ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W. North Temple, Suite 330
Salt Lake City, Utah 84116

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October 8, 2020

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-20-14
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
Commission Secretary

Please find for filing Rocky Mountain Power's Application in the above-referenced matter and Attachment No. 1 which is Appendix F, the Flexible Reserve Study, from Volume II of the 2019 IRP study.

Informal inquiries may be directed to Ted Weston, Idaho Regulatory Manager at (801) 220-2963.

Very truly yours,

Joelle Steward

Joelle Steward
Vice President, Regulation

Emily Wegener
Rocky Mountain Power
1407 West North Temple, Suite 320
Salt Lake City, Utah 84116
Telephone: 801-220-4526

Attorney for Rocky Mountain Power

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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-20-14** **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 increase the wind and solar integration rate applicable to new power purchase agreements ("PPA"), by Rocky Mountain Power of electric power from wind-powered qualified facilities, ("QFs"), from $0.57 to $1.11 per megawatt-hour ("MWh"), and the solar integration rate from $0.60 to $0.85 per MWh applicable to purchases by Rocky Mountain Power of electric power from solar-powered QFs. 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 84,000 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]

4. On August 28, 2017, after filing the 2017 Integrated Resource Plan ("IRP"), the Company filed to update the wind integration rate and implement a solar integration rate based on the results of the 2017 IRP Flexible Reserve Study.

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[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 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

5. 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 reduction to the published avoided cost rate 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.

6. On October 25, 2020, the Company filed its 2019 Integrated Resource Plan, as Case No. PAC-E-19-16. In support of this Application the Company submitted as Attachment No. 1, Appendix F – Flexible Reserve Study from Volume II of the 2019 IRP. Attachment No. 1 explains in detail the methodology used and the results derived from PacifiCorp's analysis of wind and solar integration costs.

II. 2019 IRP – FLEXIBLE RESERVE STUDY

7. Appendix F of the 2019 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 2017 through December 2017 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 2017. 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 2017 IRP, but has been enhanced in some key ways. First, regulation reserve requirements are co-optimized in a quantile regression model. Second, actual hourly load schedules are employed as compared to the proxy schedules developed in the previous study. Third, the FRS uses actual solar schedules reflecting the widespread penetration of utility scale solar facilities that has occurred since the previous study. Fourth, the FRS reflects updated data based on actual operational experience, including the data and benefits from PacifiCorp's participation in the Energy Imbalance Market ("EIM").

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 2017 IRP FRS are also included for reference.

Table F.1 - Portfolio Regulation Reserve Requirements

	Wind Capacity	Solar Capacity	Stand-alone Regulation Requirement	Portfolio Diversity Credit	Regulation Requirement with Diversity
Case	(MW)	MW	(MW)	(%)	(MW)
2017 Base Case	2,757	1,050	998	38%	617
2019 Base Case	2,750	1,021	994	47%	531

14. In the 2017 FRS, the Company calculated an inter-hour system balancing integration cost reflecting sub-optimal gas plant commitment based on day-ahead load, wind, and solar forecasts, rather than actuals. However, gas plants are dispatched in EIM to meet regional demand, not just the PacifiCorp demand reflected in the PaR model, and quick-start gas plants can be committed within EIM. In light of the minimal impact of the calculated cost in the 2017 IRP, and possible interaction with EIM, the company opted not to include inter-hour system balancing integration costs in the 2019 IRP.

15. 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 2017 IRP FRS are also included for comparison.

Table F.2 - 2019 FRS Flexible Resource Costs as Compared to 2017 Costs, $/MWh

	Wind 2017 FRS (2016$)	Solar 2017 FRS (2016$)	Wind 2019 FRS (2018$)	Solar 2019 FRS (2018$)
Study Period	2017	2017	2018-2036	2018-2036
Intra-hour Reserve	$0.43	$0.46	$1.11	$0.85
Inter-hour System Balancing	$0.14	$0.14	n/a	n/a
Flexible Resource Cost	$0.57	$0.60	$1.11	$0.85

16. Based on the results of the FRS from the 2019 IRP the Company respectfully requests that the wind integration rate be increased from $0.57 to $1.11 per MWh, in 2018 dollars, and the solar integration rate increases from $0.60 to $0.85 per MWh, 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:

Ted Weston
Idaho Regulatory Affairs Manager
Rocky Mountain Power
1407 West North Temple, Suite 330
Salt Lake City, Utah 84116
Telephone: (801) 220-2963
Email: ted.weston@pacificorp.com

Emily Wegener,
Rocky Mountain Power
1407 West North Temple, Suite 320
Salt Lake City, Utah 84116
Telephone: (801) 220-4526
Email: emily.wegener@pacificorp.com

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 Multnomah, Suite 2000
Portland, Oregon 97232

Informal questions may be directed to Ted Weston, Idaho Regulatory Affairs Manager at (801) 220-2963.

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 $1.11 per MWh for wind-powered QFs; and (3) approving the solar integration rate of $0.85 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 8th day of October, 2020.

Rocky Mountain Power

By: Emily Wegener

Emily Wegener
Rocky Mountain Power

Attachment 1

APPENDIX F – FLEXIBLE RESERVE STUDY

Introduction

This 2019 Flexible Reserve Study (FRS) estimates the regulation reserve required to maintain PacifiCorp's system reliability and comply with North American Electric Reliability Corporation (NERC) reliability standards as well as the incremental cost of this regulation reserve. The FRS also compares PacifiCorp's overall operating reserve requirements, including both regulation reserve and contingency reserve, to its flexible resource supply over the Integrated Resource Plan (IRP) study period.

PacifiCorp operates two Balancing Authority Areas (BAAs) in the Western Electricity Coordinating Council (WECC) NERC region, PacifiCorp East (PACE) and PacifiCorp West (PACW). The PACE and PACW BAAs are interconnected by a limited amount of transmission across a third-party transmission system and the two BAAs are each required to comply with NERC standards. PacifiCorp must provide sufficient regulation reserve to remain within NERC's balancing authority area control error (ACE) limit in compliance with BAL-001-2,[1] as well as the amount of contingency reserve required in order to comply with NERC standard BAL-002-WECC-2.[2] BAL-001-2 is a regulation reserve standard that became effective July 1, 2016, and BAL-002-WECC-2a is a contingency reserve standard that became effective January 24, 2017. Regulation reserve and contingency reserve are components of operating reserve, which NERC defines as "the capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection."[3]

Apart from disturbance events that are addressed through contingency reserve, regulation reserve is necessary to compensate for changes in load demand and generation output, so as to maintain ACE within mandatory parameters established by the BAL-001-2 standard. The FRS estimates the amount of regulation reserve required to manage variations in load, variable energy resources[4] (VERs), and resources that are not VERs ("Non-VERs") in each of PacifiCorp's BAAs. Load, wind, solar, and Non-VERs were each studied because PacifiCorp's data indicates that these components or customer classes place different regulation reserve burdens on PacifiCorp's system due to differences in the magnitude, frequency, and timing of their variations from forecasted levels.

The FRS is based on PacifiCorp operational data recorded from January 2017 through December 2017 for load, wind, solar, and Non-VERs. PacifiCorp's primary analysis, focuses on the

1 NERC Standard BAL-001-2, www.nerc.com/files/BAL-001-2.pdf, which became effective July 1, 2016. ACE is the difference between a BAA's scheduled and actual interchange, and reflects the difference between electrical generation and Load within that BAA.

2 NERC Standard BAL-002-WECC-2a, www.nerc.com/files/BAL-002-WECC-2a.pdf, which became effective January 24, 2017. BAL-002-WECC-2a clarified that non-traditional resources can qualify as spinning reserves if they meet technical and performance requirements.

3 NERC Glossary of Terms: www.nerc.com/files/glossary_of_terms.pdf, updated May 13, 2019.

4 VERs are resources that resources that: (1) are renewable; (2) cannot be stored by the facility owner or operator; and (3) have variability that is beyond the control of the facility owner or operator. *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246 at P 281 (2012) ("Order No. 764"); *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61,232 (2012) ("Order No. 764-A"); *order on reh'g and clarification*, Order No. 764-B, 144 FERC ¶ 61,222 at P 210 (2013) ("Order No. 764-B").

variability of load, wind, solar, and Non-VERs during 2017. A supplemental analysis discusses how the total variability of the PacifiCorp system changes with varying levels of load, 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 as a result of PacifiCorp's participation in the Energy Imbalance Market (EIM) operated by the California Independent System Operator Corporation (CAISO).

The methodology in the FRS is similar to that employed in PacifiCorp's previous regulation reserve requirement analysis in the 2017 IRP, but has been enhanced in some key ways.[5] First, regulation reserve requirements are co-optimized in a quantile regression model. Second, actual hourly load schedules are employed as compared to the proxy schedules developed in the previous study. Third, the FRS uses actual solar schedules reflecting the widespread penetration of utility scale solar facilities that has occurred since the previous study. Fourth, the FRS reflects updated data based on actual operational experience, including the data and benefits from PacifiCorp's participation in the EIM.[6]

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 was applied in the Planning and Risk (PaR) production cost model to determine the cost of the reserve requirements associated with incremental wind and solar capacity. These integration costs are applied to potential wind and solar resource options in the System Optimizer (SO) model portfolio expansion model, which does not otherwise account for regulation reserve requirements. When a portfolio is studied in the PaR model, the regulation reserve requirements specific to that portfolio are calculated and included in the study inputs, such that the production cost of the requirements is incorporated in the reported results, so it is not necessary to add integration costs to the PaR results.

Overview

The FRS first estimates the regulation reserve necessary to maintain compliance with NERC Standard BAL-001-2 given a specified portfolio of wind and solar resources. The FRS next calculates the cost of holding regulation reserve for incremental wind and solar resources. 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.

[5] 2017 Flexible Reserve Study, Appendix F in Volume II of PacifiCorp's 2017 IRP report: www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeII_2017_IRP_Final.pdf

[6] PacifiCorp presented the FRS for the 2019 IRP to the Technical Review Committee (TRC) that reviewed the FRS for the 2017 IRP. In light of the robust methodology developed for the 2017 IRP, and the relatively limited modifications for the 2019 IRP, TRC members indicated that continuing the formal review process was unnecessary.

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 the 2017 IRP is shown in Table F.1 and Table F.2.

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)
2017 Base Case	2,757	1,050	998	38%	617
2019 Base Case	2,750	1,021	994	47%	531

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	Wind 2017 FRS (2016$)	Solar 2017 FRS (2016$)	Wind 2019 FRS (2018$)	Solar 2019 FRS (2018$)
Study Period	2017	2017	2018-2036	2018-2036
Intra-hour Reserve	$0.43	$0.46	$1.11	$0.85
Inter-hour System Balancing	$0.14	$0.14	n/a	n/a
Total Flexible Resource Cost	$0.57	$0.60	$1.11	$0.85

In the 2017 FRS, PacifiCorp calculated an inter-hour system balancing integration cost reflecting sub-optimal gas plant commitment based on day-ahead load, wind, and solar forecasts, rather than actuals. However, gas plants are dispatched in EIM to meet regional demand, not just the PacifiCorp demand reflected in the PaR model, and quick-start gas plants can be committed within EIM. In light of the minimal impact of the calculated cost in the 2017 IRP, and possible interaction with EIM, the company opted not to include inter-hour system balancing integration costs in the 2019 IRP.

The 2019 FRS results are applied in the 2019 IRP portfolio development process as a cost for wind and solar generation resources. Once candidate resource portfolios are developed using the SO model, the PaR model is used to evaluate portfolio risks. The PaR model inputs include regulation reserve requirements specific to the resource portfolio developed using the SO model. As a result, the IRP risk analysis using PaR includes the impact of differences in regulation reserve requirements between portfolios.

Flexible Resource Requirements

PacifiCorp's flexible resource needs are the same as its operating reserve requirements over the planning horizon for maintaining reliability and compliance with the North American Electric Reliability Corporation (NERC) regional reliability standards. Operating reserve 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-2a.[7] Regulation reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC Control Performance Criteria in BAL-001-2.[8] Frequency response reserve is capacity that PacifiCorp holds available to ensure compliance with NERC standard BAL-003-1.[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-2a 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. In accordance with Requirement 2 of BAL-002-WECC-2a, at least half of a BAA's requirement must be met with "spinning" resources that are online and immediately responsive to system frequency deviations, while the remainder can come 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…*

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[7] NERC Standard BAL-002-WECC-2a – Contingency Reserve: www.nerc.com/files/BAL-002-WECC-2.pdf
[8] NERC Standard BAL-001-2 – Real Power Balancing Control Performance: www.nerc.com/files/BAL-001-2.pdf
[9] NERC Standard BAL-003-1 — Frequency Response and Frequency Bias Setting: www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.pdf
[10] Retirement of the minimum spinning reserve obligation in BAL-002-WECC-2a is being considered due to redundancy with frequency response obligations under BAL-003-1. More information is available online at: www.wecc.org/Standards/Pages/WECC-0115.aspx

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

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 2019 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 on 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. In order to continue providing flexible capacity in the following hour, energy must be available in storage for that hour as well. The likelihood of actually 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-003-1 specifies that each BAA must arrest frequency deviations and support the interconnection when frequency drops below the scheduled level. When a frequency drop occurs as a result 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 2019 Frequency Response Obligation was 20.2 MW/0.1Hz for PACW, and 47.4 MW/0.1Hz for PACE. PacifiCorp's combined obligation amounts to 67.6 MW for a frequency drop of 0.1 Hz, or 202.8 MW for a frequency drop of 0.3 Hz.

The performance measurement for contingency reserve under the Disturbance Control Standard (BAL-002-3)[11], 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 are capable of supporting 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 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,

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

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

To estimate the amount of regulation reserve that will be required in the future, the FRS identifies the scheduled use of the system as compared to the actual use of the system during the study term. For the baseline determination of scheduled use for load and resources, the FRS used hourly base schedules. Hourly base schedules are the power production forecasts used for imbalance settlement in the EIM and represent the best information available concerning the upcoming hour.[12]

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 of its transmission customers pursuant to the provisions of Attachment T to PacifiCorp's Federal Energy Regulatory Commission (FERC) approved Open Access Transmission Tariff (OATT). This includes EIM base schedule data (or forecasts) from all resources included in the EIM network model at transaction points. EIM base schedules are submitted by transmission customers with hourly granularity, and are settled using hourly data for load, and fifteen-minute and five-minute data for resources. A primary function of the EIM is to measure load and resource imbalance (or deviations) as the difference between the hourly base schedule and the actual metered values.

[12] 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

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 the majority of PacifiCorp's loads.

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

Actual average load data was collected separately for the PACE and PACW BAAs for each five-minute interval. Load data was downloaded from PacifiCorp's Ranger PI system and 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.[13] Wind and solar, in comparison to load, often have larger upward and downward

[13] Order No. 764 at P 281; Order No. 764-B at P 210.

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*."[14] 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 includes 2,750 megawatts of wind and 1,021 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."[15]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 on in the study.

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.

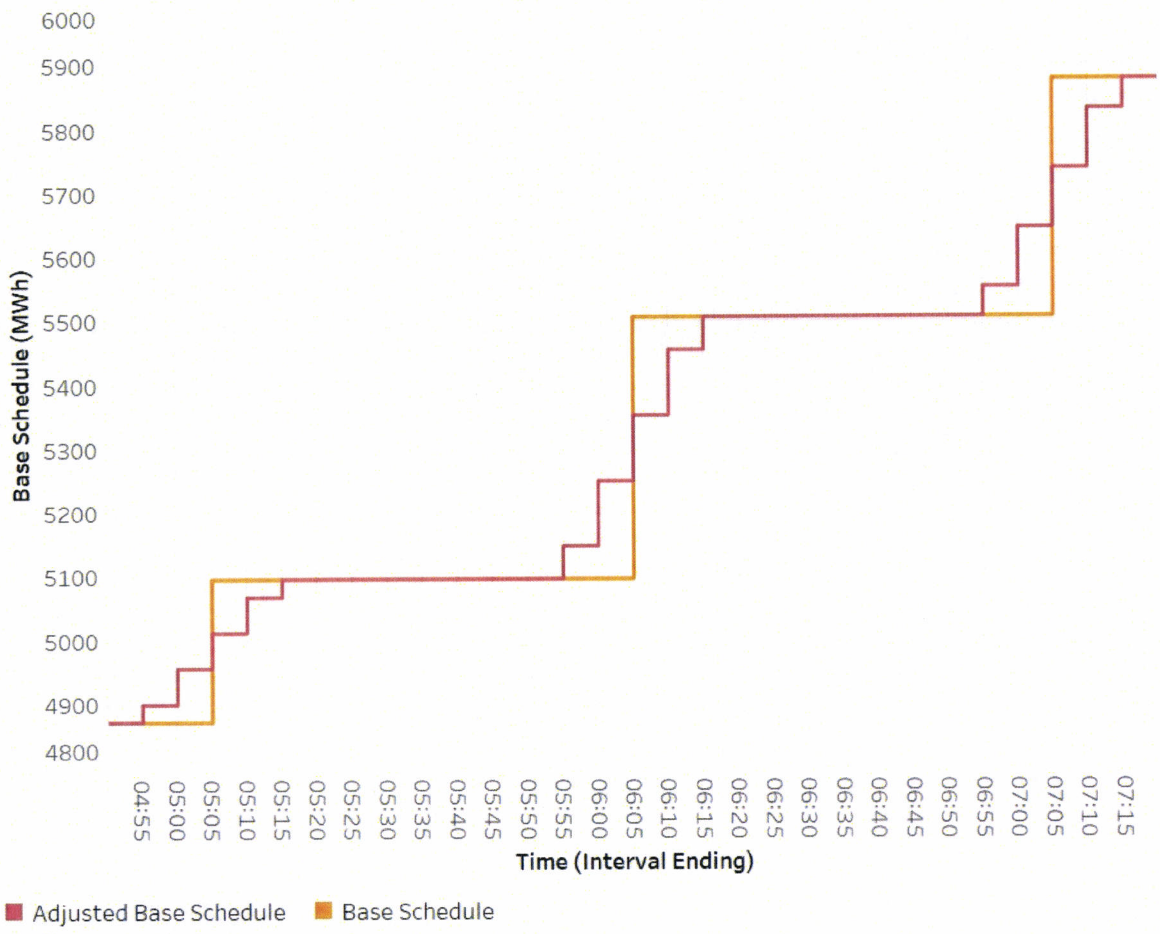
Base Schedule Ramping Adjustment

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

[14] Order No. 764 at P 20 (emphasis added).
[15] *Id.* at P 92.

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:

- Stuck meter/flat meter reading

- Telemetry spike/poor connection to meter

Wind, Solar, and Non-VERs:
- Generator trip events
- 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.

Similarly, rapid spikes in load either up or down are also unlikely to be a result of conditions which require deployment of regulation reserve, particularly when they are transient. 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. Load telemetry spike irregularities were identified by examining the intervals with the largest changes from one interval to the next, either up or down. Intervals with inexplicably large and rapid changes in load, particularly where the load reverts back within a short period, were assumed to have been covered through contingency reserve deployment or to reflect inaccurate load measurements. Because they don't reflect periods that require regulation reserve deployment, such intervals are excluded from the analysis.

As with Load, certain Wind and Non-VER deviations are more likely to be a result of conditions that allow for the deployment of contingency reserve, rather than regulation reserve. In particular, contingency reserve can be deployed to compensate for unexpected generator outages. For Non-VERs, these are relatively straightforward—namely, periods when generation drops to zero despite base schedules indicating otherwise. Certain Wind outages also qualify as contingency events. Notably, wind generators can be curtailed when wind speed exceeds the maximum rating of the equipment (sometimes referred to as "high speed cutout"). In such instances, generation is curtailed until wind speeds drop back into a safe operating range in order to protect the equipment. When wind speed oscillates above and below the cut-off point, generation may ramp down and up repeatedly. Because events which qualify for deployment of contingency reserve do not require deployment of regulation reserve they have been excluded from the analysis.

As the regulation reserve requirements are calculated using a rolling thirty-minute timeline, data from the prior hour is necessary during the first several five-minute intervals of the next hour. An error in one hour thus results in the need to remove the following hour. This is relevant to error adjustments for both Wind and Non-VERs.

After review of the data for each of the above anomaly types, and out of 105,120 five-minute intervals evaluated, only 1.1 percent and 0.52 percent of the total FRS term hours were removed from PACW and PACE, respectively. The system-wide error rate was 1.36 percent, slightly lower than the sum of the PACW and PACE rates due to coincident hours. While cleaning up or replacing anomalous hours could yield a more complete data set, determining the appropriate conditions in those hours would be difficult and subjective. By removing anomalies, the FRS sample is smaller but remains reflective of the range of conditions PacifiCorp actually experiences, including the impact on regulation reserve requirements of weather events experienced during the study 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.[16]

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 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.

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

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.[17] 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 has experience operating under the new standard, even though it did not become effective until 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.

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

[17] NERC Standard BAL-001-2, www.nerc.com/files/BAL-001-2.pdf

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 2019 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.

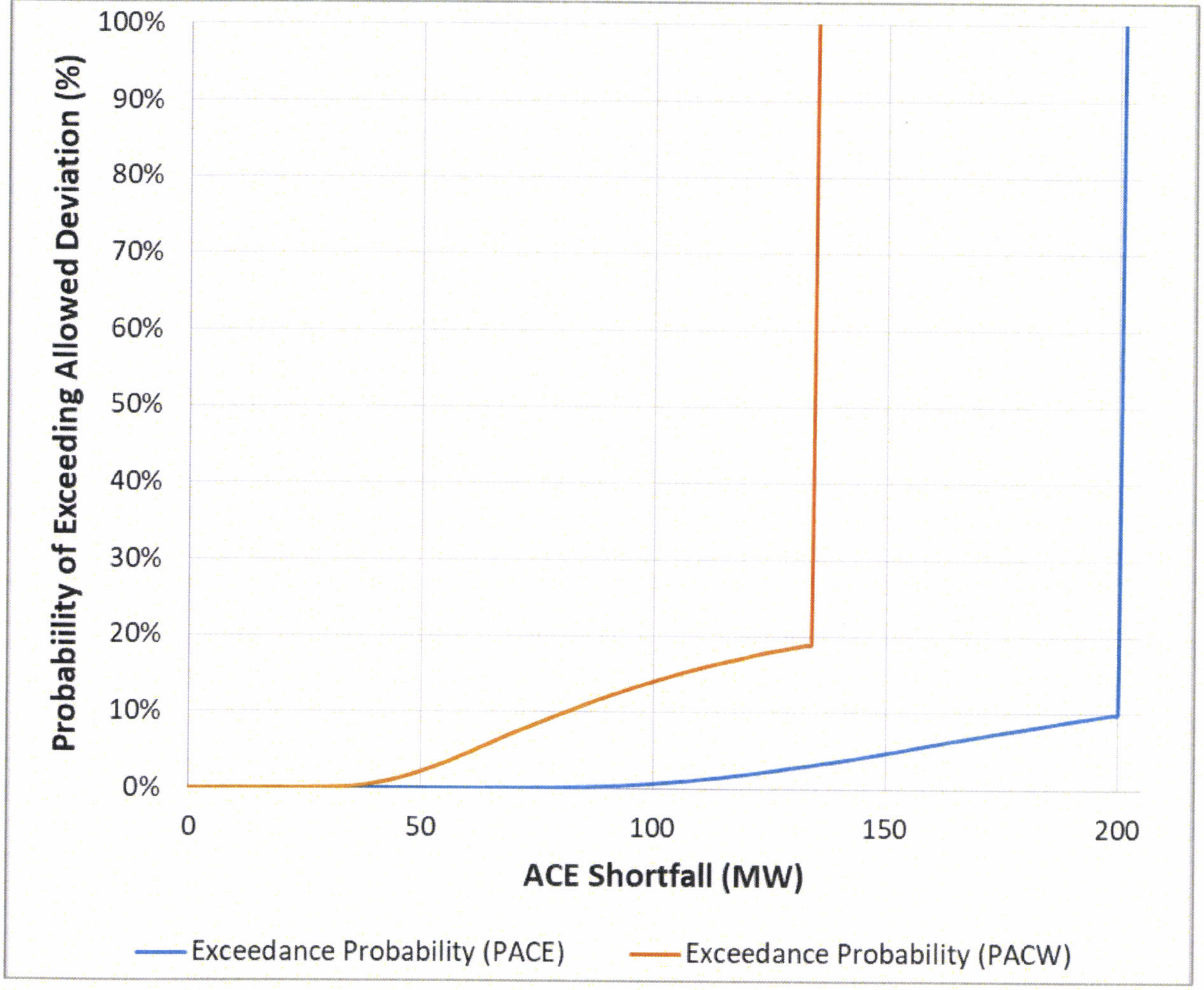
The Balancing Authority ACE Limit is specific to each BAA and is dynamic, varying as a function of interconnection frequency. When WECC frequency is close to 60 Hz, the Balancing Authority ACE Limit is large and large deviations in ACE are allowed. As WECC frequency drops further and further below 60 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 doesn't have at least one minute when its ACE is within its Balancing Authority ACE Limit.

While the specific Balancing Authority ACE Limit for a given interval cannot be known in advance, the historical probability distribution of Balancing Authority ACE Limit values is known. Figure 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, a 43 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.[18,19] This cap is reflected in Figure F.2.

[18] "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

[19] "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

Figure F.2 - Probability of Exceeding Allowed Deviation



In 2017, 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

In order 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. The regression variables consist of:

- The combined deviation of load, wind, solar, and Non-VERs;
- Forecasted load as a percentage of peak load;
- Forecasted wind generation as a percentage of total system wind capacity;
- Forecasted solar generation as a percentage of total system solar capacity; and
- Forecasted Non-VER generation as a percentage of maximum Non-VER schedules.

The combined deviations of load, wind, solar and non-VERs (Combined Diversity Error) is calculated as [Load Error – Wind Error – Solar Error – Non VER Error] as illustrated below in Table F.3 for PACE.

Table F.3 - Combined Diversity Error Example

Trading Date	Trading Hour	Trading Interval	Load Error	Non VER Error	Wind Error	Solar Error	Combined Diversity Error
1/1/2017	3	5	49	-5	-21	0	75
1/1/2017	3	10	40	-6	-16	0	61
1/1/2017	3	15	36	-3	-14	0	53
1/1/2017	3	20	35	-6	-55	0	97
1/1/2017	3	25	34	-6	-48	0	87
1/1/2017	3	30	36	-4	-26	0	67
1/1/2017	3	35	36	-7	-41	0	84
1/1/2017	3	40	32	-8	-39	0	80
1/1/2017	3	45	30	-5	-39	0	74
1/1/2017	3	50	31	2	-37	0	66
1/1/2017	3	55	37	1	-37	0	73
1/1/2017	3	60	45	2	-32	0	75

The individual errors (load, wind, solar and non-VERs) are calculated as the difference between the actual meter data and the adjusted hourly base schedules as illustrated below for PACE wind in Table F.4.

Table F.4 – Wind Error Example

Trading Date	Trading Hour	Trading Interval	Adjusted Base Schedules	Actuals	Wind Error
1/1/2017	3	5	957	936	-21
1/1/2017	3	10	956	940	-16
1/1/2017	3	15	955	941	-14
1/1/2017	3	20	955	900	-55
1/1/2017	3	25	955	908	-48
1/1/2017	3	30	955	929	-26
1/1/2017	3	35	955	914	-41
1/1/2017	3	40	955	916	-39
1/1/2017	3	45	955	916	-39
1/1/2017	3	50	955	918	-37
1/1/2017	3	55	954	917	-37
1/1/2017	3	60	951	919	-32

An illustration of the combined diversity error and the forecasted levels of load as a percentage of peak load, the forecasted levels of wind as a percentage of total system capacity, the forecasted levels of solar as a percentage of total system capacity and the forecasted levels of Non-VERs as a percentage of peak schedule are illustrated below in Table F.5 for PACE.

Table F.5 – Regression Inputs Example

Trading Date	Trading Hour	Trading Interval	Combined Diversity Error	Wind Forecast	Solar Forecast	Load Forecast	Non VER Forecast
1/1/2017	3	5	72	50.5%	0%	56%	55%
1/1/2017	3	10	60	50.4%	0%	56%	55%
1/1/2017	3	15	53	50.3%	0%	56%	55%

1/1/2017	3	20	97	50.3%	0%	56%	55%
1/1/2017	3	25	87	50.3%	0%	56%	55%
1/1/2017	3	30	67	50.3%	0%	56%	55%
1/1/2017	3	35	84	50.3%	0%	56%	55%
1/1/2017	3	40	80	50.3%	0%	56%	55%
1/1/2017	3	45	74	50.3%	0%	56%	55%
1/1/2017	3	50	66	50.3%	0%	56%	55%
1/1/2017	3	55	68	50.3%	0%	56%	55%
1/1/2017	3	60	58	50.1%	0%	56%	55%

The Load Forecast, Wind Forecast, Solar Forecast and Non VER Forecast are calculated as a percentage of some measure of capacity or peak. The forecasted levels of PACE wind as a percentage of total system capacity is illustrated below in Table F.6.

Table F.6 – Wind Forecast Level Example

Trading Date	Trading Hour	Trading Interval	Adjusted Base Schedules	Capacity	Wind Forecast
1/1/2017	3	5	957	1898	50.5%
1/1/2017	3	10	956	1898	50.4%
1/1/2017	3	15	955	1898	50.3%
1/1/2017	3	20	955	1898	50.3%
1/1/2017	3	25	955	1898	50.3%
1/1/2017	3	30	955	1898	50.3%
1/1/2017	3	35	955	1898	50.3%
1/1/2017	3	40	955	1898	50.3%
1/1/2017	3	45	955	1898	50.3%
1/1/2017	3	50	955	1898	50.3%
1/1/2017	3	55	954	1898	50.3%
1/1/2017	3	60	951	1898	50.1%

Quantile regression is a type of regression analysis. Whereas the typical method of ordinary least 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. For the 2019 FRS the response variable – Combined Diversity Error – was expressed as a function of four predictor variables – Wind Forecast, Solar Forecast, Load Forecast and Non VER Forecast. Each predictor variable contributes to the regression as a combination of linear, square, and cubic effects. Specifically:

$$\begin{gathered}\text{Combined Diversity Error} \quad \text{varies as a function of:}\\ Wind\ Forecast + Wind\ Forecast^2 + Wind\ Forecast^3 +\\ Solar\ Forecast + Solar\ Forecast^2 + Solar\ Forecast^3 +\\ Load\ Forecast + Load\ Forecast^2 + Load\ Forecast^3 +\\ Non\ VER\ Forecast + Non\ VER\ Forecast^2\end{gathered}$$

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.

2017 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 dynamical Balancing Authority ACE Limit. The combined diversity error system requirements are discussed later on in the study.

Wind

Figure F.3 illustrates the relationship between the regulation reserve requirements for PACE wind during 2017 and the forecasted level of output, stated as a capacity factor (*i.e.*, a percentage of the nameplate wind capacity). Figure F.4 illustrates this relationship for PACW.

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

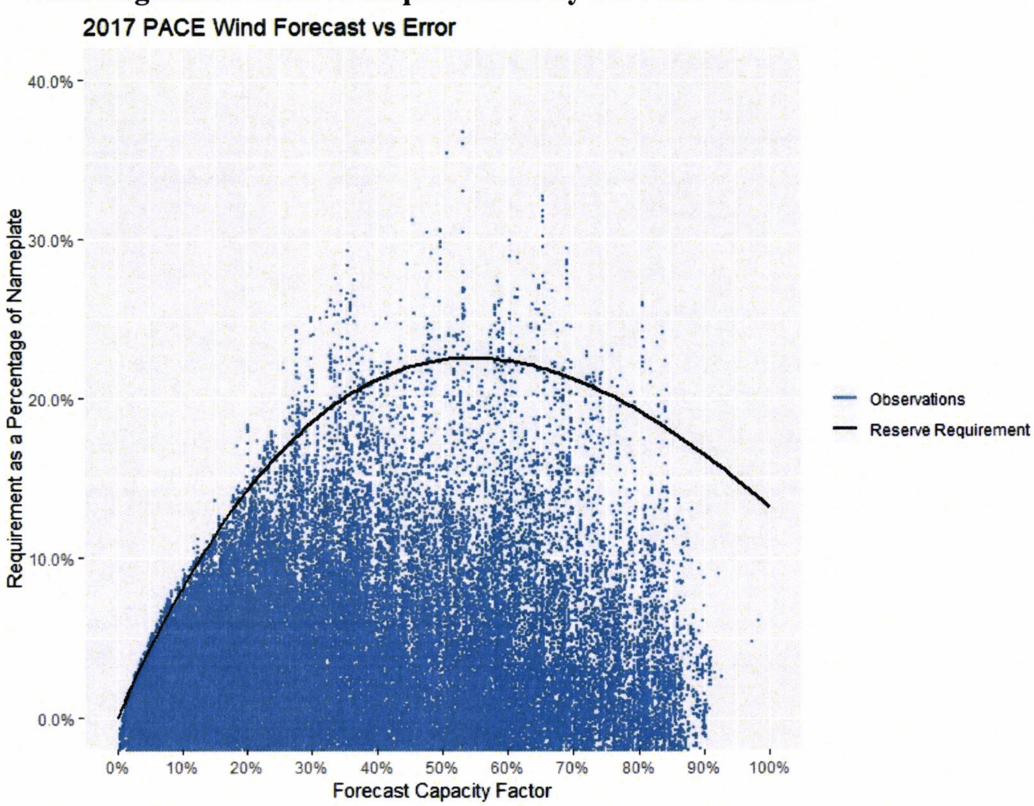
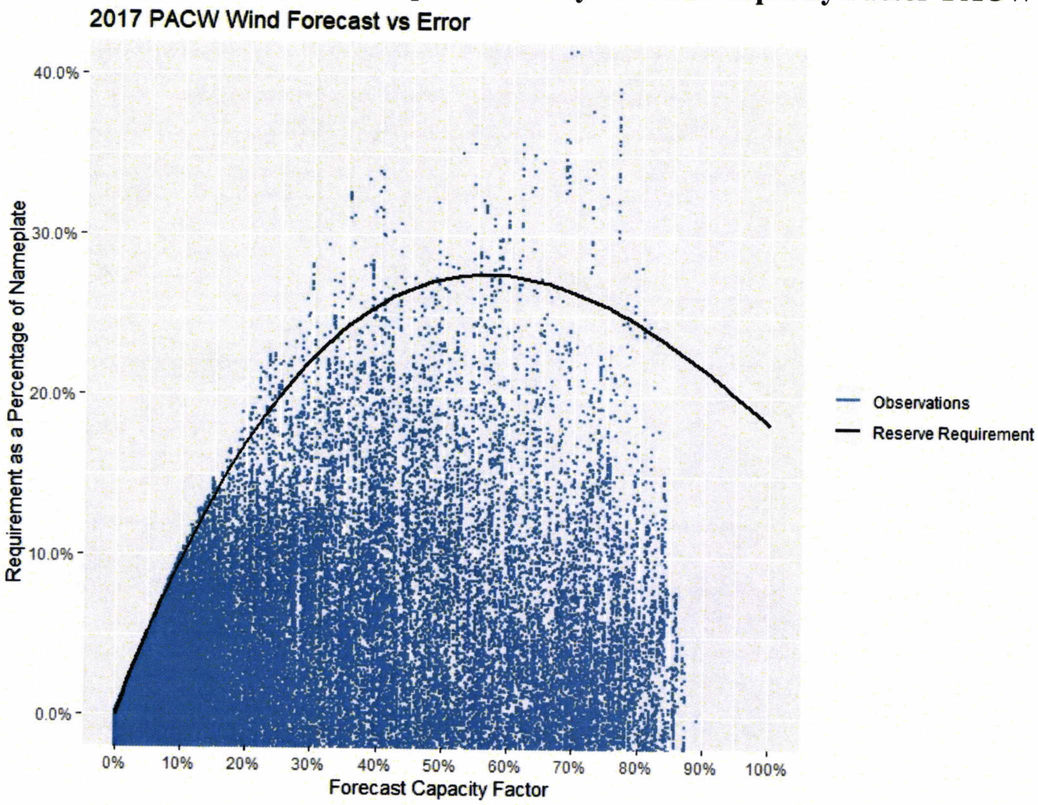


Figure F.4 - Wind Regulation Reserve Requirements by Forecast Capacity Factor-PACW



The forecast results in an average 2017 stand-alone regulation reserve requirement for wind of 434 MW for the PacifiCorp system, or approximately 15.8 percent of nameplate capacity.

Solar

Figure F.5 illustrates the relationship between the regulation reserve requirements for PACE solar during 2017 and the forecasted level of output, stated as a capacity factor (*i.e.*, a percentage of the nameplate solar capacity). Figure F.6 illustrates this relationship for PACW.

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

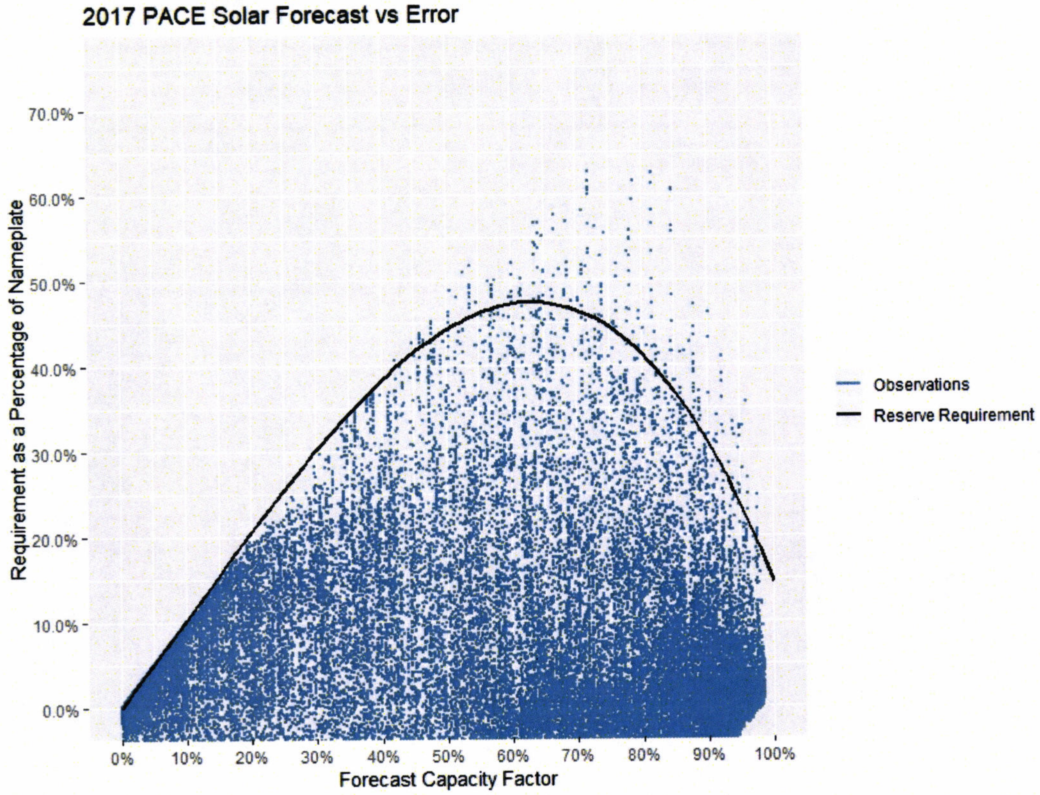
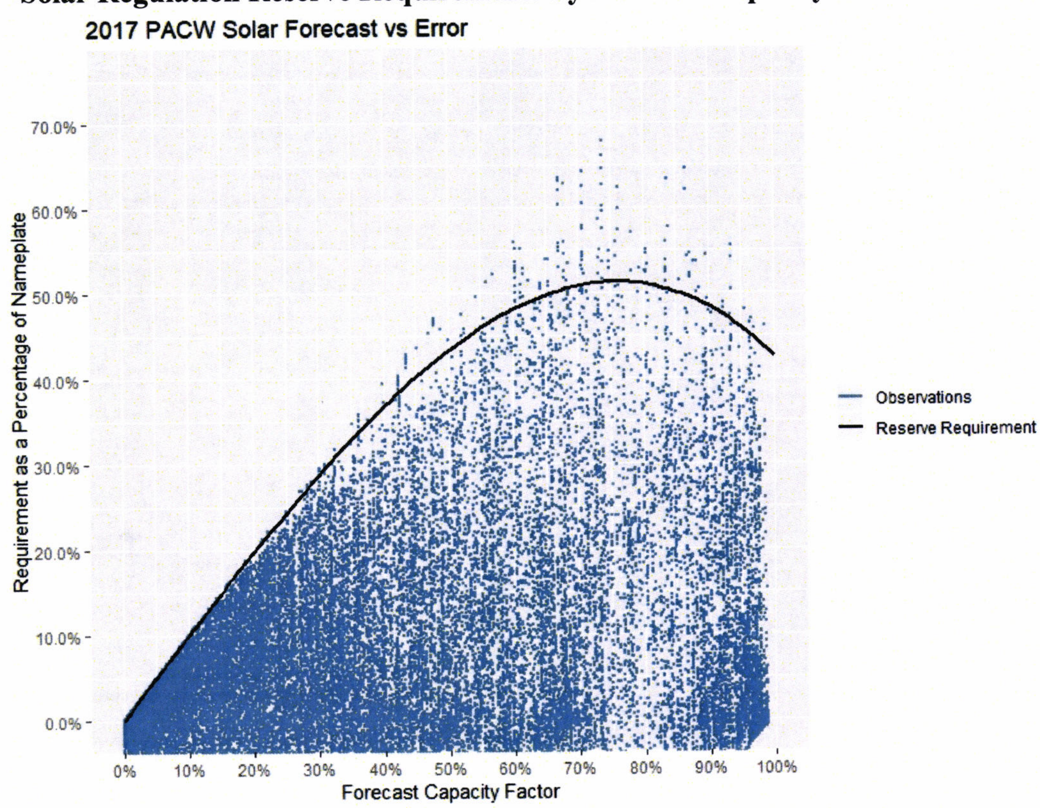


Figure F.6 - Solar Regulation Reserve Requirements by Forecast Capacity Factor-PACW



The forecast results in an average 2017 stand-alone regulation reserve requirement for solar of 145 MW for the PacifiCorp system, or approximately 14.8 percent of nameplate capacity.

Non-VERs

Figure F.7 below illustrates the regulation reserve requirements for PACE Non-VERs during 2017 as a function of the forecasted level of output, stated as a peak schedule factor (*i.e.*, a percentage of the peak Non-VER schedule observed for 2017). Figure F.8 illustrates this relationship for PACW.

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

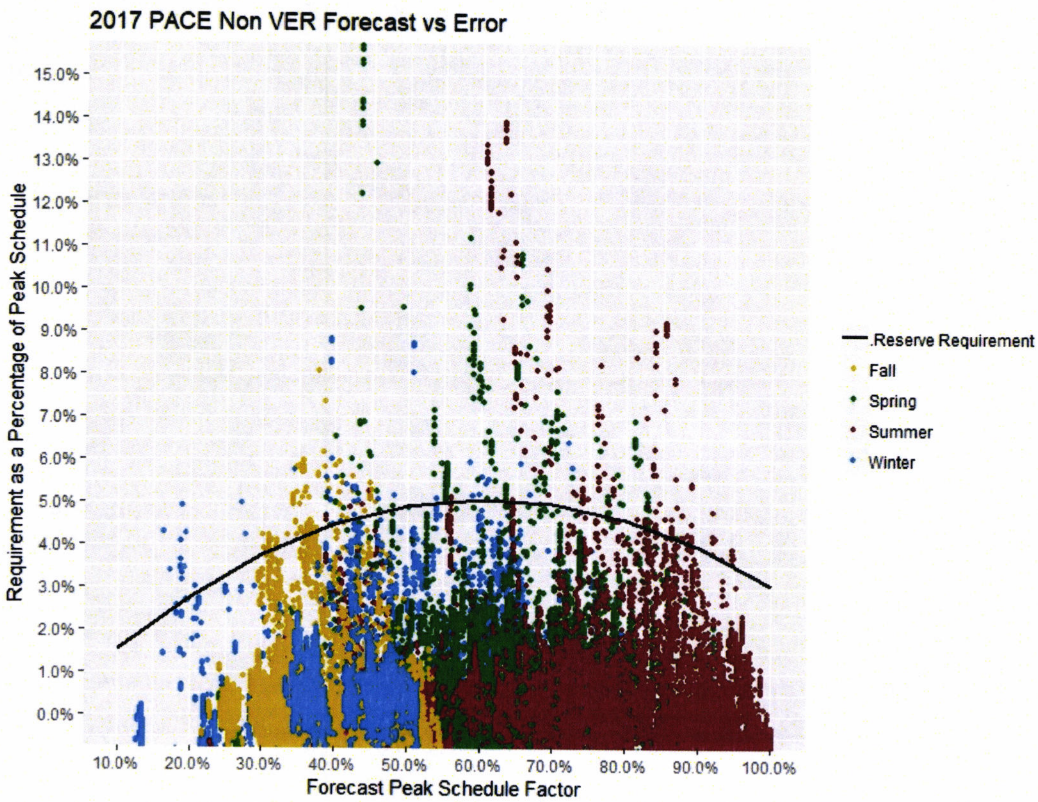
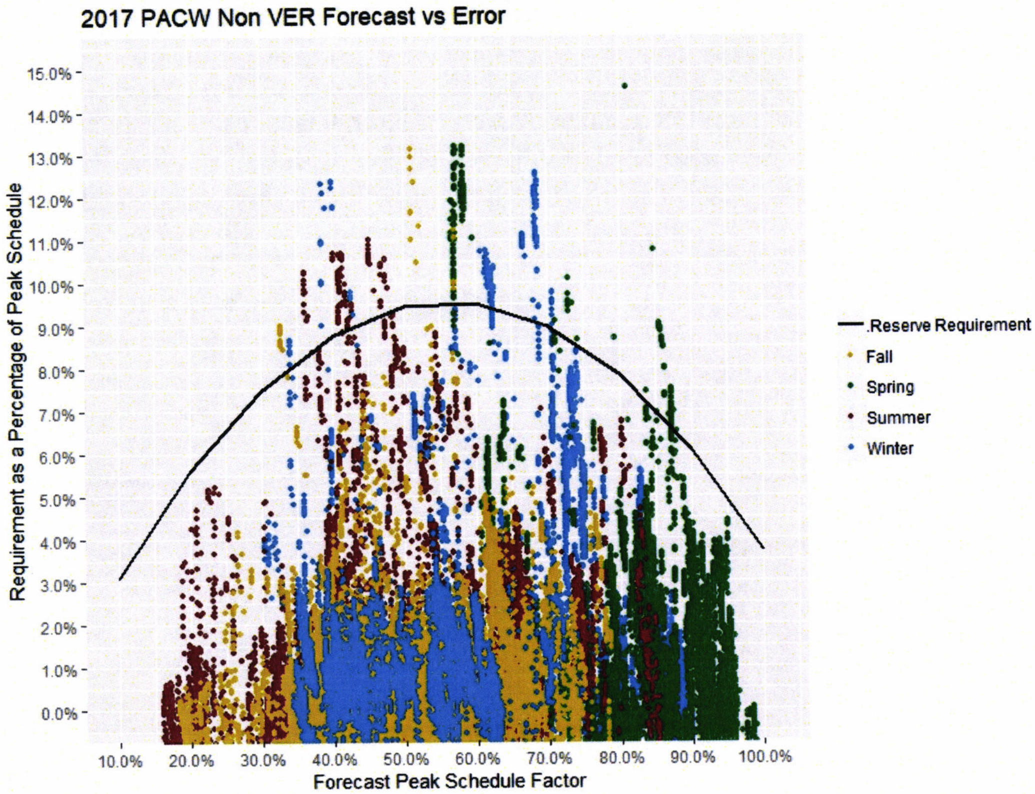


Figure F.8 – Non-VER Regulation Reserve Requirements by Forecast Schedule Factor-PACW



The forecast results in an average 2017 stand-alone regulation reserve requirement for non VERs of 110 MW for the PacifiCorp system, or approximately 5.7 percent of the peak schedule.

Load

Figure F.9 below illustrates the regulation reserve requirements for PACE load during 2017 as a function of the forecasted level of output, stated as a peak load factor (*i.e.*, a percentage of the peak load observed during 2017) for PACE. Figure F.10 illustrates this relationship for PACW.

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

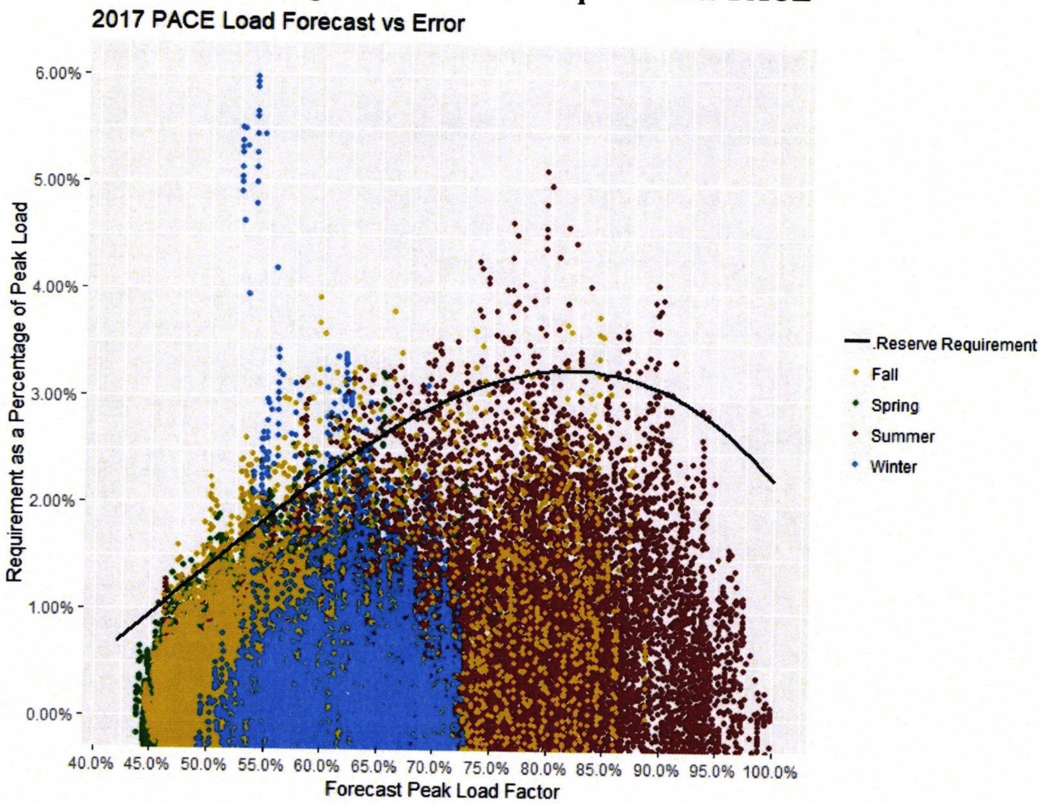
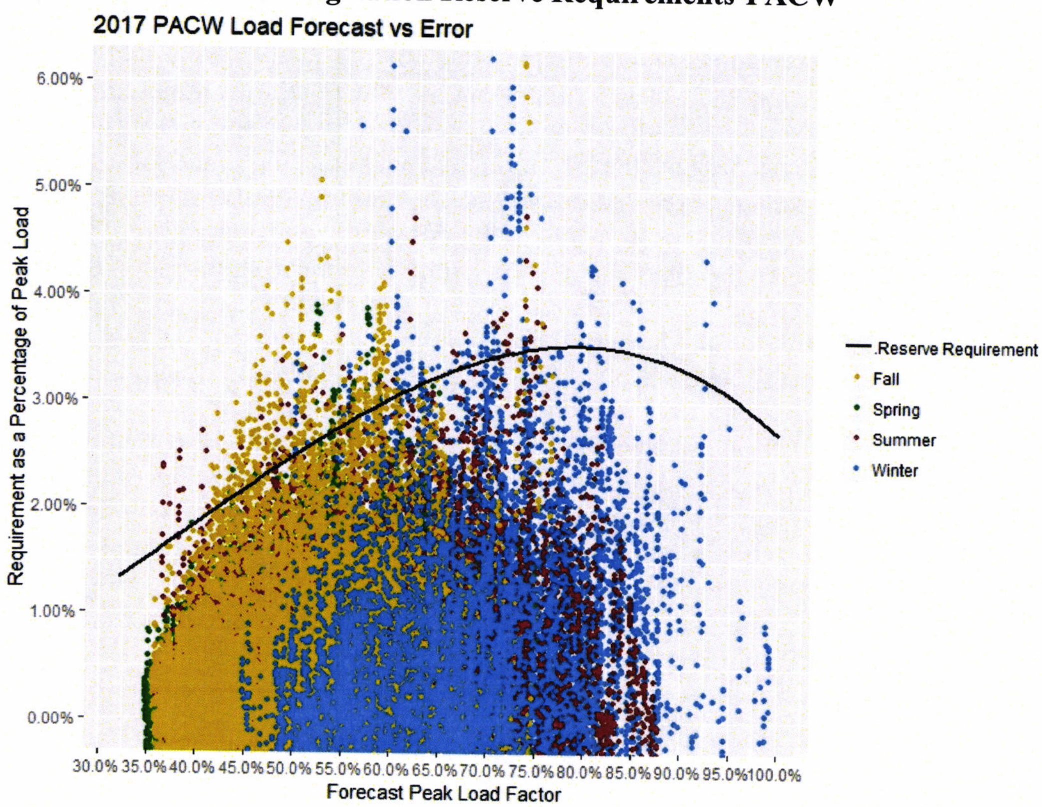


Figure F.10 – Stand-alone Load Regulation Reserve Requirements-PACW



The forecast results in an average 2017 stand-alone regulation reserve requirement for load of 305 MW for the PacifiCorp system, or approximately 3.0 percent of the peak load.

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. A number of 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, as a result 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. For this reason the portfolio regulation requirements were calculated on the Combined Diversity Error.

As shown in Table F.7 below, PacifiCorp calculated the proportional reduction to the standalone requirements that could be applied such that the PacifiCorp system achieves the target determined through the quantile regression on the Combined Diversity Error. A total portfolio requirement of 635 MW was the result of this regression, a reduction of 36 percent. Applying this 36 percent reduction to each of the stand-alone regulation forecasts results in the diversity benefits shown in the second column. The last column shows the regulation requirements for each class after subtracting the portfolio diversity benefit.

Table F.7 - Results with PacifiCorp Portfolio Diversity

Scenario	Stand-alone Regulation Forecast (aMW)	Diversity Benefit (aMW)	Portfolio Regulation Forecast (aMW)
Non-VER	110	(40)	70
Load	305	(110)	195
VER - Wind	434	(157)	277
VER - Solar	145	(53)	93
Total	**994**	**(360)**	**635**

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, wind, and solar output, EIM entities reduce the quantity of reserve required to meet flexibility needs. The EIM also facilitates procurement of flexible ramping capacity in the fifteen-minute market to address variability that may occur in the five-minute market. Because variability across different BAAs may happen in opposite directions, the flexible ramping requirement for the entire EIM footprint can be less than the sum of individual 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.8 below provides a numeric example of uncertainty requirements and application of the calculated diversity benefit.

Table F.8 - EIM Diversity Benefit Application Example

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	37.0%	61	104
2	600	110	165	100	975	636	339	34.8%	57	108
3	650	110	165	110	1,035	689	346	33.4%	55	110
4	667	120	180	113	1,080	742	338	31.3%	56	124

While the diversity benefit is uncertain, that uncertainty is not significantly different from the uncertainty in the Balancing Authority ACE Limit described above. In the 2019 FRS, PacifiCorp has credited the regulation reserve forecast with a historical distribution of calculated EIM diversity benefits. While this FRS considers regulation reserve requirements in 2017, 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 March 2018 through the beginning of this study in July 2018. Relatively small incremental EIM diversity benefits are expected going forward as additional entities participate in EIM; however, operational data on new participants was not available at the time the study was prepared.

The inclusion of EIM diversity benefits in the 2019 FRS reduces the probability of reserve shortfalls and, in doing so, reduces the overall regulation reserve requirement. This allows PacifiCorp's forecasted requirements to be reduced. As shown in Table F.9 below, the resulting regulation reserve requirement is 531 MW, a 47 percent reduction (including the portfolio diversity benefit) compared to the stand-alone requirement for each class. The average regulation reserve requirement is reduced by 104 MW relative to the PacifiCorp portfolio reserve requirement without the EIM diversity benefit. The portfolio regulation forecast is expected to achieve an LOLP of 0.5 hours per year, based on a quantile regression at a 99.35 percent exceedance level.

Table F.9 - 2017 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 (%)	2017 Capacity (MW)	Rate Determinant
Non-VER	110	5.7%	59	3.1%	1,912	12 CP
Load	305	3.0%	163	1.6%	10,044	12 CP
VER - Wind	434	15.8%	232	8.4%	2,750	Nameplate
VER - Solar	145	14.8%	78	7.9%	983	Nameplate
Total	**994**		**531**			

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 2017 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 the majority of 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 2017 Regulation Reserve Forecast described above.

To evaluate CPS1 requirements, PacifiCorp compared the net load change for each five-minute interval in 2017 to the corresponding value for Requirement 2 compliance in that hour from the 2017 Regulation Reserve Forecast, after accounting for diversity (resulting in the 531 MW average requirement shown in Table F.9). Resources may deploy for Requirement 2 compliance over up to 30 minutes, so the average requirement of 531 MW would require ramping capability of at least 17.7 MW per minute (531 MW / 30 minutes).

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. Resources capable of ensuring compliance in 95 percent of intervals are expected to be sufficient to meet CPS 1, and given that ACE may deviate in either a positive or negative direction, the 97.5th percentile of incremental requirements was evaluated. This corresponds to 87 MW, or approximately 16.3 percent of the average Requirement 2 value. Because this value is for a five-minute interval, meeting it would require a ramping capability of at least 17.3 MW per minute (87 MW / 5 minutes). This value is actually slightly lower than the ramping capability for Requirement 2.

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-003-1, based on median response during the largest events.

In light of the overlaps with BAL-001-2 Requirement 2 and BAL-003-1 described above, CPS1 compliance is not expected to result in an additional requirements beyond what is necessary to comply with those standards.

Incremental 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 measures. As PacifiCorp's portfolio grows, the diversity of that portfolio is also expected to increase. As a result, incremental regulation reserve requirements are expected to be lower than the average requirement for a given portfolio.

The need to develop realistic deviation data for a period during which resources did not exist makes measuring an incremental diversity effect a difficult proposition. Instead, PacifiCorp's FRS evaluated the change in regulation reserve requirements associated with cumulatively stacking the individual wind and solar facilities throughout the two BAAs. Under this methodology as each MW of VERs is added to the system the rate of increase of the regulation reserve requirement is quantified and incorporated in the forecasted portfolio regulation results discussed later on in the study. Figure F.11 and Figure F.12 show this relationship between increased capacity and increasing reserve requirements for wind and solar by BAA.

Similarly for load the relationship between the daily peak load and the daily maximum error over the course of 2017 was observed for both BAAs and this relationship was extrapolated forward to develop a multiplier for the effect of peak load on the reserve requirements. A linear relationship between daily peak load and daily maximum error was observed for both BAAs as illustrated in Figure F.13 through Figure F.14.

Figure F.11 – Incremental Wind Capacity

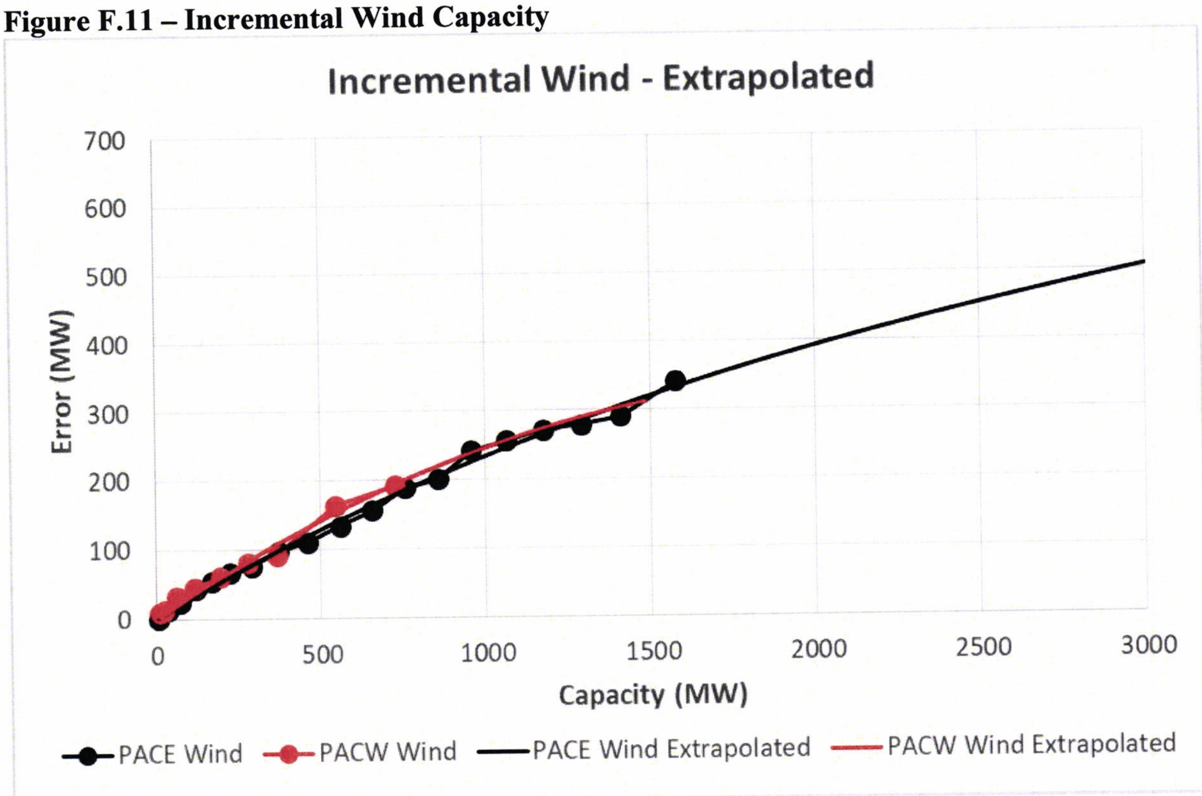


Figure F.12 – Incremental Solar Capacity

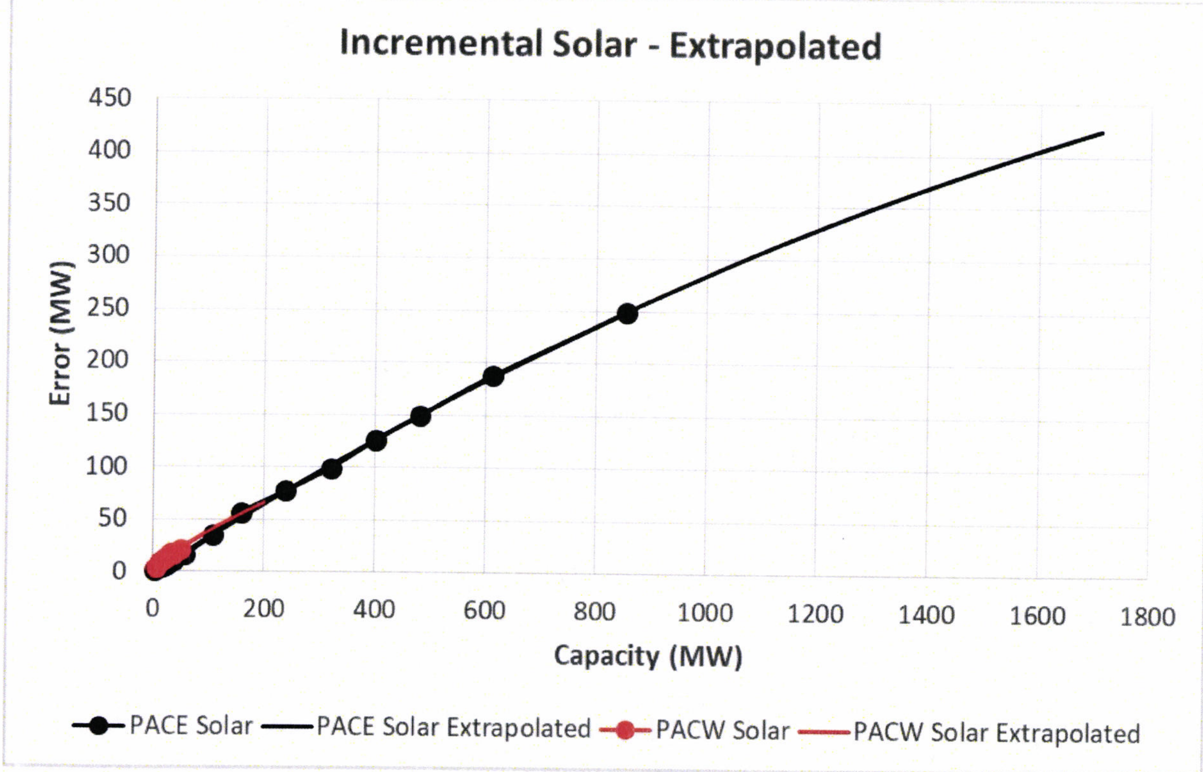


Figure F.13 – Increasing Peak Load-PACE

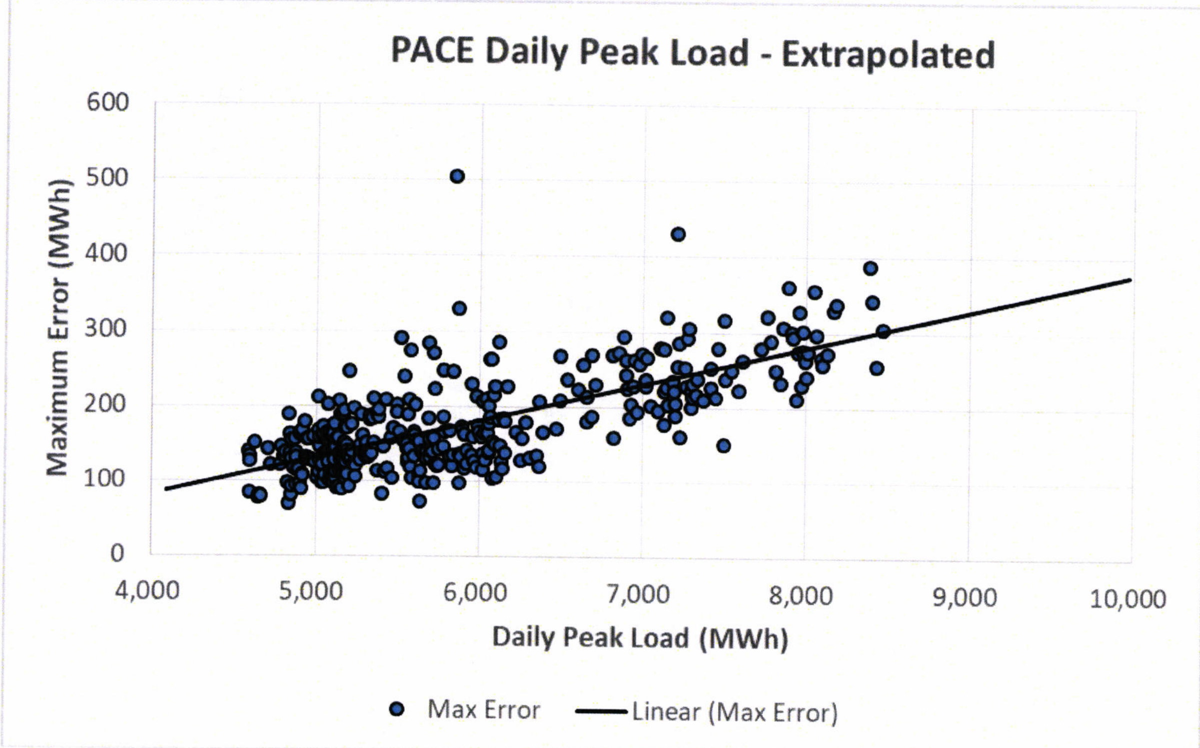
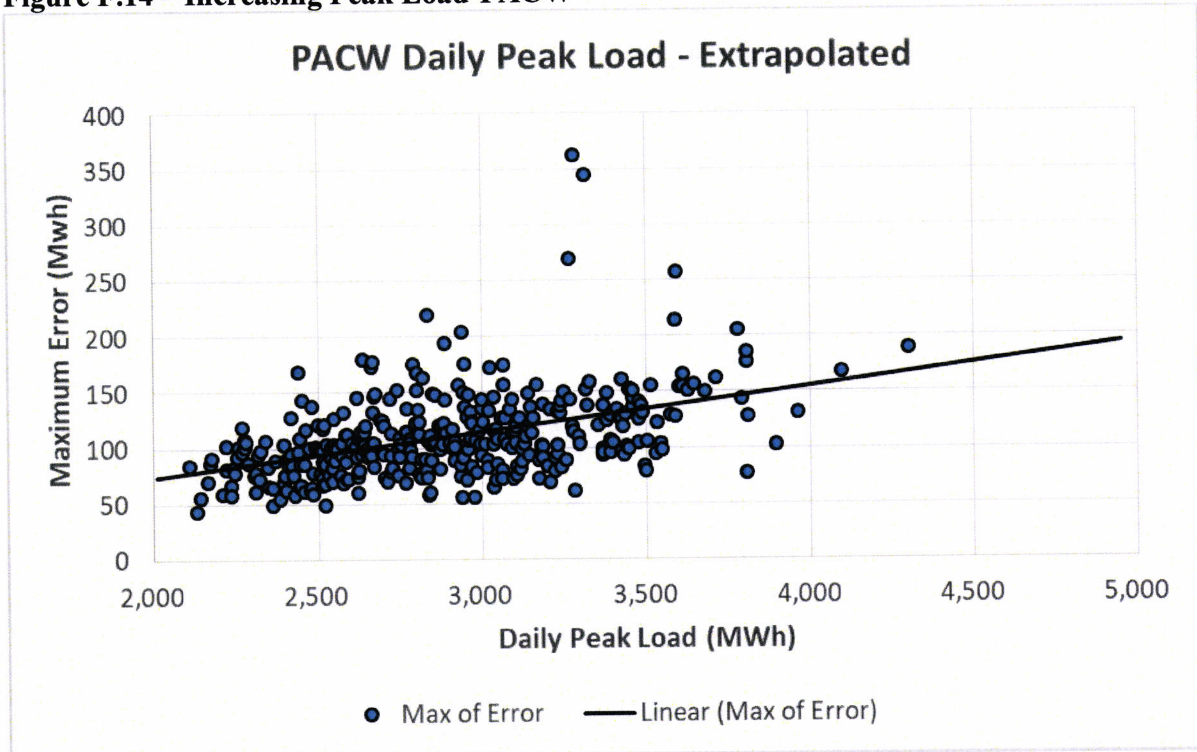


Figure F.14 – Increasing Peak Load-PACW



Portfolio Regulation Reserve Requirements

Overview

A single pool of regulation reserve is held to cover deviations by load, wind, solar, and non-dispatchable generation. Simultaneous large deviations by all classes are unlikely – as a result, this pool of regulation reserve can be smaller than what these classes would require on their own. The reduction in regulation reserve is a result of the diversity of the portfolio of requirements. The most important element in PacifiCorp's portfolio diversity estimate is the system diversity, including EIM benefits, associated with load, wind, solar and Non-VERs during 2017. This diversity reduced reserve requirements by 47 percent. This captures the majority of the regulation reserve requirements today and in likely future scenarios over the near term. However, as PacifiCorp's portfolio evolves over time, the regulation reserve requirements and diversity associated with that portfolio will vary. This section describes how incremental regulation reserve requirements for load, wind, and solar are combined to produce portfolio-specific requirements.

Results

Table F.10 presents the portfolio regulation requirement results for various scenarios. As the wind and solar capacity on PacifiCorp's system increases, regulation requirements increase, but those requirements are partially offset by the increasing diversity of the portfolio. The 2019 base case regulation reserve requirements are 531 MW. By comparison, PacifiCorp's 2017 base case from the 2017 IRP identified regulation reserve requirements of 617 MW.

Table F.10 – Total Regulation Requirement, by Scenario

Case	Portfolio	Wind Capacity (MW)	Solar Capacity (MW)	Regulation Requirement with Diversity (MW)
2017 Base Case	2015 Actuals + Projected Solar	2,757	1,050	617
2019 Base Case	2017 Actuals	2,750	1,021	531
2019 Forecast	2030 Portfolio	3,196	2,201	672
2019 Incr. Wind	2030 Portfolio + 500 MW Wind	3,696	2,201	722
2019 Incr. Solar	2030 Portfolio + 500 MW Solar	3,196	2,701	698

Table F.11 presents a comparison of the regulation reserve requirement results in the current study and the prior study.

Table F.11 - Portfolio Regulation Requirements, Percent of Nameplate/Peak Capacity

Study	Load	Wind	Non-VER	Solar	Notes
2017 FRS Base Case	2.8%	8.9%	2.4%	4.6%	2015 portfolio
2019 FRS Base Case	1.6%	8.4%	3.1%	7.9%	2017 portfolio
Sensitivities:					
Without diversity	3.0%	15.8%	5.7%	14.8%	2017 portfolio
Incremental Wind		10.1%			2030 portfolio: +500 MW wind
Incremental Solar				5.1%	2030 portfolio: +500 MW solar

The 2019 FRS calculates the regulation reserve requirement for the entire portfolio implicitly accounting for diversity among components at various penetration levels. This allows incremental requirements for load, wind and solar to be aligned with the new resource additions being contemplated in the IRP. The incremental requirements for wind are slightly higher than the average requirements for wind when diversity is included, but still well below the stand-alone requirements for wind without diversity. On the other hand, the incremental requirements for solar are less than the average requirements for solar even when diversity is included. These outcomes are reasonable since solar capacity is smaller than wind capacity in the evaluated portfolio, so incremental solar capacity makes the portfolio relatively more diverse.

For the first time, the 2019 FRS accounts for the incremental impact of changes in forecasted load on regulation reserve requirements. For instance, energy efficiency selections (which reduce load), also reduce reserve requirements. The impact of these changes is accounted for within the results reported by the PaR model.

Regulation Reserve Cost

A series of PaR scenarios were prepared to isolate the regulation reserve cost associated with incremental wind and solar capacity additions as discussed below. All studies reflect regulation reserve requirements on an hourly basis.

1. **Base Case**
   The base case portfolio is the same as that used to set the planning reserve margin for the 2019 IRP, as discussed in Appendix I. This case incorporates assumptions consistent with the 2017 IRP Update, updated to reflect current inputs as of August 2018 and without any wind or solar resources additions beyond those that had already been committed at that time. This case was evaluated over the study period 2018-2036.

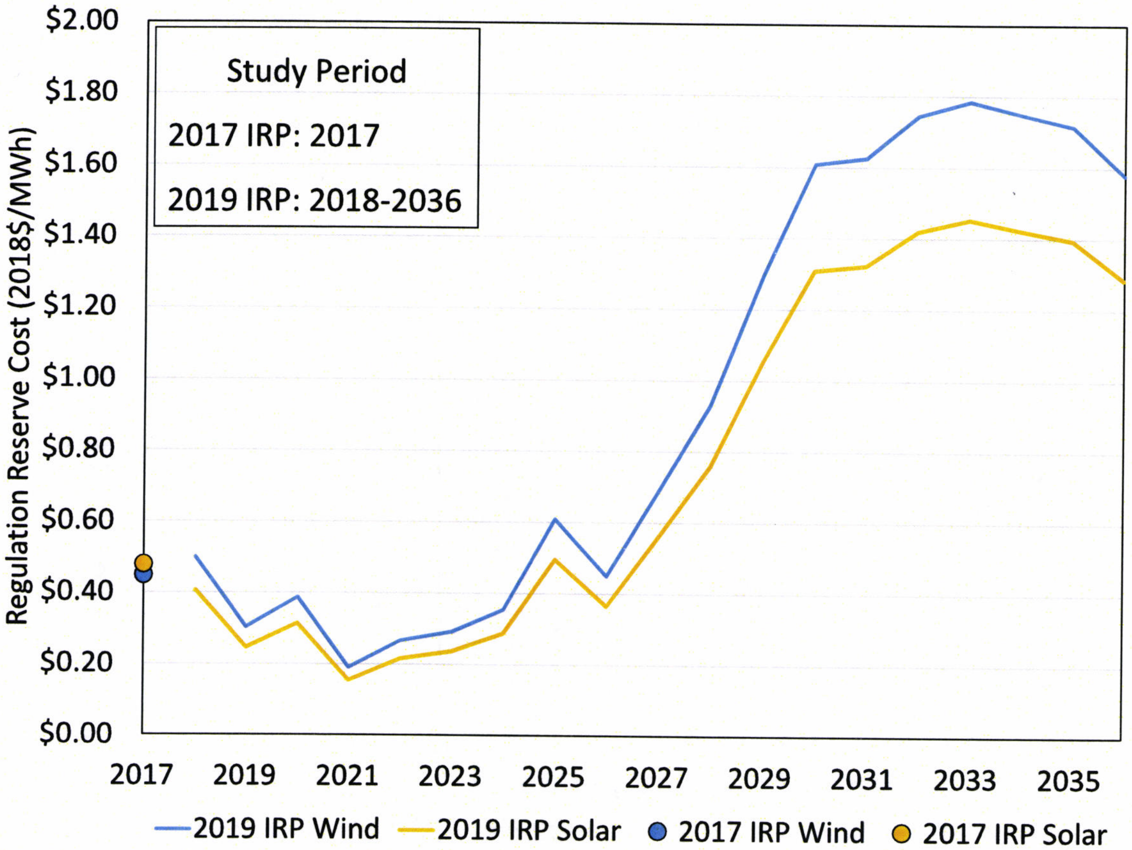
2. **Wind Reserve Case**
The wind reserve case adds the incremental regulation reserve requirement associated with 500 MW of proxy wind resource additions. Wind capacity increases by 100 MW at each of five locations: Dave Johnston, Goshen, Utah South, Walla Walla, and Yakima. The addition of this wind capacity results increases regulation reserve requirements by an average of 50 MW. This case was evaluated for the study period 2030. Wind integration costs are equal to the increase in system cost in Study 2 relative to Study 1, divided by the incremental wind generation.

3. **Solar Reserve Case**
The solar reserve case adds the incremental regulation reserve requirement associated with 500 MW of proxy solar resource additions. Solar capacity increases by 250 MW in Utah South and by 125 MW each in Southern Oregon and Yakima. The addition of this solar capacity results increases regulation reserve requirements by an average of 24 MW. This case was evaluated for the study period 2030. Solar integration costs are equal to the increase in system cost in Study 3 relative to Study 1, divided by the incremental solar generation.

4. **50 MW Reserve Case**
This case includes an additional 50 MW reserve requirement in every hour. This case was evaluated over the study period 2018-2036 and was used to escalate the wind and solar results over time, relative to the 2030 values.

The incremental regulation reserve cost results for wind and solar are shown in Figure F.15. The comparable regulation reserve costs from the 2017 FRS are also shown. While regulation reserve costs in 2018 are comparable to the result in the prior study, the 2019 FRS demonstrates how these costs are expected to vary over time.

Figure F.15 – Incremental Wind and Solar Regulation Reserve Costs



The difference in regulation reserve costs for wind and solar reflects timing differences. Per MWh of generation, the wind reserve obligation is approximately 60 percent higher than the solar obligation; however, the solar obligation is higher during the summer when market prices and marginal reserve costs are typically higher. As a result, per MWh of generation, wind integration costs are only slightly higher than solar integration costs.

The 2019 FRS results are applied in the portfolio development process as an additional cost for proxy wind and solar generation resources available for selection within the SO model. Once the SO model has developed a candidate resource portfolio, the PaR model is used to evaluate portfolio risks. The PaR model inputs include regulation reserve requirements specific to the resource portfolio developed using the SO model, so the costs identified in the 2019 FRS are not applied in the PaR results. Instead, the IRP risk analysis using PaR specifically accounts for both differences in regulation reserve requirements and the resources available to meet those requirements in each portfolio.

When evaluated in PaR, a portfolio will be evaluated on its ability to meet operating reserve requirements, including regulation reserves, but as indicated previously, the SO model does not account for either reserve obligations or the reserve capability that resources can provide. While integration costs have previously been used to account for regulation reserve obligations, for the first time in the 2019 IRP an analogous credit has been applied to highly flexible resources that primarily provide operating reserves. This "operating reserve credit" has been applied to proxy storage, gas peaking units, and Class 1 DSM (interruptible load) that are available for selection within the SO model. While other resources, such as combined cycle gas plants and renewables, are also capable of providing operating reserves these resources primarily provide energy which the SO model is already accounting for. As a result, no operating reserve credits are applied to these other resources. For a resource that is available throughout the year, such as a gas peaking unit, the operating reserve credit amounts to $50/kw-year (2018$), based on the costs calculated in the 50 MW Reserve Case relative to the Base Case. For resources with limited availability, such as seasonal Class 1 DSM resources or storage combined with wind or solar, the credits are prorated to account for the periods when a resource provides operating reserves.

Flexible Resource Needs Assessment

Overview

In its Order No. 12013 issued on January 19, 2012 in Docket No. UM 1461 on "Investigation of matters related to Electric Vehicle Charging", the Oregon Public Utility Commission (OPUC) adopted the OPUC staff's proposed IRP guideline:

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

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

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

In this section, PacifiCorp first identifies its flexible resource needs for the IRP study period of 2019 through 2038, and the calculation method used to estimate those requirements. PacifiCorp then identifies its supply of flexible capacity from its generation resources, in accordance with the Western Electricity Coordinating Council (WECC) operating reserve guidelines, demonstrating that PacifiCorp has sufficient flexible resources to meet its requirements.

Forecasted Reserve Requirements

Since contingency reserve and regulation reserve are separate and distinct components, PacifiCorp estimates the forward requirements for each separately. The contingency reserve requirements are derived from stochastic simulations run using the Planning and Risk (PaR) model. The regulating reserve requirements are part of the inputs to the PaR model, and are calculated by applying the methods developed in the Portfolio Regulation Reserve Requirements section. The contingency and regulation reserve requirements include three distinct components and are modeled separately in the 2019 IRP: 10-minute spinning reserve requirements, 10-minute non-spinning reserve requirements, and 30-minute regulation reserve requirements. The reserve requirements for PacifiCorp's two balancing authority areas are shown in Table F.12 below.

Table F.12 - Reserve Requirements (MW)

Year	East Requirement			West Requirement		
	Spin (10-minute)	Non-spin (10-minute)	Regulation (30-minute)	Spin (10-minute)	Non-spin (10-minute)	Regulation (30-minute)
2019	193	193	359	93	93	196
2020	194	194	377	94	94	207
2021	194	194	491	96	96	211
2022	196	196	493	97	97	198
2023	199	199	502	97	97	196
2024	202	202	593	98	98	283
2025	203	203	601	99	99	282
2026	203	203	592	99	99	280
2027	205	205	591	100	100	278
2028	207	207	597	101	101	275
2029	208	208	539	101	101	288
2030	210	210	651	102	102	286
2031	212	212	642	102	102	286
2032	214	214	644	102	102	282
2033	215	215	626	102	102	296
2034	216	216	620	102	102	296
2035	217	217	604	101	101	299
2036	219	219	601	101	101	308
2037	220	220	600	101	101	307
2038	221	221	560	101	101	301

Flexible Resource Supply Forecast

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

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

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

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

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

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

River as well as contracted generation from the Mid-Columbia projects. In the PacifiCorp East balancing authority area, PacifiCorp may use facilities on the Bear River to provide spinning reserve.

Thermal resources are also used to meet the spinning reserve requirements when they are online. The amount of reserve provided by these resources is determined by their ability to ramp up within a 10-minute interval. For natural gas-fired thermal resources, the amount of reserve can be close to the differences between their nameplate capacities and their minimum generation levels. In the current IRP, PacifiCorp's reserve are served not only from existing coal- and gas-fired resources, but also from new gas-fired resources selected in the preferred portfolio.

Table F.13 lists the annual reserve capability from resources in PacifiCorp's East and West balancing authority areas.[20] All the resources included in the calculation are capable of providing all types of reserve. The non-spinning reserve resources under third party contracts are excluded in the calculations. The changes in the flexible resource supply reflect retirement of existing resources, addition of new preferred portfolio resources, and variation in hydro capability due to forecasted streamflow conditions, and expiration of contracts from the Mid-Columbia projects that are reflected in the preferred portfolio.

Table F.13 - Flexible Resource Supply Forecast (MW)

Year	East Supply (10-Minute)	West Supply (10-Minute)	East Supply (30-Minute)	West Supply (30-Minute)
2019	1,843	701	2528	965
2020	1,893	703	2528	967
2021	1,897	684	2472	948
2022	1,913	671	2488	935
2023	1,931	683	2387	947
2024	2,158	965	2613	1262
2025	2,166	963	2621	1260
2026	2,278	963	2734	1260
2027	2,228	964	2734	1261
2028	2,144	1,143	2650	1440
2029	2,268	1,645	2773	1876
2030	2,562	1,645	2987	1876
2031	2,592	1,645	3017	1876
2032	2,604	1,765	3029	1996
2033	2,604	1,884	3029	2016
2034	2,426	1,884	2789	2016
2035	2,441	1,884	2804	2016
2036	2,445	1,988	2808	2120
2037	3,104	2,240	3308	2372
2038	3,601	2,622	3804	2622

Figure F.16 and Figure F.17 graphically display the balances of reserve requirements and capability of spinning reserve resources in PacifiCorp's East and West balancing authority areas

[20] 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 2024 the battery capacity added in the preferred portfolio will exceed of PacifiCorp's current 202.8 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.

respectively. The graphs demonstrate that PacifiCorp's system has sufficient resources to serve its reserve requirements throughout the IRP planning period.

Figure F.16 - Comparison of Reserve Requirements and Resources, East Balancing Authority Area (MW)

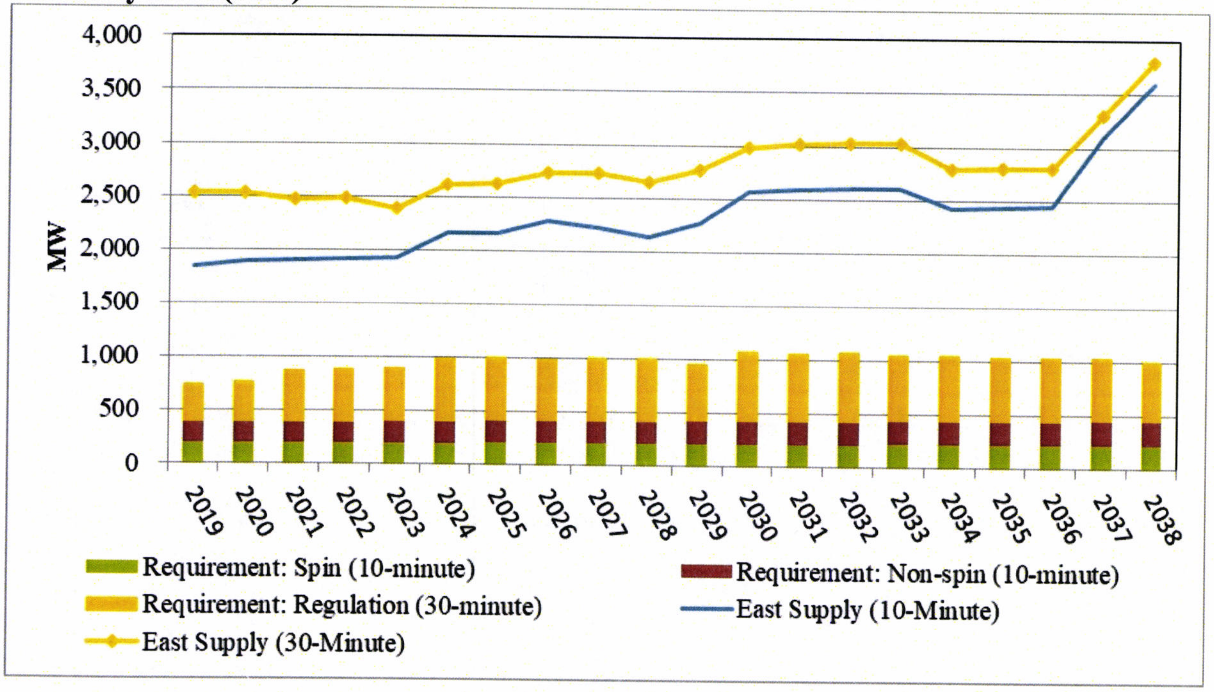
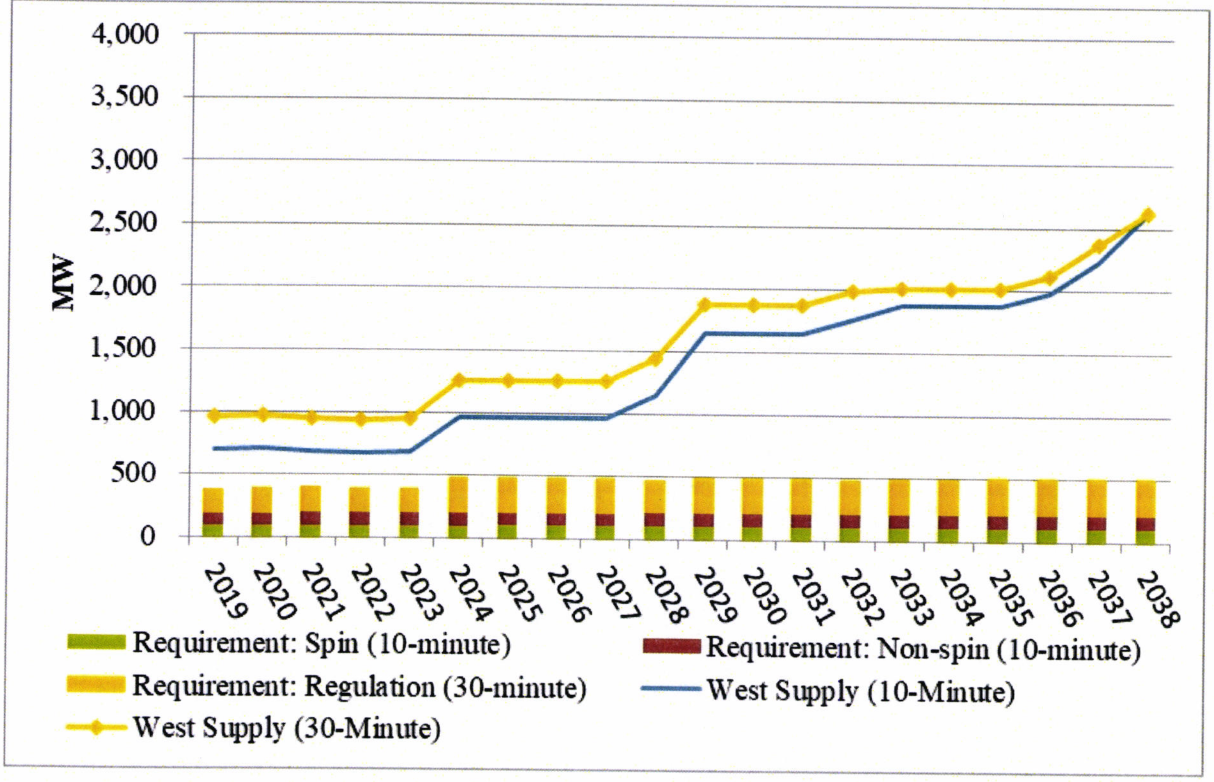


Figure F.17 - Comparison of Reserve Requirements and Resources, West Balancing Authority Area (MW)



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 2022. 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 the OPUC order, electric vehicle technologies may be able to meet flexible resource needs at some point in the future. However, the electric vehicle technology and market have not developed sufficiently to provide data for the current study. Since this analysis shows no gap between forecasted demand and supply of flexible resources over the IRP planning horizon, this IRP does not evaluate whether electric vehicles could be used to meet future flexible resource needs.