in the HH and SCGHG price-policy scenarios. If Jim Bridger Units 3 and 4 retire early, emissions from PacifiCorp's fossil-fueled resources are reduced by about 7%. While it is more likely than not that there will be some form of policy taken to impute a cost or penalty on greenhouse gas emissions, the company's analysis captures this risk in its MM price policy assumptions. In this case, early retirement of Jim Bridger Units 3 and 4 increases system costs by $60 million on a risk-adjusted basis. And while emissions costs and risks are higher with continue operation of Jim Bridger Units 3 and 4, there are many resource choices in the P02-MM portfolio that greatly mitigate this risk. Further, considering that the early retirements were selected in 2026 (Jim Bridger Unit 3) and 2029 (Jim Bridger Unit 4), there is sufficient time to continue to evaluate the potential early retirement of these two units in the 2023 IRP. This would be particularly important if base case carbon prices are projected to increase from current levels. For these reasons, the early retirement of Jim Bridger Units 3 and 4 is not included in the preferred portfolio.

Table 9.14 – PVRR(d) of the P02h-JB3-4 Retire Portfolio Relative to the P02-MM Portfolio Under Varying Price-Policy Scenarios.

	PVRR ($m)	ST PVRR + 5% of 95th Stochastic ($m)	ENS Average % of Load	CO2 Emissions 2021-2040 (Thousand Tons)
P02-MM-MM	$25,822	$26,179	0.0049%	398,953
P02-MM-LN	$22,620	$22,821	0.0054%	436,134
P02-MM-MN	$22,449	$22,637	0.0049%	511,369
P02-MM-HH	$28,807	$29,308	0.0049%	368,551
P02-MM-SCGHG	$39,667	$40,693	0.0094%	208,650
P02h-MM-MM	$25,917	$26,240	0.0050%	369,493
P02h-MM-LN	$23,000	$23,179	0.0054%	405,192
P02h-MM-MN	$22,901	$23,072	0.0050%	472,422
P02h-MM-HH	$28,632	$29,084	0.0051%	341,025
P02h-MM-SCGHG	$39,404	$40,377	0.0103%	201,974
Change from P02-MM-MM	$95	$60	0.0001%	(29,460)
Change from P02-MM-LN	$380	$359	0.0000%	(30,942)
Change from P02-MM-MN	$452	$435	0.0001%	(38,947)
Change from P02-MM-HH	($175)	($223)	0.0002%	(27,527)
Change from P02-MM-SCGHG	($262)	($317)	0.0009%	(6,676)

Portfolio Development Conclusions

P02-MM remains the top performing portfolio among the P02 variant portfolios and was further assessed relative to CETA requirements, described further in a later section.

Preferred Portfolio Selection

Final Preferred Portfolio Selection

P02-MM entered the final evaluations as the top-performing portfolio for preferred portfolio selection.

P02-MM was subsequently evaluated using the targets established by CETA[4]. CETA establishes specific targets for utilities serving customers in Washington including:

- By 2025, utilities remove coal-fueled generation from Washington's allocation of electricity;[5]
- By 2030, Washington retail sales are carbon-neutral;
  - 80 percent from long-term system resources[6]
  - 20 percent from alternative compliance using purchase of Unbundled Renewable Energy Credits (REC)[7]s;
- By 2045, Washington's retail sales are 100 percent renewable and non-carbon-emitting

[4] RCW 19.405
[5] RCW 19.405.030(1)(a)
[6] RCW 19.405.040(1)(a)(ii) requires utilities to "use electricity from renewable resources and non-emitting electric generation in an amount equal to one hundred percent of the utilities retail electric loads over each multiyear compliance period."
[7] RCW 19.405.020(38)

Evaluation of the P02-MM portfolio against the CETA targets required certain modeling assumptions to account for uncertainties related to the future of interjurisdictional cost allocation among the PacifiCorp states and resolution of outstanding CETA implementation issues. PacifiCorp currently allocates costs and benefits, including resource costs and benefits, to Washington according to the Washington Inter-Jurisdictional Allocation Methodology (WIJAM). The WIJAM expires December 31, 2023, and negotiations are underway among all six states to determine the next inter-jurisdictional allocation methodology. In addition to future inter-jurisdictional uncertainty, certain CETA implementation issues remain unresolved. [8, 9]

In addition to assumptions regarding how energy is allocated across PacifiCorp's six-state system, PacifiCorp also made assumptions regarding the amount of renewable and non-emitting resources that is eligible to apply toward the 80 percent "primary" compliance obligation. For purposes of meeting primary compliance, PacifiCorp assumed that eligible generation was limited to energy generated from long-term resources located on PacifiCorp's system where both the energy and RECs were: 1) acquired at the same time; and 2) allocated to Washington customers under the applicable interjurisdictional allocation mechanism.

By 2025, PacifiCorp will remove all coal-fired generation from Washington's allocation of electricity. By 2030, the Chehalis natural gas-fueled plant is the only Washington-located thermal resource operating on the system; all other existing and new resources in the P02-MM top-performing portfolio are renewable or non-emitting. Thus, all system energy allocated to Washington from a renewable or non-emitting resource contributes to meeting the CETA targets.[10] This includes the renewable and non-emitting resources in the P02-MM top-performing portfolio.

Upon evaluation relative to the 2030 CETA target, a shortfall of roughly 69 MW of annual capacity was identified in 2030 (the highest shortfall year), with significantly smaller shortfalls identified in the years between 2030-2033. Under a four-year compliance window for the time period 2030 – 2033, an average annual shortfall of 49 MW was identified. This shortfall is addressed with a Washington-situs assigned 160 MW wind and solar resource co-located with storage located in Yakima, Washington.

This shortfall includes lower capacity requirements from incremental demand-side management resources specific to Washington identified from the P02-SCGHG portfolio. In 2030, there was a reconfiguration of 160 MW of system solar collocated with storage located in Yakima, Washington in P02-MM, the top-performing portfolio, to become a Washington-situs assigned 160 MW resource that also includes wind, collocated with the solar and storage resource. This Washington-situs assigned resource maximizes usage of transmission interconnection availability at this location.

[8] PacifiCorp is a multi-state utility, serving customers in California, Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp operates and plans its system on an integrated, six-state basis.

[9] For existing resources and new resources added through the end of 2023, the energy from system resources was allocated to states consistent with the 2020 Protocol and Washington Inter-Jurisdictional Allocation Methodology. For resources added to the system in 2024 and beyond, assignment of energy, costs and benefits followed a potential framework, subject to the ongoing Multi-State Process discussions, that enables compliance with CETA (and Oregon law) through reassignment of certain thermal resources. These resource allocation assumptions are used to assess the generation and allocation of Renewable Energy Credits (REC) state Renewable Portfolio Standard (RPS) compliance.

[10] This is limited to system energy where Washington is also allocated the associated RECs.

These portfolio differences to P02-MM to meet the requirements of CETA result in the 2021 IRP preferred portfolio, P02-MM-CETA. As CETA establishes a target in 2045 that retail sales are 100 percent renewable or non-emitting that is outside of the 20-year IRP planning horizon, extrapolation was done that shows the P02-MM-CETA preferred portfolio meets the requirements. The P02-MM-CETA results in a PVRR(d) relative to P02-MM, the top-performing portfolio is $164m.

Table 9.15 - PVRR(d) of the P02-MM-CETA Portfolio Under Varying Price-Policy Scenarios below shows the PVRR and risk-adjusted PVRR, ENS as a percentage of load, and CO_2 emissions for the 2021 IRP preferred portfolio under five price-policy scenarios.

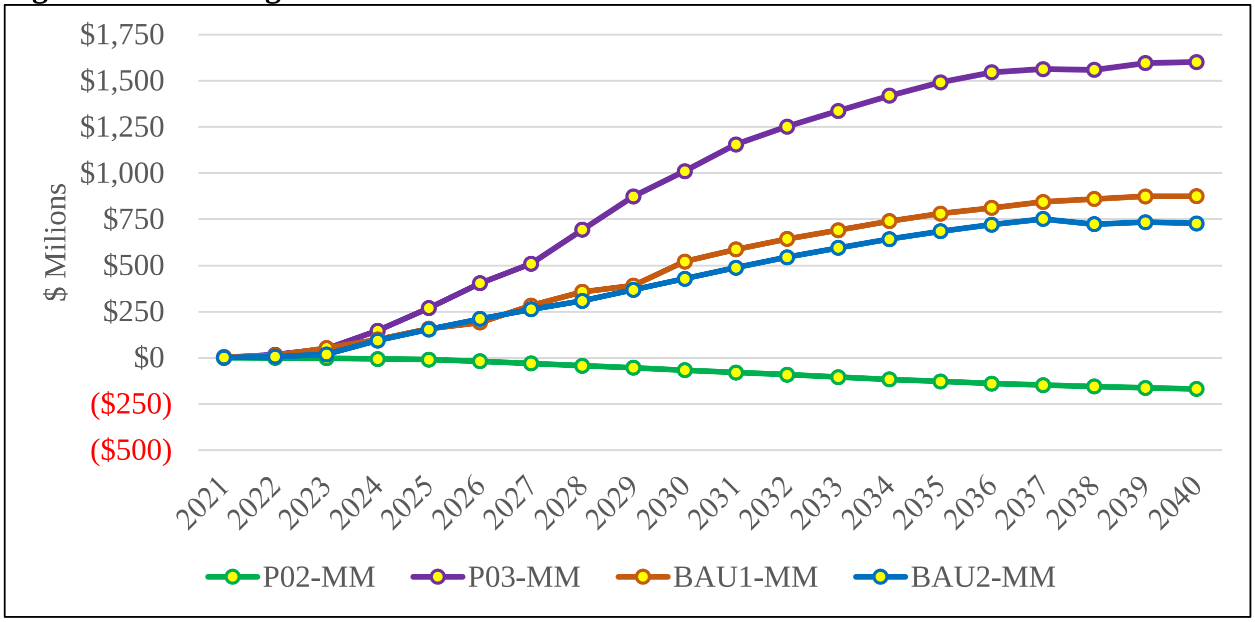
Table 9.15 - PVRR(d) of the P02-MM-CETA Portfolio Under Varying Price-Policy Scenarios

Case	ST PVRR ($m)	Risk-Adjusted PVRR ($m)	ENS Average Percent of Load	CO2 Emissions (Thousand Tons)
P02-MM-CETA-LN	22,801	23,002	0.0054%	436,414
P02-MM-CETA-MN	22,633	22,821	0.0049%	510,115
P02-MM-CETA	25,991	26,343	0.0049%	398,597
P02-MM-CETA-HH	28,979	29,476	0.0049%	368,927
P02-MM-CETA-SC	39,938	40,962	0.0103%	213,233

Customer Rate Pressure

Figure 9.30 shows the difference in the cumulative PVRR, as an indicator of rate pressure over time, among the initial portfolios discussed earlier in this chapter relative to the 2021 IRP preferred portfolio, P02-MM-CETA applying medium gas, medium CO_2 price-policy assumptions. All Portfolios P03, BAU1 and BAU2 trend higher in costs over the planning horizon relative to P02-MM-CETA whereas P02 trends lower in costs notably, as it does not include Washington-situs assigned resources relative to the requirements of CETA.

Figure 9.30 – Change in the Cumulative PVRR relative to P02-MM-CETA



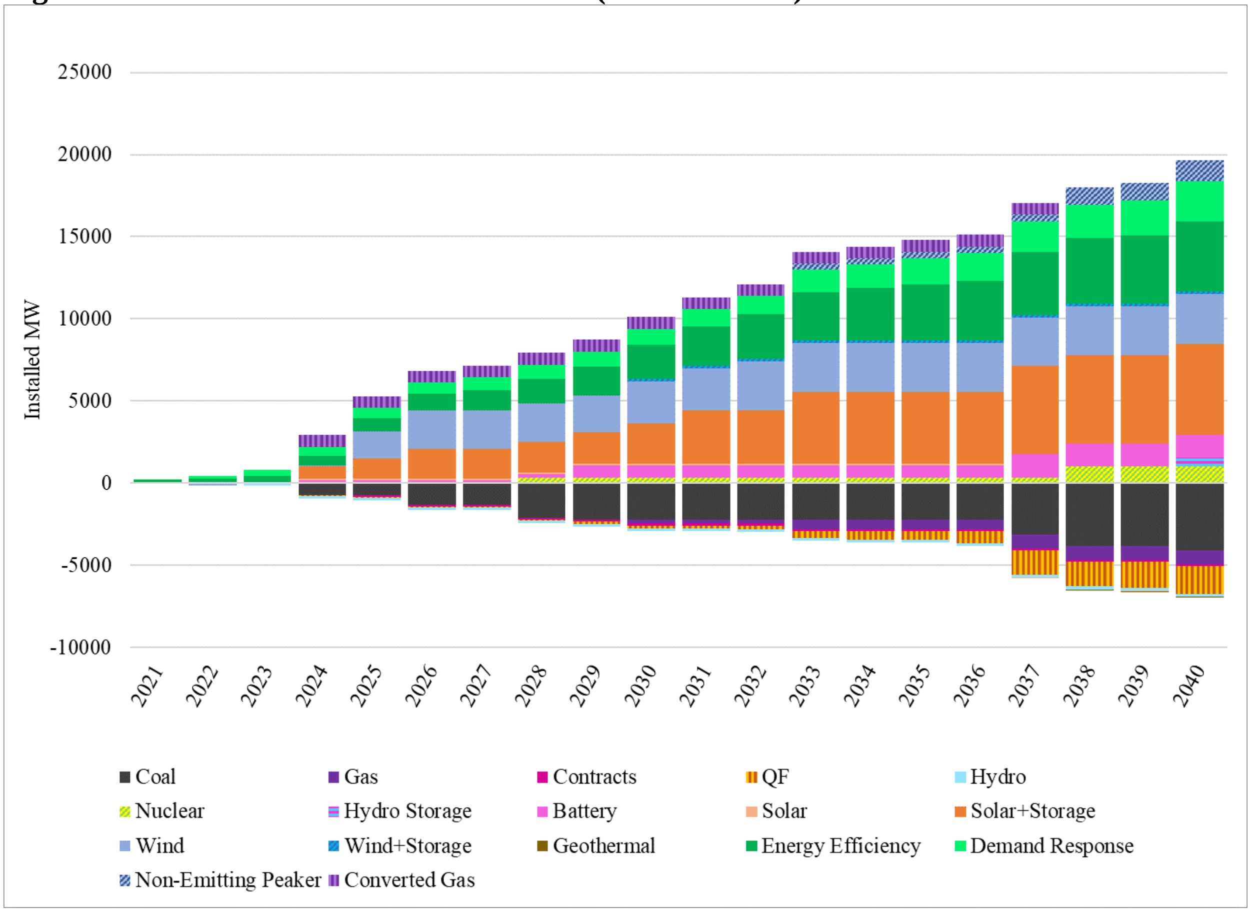
The 2021 IRP Preferred Portfolio

PacifiCorp's selection of the 2021 IRP preferred portfolio, P02-MM-CETA, is supported by comprehensive data analysis and an extensive public-input process, described in the chapters that follow. Figure 9.31 shows that PacifiCorp's 2021 preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, DSM resources, significant storage resources, and for the first time, advanced nuclear.

By the end of 2024, the 2021 IRP preferred portfolio includes the 2020 All-Source RFP final shortlist resources. These projects include 1,792 MW of wind, 1,302 MW of solar additions, and 697 MW of battery storage capacity—497 MW paired with solar and a 200 MW standalone battery. During this time, the preferred portfolio also includes the acquisition and repowering of Rock River I (49 MW) and Foote Creek II-IV (43 MW) wind projects located in Wyoming. Through the end of 2026, the 2021 IRP preferred portfolio includes an additional 745 MW of wind and an additional 600 MW solar co-located with storage. The 2021 IRP preferred portfolio includes the 500 MW advanced nuclear Natrium™ demonstration project, which will come online by summer 2028. Through 2040, the 2021 IRP preferred portfolio includes 1,000 MW of additional advanced nuclear resources and 1,226 MW of non-emitting peaking resources.

Over the 20-year planning horizon, the 2021 IRP preferred portfolio includes 3,628 MW of new wind and 5,628 MW of new solar co-located with storage.

Figure 9.31 – 2021 IRP Preferred Portfolio (All Resources)



To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission investment. Specifically, the 2021 IRP preferred portfolio includes the GWS—a new 416-mile, high-voltage 500-kilovolt transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The 2021 preferred portfolio also includes the D.1 transmission line—a new 59-mile high-voltage 230-kilovolt transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. Both transmission lines will come online by the end of 2024.

The 2021 IRP preferred portfolio also includes a 290-mile high-voltage 500-kilovolt B2H transmission line, which connects Boardman in Oregon to Hemming in Idaho. B2H is expected to come online in 2026. Further, the 2021 IRP preferred portfolio includes near-term and long-term transmission upgrades across the system that will facilitate continued and long-term growth in new resources needed to serve our customers. Table 9.16 summarizes the incremental transmission projects included in the 2021 IRP preferred portfolio.

Table 9.16 – Transmission Projects Included in the 2021 IRP Preferred Portfolio[1,2,*]

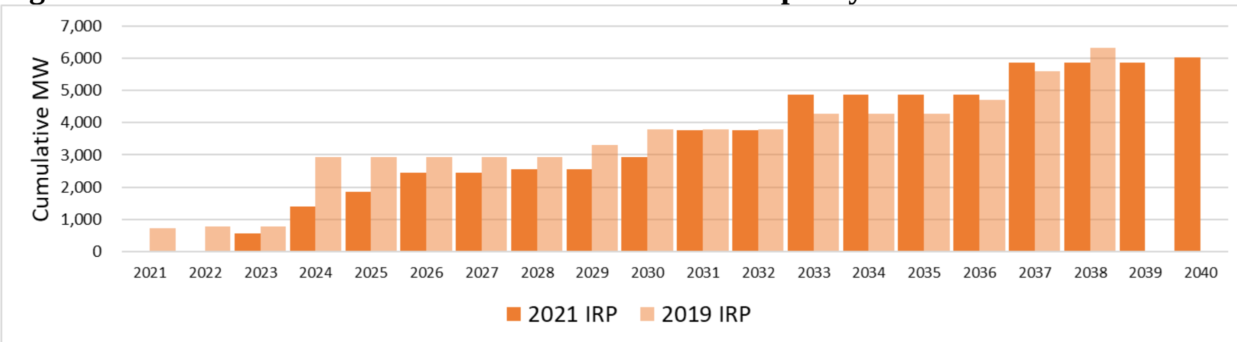
Year	Resource(s)	From	To	Description
2025	1,641 MW RFP Wind (2025)	Aeolus WY	Clover	Enables 1,930 MW of interconnection with 1700 MW of TTC: Energy Gateway South
2026	615 MW Wind (2026)	Within Willamette Valley OR Transmission Area		Enables 615 MW of interconnection: Albany OR area reinforcement
2026	130 MW Wind (2026) 450 MW Wind (2032) 650 MW Battery (2037)	Portland North Coast	Willamette Valley Southern Oregon	Enables 2080 MW of interconnection with 1950 MW TTC; Portland Coast area reinforcement, Willamette Valley and Southerm Oregon
2026	600 MW Solar+Storage (2026)	Borah-Populous	Hemingway	Enables 600 MW of interconnection with 600 MW of TTC: B2H Boardman-Hemingway
2028	41 MW Solar+Storage (2028) 377 MW Solar+Storage (2030)	Within Southern OR Transmission Area		Enables 460 MW of interconnection: Medford area reinforcement
2030	160 MW Solar+Wind+Storage (2030) 20 MW Solar+Storage (2030)	Yakima WA Transmission Area		Enables 180 MW of interconnection: Yakima local area reinforcement
2031	820 MW Solar+Storage (2031) 206 MW Non-Emitting Peaker (2033)	Northern UT Transmission Area		Enables 1040 MW of interconnection: Northern UT 345 kV reinforcement
2033	400 MW Non-Emitting Peaker (2033) 1100 MW Solar+Storage (2033)	Southern UT	Northern UT	Enables 1500 MW of interconnection with 800 MW TTC: Spanish Fork - Mercer 345 kV; New Emery – Clover 345 kV
2040	156 MW Solar+Storage (2040) 500 MW Pumped Storage (2040)	Central OR	Willamette Valley	Enables 980 MW of interconnection with 1500 MW of TTC
2028*	500 MW Adv Nuclear (2028)	Southwest Wyoming Transmission Area		Reclaimed transmission upon retirement of Naughton 1 & 2
2029*	549 MW Battery (2029)	Eastern Wyoming Transmission Area		Reclaimed transmission upon retirement of Dave Johnston Plant
2037	909 MW Solar+Storage (2037)	Southern Utah Transmission Area		Reclaimed transmission upon retirement of Huntington 1 & 2
2038	412 MW Non-Emitting Peaker (2038) 1000 MW Adv Nuclear (2038)	Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger Plant
2040	206 MW Non-Emitting Peaker (2040) 60 MW Wind (2040)	Eastern Wyoming Transmission Area		Reclaimed transmission upon retirement of Wyodak

1 - TTC = total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.
2 - Energy Gateway South is modeled in the 2021 IRP as a contingent option with bids in the 2020 All-Source Request for Proposals. Other transmission options prior to 2026 are not modeled as transmission requirements and costs are accounted for in the 2020 All-Source Request for Proposals transmission cluster study for all other resource bids.
* - Reclaimed transmission is committed with resources with a commercial operation date later than the date of retirement.

New Solar Resources

The 2021 IRP preferred portfolio includes 1,302 MW of new solar by the end of 2024 and 1,902 MW by the end of 2026. Through 2040, more than 5,600 MW of new solar is online as shown in Figure 9.32.

Figure 9.32 – 2021 IRP Preferred Portfolio New Solar Capacity*

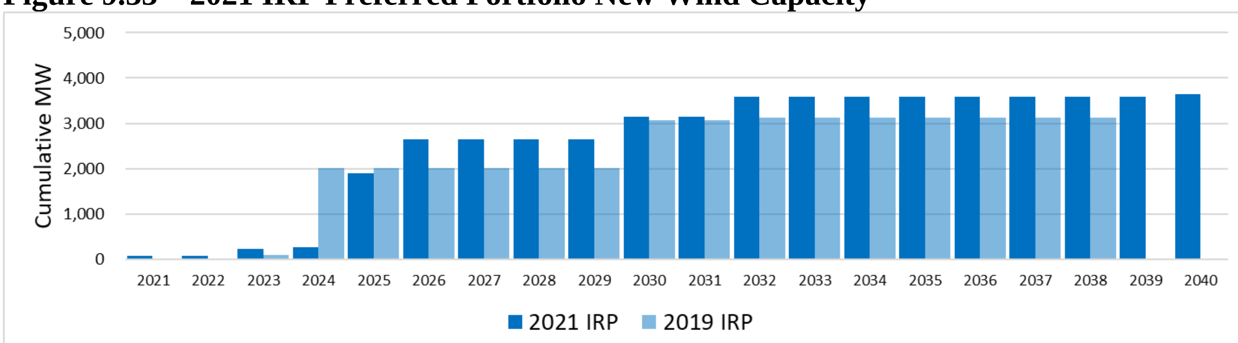


* 2021 IRP solar capacity shown in the figure includes solar resources coming via the 2020 All-Source Request for Proposals by the end of 2024. Resources are shown in the first full year of operation (the year after the year-online dates). The reported capacity for the 2020 All-Source Request for Proposals solar resources reflects their expected maximum output after degradation in their first full year of operation. The maximum solar capacity prior to degradation is 1,306 MW.

New Wind Resources

As shown in Figure 9.33, by the end of 2024, PacifiCorp's 2021 IRP preferred portfolio includes 1,792 MW of new wind generation resulting from the 2020 All-Source RFP and the acquisition and repowering of Rock River I (49 MW) and Foote Creek II-IV (43 MW). Through the end of 2026, the 2021 IRP preferred portfolio includes an additional 745 MW of new wind and more than 3,700 MW of new wind by 2040.

Figure 9.33 – 2021 IRP Preferred Portfolio New Wind Capacity*

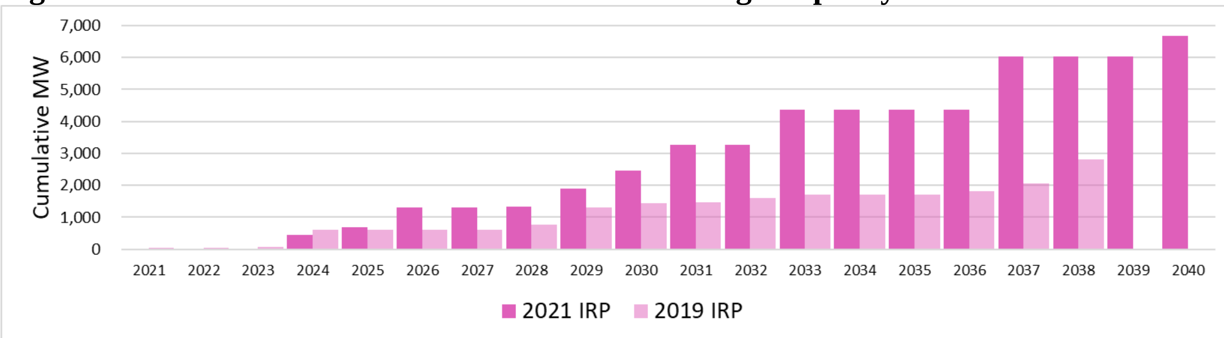


*Note: Wind additions shown are incremental to Energy Vision 2020 and other projects that have come online over the past few years. Resources are shown in the first full year of operation (the year after year-end online dates).

New Storage Resources

New storage resources in the 2021 IRP preferred portfolio are summarized in Figure 9.34. The 2021 IRP preferred portfolio includes nearly 700 MW of battery storage by the end of 2024 – 200 MW of which is a standalone battery and the remaining portion paired with solar resources resulting from the 2020 All-Source RFP. Through 2040, the 2021 IRP includes 4,781 MW of storage co-located with solar resources,1,400 MW of standalone battery, and 500 MW of pumped hydro.

Figure 9.34 – 2021 IRP Preferred Portfolio New Storage Capacity*

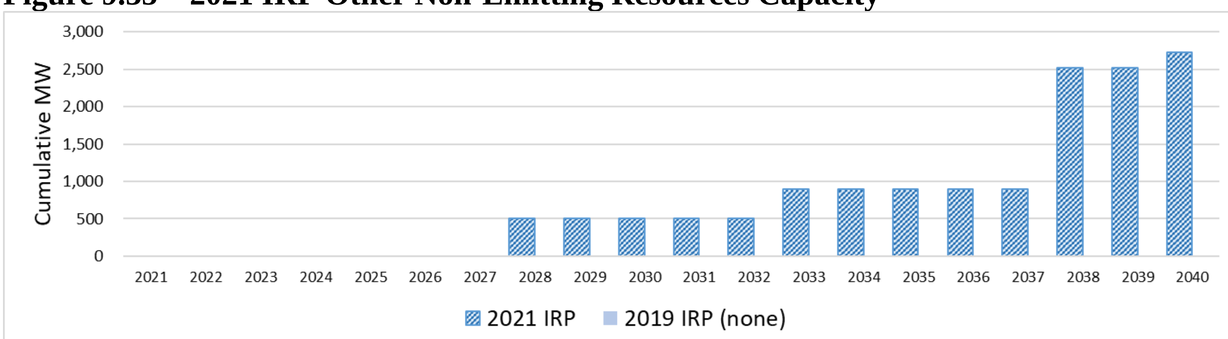


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Other Non-Emitting Resources

This is the first PacifiCorp IRP that includes new advanced nuclear and non-emitting peaking resources as part of its least-cost, least-risk preferred portfolio. As shown in Figure 9.35, the 500 MW advanced nuclear Natrium™ demonstration project will come online by summer 2028. Through 2040, the 2021 IRP preferred portfolio includes 1,000 MW of additional advanced nuclear resources and 1,226 MW of non-emitting peaking resources.

Figure 9.35 – 2021 IRP Other Non-Emitting Resources Capacity

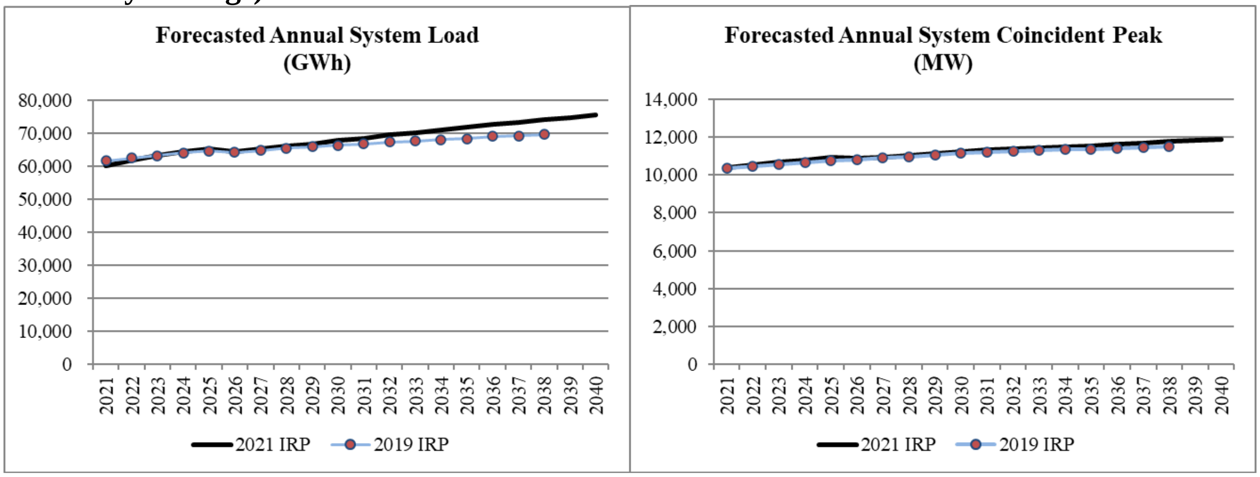


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Demand-Side Management

PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and direct load control programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP. Figure 9.36 shows that PacifiCorp's load forecast before incremental energy efficiency savings has increased relative to projected loads used in the 2019 IRP. On average, forecasted system load is up 2.2 percent and forecasted coincident system peak is up 1.1 percent when compared to the 2019 IRP. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 1.21 percent for load and 0.73 percent for peak. Changes to PacifiCorp's load forecast are driven by higher projected demand from data centers driving up the commercial forecast and an increased residential forecast.

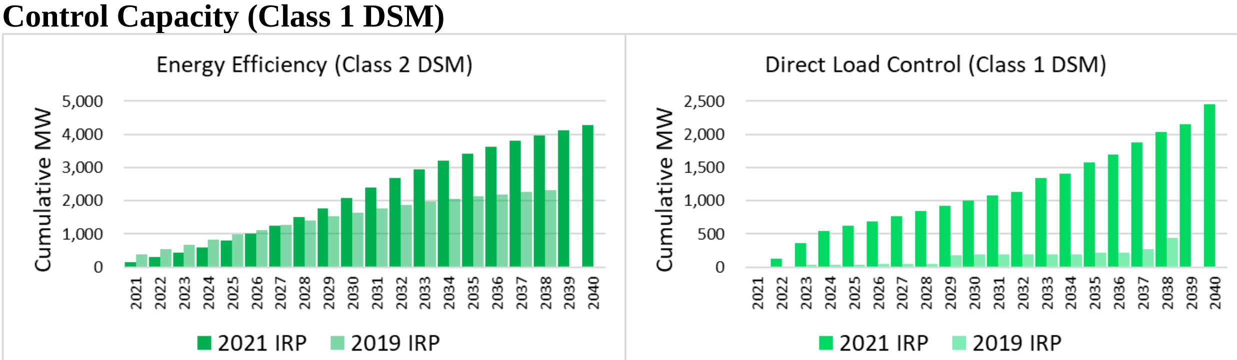
Figure 9.36 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)



DSM resources continue to play a key role in PacifiCorp's resource mix. Figure 9.37 compares total energy efficiency capacity savings in the 2021 IRP preferred portfolio relative to the 2019 IRP preferred portfolio and includes 4,290 MW by the end of the planning period.

In addition to continued investment in energy efficiency programs, the preferred portfolio shows an increasing role for incremental direct load control programs. The chart to the right in Figure 9.37 compares cumulative capacity of direct load control program capacity in the 2021 IRP preferred portfolio relative to the 2019 IRP preferred portfolio and does not include capacity from existing programs. In the 2021 IRP, direct load control resources previously identified in the 2019 IRP and solicited via a demand response RFP, were modeled in addition to resources from the CPA assessing the upper limit of demand response opportunities and value within the IRP. This allowed for the evaluation of real-time resources as a substitute for front office transactions. The 2021 IRP has a cumulative capacity of direct load control programs reaching 2,448 MW by 2040—an over 400% increase over the planning horizon from the 2019 IRP.

Figure 9.37 – 2021 IRP Preferred Portfolio Energy Efficiency (Class 2 DSM) and Direct Load Control Capacity (Class 1 DSM)



Wholesale Power Market Prices and Purchases

Figure 9.38 shows that the 2021 IRP's base case forecast for natural gas prices has decreased along with a decrease in wholesale power prices for most years relative to those in the 2019 IRP. These forecasts are based on prices observed in the forward market and on projections from third-party experts. The lower power prices observed in the 2021 IRP are primarily driven by the assumption of lower natural gas prices-than what was assumed in the 2019 IRP. Wholesale power prices are higher in 2027 to 2031 because of higher inflation impacting new resource costs. Moreover, the 2021 IRP assumed lower natural gas prices than the 2019 IRP as Henry Hub in particular, is softened by limited pipeline expansion lowering liquefied natural gas exports. While not shown in the figure below, the 2021 IRP also evaluated low and high price scenarios when evaluating the cost and risk of different resource portfolios.

Figure 9.38 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs

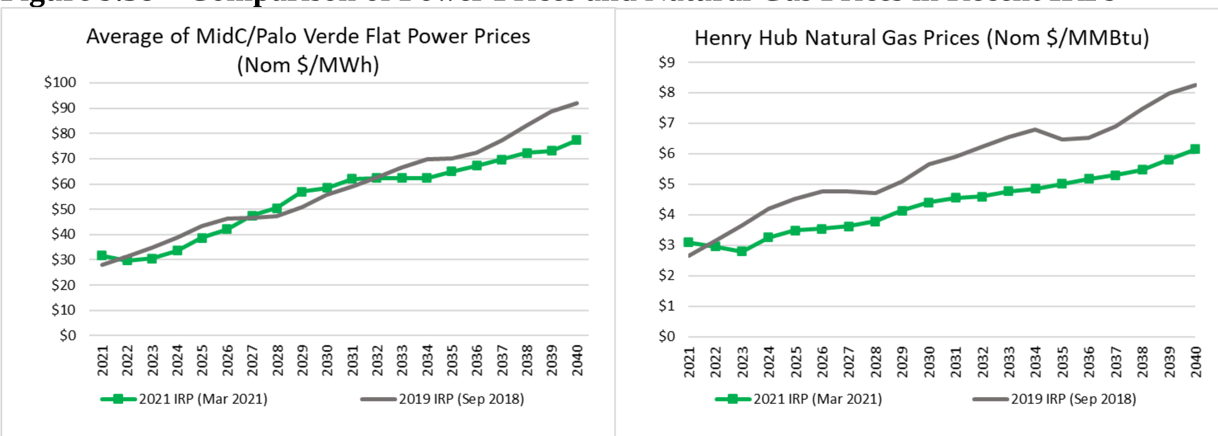
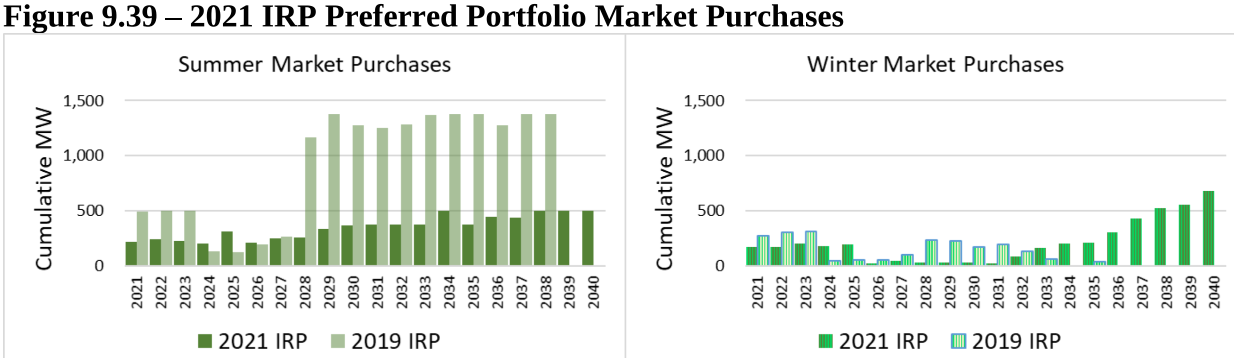


Figure 9.39 shows an overall decline in reliance on wholesale power market firm purchases in the 2021 IRP preferred portfolio relative to the wholesale power market purchases included in the 2019 IRP preferred portfolio. In particular, reliance on wholesale power market purchases during summer peak periods averages 366 MW per year over the 2020-2027 timeframe—down 60 percent from wholesale power market purchases identified in the 2019 IRP preferred portfolio. This reduction in wholesale power market purchases coincides with the period over which there are resource adequacy concerns in the region. Further, PacifiCorp is actively participating in regional efforts to develop day-ahead markets and a resource adequacy program that will help unlock regional diversity and facilitate market transactions over the long term.

Figure 9.39 – 2021 IRP Preferred Portfolio Market Purchases



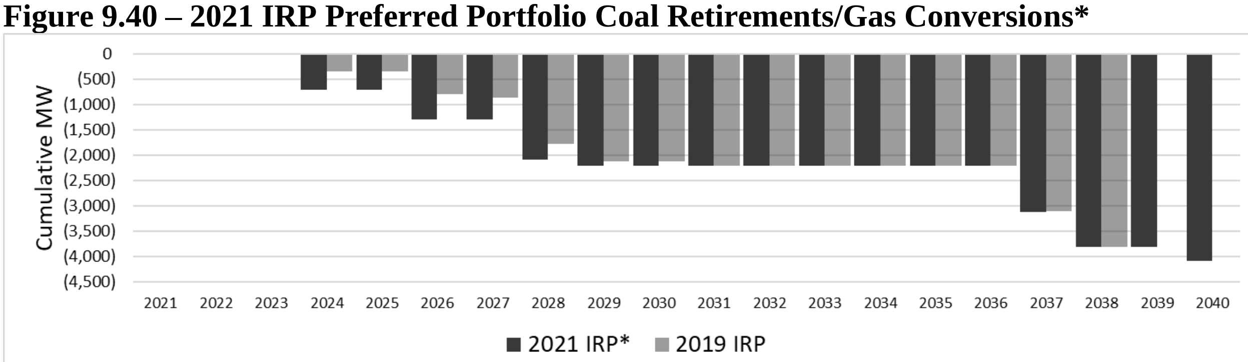
Coal and Gas Retirements/Gas Conversions

Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the EIM) that has enabled the company to reduce fuel consumption and associated costs and emissions, and instead buy increasingly low-cost, zero-emissions renewable energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy as the remaining coal units approach retirement dates. Driven in part by ongoing cost pressures on existing coal-fired facilities and dropping costs for new resource alternatives, of the 22 coal units currently serving PacifiCorp customers, the preferred portfolio includes retirement of 14 of the units by 2030 and 19 of the units by the end of the planning period in 2040. As shown in Figure 9.40, coal unit retirements/gas peaker conversions in the 2021 IRP preferred portfolio will reduce coal-fueled generation capacity by 1,300 MW by the end of 2025, over 2,200 MW by 2030, and over 4,000 MW by 2040.

Coal unit retirements scheduled under the preferred portfolio include:

- 2023 = Jim Bridger Units 1-2, converted to natural gas peakers in 2024 (same retirement year for Jim Bridger 1 in 2019 IRP and instead of 2028 for Jim Bridger 2 in the 2019 IRP).
- 2025 = Naughton Units 1-2 (same as 2019 IRP)
- 2025 = Craig Unit 1 (same as 2019 IRP)
- 2025 = Colstrip Units 3-4 (instead of 2027 in the 2019 IRP)
- 2027 = Dave Johnston Units 1-4 (same as 2019 IRP)
- 2027 = Hayden Unit 2 (instead of 2030 in the 2019 IRP)
- 2028 = Craig Unit 2 (instead of 2026 in the 2019 IRP)
- 2028 = Hayden Unit 1 (instead of 2030 in the 2019 IRP)
- 2036 = Huntington Units 1-2 (same as 2019 IRP)
- 2037 = Jim Bridger Units 3-4 (same as 2019 IRP)
- 2039 = Wyodak (same as 2019 IRP but outside of 2019 IRP planning horizon)

Figure 9.40 – 2021 IRP Preferred Portfolio Coal Retirements/Gas Conversions*



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

In addition to the coal unit retirements outlined above, the preferred portfolio reflects 1,554 MW natural gas retirements through 2040. This includes Naughton Unit 3 at the end of 2029, Gadsby at the end of 2032, Hermiston at the end of 2036, and Jim Bridger Units 1 and 2 at the end of 2037.

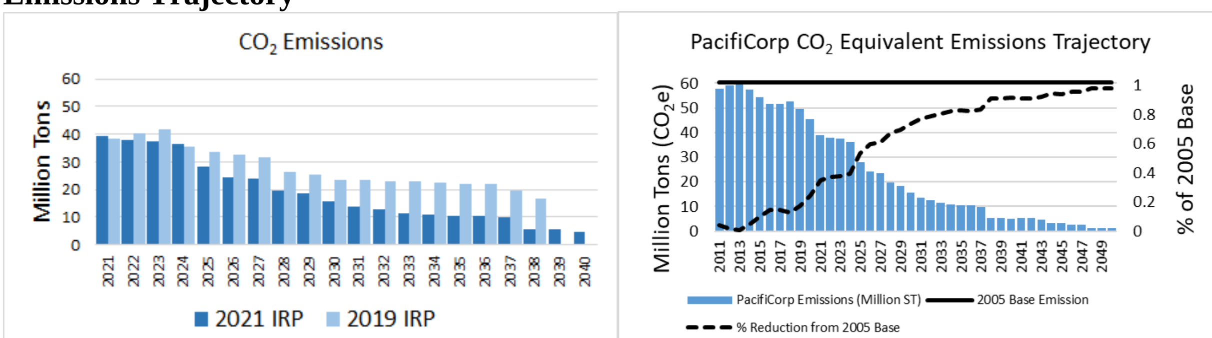
Carbon Dioxide Emissions

The 2021 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects a continued trajectory of declining carbon dioxide (CO_2) emissions. PacifiCorp's emissions have been declining and continue to decline related to several factors including PacifiCorp's participation in the EIM, which reduces customer costs and maximizes use of clean energy; PacifiCorp's on-going transition to clean-energy resources including new renewable resources, new advanced nuclear resources, new non-emitting resources, storage, transmission, and Regional Haze compliance that capitalizes on flexibility.

The chart on the left in Figure 9.41 compares projected annual CO_2 emissions between the 2021 IRP and 2019 IRP preferred portfolios. In this graph, emissions are not assigned to market purchases or sales, and in 2026, annual CO_2 emissions are down 26 percent relative to the 2019 IRP preferred portfolio. By 2030, average annual CO_2 emissions are down 34 percent relative to the 2019 IRP preferred portfolio, and down 52 percent in 2035. By the end of the planning horizon, system CO_2 emissions are projected to fall from 39.1 million tons in 2021 to 4.8 million tons in 2040—a reduction of 88 percent.

The chart on the right in Figure 9.41 includes historical data, assigns emissions at a rate of 0.4708 tons CO_2 equivalent per MWh to market purchases (with no credit to market sales), includes emissions associated with specified purchases, and extrapolates projections out through 2050. This graph demonstrates that relative to a 2005 baseline, system CO_2 equivalent emissions are down 53 percent in 2025, 74 percent in 2030, 83 percent in 2035, 92 percent in 2040, 94 percent in 2045, and 98 percent in 2050.

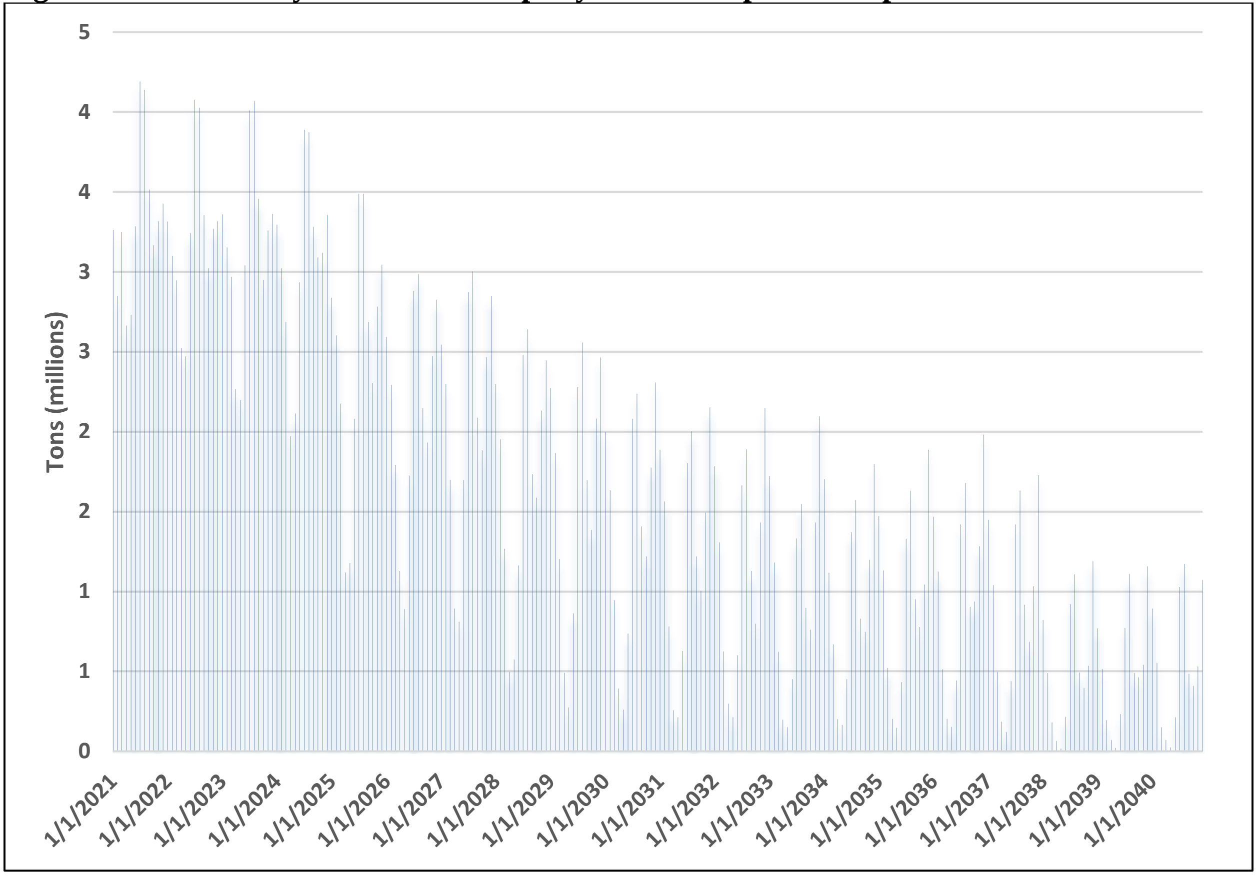
Figure 9.41 – 2021 IRP Preferred Portfolio CO_2 Emissions and PacifiCorp CO_2 Equivalent Emissions Trajectory*



*Note: PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2020 from owned facilities, specified sources and unspecified sources. From 2021 through the end of the twenty-year planning period in 2040, emissions reflect those from the 2021 IRP preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Market purchases are assigned a default emission factor (0.4708 short tons CO_2e/MWh) – emissions from sales are not removed. Beyond 2040, emissions reflect the rolling average emissions of each resource from the 2021 IRP preferred portfolio through the life of the resource. The emissions trajectory does not incorporate clean energy targets set forth in Oregon House Bill 2021 or any other state-specific emissions trajectories. PacifiCorp expects these targets, and an Oregon-specific emissions trajectory, to be incorporated following the 2023 integrated resource plan when PacifiCorp is required under the bill to file a Clean Energy Plan.

Monthly CO_2 emissions are available for the preferred portfolio as shown in Figure 9.42 below.

Figure 9.42 – Monthly CO_2 emissions per year for the preferred portfolio



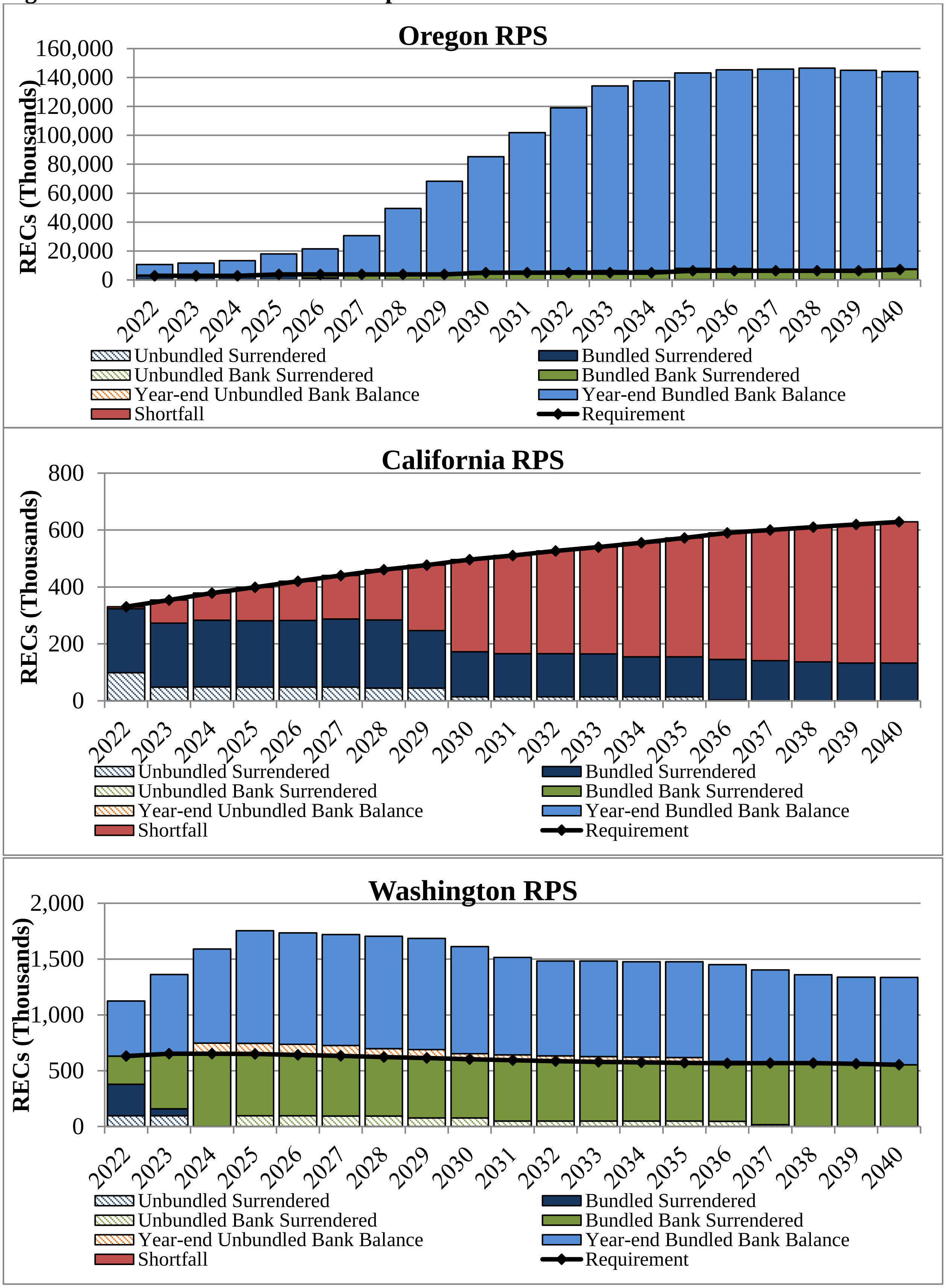
Renewable Portfolio Standards

Figure 9.43 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for new renewable resources in the preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources and are not included to specifically meet RPS targets, they nonetheless contribute to meeting RPS targets in PacifiCorp's western states.
Oregon RPS compliance is achieved through 2040 with the addition of new renewable resources and transmission in the 2021 IRP preferred portfolio. Washington RPS compliance is achieved with the benefit of increased system renewable resources beginning 2021 as well as additional resources procured that meet the state's Clean Energy Transformation Act. Under PacifiCorp's 2020 Protocol, and the Washington Interjurisdictional Allocation Methodology, Washington's RPS position is improved by receiving a system share of renewable resources across the PacifiCorp's system.

The California RPS compliance position will be met with owned and contracted renewable resources, as well as REC purchases throughout the 2021 IRP study period. The ramping RPS requirement results in an increased need for unbundled REC purchases to meet the annual and compliance period targets in 2021-2040. New renewable resources and transmission in the 2021 IRP preferred portfolio mitigate that shortfall, but the company may need to purchase approximately 200,000 RECs in compliance periods 4 and 5, 2021-2024 and 2025-2028, respectively. Beyond 2028, the company may need to purchase 200,000-300,000 RECs per year to meet the ramping RPS.

While not shown in Figure 9.43, PacifiCorp meets the Utah 2025 state target to supply 20 percent of adjusted retail sales with eligible renewable resources with existing owned and contracted resources and new renewable resources and transmission in the 2021 IRP preferred portfolio.

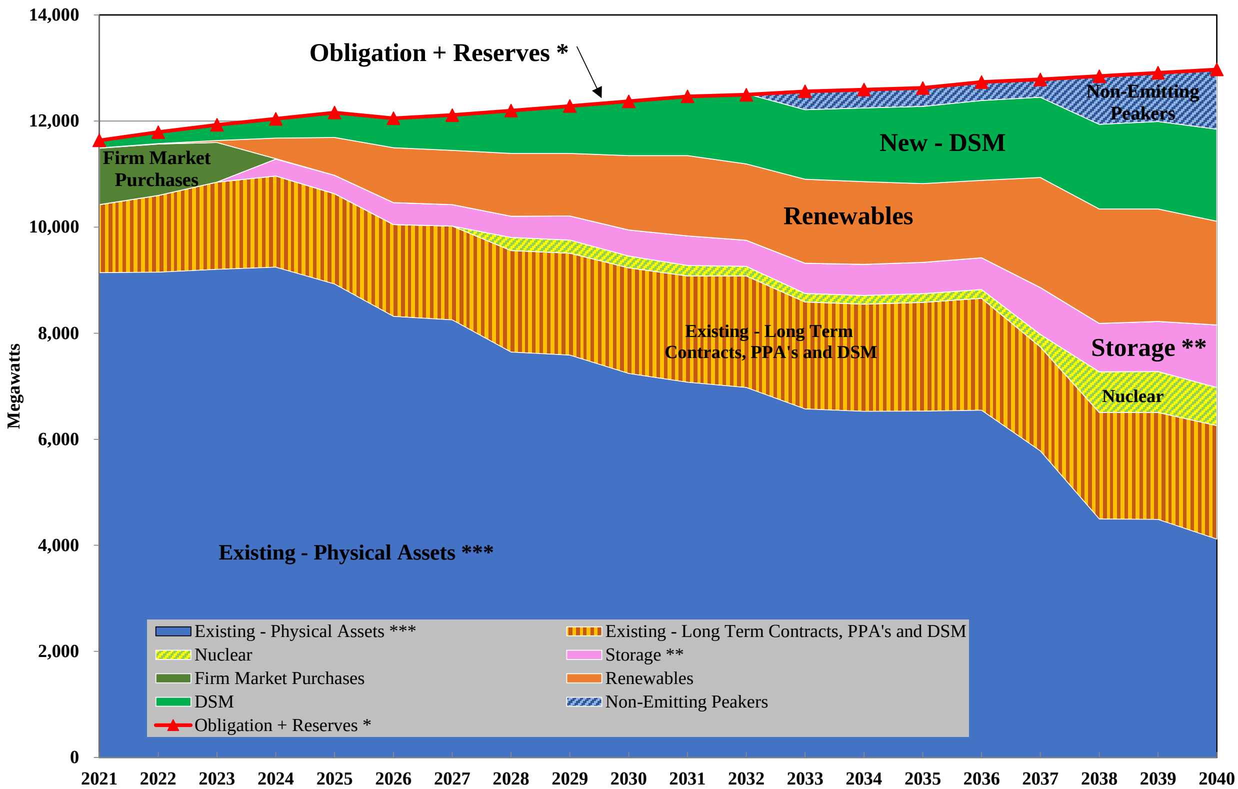
Figure 9.43 – Annual State RPS Compliance Forecast



Capacity and Energy

Figure 9.44 displays how preferred portfolio resources meet PacifiCorp's capacity needs over time. Through 2040, PacifiCorp meets its capacity needs, including a 13% planning reserve margin, through incremental acquisition of wind and solar resources and hybrid renewables (with storage) enabled by investment in transmission infrastructure, nuclear resources, strand alone storage resources, new DSM, non-emitting peaker resources, and wholesale power market purchases.

Figure 9.44 – Meeting PacifiCorp's Capacity Needs with Preferred Portfolio Resources



* Includes 13% Capacity Reserve Margin, Sales and Non-Owned Reserves
** Includes the storage component of wind and solar collocated with storage
*** Includes retirements, and gas conversions

Figure 9.45 and Figure 9.46 show how PacifiCorp's system energy and nameplate capacity mix is projected to change over time. In developing these figures, purchased power is reported in identifiable resource categories where possible. Energy mix figures are based upon base price curve assumptions. Renewable capacity and generation reflect categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.[11] On an energy basis, coal generation drops to 25 percent by 2027, falls to 9 percent by 2032, and declines to only 1 percent by the end of the planning period. On a capacity basis, coal resources drop to 18 percent by 2027, fall to 11 percent by 2032, and decline to 3 percent by the end of the

[11]The projected PacifiCorp 2021 IRP preferred portfolio "energy mix" is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with wind, biomass, geothermal and qualifying hydro facilities in PacifiCorp's energy mix may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements; (b) sold to third parties in the form of renewable energy credits or other environmental commodities; or (c) excluded from energy purchased. PacifiCorp's 2021 IRP preferred portfolio energy mix includes owned resources and purchases from third parties.

planning period. Reduced energy and capacity from coal is offset primarily by increased energy and capacity from renewable and storage resources, nuclear resources, DSM resources, and to a smaller extent later in the plan, non-emitting peaker resources.

Figure 9.45 – Projected Energy Mix with Preferred Portfolio Resources.

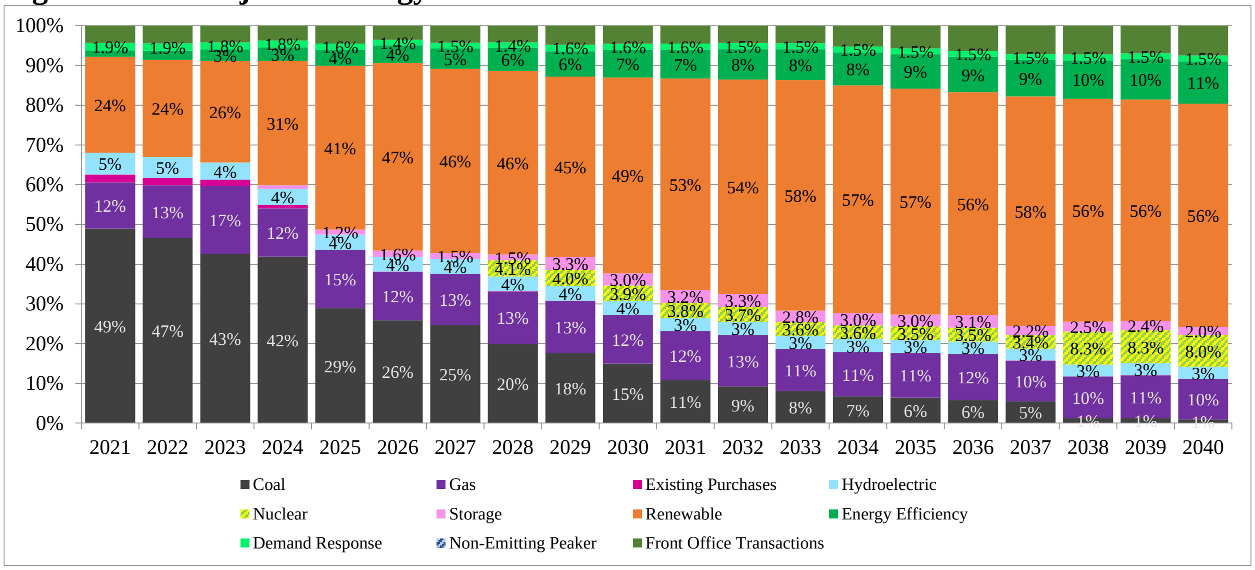
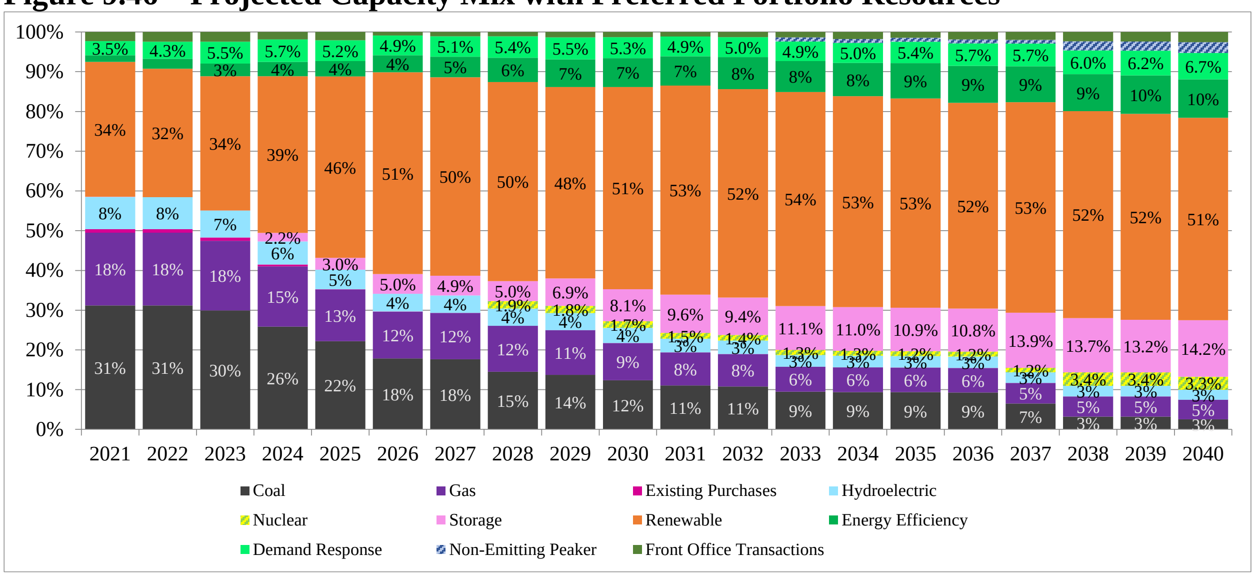


Figure 9.46 – Projected Capacity Mix with Preferred Portfolio Resources



Detailed Preferred Portfolio

Table 9.17 provides line-item detail of PacifiCorp's 2021 IRP preferred portfolio showing new resource capacity along with changes in existing resource capacity through the 20-year planning horizon. Table 9.18 shows line-item detail of PacifiCorp's peak load and resource capacity balance for summer, including preferred portfolio resources, over the 20-year planning horizon. Table 9.19 shows line-item detail of PacifiCorp's peak load and resource capacity balance for winter, including preferred portfolio resources, over the twenty-year planning horizon.

Table 9.17 – PacifiCorp's 2021 IRP Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	-	-	-	-	-	402	-	-	-	-	618	-	206	1,226
DSM - Energy Efficiency	157	138	144	164	186	211	238	263	279	304	301	293	272	249	221	195	189	171	160	156	4,290
DSM - Demand Response	-	123	242	184	79	63	69	80	78	77	82	50	213	70	160	125	183	159	108	302	2,448
Renewable - Wind	49	-	151	43	1,641	745	-	-	-	489	-	450	-	-	-	-	-	-	-	60	3,628
Renewable - Wind+Storage	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	160
Renewable - Utility Solar	-	-	-	95	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	95
Renewable - Utility Solar+Storage	-	-	-	752	455	600	-	83	-	558	820	-	1,100	-	-	-	1,009	-	-	156	5,533
Renewable - Battery, Wind+Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, Solar+Storage	-	-	-	239	258	600	-	42	-	558	820	-	1,100	-	-	-	1,009	-	-	156	4,781
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery - Stand Alone	-	-	-	200	-	-	-	-	549	1	-	-	-	-	-	-	650	-	-	-	1,400
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
Nuclear	-	-	-	-	-	-	-	345	-	-	-	-	-	-	-	-	-	690	-	-	1,035
Nuclear Storage	-	-	-	-	-	-	-	155	-	-	-	-	-	-	-	-	-	310	-	-	465
Front Office Transactions	385	412	427	383	498	231	287	285	363	394	395	459	538	703	578	747	863	1,025	1,052	1,176	560
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	-	-	(230)	-	(788)	(123)	-	-	-	-	-	-	-	(909)	(699)	-	(268)	(3,018)
Coal Early Retirements	-	-	-	-	-	(357)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(357)
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	-	-	713	-	-	-	-	-	-	-	-	-	-	-	-	-	(713)	-	-	-
Coal Plant ceases running as Coal	-	-	-	(713)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(713)
Gas Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	(247)	-	-	(356)	-	-	-	(237)	-	-	-	(840)
Retire - Hydro	-	-	(163)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(163)
Retire - Wind	-	(10)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(10)
Expire - Wind PPA	-	-	-	(41)	-	(65)	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	-	(405)
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(18)	-	-	-	(18)
Expire - Solar PPA	-	-	-	-	-	-	-	(2)	-	-	-	(8)	-	-	-	-	(73)	-	-	-	(83)
Expire - QF	-	(2)	-	(50)	-	-	(29)	-	(83)	(0)	-	(81)	(181)	(91)	(19)	(208)	(744)	(30)	(100)	(92)	(1,712)
Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(32)	-	-	(32)
Expire - Other	-	11	-	32	(91)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(49)
Total	**591**	**673**	**802**	**2,001**	**3,025**	**1,798**	**565**	**463**	**964**	**2,094**	**2,419**	**1,162**	**3,088**	**931**	**940**	**858**	**1,923**	**1,497**	**1,220**	**2,350**	

Table 9.18 – Preferred Portfolio Summer Capacity Load and Resource Balance (2021-2030)

East	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Thermal	5,478	5,466	5,429	5,425	5,459	5,044	5,002	4,293	4,182	3,953
Hydroelectric	86	86	85	69	56	52	51	56	57	52
Renewable	668	690	815	912	709	676	661	718	743	676
Purchase	193	197	202	195	138	141	142	148	143	147
Qualifying Facilities	537	521	515	488	396	357	344	364	372	346
Sale	(20)	(20)	(20)	0	0	0	0	0	0	0
East Existing Resources	**6,943**	**6,940**	**7,026**	**7,090**	**6,758**	**6,271**	**6,201**	**5,580**	**5,498**	**5,174**
Front Office Transactions	0	0	0	0	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	0	0	0	0
Wind	6	6	35	47	298	280	283	331	328	387
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	32	25	24	24	27	27	25
Solar+Storage	0	0	0	334	513	388	377	401	397	350
Storage	1	1	1	148	104	58	56	50	162	126
Nuclear	0	0	0	0	0	0	0	248	250	224
Geothermal	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**7**	**7**	**36**	**561**	**940**	**750**	**740**	**1,056**	**1,164**	**1,112**
East Total Resources	**6,950**	**6,947**	**7,062**	**7,651**	**7,698**	**7,020**	**6,940**	**6,636**	**6,661**	**6,286**
Load	7,096	7,246	7,380	7,475	7,583	7,492	7,550	7,643	7,728	7,833
Private Generation	(51)	(72)	(81)	(84)	(87)	(90)	(96)	(106)	(119)	(136)
Existing - Demand Response	(520)	(538)	(558)	(538)	(583)	(592)	(598)	(623)	(604)	(619)
New Demand Response	0	(86)	(192)	(231)	(274)	(301)	(329)	(375)	(397)	(438)
Existing - Energy Efficiency	(43)	(45)	(46)	(45)	(49)	(49)	(50)	(52)	(50)	(52)
New Energy Efficiency	(48)	(95)	(149)	(199)	(280)	(349)	(429)	(529)	(597)	(698)
East Total obligation	**6,434**	**6,410**	**6,353**	**6,378**	**6,311**	**6,110**	**6,048**	**5,958**	**5,961**	**5,890**
East Reserve Margin	8%	8%	11%	20%	22%	15%	15%	11%	12%	7%
West										
Thermal	2,139	2,165	2,168	2,144	2,149	2,019	2,015	2,014	2,036	2,035
Hydroelectric	577	567	521	508	407	386	380	420	423	390
Renewable	194	177	185	184	148	139	140	144	144	134
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	158	153	145	141	116	105	87	91	79	71
Sale	(109)	(76)	(76)	(54)	(44)	(42)	(41)	(44)	(44)	(41)
West Existing Resources	**2,961**	**2,986**	**2,945**	**2,924**	**2,777**	**2,608**	**2,582**	**2,626**	**2,638**	**2,591**
Front Office Transactions	1,064	972	747	8	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	177	177	211	194	189
Wind+Storage	0	0	0	0	0	0	0	0	0	39
Solar	0	0	0	0	0	0	0	0	0	0
Solar+Storage	0	0	0	147	119	522	511	564	526	775
Storage	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**1,064**	**972**	**747**	**154**	**119**	**699**	**688**	**775**	**720**	**1,003**
West Total Resources	**4,025**	**3,959**	**3,691**	**3,079**	**2,897**	**3,307**	**3,270**	**3,401**	**3,358**	**3,594**
Load	3,351	3,400	3,443	3,472	3,506	3,530	3,557	3,584	3,610	3,638
Private Generation	(23)	(39)	(51)	(56)	(60)	(65)	(71)	(78)	(86)	(96)
Existing - Demand Response	0	0	0	0	0	0	0	0	0	0
New Demand Response	0	(45)	(127)	(179)	(238)	(276)	(310)	(355)	(369)	(411)
Existing - Energy Efficiency	(24)	(25)	(26)	(25)	(27)	(28)	(28)	(29)	(28)	(29)
New Energy Efficiency	(26)	(51)	(76)	(95)	(126)	(152)	(178)	(213)	(234)	(266)
West Total obligation	**3,278**	**3,241**	**3,163**	**3,117**	**3,054**	**3,010**	**2,970**	**2,910**	**2,893**	**2,835**
West Reserve Margin	23%	22%	17%	-1%	-5%	10%	10%	17%	16%	27%
System										
Total Resources	10,975	10,905	10,753	10,730	10,595	10,328	10,210	10,037	10,020	9,880
Obligation	9,712	9,651	9,516	9,495	9,366	9,120	9,017	8,868	8,854	8,726
Capacity Reverve Margin (13%)	1,263	1,255	1,237	1,234	1,218	1,186	1,172	1,153	1,151	1,134
Obligation + Reserves	10,975	10,905	10,753	10,730	10,583	10,306	10,190	10,021	10,005	9,860
System Position	0	0	0	0	12	22	21	16	15	20
Reserve Margin	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**

Table 9.18 (cont'd) – Preferred Portfolio Summer Capacity Load and Resource Balance (2031-2040)

East	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Thermal	3,945	3,955	3,629	3,607	3,613	3,613	2,765	2,759	2,757	2,491
Hydroelectric	47	43	40	40	40	40	57	63	64	58
Renewable	582	525	471	465	465	465	587	595	586	539
Purchase	146	157	145	144	142	144	138	137	136	138
Qualifying Facilities	310	266	220	204	192	162	34	29	12	0
Sale	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**5,031**	**4,947**	**4,505**	**4,459**	**4,452**	**4,424**	**3,582**	**3,583**	**3,555**	**3,226**
Front Office Transactions	0	0	0	0	0	0	0	0	0	0
NonEmitting Peaker	0	0	369	369	368	371	373	375	374	562
Wind	360	322	308	326	307	305	419	461	463	439
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	22	20	18	17	16	15	19	20	19	17
Solar+Storage	677	604	951	929	906	870	1,364	1,377	1,383	1,228
Storage	131	115	99	99	99	104	119	124	93	86
Nuclear	198	181	161	166	163	165	231	260	262	242
Geothermal	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**1,388**	**1,242**	**1,906**	**1,906**	**1,859**	**1,829**	**2,525**	**2,615**	**2,594**	**2,573**
East Total Resources	**6,419**	**6,189**	**6,411**	**6,365**	**6,311**	**6,253**	**6,107**	**6,199**	**6,149**	**5,799**
Load	7,938	8,041	8,138	8,232	8,336	8,343	8,413	8,520	8,390	8,488
Private Generation	(160)	(189)	(218)	(251)	(291)	(181)	(205)	(230)	(119)	(132)
Existing - Demand Response	(615)	(660)	(609)	(604)	(598)	(607)	(582)	(579)	(574)	(581)
New Demand Response	(468)	(521)	(570)	(593)	(627)	(673)	(705)	(740)	(771)	(849)
Existing - Energy Efficiency	(51)	(55)	(51)	(50)	(50)	(51)	(48)	(48)	(48)	(48)
New Energy Efficiency	(773)	(906)	(907)	(962)	(1,009)	(1,039)	(1,052)	(1,111)	(1,170)	(1,248)
East Total obligation	**5,871**	**5,710**	**5,784**	**5,771**	**5,762**	**5,792**	**5,820**	**5,812**	**5,707**	**5,630**
East Reserve Margin	9%	8%	11%	10%	10%	8%	5%	7%	8%	3%
West										
Thermal	2,027	2,021	2,024	2,023	2,023	2,031	1,807	456	456	456
Hydroelectric	355	323	301	299	296	298	435	483	485	446
Renewable	117	108	105	92	92	100	129	142	143	128
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	64	49	45	39	37	38	25	22	9	6
Sale	(38)	(34)	(32)	(32)	(32)	(31)	(34)	(32)	(32)	(28)
West Existing Resources	**2,527**	**2,468**	**2,443**	**2,422**	**2,417**	**2,435**	**2,364**	**1,072**	**1,061**	**1,009**
Front Office Transactions	0	0	0	0	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	0	573	573	577
Wind	168	241	230	239	228	248	338	371	374	348
Wind+Storage	39	32	31	31	33	33	45	49	50	47
Solar	0	0	0	0	0	0	0	0	0	0
Solar+Storage	670	594	515	503	489	484	576	584	587	583
Storage	0	0	0	0	0	0	78	84	95	387
Nuclear	0	0	0	0	0	0	0	508	509	475
Geothermal	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**877**	**868**	**775**	**773**	**750**	**765**	**1,038**	**2,168**	**2,188**	**2,417**
West Total Resources	**3,404**	**3,336**	**3,219**	**3,195**	**3,166**	**3,200**	**3,401**	**3,240**	**3,249**	**3,426**
Load	3,676	3,707	3,740	3,773	3,805	3,752	3,793	3,825	3,758	3,782
Private Generation	(118)	(158)	(205)	(258)	(316)	(263)	(305)	(351)	(195)	(225)
Existing - Demand Response	0	0	0	0	0	0	0	0	0	0
New Demand Response	(441)	(485)	(461)	(469)	(488)	(519)	(512)	(531)	(544)	(594)
Existing - Energy Efficiency	(29)	(31)	(28)	(28)	(28)	(28)	(27)	(27)	(27)	(27)
New Energy Efficiency	(289)	(334)	(329)	(348)	(366)	(388)	(386)	(410)	(409)	(414)
West Total obligation	**2,800**	**2,699**	**2,717**	**2,669**	**2,607**	**2,554**	**2,563**	**2,507**	**2,584**	**2,521**
West Reserve Margin	22%	24%	18%	20%	21%	25%	33%	29%	26%	36%
System										
Total Resources	9,823	9,524	9,630	9,560	9,477	9,453	9,509	9,438	9,398	9,225
Obligation	8,671	8,410	8,500	8,440	8,369	8,346	8,383	8,319	8,291	8,150
Capacity Reverve Margin (13%)	1,127	1,093	1,105	1,097	1,088	1,085	1,090	1,081	1,078	1,060
Obligation + Reserves	9,798	9,503	9,605	9,537	9,457	9,431	9,473	9,400	9,369	9,210
System Position	25	22	25	23	21	22	35	38	29	15
Reserve Margin	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**

Table 9.19 – Preferred Portfolio Winter Capacity Load and Resource Balance (2021-2030)

East	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Thermal	5,478	5,383	5,540	5,364	5,550	5,057	5,143	4,229	4,140	3,835
Hydroelectric	50	52	46	43	30	31	29	39	42	42
Renewable	765	929	885	860	546	676	639	796	843	802
Purchase	173	169	167	158	115	116	120	125	110	113
Qualifying Facilities	204	225	192	213	105	136	123	208	227	233
Sale	(16)	(17)	(15)	0	0	0	0	0	0	0
Transfers	(277)	(267)	(247)	(535)	(275)	(79)	(99)	(588)	(561)	(369)
East Existing Resources	**6,378**	**6,474**	**6,568**	**6,104**	**6,071**	**5,937**	**5,955**	**4,809**	**4,802**	**4,657**
Front Office Transactions	0	0	0	0	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	0	0	0	0
Wind	12	14	52	69	362	398	406	499	533	686
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	17	6	9	8	14	16	16
Solar+Storage	0	0	0	201	205	178	169	235	247	242
Storage	1	1	1	128	83	55	52	51	179	153
Nuclear	0	0	0	0	0	0	0	217	231	233
Geothermal	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**13**	**15**	**53**	**415**	**657**	**640**	**636**	**1,017**	**1,206**	**1,331**
East Total Resources	**6,391**	**6,489**	**6,621**	**6,518**	**6,728**	**6,577**	**6,591**	**5,825**	**6,008**	**5,987**
Load	5,538	5,678	5,800	5,860	5,943	5,874	5,915	6,008	6,081	6,161
Private Generation	(0)	(1)	(2)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Existing - Demand Response	(239)	(251)	(255)	(252)	(255)	(258)	(267)	(277)	(246)	(251)
New Demand Response	0	(76)	(164)	(198)	(218)	(239)	(268)	(304)	(293)	(323)
Existing - Energy Efficiency	(32)	(33)	(34)	(33)	(34)	(34)	(35)	(37)	(33)	(33)
New Energy Efficiency	(39)	(74)	(109)	(143)	(181)	(213)	(259)	(309)	(308)	(356)
East Total obligation	**5,229**	**5,244**	**5,237**	**5,231**	**5,251**	**5,127**	**5,081**	**5,076**	**5,195**	**5,189**
East Reserve Margin	22%	24%	26%	25%	28%	28%	30%	15%	16%	15%
West										
Thermal	2,205	2,211	2,186	1,930	2,203	2,064	2,060	1,982	2,010	1,991
Hydroelectric	497	518	434	456	320	330	317	410	439	439
Renewable	105	75	69	86	56	63	52	84	92	95
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	53	50	45	54	37	36	19	39	36	33
Sale	(88)	(71)	(59)	(45)	(32)	(33)	(32)	(38)	(41)	(40)
Transfers	277	267	247	535	275	79	99	588	561	369
West Existing Resources	**3,049**	**3,051**	**2,922**	**3,017**	**2,860**	**2,540**	**2,517**	**3,066**	**3,097**	**2,887**
Front Office Transactions	163	62	5	0	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	85	79	120	125	135
Wind+Storage	0	0	0	0	0	0	0	0	0	30
Solar	0	0	0	0	0	0	0	0	0	0
Solar+Storage	0	0	0	46	22	252	232	325	315	479
Storage	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**163**	**62**	**5**	**46**	**22**	**337**	**311**	**445**	**441**	**643**
West Total Resources	**3,212**	**3,113**	**2,927**	**3,063**	**2,882**	**2,878**	**2,828**	**3,511**	**3,538**	**3,530**
Load	3,318	3,358	3,397	3,421	3,449	3,479	3,516	3,550	3,585	3,615
Private Generation	(0)	(0)	(1)	(1)	(1)	(1)	(2)	(2)	(3)	(3)
Existing - Demand Response	0	0	0	0	0	0	0	0	0	0
New Demand Response	0	(33)	(91)	(129)	(159)	(186)	(216)	(248)	(238)	(263)
Existing - Energy Efficiency	(23)	(24)	(24)	(24)	(24)	(24)	(25)	(26)	(23)	(24)
New Energy Efficiency	(25)	(48)	(69)	(86)	(105)	(124)	(149)	(176)	(176)	(200)
West Total obligation	**3,270**	**3,253**	**3,213**	**3,182**	**3,160**	**3,142**	**3,123**	**3,098**	**3,146**	**3,124**
West Reserve Margin	-2%	-4%	-9%	-4%	-9%	-8%	-9%	13%	12%	13%
System										
Total Resources	9,603	9,602	9,548	9,581	9,609	9,454	9,419	9,336	9,546	9,518
Obligation	8,498	8,497	8,450	8,412	8,411	8,269	8,205	8,174	8,341	8,314
Capacity Reverve Margin (13%)	1,105	1,105	1,098	1,094	1,093	1,075	1,067	1,063	1,084	1,081
Obligation + Reserves	9,603	9,602	9,548	9,506	9,505	9,344	9,271	9,236	9,425	9,394
System Position	0	0	0	75	105	110	148	100	120	123
Reserve Margin	**13%**	**13%**	**13%**	**14%**	**14%**	**14%**	**15%**	**14%**	**14%**	**14%**

Table 9.19 (cont'd) – Preferred Portfolio Winter Capacity Load and Resource Balance (2031-2040)

East	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Thermal	3,901	3,947	3,646	3,554	3,677	3,411	2,830	2,643	2,783	2,421
Hydroelectric	36	36	34	37	38	43	47	48	52	49
Renewable	665	662	620	668	703	752	782	756	832	778
Purchase	129	129	131	119	109	111	136	133	134	119
Qualifying Facilities	186	178	133	124	119	80	15	13	4	0
Sale	0	0	0	0	0	0	0	0	0	(0)
Transfers	(415)	(387)	(518)	(468)	(504)	(416)	(541)	(472)	(804)	(382)
East Existing Resources	**4,502**	**4,566**	**4,045**	**4,034**	**4,142**	**3,981**	**3,270**	**3,120**	**3,002**	**2,986**
Front Office Transactions	0	0	0	0	0	0	0	0	0	0
NonEmitting Peaker	0	2	378	378	379	375	376	376	381	567
Wind	595	570	555	619	654	706	736	725	807	778
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	12	13	11	11	11	12	13	13	13	12
Solar+Storage	429	427	629	689	699	776	969	942	1,008	936
Storage	142	140	120	138	147	157	125	113	88	83
Nuclear	202	197	182	202	209	236	241	240	265	249
Geothermal	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**1,380**	**1,349**	**1,875**	**2,036**	**2,099**	**2,263**	**2,459**	**2,408**	**2,563**	**2,626**
East Total Resources	**5,882**	**5,915**	**5,920**	**6,070**	**6,241**	**6,244**	**5,729**	**5,528**	**5,565**	**5,612**
Load	6,240	6,328	6,415	6,517	6,595	6,672	6,407	6,504	6,589	6,682
Private Generation	(9)	(10)	(12)	(13)	(14)	(16)	(33)	(37)	(41)	(45)
Existing - Demand Response	(288)	(287)	(291)	(264)	(243)	(247)	(303)	(295)	(299)	(267)
New Demand Response	(398)	(414)	(483)	(461)	(449)	(488)	(654)	(669)	(713)	(705)
Existing - Energy Efficiency	(38)	(38)	(39)	(35)	(32)	(33)	(40)	(39)	(40)	(35)
New Energy Efficiency	(446)	(480)	(513)	(494)	(481)	(504)	(659)	(695)	(758)	(726)
East Total obligation	**5,061**	**5,099**	**5,078**	**5,250**	**5,375**	**5,384**	**4,718**	**4,769**	**4,738**	**4,904**
East Reserve Margin	16%	16%	17%	16%	16%	16%	21%	16%	17%	14%
West										
Thermal	2,076	2,053	2,032	2,080	2,072	2,025	1,808	489	490	490
Hydroelectric	373	374	351	388	406	448	481	487	536	503
Renewable	79	79	70	78	78	91	101	104	111	107
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	25	23	19	19	19	19	17	16	13	8
Sale	(35)	(34)	(32)	(34)	(36)	(38)	(32)	(29)	(32)	(30)
Transfers	415	387	518	468	504	416	541	472	804	382
West Existing Resources	**2,934**	**2,883**	**2,960**	**2,999**	**3,044**	**2,961**	**2,917**	**1,541**	**1,923**	**1,459**
Front Office Transactions	0	0	0	0	0	0	0	560	59	420
NonEmitting Peaker	0	0	0	0	0	0	15	581	582	571
Wind	111	176	164	182	178	209	232	246	266	254
Wind+Storage	24	24	23	25	24	29	32	34	37	35
Solar	0	0	0	0	0	0	0	0	0	0
Solar+Storage	359	355	294	317	325	357	364	358	385	394
Storage	0	0	0	0	0	1	94	88	111	399
Nuclear	0	0	0	0	0	0	13	480	531	487
Geothermal	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**494**	**555**	**480**	**524**	**527**	**597**	**748**	**2,347**	**1,970**	**2,561**
West Total Resources	**3,428**	**3,438**	**3,441**	**3,523**	**3,571**	**3,557**	**3,666**	**3,887**	**3,893**	**4,020**
Load	3,643	3,681	3,721	3,760	3,797	3,826	4,271	4,322	4,375	4,425
Private Generation	(4)	(4)	(5)	(6)	(7)	(8)	(9)	(11)	(12)	(13)
Existing - Demand Response	0	0	0	0	0	0	0	0	0	0
New Demand Response	(327)	(336)	(350)	(328)	(331)	(354)	(449)	(458)	(480)	(460)
Existing - Energy Efficiency	(27)	(27)	(28)	(25)	(23)	(23)	(29)	(28)	(28)	(25)
New Energy Efficiency	(252)	(271)	(293)	(283)	(276)	(293)	(372)	(385)	(409)	(369)
West Total obligation	**3,033**	**3,042**	**3,045**	**3,118**	**3,160**	**3,148**	**3,412**	**3,440**	**3,445**	**3,558**
West Reserve Margin	13%	13%	13%	13%	13%	13%	7%	13%	13%	13%
System										
Total Resources	9,310	9,353	9,360	9,593	9,812	9,801	9,395	9,415	9,458	9,632
Obligation	8,095	8,141	8,122	8,368	8,536	8,532	8,131	8,209	8,183	8,462
Capacity Reverve Margin (13%)	1,052	1,058	1,056	1,088	1,110	1,109	1,057	1,067	1,064	1,100
Obligation + Reserves	9,147	9,200	9,178	9,455	9,645	9,641	9,188	9,276	9,247	9,562
System Position	163	153	182	138	167	160	207	139	211	70
Reserve Margin	**15%**	**15%**	**15%**	**15%**	**15%**	**15%**	**16%**	**15%**	**16%**	**14%**

Washington Clean Energy Transformation Act Required Scenarios

Washington's CETA legislation requires utilities to conduct three scenarios:

- **Alternative Lowest Reasonable Cost** - WAC 480-100-620(10)(a) instructs utilities to "describe the alternative lowest reasonable cost and reasonably available portfolio that the utility would have implemented if not for the requirement to comply" with CETA's Clean Energy Transformation Standards.

- **Climate Change** - WAC 480-100-620(10)(b) instructs utilities to "incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change."

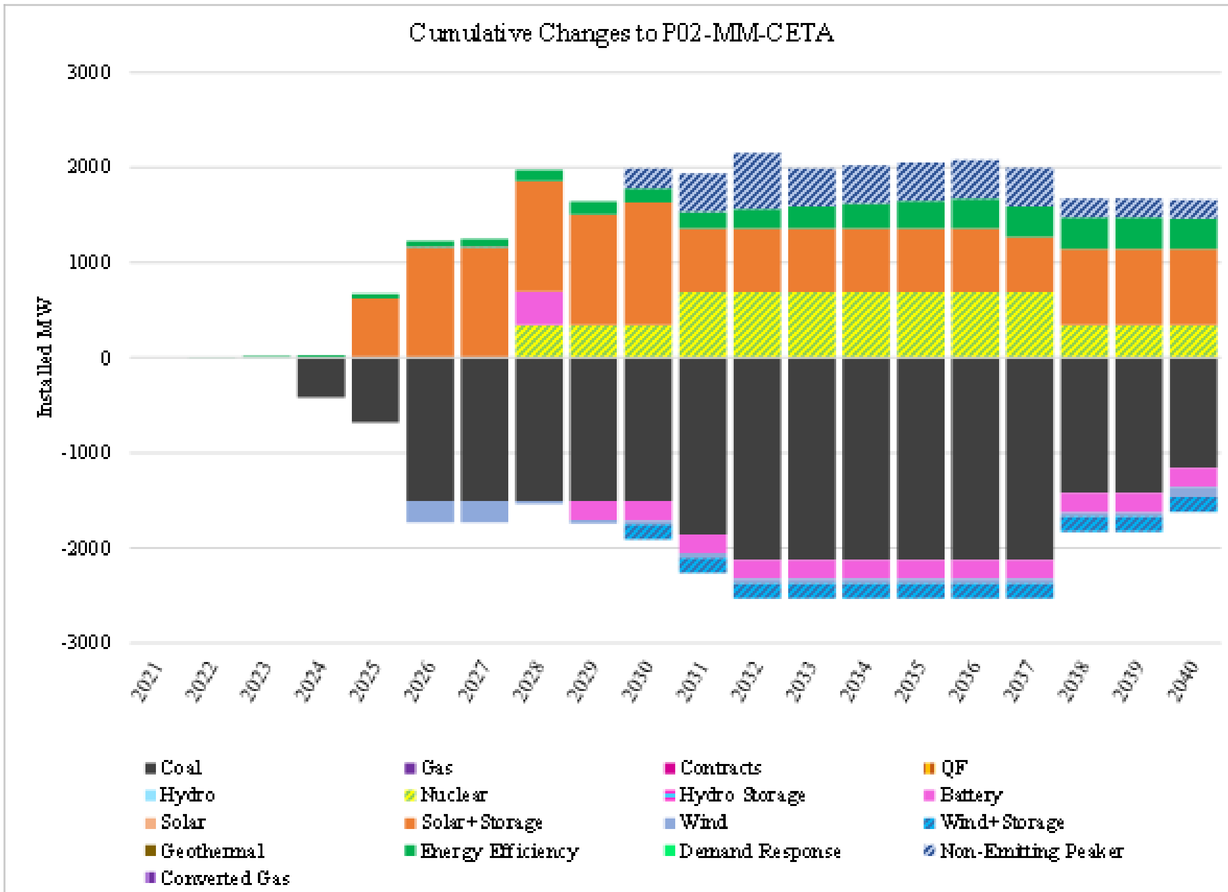
- **Maximum Customer Benefit** - WAC 480-100-620(10)(c) instructs utilities to "model the maximum amount of customer benefits described in RCW 19.405.040(8) prior to balancing against other goals."

In this section, PacifiCorp discusses each of these portfolio outcomes relative to the preferred portfolio P02-MM-CETA. Note, that the Alternative Lowest Reasonable Cost scenario is also discussed relative to the P02-MM portfolio.

Alternative Lowest Reasonable Cost

WAC 480-100-620(10)(a) instructs utilities to "describe the alternative lowest reasonable cost and reasonably available portfolio that the utility would have implemented if not for the requirement to comply" with CETA's Clean Energy Transformation Standards and must include the social cost of greenhouse gases (SCGHG) in the resource acquisition decision. In the absence of a requirement to assume SCGHG during portfolio development, the alternative lowest reasonable cost portfolio is P02-MM, and what we would have implemented but for CETA requirements. The preferred portfolio, P02-MM-CETA, adds a present value revenue requirement of $164m compared to P02-MM to meet CETA requirements. Accounting for the requirement to include the SCGHG price-policy assumption in portfolio development, the alternate scenario becomes the same as an SCGHG portfolio run under the medium gas, medium CO_2 price-policy scenario. Comparing this Alternative Lowest Reasonable Cost case to the preferred portfolio (P02-MM-CETA) yields a PVRR(d) system cost of $182m.

Figure 9.47 – Cumulative Portfolio Resource Changes P02-SCGHG Compared to the 2021 IRP Preferred Portfolio

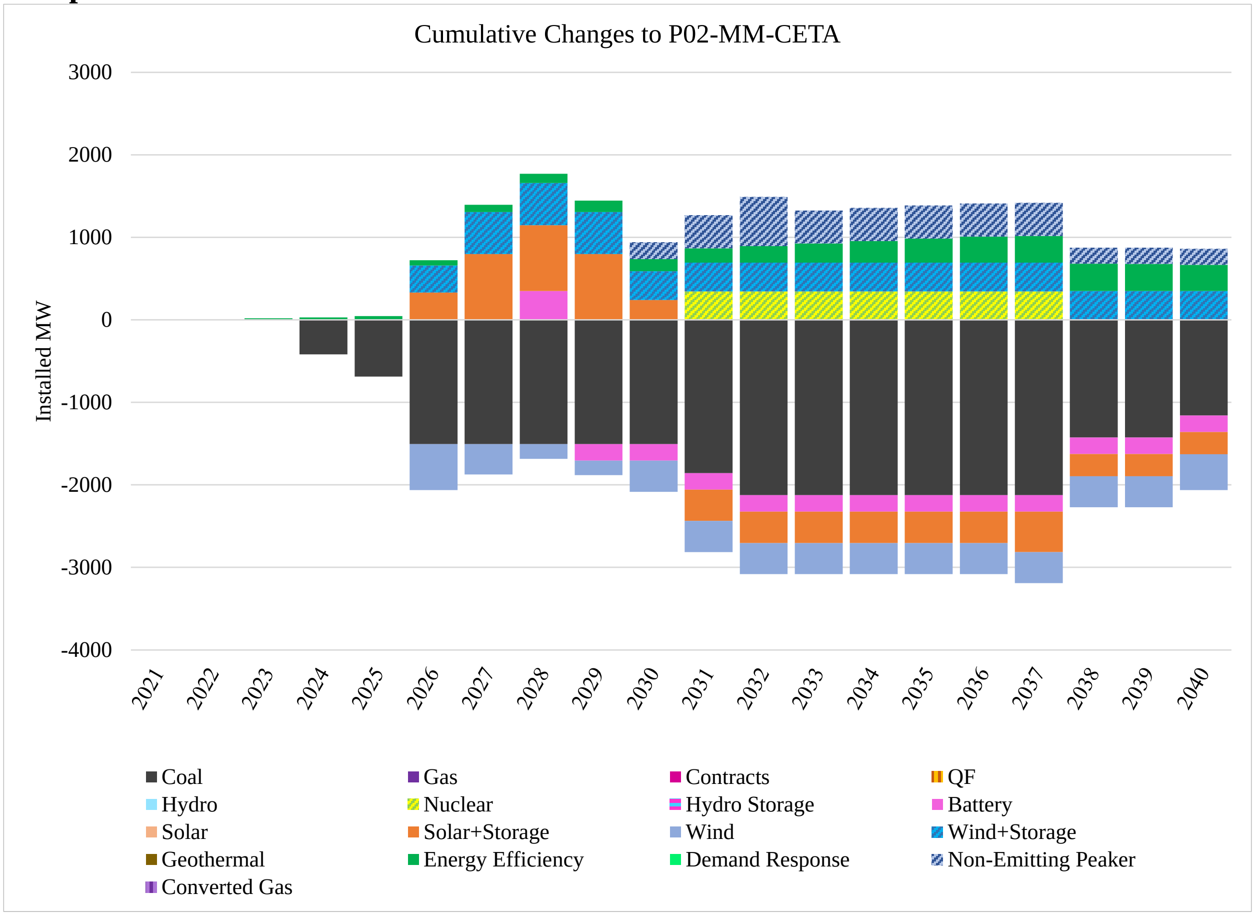


Climate Change

The Washington climate change scenario includes an updated load forecast to incorporate regional studies on potential temperature change (and associated impact to demand and energy). Relative to the 2021 IRP forecast, the climate change scenario results in summer peaks being higher by approximately 50 MW (<1% higher) over the 2021-2025 timeframe. By 2040, summer peaks are projected to be 318 MW (2.7%) higher than the 2021 IRP Base. Higher winter temperatures result in less heating load, which are driving lower winter peaks. By 2040, winter peaks are projected to be 259 MW (2.3%) lower than the 2021 IRP Base. Please see Appendix A for additional detail regarding the climate change scenario.

The scenario also includes analysis of impacts from climate change (precipitation, streamflow, etc.) on Lewis River hydroelectric generating facilities, resulting in a reduction of approximately 7% in energy production, relative to the 2021 IRP base. Compared to the preferred portfolio, the climate change scenario increases system costs by $14.6 billion, driven in large part by the SCGHG price-policy assumption.

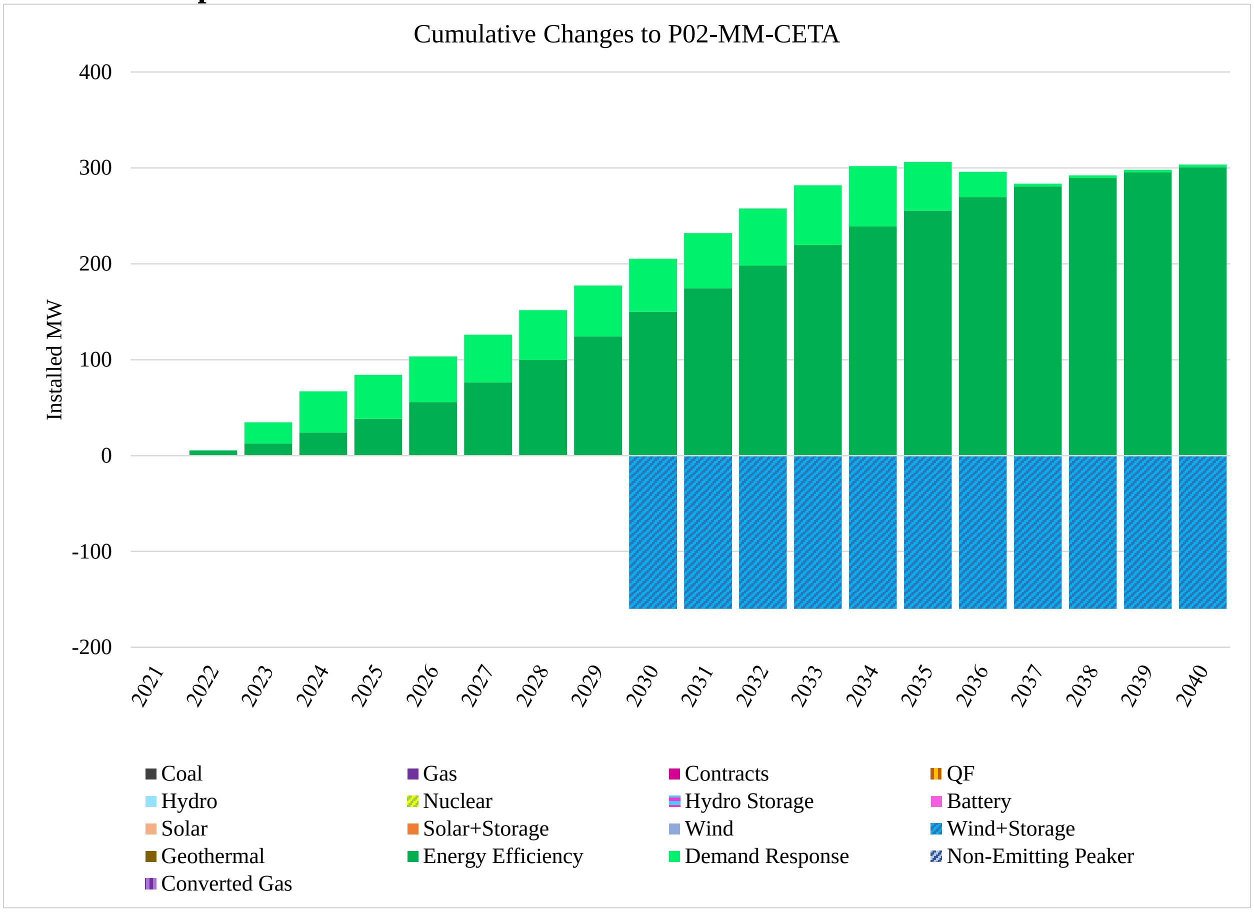
Figure 9.48 – Cumulative Portfolio Resource Changes, Climate Change Portfolio Compared to the 2021 IRP Preferred Portfolio



Maximum Customer Benefit

The maximum customer benefit scenario focuses on adding distributed generation, demand response, and energy efficiency in Washington, as well as avoiding high-voltage transmission upgrades in PacifiCorp's Yakima and Walla Walla communities to minimize burdens and maximize benefits to Washington customers. Washington load forecast reflects the high private generation forecast. The portfolio assumes the social cost of greenhouse gas price-policy scenario, and includes all available Washington energy efficiency and demand response. 335 MW of needed Yakima resource is assumed to be small scale PVS, adjusting operating costs and mitigating transmission costs. Due to higher DSM selections, it was not necessary to create a hybrid Yakima resource by adding 160 MW of co-located wind to the selected PVS resource in year 2030. As a result, a 160 MW reduction in wind capacity is visible in the cumulative changes graph beginning 2030 relative to the preferred portfolio. The Maximum customer benefits sensitivity increases costs by $16.9 billion relative to the preferred portfolio, driven primarily by the SCGHG price-policy assumption and the inclusion of all available DSM.

Figure 9.49 – Cumulative Portfolio Resource Changes, Maximum Customer Benefit Portfolio Compared to the 2021 IRP Preferred Portfolio



Additional Sensitivity Analysis

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

Table 9.20 lists additional sensitivity studies to be performed for the 2021 IRP. To isolate the impact of a given planning assumption, all sensitivity cases will be evaluated as a variant of the BAU1 and BAU2 portfolios along with the preferred portfolio (P02-MM-CETA).

Table 9.20 – Summary of Additional Sensitivity Cases

Case	Description	Risk-Adjusted PVRR ($m)	Load	Private Gen	CO_2 Policy
S-01	High Load		High	Base	Medium gas / Medium CO_2
S-02	Low Load		Low	Base	Medium gas / Medium CO_2
S-03	1 in 20 Load Growth		1 in 20	Base	Medium gas / Medium CO_2
S-04	New Proxy Gas Allowed		Base	Base	Medium gas / Medium CO_2
S-05	Business Plan		Base	Base	Medium gas / Medium CO_2
S-06	Levelized Cost of Energy Efficiency Bundles		Base	Base	Medium gas / Medium CO_2
S-07	High Private Generation		Base	High	Medium gas / Medium CO_2
S-08	Low Private Generation		Base	Low	Medium gas / Medium CO_2

PacifiCorp will file a supplemental filing to its 2021 IRP filing that includes discussion and results of these sensitivities. The supplemental filing will also be posted to PacifiCorp's IRP webpage at the following location: www.pacificorp.com/energy/integrated-resource-plan.

CHAPTER 10 – ACTION PLAN

CHAPTER HIGHLIGHTS

- The 2021 Integrated Resource Plan (IRP) action plan identifies steps that PacifiCorp will take over the next two-to-four years to deliver resources in the preferred portfolio.
- PacifiCorp's 2021 IRP action plan includes action items for existing resources, new resources, transmission, demand-side management (DSM) resources, short-term firm market purchases, and the purchase and sale of renewable energy credits (RECs).
- The 2021 IRP acquisition path analysis provides insight on how changes in the planning environment might influence future resource procurement activities. Key uncertainties addressed in the acquisition path analysis include load, private generation, changes in available resources, and carbon dioxide (CO_2) emission polices.
- PacifiCorp further discusses how it can mitigate procurement delay risk, summarizes planned procurement activities tied to the action plan, assesses trade-offs between owning or purchasing third-party power, discusses its hedging practices, and identifies the types of risks borne by customers and the types of risks borne by shareholders.

Introduction

PacifiCorp's 2021 IRP action plan identifies the steps the company will take over the next two-to-four years to deliver its preferred portfolio, with a focus on the front ten years of the planning horizon. Associated with the action plan is an acquisition path analysis that anticipates potential major regulatory actions and other trigger events during the action plan time frame that could materially impact resource acquisition strategies.

The 2021 IRP action plan is based on the latest and most accurate information available at the time portfolios are being developed and analyzed on cost and risk metrics. PacifiCorp recognizes that the preferred portfolio, upon which the action plan is based, is developed in an uncertain and evolving planning environment and that resource acquisition strategies need to be regularly evaluated as planning assumptions change.

Resource information used in the 2021 IRP, such as capital and operating costs, are based upon recent cost-and-performance data. However, it is important to recognize that resources identified in the plan include proxy resources, which act as a guide for resource procurement and not as a commitment. Resources evaluated as part of procurement initiatives may vary from the proxy resources identified in the plan with respect to resource type, timing, size, cost, and location.

PacifiCorp recognizes the need to support and justify resource acquisitions consistent with then-current laws, regulatory rules and requirements, and commission orders.

In addition to presenting the 2021 IRP action plan, reporting on progress in delivering the prior action plan, and presenting the 2021 IRP acquisition path analysis, this chapter also includes discussion of the following resource procurement topics:

- Procurement delays;
- IRP action plan linkage to the business plan;
- Resource procurement strategy;

- Assessment of owning assets vs. purchasing power;
- Managing carbon risk for existing plants;
- Purpose of hedging; and
- Treatment of customer and investor risks.

The 2021 IRP Action Plan

The 2021 IRP action plan identifies specific actions PacifiCorp will take over roughly the next two-to-four years to deliver its preferred portfolio. Action items are based on the size, type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2021 IRP public-input process. Table 10.1 details specific 2021 IRP action items by resource category.

Table 10.1 – 2021 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	**<u>Colstrip Units 3 and 4:</u>** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2021 IRP preferred portfolio target exit date of December 31, 2025.
1b	**<u>Craig Unit 1:</u>** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2021 IRP preferred portfolio target exit date of December 31, 2025.
1b	**<u>Naughton Units 1 and 2:</u>** • PacifiCorp will initiate the process of retiring Naughton Units 1-2 by the end of December 2025, including completion of all required regulatory notices and filings. • By the end of Q2 2023, PacifiCorp will confirm transmission system reliability assessment and year-end 2025 retirement economics in 2023 IRP filing. • By the end of Q4 2023, PacifiCorp will initiate the process with the Wyoming Public Service Commission for approval of a reverse request for proposals for a potential sale of Naughton Units 1 and 2. • By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements.

1c	**<u>Jim Bridger Units 1 and 2 Gas Conversion:</u>** • PacifiCorp will initiate the process of ending coal-fueled operations and seeking permitting for a natural-gas conversion by 2024, including completion of all required regulatory notices and filings. • By the end of Q2 2022, PacifiCorp will finalize an employee transition plan. • By the end of Q2 2022, PacifiCorp will develop a community action plan in coordination with community leaders. • By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements. • By the end of Q4, 2023, PacifiCorp will remove units 1 and 2 from Washington's allocation of electricity.
1d	**<u>Carbon Capture, Utilization, and Sequestration/Wyoming House Bill 200 Compliance:</u>** • PacifiCorp issued a carbon capture, utilization, and sequestration (CCUS) request for expression of interest (REOI) on June 29, 2021. PacifiCorp will complete the 2021 CCUS REOI process and utilize any new relevant information. Additional model sensitivities will be run accordingly. • PacifiCorp will issue a CCUS Request for Proposals (RFP) in 2022. The 2021 CCUS REOI responses will inform the scope of the CCUS RFP. • A completed CCUS Front End Engineering & Design Study (FEED Study) based on a new CCUS technology was submitted to PacifiCorp in July 2021 for Dave Johnston Unit 2. Third-party review of the FEED Study will be completed by Q1 2022, and model sensitivities will subsequently be run as needed, with FEED Study assumptions and inputs as appropriate. • Subject to finalization of rules by the Wyoming Public Service Commission (WPSC) to implement House Bill 200 (HB 200), the Wyoming Low Carbon Energy Standard (anticipated by Q4 2021), by March 31, 2022, PacifiCorp will file with the WPSC an initial CCUS application to establish intermediate CCUS standards and requirements. • Subject to finalization of rules by the WPSC to implement HB 200, the Wyoming Low Carbon Energy Standard (anticipated by Q4 2021), PacifiCorp will submit for WPSC approval a final plan with its proposed energy portfolio standard for dispatchable and reliable low-carbon electricity, its plan for achieving the standard, and a target date of no later than July 1, 2030.

1e	**<u>Regional Haze Compliance:</u>** • Following the resolution of first planning period regional haze compliance disputes, and the submission of second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the Environmental Protection Agency, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.
Action Item	**2. New Resource Actions**
2a	**<u>Customer Preference Request for Proposals:</u>** • Consistent with Utah Community Renewable Energy Act, PacifiCorp continues to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp anticipates filing an application for approval of the program with the Utah Public Service Commission in 2022, which may necessitate issuance of a request for proposals to procure resources within the action plan window.
2b	**<u>Acquisition and Repowering of Foote Creek II-IV and Rock River I:</u>** • In Q3 2021, PacifiCorp will pursue necessary regulatory approvals to authorize the acquisition and repowering of Foote Creek II-IV in order to issue repowering contracts in Q1 2022 in support of a late 2023 in-service date. • In Q1 2022, PacifiCorp will pursue necessary regulatory approvals to authorize the acquisition and repowering of Rock River I following the expiration of the existing power purchase agreement in order to issue repowering contracts in Q3 2022 to support a late 2024 in-service date.
2c	**<u>Natrium™ Demonstration Project:</u>** • PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable. • By the end of 2022, PacifiCorp will finalize commercial agreements for the Natrium™ project. • Q1 2022, PacifiCorp will develop a community action plan in coordination with community leaders. • By 2025, PacifiCorp will begin training operators. • PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable, including, but not limited to, a request for the Oregon Public Utility Commission to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.

2d	**<u>2022 All-Source Request for Proposals:</u>** • PacifiCorp will issue an all-source Request for Proposals (RFP) to procure resources that can achieve commercial operations by the end of December 2026. • In September 2021, PacifiCorp will notify the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, of PacifiCorp's need for an independent evaluator. • In October 2021, PacifiCorp will file a draft all-source RFP with applicable state utility commissions. • In January 2022, PacifiCorp expects to receive approval of the all-source RFP from applicable state utility commissions and issue the RFP to the market. • In Q2 2022, PacifiCorp will identify an initial shortlist in advance of annual Cluster Request Window. • In Q1 2023, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon, file, certificate of public convenience and necessity (CPCN) applications, as applicable. • By Q2 2023 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • By Q4 2025-2026, winning bids from the all-source RFP are expected to achieve commercial operation. Resources must have commercial operation date of December 31, 2026, or earlier.
2e	**<u>2020 All-Source Request for Proposals:</u>** • PacifiCorp filed for approval of the final shortlist in Oregon in June 2021. • In September 2021, PacifiCorp will file CPCN applications in Wyoming, as applicable, for final shortlist. • In Q4 2021, PacifiCorp will make a filing in Utah for significant energy resources on final shortlist.
Action Item	**3. Transmission Action Items**
3a	**<u>Energy Gateway South Segment F (Aeolus-Clover 500 kV transmission line):</u>** • By Q2 2022, obtain Utah and Wyoming Certificates of Public Convenance and Necessity. • By the end of Q1 2022, Bureau of Land Management notice to proceed to construct Energy Gateway South. • In Q3 2024, construction of Energy Gateway South is expected to be completed and placed in service.
3b	**<u>Energy Gateway West, Segment D.1 (Windstar-Shirley Basin 230 kV transmission line):</u>** • By Q2 2022, obtain conditional Wyoming Certificate of Public Convenance and Necessity • By Q3 2022 complete ROW easement acquisition and option full Wyoming CPCN • In Q3 2024, construction of Energy Gateway West segment D.1 to be completed and placed in service.

3c	**<u>Boardman-to-Hemingway (500 kV transmission line):</u>** • Continue to support the project under the conditions of the Boardman-to-Hemingway Transmission Project (B2H) Joint Permit Funding Agreement. • Continue to participate in the development and negotiations of the construction agreement. • Continue to participate in "pre-construction" activities in support of the 2026 in-service date. • Continue negotiations for plan of service post B2H for parties to the permitting agreement.
3d	Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids
3e	Continue permitting support for Gateway West segments D.3 and E.
Action Item	**4. Demand-Side Management (DSM) Actions**

<table>
<tr><td>4a</td><td>
<u>Energy Efficiency Targets:</u>

PacifiCorp will acquire cost-effective Class 2 DSM (energy efficiency) resources targeting annual system energy and capacity selections from the preferred portfolio as summarized below. PacifiCorp’s state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2021 IRP.
PacifiCorp will pursue cost-effective energy efficiency resources as summarized in the table below:

<table>
<tr><th>Year</th><th>Annual 1st Year Energy (GWh)</th><th>Annual Incremental Capacity (MW)</th></tr>
<tr><td>2021</td><td>510</td><td>157</td></tr>
<tr><td>2022</td><td>492</td><td>138</td></tr>
<tr><td>2023</td><td>486</td><td>144</td></tr>
<tr><td>2024</td><td>529</td><td>164</td></tr>
</table>

PacifiCorp will pursue cost-effective Class 1 (demand response) resources targeting annual system capacity[1] selections from the preferred portfolio[2] as summarized in the table below:

<table>
<tr><th>Year</th><th>Annual Incremental Capacity (MW)</th></tr>
<tr><td>2021</td><td>0</td></tr>
<tr><td>2022</td><td>123</td></tr>
<tr><td>2023</td><td>242</td></tr>
<tr><td>2024</td><td>184</td></tr>
</table>
[1] Capacity impacts for demand response include both summer and winter impacts within a year.
[2]A portion of cost-effective demand response resources identified in the 2021 preferred portfolio are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2019 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to resources subsequently procured under the previously issued RFP in compliance with state level procurement requirements.
</td></tr>
<tr><td>Action Item</td><td>5. Market Purchases</td></tr>
</table>

5a	**Market Purchases:** • Acquire short-term firm market purchases for on-peak delivery from 2021-2023 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. • Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. • Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.
Action Item	**6. Renewable Energy Credit (REC) Actions**
6a	**Renewable Portfolio Standards (RPS):** • PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • As needed, issue RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting California RPS targets through 2024.
6b	**Renewable Energy Credit Sales:** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

Progress on Previous Action Plan Items

This section describes progress that has been made on previous action plan items documented in the 2019 IRP filed with state commissions on October 18, 2019. Many of these action items have been superseded in some form by items identified in the 2021 IRP action plan. The status for all action items from the 2019 IRP is summarized in Table 10.2.

Table 10.2 – 2019 IRP Action Plan Status Update

Action Item	3. Existing Resource Actions	Status
1a	**Naughton Unit 3:** • PacifiCorp will complete the gas conversion of Naughton Unit 3, including completion of all required regulatory	This action is complete. PacifiCorp filed an amended certificate of public convenience and necessity (CPCN) notice with the Wyoming Public Service Commission on 11/21/2019. The notice requested a determination that a

	notices and filings, in 2020. Initiate procurement of materials in Q4 2019. Conversion completed in 2020.	CPCN was not required to convert the unit to natural gas. The Commission approved the notice by a letter order issued on 11/27/2019. Gas conversion was complete in July 2020.
1b	**<u>Cholla Unit 4:</u>** • PacifiCorp will initiate the process of retiring Cholla Unit 4, including all required regulatory notices and filings, as soon as practicable, but will remove Cholla Unit 4 from service no later than January 2023 and earlier if possible. • PacifiCorp will continue to coordinate with the plant operator to transition employees, develop plans to cease plant operations, safely remove the unit from service, finalize decommissioning plans and confirm joint-ownership obligations; complete required regulatory notices and filings; administer termination, amendment, or close-out of existing permits, contracts and other agreements; and coordinate with state and local stakeholders as appropriate. • By the end of Q1 2020, the plant operator will be requested to develop plans to cease plant operations, safely remove the unit from service, finalize decommissioning plans, and confirm joint-ownership obligations. • By the end of Q2 2020, the plant operator will be requested to file required transmission interconnection and transmission services unit retirement notices/request for study. • By the end of Q4 2020, PacifiCorp will finalize an employee transition agreement with the plant operator.	Cholla Unit 4 regulatory, compliance, environmental, transmission, permits, operations, and other associated closure communications and requirements were performed throughout 2020. Cholla Unit 4 was retired on 12/31/2020. PacifiCorp continues to work with the operator on joint-owner obligations, transition, and decommissioning plans.

1c	**Jim Bridger Unit 1:** • PacifiCorp will initiate the process of retiring Jim Bridger Unit 1 by the end of December 2023, including completion of all required regulatory notices and filings. By the end of Q2 2020, file a request with PacifiCorp transmission to study the year-end 2023 retirement of Jim Bridger Unit 1. By the end of Q2 2021, confirm transmission system reliability assessment and year-end 2023 retirement economics in 2021 IRP filing. • By the end of Q2 2021, finalize an employee transition plan. • By the end of Q2 2021, develop a community action plan in coordination with community leaders. • By the end of Q4 2021, initiate the process with the Wyoming Public Service Commission for approval of a reverse request for proposals for a potential sale of Jim Bridger Unit 1. • By the end of Q4 2023, administer termination, amendment, or close-out of existing permits, contracts, and other agreements.	Finalizing plans for the process of retiring Jim Bridger Unit 1 are dependent on the preferred portfolio of the 2021 IRP, which will be filed by September 1, 2021. Jim Bridger regulatory, compliance, environmental, permits, operations, and other associated closure impacts will be addressed as required by state laws. The request to study Jim Bridger Unit 1 retirement was received in Q1 2021 by PacifiCorp transmission. The results are posted to OASIS. The employee transition plan and community action plan are ongoing. The initiation of a process for approval of a reverse request for proposals for potential sale of Jim Bridger 1 is dependent on the preferred portfolio of the 2021 IRP. If the outcome of the 2021 IRP continues to show customer benefits to retire the unit at the end of 2023, PacifiCorp will file an application with the Wyoming Public Service Commission in Q4 2021 to initiate the process to solicit a buyer for the unit, in accordance with the administrative rules adopted by the commission to implement Wyo. Stat. 37-2-133 and 37-3-117.
1d	**Naughton Units 1-2:** • PacifiCorp will initiate the process of retiring Naughton Units 1-2 by the end of December 2025, including completion of all required regulatory notices and filings.	PacifiCorp is proceeding with this action item on schedule. Additional information on this action item is included in the 2021 action plan.

	By the end of Q2 2022, file a request with PacifiCorp transmission to study the year-end 2025 retirement of Naughton Units 1 and 2. • By the end of Q2 2022, finalize an employee transition plan. • By the end of Q2 2022, develop a community action plan in coordination with community leaders. • By the end of Q2 2023, confirm transmission system reliability assessment and year-end 2025 retirement economics in 2023 IRP filing. • By the end of Q4 2023, initiate the process with the Wyoming Public Service Commission for approval of a reverse request for proposals for a potential sale of Naughton Units 1 and 2. • By the end of Q4 2023, administer termination, amendment, or close-out of existing permits, contracts, and other agreements.	
1e	**<u>Craig Unit 1:</u>** • The plant operator will be requested to administer termination, amendment, or close-out of existing permits, contracts, and other agreements to support retiring Craig Unit 1, including completion of all required regulatory notices and filings, by the end of December 2025.	PacifiCorp is proceeding with this action item on schedule.
Action Item	**4. New Resource Actions**	**Status**
2a	**<u>Customer Preference Request for Proposals:</u>** • PacifiCorp will work with customers to achieve their respective resource preference requirements. By the end of Q4 2019, sign a fifteen year 80 megawatt (MW) Power	PacifiCorp signed a long-term 80 MW PPA for six Utah Schedule 34 customers.

	Purchase Agreement (PPA) for Utah solar for six Utah Schedule 34 customers. By the end of Q4 2019, sign two 20-year PPAs of approximately 80 MW for a large Utah Schedule 34 customer. Monitor the finalization of rules by the Public Service Commission of Utah for House Bill (HB) 411 (anticipated by the end of Q1 2020), that provides a path forward for development of a program for participating communities to begin procuring renewable resources.	PacifiCorp signed four long-term PPAs (75 MW, 80 MW, 120 MW & 80 MW) for a large Utah Schedule 34 customer. PacifiCorp signed a long-term 20 MW PPA for a large Utah Schedule 32 customer. Rules for Utah HB 411 were finalized by the Public Service Commission of Utah providing a path forward for development of a program to meet the communities' goals. PacifiCorp is currently working with the consortium of customers to develop the program.
2b	**<u>All Source Request for Proposals:</u>** • PacifiCorp will issue an all-source request for proposals (RFP) to procure resources that can achieve commercial operations by the end of December 2023. • By the end of Q4 2019, file a request for interconnection queue reform with the Federal Energy Regulatory Commission (FERC) and make state filings to initiate the process of identifying an independent evaluator. • In Q1 2020, file a draft all-source RFP with the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, as applicable. • In Q2 2020, receive approval from FERC to reform the interconnection queue. • In Q2 2020, receive approval of the all-source RFP from applicable state regulatory commissions and issue the RFP to the market.	A draft of PacifiCorp's 2020 All-Source RFP ("2020AS RFP") was filed for approval with the Utah PSC and the Oregon PUC in April 2020. In July 2020, the Utah PSC and the Oregon PUC approved the 2020AS RFP, and PacifiCorp issued the 2020AS RFP to market. The 2020AS RFP sought bids for resources capable of coming online by the end of 2024 up to the level of resources identified in PacifiCorp's 2019 IRP. Bids were submitted in August 2020. An initial shortlist was identified in October 2020. The initial shortlist included a total of 6,982 MWs of new generation and storage capacity. Of the total, 5,652 MWs are new generation resources (represented by 3,173 MWs of solar generation and 2,479 MWs of wind generation) and an additional 1,330 MWs of new battery storage assets, which includes 1,130 MWs of solar collocated battery storage and 200 MWs of stand-alone battery storage. The final shortlist of winning bids was filed in Oregon in June 2021. PacifiCorp is finalizing

	• In Q3 2020, identify a preliminary final shortlist from the all-source RFP and initiate transmission interconnection studies consistent with queue reform as approved by FERC. • In Q2 2021, identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon, file, certificate of public convenience and necessity (CPCN) applications, as applicable. • By Q2 2022 execute definitive agreements with winning bids from the all-source RFP. • By Q4 2023, winning bids from the all-source RFP achieve commercial operation.	both build and transfer and power purchase agreement updated drafts that will be forwarded to all final shortlisted participants prior to September 1, 2021. Contract negotiations are expected to proceed into early Q1 2022. All necessary final state regulatory approvals and proceedings are expected to be complete by Q2 2022. On January 31, 2020, as amended March 13, 2020, PacifiCorp submitted revisions to its Open Access Transmission Tariff (OATT) to implement revisions to its interconnection process. PacifiCorp proposed revisions to its Large Generator Interconnection Procedures, Small Generator Interconnection Procedures, and associated appendices, including the Large Generator Interconnection Agreement and Small Generator Interconnection Agreement. On May 12, 2020, the FERC issued an order accepting the proposed Tariff revisions, subject to condition. As a result of the acceptance, PacifiCorp's interconnection process changed from a serial, first =-come, first-served process, to a first-ready, first-served interconnection process. The prospective interconnection processes use cluster studies, under which interconnection requests received during an annual "Cluster Request Window" are studied in groups (as opposed to serially and individually). The revised interconnection process should allow commercially-ready projects to proceed on a more accelerated basis while allowing less-developed projects to have access to non-binding estimates of cost responsibility and time to construct to assist with preliminary siting decisions.

<table>
<tr><th>Action Item</th><th>3. Transmission Action Items</th><th></th></tr>
<tr><td>3a</td><td><u>Energy Gateway South:</u>
By December 31, 2023, PacifiCorp will seek to build the approximately 400-mile, 500-kilovolt (kV) transmission line from the Aeolus substation near Medicine Bow, Wyoming to the Clover substation near Mona, Utah.
By Q2 2021, receive the final CPCN from the Wyoming Public Service Commission and the Public Service Commission of Utah (initial filing dates for the CPCN to be determined after stakeholder engagement).
By the end of Q4 2021, issue full notice to proceed to construct Energy Gateway South.
In Q4 2023, construction of Energy Gateway South is completed and placed in service.</td><td>Energy Gateway South has been moved to a target in-service date of Q4 2024.

This action item has been superseded by the Energy Gateway South Action in the 2021 action plan.</td></tr>
<tr><td>3b</td><td><u>Utah Valley Reinforcements:</u>
Utah Valley Reinforcements: As necessary to facilitate interconnection of customer-preference resources, PacifiCorp will proceed with system reinforcements in the Utah Valley.
In Q2 2020, complete the Spanish Fork 345 kV/138 kV transformer upgrade.
In Q4 2020, complete rebuild of approximately five miles of the Spanish Fork-Timp138 kV line in the Utah Valley.</td><td>In-service dates have been revised based on current project schedules as follows:
In Q1 2021, PacifiCorp completed the Spanish Fork 345 kV/138 kV transformer upgrade. The completion date for the transformer upgrade was shifted to 2021 due to outage constraints on the line. The remaining scope to complete improvements at a third-party owned substation will be completed in fall 2021.
In Q2 2021, PacifiCorp will complete rebuild of approximately five miles of the Spanish Fork-Timp138 kV line in the Utah Valley. The completion of this project shifted to 2021 due to delays in steel pole deliveries.</td></tr>
</table>

3c	**<u>Northern Utah Reinforcements:</u>** • Rebuild two miles of the Morton Court –Fifth West 138 kV line. • Loop existing Populus Terminal 345 kV line into both Bridger and Ben Lomond; build 345 kV yard with 345/138 transformer and 138 kV yard buildout at Bridger plus ancillary 345 kV and 230 kV circuit breakers at Ben Lomond. • Complete identified plan of service supporting 2019 IRP preferred portfolio for resource additions in northern Utah.	Transmission cluster studies are underway and final short list RFP results will be available no later than June 2021 which could impact final project schedules. The rebuild of two miles of the Morton Court –Fifth West 138 kV line is scheduled for Q4 2023. The project to loop existing Populus Terminal 345 kV line into both Bridger and Ben Lomond; build 345 kV yard with 345/138 transformer and 138 kV yard buildout at Bridger plus ancillary 345 kV and 230 kV circuit breakers at Ben Lomond is now scheduled for Q4 2023.
3d	**<u>Utah South Reinforcements:</u>** • Develop plan of service in support of 2019 IRP preferred portfolio for resource additions in southern Utah. • Complete rebuild of the Mona –Clover #1 & #2 345 kV lines. • Identify route and terminals for new approximately 70-mile 345 kV line in southern/central Utah. • Yakima Washington Reinforcements: To facilitate interconnection of preferred portfolio resources in the Yakima area, PacifiCorp will proceed with protection system and remedial action scheme upgrades to local 230 kV and 115 kV substations not otherwise included in network upgrade requirements for generator interconnection requests. • In Q2 2020, complete the Vantage-Pomona Heights 230 kV line (in process).	In-service dates have been revised based on current project schedules. Cluster studies continue and final short list RFP results will be available no later than June 2021 which could impact final project schedules. Washington action items are addressed in PacifiCorp's response to item 3e below. In Q3 2024 PacifiCorp is scheduled complete rebuild of the Mona –Clover #1 & #2 345 kV lines. In Q2 2026 PacifiCorp is scheduled to identify route and terminals for new approximately 70-mile 345 kV line in southern/central Utah.

	• By Q2 2022, establish the type and location of new resources and finalize project scope, as necessary.	
3e	**<u>Yakima Washington Reinforcements:</u>** • To facilitate interconnection of preferred portfolio resources in the Yakima area, PacifiCorp will proceed with protection system and remedial action scheme upgrades to local 230 kV and 115 kV substations not otherwise included in network upgrade requirements for generator interconnection requests. • In Q2 2020, complete the Vantage-Pomona Heights 230 kV line (in process). • By Q2 2022, establish the type and location of new resources and finalize project scope, as necessary.	The cluster studies are underway and final short list RFP results will be available no later than June 2021 which could impact final project schedules. The Vantage-Pomona Heights 230kV line was completed in Q3 2020.
3f	**<u>Boardman to Hemmingway:</u>** • Continue to support the project under the conditions of the Boardman to Hemingway Transmission Project (B2H) Joint Permit Funding Agreement. • Continue to participate in the development and negotiations of the construction agreement. • Continue analysis in efforts to identify customer benefits that may include contributions to reliability, interconnection of additional resources, geographical diversity of intermittent resources, Energy Imbalance Market, and resource adequacy. • Continue negotiations for plan of service post B2H for parties to the permitting agreement.	Negotiations with partners are ongoing. PacifiCorp continues to study this transmission segment as part of its 2021 IRP.
3g	**<u>Energy Gateway West:</u>**	Energy Gateway West Segment D.2 was completed in Q4 2020. The other action items remain on schedule.

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- Energy Gateway West Segment D.2, continue construction with target in-service date of 12/31/2020.
- Continue permitting for the Energy Gateway transmission plan, with near term targets as follows:
- For Segments D.3, and E, continue funding of the required federal agency permitting environmental consultant actions required as part of the federal permits. Also, continue to support the projects by providing information and participating in public outreach.

</td><td>This action item has been superseded by the Energy Gateway West Action in the 2021 action plan.</td></tr>
<tr><th>Action Item</th><th>4. Demand-Side Management (DSM) Actions</th><th>Status</th></tr>
<tr><td>4a</td><td>

<u>Energy Efficiency Targets:</u>

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

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

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

- Energy Efficiency Bundling: PacifiCorp will continue to evaluate alternate bundling methodologies of Class 2 DSM in the 2019 IRP.
- Direct-Load Control: PacifiCorp will acquire cost-effective Class 1 DSM (i.e., demand response) in Utah

</td><td>

In October 2020, the Utah PSC approved a new Wattsmart battery demand response program. With the addition of this new program and program modifications occurring with Cool Keeper and Irrigation Load Control, the Company is currently on track to achieve the incremental capacity.

Energy Efficiency Targets

2019 reporting indicates the company acquired 506 GWh of energy efficiency system wide. This equates to 113 MW of capacity reductions.

Preliminary 2020 reporting indicates the company acquired 561 GWh of energy efficiency system wide. This equates to 138 MW of capacity reductions.

</td></tr>
</table>

	targeting approximately 29 MW of incremental capacity from 2020 through 2023.	Coupling preliminary 2020 reporting with 2019 actuals, acquired 1,067 GWh of energy efficiency over the two years. This equates to capacity reductions of 251 MW (using the same GWh/MW relationship) PacifiCorp continues to evaluate alternative bundling methodologies as part of the 2021 IRP process, and presented its methodology at the January 29, 2021 IRP public-input meeting. At the end of January 2021, PacifiCorp issued a demand response RFP to identify the potential acquisition of cost-effective flexible capacity. The final shortlist of bids was identified in June 2021 and includes over 600 MW of capacity during the planning horizon. PacifiCorp is finalizing the procurement and negotiation of demand response resources following the completion of 2021 IRP. Contract negotiations and program filings are expected to conclude in Q4 of 2021. All necessary state regulatory approvals and proceedings are expected to be complete in the winter and spring of 2022.
Action Item	**5. Front Office Transactions**	**Status**
5a	**<u>Market Purchases:</u>** • Acquire short-term firm market purchases for on-peak delivery from 2019-2021 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term	Market purchases, inclusive of day-ahead, balance of month, prompt, and forward hedging transactions, but not accounting for any offsetting hedging sales, were made for on peak delivery in the following periods and at the following quantities:

	firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. • Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. • Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.	2019: 350 to 2561 MW 2020: 650 to 2720 MW 2021: 125 to 1150 MW Market purchases are made in accordance with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices and include a mix of the transaction types identified in item 5a.
Action Item	**6. Renewable Energy Credit Actions**	**Status**
6a	**<u>Renewable Portfolio Standards (RPS):</u>** • PacifiCorp will pursue unbundled RFPs to meet its state RPS compliance requirements. • As needed, issue RFPs seeking then current-year vintage unbundled RECs that will qualify in meeting California RPS targets through 2020. As needed, issue RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting Washington RPS targets.	PacifiCorp will continue to evaluate the need for unbundled RECs and issue RFPs to meet its state RPS compliance requirements as needed for both California and Washington. Most recently, PacifiCorp issued an RFP for RECs in 2019 to meet its state RPS compliance requirements.
6b	**<u>Renewable Energy Credit Sales:</u>** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.	PacifiCorp issued reverse RFPs in April 2019, March 2020, and February 2021. PacifiCorp will continue to engage in bilateral REC sales and issue reverse RFPs to maximize the sale of RECs that are not required to meet state RPS compliance obligations.

Acquisition Path Analysis

Resource and Compliance Strategies

PacifiCorp worked with stakeholders to define its portfolio development process and cost and risk analysis in the 2021 IRP. This analysis reflects a combination of specific planning assumptions related to key uncertainties addressed in the acquisition path analysis include load, private generation, changes in available resources, and CO_2 emission polices. PacifiCorp will further analyze sensitivity cases on planning assumptions related primarily to the load forecasts and private generation penetration levels. The array of planning assumptions that define the studies used to develop resource portfolios provides the framework for a resource acquisition path analysis by evaluating how resource selections are impacted by changes to planning assumptions.

Given current load expectations, portfolio modeling performed for the 2021 IRP shows the resource acquisition path in the preferred portfolio is robust among a wide range of policy and market conditions, particularly in the near-term, when cost-effective renewable resources that qualify for federal income tax credits, market purchases, and energy efficiency and demand response resources are consistently selected. Further, the procurement processes associated with these resource actions are well underway. With regard to renewable resource acquisition, the portfolio development modeling performed in the 2021 IRP shows that new renewable resource needs are driven primarily by economics and reliability. Beyond load, CO_2 policy also influences resource selections in the 2021 IRP. For these reasons, the acquisition path analysis focuses on economic, load, reliability, and environmental policy trigger events that would require alternative resource acquisition strategies. For each trigger event, PacifiCorp identifies the planning scenario assumption affecting both short-term (2021-2030) and long-term (2031-2040) resource strategies.

Acquisition Path Decision Mechanism

The Public Service Commission of Utah requires that PacifiCorp provide "[a] plan of different resource acquisition paths with a decision mechanism to select among and modify as the future unfolds."[1] PacifiCorp's decision mechanism is centered on the IRP process and ongoing updates to the IRP modeling tools between IRP cycles. The same modeling tools used in the IRP are also used to evaluate and inform the procurement of resources. The IRP models are used on a macro-level to evaluate alternative portfolios and futures as part of the IRP process, and then on a micro-level to evaluate the economics and system benefits of individual resources as part of the supply-side resource procurement and demand-side management target-setting/valuation processes. PacifiCorp uses the IRP development process, and the IRP modeling tools to serve as decision support tools to guide prudent resource acquisition paths that maintain system reliability at a reasonable cost. Table 10.3 summarizes PacifiCorp's 2021 IRP acquisition path analysis, which provides insight on how changes in the planning environment might influence future resource procurement activities. Changes in procurement activities driven by changes in the planning environment will ultimately be reflected in future IRPs and resource procurement decisions.

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

Table 10.3 – Near-term and Long-term Resource Acquisition Paths

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2021-2030)	Long Term Resource Acquisition Strategy (2031-2040)
Higher sustained load growth	High economic drivers accounting for 95% prediction interval.	• In 2026, there is an increase of 5 percent higher sustained load growth than the base case forecast, resulting in an increase in peak capacity requirements of 545 MW increasing further to nearly 600 MW in 2030. • Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • The higher peak capacity requirements relative to the base case forecast results in additional resource need, increased market reliance and/or shifts in timing of planned resources or coal unit retirements.	• In 2040, there is an increase of 7 percent higher sustained load growth than the base case forecast, resulting in an increase in peak capacity requirements of 890 MW. • The higher peak capacity requirements relative to the base case forecast results in additional resource need, increased market reliance and/or shifts in timing of planned resources or coal unit retirements.
Lower sustained load growth	Low economic drivers accounting for 95% prediction interval.	• In 2026, there is 6 percent lower sustained load growth than the base case forecast, resulting in a decrease in peak capacity requirements of 628 MW decreasing further 861 MW in 2030. • Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • The lower peak capacity requirements relative to the base case forecast results in a reduction in resource need, decreased market reliance and/or shifts in timing of planned resources or coal unit retirements.	• In 2040, there is a 7 percent lower sustained load growth than the base case forecast, resulting in a decrease in peak capacity requirements of 890 MW. • The lower peak capacity requirements relative to the base case forecast results in a reduction in resource need, decreased market reliance and/or shifts in timing of planned resources or coal unit retirements.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2021-2030)	Long Term Resource Acquisition Strategy (2031-2040)
Higher sustained private generation penetration levels	More aggressive technology cost reductions, improved technology performance, and higher electricity retail rates	• In 2026, peak capacity requirements are lower by 53 MW due to higher sustained private generation levels relative to the base case forecast. • In 2030, peak capacity requirements are lower by 249 MW due to higher sustained private generation levels relative to the base case forecast. • Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Small changes to the portfolio would require minimal changes to the resource acquisition strategy.	• In 2040, peak capacity requirements are lower by 172 MW due to higher sustained private generation levels relative to the base case forecast. • Small changes to the portfolio would require minimal changes to the resource acquisition strategy. • Timing differences in resource capacity would need to be assessed in procurement processes to achieve the appropriate balance of energy and capacity.
Lower sustained private generation penetration levels	Less aggressive technology cost reductions, reduced technology performance, and lower electricity retail rates	• In 2026, peak capacity requirements are higher by 31 MW due to lower sustained private generation levels relative to the base case forecast. • In 2030, peak capacity requirements are higher by 61 MW due to lower sustained private generation levels relative to the base case forecast. • Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Small changes to the portfolio would require minimal changes to the resource acquisition strategy.	• In 2040, peak capacity requirements are higher by 342 MW due to lower sustained private generation levels relative to the base case forecast. • Timing differences in resource capacity would need to be assessed in procurement processes to achieve the appropriate balance of energy and capacity.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2021-2030)	Long Term Resource Acquisition Strategy (2031-2040)
High CO_2 prices with accelerated coal retirements	Fossil-fired generation is faced with a high CO_2 price beginning in 2025 at $22.57/ton and reaching $102.48/ton by 2040 that drives all coal to be retired by 2030	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Accelerate timing of new resource additions including an advanced nuclear resource from 2038 to 2030 and 1,009 MW of solar co-located with storage from 2037 to 2024 through 2028 with an additional 330 MW added over that time period. Accelerate a non-emitting peaking unit from 2040 to 2030 with two additional non-emitting peaking units added in that year. • Increase procurement of market purchases with the potential for accelerated coal retirements. • Increase procurement of energy efficiency: energy efficiency capacity is accelerated and increases by 108 MW by 2030.	• Through 2040, new non-emitting peaking capacity is increased by 412 MW. • Through 2040, energy efficiency is increased by 111 MW and solar co-located with solar capacity is increased by over 330 MW. • Through 2040, market purchases increase by an average of 381 MW.
No Natrium™ Advanced Nuclear Demonstration Project in 2028	See Volume 1, Chapter 9, Modeling and Portfolio Selection Results, P02e-No Nuc portfolio	• Without the NatriumTM demonstration project, 348 MW of solar co-located with storage is added to the portfolio in 2026 and an additional 240 MW is added in 2030. • Higher costs and emissions result from increased fossil-fueled generation, emissions and net market transactions.	• In 2037, a non-emitting peaker displaces solar co-located with storagesolar co-located with storage resource capacity.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2021-2030)	Long Term Resource Acquisition Strategy (2031-2040)
No Boardman-to-Hemingway (B2H) transmission segment in 2026	See Volume 1, Chapter 9, Modeling and Portfolio Selection Results, P02b-No B2H portfolio	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Without B2H, 405 MW of wind and 200 MW of solar co-located with storage is removed from the portfolio in 2026. Approximately 200 MW of storage capacity is removed from eastern Wyoming in 2029, which must be replaced by just over 200 MW of non-emitting peaking capacity in 2030. • A reduction in resources results in increased reliance on the market and higher emissions from an increase in coal and gas generation. • Reduced flexibility and load-serving capability of the transmission system.	• 725 MW of incremental 4-hour battery resources and other transmission upgrades would be needed in southern Oregon if the B2H transmission line is not built.

Procurement Delays

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

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

- In circumstances where PacifiCorp is engaged in an active RFP where a specific bidder is unable to perform, alternative bids can be pursued.
- PacifiCorp can issue an emergency RFP for a specific resource and with specified availability.
- PacifiCorp can seek to negotiate an accelerated delivery date of a potential resource with the supplier/developer.

- PacifiCorp can seek to procure near-term purchased power and transmission until a longer-term alternative is identified, acquired through customized market RFPs, exchange transactions, brokered transactions or bi-lateral, sole source procurement.
- Accelerate acquisition timelines for direct load control programs.
- Procure and install temporary generators to address some or all of the capacity needs.
- Temporarily drop below its planning reserve margin.
- Implement load control initiatives, including calls for load curtailment via existing load curtailment contracts.

IRP Action Plan Linkage to Business Planning

The 2021 IRP includes a sensitivity that complies with the Utah requirement to perform a business plan sensitivity case consistent with the commission's order in Docket No. 15-035-04. This order sets forth the following parameters for this sensitivity case:

- Over the first three years, resources align with those assumed in PacifiCorp's December 2020 Business Plan.
- Beyond the first three years of the study period, unit retirement assumptions are aligned with the preferred portfolio.
- All other resources are optimized.

PacifiCorp will file a supplemental filing to its 2021 IRP filing that includes discussion and results of the sensitivities outlined in Volume I, Chapter 9 – Modeling and Portfolio Selection Results, including a discussion of this business plan sensitivity case summarizing portfolio differences between the business plan sensitivity case and the 2021 IRP preferred portfolio, including changes to the resource mix, present value revenue requirement of system costs, and implications on the near-term action plan. The supplemental filing will also be posted to PacifiCorp's IRP webpage at the following location: www.pacificorp.com/energy/integrated-resource-plan.

Resource Procurement Strategy

To acquire resources outlined in the 2021 IRP action plan, PacifiCorp intends to continue using competitive solicitation processes in accordance with applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. PacifiCorp will also continue to pursue opportunistic acquisitions identified outside of a competitive procurement process that provide economic benefits to customers. Regardless of the method for acquiring resources, PacifiCorp will support its resource procurement activities with the appropriate financial analysis using then-current assumptions for inputs such as load forecasts, commodity prices, resource costs, and policy developments. Any such financial analysis will account for any applicable long-term system benefits with least-cost, least-risk planning principles in mind. The sections below profile the general procurement approaches for the key resource categories covered in the 2021 IRP action plan.

Renewable Resources, Storage Resources, and Dispatchable Resources

PacifiCorp will use a competitive RFPs to procure supply-side resources consistent applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. In Oregon and Utah, these state requirements involve the oversight of an independent evaluator. In Washington, an independent evaluator may be used if benchmark resources (PacifiCorp built and owned resources) are being considered after consultation with Washington staff and stakeholders. The all-source RFPs outline the types of resources being pursued, defines specific information required of potential bidders and details both price and non-price scoring metrics that will be used to evaluate proposals.

Renewable Energy Credits

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

Demand-Side Management

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

Assessment of Owning Assets versus Purchasing Power

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

With owned resources, PacifiCorp is in a better position to control costs, make life extension improvements (as was implemented with the wind repower project), use the site for additional resources in the future, change fueling strategies or sources (as was implemented for the Naughton Unit 3 gas conversion and as planned for Jim Bridger Units 1 and 2), efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and use the plant at embedded cost as long as it remains economic. In addition, by owning a plant, PacifiCorp can hedge itself against the uncertainty of third-party performance consistent with the terms and conditions outlined in a power-purchase agreement over time.

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

Managing Carbon Risk for Existing Plants

CO_2 reduction regulations at the federal, regional, or state levels could prompt PacifiCorp to continue to look for measures to lower CO_2 emissions of fossil-fired power plants through cost-effective means. The cost, timing, and compliance flexibility afforded by CO_2 reduction rules will impact what types of measures might be cost effective and practical from operational and regulatory perspectives. As evident in the 2021 IRP, known and prospective environmental regulations can impact utilization of resources and investment decisions.

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

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

Purpose of Hedging

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

Risk Management Policy and Hedging Program

PacifiCorp's risk management policy and hedging program were designed to follow electric industry best practices and are reviewed at least annually by the company's risk oversight committee. The risk oversight committee includes PacifiCorp representatives from the front office, finance, risk management, treasury, and legal department. The risk oversight committee makes recommendations to the president of Pacific Power, who ultimately must approve any change to the risk management policy.

The main components of PacifiCorp's risk management policy and hedging program are natural gas percent hedged volume limits and power volume hedge limits. These limits force PacifiCorp to monitor the open positions it holds in power and natural gas on behalf of its customers on a daily basis and limit the size of short positions by prescribed time frames in order to reduce customer exposure to price concentration and price volatility. The hedge program requires purchases of natural gas and power at fixed prices in gradual stages in advance of when it is required to reduce the size of short positions and associated customer risk.

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

Cost Minimization

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

contract resources, serves retail load, and then sells any excess generation to generate wholesale revenue to reduce net power costs for customers. PacifiCorp also purchases power when it is less expensive to purchase power than to generate power from our owned and contracted resources.

Hedging cannot be used to minimize net power costs. Hedging does not produce a different expected outcome than not hedging and therefore cannot be considered a cost minimization tool. Hedging is solely a tool to mitigate customer exposure to net power cost volatility and the risk of adverse price movement. However, PacifiCorp does minimize the cost of hedging by transacting in liquid markets and utilizing robust protections to mitigate the risk of counterparty default.

Portfolio

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

Instruments

PacifiCorp's hedging program allows the use of several instruments including financial swaps, fixed price physical and options for these products. PacifiCorp chooses instruments that generally have greater liquidity and lower transaction costs.

Treatment of Customer and Investor Risks

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

Stochastic Risk Assessment

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

Capital Cost Risks

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

Scenario Risk Assessment

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

To address these risks, PacifiCorp evaluates resources in the IRP and for competitive procurements using a range of CO_2 policy assumptions consistent with the scenario analysis methodology adopted for PacifiCorp's 2021 IRP portfolio development and evaluation process. The company's use of IRP sensitivity analysis covering different resource policy and cost assumptions also addresses the need for consideration of scenario risks for long-term resource planning. The extent to which future regulatory policy shifts do not align with PacifiCorp's resource investments determined to be prudent by state commissions is a risk borne by customers.

Attachment D

PacifiCorp's Response to CREA Data Request No. 2.4

CREA Data Request 2.4

Reference Table 7.1 in PacifiCorp's application filed on April 28, 2022. Please explain why the proposed avoided cost rates for a Base Load QF are $11.87/MWh to $16.95/MWh lower than the rates currently effective.

Response to CREA Data Request 2.4

Please refer to the work papers supporting PacifiCorp's April 28, 2022 filing, specifically file "1_OR Standard QF AC Study_2022 04 20.xlsx". Note: the work papers supporting PacifiCorp's April 28, 2022 filing are provided with the Company's response to CREA Data Request 2.1.

The referenced values of $11.87 per megawatt-hour ($/MWh) to $16.95/MWh from column "Difference 2021 IRP" do not reflect the difference between the proposed avoided cost rates and the currently reflective rates. These values only reflect the changes related to the update to incorporate assumptions from PacifiCorp's recently acknowledged 2021 Integrated Resource Plan (IRP). Impacts related to the most recent official forward price curve (OFPC_ are shown in column "Difference OFPC" and largely offset the impacts related to the 2021 IRP. The overall impact between the proposed "Base Load QF" prices and the currently effective prices is shown in column "Difference".

The referenced values primarily are a result of lower capitalized energy costs, as shown on tab "Tables 3 to 6", because the proxy combined cycle combustion turbine (CCCT) in PacifiCorp's 2021 IRP supply-side table has a lower cost than the CCCT from the 2019 IRP. Non-renewable pricing for all qualifying facility (QF) types during the deficiency period reflects energy compensation based on the proxy CCCT fuel cost and heat rate, plus capitalized energy costs, which account for capacity costs in excess of the cost of the simply cycle combustion turbine (SCCT). The proxy costs for a SCCT did not change significantly from the 2019 IRP to the 2021 IRP. Please refer to tab "Table 9 SCCT_CCCT" for more detail on the CCCT and SCCT costs.

Attachment E

PacifiCorp’s Response to CREA Data Request No. 2.5

CREA Data Request 2.5

Reference Table 3 in PacifiCorp's application filed on April 28, 2022, providing Capitalized Energy Costs. Please explain why the Combined Cycle CT Fixed Costs have declined substantially in the proposed rates as compared to the currently effective rates.

Response to CREA Data Request 2.5

The difference between the costs for the combined cycle combustion turbine (CCCT) in the proposed avoided costs / standard rates in PacifiCorp's April 28, 2022 filing and the currently effective avoided costs / standard rates is caused by the following:

First, the capital costs in the 2021 Integrated Resource Plan (IRP) decreased by approximately 4 percent relative to the capital costs in the 2019 IRP due to a soft United States (U.S.) market for utility scale combustion turbine (CT) based generating units.

Second, the fixed operations and maintenance costs were separated from variable operations and maintenance costs in the currently effective avoided costs / standard rates. All fixed and variable operations and maintenance for the simple-cycle combustion turbine (SCCT) costs were combined in the variable operations and maintenance cost in the proposed avoided costs / standard rates. The fixed operations costs for the CCCT were only the pipeline costs in the proposed avoided costs / standard rates. Because new natural gas-fired resources were not considered as resource options in the 2021 IRP outside of a sensitivity, this issue with CCCT costs was not identified during the 2021 IRP process. The supply-side resource table for the 2019 IRP identified fixed operations and maintenance costs for a "J" size CCCT and associated duct firing capability that remain reasonable. Incorporating the 2019 IRP fixed operations and maintenance costs for a CCCT would increase the capitalized energy cost by $3.28/MWh starting in 2026. This has the same impact on the non-renewable rates for all resource types. Please refer to Attachment CREA 2.5 for details, specifically tabs "Table 9" and "Table 3 to 6".

Third, the current effective rates were based on an "H" size CT having a total CCCT net capacity of 447 megawatts (MW) reflecting assumptions in the 2019 IRP. The April 28, 2022, application is based on the "J" size CT having a total CCCT net capacity of 645 MW reflecting assumptions in the 2021 IRP. The capital cost for the "J" CCCT was spread over 44 percent more generating capacity resulting in a 22 percent lower costs per kilowatt ($/kW).

Attachment F

PacifiCorp's Response to CREA Data Request No. 2.6

CREA Data Request 2.6

Reference Table 9, Total Cost of Displaceable Resources, 645 MW - CCCT Dry "J", 1x1 - West Side Resource (1,500'), in PacifiCorp's application filed on April 28, 2022.

(a) The "Estimated Capital Cost" for the CCCT used in the proposed rates, set forth in Table 9 column (a), is $1,054/kW; whereas the same figure for the "Estimated Capital Cost" for the CCCT used in the rates currently in effect, as set forth in Table 9 column (a) of the application filed June 8, 2020, $1,429/kW – a decrease of over 25% in the capital costs of the CCCT used for setting avoided cost rates. Please explain how the costs of a CCCT could have dropped 25% since the last IRP rate cycle.

(b) Please explain whether PacifiCorp took recent supply chain shortages into account in calculating this significant reduction in capital costs of a CCCT.

Response to CREA Data Request 2.6

(a) Please refer to the Company's response to CREA Data Request 2.5.

(b) No, recent supply chain shortages are not included in the calculation. Cost estimates used in PacifiCorp's April 28, 2022 filing reflect assumptions used in PacifiCorp's 2021 Integrated Resource Plan (IRP) that were prepared in the summer of 2020, prior to the start of supply chain shortages.

Attachment G

PacifiCorp's Response to CREA Data Request No. 2.3

CREA Data Request 2.3

Identify and provide the natural gas price forecast that PacifiCorp used in its most recently effective or proposed avoided cost rates in each of the Company's other jurisdictions and describe the following regarding the forecast:

(a) Was the forecast created solely by PacifiCorp or with the assistance of third-party vendors, and if assisted by third-party vendors identify such parties and their role in developing the gas forecast.

(b) Describe the data relied upon in the development of the gas forecast.

(c) Identify the delivery hub used in this forecast.

(d) Date the forecast was completed and made available for use in regulatory proceedings.

Response to CREA Data Request 2.3

The natural gas price forecast used in its most recently effective or proposed avoided cost rates in PacifiCorp's jurisdictions (other than Oregon) is as follows:

- California – PacifiCorp uses the Oregon avoided cost rates and methodologies for California.

- Idaho – PacifiCorp does not supply the natural gas price forecast for standard avoided cost rates in Idaho as the calculation is prepared by Idaho Public Utilities Commission (IPUC) staff. The current forecast, for rates effective June 1, 2022, reflects the United States (U.S.) Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2022. Please refer to Table 3.8 Mountain, Energy Prices by sector, Electric Power – Natural Gas (nom $/MMBTU), publicly available at:

  https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2022&region=1-8&cases=ref2022

- Utah – Published avoided cost rates effective June 1, 2022 reflect production cost modeling that incorporates power and natural gas pricing from PacifiCorp's March 31, 2022 official forward price curve (OFPC), the March 2022 OFPC (or 0322 OFPC).

- Washington – Published avoided cost rates do not utilize a natural gas price forecast, but the rates effective January 1, 2022 reflect power prices from PacifiCorp's September 30, 2021 OFPC (the September 2022 OFPC or 0921 OFPC).

- Wyoming - Published avoided cost rates effective June 1, 2022 reflect production cost modeling that incorporates power and natural gas pricing from PacifiCorp's June 29, 2018 OFPC (the June 2018 OFPC or 0618 OFPC).

Please refer to Attachment CREA 2.3 which provides copies of PacifiCorp's June 2018 OFPC, September 2021 OFPC and March 2022 OFPC.

(a) Both the June 2018 OFPC and the September 2021 OFPC were produced in-house by PacifiCorp. For the March 2022 OFPC, please refer to the Company's response to CREA Data Request 2.2 subpart (a).

(b) For both the June 2018 OFPC and the September 2021 OFPC, PacifiCorp used long-term natural gas price forecasts obtained under licensed subscription services from two third party providers (IHS Markit and Wood Mackenzie). PacifiCorp's natural gas and electricity OFPC were developed from a combination of market forwards and a long-term fundamentals-based price forecast. The first 36 months of the curve reflect broker quotes and/or settled prices in the forwards market. Month 37 through month 48 is a forwards-fundamentals blend that segues into the long-term forecast starting in month 49.

For the March 2022 OFPC, please refer to the Company's response to CREA Data Request 2.2 subpart (b).

(c) Other than Oregon, none of PacifiCorp's other jurisdictions have adopted an avoided cost methodology that is calculated directly from forecasted natural gas prices in the quarterly OFPC. Utah and Wyoming avoided costs reflect production cost modeling that includes natural gas prices specific to each of PacifiCorp's existing natural gas-fired facilities, as well as planned facilities identified in an Integrated Resource Plan (IRP) or IRP Update preferred portfolio. Washington avoided costs are based on power prices and do not have natural gas prices as an input. Idaho uses a natural gas forecast from the U.S. EIA AEO as described above. Note: California uses the Oregon avoided cost rates and methodologies.

(d) PacifiCorp's June 2018 OFPC was completed on June 29, 2018. PacifiCorp's September 2021 OFPC was completed on October 1, 2021. For the March 2022 OFPC, please refer to the Company's response to CREA Data Request 2.2 subpart (d).

The confidential attachment is designated as Protected Information under Order No. 16-144 and may only be disclosed to qualified persons as defined in that order.