ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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VIA ELECTRONIC DELIVERY

Jan Noriyuki
Commission Secretary
Idaho Public Utilities Commission
11331 W. Chinden Blvd
Building 8 Suite 201A
Boise, ID 83714

RE: CASE NO. PAC-E-23-24
IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORIZATION TO UPDATE THE WIND AND SOLAR INTEGRATION RATE FOR SMALL POWER GENERATION QUALIFYING FACILITIES

Attention: Jan Noriyuki

Please find for filing Rocky Mountain Power's Application in the above-referenced matter which includes two attachments. Attachment No.1 is Appendix F, the Flexible Reserve Study from Volume II of the 2023 IRP and Attachment No. 2 is the non-levelized wind and solar integration rates in the format required by Order No. 34966. Workpapers also accompany this application.

Informal inquiries may be directed to Mark Alder, Idaho Regulatory Manager at (801) 220-2313.

Very truly yours,

Joelle Steward
Senior Vice President, Regulation and Customer & Community Solutions

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Attorney for Rocky Mountain Power

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORIZATION TO UPDATE THE WIND AND SOLAR INTEGRATION RATE FOR SMALL POWER GENERATION QUALIFYING FACILITIES	))))))	**CASE NO. PAC-E-23-24** **APPLICATION**

Rocky Mountain Power, a division of PacifiCorp ("the Company"), in accordance with Idaho Code §61-502, §61-503, and RP 052*,* hereby respectfully submits this application ("Application") to the Idaho Public Utilities Commission ("Commission") requesting authorization to modify the wind and solar integration rates applicable to new power purchase agreements ("PPA"). Specifically, purchases by Rocky Mountain Power of electric power from wind-powered qualified facilities, ("QFs"), would drop from the current $1.25 per megawatt-hour ("MWh") in 2024 dollars to a comparable real-levelized charge of $1.18/MWh, while the solar integration rate would rise from $0.96/MWh in 2024 dollars to a comparable real-levelized charge of $1.40/MWh, applicable to purchases by Rocky Mountain Power of electric power from solar-powered QFs. The charges applicable annually vary consistent with the results identified in the 2023 IRP. These amounts represent the integration costs of wind and solar power to be applied against published avoided cost rates except in those circumstances where the QF developer specifies in the PPA to deliver the QF output to Rocky Mountain Power on a firm hourly schedule. In support of this Application, Rocky Mountain Power states as follows:

1. Rocky Mountain Power is a division of PacifiCorp, an Oregon corporation, which provides electric service to retail customers through its Rocky Mountain Power division in the states of Idaho, Utah, and Wyoming. Rocky Mountain Power is a public utility in the state of Idaho and is subject to the Commission's jurisdiction with respect to its prices and terms of electric service to retail customers in Idaho pursuant to Idaho Code § 61-129. Rocky Mountain Power is authorized to do business in the state of Idaho and provides retail electric service to approximately 88,870 customers in the state.

I. BACKGROUND

2. Commission Order No. 29839[1] stated: "we find that the unique supply characteristics of wind generation and the related integration costs provided a basis for adjustment to the published avoided cost rates, a calculated figure that may be different for each regulated utility."

3. Pursuant to Order No. 29839 Rocky Mountain Power filed Case No. PAC-E-07-07 on April 23, 2007, requesting approval of a utility-specific wind integration adjustment to the published avoided costs rates. The Commission reviewed the facts and the stipulation entered into by the parties in that case and determined that a utility-specific wind integration cost adjustment to a utility's published avoided costs, among other adjustments, was appropriate.[2] The Commission also ordered the Company to file any changes to its wind integration charge as reflected in subsequent IRPs.[3] Subsequently, in Case No. PAC-E-17-11, the Commission

[1] *In the Matter of the Petition of Idaho Power Company for an Order Temporarily Suspending Idaho Power's PURPA Obligation to Enter into Contracts to Purchase Energy Generated by Wind-Powered Small Power Production Facilities.* Case No. IPC-E-05-22, Order No. 29839 at 8 (August 4, 2005).
[2] *In the Matter of the Petition of Rocky Mountain Power for an Order Revising Certain Obligations to Enter into Contracts to Purchase Energy Generated by Wind-Powered Small Power Generation Qualified Facilities*, Case No. PAC-E-7-07, Final Order No. 30497 at 12 (February 20, 2008).
[3] *Id.* at 13.

requested that any updates to the Company's integration charges be filed after the IRP is acknowledged.[4]

4. On October 8, 2020, the Company filed, and the Commission later approved, an update to the wind and solar integration rates based on the results of the 2019 IRP Flexible Reserve Study.[5]

5. On October 31, 2023, the Commission acknowledged the Company's 2023 Integrated Resource Plan ("IRP").[6]

6. In compliance with Order No. 30497, Rocky Mountain Power hereby files this Application to update its wind and solar integration rates that can be deducted from the published avoided cost rates to determine a purchase and sale price established for the duration of the PPA with a QF. This modification to the published avoided cost rates is intended to reflect the cost of integrating wind and solar generation into the Company's electrical system. These integration rates assure that QFs that deliver less than 100 KW have a predictable rate. In support of this Application the Company includes Attachment No. 1, Appendix F – Flexible Reserve Study from Volume II of the 2023 IRP, and Attachment No. 2. Attachment No. 1 explains in detail the methodology used and the results derived from PacifiCorp's analysis of wind and solar integration costs. Attachment No. 2 includes the non-levelized wind and solar integration rates in the format required by Order No. 34966.[7]

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[4] *In the Matter of the Application of Rocky Mountain Power to Revise the Wind Integration Rate and Implement a Solar Integration Rate for Small Power Generation Qualifying Facilities*, Case No. PAC-E-17-11, Order No. 33937.

[5] *In the Matter of the Application of Rocky Mountain Power to Update the Wind and Solar Integration Rate for Small Power Generation Qualifying Facilities*, Case No. PAC-E-20-14, Order No. 34966.

[6] *In the Matter of PacifiCorp's Application for Acknowledgment of the 2023 Integrated Resource Plan*, Case No. PAC-E-23-10, Order No. 35977 (October 31, 2023).

[7] *In the Matter of the Application of Rocky Mountain Power to Update the Wind and Solar Integration Rate for Small Power Generation Qualifying Facilities*, Case No. PAC-E-20-14, Order No. 34966 at p.5.

II. 2023 IRP – FLEXIBLE RESERVE STUDY

7. Appendix F of the 2023 IRP summarizes a Flexible Reserve Study ("FRS") which estimates the regulation reserve required to maintain PacifiCorp's system reliability and comply with North American Electric Reliability Corporation ("NERC") reliability standards as well as the incremental cost of this regulation reserve. The FRS also compares PacifiCorp's overall operating reserve requirements, including both regulation reserve and contingency reserve, to its flexible resource supply over the IRP study period.

8. The FRS is based on PacifiCorp's actual operational data from January 2018 through December 2019 for load, wind, solar, and Non-Variable Energy Resources ("Non-VERs"). PacifiCorp's primary analysis, focuses on the variability of load, wind, solar, and Non-VERs during this period. A supplemental analysis discusses how the total variability of PacifiCorp's system changes with varying levels of load, wind and solar capacity.

9. The methodology in the FRS is similar to that employed in PacifiCorp's previous regulation reserve requirement analysis in the 2019 IRP used in the current effective integration charges, but has been enhanced in some key ways. First, the historical period was enhanced to capture a larger sample of system conditions. Second, the methodology for extrapolating results for higher renewable resource penetration levels has been modified to better capture the diversity between growing wind and solar portfolios.

10. The estimated regulation reserve amounts determined in the FRS represent the incremental capacity needed in a particular operating hour to ensure compliance with NERC Standard BAL-001-2. The regulation reserve requirement for the combined portfolio is the sum of the individual requirements for load, wind, solar, and Non-VERs, less the reserve "savings" associated with diversity between the different classes, including diversity benefits realized as a

result of PacifiCorp's participation in the EIM operated by the California Independent System Operator Corporation.

11. The FRS produces an hourly forecast of the regulation reserve requirements for each of PacifiCorp's Balancing Authority Areas that is sufficient to ensure the reliability of the transmission system and compliance with NERC and WECC standards. This regulation reserve forecast covers the combined deviations of the load, wind, solar and Non-VERs on PacifiCorp's system and varies as a function of the wind and solar capacity on PacifiCorp's system, as well as forecasted levels of wind, solar, and load.

12. The FRS first estimates the regulation reserve necessary to maintain compliance with NERC Standard BAL-001-2 given a specified portfolio of wind and solar resources. Next the FRS calculates the cost of holding regulation reserve for incremental wind and solar resources. Finally, the FRS compares PacifiCorp's overall operating reserve requirements over the IRP study period, including both regulation reserve and contingency reserve, to its flexible resource supply.

13. In addition to estimating the regulation reserve based on the specific requirements of NERC Standard BAL-001-2, the FRS also incorporates the current timeline for EIM market processes, as well as EIM resource deviations and flexibility reserve benefits based on actual results. The FRS also includes adjustments to regulation reserve requirements to account for the changing portfolio of solar and wind resources on PacifiCorp's system and for the diversity of using a single portfolio of regulation reserve resources to cover variations in load, wind, solar, and Non-VERs. Table F.1 summarizes the regulation reserve requirements for the various portfolios considered in this analysis, the 2019 IRP FRS are also included for reference.

Table F.1 – Portfolio Regulation Reserve Requirements

Case	Wind Capacity (MW)	Solar Capacity (MW)	Stand-alone Regulation Requirement (MW)	Portfolio Diversity Credit (%)	Regulation Requirement with Diversity (MW)
CY2017 (2019 IRP)	**2,750**	**1,021**	**994**	**47%**	**531**
2018-2019 (2021 IRP)	**2,745**	**1,080**	**1,057**	**49%**	**540**

14. The integration costs determined from the FRS are summarized in Table F.2 which provides the wind and solar costs on a dollar per megawatt-hour ($/MWh) of generation basis. The results of the 2019 IRP FRS used to set the current integration charges are also included for comparison.

Table F.2 – 2023 FRS Flexible Resource Costs as Compared to 2019 Costs, $/MWh

	Wind 2023 FRS (2022$)	Solar 2023 FRS (2022$)	Wind 2019 FRS (2018$)	Solar 2019 FRS (2018$)
Study Period	2025-2042	2025-2042	2018-2036	2018-2036
Flexible Resource Cost	$1.38	$1.59	$1.11	$0.85

15. Based on the results of the FRS from the 2023 IRP, and after adjusting for inflation, the Company respectfully requests that the wind integration rate be decreased from $1.25 to $1.18 per MWh, in 2024 dollars, and the solar integration rate increased from $0.96 to $1.40 per MWh, in 2024 dollars, applicable to wind and solar QFs that qualify for the Company's published QF rates.

III. COMMUNICATIONS

Communications regarding this filing should be addressed to:

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In addition, Rocky Mountain Power requests that all data requests regarding this Application be sent in Microsoft Word to the following:

By email (preferred): datarequest@pacificorp.com

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

Informal questions may be directed to Mark Alder, Idaho Regulatory Affairs Manager at (801) 220-2313.

IV. MODIFIED PROCEDURE

Rocky Mountain Power believes that a hearing is not necessary to consider the issues presented herein and respectfully requests that this Application be processed under Modified Procedure; i.e., by written submissions rather than by hearing, RP 201. If, however, the Commission determines that a technical hearing is required, the Company stands ready to prepare and present its testimony in such hearing.

V. REQUEST FOR RELIEF

WHEREFORE, Rocky Mountain Power respectfully requests that the Commission issue an Order: (1) authorizing this Application to be processed under Modified Procedure; (2) approving the wind integration rate of $1.18 per MWh for wind-powered QFs; and (3) approving the solar integration rate of $1.40 per MWh. These rates will be used by the Company for purchase of electric power from wind or solar-powered QFs, which amounts represents the integration costs of wind and solar power, to be applied against avoided cost rates in those circumstances, except where the QF developer agrees in the power purchase agreement with Rocky Mountain Power to schedule and deliver, via a transmission provider, the QF output to Rocky Mountain Power on a firm hourly basis.

RESPECTFULLY SUBMITTED this 29th day of November 2023.

Rocky Mountain Power

By: ______________________________
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Attachment No. 1

APPENDIX F – FLEXIBLE RESERVE STUDY

Introduction

While PacifiCorp had significant increases in both wind and solar capacity on its system in 2021, there has not yet been time to collect and assess sufficient historical data that includes this expanded output. Therefore, for the 2023 IRP, PacifiCorp is continuing to use the methodology developed in its 2021 Flexible Reserve Study (FRS), which relied upon historical data from 2018-2019, as discussed below.[1]

The 2021 Flexible Reserve Study (FRS) estimated the regulation reserve required to maintain PacifiCorp's system reliability and comply with North American Electric Reliability Corporation (NERC) reliability standards. Because the FRS methodology accounts for changes in PacifiCorp's resource mix, both the quantity and cost of reserves has been updated for the 2023 IRP, as reported herein.

PacifiCorp operates two balancing authority areas (BAAs) in the Western Electricity Coordinating Council (WECC) NERC region--PacifiCorp East (PACE) and PacifiCorp West (PACW). The PACE and PACW BAAs are interconnected by a limited amount of transmission across a third-party transmission system and the two BAAs are each required to comply with NERC standards. PacifiCorp must provide sufficient regulation reserve to remain within NERC's balancing authority area control error (ACE) limit in compliance with BAL-001-2,[2] as well as the amount of contingency reserve required to comply with NERC standard BAL-002-WECC-2.[3] BAL-001-2 is a regulation reserve standard that became effective July 1, 2016, and BAL-002-WECC-3 is a contingency reserve standard that became effective June 28, 2021. Regulation reserve and contingency reserve are components of operating reserve, which NERC defines as "the capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection."[4]

Apart from disturbance events that are addressed through contingency reserve, regulation reserve is necessary to compensate for changes in load demand and generation output to maintain ACE within mandatory parameters established by the BAL-001-2 standard. The FRS estimates the amount of regulation reserve required to manage variations in load, variable energy resources[5]

[1] 2021 IRP Volume II, Appendix F (Flexible Reserve Study): https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20II%20-%209.15.2021%20Final.pdf

[2] NERC Standard BAL-001-2, https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf, which became effective July 1, 2016. ACE is the difference between a BAA's scheduled and actual interchange and reflects the difference between electrical generation and Load within that BAA.

[3] NERC Standard BAL-002-WECC-3, https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-WECC-3.pdf, which became effective June 28, 2021. BAL-002-WECC-3 removed the requirement that at least 50% of contingency reserves be held as "spinning" resources, as this was deemed redundant with frequency response requirements under BAL-003-2.

[4] Glossary of Terms Used in NERC Reliability Standards: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf, updated March 8, 2023.

[5] VERs are resources that resources that: (1) are renewable; (2) cannot be stored by the facility owner or operator; and (3) have variability that is beyond the control of the facility owner or operator. *Integration of Variable Energy*

(VERs), and resources that are not VERs ("Non-VERs") in each of PacifiCorp's BAAs. Load, wind, solar, and Non-VERs were each studied because PacifiCorp's data indicates that these components or customer classes place different regulation reserve burdens on PacifiCorp's system due to differences in the magnitude, frequency, and timing of their variations from forecasted levels.

The FRS is based on PacifiCorp operational data recorded from January 2018 through December 2019 for load, wind, solar, and Non-VERs. PacifiCorp's primary analysis focuses on the actual variability of load, wind, solar, and Non-VERs during 2018-2019. A supplemental analysis discusses how the total variability of the PacifiCorp system changes with varying levels of wind and solar capacity. The estimated regulation reserve amounts determined in this study represent the incremental capacity needed to ensure compliance with BAL-001-2 for a particular operating hour. The regulation reserve requirement covers variations in load, wind, solar, and Non-VERs, while implicitly accounting for the diversity between the different classes. An explicit adjustment is also made to account for diversity benefits realized because of PacifiCorp's participation in the Energy Imbalance Market (EIM) operated by the California Independent System Operator Corporation (CAISO).

The methodology in the FRS is like that employed in PacifiCorp's 2019 IRP but has been enhanced in two areas.[6] First, the historical period evaluated in the study has been expanded to include two years, rather than one, to capture a larger sample of system conditions. Second, the methodology for extrapolating results for higher renewable resource penetration levels has been modified to better capture the diversity between growing wind and solar portfolios.

The FRS results produce an hourly forecast of the regulation reserve requirements for each of PacifiCorp's BAAs that is sufficient to ensure the reliability of the transmission system and compliance with NERC and WECC standards. This regulation reserve forecast covers the combined deviations of the load, wind, solar and Non-VERs on PacifiCorp's system and varies as a function of the wind and solar capacity on PacifiCorp's system, as well as forecasted levels of wind, solar and load.

The regulation reserve requirement methodologies produced by the FRS are applied in production cost modeling to determine the cost of the reserve requirements associated with incremental wind and solar capacity. After a portfolio is selected, the regulation reserve requirements specific to that portfolio can be calculated and included in the study inputs, such that the production cost impact of the requirements is incorporated in the reported results. As a result, this production cost impact is dependent on the wind and solar resources in the portfolio as well as the characteristics of the dispatchable resources in the portfolio that are available to provide regulation reserves.

Resources, Order No. 764, 139 FERC ¶ 61,246 at P 281 (2012) ("Order No. 764"); *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61,232 (2012) ("Order No. 764-A"); *order on reh'g and clarification*, Order No. 764-B, 144 FERC ¶ 61,222 at P 210 (2013) ("Order No. 764-B").

[6] 2019 IRP Volume II, Appendix F (Flexible Reserve Study): https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_II_Appendices_A-L.pdf

Overview

The primary analysis in the FRS is to estimate the regulation reserve necessary to maintain compliance with NERC Standard BAL-001-2 given a specified portfolio of wind and solar resources. The FRS next calculates the cost of holding regulation reserve for incremental wind and solar resources. Finally, the FRS compares PacifiCorp's overall operating reserve requirements over the IRP study period, including both regulation reserve and contingency reserve, to its flexible resource supply.

The FRS estimates regulation reserve based on the specific requirements of NERC Standard BAL-001-2. It also incorporates the current timeline for EIM market processes, as well as EIM resource deviations and diversity benefits based on actual results. The FRS also includes adjustments to regulation reserve requirements to account for the changing portfolio of solar and wind resources on PacifiCorp's system and accounts for the diversity of using a single portfolio of regulation reserve resources to cover variations in load, wind, solar, and Non-VERs. A comparison of the results of the current analysis and that from previous IRPs is shown in Table F.1 and Table F.2. Flexible resource costs are portfolio dependent and vary over time. For more details, please refer to Figure F.11 – Incremental Wind and Solar Regulation Reserve Costs.

Table F.1 - Portfolio Regulation Reserve Requirements

Case	Wind Capacity (MW)	Solar Capacity MW	Stand-alone Regulation Requirement (MW)	Portfolio Diversity Credit (%)	Regulation Requirement with Diversity (MW)
CY2017 (2019 FRS)	2,750	1,021	994	47%	531
2018-2019 (2021 FRS)	2,745	1,080	1,057	49%	540

Table F.2 - 2023 Flexible Resource Costs as Compared to 2021 Costs, $/MWh

	Wind 2023 FRS (2022$)	Solar 2023 FRS (2022$)	Wind 2021 FRS (2022$)	Solar 2021 FRS (2022$)
Study Period	2025-2042	2025-2042	2023-2040	2023-2040
Flexible Resource Cost	$1.20	$1.48	$1.58	$1.32

Flexible Resource Requirements

PacifiCorp's flexible resource needs are the same as its operating reserve requirements over the planning horizon for maintaining reliability and compliance with NERC regional reliability standards. Operating reserve generally consists of three categories: (1) contingency reserve (i.e., spinning, and supplemental reserve), (2) regulation reserve, and (3) frequency response reserve. Contingency reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC regional reliability standard BAL-002-WECC-3.[7] Regulation reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC Control Performance Criteria in

[7] NERC Standard BAL-002-WECC-3 – Contingency Reserve: https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-WECC-3.pdf

BAL-001-2.[8] Frequency response reserve is capacity that PacifiCorp holds available to ensure compliance with NERC standard BAL-003-2.[9] Each type of operating reserve is further defined below.

Contingency Reserve

Purpose: Contingency reserve may be deployed when unexpected outages of a generator or a transmission line occur. Contingency reserve may not be deployed to manage other system fluctuations such as changes in load or wind generation output.

Volume: NERC regional reliability standard BAL-002-WECC-3 specifies that each BAA must hold as contingency reserve an amount of capacity equal to three percent of load and three percent of generation in that BAA.

Duration: Except within 60 minutes of a qualifying contingency event, a BAA must maintain the required level of contingency reserve at all times. Generally, this means that up to 60 minutes of generation are required to provide contingency reserve, though successive outage events may result in contingency reserves being deployed for longer periods. To restore contingency reserves, other resources must be deployed to replace any generating resources that experienced outages, typically either market purchases or generation from resources with slower ramp rates.

Ramp Rate: Only up capacity available within ten minutes can be counted as contingency reserve. This can include "spinning" resources that are online and immediately responsive to system frequency deviations to maintain compliance with frequency response obligations under BAL-003-1.1, as well as from "non-spinning" resources that do not respond immediately, though they must still be fully deployed in ten minutes.[10]

Regulation Reserve

Purpose: NERC standard BAL-001-2, which became effective July 1, 2016, does not specify a regulation reserve requirement based on a simple formula, but instead requires utilities to hold sufficient reserve to meet specified control performance standards. The primary requirement relates to area control error ("ACE"), which is the difference between a BAA's scheduled and actual interchange and reflects the difference between electrical generation and load within that BAA. Requirement 2 of BAL-001-2 defines the compliance standard as follows:

> *Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes…*

[8] NERC Standard BAL-001-2 – Real Power Balancing Control Performance: https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf
[9] NERC Standard BAL-003-2 — Frequency Response and Frequency Bias Setting: https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-2.pdf
[10] While the minimum spinning reserve obligation previously contained within BAL-002-WECC-2a was retired due to redundancy with frequency response obligations under BAL-003-2, PacifiCorp's 2023 IRP does not explicitly model the frequency response obligation and retains the spinning obligation to ensure a supply of rapidly responding resources is maintained.

In addition, Requirement 1 of BAL-001-2 specifies that PacifiCorp's Control Performance Standard 1 ("CPS1") score must be greater than equal to 100 percent for each preceding 12 consecutive calendar month period, evaluated monthly. The CPS1 score compares PacifiCorp's ACE with interconnection frequency during each clock minute. A higher score indicates PacifiCorp's ACE is helping interconnection frequency, while a lower score indicates it is hurting interconnection frequency. Because CPS1 is averaged and evaluated monthly, it does not require a response to every ACE event, but rather requires that PacifiCorp meet a minimum aggregate level of performance in each month. Regulation reserve is thus the capacity that PacifiCorp holds available to respond to changes in generation and load to manage ACE within the limits specified in BAL-001-2.

Volume: NERC standard BAL-001-2 does not specify a regulation reserve requirement based on a simple formula, but instead requires utilities to hold sufficient reserve to meet performance standards as discussed above. The FRS estimates the regulation reserve necessary to meet Requirement 2 by compensating for the combined deviations of the load, wind, solar and Non-VERs on PacifiCorp's system. These regulation reserve requirements are discussed in more detail later in the study.

Ramp Rate: Because Requirement 2 includes a 30-minute time limit for compliance, ramping capability that can be deployed within 30 minutes contributes to meeting PacifiCorp's regulation reserve requirements. The reserve for CPS1 is not expected to be incremental to the need for compliance with Requirement 2 but may require that a subset of resources held for Requirement 2 be able to make frequent rapid changes to manage ACE relative to interconnection frequency.

Duration: PacifiCorp is required to submit balanced load and resource schedules as part of its participation in EIM. PacifiCorp is also required to submit resources with up flexibility and down flexibility to cover uncertainty and expected ramps across the next hour. Because forecasts are submitted prior to the start of an hour, deviations can begin before an hour starts. As a result, a flexible resource might be called upon for the entire hour. To continue providing flexible capacity in the following hour, energy must be available in storage for that hour as well. The likelihood of deploying for two hours or more for reliability compliance (as opposed to economics) is expected to be small.

Frequency Response Reserve

Purpose: NERC standard BAL-003-2 specifies that each BAA must arrest frequency deviations and support the interconnection when frequency drops below the scheduled level. When a frequency drop occurs because of an event, PacifiCorp will deploy resources that increase the net interchange of its BAAs and the flow of generation to the rest of the interconnection.

Volume: When a frequency drop occurs, each BAA is expected to deploy resources that are at least equal to its frequency response obligation. The incremental requirement is based on the size of the frequency drop and the BAA's frequency response obligation, expressed in megawatt (MW)/0.1 Herts (Hz). To comply with the standard, a BAA's median measured frequency response during a sampling of under-frequency events must be equal to or greater than its frequency response obligation. PacifiCorp's 2022 frequency response obligation was 25.3

MW/0.1Hz for PACW, and 63.5 MW/0.1Hz for PACE.[11] PacifiCorp's combined obligation amounts to 88.8 MW for a frequency drop of 0.1 Hz, or 266.4 MW for a frequency drop of 0.3 Hz.

The performance measurement for contingency reserve under the Disturbance Control Standard (BAL-002-3)[12], allows for recovery to the lesser of zero or the ACE value prior to the contingency event, so increasing ACE above zero during a frequency event reduces the additional deployment needed if a contingency event occurs. Because contingency, regulation, and frequency events are all relatively infrequent, they are unlikely to occur simultaneously. Because the frequency response standard is based on median performance during a year, overlapping requirements that reduced PacifiCorp's response during a limited number of frequency events would not impact compliance.

As a result, any available capacity not being used for generation is expected to contribute to meeting PacifiCorp's frequency response obligation, up to the technical capability of each unit, including that designated as contingency or regulation reserves. Frequency response must occur very rapidly, and a generating unit's capability is limited based on the unit's size, governor controls, and available capacity, as well as the size of the frequency drop. As a result, while a few resources could hold a large amount of contingency or regulation reserve, frequency response may need to be spread over a larger number of resources. Additionally, only resources that have active and tuned governor controls as well as outer loop control logic will respond properly to frequency events.

Ramp Rate: Frequency response performance is measured over a period of seconds, amounting to under a minute. Compliance is based on the average response over the course of an event. As a result, a resource that immediately provides its full frequency response capability will provide the greatest contribution. That same resource will contribute a smaller amount if it instead ramps up to its full frequency response capability over the course of a minute or responds after a lag.

Duration: Frequency response events are less than one minute in duration.

Black Start Requirements

Black start service is the ability of a generating unit to start without an outside electrical supply and is necessary to help ensure the reliable restoration of the grid following a blackout. At this time, PACW grid restoration would occur in coordination with Bonneville Power Administration black start resources. The Gadsby combustion turbine resources can support grid restoration in PACE. PacifiCorp has not identified any incremental needs for black start service during the IRP study period.

Ancillary Services Operational Distinctions

In actual operations, PacifiCorp identifies two types of flexible capacity as part of its participation in the EIM. The contingency reserve held on each resource is specifically identified and is not

[11] NERC. BAL-003-2 Frequency Response Obligation Allocation and Minimum Frequency Bias Settings for Operating Year 2022. https://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Frequency%20Response%20Standard%20Resources/BA_FRO_Allocations_for_OY2022-document(002).pdf

[12] NERC Standard BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event: https://www.nerc.com/pa/Stand/Reliability Standards/BAL-002-3.pdf

available for economic dispatch within the EIM. Any remaining flexible capacity on participating resources that is not designated as contingency reserve can be economically dispatched in EIM based on its operating cost (i.e. bid) and system requirements and can contribute to meeting regulation reserve obligations. Because of this distinction, resources must either be designated as contingency reserve or as regulation reserve. Contingency events are relatively rare while opportunities to deploy additional regulation reserve in EIM occur frequently. As a result, PacifiCorp typically schedules its lowest-cost flexible resources to serve its load and blocks off capacity on its highest-cost flexible resources to meet its contingency obligations, subject to any ramping limitations at each resource. This leaves resources with moderate costs available for dispatch up by EIM, while lower-cost flexible resources remain available to be dispatched down by EIM.

Regulation Reserve Data Inputs

Overview

This section describes the data used to determine PacifiCorp's regulation reserve requirements. To estimate PacifiCorp's required regulation reserve amount, PacifiCorp must determine the difference between the expected load and resources and actual load and resources. The difference between load and resources is calculated every four seconds and is represented by the ACE. ACE must be maintained within the limits established by BAL-001-2, so PacifiCorp must estimate the amount of regulation reserve that is necessary to maintain ACE within these limits.

To estimate the amount of regulation reserve that will be required in the future, the FRS identifies the scheduled use of the system as compared to the actual use of the system during the study term. For the baseline determination of scheduled use for load and resources, the FRS used hourly base schedules. Hourly base schedules are the power production forecasts used for imbalance settlement in the EIM and represent the best information available concerning the upcoming hour.[13]

The deviation from scheduled use was derived from data provided through participation in the EIM. The deviations of generation resources in EIM were measured on a five-minute basis, so five-minute intervals are used throughout the regulation reserve analysis.

EIM base schedule and deviation data for each wind, solar and Non-VER transaction point were downloaded using the SettleCore application, which is populated with data provided by the CAISO. Since PacifiCorp's implementation of EIM on November 1, 2014, PacifiCorp requires certain operational forecast data from all its transmission customers pursuant to the provisions of Attachment T to PacifiCorp's Federal Energy Regulatory Commission (FERC) approved Open

[13] The CAISO, as the market operator for the EIM, requests base schedules at 75 minutes (T-75) prior to the hour of delivery. PacifiCorp's transmission customers are required to submit base schedules by 77 minutes (T-77) prior to the hour of delivery – two minutes in advance of the EIM Entity deadline. This allows all transmission customer base schedules enough time to be submitted into the EIM systems before the overall deadline of T-75 for the entirety of PacifiCorp's two BAAs. The base schedules are due again to CAISO at 55 minutes (T-55) prior to the delivery hour and can be adjusted up until that time by the EIM Entity (i.e., PacifiCorp Grid Operations). PacifiCorp's transmission customers are required to submit updated, final base schedules no later than 57 minutes (T-57) prior to the delivery hour. Again, this allows all transmission customer base schedules enough time to be submitted into the EIM systems before the overall deadline of T-55 for the entirety of PacifiCorp's two BAAs. Base schedules may be finally adjusted again, by the EIM Entity only, at 40 minutes (T-40) prior to the delivery hour in response to CAISO sufficiency tests. T-40 is the base schedule time point used throughout this study.

Access Transmission Tariff (OATT). This includes EIM base schedule data (or forecasts) from all resources included in the EIM network model at transaction points. EIM base schedules are submitted by transmission customers with hourly granularity, and are settled using hourly data for load, and fifteen-minute and five-minute data for resources. A primary function of the EIM is to measure load and resource imbalance (or deviations) as the difference between the hourly base schedule and the actual metered values.

A summary of the data gathered for this analysis is listed below, and a more detailed description of each type of source data is contained in the following subsections.

Source data:

- Load data
    - Five-minute interval actual load
    - Hourly base schedules

- VER data
    - Five-minute interval actual generation
    - Hourly base schedules

- Non-VER data
    - Five-minute interval actual generation
    - Hourly base schedules

Load Data

The load class represents the aggregate firm demand of end users of power from the electric system. While the requirements of individual users vary, there are diurnal and seasonal patterns in aggregated demand. The load class can generally be described to include three components: (1) average load, which is the base load during a particular scheduling period; (2) the trend, or "ramp," during the hour and from hour-to-hour; and (3) the rapid fluctuations in load that depart from the underlying trend. The need for a system response to the second and third components is the function of regulation reserve in order to ensure reliability of the system.

The PACE BAA includes several large industrial loads with unique patterns of demand. Each of these loads is either interruptible at short notice or includes behind the meter generation. Due to their large size, abrupt changes in their demand are magnified for these customers in a manner which is not representative of the aggregated demand of the large number of small customers which make up most PacifiCorp's loads.

In addition, interruptible loads can be curtailed if their deviations are contributing to a resource shortfall. Because of these unique characteristics, these loads are excluded from the FRS. This treatment is consistent with that used in the CAISO load forecast methodology (used for PACE and PACW operations), which also nets these interruptible customer loads out of the PACE BAA.

Actual average load data was collected separately for the PACE and PACW BAAs for each five-minute interval. Load data has not been adjusted for transmission and distribution losses.

Wind and Solar Data

The wind and solar classes include resources that: (1) are renewable; (2) cannot be stored by the facility owner or operator; and (3) have variability that is beyond the control of the facility owner or operator.[14] Wind and solar, in comparison to load, often have larger upward and downward fluctuations in output that impose significant and sometimes unforeseen challenges when attempting to maintain reliability. For example, as recognized by FERC in Order No. 764, "Increasing the relative amount of [VERs] on a system can increase operational uncertainty that the system operator must manage through operating criteria, practices, and procedures, *including the commitment of adequate reserves*."[15] The data included in the FRS for the wind and solar classes include all wind and solar resources in PacifiCorp's BAAs, which includes: (1) third-party resources (OATT or legacy contract transmission customers); (2) PacifiCorp-owned resources; and (3) other PacifiCorp-contracted resources, such as qualifying facilities, power purchases, and exchanges. In total, the FRS study period includes an average of 2,745 megawatts of wind and 1,080 megawatts of solar.

Non-VER Data

The Non-VER class is a mix of thermal and hydroelectric resources and includes all resources which are not VERs, and which do not provide either contingency or regulation reserve. Non-VERs, in contrast to VERs, are often more stable and predictable. Non-VERs are thus easier to plan for and maintain within a reliable operating state. For example, in Order No. 764, FERC suggested that many of its rules were developed with Non-VERs in mind and that such generation "could be scheduled with relative precision."[16]The output of these resources is largely in the control of the resource operator, particularly when considered within the hourly timeframe of the FRS. The deviations by resources in the Non-VER class are thus significantly lower than the deviations by resources in the wind class. The Non-VER class includes third-party resources (OATT or legacy transmission customers); many PacifiCorp-owned resources; and other PacifiCorp-contracted resources, such as qualifying facilities, power purchases, and exchanges. In total, the FRS includes 2,202 megawatts of Non-VERs.

In the FRS, resources that provide contingency or regulation reserve are considered a separate, dispatchable resource class. The dispatchable resource class compensates for deviations resulting from other users of the transmission system in all hours. While non-dispatchable resources may offset deviations in loads and other resources in some hours, they are not in the control of the system operator and contribute to the overall requirement in other hours. Because the dispatchable resource class is a net provider rather than a user of regulation reserve service, its stand-alone regulation reserve requirement is zero (or negative), and its share of the system regulation reserve requirement is also zero. The allocation of regulation reserve requirements and diversity benefits is discussed in more detail later in the study.

[14] Order No. 764 at P 281; Order No. 764-B at P 210.
[15] Order No. 764 at P 20 (emphasis added).
[16] *Id.* at P 92.

Regulation Reserve Data Analysis and Adjustment

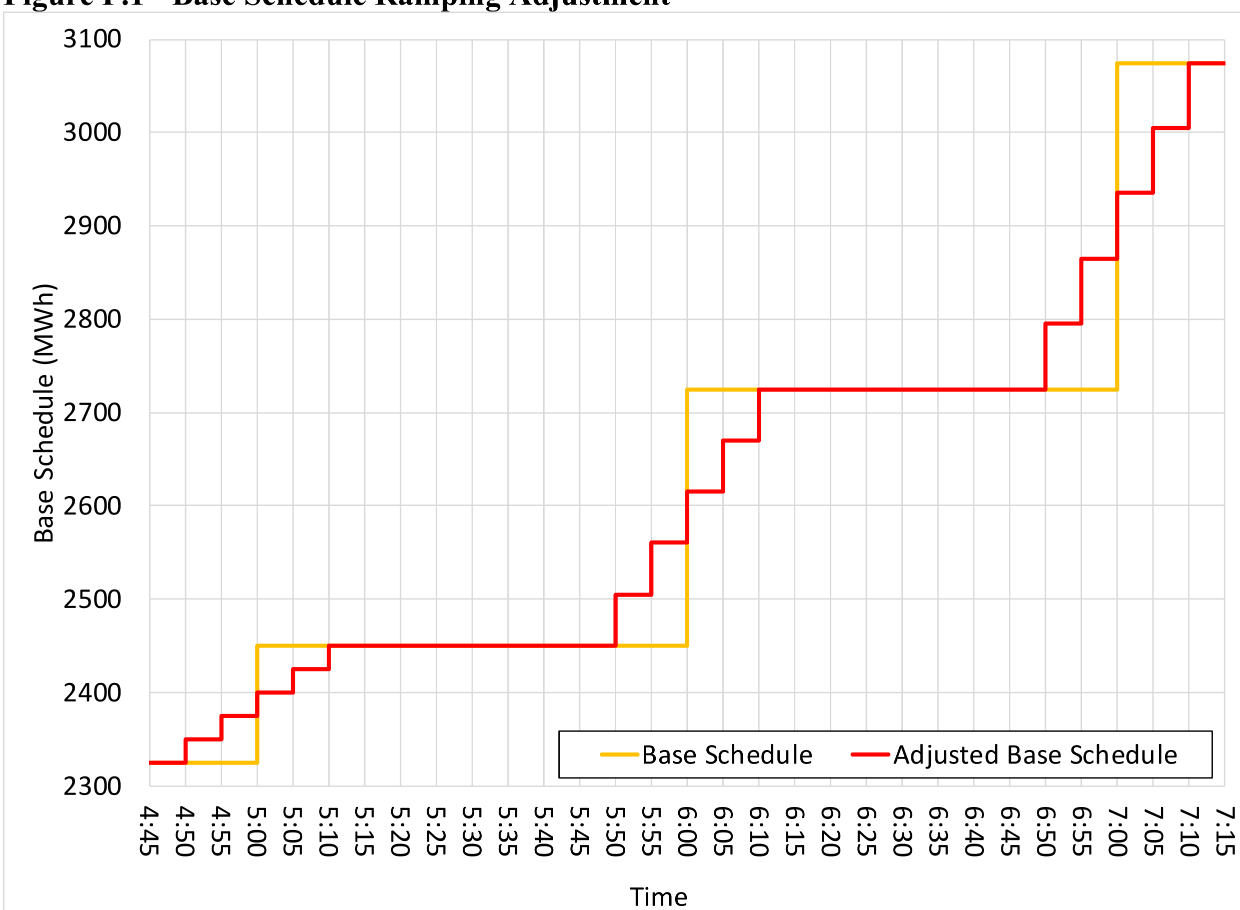
Overview

This section provides details on adjustments made to the data to align the ACE calculation with actual operations, and address data issues.

Base Schedule Ramping Adjustment

In actual operations, PacifiCorp's ACE calculation includes a linear ramp from the base schedule in one hour to the base schedule in the next hour, starting ten-minutes before the hour and continuing until ten-minutes past the hour. The hourly base schedules used in the study are adjusted to reflect this transition from one hour to the next. This adjustment step is important because, to the extent actual load or generation is transitioning to the levels expected in the next hour, the adjusted base schedules will result in reduced deviations during these intervals, potentially reducing the regulation reserve requirement. Figure F.1 below illustrates the hourly base schedule and the ramping adjustment. The same calculation applies to all base schedules: Load, Wind, Non-VERs, and the combined portfolio.

Figure F.1 - Base Schedule Ramping Adjustment



Data Corrections

The data extracted from PacifiCorp's systems for, wind, solar and Non-VERs was sourced from

CAISO settlement quality data. This data has already been verified for inconsistencies as part of the settlement process and needs minimal cleaning as described below. Regarding five-minute interval load data from the PI Ranger system, intervals were excluded from the FRS results if any five-minute interval suffered from at least one of the data anomalies that are described further below:

Load:
- Telemetry spike/poor connection to meter
- Missing meter data
- Missing base schedules

VERs:
- Curtailment events

Load in PacifiCorp's BAAs changes continuously. While a BAA could potentially maintain the exact same load levels in two five-minute intervals in a row, it is extremely unlikely for the exact same load level to persist over longer time frames. When PacifiCorp's energy management system (EMS) load telemetry fails, updated load values may not be logged, and the last available load measurement for the BAA will continue to be reported.

Rapid spikes in load telemetry either up or down are unlikely to be the result of conditions which require deployment of regulation reserve, particularly when they are transient. Such events could be a result of a transmission or distribution outage, which would allow for the deployment of contingency reserve, and would not require deployment of regulation reserve. Such events are also likely to be a result of a single bad load measurement. Load telemetry spike irregularities were identified by examining the intervals with the largest changes from one interval to the next, either up or down. Intervals with inexplicably large and rapid changes in load, particularly where the load reverts within a short period, were assumed to have been covered through contingency reserve deployment or to reflect inaccurate load measurements. Because they do not reflect periods that require regulation reserve deployment, such intervals are excluded from the analysis. During the study period, in PACW 15 minutes' worth of telemetry spikes were excluded while no telemetry spikes were observed in PACE. There were also 10 minutes' worth of missing load meter data, and 82 hours of missing load base schedules.

The available VER data includes wind curtailment events which affect metered output. When these curtailments occur, the CAISO sends data, by generator, indicating the magnitude of the curtailment. This data is layered on top of the actual meter data to develop a proxy for what the metered output would have been if the generator were not curtailed. Regulation reserve requirements are calculated based on the shortfall in actual output relative to base schedules. By adding back curtailed volumes to the actual metered output, the shortfall relative to base schedules is reduced, as is the regulation reserve requirement. This is reasonable since the curtailment is directed by the CAISO or the transmission system operator to help maintain reliable operation, so it should not exacerbate the calculated need for regulation reserves.

After review of the data for each of the above anomaly types, and out of 210,216 five-minute intervals evaluated, approximately 1,000 five-minute intervals, or 0.5% of the data, was removed due to data errors. While cleaning up or replacing anomalous hours could yield a more complete data set, determining the appropriate conditions in those hours would be difficult and subjective.

By removing anomalies, the FRS sample is smaller but remains reflective of the range of conditions PacifiCorp experiences, including the impact on regulation reserve requirements of weather events experienced during the study period.

Regulation Reserve Requirement Methodology

Overview

This section presents the methodology used to determine the initial regulation reserve needed to manage the load and resource balance within PacifiCorp's BAAs. The five-minute interval load and resource deviation data described above informs a regulation reserve forecast methodology that achieves the following goals:

- Complies with NERC standard BAL-001-2;
- Minimizes regulation reserve held; and
- Uses data available at time of EIM base schedule submission at T-40.[17]

The components of the methodology are described below, and include:

- Operating Reserve: Reserve Categories;
- Calculation of Regulation Reserve Need;
- Balancing Authority ACE Limit: Allowed Deviations;
- Planning Reliability Target: Loss of Load Probability ("LOLP"); and
- Regulation Reserve Forecast: Amount Held.

Following the explanation below of the components of the methodology, the next section details the forecasted amount of regulation reserve for:

- Wind;
- Solar;
- Non-VERs; and
- Load.

Components of Operating Reserve Methodology

Operating Reserve: Reserve Categories
Operating reserve consists of three categories: (1) contingency reserve (i.e., spinning and supplemental reserve), (2) regulation reserve, and (3) frequency response reserve. These requirements must be met by resources that are incremental to those needed to meet firm system demand. The purpose of the FRS is to determine the regulation reserve requirement. The contingency reserve and frequency response requirements are defined formulaically by their respective reliability standards.

Of the three categories of reserve referenced above, the FRS is primarily focused on the requirements associated with regulation reserve. Contingency reserve may not be deployed to manage other system fluctuations such as changes in load or wind generation output. Because deviations caused by contingency events are covered by contingency reserve rather than regulation

[17] *See* footnote 12 above for explanation of PacifiCorp's use of the T-40 base schedule time point in the FRS.

reserve, they are excluded from the determination of the regulation reserve requirements. Because frequency response reserve can overlap with that held for contingency and regulation reserve requirements it is similarly excluded from the determination of regulation reserve requirements. The types of operating reserve and relationship between them are further defined in in the Flexible Resource Requirements section above.

Regulation reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC Control Performance Criteria in BAL-001-2, which requires a BAA to carry regulation reserve incremental to contingency reserve to maintain reliability.[18] The regulation reserve requirement is not defined by a simple formula, but instead is the amount of reserve required by each BAA to meet specified control performance standards. Requirement two of BAL-001-2 defines the compliance standard as follows:

> *Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes…*

PacifiCorp has been operating under BAL-001-2 since March 1, 2010, as part of a NERC Reliability-Based Control field trial in the Western Interconnection, so PacifiCorp had experience operating under the standard, even before it became effective on July 1, 2016.

The three key elements in BAL-001-2 are: (1) the length of time (or "interval") used to measure compliance; (2) the percentage of intervals that a BAA must be within the limits set in the standard; and (3) the bandwidth of acceptable deviation used under each standard to determine whether an interval is considered out of compliance. These changes are discussed in further detail below.

The first element is the length of time used to measure compliance. Compliance under BAL-001-2 is measured over rolling thirty-minute intervals, with 60 overlapping periods per hour, some of which include parts of two clock-hours. In effect, this means that every minute of every hour is the beginning of a new, thirty-minute compliance interval under the new BAL-001-2 standard. If ACE is within the allowed limits at least once in a thirty-minute interval, that interval is in compliance, so only the minimum deviation in each rolling thirty-minute interval is considered in determining compliance. As a result, PacifiCorp does not need to hold regulation reserve for deviations with duration less than 30 minutes.

The second element is the number of intervals where deviations are allowed to be outside the limits set in the standard. BAL-001-2 requires 100 percent compliance, so deviations must be maintained within the requirement set by the standard for all rolling thirty-minute intervals.

The third element is the bandwidth of acceptable deviation before an interval is considered out of compliance. Under BAL-001-2, the acceptable deviation for each BAA is dynamic, varying as a function of the frequency deviation for the entire interconnect. When interconnection frequency exceeds 60 Hz, the dynamic calculation does not require regulation resources to be deployed regardless of a BAA's ACE. As interconnection frequency drops further below 60 Hz, a BAA's permissible ACE shortfall is increasingly restrictive.

[18] NERC Standard BAL-001-2, https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf

Planning Reliability Target: Loss of Load Probability
When conducting resource planning, it is common to use a reliability target that assumes a specified loss of load probability (LOLP). In effect, this is a plan to curtail firm load in rare circumstances, rather than acquiring resources for extremely unlikely events. The reliability target balances the cost of additional capacity against the benefit of incrementally more reliable operation. By planning to curtail firm load in the rare event of a regulation reserve shortage, PacifiCorp can maintain the required 100 percent compliance with the BAL-001-2 standard and the Balancing Authority ACE Limit. This balances the cost of holding additional regulation reserve against the likelihood of regulation reserve shortage events.

The FRS assumes that a regulation reserve forecasting methodology that results in 0.50 loss of load hours per year due to regulation reserve shortages is appropriate for planning and ratemaking purposes. This is in addition to any loss of load resulting from transmission or distribution outages, resource adequacy, or other causes. The FRS applies this reliability target as follows:

- If the regulation reserve available is greater than the regulation reserve need for an hour, the LOLP is zero for that hour.
- If the regulation reserve held is less than the amount needed, the LOLP is derived from the Balancing Authority ACE Limit probability distribution as illustrated below.

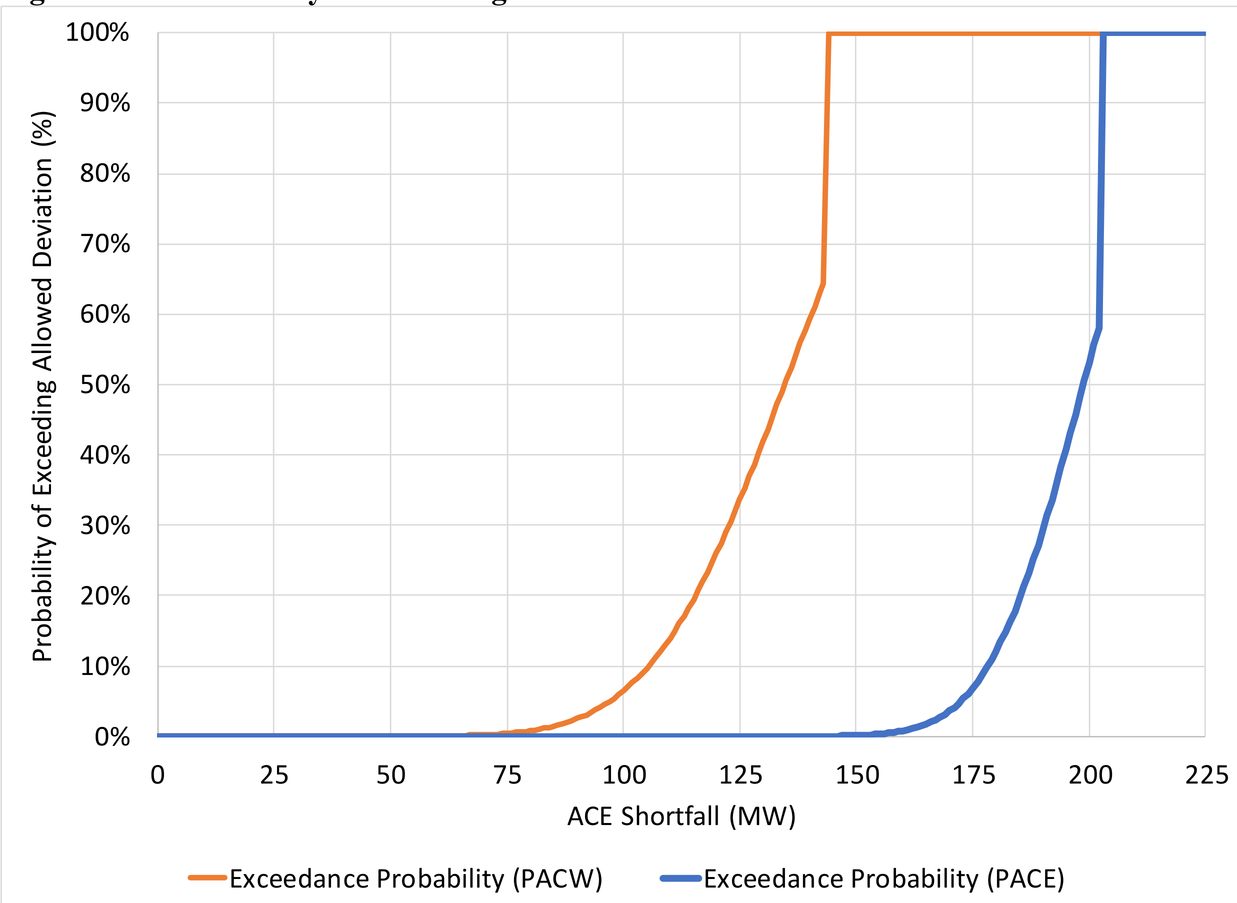
Balancing Authority ACE Limit: Allowed Deviations
Even if insufficient regulation reserve capability is available to compensate for a thirty-minute sustained deviation, a violation of BAL-001-2 does not occur unless the deviation also exceeds the Balancing Authority ACE Limit.

The Balancing Authority ACE Limit is specific to each BAA and is dynamic, varying as a function of interconnection frequency. When WECC frequency is close to 60 Hz, the Balancing Authority ACE Limit is large and large deviations in ACE are allowed. As WECC frequency drops further and further below 60 Hz, ACE deviations are increasingly restricted for BAAs that are contributing to the shortfall, i.e. those BAAs with higher loads than resources. A BAA commits a BAL-001-2 reliability violation if in any thirty-minute interval it does not have at least one minute when its ACE is within its Balancing Authority ACE Limit.

While the specific Balancing Authority ACE Limit for a given interval cannot be known in advance, the historical probability distribution of Balancing Authority ACE Limit values is known. Figure F.2 below shows the probability of exceeding the allowed deviation during a five-minute interval for a given level of ACE shortfall. For instance, an 82 MW ACE shortfall in PACW has a one percent chance of exceeding the Balancing Authority ACE Limit. WECC-wide frequency can change rapidly and without notice, and this causes large changes in the Balancing Authority ACE Limit over short time frames. Maintaining ACE within the Balancing Authority ACE Limit under those circumstances can require rapid deployment of large amounts of operating reserve. To limit the size and speed of resource deployment necessitated by variation in the Balancing Authority ACE Limit, PacifiCorp's operating practice caps permissible ACE at the lesser of the Balancing

Authority ACE Limit or four times L_{10}. This also limits the occurrence of transmission flows that exceed path ratings as result of large variations in ACE.[19,20] This cap is reflected in Figure F.2.

Figure F.2 - Probability of Exceeding Allowed Deviation



In 2018-2019, PacifiCorp's deviations and Balancing Authority ACE Limits were uncorrelated, which indicates that PacifiCorp's contribution to WECC-wide frequency is small. PacifiCorp's deviations and Balancing Authority ACE Limits were also uncorrelated when periods with large deviations were examined in isolation. If PacifiCorp's large deviations made distinguishable contributions to the Balancing Authority ACE Limit, ACE shortfalls would be more likely to exceed the Balancing Authority ACE Limit during large deviations. Since this is not the case, the probability of exceeding the Balancing Authority ACE Limit is lower, and less regulation reserve is necessary to comply with the BAL-001-2 standard.

Regulation Reserve Forecast: Amount Held

To calculate the amount of regulation reserve required to be held while being compliant with BAL-001-2 – using a LOLP of 0.5 hours per year or less – a quantile regression methodology was used. Quantile regression is a type of regression analysis. Whereas the typical method of ordinary least

[19] "Regional Industry Initiatives Assessment." NWPP MC Phase 3 Operations Integration Work Group. Dec. 31, 2014. Pg. 14. Available at: www.nwpp.org/documents/MC-Public/NWPP-MC-Phase-3-Regional-Industry-Initiatives-Assessment12-31-2014.pdf

[20] "NERC Reliability-Based Control Field Trial Draft Report." Western Electricity Coordinating Council. Mar. 25, 2015. Available at: www.wecc.biz/Reliability/RBC%20Field%20Trial%20Report%20Approved%203-25-2015.pdf

squares results in estimates of the conditional mean (50th percentile) of the response variable given certain values of the predictor variables, quantile regression aims at estimating other specified percentiles of the response variable. Eight regressions were prepared, one for each class (load/wind/solar/non-VER) and area (PACE/PACW). Each regression uses the following variables:

- Response Variable: the error in each interval, in megawatts;
- Predictor Variable: the forecasted generation or load in each interval, expressed as a percentage of area capacity;

The forecasted generation or load in each interval used as the predictor variable contributes to the regression as a combination of linear, square, and higher order exponential effects. Specifically, the regression identifies coefficients that correspond to the following functions for each class:

Load Error: Load Forecast^1 + Constant
Wind Error: Wind Forecast^2 + Wind Forecast^1
Solar Error: Solar Forecast^4 + Solar Forecast^3 + Solar Forecast^2 + Solar Forecast^1
Non-VER Error: Non-VER Forecast^2 + Non-VER Forecast^1

The instances requiring the largest amounts of regulation reserve occur infrequently, and many hours have very low requirements. If periods when requirements are likely to be low can be distinguished from periods when requirements are likely to be high, less regulation reserve is necessary to achieve a given reliability target. The regulation reserve forecast is not intended to compensate for every potential deviation. Instead, when a shortfall occurs, the size of that shortfall determines the probability of exceeding the Balancing Authority ACE Limit and a reliability violation occurring. The forecast is adjusted to achieve a cumulative LOLP that corresponds to the annual reliability target.

Regulation Reserve Forecast

Overview

The following forecasts are polynomial functions that cover a targeted percentile of all historical deviations. These forecasts are stand-alone forecasts, based on the difference between hour-ahead base schedules and actual meter data, expressing the errors as a function of the level of forecast. The stand-alone reserve requirement shown achieves the annual reliability target of 0.5 hours per year, after accounting for the dynamic Balancing Authority ACE Limit. The combined diversity error system requirements are discussed later in the study. Figure F.3- Figure F.8 illustrate the relationship between the regulation reserve requirements during 2018-2019 and the forecasted level of output, for each resource class and control area. Both the regulation reserve requirements and the forecasted level of output are expressed as a percentage of resource nameplate (i.e., as a capacity factor). Figure F.9 and Figure F.10 illustrate the same relationship between the regulation reserve requirements during 2018-2019 and the forecasted load for each control area. Both the regulation reserve requirements and the forecasted load are expressed as a percentage of the annual peak load (i.e., as a load factor).

Figure F.3 - Wind Regulation Reserve Requirements by Forecast - PACE

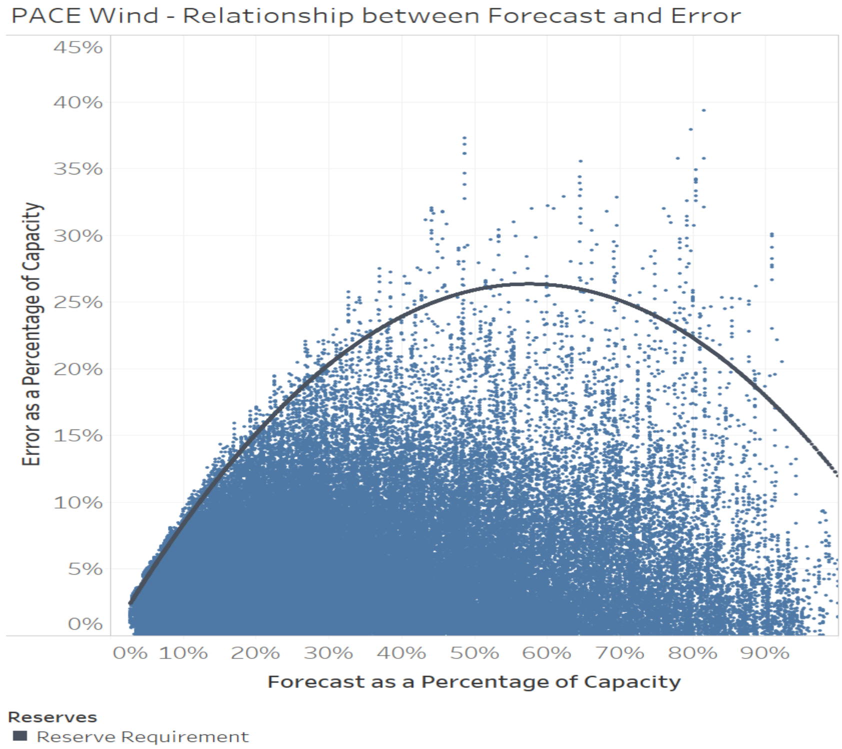


Figure F.4 - Wind Regulation Reserve Requirements by Forecast Capacity Factor - PACW

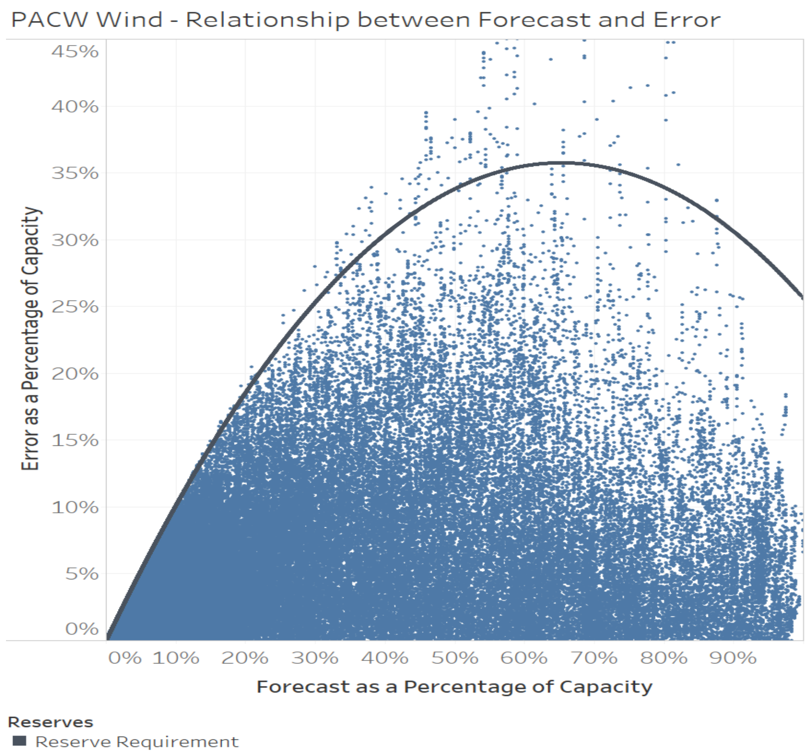


Figure F.5 - Solar Regulation Reserve Requirements by Forecast Capacity Factor - PACE

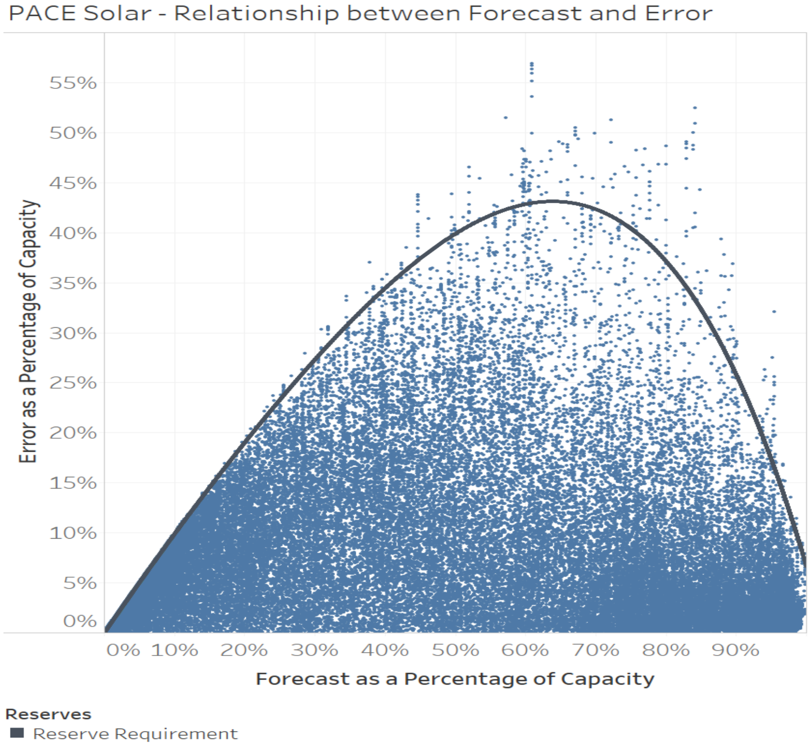


Figure F.6 - Solar Regulation Reserve Requirements by Forecast Capacity Factor - PACW

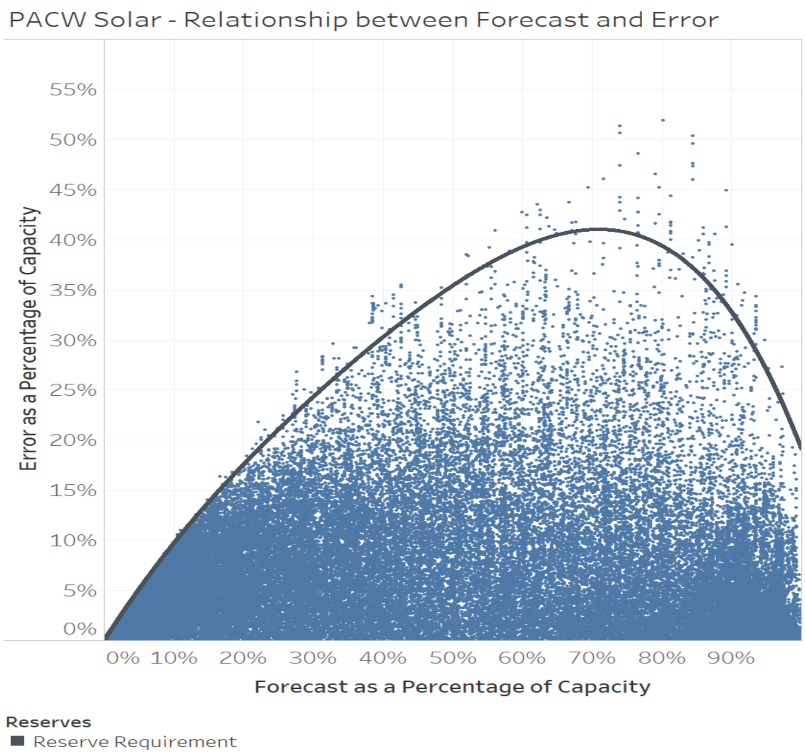


Figure F.7 – Non-VER Regulation Reserve Requirements by Capacity Factor - PACE

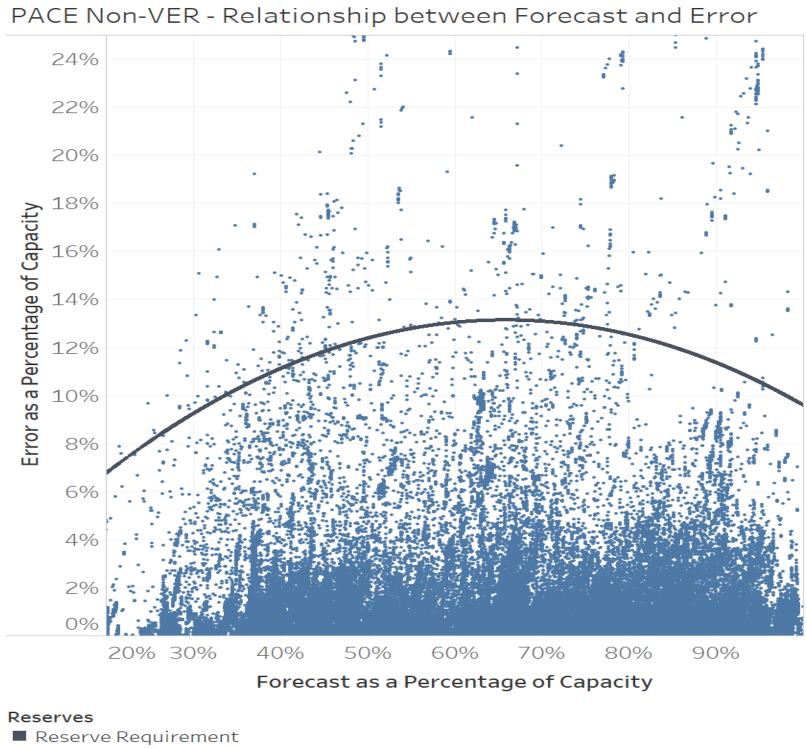


Figure F.8 – Non-VER Regulation Reserve Requirements by Capacity Factor - PACW

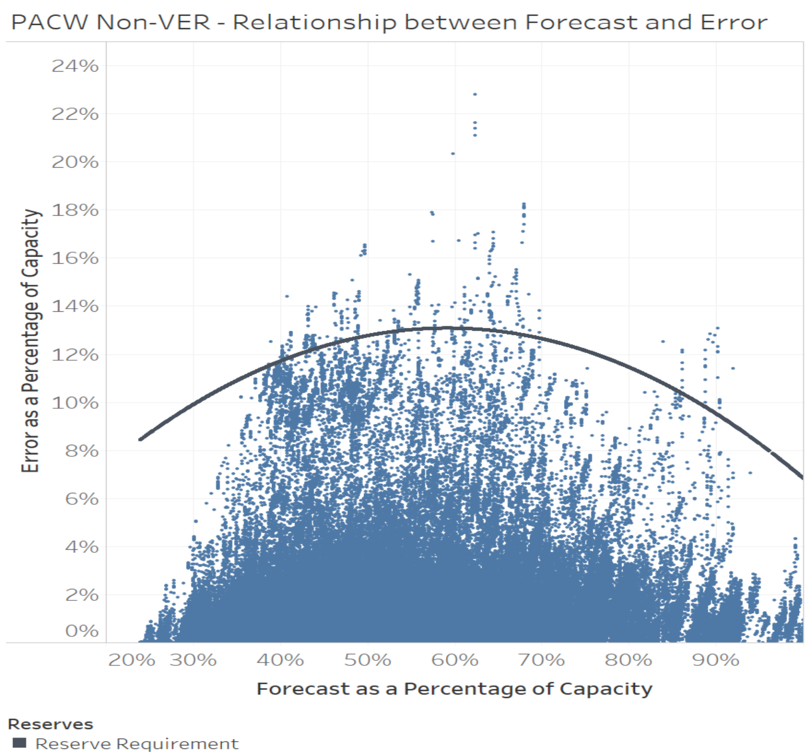


Figure F.9 – Stand-alone Load Regulation Reserve Requirements - PACE

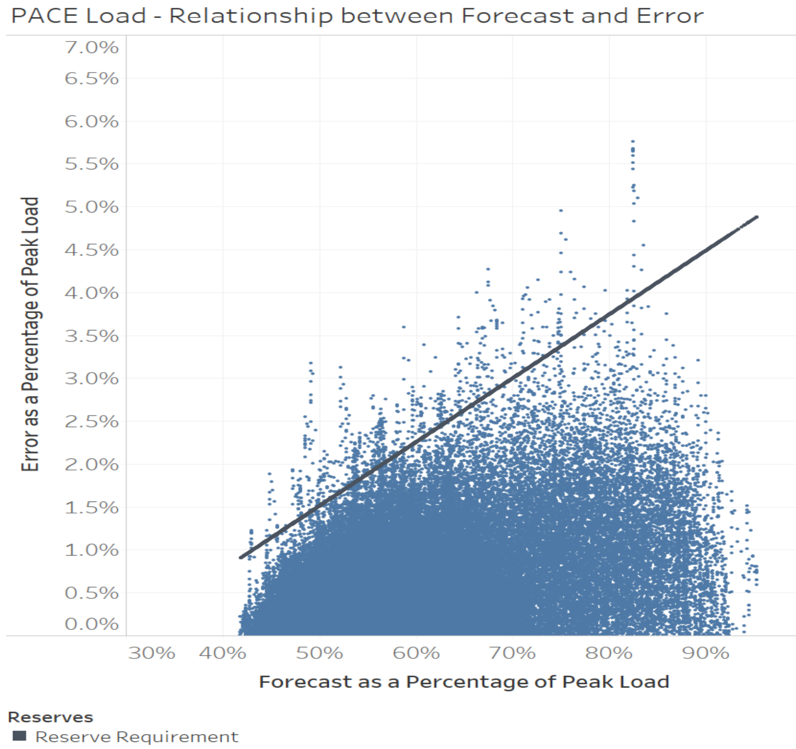
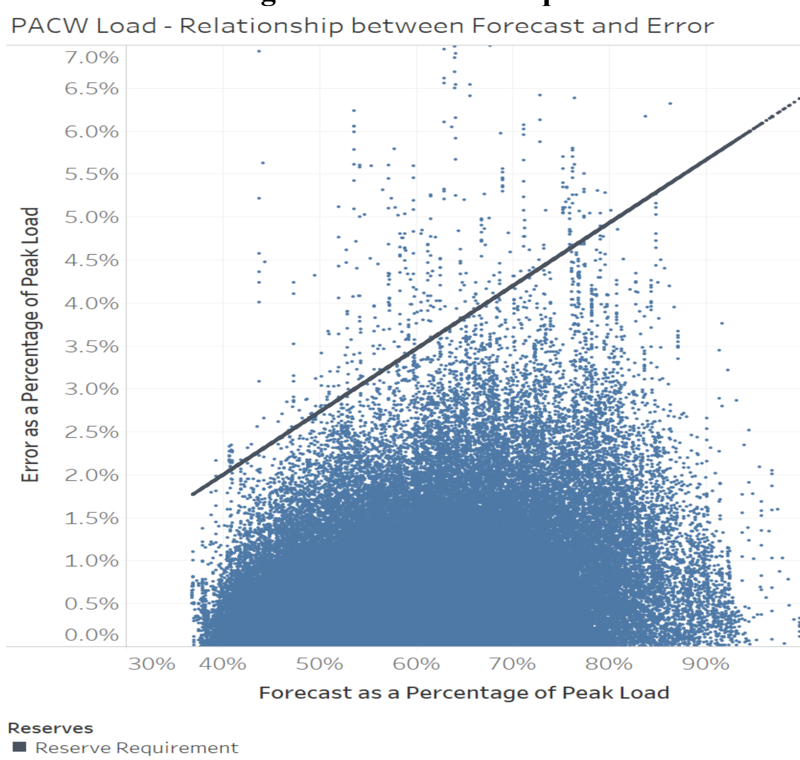


Figure F.10 – Stand-alone Load Regulation Reserve Requirements - PACW



The results of the analysis are shown in Table F.3 below.

Table F.3 – Summary of Stand-alone Regulation Reserve Requirements

Scenario	Stand-alone Regulation Forecast (aMW)	Capacity (MW)	Stand-alone Regulation Forecast (%)
Non-VER	106	1,304	8.2%
Load	334	10,094	3.3%
VER - Wind	457	2,745	16.7%
VER - Solar	159	1,080	14.8%
Total	**1,057**		

Portfolio Diversity and EIM Diversity Benefits

The EIM is a voluntary energy imbalance market service through the CAISO where market systems automatically balance supply and demand for electricity every fifteen and five minutes, dispatching least-cost resources every five minutes.

PacifiCorp and CAISO began full EIM operation on November 1, 2014. Several additional participants have since joined the EIM, and more participants are scheduled to join in the next several years. PacifiCorp's participation in the EIM results in improved power production forecasting and optimized intra-hour resource dispatch. This brings important benefits including reduced energy dispatch costs through automatic dispatch, enhanced reliability with improved situational awareness, better integration of renewable energy resources, and reduced curtailment of renewable energy resources.

The EIM also has direct effects related to regulation reserve requirements. First, because of EIM participation, PacifiCorp has improved data used in the analysis contained in this FRS. The data and control provided by the EIM allow PacifiCorp to achieve the portfolio diversity benefits described in the first part of this section. Second, the EIM's intra-hour capabilities across the broader EIM footprint provide the opportunity to reduce the amount of regulation reserve necessary for PacifiCorp to hold, as further explained in the second part of this section.

Portfolio Diversity Benefit

The regulation reserve forecasts described above independently ensure that the probability of a reliability violation for each class remains within the reliability target; however, the largest deviations in each class tend not to occur simultaneously, and in some cases, deviations will occur in offsetting directions. Because the deviations are not occurring at the same time, the regulation reserve held can cover the expected deviations for multiple classes at once and a reduced total quantity of reserve is sufficient to maintain the desired level of reliability. This reduction in the reserve requirement is the diversity benefit from holding a single pool of reserve to cover deviations in Solar, Wind, Non-VERs, and Load. As a result, the regulation reserve forecast for the portfolio can be reduced while still meeting the reliability target. In the historical period, portfolio diversity from the interactions between the various classes results in a regulation reserve requirement that is 36% lower than the sum of the stand-alone requirements, or approximately 679 MW.

EIM Diversity Benefit

In addition to the direct benefits from EIM's increased system visibility and improved intra-hour operational performance described above, the participation of other entities in the broader EIM footprint provides the opportunity to further reduce the amount of regulation reserve PacifiCorp must hold.

By pooling variability in load and resource output, EIM entities reduce the quantity of reserve required to meet flexibility needs. The EIM also facilitates procurement of flexible ramping capacity in the fifteen-minute market to address variability that may occur in the five-minute market. Because variability across different BAAs may happen in opposite directions, the flexible ramping requirement for the entire EIM footprint can be less than the sum of individual BAA requirements. This difference is known as the "diversity benefit" in the EIM. This diversity benefit reflects offsetting variability and lower combined uncertainty. This flexibility reserve (uncertainty requirement) is in addition to the spinning and supplemental reserve carried against generation or transmission system contingencies under the NERC standards.

The CAISO calculates the EIM diversity benefit by first calculating an uncertainty requirement for each individual EIM BAA and then by comparing the sum of those requirements to the uncertainty requirement for the entire EIM area. The latter amount is expected to be less than the sum of the uncertainty requirements from the individual BAAs due to the portfolio diversification effect of forecasting a larger pool of load and resources using intra-hour scheduling and increased system visibility in the hypothetical, single-BAA EIM. Each EIM BAA is then credited with a share of the diversity benefit calculated by CAISO based on its share of the stand-alone requirement relative to the total stand-alone requirement.

The EIM does not relieve participants of their reliability responsibilities. EIM entities are required to have sufficient resources to serve their load on a standalone basis each hour before participating in the EIM. Thus, each EIM participant remains responsible for all reliability obligations. Despite these limitations, EIM imports from other participating BAAs can help balance PacifiCorp's loads and resources within an hour, reducing the size of reserve shortfalls and the likelihood of a Balancing Authority ACE Limit violation. While substantial EIM imports do occur in some hours, it is only appropriate to rely on PacifiCorp's diversity benefit associated with EIM participation, as these are derived from the structure of the EIM rather than resources contributed by other participants.

Table F.4 below provides a numeric example of uncertainty requirements and application of the calculated diversity benefit.

Table F.4 – EIM Diversity Benefit Application Example

	a	b	c	d	e =a+b+c+d	f	g = e-f	h = g / e	i = c * h	j = c - i
Hour	CAISO req't. before benefit (MW)	NEVP req't. before benefit (MW)	PACE req't. before benefit (MW)	PACW req't. before benefit (MW)	Total req't. before benefit (MW)	Total req't. after benefit (MW)	Total diversity benefit (MW)	Diversity benefit ratio (MW)	PACE benefit (MW)	PACE req't. after benefit (MW)
1	550	110	165	100	925	583	342	37.00%	61	104
2	600	110	165	100	975	636	339	34.80%	57	108
3	650	110	165	110	1,035	689	346	33.40%	55	110
4	667	120	180	113	1,080	742	338	31.30%	56	124

While the diversity benefit is uncertain, that uncertainty is not significantly different from the uncertainty in the Balancing Authority ACE Limit previously described. In the FRS, PacifiCorp has credited the regulation reserve forecast based on a historical distribution of calculated EIM diversity benefits. While this FRS considers regulation reserve requirements in 2018-2019, the CAISO identified an error in their calculation of uncertainty requirements in early 2018. CAISO's published uncertainty requirements and associated diversity benefits are now only valid for March 2018 forward. To capture these additional benefits for this analysis, PacifiCorp has applied the historical distribution of EIM diversity benefits from the 12 months beginning March 2018. In the historical study period, EIM diversity benefits used in the FRS would have reduced regulation reserve requirements by approximately 140 MW.

The inclusion of EIM diversity benefits in the FRS reduces the magnitude, and thus probability, of reserve shortfalls and, in doing so, reduces the overall regulation reserve requirement. This allows PacifiCorp's forecasted requirements to be reduced. As shown in Table F.5 below, the resulting regulation reserve requirement is 540 MW, which is a 49 percent reduction (including the portfolio diversity benefit) compared to the stand-alone requirement for each class. This portfolio regulation forecast is expected to achieve an LOLP of 0.5 hours per year.

Table F.5 – 2018-2019 Results with Portfolio Diversity and EIM Diversity Benefits

Scenario	Stand-alone Regulation Forecast (aMW)	Stand-alone Rate (%)	Portfolio Regulation Forecast w/EIM (aMW)	Portfolio Rate (%)	Capacity (MW)	Rate Determinant
Non-VER	106	8.2%	55	4.2%	1,304	Nameplate
Load	334	3.3%	172	1.7%	10,094	12 CP
VER - Wind	457	16.7%	237	8.6%	2,745	Nameplate
VER - Solar	159	14.8%	76	7.1%	1,080	Nameplate
Total	**1,057**		**540**			

Fast-Ramping Reserve Requirements

As previously discussed, Requirement 1 of BAL-001-2 specifies that PacifiCorp's CPS1 score must be greater than equal to 100 percent for each preceding 12 consecutive calendar month period, evaluated monthly. The CPS1 score compares PacifiCorp's ACE with interconnection frequency during each clock minute. A higher score indicates PacifiCorp's ACE is helping interconnection frequency, while a lower score indicates it is hurting interconnection frequency. Because CPS1 is averaged and evaluated on a monthly basis, it does not require a response to each and every ACE event, but rather requires that PacifiCorp meet a minimum aggregate level of performance in each month.

The Regulation Reserve Forecast described above is evaluating requirements for extreme deviations that are at least 30 minutes in duration, for compliance with Requirement 2 of BAL-001-2. In contrast, compliance with CPS1 requires reserve capability to compensate for most conditions over a minute-to-minute basis. These fast-ramping resources would be deployed frequently and would also contribute to compliance with Requirement 2 of BAL-001-2, so they are a subset of the Regulation Reserve Forecast described above.

To evaluate CPS1 requirements, PacifiCorp compared the net load change for each five-minute interval in the study period to the corresponding value for Requirement 2 compliance in that hour from the Regulation Reserve Forecast, after accounting for diversity (resulting in a 540 MW average requirement). Resources may deploy for Requirement 2 compliance over up to 30 minutes, so the average requirement of 540 MW would require ramping capability of at least 18.0 MW per minute (540 MW / 30 minutes).

Because CPS1 is averaged and evaluated monthly, it does not require a response to each and every ACE event, but rather requires that PacifiCorp meet a minimum aggregate level of performance in each month. Resources capable of ensuring compliance in 95 percent of intervals are expected to be sufficient to meet CPS1 and given that ACE may deviate in either a positive or negative direction, the 97.5th percentile of incremental requirements versus Requirement 2 in that interval was evaluated. At the 97.5th percentile, fast ramping requirements for PACE and PACW are 1.7 MW/minute and 0.8 MW/minute higher than the Requirement 2 ramp rate, respectively; however, if dynamic transfers between the BAAs are available, the 97.5th percentile for system is 0.6 MW / minute lower than the Requirement 2 value. When viewed on a system basis, this means that 30-minute ramping capability held for Requirement 2 would be sufficient to cover an adequate portion of the fast-ramping events to ensure CPS1 compliance.

Note that resources must respond immediately to ensure compliance with Requirement 1, as performance is measured on a minute-to-minute basis. As a result, resources that respond after a delay, such as quick-start gas plants or certain interruptible loads, would not be suitable for Requirement 1 compliance, so these resources cannot be allocated the entire regulation reserve requirement. However, because Requirement 1 compliance is a small portion of the total regulation reserve requirement, these restrictions on resource type are unlikely to be a meaningful constraint.

In addition, CPS1 compliance is weighted toward performance during conditions when interconnection frequency deviations are large. The largest frequency deviations would also result in deployment of frequency response reserves, which are somewhat larger in magnitude, though they have a less stringent performance metric under BAL-003-2, based on median response during the largest events.

In light of the overlaps with BAL-001-2 Requirement 2 and BAL-003-2 described above, CPS1 compliance is not expected to result in an additional requirement beyond what is necessary to comply with those standards.

Portfolio Regulation Reserve Requirements

The IRP portfolio optimization process contemplates the addition of new wind and solar capacity as part of its selection of future resources, as well as changes in peak load due to load growth and energy efficiency measure selection. These load and resource changes are expected to drive changes in PacifiCorp's regulation reserve requirements that will vary from portfolio to portfolio.

The locations that have been identified as likely sites for future wind and solar additions are in relatively close proximity to existing wind and solar resources, and PacifiCorp's portfolio of resources is already relatively diverse with significant wind in Wyoming, along the Columbia River gorge, and in eastern Idaho/western Wyoming and significant solar in southern Utah and southern Oregon. Because future resources are likely to be added in relatively close proximity to these existing resources, they are not likely to change the diversity for that class of resources as a whole. Given the sizeable sample of existing wind and solar resources in PACE and PACW, maintaining the existing level of diversity as a class of resources doubles or quadruples is a more likely outcome than the continuing improvements previously assumed in the 2019 FRS. With that in mind, the incremental regulation reserve analysis for the 2021 FRS methodology assumes that wind, solar, and load deviations scale linearly with capacity increases from the actual data in the 2018-2019 historical period.

While diversity within each class is not expected to change significantly, there is the opportunity for greater diversity among the wind, solar, and load requirements. These portfolio-related benefits are inherently tied to the portfolio, so it is appropriate that they vary with the portfolio. To that end, the 2021 FRS methodology calculates the portfolio diversity benefits specific to a wide variety of wind and solar capacity combinations, rather than relying upon the historical portfolio diversity value.

As part of the portfolio diversity calculation, the analysis assumes that minimum EIM flexible reserve requirements and EIM diversity benefits scale with changes in portfolio capacity. EIM minimum flexible reserve requirements are tied to the uncertainty in PacifiCorp's requirements, which grow with changes portfolio capacity, so it would be impacted directly. EIM diversity benefits reflect PacifiCorp's share of stand-alone requirements relative to those of the rest of the BAA's participating in EIM. All else being equal, increases in PacifiCorp's portfolio capacity would result in a greater proportion of the EIM diversity benefits being allocated to PacifiCorp.

Portfolio diversity is driven by interplay among the deviations by wind, solar, and load, so it is not a single number, but rather is dependent on the specific conditions. The 2021 FRS methodology incorporates two mechanisms to better account for these interactions. First, a portfolio diversity value is calculated specific to each hour of the day in each season. Second, rather than applying an equal percentage reduction to all hours, diversity benefits are assumed to be highest when stand-alone requirements are highest. For example, there is more opportunity for offsetting requirements when load, wind, and solar all have significant stand-alone requirements. With that in mind, diversity is applied as an exponent to the incremental requirement more than the EIM minimum requirement. The result of this calculation is a diversity benefit which is highest for large reserve requirements, and which approaches zero as the requirement approaches the EIM minimum, as illustrated in Table F.6.

Table F.6 – Portfolio Diversity Exponent Example

			Incremental Requirement w/ Diversity (MW) By Diversity Exponent			Portfolio Diversity (%) By Diversity Exponent		
Stand-alone Reserve Req. (MW)	**EIM Floor (MW)**	**Stand-alone Incremental Req. (MW)**	**d = c ^ 75%**	**e = c ^ 85%**	**f = c ^ 95%**	**g = 1 - (b + d)/a**	**h = 1 - (b + e)/a**	**i = 1 - (b + f)/a**
a	**b**	**c = a - b**	**75%**	**85%**	**95%**	**75%**	**85%**	**95%**
200	200	0	0	0	0	0%	0%	0%
250	200	50	19	28	41	12%	9%	4%
300	200	100	32	50	79	23%	17%	7%
350	200	150	43	71	117	31%	23%	9%
400	200	200	53	90	153	37%	27%	12%
450	200	250	63	109	190	42%	31%	13%
500	200	300	72	128	226	46%	34%	15%

For each combination of wind and solar capacity, the hourly portfolio diversity exponents for each season are increased in a stepwise fashion until the risk of regulation reserve shortfalls during an interval is sufficiently low and the overall risk of regulation reserve shortfalls achieves the target of 0.5 hours per year. The resulting portfolio diversity is maximized for a combination of wind and solar as summarized in Table F.77 and Table F.8 for PacifiCorp East and PacifiCorp West, respectively.

Table F.7 – PacifiCorp East Diversity by Portfolio Composition

(% Reduction vs. Stand-alone Requirements)

East Wind Capacity MW	%								
8,224	**548%**	17.2%	18.8%	20.6%					
7,184	**472%**	19.2%	21.5%	23.0%	25.5%	26.5%			
6,144	**395%**	22.9%	24.1%	25.6%	27.9%	28.5%	29.0%		
5,104	**319%**	26.0%	27.3%	29.2%	30.7%	30.7%	30.5%	29.5%	
4,064	**242%**	30.4%	31.6%	32.9%	33.8%	32.7%	32.8%	32.8%	
3,024	**166%**	35.0%	36.2%	38.5%	37.1%	37.6%	36.2%	33.9%	31.9%
1,575	**100%**		$\boxed{48.0\%}$	45.8%	43.1%	39.5%	35.8%	32.2%	29.4%
788	**50%**			46.4%	40.3%	36.4%	33.0%	30.0%	27.3%
	%	**50%**	**100%**	**166%**	**329%**	**493%**	**656%**	**820%**	**983%**
	MW	**428**	**855**	**1,462**	**2,502**	**3,542**	**4,582**	**5,622**	**6,662**

East Solar Capacity

$\boxed{}$ 2018-2019 Actual Wind and Solar Capacity

Table F.8 – PacifiCorp West Diversity by Portfolio Composition

(% Reduction vs. Stand-alone Requirements)

West Wind Capacity MW	%	50% / 111	100% / 221	166% / 321	329% / 1,041	493% / 1,761	656% / 2,481	820% / 3,201	983% / 3,921
4,389	548%	21.1%	22.4%	22.9%					
3,669	472%	23.4%	24.8%	25.4%	29.0%	33.0%			
2,949	395%	26.2%	26.7%	27.6%	32.1%	34.8%	38.1%		
2,229	319%	29.6%	30.6%	31.4%	36.2%	39.5%	42.7%	42.7%	
1,509	242%	33.8%	34.5%	36.3%	40.8%	45.2%	46.2%	43.9%	
789	166%	38.8%	41.6%	43.1%	47.6%	48.4%	47.7%	45.0%	44.3%
726	100%		42.4%	42.9%	48.6%	49.3%	47.7%	46.2%	44.4%
363	50%			41.7%	47.1%	49.8%	47.4%	45.0%	43.2%

West Solar Capacity (% / MW)

2018-2019 Actual Wind and Solar Capacity

After portfolio selection is complete, regulation reserve requirements are calculated specific to a portfolio's load, wind, and solar resources in each year. The hourly regulation reserve requirement varies as a function of annual peak load net of energy efficiency selections as well as total wind and solar capacity. The regulation reserve requirement also varies based on the hourly load net of energy efficiency and hourly wind and solar generation values. Diversity exponents specific to the wind and solar capacity in each year are applied by hour and season, by interpolating among the scenarios illustrated in Tables F.7 and F.8. For example, the diversity exponent for hour five in the spring for a PACW study with 1,000 MW of wind and 1,000 MW of solar would reflect a weighting of diversity exponents in hour five in the spring from four scenarios. The highest weighting would apply to the 789 MW wind/1,041 MW solar scenario, and successively lower weightings would apply to 1,509 MW wind/1,041 MW solar, 789 MW wind/321 MW solar, and 1,509 MW wind/321 MW solar, with the total weighting for all four scenarios summing to 100%.

Finally, an adjustment is made to account for the ability of resources that are combined with storage to offset their own generation shortfalls beyond what is already captured by the model. For example, combined solar and storage resources can offset their own generation shortfalls, up to their interconnection limit. In actual operation, a reduction in solar generation would enable additional storage discharge. However, within the PLEXOS model, there are no intra-hour variations in load or renewable resource output and thus no potential increase in storage discharge. Note that combined storage can only be discharged when there is a generation shortfall at the adjacent resource, so it cannot cover all shortfalls across the system. For example, many solar resources do not have co-located storage, and their errors would continue to need to be met with incremental reserves. Nonetheless, combined solar and storage can cover a portion of their own shortfalls, and that portion increases as more combined storage resources are added to the system. This adjustment reduces the hourly regulation reserve requirement that is entered in the model.

Regulation Reserve Cost

The PLEXOS model reports marginal reserve prices on an hourly basis. So long as the change in reserve obligations or capability from what was input for a study is relatively small, this reserve price can provide a reasonable estimate of the impact of changes in reserves, without requiring additional model runs.

To estimate wind and solar integration costs for the 2023 IRP, PacifiCorp prepared a PLEXOS scenario that reflected the final regulation reserve requirements, consistent with the Company's existing wind and resources plus selections in the preferred portfolio. Hourly regulation reserve prices were reported from this study.

Wind Integration

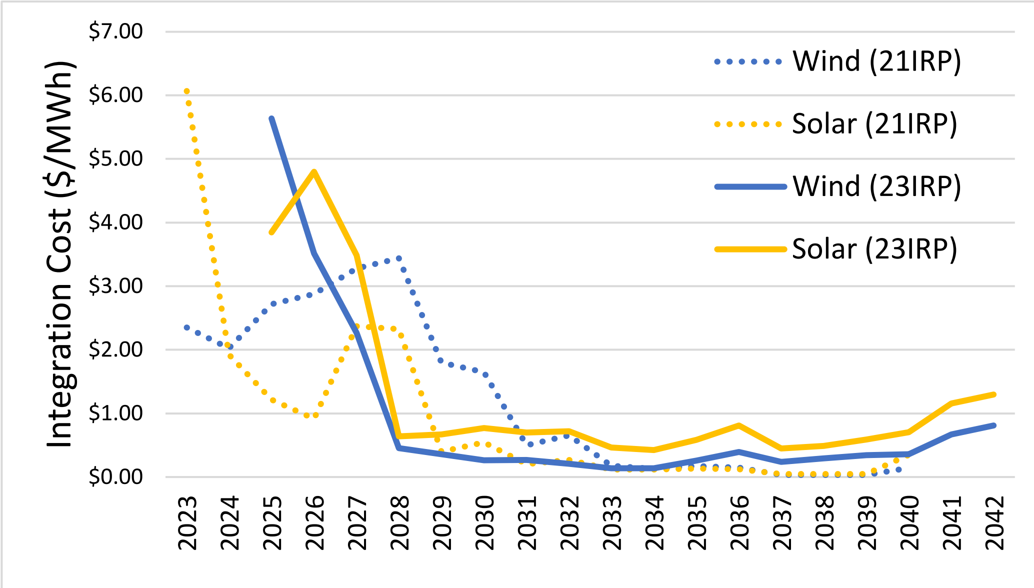
The wind reserve case uses the 2021 FRS methodology to recalculate the wind reserve requirement for a portfolio with 5 MW more wind resources starting in the first-year proxy resources are potentially available and extending to the end of the IRP study horizon (2025-2042). The change in resources is applied equally between PACE and PACW, and is allocated pro-rata among all wind resources in the area, such that the aggregate hourly capacity factor is not impacted by the change in capacity. The change in wind capacity results in incremental regulation reserve requirements that average approximately 16% of the nameplate capacity of the wind. Wind integration costs are calculated by multiplying the hourly change in reserve requirements (in MW) by the hourly regulation reserve price in each hour of the year, and then dividing that total by the incremental wind generation over the year.

Solar Integration

The solar reserve case uses the 2021 FRS methodology to recalculate the solar reserve requirement for a portfolio with 5 MW more solar resources starting in the first-year proxy resources are potentially available and extending to the end of the IRP study horizon (2025-2042). The reduction in resources is applied equally between PACE and PACW, and is allocated pro-rata among all solar resources in the area, such that the aggregate hourly capacity factor is not impacted by the change in capacity. The change in solar capacity results in incremental regulation reserve requirements that average approximately 10% of the nameplate capacity of the solar. Solar integration costs are calculated by multiplying the hourly change in reserve requirements (in MW) by the hourly regulation reserve price in each hour of the year, and then dividing that total by the incremental solar generation over the year.

The incremental regulation reserve cost results for wind and solar are shown in Figure F.11. The comparable regulation reserve costs from the 2021 FRS are also shown. Integration costs are high in the near term, as market prices are currently high and flexible capacity is somewhat limited. Integration costs fall as energy storage resources are added to the portfolio, as they can provide free operating reserves while charging and in any hour in which they are not discharging and not fully depleted, which for a four-hour energy storage resource is most of the day.

Figure F.11 – Incremental Wind and Solar Regulation Reserve Costs



Flexible Resource Needs Assessment

Overview

In its Order No. 12-013 issued on January 19, 2012, in Docket No. UM 1461 on "Investigation of matters related to Electric Vehicle Charging", the Oregon Public Utility Commission (OPUC) adopted the OPUC staff's proposed IRP guideline:

1. Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period;

2. Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period; and

3. Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options including the use of electric vehicles (EVs), on a consistent and comparable basis.

In this section, PacifiCorp first identifies its flexible resource needs for the IRP study period of 2023 through 2042, and the calculation method used to estimate those requirements. PacifiCorp then identifies its supply of flexible capacity from its generation resources, in accordance with the Western Electricity Coordinating Council (WECC) operating reserve guidelines, demonstrating that PacifiCorp has sufficient flexible resources to meet its requirements.

Forecasted Reserve Requirements

Since contingency reserve and regulation reserve are separate and distinct components, PacifiCorp estimates the forward requirements for each separately. The contingency reserve requirements are derived from the PLEXOS model. The regulating reserve requirements are part of the inputs to the PLEXOS model and are calculated by applying the methods developed in the Portfolio Regulation Reserve Requirements section. The contingency and regulation reserve requirements include three distinct components and are modeled separately in the 2023 IRP: 10-minute spinning reserve requirements, 10-minute non-spinning reserve requirements, and 30-minute regulation reserve requirements. The average reserve requirements for PacifiCorp's two balancing authority areas are shown in Table F.99 below.

Table F.9 - Reserve Requirements (Average MW)

Year	East Requirement			West Requirement		
	Spin (10-minute)	Non-spin (10-minute)	Regulation (30-minute)	Spin (10-minute)	Non-spin (10-minute)	Regulation (30-minute)
2023	342	342	850	272	272	261
2024	343	343	1,113	278	278	274
2025	347	347	1,268	283	283	291
2026	344	344	1,539	285	285	381
2027	347	347	1,534	289	289	422
2028	353	353	1,548	294	294	424
2029	355	355	1,640	296	296	425
2030	356	356	1,633	296	296	425
2031	358	358	1,602	298	298	424
2032	357	357	1,598	298	298	422
2033	359	359	1,597	299	299	424
2034	360	360	1,634	300	300	495
2035	361	361	1,837	301	301	606
2036	362	362	2,216	301	301	757
2037	365	365	1,801	303	303	910
2038	367	367	1,789	303	303	921
2039	368	368	1,963	305	305	947
2040	369	369	2,047	306	306	950
2041	382	382	2,048	310	310	954
2042	386	386	2,074	312	312	968

Flexible Resource Supply Forecast

Requirements by NERC and the WECC dictate the types of resources that can be used to serve the reserve requirements.

- **10-minute spinning reserve** can only be provided by resources currently online and synchronized to the transmission grid;

- **10-minute non-spinning reserve** may be served by fast-start resources that are capable of being online and synchronized to the transmission grid within ten minutes. Interruptible load can only provide non-spinning reserve. Non-spinning reserve may be provided by resources that are capable of providing spinning reserve.

- **30-minute regulation reserve** can be provided by unused spinning or non-spinning reserve. Incremental 30-minute ramping capability beyond the 10-minute capability captured in the categories above also counts toward this requirement.

The resources that PacifiCorp employs to serve its reserve requirements include owned hydro resources that have storage, owned thermal resources, and purchased power contracts that provide reserve capability.

Hydro resources are generally deployed first to meet the spinning reserve requirements because of their flexibility and their ability to respond quickly. The amount of reserve that these resources can provide depends upon the difference between their expected capacities and their generation level at the time. The hydro resources that PacifiCorp may use to cover reserve requirements in the PacifiCorp West balancing authority area include its facilities on the Lewis River and the Klamath River as well as its share of generation and capacity from the Mid-Columbia projects. In the PacifiCorp East balancing authority area, PacifiCorp may use facilities on the Bear River to provide spinning reserve.

Thermal resources are also used to meet the spinning reserve requirements when they are online. The amount of reserve provided by these resources is determined by their ability to ramp up within a 10-minute interval. For natural gas-fired combustion turbines, the amount of reserve can be close to the differences between their nameplate capacities and their minimum generation levels. In contrast, both coal and gas-converted steam turbines have slower ramp rates, and may ramp from minimum to maximum over an hour or more. In the current IRP, PacifiCorp’s reserve needs are increasingly met by energy storage resources, including contracted resources and proxy resource selections in the preferred portfolio.

Table F.10 lists the annual reserve capability from resources in PacifiCorp’s East and West balancing authority areas.[21] The changes in the flexible resource supply reflect retirement of existing resources, addition of new preferred portfolio resources, and variation in hydro capability due to forecasted streamflow conditions, and expiration of contracts from the Mid-Columbia projects that are reflected in the preferred portfolio.

[21] Frequency response capability is a subset of the 10-minute capability shown. Battery resources are capable of responding with their maximum output during a frequency event and can provide an even greater response if they were charging at the start of an event. PacifiCorp has sufficient frequency response capability at present and by 2025 the battery capacity currently contracted or added in the preferred portfolio will exceed PacifiCorp’s current 266.4 MW frequency response obligation for a 0.3 Hz event. As a result, compliance with the frequency response obligation is not anticipated to require incremental supply.

Table F.10 - Flexible Resource Supply Forecast (Average MW)

Year	East Supply (10-Minute)	West Supply (10-Minute)	East Supply (30-Minute)	West Supply (30-Minute)
2023	1,301	922	1,823	895
2024	1,291	934	2,221	1,036
2025	1,247	949	2,606	992
2026	1,245	911	2,734	1,819
2027	1,231	1,104	2,714	1,970
2028	1,333	824	3,022	1,837
2029	1,274	858	3,233	1,925
2030	1,277	855	3,335	1,912
2031	1,282	858	3,304	1,887
2032	1,202	2,314	3,089	2,186
2033	1,237	2,295	3,202	2,206
2034	3,256	2,199	3,264	2,117
2035	3,357	2,138	3,529	2,273
2036	3,463	2,164	3,974	2,510
2037	3,544	2,171	3,748	2,495
2038	3,517	2,154	3,842	2,648
2039	3,672	2,190	3,965	2,695
2040	3,725	2,205	4,000	2,693
2041	3,742	2,157	4,078	2,697
2042	3,756	2,015	4,106	2,541

Figure F.12 and **Figure F.13** graphically display the balances of reserve requirements and capability of spinning reserve resources in PacifiCorp's East and West balancing authority areas respectively. The graphs demonstrate that PacifiCorp's system has sufficient resources to serve its reserve requirements throughout the IRP planning period. Note that keeping minimum amounts in energy storage or bringing thermal plants online and/or reducing their generation while online could increase the available response beyond that shown in the figures, and accounts for some of the increase in supply after 2030. In addition, PacifiCorp currently can transfer a portion of the operating reserves held in either of its balancing authority areas to help meet the requirements of its other balancing authority area, based on the reserve need and relative economics of the available supply.

Figure F.12 - Comparison of Reserve Requirements and Resources, East Balancing Authority Area (MW)

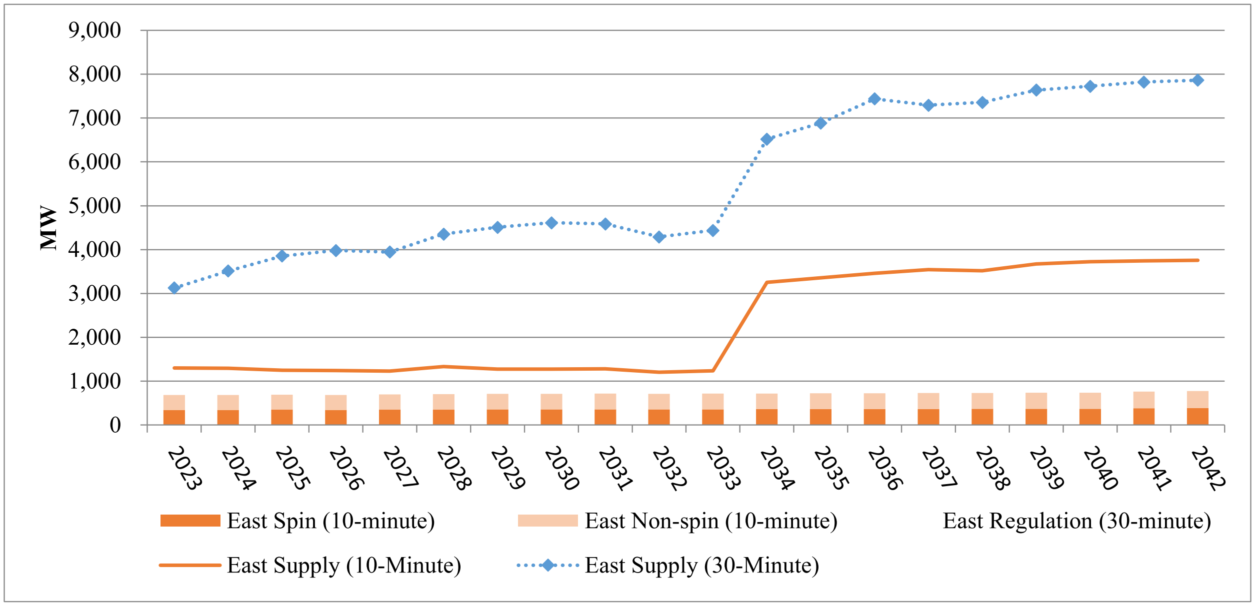
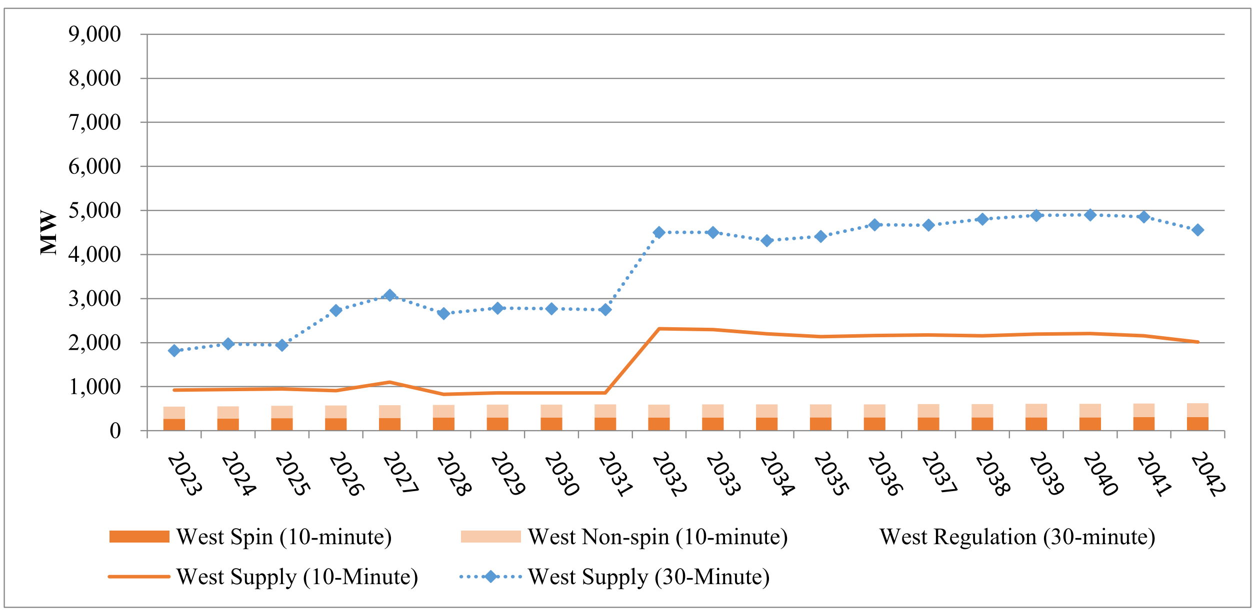


Figure F.13 - Comparison of Reserve Requirements and Resources, West Balancing Authority Area (MW)



Flexible Resource Supply Planning

In actual operations, PacifiCorp has been able to serve its reserve requirements and has not experienced any incidents where it was short of reserve. PacifiCorp manages its resources to meet its reserve obligation in the same manner as meeting its load obligation – through long term planning, market transactions, utilization of the transmission capability between the two balancing authority areas, and operational activities that are performed on an economic basis.

PacifiCorp and the California Independent System Operator Corporation implemented the energy imbalance market (EIM) on November 1, 2014, and participation by other utilities has expanded significantly with more participants scheduled for entry through 2023. By pooling variability in load and resource output, EIM entities reduce the quantity of reserve required to meet flexibility needs. Because variability across different BAAs may happen in opposite directions, the uncertainty requirement for the entire EIM footprint can be less than the sum of individual BAAs' requirements. This difference is known as the "diversity benefit" in the EIM. This diversity benefit reflects offsetting variability and lower combined uncertainty. PacifiCorp's regulation reserve forecast includes a credit to account for the diversity benefits associated with its participation in EIM.

As indicated in OPUC order 12-013, electric vehicle technologies may be able to meet flexible resource needs. For the first time in the 2023 IRP, electric vehicle load control is one of the demand response options available for selection. While electric vehicle load control was not one of the programs selected to the preferred portfolio, new demand response programs included in the preferred portfolio provide 275 average megawatts of operating reserves by 2030, and 860 average megawatts of operating reserves by 2042. While operating reserves supply is projected to be well in excess of operating reserve requirements, the rising supply of zero-cost renewable resources increases the value associated with shifting load within the day and seasonally, rather than just within the hour as contemplated in this appendix.

Attachment No. 2

Table 1. Wind Integration Charges

	Non-Levelized Rates	Levelized Rates	Online Year					
Year	$/MWh	Contract Length	2024	2025	2026	2027	2028	2029
2024	2.03	1	$2.03	$5.64	$3.51	$2.26	$0.45	$0.36
2025	5.64	2	$3.76	$4.61	$2.91	$1.39	$0.41	$0.31
2026	3.51	3	$3.68	$3.89	$2.15	$1.07	$0.36	$0.30
2027	2.26	4	$3.37	$3.13	$1.76	$0.89	$0.34	$0.28
2028	0.45	5	$2.87	$2.66	$1.50	$0.79	$0.32	$0.26
2029	0.36	6	$2.53	$2.33	$1.33	$0.71	$0.30	$0.24
2030	0.27	7	$2.28	$2.10	$1.21	$0.64	$0.28	$0.24
2031	0.27	8	$2.09	$1.92	$1.11	$0.60	$0.28	$0.26
2032	0.21	9	$1.94	$1.78	$1.03	$0.57	$0.28	$0.25
2033	0.14	10	$1.81	$1.66	$0.98	$0.56	$0.28	$0.26
2034	0.14	11	$1.71	$1.58	$0.94	$0.54	$0.28	$0.26
2035	0.26	12	$1.63	$1.52	$0.90	$0.53	$0.29	$0.27
2036	0.39	13	$1.58	$1.46	$0.87	$0.52	$0.29	$0.29
2037	0.24	14	$1.52	$1.41	$0.85	$0.51	$0.30	$0.31
2038	0.29	15	$1.48	$1.37	$0.83	$0.52	$0.32	$0.33
2039	0.34	16	$1.44	$1.34	$0.83	$0.53	$0.34	$0.34
2040	0.36	17	$1.41	$1.32	$0.83	$0.54	$0.36	$0.36
2041	0.67	18	$1.39	$1.30	$0.83	$0.54	$0.37	$0.37
2042	0.81	19	$1.37	$1.29	$0.83	$0.55	$0.38	$0.39
2043	0.83	20	$1.36	$1.28	$0.83	$0.56	$0.39	$0.40
2044	0.84	21						
2045	0.86	22						
2046	0.88	23						
2047	0.90	24						
2048	0.91	25						

Table 2. Solar Integration Charges

	Non-Levelized Rates	Levelized Rates	Online Year					
Year	$/MWh	Contract Length	2024	2025	2026	2027	2028	2029
2024	1.92	1	$1.92	$3.85	$4.80	$3.48	$0.64	$0.67
2025	3.85	2	$2.85	$4.30	$4.17	$2.12	$0.65	$0.72
2026	4.80	3	$3.45	$4.05	$3.08	$1.67	$0.69	$0.71
2027	3.48	4	$3.46	$3.29	$2.54	$1.47	$0.69	$0.71
2028	0.64	5	$2.98	$2.85	$2.24	$1.34	$0.70	$0.67
2029	0.67	6	$2.66	$2.56	$2.03	$1.26	$0.67	$0.64
2030	0.77	7	$2.45	$2.35	$1.88	$1.17	$0.64	$0.63
2031	0.70	8	$2.28	$2.20	$1.75	$1.10	$0.63	$0.65
2032	0.72	9	$2.16	$2.06	$1.64	$1.06	$0.65	$0.63
2033	0.46	10	$2.04	$1.95	$1.57	$1.04	$0.63	$0.62
2034	0.43	11	$1.94	$1.87	$1.53	$1.00	$0.62	$0.62
2035	0.58	12	$1.87	$1.81	$1.47	$0.98	$0.62	$0.62
2036	0.81	13	$1.82	$1.75	$1.42	$0.96	$0.63	$0.65
2037	0.45	14	$1.77	$1.70	$1.39	$0.95	$0.65	$0.68
2038	0.49	15	$1.72	$1.65	$1.36	$0.96	$0.67	$0.70
2039	0.59	16	$1.68	$1.62	$1.36	$0.97	$0.69	$0.72
2040	0.70	17	$1.65	$1.61	$1.35	$0.98	$0.71	$0.74
2041	1.16	18	$1.64	$1.60	$1.35	$0.99	$0.73	$0.76
2042	1.30	19	$1.63	$1.59	$1.35	$1.00	$0.75	$0.78
2043	1.32	20	$1.62	$1.59	$1.35	$1.01	$0.76	$0.79
2044	1.35	21						
2045	1.38	22						
2046	1.40	23						
2047	1.43	24						
2048	1.46	25						