APPENDIX F – FLEXIBLE RESERVE STUDY

Introduction

This 2017 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 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 new regulation reserve standard that became effective July 1, 2016, and BAL-002-WECC-2 is a contingency reserve standard that became effective October 1, 2014. 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. Specifically, PacifiCorp's calculations demonstrate that the regulation reserve burden associated with wind deviations from scheduled amounts are twice the amount associated with solar, three times the amount associated with load, and four times the amount associated with Non-

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1 NERC Standard BAL-001-2, http://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-2, http://www.nerc.com/files/BAL-002-WECC-2.pdf, which became effective October 1, 2014.

3 NERC Glossary of Terms: http://www.nerc.com/files/glossary_of_terms.pdf, updated July 13, 2016.

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").

VERs. As a result, PacifiCorp attributes different levels of regulation reserve to load, wind, solar, and Non-VERs.

The FRS is based on PacifiCorp operational data recorded from January 2015 through December 2015 for load, wind, and Non-VERs. Solar generation on PacifiCorp's system was insignificant during that time period, but is expected to amount to over 1,000 MW by the end of 2017. PacifiCorp's primary analysis, focuses on the variability of load, wind, and Non-VERs during 2015. A supplemental analysis discusses how the total variability of the PacifiCorp system changes with varying levels of wind and solar capacity. The estimated regulation reserve amounts determined in this study represent the incremental capacity needed to ensure compliance with BAL-001-2 for a particular operating hour. The regulation reserve requirement 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 Energy Imbalance Market ("EIM") operated by the California Independent System Operator Corporation ("CAISO").

The methodology in the FRS differs in several ways from that employed in PacifiCorp's previous regulation reserve requirement analyses.[5,6,7] First, regulation reserve requirements are now tied directly to compliance with the BAL-001-2 standard. Second, the FRS uses a portfolio wide approach to determine the overall regulation reserve requirement, including the aggregated diversity benefits for all customer classes. Third, all customer classes that contribute to the overall regulation reserve requirement are now allocated a share of the diversity benefits resulting from aggregating their requirement with that of the system as a whole. Fourth, the FRS reflects updated data based on actual operational experience, including the data and benefits from PacifiCorp's participation in the EIM.

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 wind and solar output.

The regulation reserve requirements produced by the FRS were 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 costs are attributed to the integration of wind and solar generation resources in the 2017 Integrated Resource Plan (IRP).

[5] 2012 Wind Integration Study report, Appendix H in Volume II of PacifiCorp's 2013 IRP report: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol2-Appendices_4-30-13.pdf

[6] 2013 PacifiCorp Schedule 3 and 3A Study, Exhibit PAC-8 in testimony of Greg Duvall, FERC Docket No. ER13-1206 (filed April 1, 2013).

[7] 2014 Wind Integration Study, Appendix H in Volume II of PacifiCorp's 2015 IRP report: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol2-Appendices.pdf

Executive Summary

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 and the cost of using day-ahead load, wind, and solar forecasts to commit gas units. Finally, the FRS compares PacifiCorp's overall operating reserve requirements over the IRP study period, including both regulation reserve and contingency reserve, to its flexible resource supply.

The FRS estimates regulation reserve based on the specific requirements of NERC Standard BAL-001-2. It also incorporates the current timeline for EIM market processes, as well as EIM resource deviations and 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 accounts for the diversity of using a single portfolio of regulation reserve resources to cover variations in load, wind, solar, and Non-VERs. The regulation reserve requirements for the various portfolios considered in this analysis including values from the 2014 Wind Integration Study for reference are shown in Table F.1.

Table F.1 - Portfolio Regulation Reserve Requirements, by Scenario

Case	Wind Capacity (MW)	Solar Capacity (MW)	Stand-alone Regulation Requirement (MW)	Portfolio Diversity Credit (%)	Regulation Requirement with Diversity (MW)
2014 WIS	2,543	n/a	n/a	n/a	626
2015 (No Solar)	2,588	0	900	37.5%	562
2017 Base Case	2,757	1,050	998	38.2%	617
Incremental Wind	3,007	1,050	1,023	38.3%	631
Incremental Solar 1	2,757	1,550	1,033	38.6%	635
Incremental Solar 2	2,757	2,050	1,074	39.2%	653

Two categories of flexible resource costs are estimated using the Planning and Risk (PaR) model: one for meeting intra-hour regulation reserve requirements, and one for inter-hour system balancing costs associated with committing gas plants using day-ahead forecasts of load, wind, and solar. Table F.2 provides the wind and solar costs on a dollar per megawatt-hour ($/MWh) of generation basis. The results of the 2014 Wind Integration Study are also included for reference.

Table F.2 - 2017 FRS Flexible Resource Costs as Compared to 2014 WIS Costs, $/MWh

	Wind 2014 WIS (2014$)	Wind 2017 FRS (2016$)	Solar 2017 FRS (2016$)
Intra-hour Reserve	$2.35	$0.43	$0.46
Inter-hour/System Balancing	$0.71	$0.14	$0.14
Total Flexible Resource Cost	**$3.06**	**$0.57**	**$0.60**

The 2017 FRS results are applied in the 2017 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 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-2.[8] Regulation reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC Control Performance Criteria in BAL-001-2.[9] Frequency response reserve is capacity that PacifiCorp holds available to ensure compliance with NERC standard BAL-003-1.[10] Each type of operating reserve is further defined below.

Contingency Reserve

NERC regional reliability standard BAL-002-WECC-2 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. Contingency reserve must be available within ten minutes, and at least half must be from "spinning" resources that are online and immediately responsive to system fluctuations. 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.

Regulation Reserve

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*

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[8] NERC Standard BAL-002-WECC-2 – Contingency Reserve: http://www.nerc.com/files/BAL-002-WECC-2.pdf

[9] NERC Standard BAL-001-2 – Real Power Balancing Control Performance: http://www.nerc.com/files/BAL-001-2.pdf

[10] NERC Standard BAL-003-1 — Frequency Response and Frequency Bias Setting: http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.pdf

(BAAL) for more than 30 consecutive clock-minutes…

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. 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. PacifiCorp has not specifically evaluated reserve needs for CPS1 compliance. 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. Regulation reserve requirements are discussed in more detail later on in the study.

Frequency Response Reserve

NERC standard BAL-003-1 specifies that each BAA must arrest frequency deviations and support interconnection frequency when it drops below the scheduled level. 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 MW/0.1Hz. The additional capacity must be deployed immediately, and performance is measured over a period of seconds, amounting to under a minute. 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 2017 Frequency Response Obligation was 19.51 MW/0.1Hz for PACW, and 48.93 MW/0.1Hz for PACE. PacifiCorp's combined obligation amounts to 68.44 MW for a frequency drop of 0.1 Hz, or 205.32 MW for a frequency drop of 0.3 Hz.

Because the performance measurement for contingency reserve under the Disturbance Control Standard (BAL-002-1) is similar to that for BAL-003-1, frequency response capacity is effectively incremental to contingency reserve obligations. As Standard BAL-003-1 is based on median performance under selected WECC-wide events, while regulation reserve obligations under BAL-001-2 are based on minimum performance during BAA-specific events, frequency response capacity can be considered a subset of the BAL-001-2 obligation. Since median performance is adequate for BAL-003-1 compliance, BAL-001-2 compliance can take precedence, so long as the overlap is sufficiently low, i.e. BAL-001-2 events are rare and there don't have a positive correlation with BAL-003-1 events.

While frequency response reserve can meet regulation reserve requirements, the reverse is not necessarily true. 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 regulation reserve, frequency response needs to be spread over a larger number of resources. Because PacifiCorp has excess spinning reserve capability compared to its contingency reserve obligation, the capacity and response time requirements for its frequency response obligations are expected to be met by drawing from its existing pool of regulation reserve resources. As a result, no incremental capacity requirements or resource constraints related to frequency response were included in the 2017 IRP analysis beyond those already included for contingency and regulation reserve.

Description of 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.[11]

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 the Regulation Reserve Study used five-minute intervals throughout the analysis.

EIM base schedule and deviation data for each wind and Non-VER transaction point were downloaded using the Report Explorer application to query PacifiCorp's nMarket Application database, 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

[11] 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-55 is the base schedule time point used throughout this study because it is the deadline which most closely corresponds to the final T-57 deadline for all transmission customers to submit final base schedules.

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.

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
  - Proxy hourly base schedules developed from actual prior hour and prior week data

- VER data
  - Five-minute EIM deviations
  - Hourly base schedules

- Non-VER data
  - Five-minute EIM deviations
  - 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 over the Study Term. Load data for the Study Term was downloaded from PacifiCorp's Ranger PI system and has not been adjusted for transmission and distribution losses. Only actual load data is available from Ranger PI, not base schedule data that could be used to determine the deviation associated with Load. Because of differences in the load defined in EIM and in the Ranger PI system, the EIM load base schedules are not consistent with the Ranger PI actual results. To address the inconsistency, PacifiCorp developed proxy load base schedules, as discussed below.

Wind Data

The Wind class includes 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.[12] Wind, in comparison to load, often has larger upward and downward fluctuations in output that impose significant and sometimes unforeseen challenges when attempting to maintain reliability. For example, as recognized by FERC in Order No. 764, "Increasing the relative amount of [VERs] on a system can increase operational uncertainty that the system operator must manage through operating criteria, practices, and procedures, *including the commitment of adequate reserves*."[13] The data included in the FRS for the Wind class includes all wind 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. Appendix F.B, Table 1 contains the list of the wind plants included in the study. In total, the FRS includes 2,588 megawatts of wind.

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."[14] 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. Appendix F.B, Table 2 contains the list of the Non-VERs included in the study. In total, the FRS includes 2,228 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

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

[13] Order No. 764 at P 20 (emphasis added).

[14] *Id.* at P 92.

requirement is also zero. The allocation of regulation reserve requirements and diversity benefits is discussed in more detail later on in the study..

Data Analysis and Adjustment

Overview

This section provides details on adjustments made to the data to develop base schedules that correspond to the load data, align the ACE calculation with actual operations, and address data issues.

Load Base Schedule Development

Load deviations are settled using hourly imbalance data in EIM, whereas resource deviations are settled using fifteen-minute and five-minute imbalance data. As a result, the five-minute deviations necessary to assess the regulation reserve requirements associated with Load were not available through EIM. For the FRS, PacifiCorp used actual load data from its Ranger PI system, which can provide data at a five-minute granularity. The Ranger PI system does not have the associated base schedules necessary to calculate deviations, however, so PacifiCorp developed proxy load base schedules consistent with the measured actual loads.

The load base schedule for each hour was calculated from actual load at 55 minutes prior to the hour ("T-55") in question, with a scaling factor applied based on the change in load over that same interval in the prior week. The five-minute interval ending at T-55 is the last load data point available prior to base schedule submission to CAISO at hour T-55 and represents the current state of load in the PacifiCorp BAAs. Load follows different patterns depending on season and day of the week. Using data from one week prior ensures that recent conditions on a similar day are used in the calculation of the load base schedule.

Figure F.1 below illustrates measurement of the expected load change between T-55 data and the hourly base schedule over three hours. The five-minute interval ending at 17:05 (first green column) has a load of 2,643 MW. The actual load in hour 18 averages 2,837 MW (middle solid horizontal line), an increase of 7.4 percent. Similarly, the expected load change from the five-minute interval ending at 18:05 to hour 19 is a decrease of 1.1 percent (difference between second green column and second horizontal line). Figure F.2 below shows how those load measurements are applied seven days later to determine the proxy load base schedules for hours 18 and 19. The proxy load base schedule for hour 18 is calculated as the actual load in the five-minute interval ending at 17:05, plus an additional 7.4 percent. The proxy load base schedule for hour 19 is calculated as the actual load in the five-minute interval ending at 18:05, minus 1.1 percent. Deviations are then calculated as the difference between the proxy load base schedule and actual five-minute loads over the hour.

Figure F.1 - Expected Load Change from Prior Week

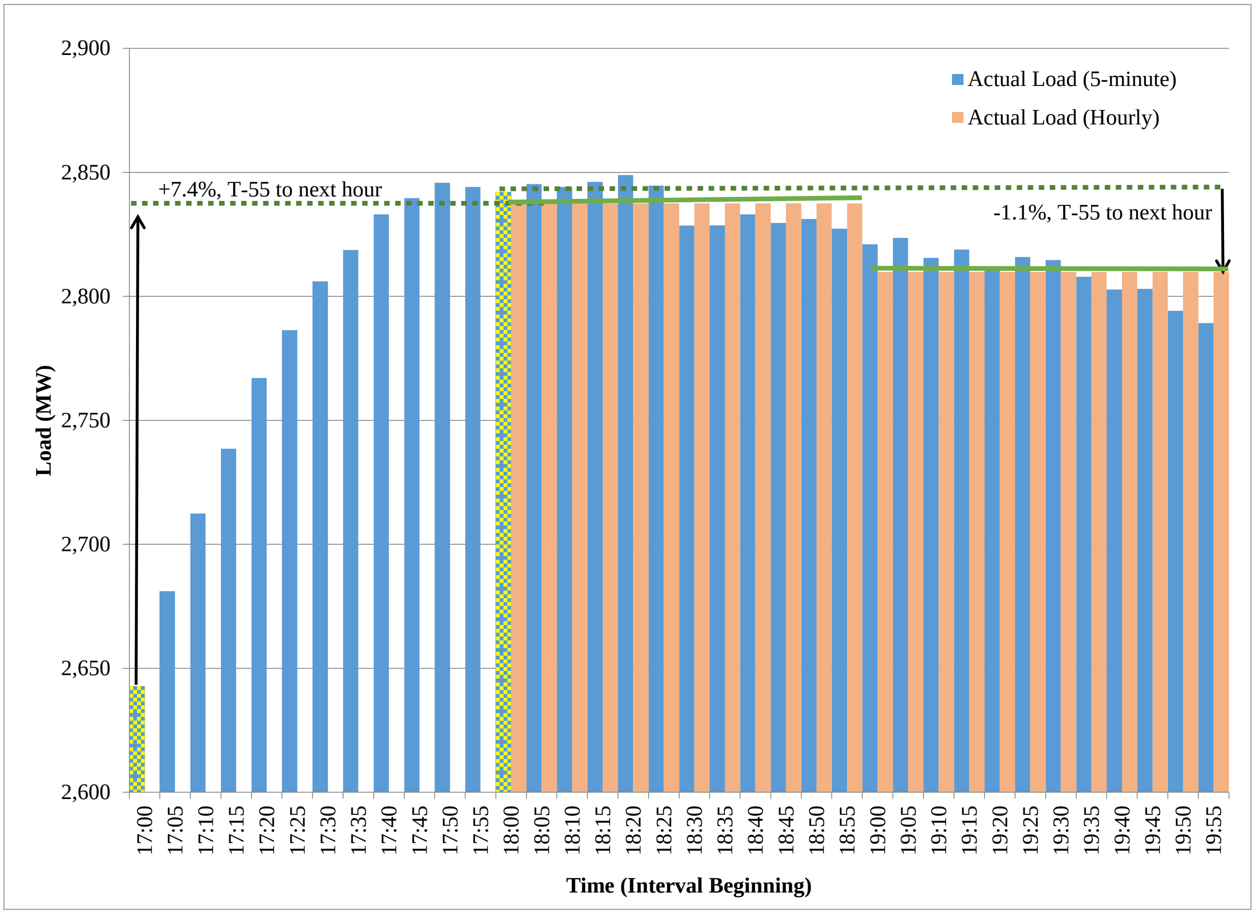
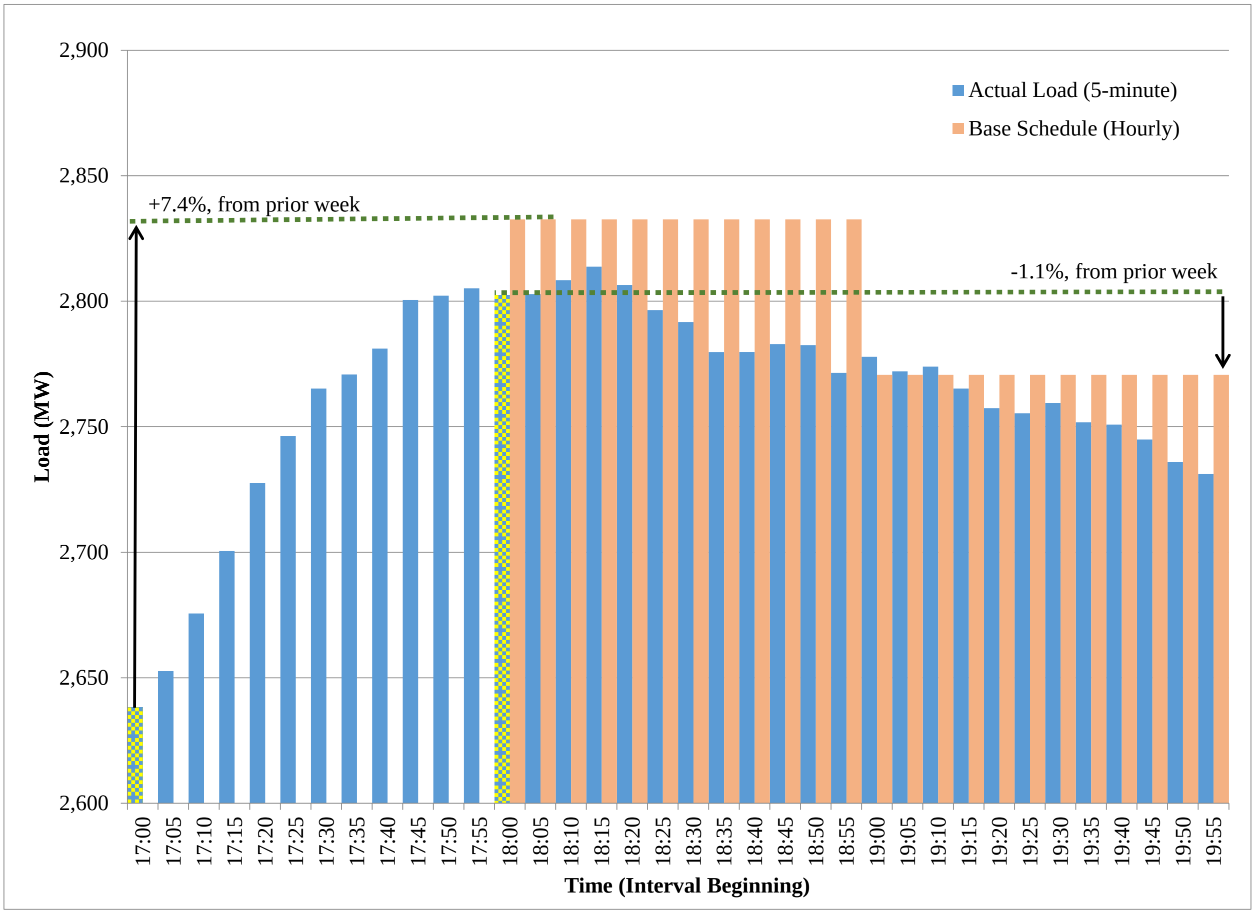


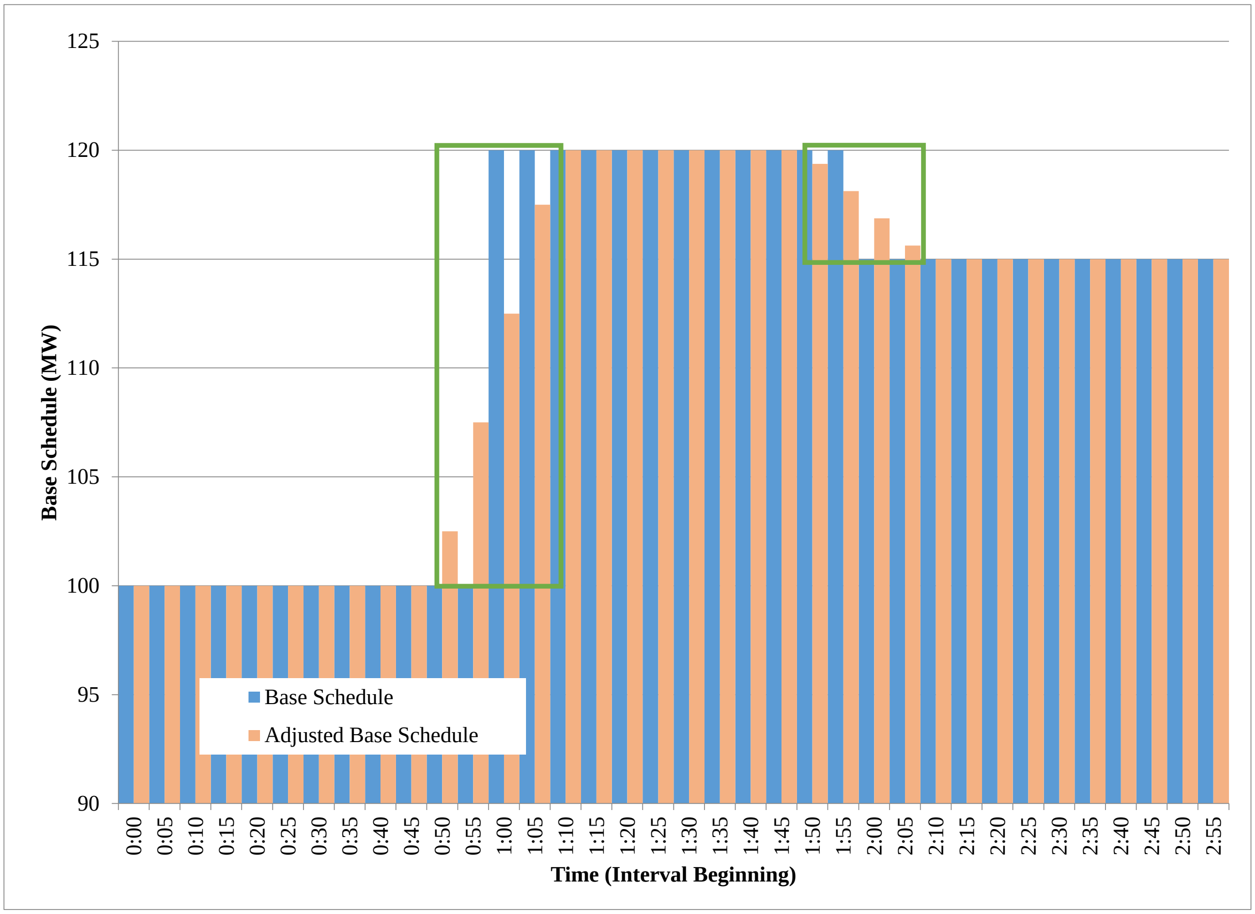
Figure F.2 - Proxy Load Base Schedule



Base Schedule Ramping Adjustment

In actual operations, PacifiCorp's ACE calculation includes a linear ramp from the base schedule in one hour to the base schedule in the next hour, starting ten-minutes before the hour and continuing until ten-minutes past the hour. The hourly base schedules used in the study are adjusted to reflect this transition from one hour to the next. This adjustment step is important because, to the extent actual load or generation is transitioning to the levels expected in the next hour, the adjusted base schedules will result in reduced deviations during these intervals, potentially reducing the regulation reserve requirement. Figure F.3 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.3 - Base Schedule Ramping Adjustment



Data Corrections

The raw data extracted from PacifiCorp's systems for Load, Wind, and Non-VERs was reviewed to identify potentially spurious data points prior to performing the regulation reserve requirement calculations contained in the next section. Hourly intervals of data were excluded from the FRS results if any five-minute interval within that hour 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 and Non-VERs:
- Deviations missing in CAISO database
- Base schedules missing in CAISO database
- Generator trip events
- Wind 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. For instance, in one observed example, PACW BAA load remained stuck at a single level for two days beginning at 2:00 PM on January 6, 2015. The change in load relative to the prior interval was calculated for the entire test period and instances where multiple successive intervals showed no change in load were excluded from the analysis since they are not indicative of actual operating conditions.

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. For example, a 637 MW drop in PACE BAA load occurred over one five-minute interval on May 15, 2015. Roughly one hour later, PACE BAA load increased by 849 MW over two five-minute intervals. 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. A similar spike on March 23, 2015, spanned just one five-minute interval, and was likely a result of a single bad load measurement. Load telemetry spike irregularities were identified by examining the intervals with the largest changes from one interval to the next, either up or down. Intervals with inexplicably large and rapid changes in load, particularly where the load reverts 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.

The available Wind and Non-VER data also includes some data irregularities. PacifiCorp evaluated these irregularities and in some cases removed data that appears to be inaccurate. For instance, PACW wind deviation data is missing in 36 five-minute intervals out of the 105,108 intervals in the study. Deviations are directly tied to regulation reserve requirements, so the hours in which deviation data is missing are excluded from the analysis. Base schedules for PACE Non-VERs are missing in 75 hours, while the other wind and Non-VER categories have smaller amounts of missing data. While Wind base schedules are directly linked to the regulation requirement forecast, missing base schedule data in PacifiCorp's database may be indicative of inconsistencies in deviation results, which may be calculated off of a stale or erroneous base. Given the limited frequency of such events, PacifiCorp has excluded from the analysis intervals where deviations or base schedules are missing.

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.

For load, an hour of spurious data will prevent the calculation of the base schedule for the next hour, since the actual load at T-55 is not available. The spurious data also impacts the same two hours in the following week as the expected load change used to determine the base schedule for those hours utilizes the hour in question. For example, if the hour beginning at midnight on February 1, 2015, is found to be spurious, four hours are removed from the Study Term: the spurious hour (the hour ending midnight, February 1, 2015); the hour following the spurious hour (the hour ending 1:00 AM, February 1, 2015), which relies on the spurious hour to inform the regulation forecast; and the two corresponding hours in the following week (the hour ending at midnight, February 8, 2015 and the hour ending at 1:00 AM, February 8, 2015), each of which no longer has a valid prior-week hour from which to develop a proxy load base schedule. The description of "Load Base Schedule Development" above contains further discussion about this relationship and development of the base schedule.

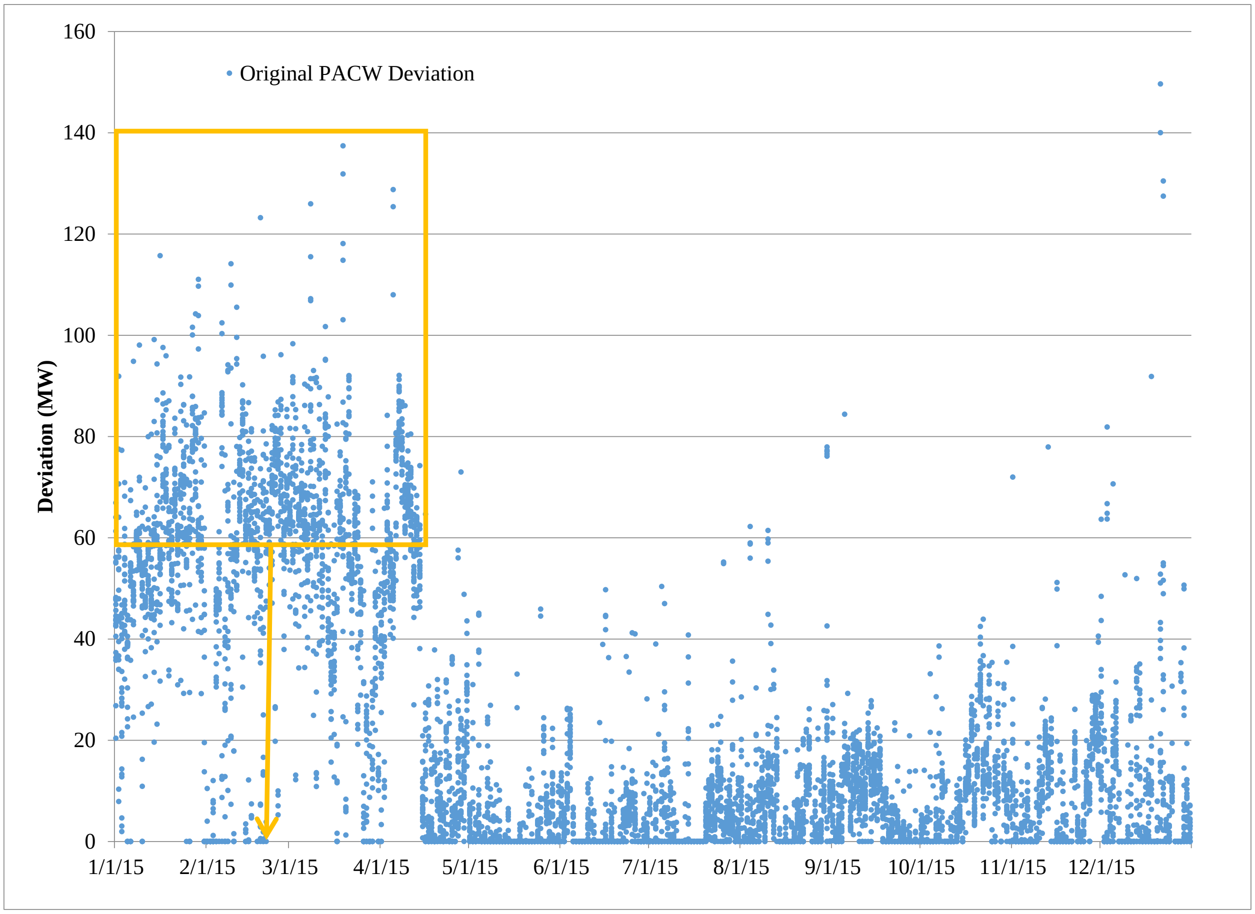
After review of the data for each of the above anomaly types, and out of 105,120 five-minute intervals in the Study Term, only 5.9 percent and 3.6 percent of the total FRS term hours were removed from PACW and PACE, respectively. The system-wide error rate was 9.1 percent, slightly lower than the sum 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 Term.

Non-VER Deviation Adjustment

The deviations associated with the Non-VER class show a clear anomaly between January 2015 and April 14, 2015. The abrupt change is evident in the hourly data for PACW shown in Figure 4 below and a comparable anomaly was seen over the same time frame for PACE (not shown). The anomaly ends abruptly at midnight on April 14, 2015, in both BAAs. PacifiCorp has concluded that this issue is a result of errors in base schedule submission rather than an actual deviation. During the early stages of the EIM there were differences between the CAISO's EIM model and PacifiCorp's EMS. The modeling of Colstrip generation was one of those differences. Within the PacifiCorp EMS, 100 percent of Colstrip generation output is pseudo-tied into the PACW BAA. However, the EIM modeled 50 percent of Colstrip generation as being in the PACW BAA and the other 50 percent of Colstrip generation as modeled in the PACE BAA. This mismatch between the two systems resulted in the measured deviation.

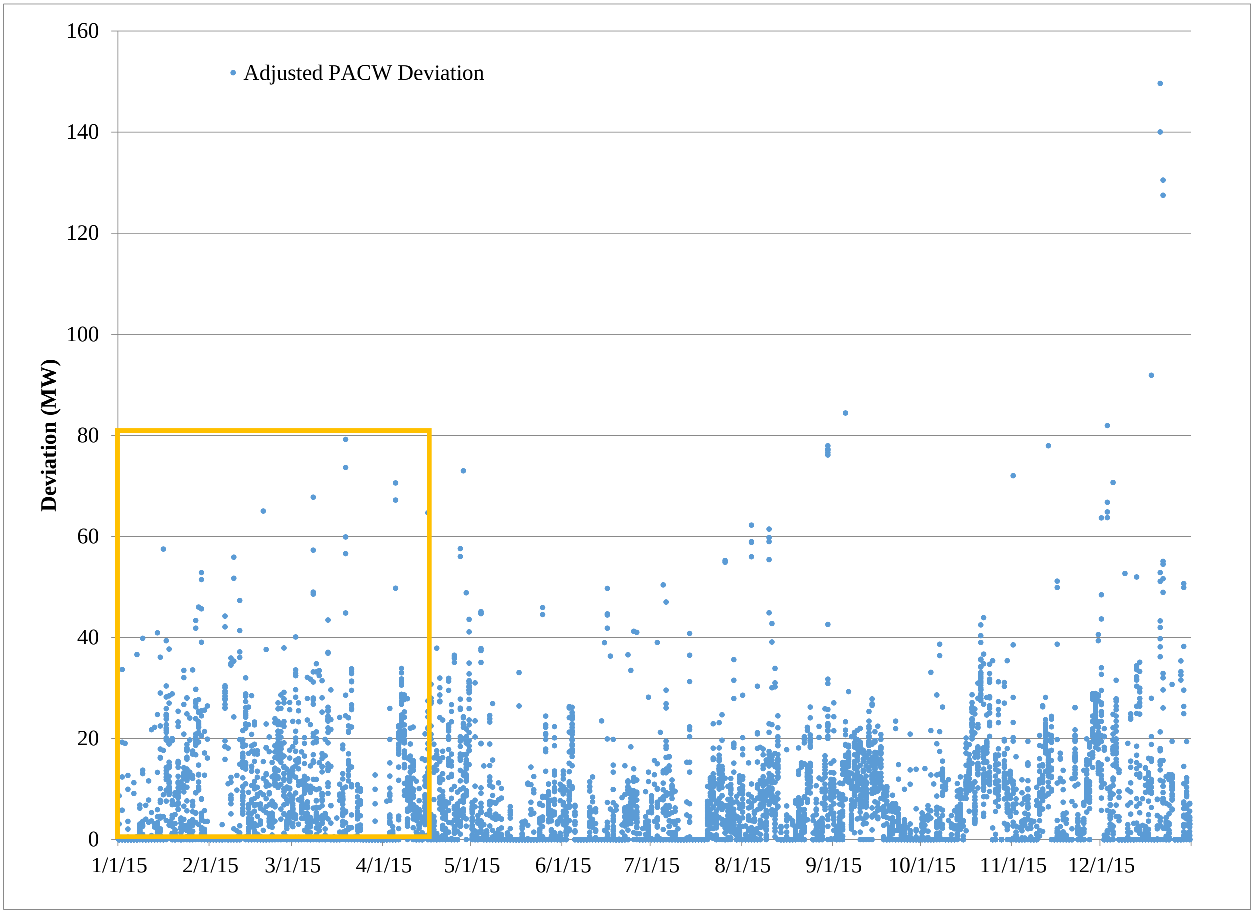
The Colstrip EIM base schedule of 50 percent to PACE and 50 percent to PACW was compared to the EMS output of 100 percent to PACW to determine the deviation. This resulted in a positive deviation to base schedule for PACW. When the EIM model mismatch was discovered it was corrected to align to PacifiCorp's EMS system. This eliminated the persistent deviation on April 14, 2015. For the purposes of the FRS, the regulation reserve requirement for this period was reduced by 58 MW such that the average requirement during this period is equal to the average in the remainder of 2015. The box in Figures F.4 and F.5 below shows the affected data before and after the adjustment is applied.

Figure F.4 - Original PACW Non-VER Deviations



The adjusted regulation reserve requirement is shown in Figure F.5 below.

Figure F.5 - Adjusted PACW Non-VER Deviations



Methodology to Determine Initial Regulation Reserve Requirement

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-55.[15]

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

[15] *See* footnote 11 above for explanation of PacifiCorp's use of the T-55 base schedule time point in the FRS.

- 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;
- 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 requirement is defined formulaically by a regional reliability standard.

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. On the other hand, frequency response reserve can be considered a subset of the regulation reserve obligation, though it requires faster responding resources than those contemplated in the FRS. Because PacifiCorp has excess spinning reserve capability compared to its contingency reserve obligation, the capacity and response time requirements for its frequency response obligations are expected to be met by drawing from its existing pool of regulation reserve resources. As a result, no incremental capacity requirements or resource constraints related to frequency response were included in the FRS analysis. 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.[16] 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 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…*

The BAL-001-2 standard became effective as of July 1, 2016 and, upon its effectiveness, officially replaced the BAL-001-1 standard. The new BAL-001-2 standard is a fundamentally different

16 NERC Standard BAL-001-2, http://www.nerc.com/files/BAL-001-2.pdf

requirement than the prior standard, BAL-001-1, though it is intended to achieve a similar result. BAL-001-1 required ten-minute average ACE to be within the static L_{10} limit in at least 90 percent of non-overlapping ten-minute intervals in a month.[17] The new BAL-001-2 standard requires average ACE to be within a dynamic limit for at least one minute in 100 percent of all rolling thirty-minute intervals. 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.

PacifiCorp's 2012, 2013, and 2014 studies were all based on compliance with BAL-001-1. These studies utilized deviations over ten-minute intervals and allowed deviations up to the fixed L_{10} value.[18,19] While these studies all used a 99.7 percent confidence interval, they did not necessarily achieve 99.7 percent compliance with the BAL-001-1 standard. For instance, the 2014 Wind Integration Study had a failure rate of 1.4 percent for PACE and 2.0 percent for PACW.[20] This is higher than the 90 percent compliance requirement under BAL-001-1, but significantly lower than the 100 percent compliance requirement under BAL-001-2. In addition, prior studies separately distinguished between three categories of regulation reserve, all of which were intended to capture the total potential deviation over the ten-minute interval relevant under BAL-001-1:

- Ramping – flexibility required to follow the change in actual net system Load from hour to hour;
- Regulating – flexibility required to manage forecast uncertainty over ten-minute intervals; and
- Following – flexibility required to manage forecast uncertainty over sixty-minute intervals.

The FRS fundamentally differs from the 2012, 2013, and 2014 studies because it is based on compliance with BAL-001-2. The impacts of the changes in three key elements of the new BAL-001-2 standard relative to the old standard are summarized in Table F.3 below. The three key elements shown in Table F.3 include: (1) the length of time (or "interval") used to measure compliance under the old versus new BAL standard; (2) the change in compliance threshold between the two standards, which represents 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.

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[17] BAL-001-1 (R2) stated: Each Balancing Authority shall operate such that its average ACE for at least 90 percent of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}.

[18] L_{10} represents a bandwidth of acceptable deviation under BAL-001-1 prescribed by WECC between the net scheduled interchange and the net actual electrical interchange of PacifiCorp's BAAs.

[19] The L_{10} for PacifiCorp's BAAs in 2015 were approximately 33.49 MW for PACW and 49.92 MW for PACE. For more information, please refer to: http://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/CPS2%20Bounds%20Reports/2015%20CPS2%20Bounds%20Report%20Final%2020150615.pdf

[20] *See* Redacted Rebuttal Testimony of Brian S. Dickman, Wyoming Public Service Commission Docket No. 20000-469-ER-15 at p. 46:1-6 (filed Sept. 16, 2015).

Table F.3 - BAL-001-1 vs BAL-001-2

	Interval (minutes)	Compliance %	Allowed Variance
BAL-001-1	10	90%	Fixed: L_{10}
BAL-001-2	30	100%	Dynamic: BAAL
Impact on Requirement	Down	Up	Varies

The first change in Table F.3 is related to the length of time used to measure compliance. Under the prior standard, BAL-001-1, compliance was measured over six, non-overlapping ten-minute intervals within each hour. If ACE was within the allowed limits for all ten minutes of an interval, that interval was in compliance, and only the maximum deviation in that interval was considered in determining compliance. Compliance under BAL-001-2 is measured over rolling thirty-minute intervals, with sixty 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 was in compliance, and only the minimum deviation in each thirty-minute interval is considered in determining compliance. This change reduces regulation reserve requirements because PacifiCorp does not need to hold regulation reserve for deviations with duration less than 30 minutes.

The second change in Table F.3 above is related to the compliance percentage, or the number of intervals where deviations are allowed to be outside the limits set in the standard. BAL-001-1 required 90 percent compliance, that is, 10 percent of ten minute intervals were allowed to have deviations in excess of the requirement 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. Under the old standard, overall compliance could be achieved despite shortfalls in the intervals with the largest deviations. Because shortfalls are not permitted when the compliance requirement is 100 percent, this change increases regulation reserve requirements.

The third change in Table F.3 is related to the bandwidth of acceptable deviation before an interval is considered out of compliance. Under BAL-001-1, the acceptable deviation for each BAA was set at a fixed value in all intervals, referred to as L_{10}.[21] Under BAL-001-2, the acceptable deviation for each BAA is dynamic, varying as a function of the frequency deviation for the entire interconnect. The impact of this change is mixed as the limits under BAL-001-2 are generally higher, but at times can be lower than the limits under BAL-001-1.

In addition, the FRS identifies a single category of flexible capacity, rather than the three categories used in the prior studies performed in compliance with the old standard. Because deviations over ten-minute intervals are only relevant to the extent they exacerbate deviations over longer time

[21] The L_{10} for PacifiCorp's BAAs in 2015 were approximately 33.49 MW for PACW and 49.92 MW for PACE. For more information, please refer to: http://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/CPS2%20Bounds%20Reports/2015%20CPS2%20Bounds%20Report%20Final%2020150615.pdf .

frames, measuring three separate categories does not provide an accurate depiction of the requirements under BAL-001-2. In addition, while the following and regulating requirements in prior studies were statistically uncorrelated over the course of the year, the root sum square methodology used in the prior studies fails to account for the few random intervals when these components both show large requirements. Because the root sum square methodology underestimates the frequency of outlier events, it underestimates the capacity needed to cover them. The FRS eliminates complexity and distortion associated with combining multiple requirements by directly calculating a single component that allows for compliance with the BAL-001-2 standard.

Calculation of Regulation Reserve Need

The next step of the operating reserve methodology is to calculate the amount of regulation reserve required to be held under BAL-001-2. Regulation reserve requirements were calculated from five-minute EIM deviation data in a manner that emulates the requirements of the BAL-001-2 standard. The same calculation applies to all types of imbalances: Load, Wind, Non-VERs, and the combined portfolio.

First, the minimum five-minute imbalance was calculated for each thirty-minute rolling period in the Study Term. Second, for each hour, the maximum five-minute imbalance was selected from the values identified in the first step. An example is provided in the Table 2 and Figure 6 below.

In the example in Table F.4 below, the minimum five-minute imbalance in the thirty minutes beginning at 0:15 is 40 MW. This is also the maximum five-minute imbalance in any thirty-minute period in this hour. Assuming 40 MW of regulation reserve was available in this hour and the allowable ACE deviation was zero, this hour would still be compliant with the BAL-001-2 requirement—even though the imbalance exceeds the regulation reserve available for five consecutive, five-minute intervals—because the allowable ACE deviation was exceeded for less than 30 minutes.

Table F.4 - Deviation and Regulation Reserve Requirement Example

Interval	Base Schedule	Actual	5-Minute Deviation	30-Minute Deviation	Reserve Requirement
0:00	2500	2510	10	10	40
0:05		2520	20	10	40
0:10		2530	30	10	40
0:15		2540	**40**	10	40
0:20		2550	50	10	40
0:25		2560	60	10	40
0:30		2570	70	20	40
0:35		2560	60	30	40
0:40		2550	50	**40**	40
0:45		2540	40	40	40
0:50		2530	30	30	40
0:55		2520	20	20	40

As shown in Figure F.6 below, if the ACE deviations were only allowed for a ten minute interval, the requirement would be higher.

Figure F.6 - Deviation and Regulation Reserve Requirement Example

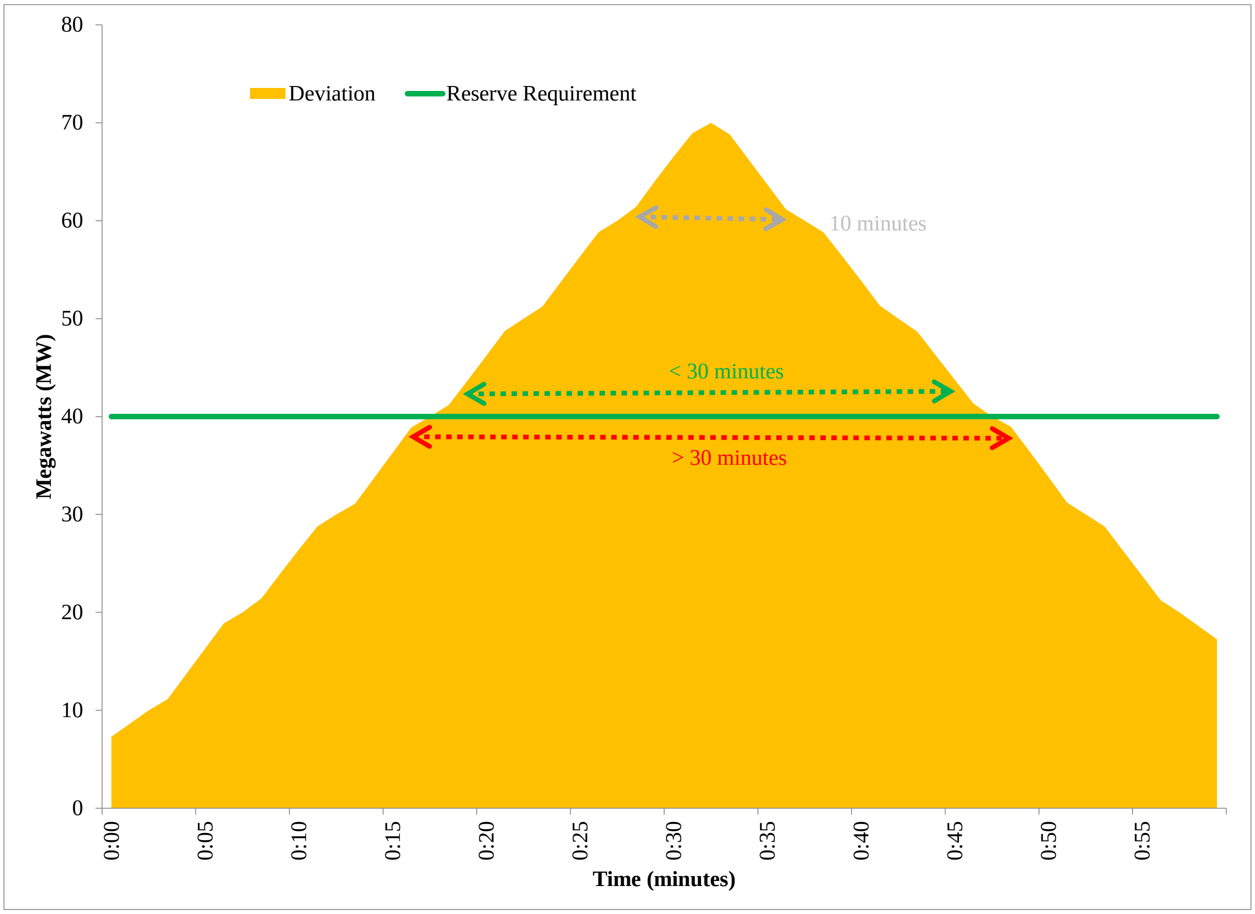
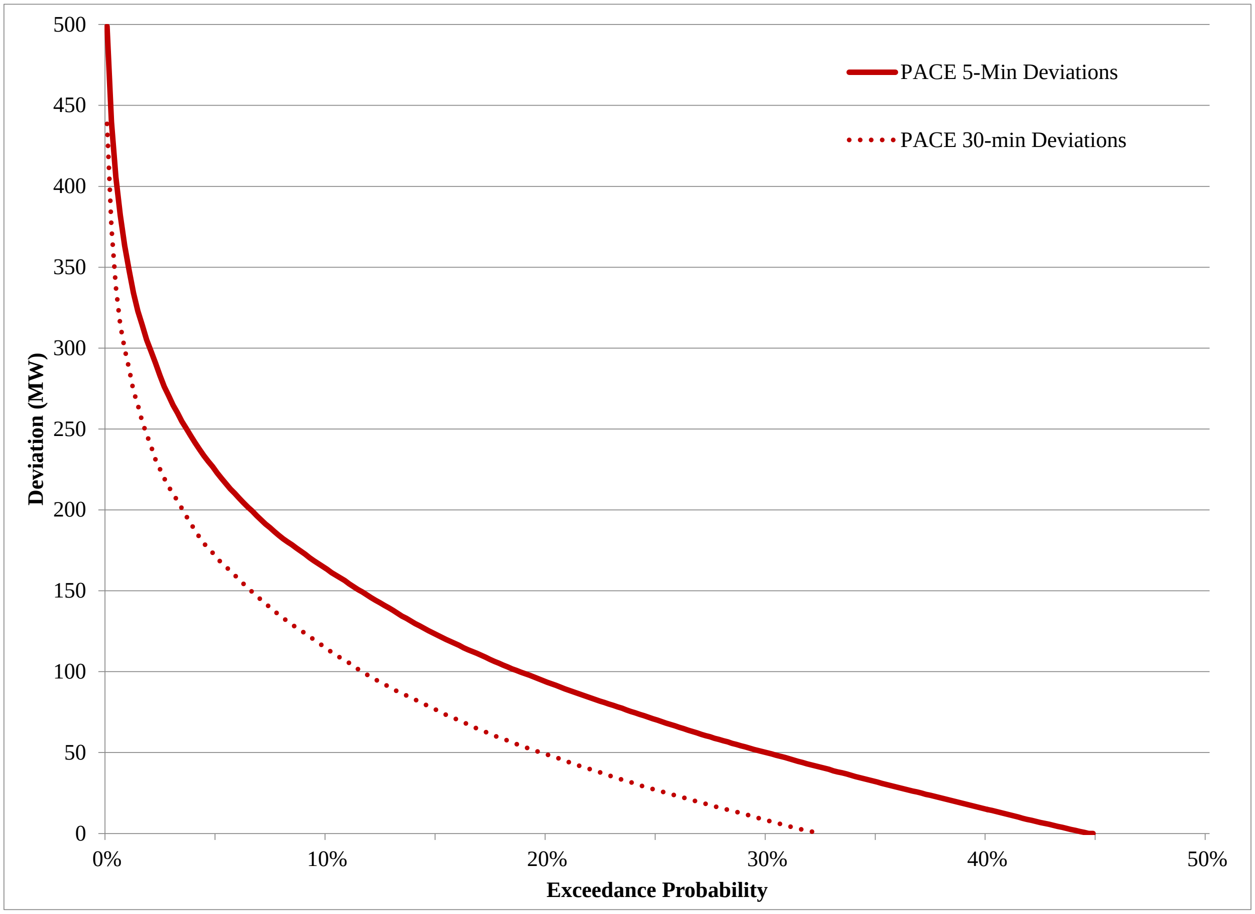


Figure F.7 below illustrates the distribution of the combined five-minute deviations for Load, Wind, and Non-VERs in PACE during 2015, as well as the distribution of thirty-minute sustained deviations relevant to the BAL-001-2 standard. The effect for PACW was comparable (not shown). The thirty-minute window for compliance reduces the regulation reserve need. The thirty-minute window can be particularly helpful with deviations in the last few intervals of each hour. This period has the longest forecast horizon (*i.e.*, the furthest out from T-55), so the potential deviations are expected to be larger. However, if the change resulting in the deviation is reflected in the base schedule for the next hour, PacifiCorp's ACE will return to zero on its own a few minutes later. Thus, so long as the duration of the deviation is less than 30 minutes, the size of the deviation in the last few intervals is irrelevant for compliance with BAL-001-2.

Figure F.7 - Probability Distribution of PACE Combined Portfolio Deviations



Balancing Authority ACE Limit: Allowed Deviations

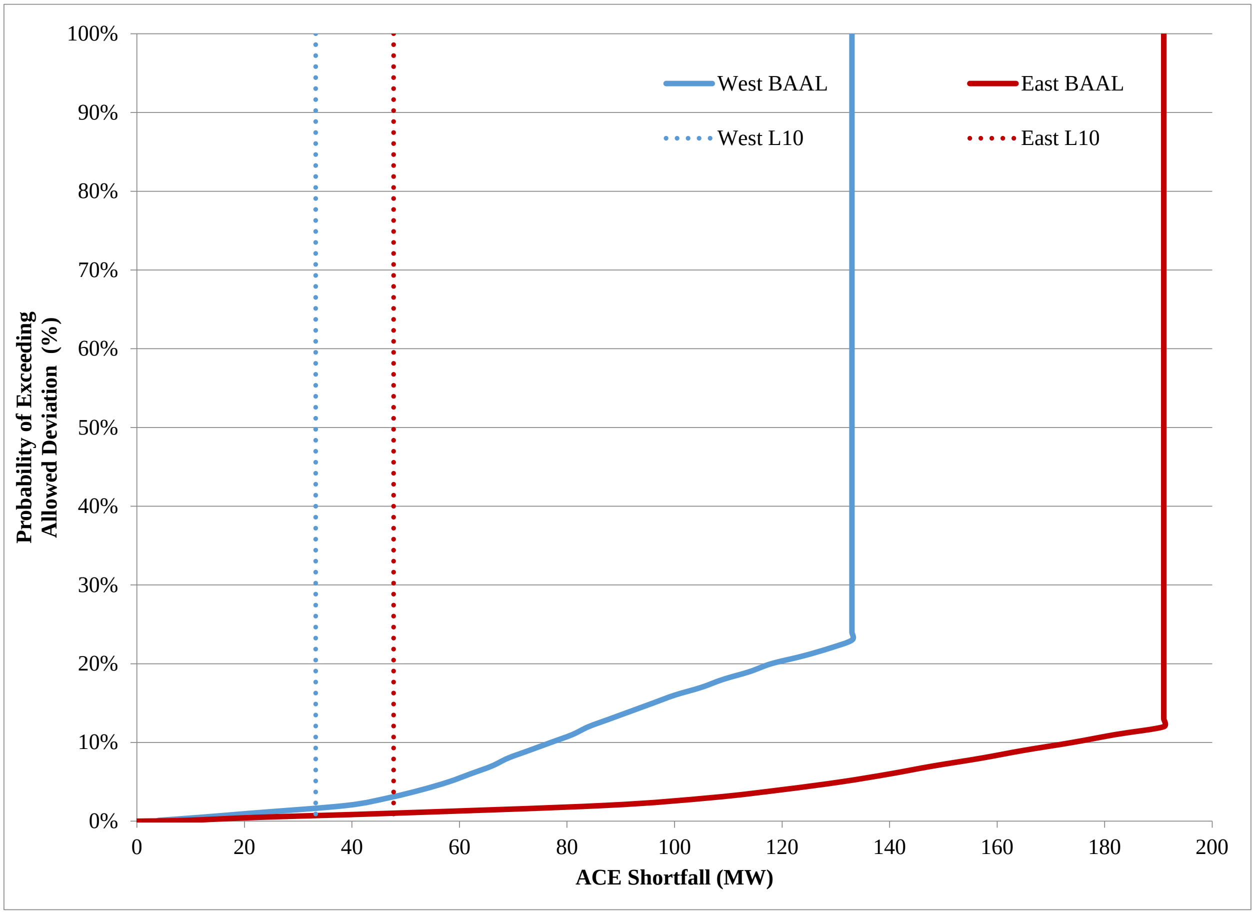
Even if insufficient regulation reserve capability is available to compensate for a thirty-minute sustained deviation, a violation of BAL-001-2 does not occur unless the deviation also exceeds the Balancing Authority ACE Limit.

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 8 below shows the probability of exceeding the allowed deviation during a five-minute interval for a given level of ACE shortfall. For instance, a 47 MW ACE shortfall in PACE has a one percent chance of exceeding the Balancing Authority ACE Limit. The fixed value under the prior BAL-001-1 standard for L_{10} is also plotted for comparison. 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.[22,23] This cap is reflected in Figure F.8.

Figure F.8 - Probability of Exceeding Allowed Deviation



In 2015, 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.

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

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

Planning Reliability Target: Loss of Load Probability

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

PacifiCorp's 2015 Integrated Resource Plan ("IRP") utilized a planning reserve margin of 13 percent, which is intended to achieve 0.88 loss of load hours per year.[24] This FRS assumes that 0.88 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 the magnitude of the shortfall increases, the probability of exceeding the Balancing Authority ACE Limit increases. For instance, as indicated above, a 47 MW ACE shortfall in PACE has a one percent chance of exceeding the Balancing Authority ACE Limit. A one percent probability of failing to meet the Balancing Authority ACE Limit in one hour is 0.01 loss of Load hours per year. A one percent probability of failing to meet the Balancing Authority ACE Limit in eighty-eight hours would be 0.88 loss of load hours per year and corresponds to the targeted level of reliability.

Regulation Reserve Forecast: Amount Held

As previously shown in Figure 7, 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. As described above, 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 should achieve a cumulative LOLP that corresponds to the annual reliability target.

PacifiCorp submits balanced base schedules to CAISO for its load and resources by T-55.[25] Operating reserve is intended to cover demand in excess of the balanced load and resources submitted in base schedules. Capacity to be used as operating reserve needs to be identified and

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[24] 2015 IRP, Appendix I, Table I.3

[25] *See* footnote 9 for explanation of PacifiCorp's use of the T-55 base schedule time point in the Regulation Reserve Study.

set aside so that it is not utilized in the base schedule submission. Likewise, the regulation reserve forecast identifying the quantity of operating reserve to be set aside for the upcoming hour needs to be finalized by T-55.

The base schedule itself reflects the best, most up-to-date information about conditions in the upcoming hour. The next section describes how the information available can be used to forecast regulation reserve requirements for each of the regulation reserve classes while maintaining reliability. The portfolio regulation reserve requirement forecast incorporates each of the resource/load class forecasts and accounts for the reduced requirements resulting from diversity between the classes. All of these calculations are prepared separately for each of the PacifiCorp BAAs.

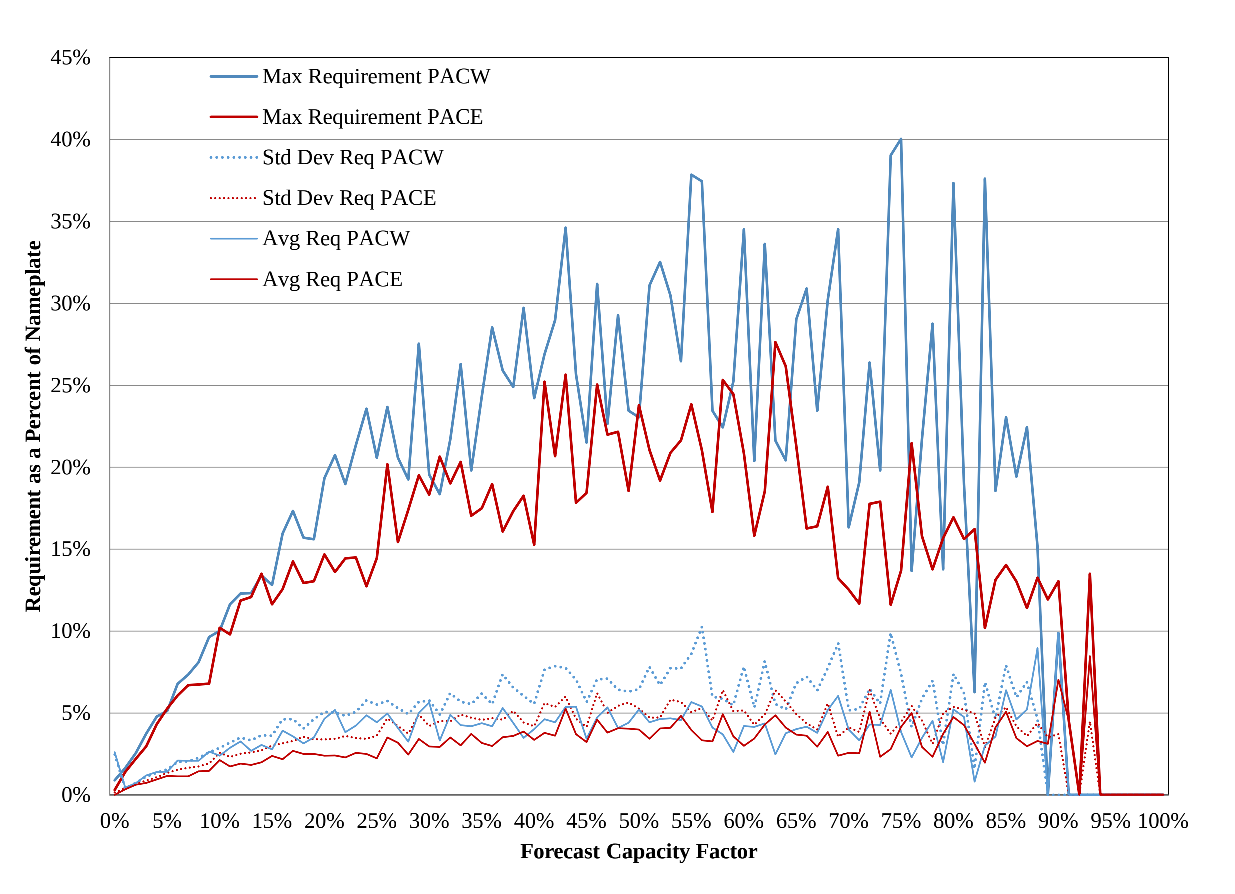
2015 Regulation Reserve Forecast

Wind

Figure F.9 illustrates the relationship between the observed regulation reserve requirements for wind during 2015 and the forecasted level of output, stated as a capacity factor (*i.e.*, a percentage of the nameplate wind capacity).

Three distinct patterns are apparent in the figure. First, for capacity factors from zero percent to approximately 20 percent, the regulation reserve requirement increases linearly. The linear relationship in this first range reflects the fact that the largest possible deviation is equal to the base schedule and a very small amount of negative generation (station service). Second, for capacity factors from approximately 20 percent to approximately 80 percent, the maximum requirement varies somewhat widely and does not exhibit significant trends. Third, as capacity factors increase above approximately 80 percent, the observed maximum requirement declines.

Figure F.9 - Wind Regulation Reserve Requirements by Forecast Capacity Factor



When evaluating the distribution of maximum requirements above an approximately 20 percent capacity factor, it is important to consider the characteristics of an observed maximum within a sample. The mean of a sample may be higher or lower than the mean of the population from which it is drawn, but it is not expected to vary systematically with sample size. This is not the case for the maximum of a sample, which will always be less than or equal to the maximum of the population from which it is drawn. In addition, the expected value of the sample maximum increases as the sample size increases.

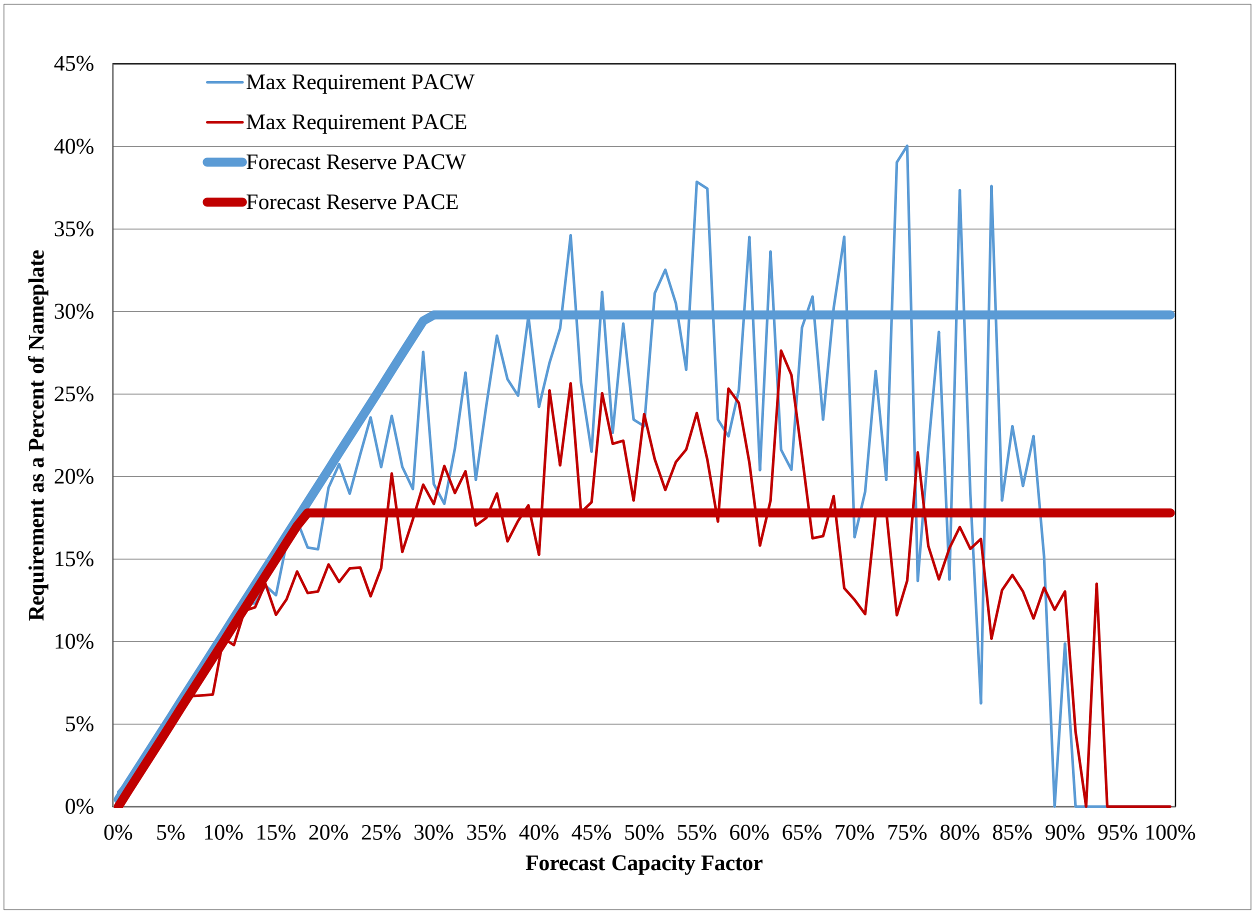
The sample size of each forecasted capacity factor varies, with very high capacity factors occurring less frequently. With this consideration in mind, the decline in observed maximum requirements at high capacity factors can be viewed as an artifact of the sample rather than a real trend related to the behavior of wind under those specific conditions. This view is reinforced by the fact that the average and standard deviation of the requirements are relatively constant at forecasted capacity factors above roughly 20 percent. Because the probability of a large deviation doesn't vary for capacity factors above roughly 20 percent, a single regulation reserve requirement is a reasonable forecast for that range.

Figure F.10 below presents the regulation reserve forecast for PACE and PACW wind, incorporating the two trends described above: (1) the linear increase in requirements at low capacity factors (*i.e.*, below 20 percent); and (2) a uniform requirement at higher capacity factors (*i.e.*, from 20 percent to 100 percent). As illustrated in Figure 10, PACW had 888 hours with forecasted capacity factors between 41 percent and 55 percent, while PACE had 1,115 hours in that range. PACW only had 64 hours with forecasted capacity factors of 85 percent or more, while PACE only had 109 hours in that range.

The wind regulation reserve forecast is a fixed percentage of the wind nameplate capacity, but never more than the difference between minimum actual output and the base schedule. The fixed percentage of nameplate capacity is set at the minimum level that achieves the reliability target of 0.88 loss of load hours per year. The forecast resulted in the possibility of reliability violations in roughly one percent of the hours. While the forecast does not result in any potential reliability violations at high capacity factors, this is likely due to the small number of observations in this range, as described above.

Using a forecast based on the hour-ahead base schedule results in a 2015 stand-alone regulation reserve requirement for wind of 384 MW, or approximately 14.8 percent of nameplate capacity. This forecast does not account for any diversity benefit from combining the reserve requirements for wind with the requirements of other classes. Diversity benefits are discussed later on in the study.

Figure F.10 - Stand-alone Wind Regulation Reserve Forecast



Non-VERs

Figure F.11 below illustrates the observed regulation reserve requirements for Non-VERs during 2015 as a function of the forecasted level of output, stated as a capacity factor (*i.e.*, a percentage of the nameplate Non-VERs capacity). For Non-VERs, the forecasted capacity factors during 2015 fall within limited ranges and do not approach either zero or 100 percent. Since the distribution of errors appears to be essentially random, the base schedule provides limited forecasting value for Non-VERs, resulting in a single reserve value applied in all hours.

Figure F.11 - Non-VER Regulation Reserve Requirements by Forecast Capacity Factor

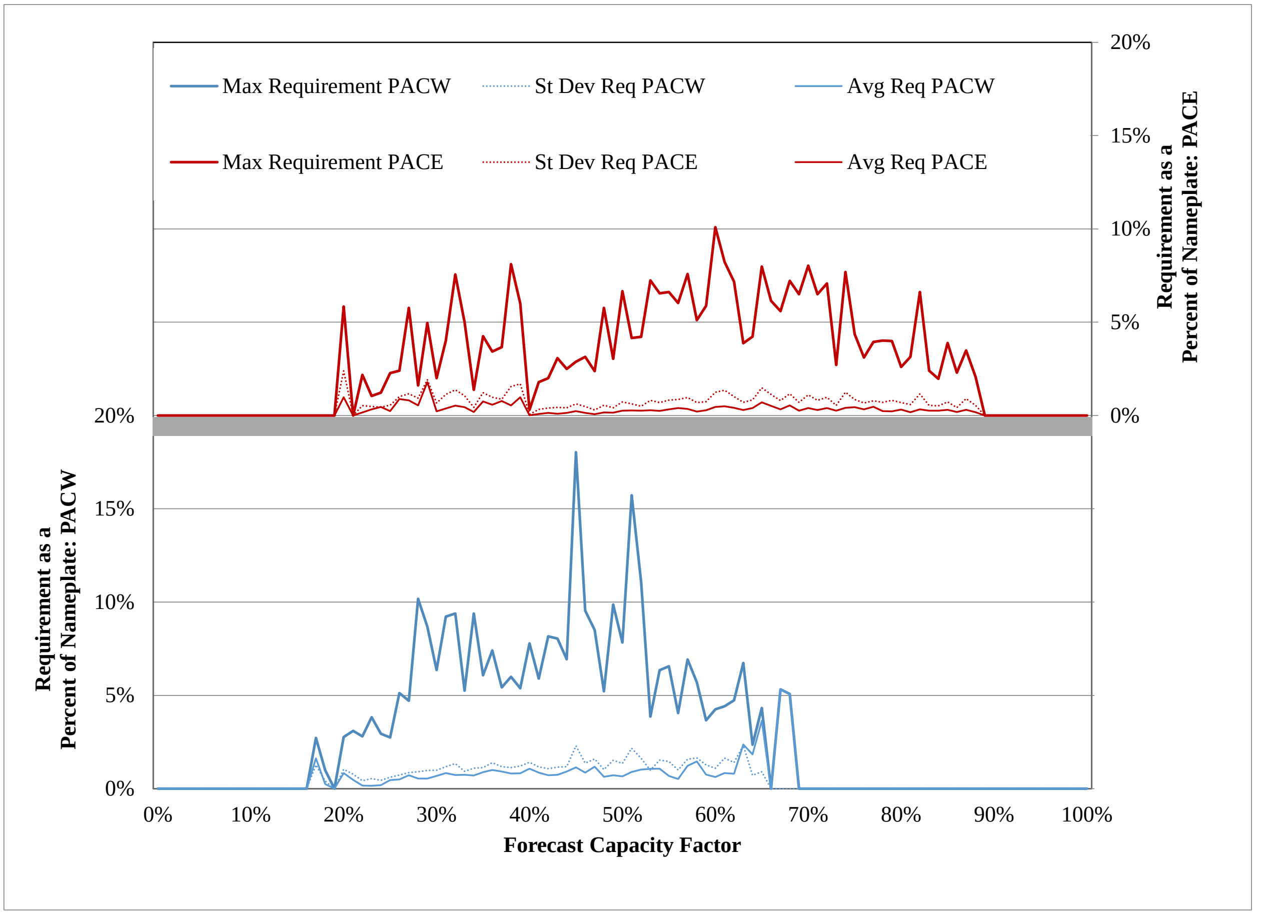


Figure F.12 below illustrates the observed regulation reserve requirements for Non-VERs during 2015 as a function of hour of the day. The average and standard deviation are very low compared to the maximum events, indicating the relative rarity of large deviation events. However, the maximum, average, and standard deviation all exhibit comparable trends, indicating that the characteristics of the maximum are also reflected in the rest of the data for those periods. While an overall diurnal pattern is noticeable, significant volatility in the observed maximum requirements is apparent from hour to hour. For example, consider the significant drop in the observed maximum requirement for PACW in hour 19 relative to hours 18 and 20. The average and standard deviation do not indicate that hour 19 is significantly different from hours 18 and 20. As a result, this drop is more likely to be from randomness in the sample, rather than a specific characteristic of hour 19 itself.

Figure F.12 - Non-VER Regulation Reserve Requirements by Hour of the Day

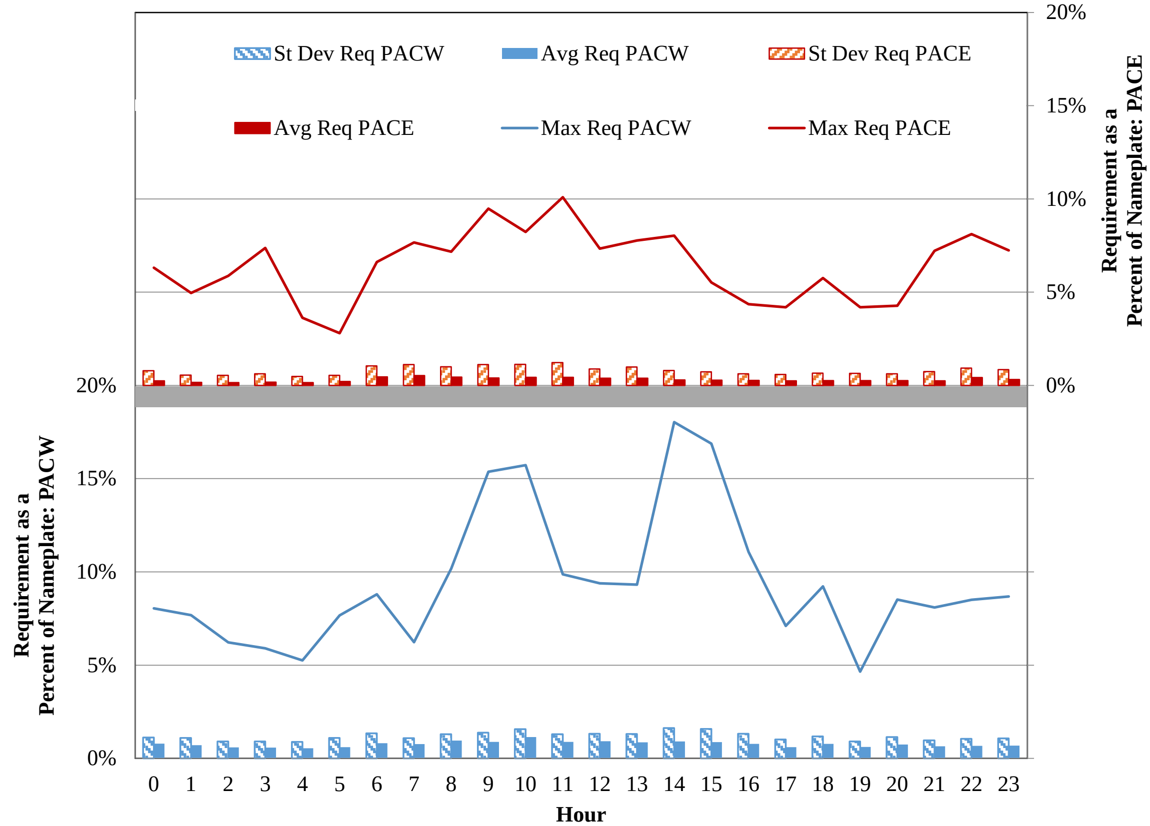
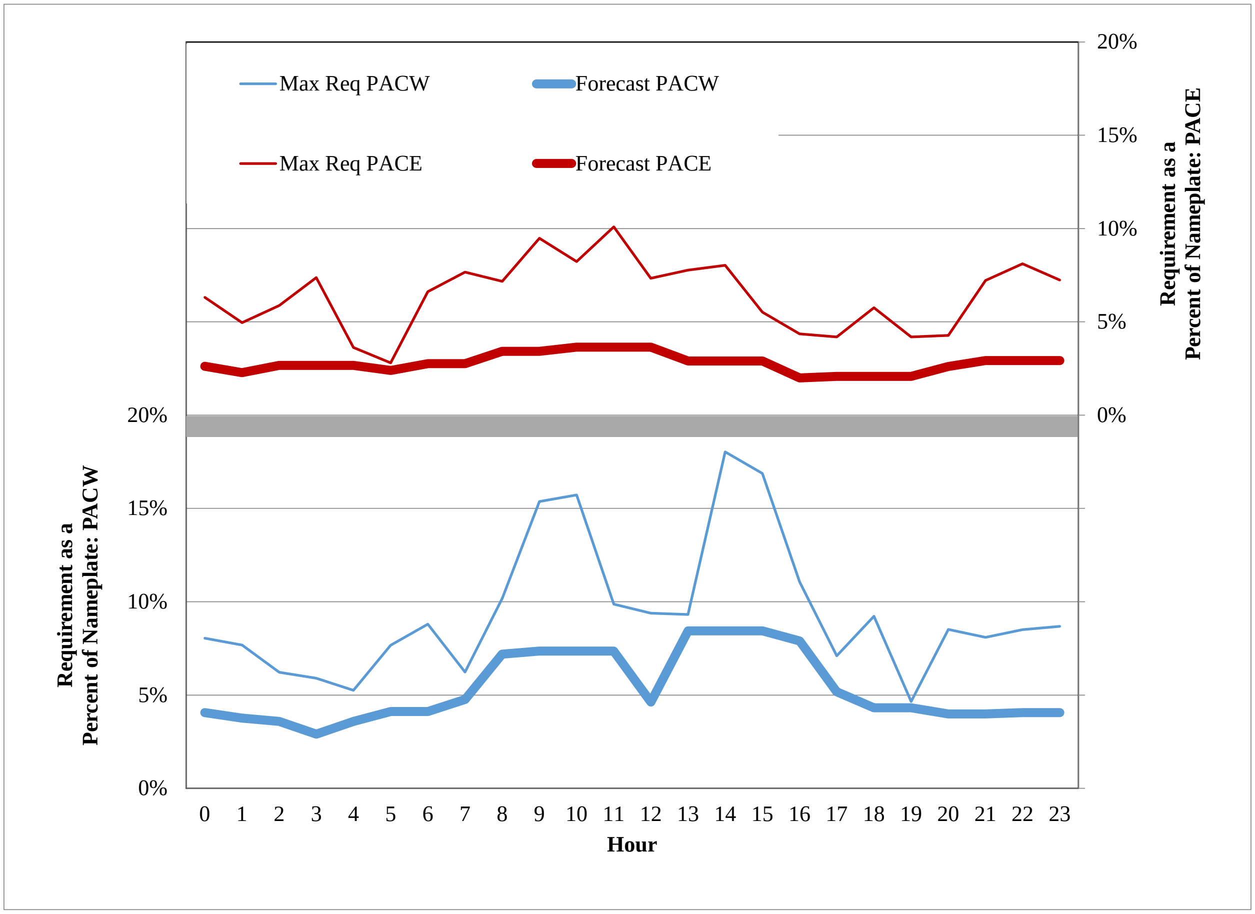


Figure F.13 below presents the regulation reserve forecast for each hour of the day for PACE and PACW Non-VERs. The forecast is based on the rolling three-hour maximum of regulation reserve requirements from 2015. This produces a smoother forecast, reflecting realistic hourly variation rather than just aligning with the large events in the sampled data for 2015. The forecasted requirement is then reduced by a fixed percentage until it reaches the minimum level necessary to achieve the reliability target of 0.88 loss of load hours per year. This forecast resulted in the possibility of reliability violations roughly 1.1 percent of the time on PACW, and 2.6 percent of the time on PACE. Due to the lower probability of a reliability violation in each hour for PACE Non-VERs, more hours of potential violations are aggregated to reach the reliability target of 0.88 loss of load hours per year. Using a forecast based on the hour of the day results in a 2015 stand-alone regulation reserve requirement for Non-VERs of 83 MW, or approximately 3.7 percent of nameplate capacity. This forecast does not account for any diversity benefit from combining the regulation reserve requirements for Non-VERs with the requirements of other classes.

Figure F.13 - Stand-alone Non-VER Regulation Reserve Forecast



Load

Figure F.14 below illustrates the relationship between the observed regulation reserve requirements for load during 2015 and hour of the day. Similar to the results for Non-VERs, the average and standard deviation are very low compared to the maximum events, indicating the relative rarity of large deviation events. However, the maximum, average, and standard deviation all exhibit comparable trends, indicating that the characteristics of the maximum are also reflected in the rest of the data for those periods.

Figure F.14 - Stand-alone Load Regulation Reserve Requirements by Hour of the Day

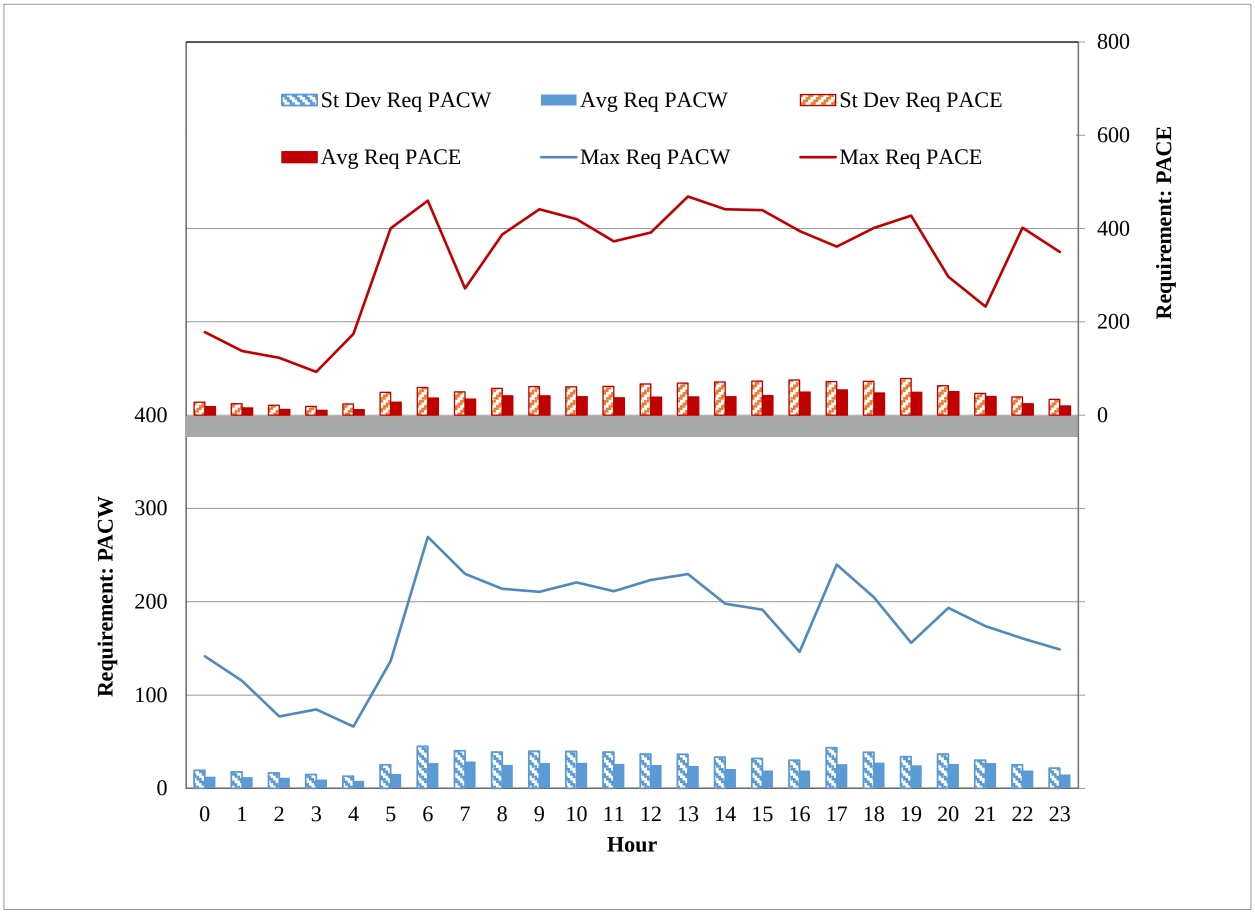
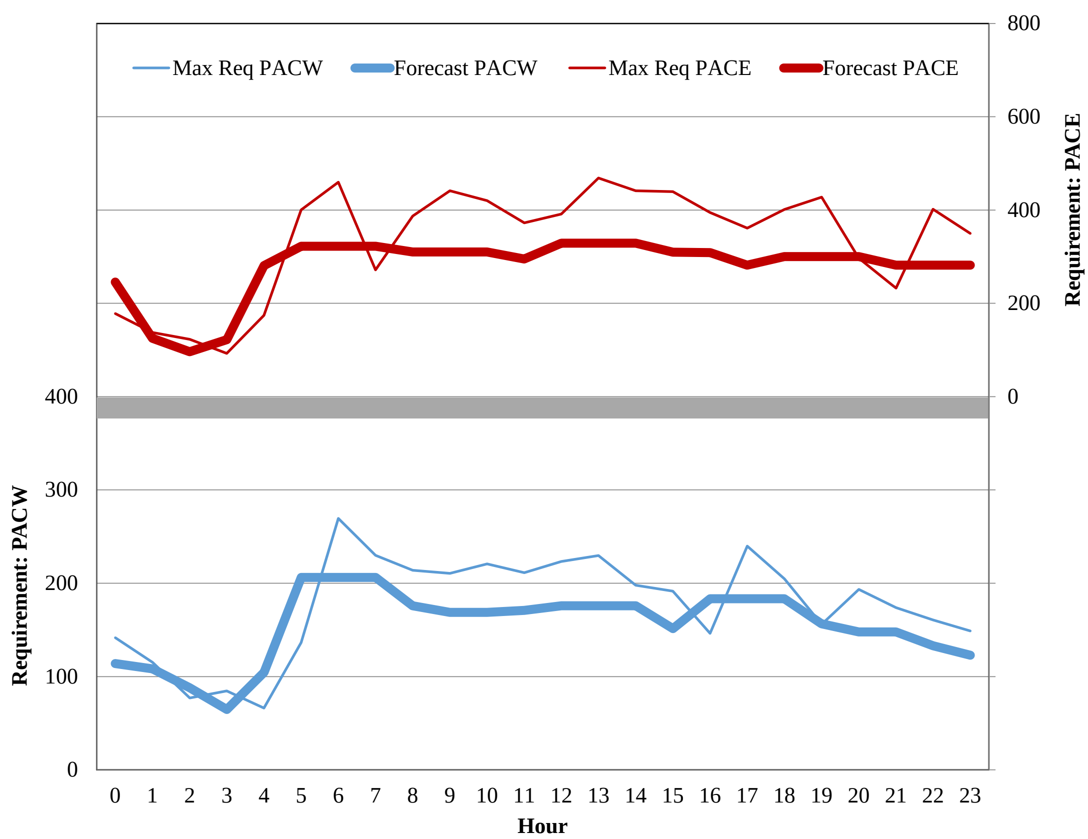


Figure F.15 below presents the regulation reserve forecast for each hour of the day for PACE and PACW load. The forecast is based on the rolling three-hour maximum of regulation reserve requirements from 2015. This produces a smoother forecast, reflecting realistic hourly variation rather than just aligning with the large events in the sampled data for 2015. The forecasted requirement is then reduced by a fixed percentage until it reaches the minimum level necessary to achieve the reliability target of 0.88 loss of load hours per year. This forecast resulted in the possibility of reliability violations roughly 0.7 percent of the time in both PACW and PACE. Using a forecast based on the hour of the day results in a 2015 stand-alone regulation reserve requirement for load of 433 MW, or approximately 4.5 percent of the 12CP. This forecast does not account for any diversity benefit from combining the reserve requirements for load with the requirements of other classes.

Figure F.15 - Stand-alone Load Regulation Reserve Forecast



2015 PacifiCorp System Diversity and EIM Diversity Benefits

PacifiCorp System-Wide Portfolio Diversity Benefit

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

PacifiCorp began full EIM operation on November 1, 2014. NV Energy began full operation in EIM on December 1, 2015. Puget Sound Energy and Arizona Public Service Company commenced EIM participation on October 1, 2016. Additionally, several other entities have announced their intention to begin participating over the next few 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

EIM also direct effects related to regulation reserve requirements. First, as a result of EIM participation, PacifiCorp has improved granularity for data used in the analysis contained in this FRS. The data and control provided EIM allow PacifiCorp to achieve the portfolio diversity benefits described in 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 next section.

The regulation reserve forecasts described above (384 MW for Wind, 83 MW for Non-VERs, and 433 MW for Load) 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 Wind, Non-VERs, and Load. As a result, the regulation reserve forecast for the portfolio can be reduced while still meeting the reliability target.

As shown in Table F.5 below, the sum of the stand-alone forecasts for each class results in a cumulative LOLP of 0.03 hours per year. This is significantly less than the target of 0.88 hours per year as a result of the diversity among the different classes. PacifiCorp then calculated the proportional reduction to the standalone requirement—the diversity benefit shown in the second column of values in Table 3—that could be applied such that the PacifiCorp system just achieves the reliability target for the Study Term. A total portfolio requirement of 654 MW is sufficient to achieve the reliability target, resulting in diversity benefits equal to 118 MW for Load, 105 MW for Wind, and 23 MW for Non-VERs. The last column of Table 3 shows the regulation requirements for each class that incorporates the proportional allocation of portfolio diversity benefits. The diversity benefits result in a 27 percent reduction from the total standalone requirement of 900 MW.

Table F.5 - Results with PacifiCorp Portfolio Diversity

Scenario	Stand-alone Regulation Forecast (aMW)	Diversity Benefit (aMW)	Portfolio Regulation Forecast (aMW)
Non-VER	83	(23)	60
Load	433	(118)	315
VER - Wind	384	(105)	279
Total	900	(246)	654
Portfolio LOLP (hours/year)	0.03		0.88

EIM Intra-Hour 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—such as NV Energy, Puget Sound Energy, and Arizona Public Service Company—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 BAAs' requirements. This difference is known as the "flexible ramping procurement diversity savings" in the EIM. This intra-hour benefit reflects offsetting variability and lower combined uncertainty. This flexibility reserve 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 intra-hour benefit by first calculating a flexible reserve requirement for each individual EIM BAA and then by comparing the sum of those requirements to the flexible reserve requirement for the entire EIM area. The latter amount is expected to be less than the sum of the flexible reserve 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 intra-hour 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 share of the intra-hour benefits associated with EIM, as these are derived from the structure of the EIM rather than resources contributed by other participants.

Under the current EIM operational structure, the calculated EIM intra-hour benefit is not known to PacifiCorp prior to its base schedule submission at T-55. The CAISO does not finalize the intra-hour benefit until T-40, therefore making it too late to incorporate any of the benefit into PacifiCorp's base schedule.

Table F.6 below provides a numeric example of flexible reserve requirements for each EIM participating BAA and application of the calculated intra-hour benefit.

Table F.6 - EIM Flexible Reserve Diversity Benefit Application Example

Interval	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)	PACE share (%)	PACE benefit (MW)	PACE req't. after benefit (MW)
15-minute Interval 1	550	110	165	100	925	583	342	17.8%	61	104
15-minute Interval 2	600	110	165	100	975	636	339	16.9%	57	108
15-minute Interval 3	650	110	165	110	1,035	689	346	15.9%	55	110
15-minute Interval 4	667	120	180	113	1,080	742	338	16.7%	56	124

While the intra-hour benefit is uncertain, that uncertainty is not significantly different from the uncertainty in the Balancing Authority ACE Limit described above. PacifiCorp proposes crediting its regulation reserve forecast with a probability distribution of calculated EIM intra-hour benefits based on historical results. When a potential regulation shortfall occurs, the probability that the EIM intra-hour benefit would have exceeded that level can be calculated, and the LOLP associated with that event goes down. As a result, PacifiCorp's regulation reserve requirements can be reduced until the reliability target is again just achieved. While this FRS considers regulation reserve requirements in 2015, the participation of NV Energy in the EIM starting in December 2015 has resulted in increased intra-hour benefits. To capture these additional benefits for this analysis, PacifiCorp has applied the probability distribution of EIM intra-hour benefits from January 2016 through June 2016 because it is a more reasonable representation of actual operations going forward than the 2015 results. 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 intra-hour benefits in the 2015 regulation reserve analysis 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 until the PacifiCorp system just achieves the reliability target for the 2015 Study Term. As shown in Table F.7 below, the resulting regulation reserve requirement is 562 MW, a 38 percent reduction (including the portfolio diversity benefit) compared to the stand-alone requirement for each class. The average regulation reserve requirement is reduced by 92 MW relative to the PacifiCorp portfolio reserve requirement without the EIM intra-hour benefit.

Table F.7 - 2015 Results with PacifiCorp Portfolio Diversity and EIM Intra-Hour Benefit

Scenario	Stand-alone Regulation Forecast (aMW)	Stand-alone Rate (%)	Portfolio Regulation Forecast with EIM (aMW)	Portfolio Rate with EIM (%)	2015 Capacity (MW)	Rate Determinant
Non-VER	83	3.7%	52	2.3%	2,228	Nameplate
Load	433	4.4%	271	2.7%	9,852	12 CP
VER - Wind	384	14.8%	240	9.2%	2,588	Nameplate
Total	**900**		**562**			
Portfolio LOLP (hours/year)	0.03		0.88			
Diversity Savings (%)			38%			

Incremental Wind Regulation Reserve Requirements

Since 2015, 153 MW of wind resources have been added to PacifiCorp's system. Furthermore, the IRP portfolio optimization process contemplates the addition of new wind capacity as part of its selection of future resources. As PacifiCorp's portfolio of resources 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 decremental diversity associated with reducing the size of PacifiCorp's wind portfolio. Removing specific resources produces a similar change in the size of PacifiCorp's portfolio without requiring the creation of any data points. Specifically, the PacifiCorp system-wide results described above were recalculated using only 90 percent of the available wind resources, by removing approximately 10 percent of the wind capacity from each geographic location.

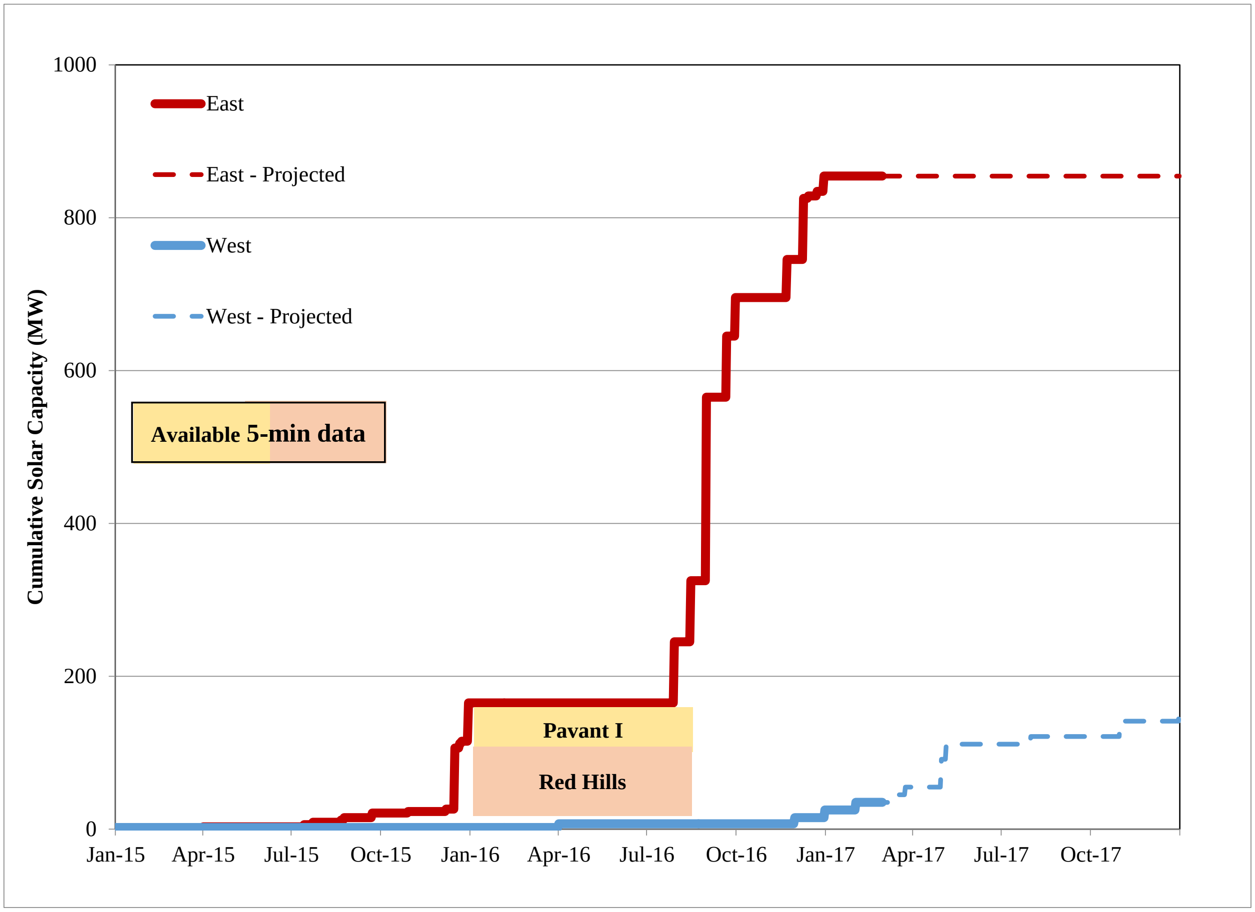
Regulation reserve requirements for PacifiCorp's system-wide portfolio dropped by 6.1percent of the wind capacity removed. This is lower than the average requirement of 9.2 percent in the 2015 portfolio results shown in Table F.7 above. This indicates that diversity is increasing as the pool of requirements increases, as expected. These incremental wind regulation requirement results are incorporated in the forecasted portfolio regulation results discussed later on in the study.

Solar Regulation Reserve Requirements

Overview

At the start of 2015, PacifiCorp had less than three megawatts of utility-scale solar generating capacity on its system. Over the course of 2015, an additional 165 MW was added but the majority was from two large resources which only came online in the second half of December. As shown in Figure F.16, solar capacity has increased rapidly in both PACE and PACW and by the end of 2017 is expected to total over 1,000 MW. Reference Table F.25 on page 64 contains the list of solar resources included in the study. Because solar resources have only recently been added to PacifiCorp's system, the 2015 study period used for the regulation reserve requirements for load, wind, and Non-VERs does not have data suitable predict current and future solar regulation reserve requirements.

Figure F.16 - Solar Capacity Additions



Five-minute solar data was collected from PacifiCorp's Ranger PI system for Jan. 1, 2016 through Aug. 23rd, 2016 for two large solar resources in southern Utah totaling 130 MW.[26] PacifiCorp's solar forecast service provider, DNV GL, provided generation forecasts for these resources during this timeframe, which were submitted to EIM. While EIM deviation data is available for a portion of this period, certain meteorological monitoring equipment was not in place for the entire timeframe, and the limited availability of historical results are expected to make the forecasts for these resources less accurate than what will be possible going forward. Instead, proxy solar base schedules were developed for these two resources, as described in the next section. To make the results easier to compare and apply elsewhere, the actual output of the resources was normalized by their capacity. The calculations described below were all carried out on a capacity factor basis.

Proxy Solar Base Schedule Development

Solar resource output is primarily a function of two attributes: the position of the sun, and the amount of cloud cover. The position of the sun is comparable from day to day at a given time, though over the course of weeks it changes by meaningful amounts. To estimate the maximum possible output for a particular date and time, the maximum output at that time from two weeks prior to two weeks following is calculated. The four week span helps ensure that at least one data point is likely to have very little cloud cover and maximum output, while limiting the effect of

[26] Pavant I, 50 MW and Utah Red Hills, 80 MW.

seasonal changes in the position of the sun. Identifying the maximum possible output for each interval allows the forecast to account for changes in output as the sun rises and sets. The following calculations were carried out independently for the two solar resources.

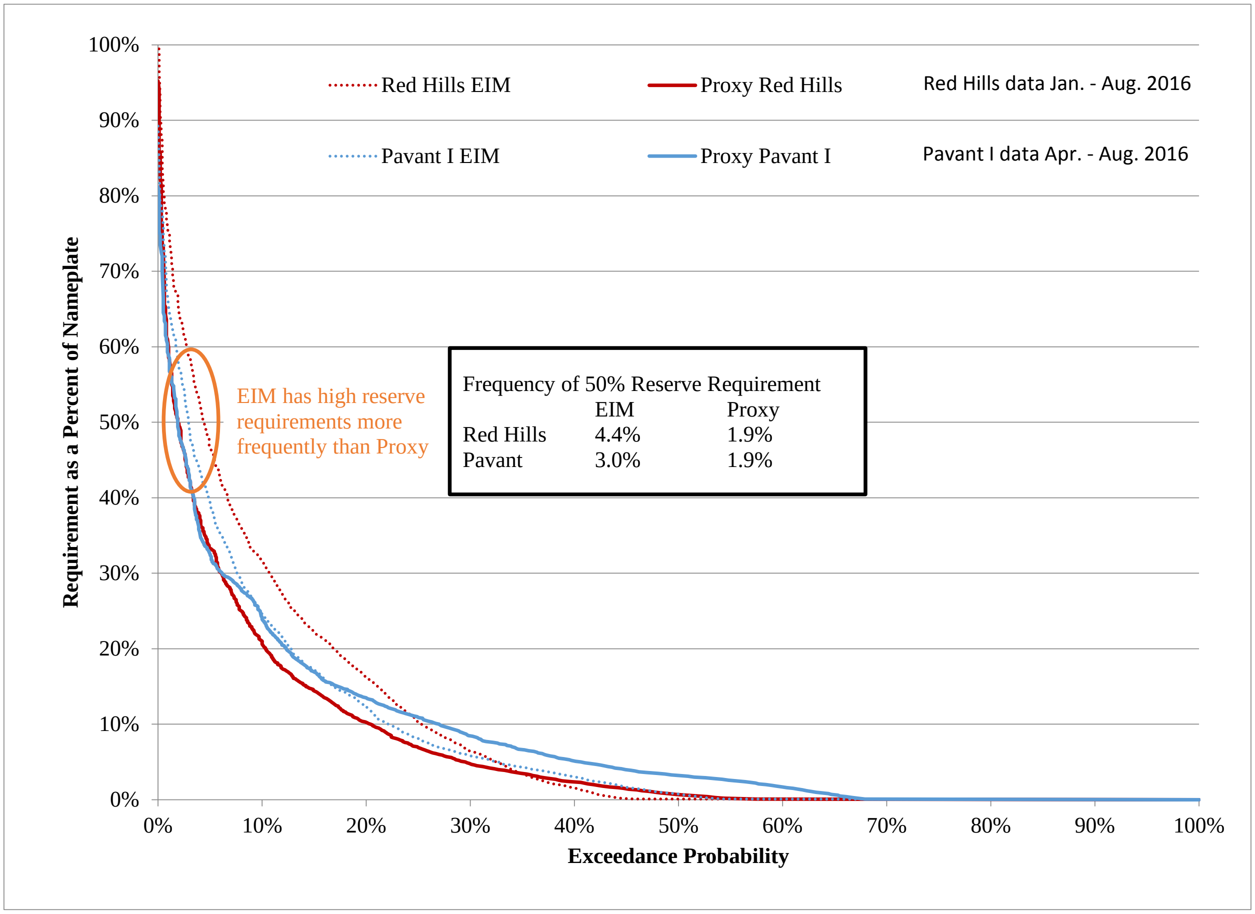
To estimate the amount of cloud cover, the solar availability is calculated by dividing the actual output in each five-minute interval by the maximum output for that interval, as identified above. This removes the effect of the position of the sun, and the changes that remain should primarily be primarily associated with cloud cover. From day to day, cloud cover is expected to vary widely, but from T-55 when the solar resource forecast is submitted as an hourly base schedule to EIM through the course of that upcoming hour, it is reasonable to assume the prevailing cloud conditions will continue. To improve further upon the cloud cover forecast using the available data, the trend in cloud conditions leading up to the time of forecast submission was also accounted for. If it is less cloudy at T-55 than it was twenty minutes earlier, that trend is also extrapolated forward to the forecast period. The weighting of the trend versus the final measurement before the forecast is submitted was set to maximize the correlation between the actual solar output and the forecasted hourly base schedule, i.e. to produce the best achievable forecast. Due to the absence of generation output, cloud cover can't be estimated from intervals prior to sunrise, so the forecasted output during the first hours after sunrise is set at the monthly average for those intervals.

The proxy solar base schedules incorporate cloud cover data and solar position data as follows. The cloud cover measurement is the primary component in the forecast for the upcoming hour. The cloud cover trend over the preceding intervals, and the cloud cover in the last interval are locked in at the values measured just prior to base schedule submission. On the other hand the position of the sun, embedded in the maximum output for each interval, is assumed to be fixed and known in advance. The base schedule submission looks forward in time to the forecast hour and incorporate the expected solar position changes over each five-minute interval in the hour.

While the forecast is created with a five-minute granularity, the base schedule submission to EIM at T-55 reflects an hourly average value in accordance with EIM operating procedures. The difference between this hourly average and the five-minute actual resource output (i.e. the original source data) is the deviation of the solar resource. Once base schedule and deviation data were prepared for the two solar resources, those deviations were applied in the same template used to calculate hourly regulation reserve requirements for load, wind, and Non-VERs, including the base schedule ramping adjustment described previously. This identifies the minimum hourly regulation reserve needed to guarantee compliance with BAL-001-2 with the resource in question viewed in isolation.

As shown in Figure F.17, the proxy solar forecasts have less frequent large deviations, and thus produce fewer instances of large regulation reserve requirements than the available EIM deviation data from the same period. Note that while Pavant I become operational in 2015, EIM deviations only became available starting April 1, 2016. For comparability, the proxy and EIM results for each generator are shown for the overlapping time period only. Regulation reserve requirements in excess of approximately 15 percent of nameplate capacity occurred more frequently in the EIM data than the proxy data. Because the largest errors are most likely to cause a BAAL violation, they drive the majority of the reserve requirement. Future results will show whether the forecast accuracy that can be achieved in actual practice is higher or lower than that in the proxy data used in this analysis.

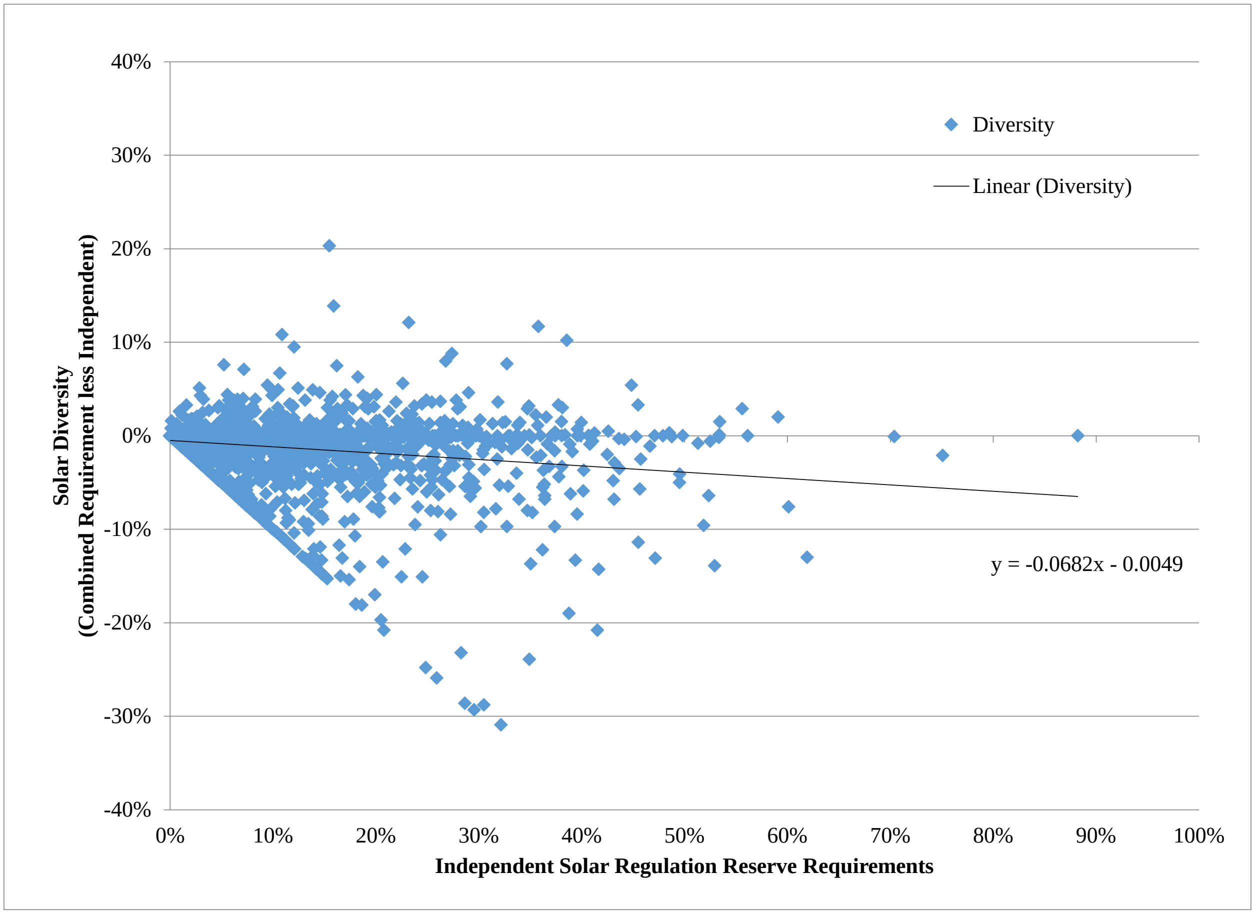
Figure F.17 - Solar Regulation Reserve Requirements: Proxy vs EIM



Solar Diversity

When the hourly regulation reserve requirements of the two solar resources are measured independently, as described above, the results do not capture any of the potential for diversity in the intra-hour requirements. To identify the potential diversity between the two solar resources, the average of their base schedules and actual output was used in the hourly regulation reserve calculation. The difference between the requirements when measured independently and the requirements when measured in aggregate is the result of diversity. The results of this diversity measurement are shown in Figure F.18.

Figure F.18 - Solar Diversity



As shown in Figure F.18, diversity is not guaranteed to reduce hourly regulation reserve requirements. While this is not intuitive, it is a direct result of the 30 minute maximum time limit for deviations under BAL-001-2. If two resources each have deviations that are only 20 minutes long, the regulation reserve requirement is zero. If the deviations both started at the same time, then viewed together they will overlap perfectly, and the length of the deviation remains just 20 minutes with a regulation reserve requirement of zero. However, if one resource's deviation starts 15 minutes earlier than the other, the length of the aggregate deviation will be 35 minutes, and the regulation reserve requirement will be greater than zero to ensure compliance with BAL-001-2.

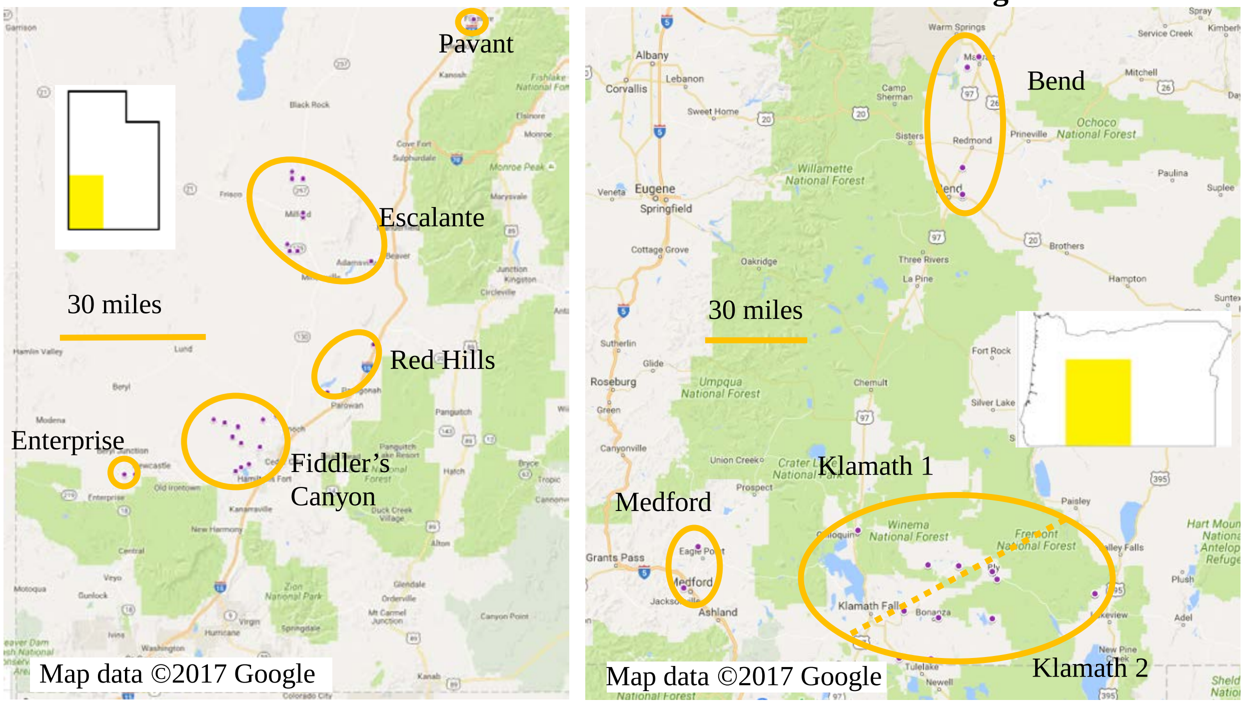
Despite the potential for increased aggregate requirements in some instances, on average the aggregate requirements are lower as a result of diversity. Because the regulation requirements are bounded by zero, the diversity benefit is limited to the size of the independent requirement.
As a result, the diversity benefits increase as the independent requirements increase.

Solar Locations

The solar facilities on PacifiCorp's system are concentrated in southeastern Utah and southern and central Oregon. As shown in Figure F.19, within these areas multiple facilities are also clustered within relatively close proximity. Five clusters were identified in Utah, while three were identified in Oregon. Because one of the Oregon clusters is relatively dispersed, it is treated as two independent clusters.

Figure F.19 - Solar Resource Locations

Southeastern Utah **South/Central Oregon**



While all of the clusters identified are in close enough proximity to experience most of the same passing weather systems, different clusters experience different cloud cover at the time of forecast submission, and different cloud cover over the course of the operating hour. These differences are in turn reflected in their actual output and deviations. On the other hand, due to their proximity, facilities within a given cluster are expected to reflect more closely-related weather conditions in their forecasts and deviations. As a result, the aggregate capacity within a given cluster is not expected to experience offsetting deviations, i.e. diversity benefits, whereas the effect of capacity spread among multiple clusters should create opportunities for offsetting deviations.

The IRP is focused not just on regulation reserve requirements for existing solar resources, but also on the requirements associated with incremental solar resources added in the future. Tables F.8 and F.9 present the solar capacity on PacifiCorp's system in three scenarios. The base scenario reflects the contracted solar resources scheduled to be online in 2017, while two incremental scenarios reflect the addition of 500 MW and 1000 MW of new solar resources. The incremental solar capacity is split between the PACE and PACW BAAs, and among existing and new clusters.

Table F.8 - East Solar Clusters by Scenario

East Cluster	Base	Incr. Solar 1	Incr. Solar 2
Enterprise	83	+17	+17
Fiddler's Canyon	311	+62	+62
Escalante	257	+51	+51
Red Hills	83	+17	+17
Pavant	120	+24	+24
New Cluster 1		+229	
New Cluster 2			+229
Total	**855**	**1,255**	**1,655**
% Change vs Base		47%	94%

Table F.9 - West Solar Clusters by Scenario

West Cluster	Base	Incr. Solar 1	Incr. Solar 2
Bend	50	+31	+6
Medford	20	+12	+2
Klamath 1	47	+29	+6
Klamath 2	47	+29	+6
New Cluster 1			+80
Total	**163**	**263**	**363**
% Change vs Base		61%	123%

Solar Portfolio Data

Red Hills and Pavant have proxy base schedules, hourly regulation reserve requirements, and diversity based on actual generation. It is reasonable to assume other solar resources within those two clusters would experience comparable conditions and results. Therefore, the Red Hills and Pavant results are scaled up to reflect any additional capacity within the cluster.

At the time the study was prepared, actual data for the other clusters in PACE and all of the clusters in PACW was unavailable. While the varying geographic locations of these clusters impact the timing of weather conditions, they are all relatively sunny locations, and it is reasonable to assume that the likelihood of over-forecasting resource output, resulting in a regulation reserve requirement, is similar in all of the clusters. With this in mind, all of the hourly regulation reserve requirements for Red Hills and Pavant (measured independently) were taken as a single data set and hourly regulation reserve requirements for the other clusters were assigned randomly from this distribution. While the resulting hourly regulation reserve requirements vary from 0 percent to 95 percent of the solar nameplate capacity, 18.7 percent of the regulation reserve requirements are zero, and half of the regulation reserve requirements are less than 2 percent of the solar nameplate. Despite being predominantly random, there is a relatively small positive correlation (+0.2638) between the hourly regulation reserve requirements for Red Hills and Pavant. This may reflect weather conditions that occur at the same time over a broad area, such as afternoon thundercloud formation, rather than as a result of passing weather fronts. This relationship is assumed to be real effect and is reflected in each of the calculated clusters by blending a random regulation requirement and the simultaneous requirement for one of the two source clusters. The weighting of the blend was set such that the average correlation between the new clusters and the existing clusters matches the correlation measured between the existing clusters.

Because the hourly regulation reserve requirements described above reflect the independent regulation reserve requirements for Red Hills and Pavant, they do not capture the diversity between different clusters of solar resources. As discussed above, diversity is partly a linear function of the independent hourly regulation reserve requirements – the greater the requirement, the greater the diversity credit. However, much of the variation in diversity values appears to be unpredictable, i.e. largely random. In a similar manner to the regulation reserve requirements described above, the diversity results for Red Hills and Pavant were taken as a single data set and assigned randomly to each of the clusters. A weighted average diversity value was then calculated that takes into account the number of clusters since diversity requires two or more. In addition, because diversity benefits are bounded by a zero regulation reserve requirement, they may be truncated in manner that under-represents the potential diversity available. Instances when diversity leads to higher requirements are not bounded in this manner in the sample. With more than two clusters, it may be possible to utilize additional diversity benefits before hitting the zero bound. To help reflect this, whenever the sampled diversity components indicated an increase in requirements, the increase was reduced by half.

The random assignment of regulation reserve requirements described above disregards the hour of the day, and can overstate requirements when little output is expected such as during the morning ramp. To compensate, the aggregate regulation reserve requirements are reduced during the morning ramp to align with the requirements seen for Pavant and Red Hills.

Solar Regulation Reserve Forecast

The solar regulation reserve forecast is comparable to that developed for wind, representing a fixed percentage of the solar nameplate capacity, but never more than the maximum output in that hour, including a portion of the ramp up across the hour in the morning and down across the hour in the afternoon. The fixed percentage of nameplate capacity is set at the minimum level that achieves the reliability target of 0.88 loss of load hours per year. The reserve requirement necessary to achieve the reliability target varies in PACE and PACW, and with changes in total solar capacity.

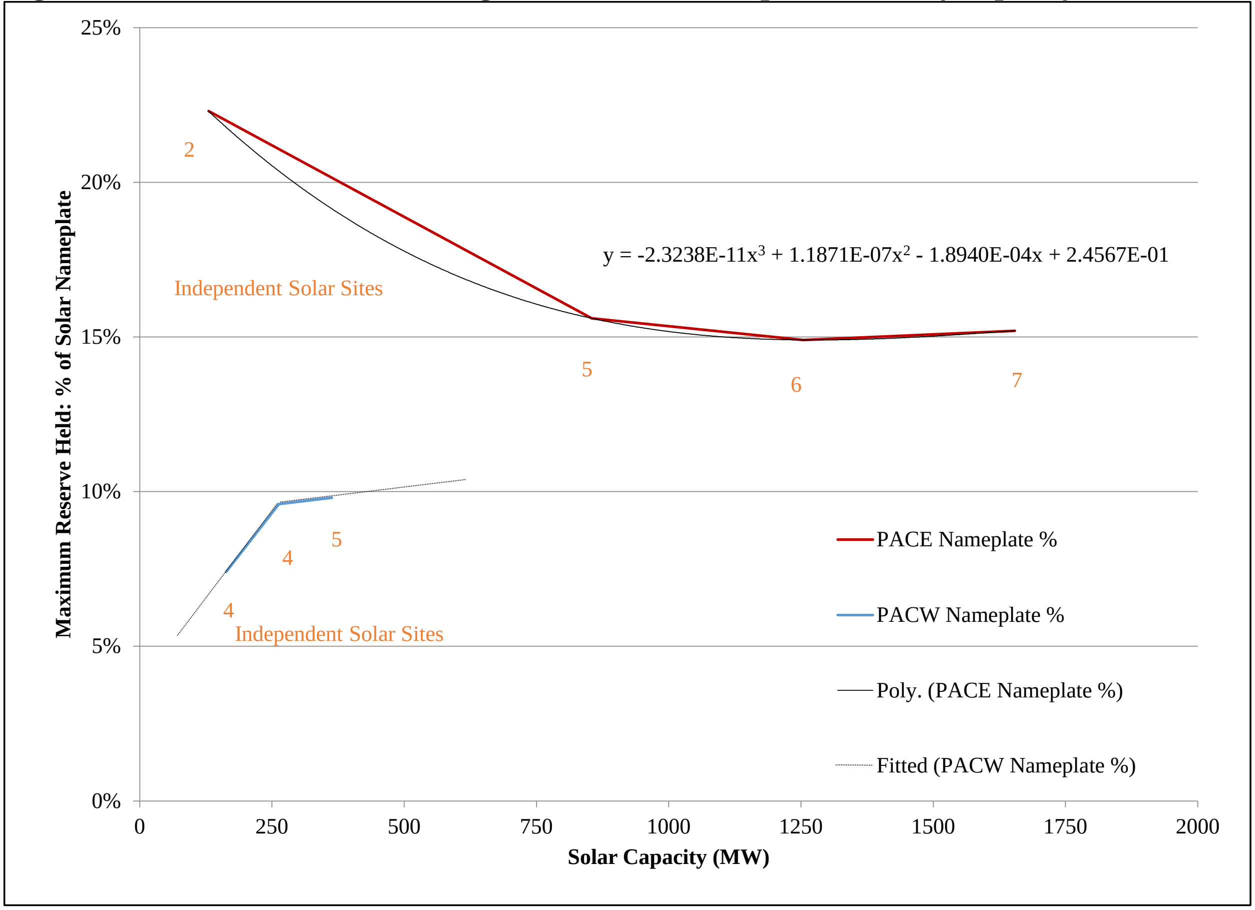
The results of the solar regulation requirements in the various scenarios is shown in Table F.10 below, with the wind results shown for comparison. Note that while the fixed percentage of nameplate capacity (i.e. the maximum reserve held) for solar and wind in PACE is similar, ranging from 14.9 percent to 18.6 percent of nameplate capacity, the average requirement for solar is significantly lower than that for wind. This is because solar output is zero for half of the hours in the year, whereas PACE wind output drops below the maximum reserve held infrequently. PACW wind output is more strongly correlated and drops to zero more frequently than PACE wind.

Table F.10 - Solar and Wind Stand-alone Regulation Requirements, as Percentage of Nameplate Capacity

	Average Reserve Held		Max Reserve Held	
Scenario	**East**	**West**	**East**	**West**
No Solar	12.3%	n/a	22.3%	n/a
Base Solar	8.8%	4.2%	15.6%	7.4%
Incr. Solar 1	8.5%	5.3%	14.9%	9.6%
Incr. Solar 2	8.6%	5.4%	15.2%	9.8%
90% Wind	15.1%	15.8%	18.6%	32.3%
Base Wind	14.6%	15.2%	17.8%	29.8%

For solar, the fixed percentage of nameplate in the reserve requirement calculation varies with the size of the solar capacity. There are two offsetting trends related to increasing solar capacity. First, more diverse solar resources (i.e. more clusters) have lower requirements, but the incremental benefit declines as more diversity is added. Second, spreading the fixed allowable BAAL variation across more capacity increases requirements, and the incremental impact increases as capacity increases. Figure F.20 shows these relationships as well as fitted curves used to project the solar regulation reserve requirements as a function of capacity for PACE and PACW. The solar regulation reserve requirement in PACE is assumed to be related to capacity using a third-order polynomial. The solar regulation reserve requirement in PACW is assumed to be related to capacity using two linear extrapolations.

Figure F.20 - Stand-alone Solar Regulation Reserve Requirements, by capacity



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. While the diversity of load, wind, and Non-VER generation was measured using 2015 data, the solar deviations are from 2016 and are extrapolated from a very limited sample. As such, it is not currently possible to measure the diversity of the PacifiCorp system, inclusive of requirements for solar. Instead, several characteristics of the diversity of PacifiCorp's system were used to produce an estimate of the relationship between the amount of diversity and the portfolio of regulation requirements. These characteristics are discussed below.

Methodology

The most important element in PacifiCorp's portfolio diversity estimate is the system diversity, including EIM benefits, associated with load, wind, and Non-VERs during 2015. The diversity in the 2015 portfolio reduced reserve requirements by 37.51 percent. This captures the vast majority of the regulation reserve requirements both today and in likely future scenarios over the near term. For example, approximately 1000 MW of solar capacity is expected to be on the PacifiCorp system in 2017, and no solar was included in the 2015 results. However, this additional solar increases the stand-alone regulation reserve requirement (before accounting for diversity) by less than 10 percent. Since diversity only occurs in intervals when two or more regulation reserve requirements exist, changes in diversity in 10 percent of the intervals will have relatively limited effects.

In a portfolio without solar capacity, incremental wind generation was calculated to have reserve requirements of 6.1 percent of nameplate, after accounting for portfolio diversity, compared to an average requirement of 9.2 percent for the entire wind fleet. Much of the benefits are captured within the wind class – its stand-alone requirements increase by a limited amount; however, the diversity of the entire portfolio increases slightly when the reserve requirements for the incremental wind are added. This relationship between stand-alone reserve requirements and portfolio diversity is assumed to be linear - a small increase in diversity as the reserve requirements of the existing classes grows.

As a starting point, solar regulation reserve requirements are assumed to create equivalent amounts of diversity as the components of the pre-solar portfolio, including the linear increase as requirements grow. In addition, incremental diversity as a result of solar is assumed to occur in relation to the size of the stand-alone solar regulation requirements. When the solar requirements are equivalent in size to the requirements for load, wind, and Non-VERs, the incremental diversity benefits are assumed to be maximized at 20 percent of the solar requirement. At lower levels of solar requirements (i.e. for less solar capacity), the incremental diversity benefits are smaller and are assumed to proportional to the size of the solar requirements relative to the other regulation requirements. With four categories of requirements (load, wind, solar, Non-VER), solar requirements would need to be 25 percent of the total to achieve the maximum level of diversity. In the base scenario, solar requirements are 81 MW out of 998 MW total, and result in incremental diversity benefits of 5.3 MW, on top of approximately 30 MW of benefits based on the diversity in the pre-solar portfolio.[27]

Based on the above, hourly regulation requirements for PACE and PACW are calculated as a function of: wind and solar nameplate capacity, forecasted wind output and month/hour as a proxy for expected solar output, and static hourly regulation reserve requirements for load and non-VER generation. Diversity is a function of the total requirements and is calculated dynamically as described above.

Results

Table F.11 presents the portfolio regulation requirement results from the various scenarios described above. 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 2017 Base Case regulation reserve requirements are 617 MW. By comparison, PacifiCorp's 2014 Wind Integration Study identified requirements of 626 MW for a smaller amount of wind, and without any requirements for solar or Non-VERs.

Table F.11 - Portfolio Regulation Requirement Results, by Scenario

Scenario	Wind capacity (MW)	Solar capacity (MW)	Stand-alone regulation requirement (MW)	Portfolio diversity credit (%)	Regulation requirement with diversity (MW)
2014 WIS	2,543	n/a	n/a	n/a	626
2015 (No Solar)	2,588	0	900	37.5%	562
2017 Base Case	2,757	1,050	998	38.2%	617
Incremental Wind	3,007	1,050	1,023	38.3%	631
Incremental Solar 1	2,757	1,550	1,033	38.6%	635
Incremental Solar 2	2,757	2,050	1,074	39.2%	653

There are a significant number of changes between the PacifiCorp's 2014 Wind Integration Study and the current study. First, the specific requirements of the BAL-001-2 standard are being applied, as previously discussed. Second, the updated requirements are based on an expanded portfolio of resources, including solar, Non-VERs, and additional wind capacity. Finally, diversity benefits are now shared among all requirements, rather than being allocated solely to wind resources as was done in the 2014 Study. Table F.12 presents a comparison of the regulation reserve requirement results in the current study and prior studies.

[27] 81 MW solar requirement / (998 MW total requirement / 4 classes) * 20% incremental diversity = 5.3 MW.

81 MW solar requirement * 37.6% pre-solar portfolio diversity = ~30 MW

Table F.12 - Portfolio Regulation Requirement Results, Percent of Nameplate Capacity

Study	Load	Wind	Non-VER	Solar	Method
2012 WIS: 2011	4.0%	8.7%	n/a	n/a	Load -> Incr Wind
2014 WIS: 2012	4.1%	8.1%	n/a	n/a	Load -> Incr Wind
2014 WIS: 2013	4.5%	7.3%	n/a	n/a	Load -> Incr Wind
2016 FRS	2.8%	8.9%	2.4%	4.6%	Portfolio Diversity (Base)
2016 FRS	n/a	5.8%	n/a	n/a	Base -> Incr Wind
2016 FRS	n/a	n/a	n/a	3.6%	Base -> Incr Solar 1
2016 FRS	n/a	n/a	n/a	3.8%	Incr Solar 1 -> Incr Solar 2

The 2012 and 2014 Wind Integration Studies calculated the regulation reserve requirement for load only, then the incremental requirement for the entire wind fleet, allocating all diversity to wind. The FRS calculates the regulation reserve requirement for the 2017 resource mix, allocating the diversity among all components. As compared to prior studies, the diversity allocation decreases the load requirement and increases the wind requirement, the changes in standards and methodology notwithstanding. In an additional step, the FRS also calculates incremental requirements for wind and solar which are more closely aligned with the obligations resulting from new resource additions contemplated in the IRP. While these requirements are lower than the average requirements in the base case, they will call on higher cost resources, as the least-cost regulation reserve resources are dispatched first. The cost of the regulation reserve obligation is discussed in more detail in the next section.

Regulation Reserve Cost

A series of PaR scenarios were prepared to isolate the regulation reserve cost associated with wind and solar generation. The scenarios are shown in Table F.13. These scenarios were based on 2017 and included the existing resources in the 2015 IRP Update. In the 2014 Wind Integration Study reserve requirements were modeled on both an hourly and monthly basis to reflect the timing differences of reserve requirements. While the requirements are calculated on an hourly basis, due to difficulties incorporating those requirements in the PaR model at that granularity, monthly requirements were used to calculate regulation reserve costs discussed herein. Where possible, it is recommended that hourly regulation requirements be modeled that are consistent with the resource capacity and generation profiles of the specific portfolio under evaluation.

Table F.13 - Regulation Reserve PaR Scenarios

#	Scenario	Resources	Regulation requirement
B.1	Base No Reserve	1/1/17 wind and solar	None
B.2	Base With Reserve	1/1/17 wind and solar	1/1/17 wind and solar
W.1	Incr. Wind, Base Reserve	Study B.2 + 250MW wind	1/1/17 wind and solar
W.2	Incr. Wind + Reserve	Study B.2 + 250MW wind	1/1/17 wind and solar + 250MW wind
S1.1	Incr. Solar 1, Base Reserve	Study B.2 + 500MW solar	1/1/17 wind and solar
S1.2	Incr. Solar 1 + Reserve	Study B.2 + 500MW solar	1/1/17 wind and solar + 500MW solar
S2.1	Incr. Solar 2, Base Reserve	Study B.2 + 1000MW solar	1/1/17 wind and solar
S2.2	Incr. Solar 2 + Reserve	Study B.2 + 1000MW solar	1/1/17 wind and solar + 1000MW solar

The regulation reserve cost results are shown in Table F.14. The 2014 Wind Integration Study identified regulation reserve costs for wind generation of $2.35/MWh. This value measured the incremental cost when regulation reserve for the existing wind fleet were added to the regulation reserve for load. The most comparable wind reserve cost from the FRS is $0.30/MWh. This represents the cost of the regulation reserve for existing wind, load, solar, and Non-VERs, relative to a scenario with no regulation reserve. The result is adjusted to account for the wind regulation reserve requirement relative to the total regulation reserve requirement.

Table F.14 - Regulation Reserve Cost Calculations

#	Value	Calculation	Units	Results
a	Base regulation reserve cost	[Study B.2] - [Study B.1]	$	5,936,990
b	Wind reserve requirement	[Wind req.] / [Total req.]	%	40%
c	Wind generation	[Study B.1]	MWh	7,802,061
	Base wind reserve rate	**[a] x [b] / [c]**	**$/MWh**	**$0.30**
a'	Incremental regulation reserve cost	[Study W.2] - [Study W.1]	$	$389,890
b'	Incremental wind generation	[Study W.1] - [Study B.1]	MWh	909,050
	Incremental wind reserve rate	**[a'] / [b']**	**$/MWh**	**$0.43**
a"	Incremental regulation reserve cost	[Study S2.2] - [Study S2.1]	$	$1,221,610
b"	Incremental solar generation	[Study S2.1] - [Study B.1]	MWh	2,667,200
	Incremental solar reserve rate	**[a"] / [b"]**	**$/MWh**	**$0.46**

The change in regulation reserve costs is primarily attributable to the following factors: lower market prices, transmission congestion, and 30-minute regulation reserve capability. Assuming sufficient regulating capability is available within PacifiCorp's portfolio, the cost of regulation reserve reflects the lost margin on resources that can provide the service, i.e. the difference between the market price or alternative generation cost and their fuel cost. Since the prior study, market prices have declined, which reduces this margin, and a 10 percent drop in market price can reduce the margin by more than 10 percent. In addition, transmission congestion has increased, primarily as a result of substantial additions of solar, which has reduced the ability of resources to get to market. If regulation-capable resources are already backed down due to transmission congestion there is no additional cost to count that capacity as regulation reserve. Finally, in the prior study the entire regulation reserve requirement was included in the spinning reserve category, which is limited to capacity available within 10 minutes. The FRS assumes that dispatchable capacity available within 30-minutes can be counted toward the regulation reserve requirement. This increases the supply of regulation resources and reduces costs when 30-minute capacity from the unit with the lowest-cost reserve can be used instead of being limited to only the 10-minute capacity of that unit.

While the Base wind reserve rate is helpful for comparison with the 2014 Wind Integration Study, it is not representative of the incremental cost of regulation reserve for new wind resources. Instead, PacifiCorp's FRS calculates regulation reserve requirements specific to the incremental resource additions contemplated in the IRP. As shown in Table F.14 above, the addition of 250 MW of wind capacity results in incremental regulation reserve costs of $0.43/MWh, while the addition of 1000 MW of solar capacity results in incremental regulation reserve costs of $0.46/MWh. It should be noted that the difference in reserve costs for wind and solar reflects timing differences. Per MWh of generation, the wind reserve obligation is 16 percent higher than the solar obligation; however, the solar obligation is higher during the summer and during the day, when market prices and marginal reserve costs are higher.

While incremental reserve costs generally increase with volume, the 500 MW solar scenario had a slightly higher cost than the 1000 MW scenario, likely due to lower transmission congestion. For simplicity, the 1000 MW result was used where a specific dollar value was required in the IRP. The 2017 FRS results are applied in the 2017 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. Ideally, the hourly regulation reserve requirements should be used to determine costs specific to the requirements of the resource and portfolio under consideration. This ensures regulation reserve costs reflect changes in market prices and fuel costs, transmission congestion, and regulation reserve capability relative to the IRP analysis. The corollary of a more accurate estimate of incremental regulation reserve cost is a more accurate estimate of the value of resources that supply regulation reserve, including energy storage and direct load control.

Day-ahead System Balancing Costs

In addition to using PaR for evaluating operating reserve cost, the PaR model is also used to estimate the costs associated with daily system balancing activities. These system balancing costs result from the unpredictable nature of load and wind generation on a day-ahead basis and can be characterized as system costs borne from committing generation resources against a forecast of load and wind generation and then dispatching generation resources under actual load and wind conditions as they occur in real time. The methodology is comparable to that used in the 2014 Wind Integration Study, with modifications to account for solar and the allocation of costs between load, wind, and solar.

The PaR model simulates production costs of a system by committing and dispatching resources to meet system load. For this study, PacifiCorp developed nine different PaR simulations as summarized in Table F.15. These simulations isolate the system balancing costs of load, wind, and solar, plus the system balancing costs of the overall portfolio. These simulations were run assuming operation in the 2017 calendar year, applying 2015 load, wind, and solar data collected from PacifiCorp's wind forecast service provider, DNV GL. This calculation method combines the benefits of using actual system data with current forward price curves pertinent to calculating the costs for wind integration service on a forward basis, as well as the current resource portfolio.[28] PacifiCorp resources used in the simulations are based upon its existing resource portfolio.

[28] The Study uses the October 12, 2016 official forward price curve (OFPC).

Table F.15 - System Balancing Cost Simulations in PaR

#	Load	Wind profile	Solar profile	Commitment	Day-ahead forecast error
1	Day-ahead	Day-ahead	Day-ahead	Study 1	n/a
2	Actual	Actual	Actual	Study 2	None
3	Actual	Actual	Actual	***Study 1***	For Load/Wind/Solar
4	Day-ahead	Actual	Actual	Study 4	n/a
5	Actual	Day-ahead	Actual	Study 5	n/a
6	Actual	Actual	Day-ahead	Study 6	n/a
7	Actual	Actual	Actual	***Study 4***	For Load
8	Actual	Actual	Actual	***Study 5***	For Wind
9	Actual	Actual	Actual	***Study 6***	For Solar

Simulation 1 identifies the unit commitment using day-ahead forecasts of load, wind, and solar. Simulation 2 identifies the unit commitment using actual load, wind, and solar, and represents the optimal dispatch of the system. Simulation 3 uses the unit commitment from Simulation 1, along with the actual load, wind, and solar from Simulation 2. Since Simulation 2 and 3 both have identical load, wind, and solar, differences between them are solely due to unit commitment and Simulation 3 represents the achievable optimization of unit commitment using the information available on a day-ahead basis when unit commitment occurs. The difference in cost between Simulation 3 and Simulation 2 is the system balancing cost associated with changes between day-ahead load, wind, and solar forecasts and actual output.

Simulations 4-9 isolate the total day-ahead forecast cost of the individual components. Simulations 4-6 each calculate unit commitment using one day-ahead forecast and two actual results. Simulations 7-9 calculate the costs of those day-ahead unit commitment decisions under actual output. The relative costs of Simulations 7-9 are used to determine the relative allocation of the portfolio among the individual components. The simulation results and day-ahead balancing cost for each category is shown in Table F.16.

Table F.16 - Day-ahead Forecast System Balancing Cost Results

#	Value	Cost calculation	Cost ($)	Diversity calculation	Rate w/ diversity ($/MWh)
a	Total Combined	[Study 3] - [Study 2]	$6,208,760		
b	Load Only	[Study 7] - [Study 2]	$6,132,860	[b] * ([a] / [e]) / [Actual Load MWh]	**$0.09**
c	Wind Only	[Study 8] - [Study 2]	$1,053,530	[c] * ([a] / [e]) / [Actual Wind MWh]	**$0.14**
d	Solar Only	[Adjusted]	$31,111	[Set equal to wind result]	**$0.14**
e	Total One-off	[b] + [c] + [d]	$7,217,501		

As indicated in the Regulation Reserve section above, the actual solar on PacifiCorp's system in 2015 was very limited, and the available solar generation averages just 21 megawatts, or roughly 3 percent of the available wind generation. Because unit commitment changes have low granularity (a unit is either on or off), small differences can sometimes have a large effect, and this appears to be the case for the solar results, which were far out of proportion with the measured volumes. In light of the limited solar data set, it is unlikely those results would scale up to the current level of solar on PacifiCorp's system. In light of this, the day-ahead forecast cost for solar generation has been reduced to the level calculated for wind generation.[29]

Table F.16 above has been modified from what was presented in the 2014 Wind Integration Study. In that study, day-ahead system balancing costs associated with load were calculated first, and incremental day-ahead system balancing costs associated with wind were calculated second. In this analysis, the total day-ahead system balancing costs are calculated for the portfolio and are allocated among the components based on their individual contributions. This attributes diversity in the requirements to all of the components and avoids differences related to the order the studies are conducted. A comparison of the day-ahead system balancing costs in the FRS and 2014 Wind Integration Study is shown in Table F.17.

Table F.17 - Day-Ahead System Balancing Cost Comparison

	2014 WIS (2014$/MWh)	2017 FRS (2016$/MWh)
Load	$0.01	$0.09
Wind	$0.71	$0.14
Solar	n/a	$0.14

The increase in the day-ahead system balancing costs associated with load do not appear to be a result of the portfolio allocation methodology, as load was previously calculated on a stand-alone basis, and the portfolio adjustment reduces the stand-alone day-ahead system balancing costs by 14 percent. Instead the difference appears to be related to market prices and the composition of the PacifiCorp's system. Market prices influence the relative costs of PacifiCorp's gas resources and determine how close they are to being economic or uneconomic. Resources generally only are faced with commitment changes when they have low margins. Because falling market prices have reduced margins, this occurs more frequently. In addition, transmission congestion has reduced the ability of resources to get to market. When resources are committed in anticipation of high load or low resources, there may not be sufficient transmission to get them to market if load is lower than expected or resources are higher. The costs of backing down economic resources due to transmission constraints is higher than the cost of forgone market sales, and thus contributes to higher day-ahead system balancing costs.

Technical Review Committee

As was done for its prior Wind Integration Studies, PacifiCorp engaged a Technical Review Committee (TRC) to review the study results from the FRS. PacifiCorp thanks each of the TRC members, identified below, for their participation and professional feedback. The members of the TRC are:

- **Andrea Coon** - Director, Western Renewable Energy Generation Information System (WREGIS) for the Western Electricity Coordinating Council (WECC)
- **Michael Milligan** - Principal Analyst at the National Renewable Energy Laboratory (NREL)
- **J. Charles Smith** - Executive Director, Utility Variable-Generation Integration Group (UVIG)

[29] The calculated Solar Only Day-Ahead Forecast Cost, [Study 9] – [Study 2], was $805k, or over $4/MWh.

- **Robert Zavadil -** Executive Vice President, EnerNex LLC

In its technical review[30] of PacifiCorp's FRS, the TRC provided comments and questions on specific aspects of the analysis.

Table F.18 - FRS TRC Recommendations

2016 FRS TRC Recommendations	Response to TRC Recommendations
The TRC feels that it might be useful to state the role of key assumptions generally - but specifically how key requirements of the EIM may have an impact on reserves (don't study it, just point out key issues).	EIM operating processes underlie PacifiCorp's regulation reserve requirements and the calculations in the FRS. Specific details on the EIM market process are available in the FRS, specifically in footnote 11.
On Slide page 8 of the presentation provided to the TRC, below the table: should that be 70 MW instead of 40 MW?	This references Figure F.6 in the FRS. The presentation stated: 40 MW is the maximum five-minute imbalance in any thirty-minute period in this hour. This is more accurately stated as: <u>When the minimum imbalances in every rolling thirty-minute period are compared,</u> 40 MW is the maximum five-minute imbalance in any thirty-minute period in this hour.
Would be helpful to include a few sentences about the ACE cap of 4L10?	This is addressed in the FRS in the section entitled "Balancing Authority ACE Limit: Allowed Deviations."
The use of what has traditionally been a resource adequacy metric – LOLH – use in long term capacity planning as a key criterion for estimating regulation reserve requirements is both interesting and a departure from previous studies – by Pacificorp as well as the general wind integration community in the U.S. This approach has been employed in a few recent integration analyses, but given the uniqueness, it would be good if it were more clearly called out/highlighted in the description of the analytical methodology. The discussion of 0.88 LOLH was helpful on the call. It would be useful to have a similar explanation in the report - something along the lines that the RA target resulted in 0.88 LOLH/year and that was judged to be an acceptable reliability level. Using the same target for operations, there are different drivers, but assuming resource adequacy is not the constraint, the 0.88 LOLH may instead result from UC errors that result in too little regulation being available when needed.	This is addressed in the FRS in the section entitled "Planning Reliability Target: Loss of Load Probability." The FRS identifies the "up" regulation reserve needed to maintain compliance with BAL-001-2. The 0.88 LOLH in the FRS assumes that resources are available to provide the identified hourly regulation requirements. To the extent resources are not available to meet the identified requirements, LOLH would increase. PacifiCorp's Flexible Resource Needs Assessment in the FRS assesses the availability of resources to meet its reserve requirements over the long term. In addition, over the short term, maintaining adequate reserve can be dependent on the availability of hourly market balancing opportunities. While a single unit can provide reserve in each hour of for a multi-hour ramp, it can only do so to the extent alternate resources can be procured so that it can ramp back to its starting point. Potential market balancing constraints are an area for future work.

[30] PacifiCorp 2016 Wind Integration Study Technical Review, Dec. 12, 2016. Available at: http://www.pacificorp.com/es/irp/irpsupport.html

2016 FRS TRC Recommendations	Response to TRC Recommendations
Would be useful to have discussion of how wind (and solar) are treated in the study - do they respond to AGC or dispatch or both? Impact of lost RECs vs. operational flexibility etc.	The FRS identifies the "up" regulation reserve needed to maintain compliance with BAL-001-2. The ability of wind or solar to provide "up" regulation reserve would impact the cost of meeting that need. Generally, the opportunity cost of foregone renewable resource output is higher than the variable cost of PacifiCorp's regulation reserve resources. When considered relative to the cost of adding flexible resource capacity, in some circumstances providing regulation reserve with wind or solar resources may be economic.
Is there a reference to the method used by the CAISO to allocate the diversity benefits for each EIM participant?	This is addressed in the FRS in the section entitled "EIM Intra-hour Benefit."
There is some remaining confusion on the part of the TRC regarding the assumptions and utilization of forecasting into the production simulations for calculating integration cost. Specifically, the forecast lead time is nearly one hour prior to the operating hour. The disconnect on the part of the TRC is likely driven by current operation in some larger RTOs, where very short term persistence forecasts (5 minutes ahead) are used to dispatch generators participating in the sub-hourly energy markets, which substantially reduces the remaining requirement for generators providing regulation.	While the EIM uses forecasts up to 7.5 minutes prior to the start of an interval, it can only dispatch the resources made available by participants. Because of EIM operating timelines, balanced load and resource schedules with regulation reserve capacity identified have to be submitted by 55 minutes prior to the hour. Once a resource is deployed, for instance to cover increasing load or decreasing wind, PacifiCorp cannot restore that regulating capacity to its original levels without buying additional resources from a third party. Bilateral hourly markets in the West have historically been liquid enough for this purpose, whereas sub-hourly markets, other than EIM, have not. Because EIM is an *Energy* Imbalance Market, each participant is independently responsible for meeting its reliability obligations and it is inappropriate to rely upon the availability of resources from other participants, though they will be deployed in the EIM if it is economic to do so. As discussed in the section entitled "EIM Intra-hour Benefit", the FRS incorporates benefits associated with the diversity of the EIM as whole, rather than the resources of other participants.
The use of actual high temporal resolution operating data, especially for wind generation (rather than synthesized data from numerical weather simulations) has been a key feature of the Pacificorp integration studies dating back to 2012. Going forward, the TRC feels that future Pacificorp integration studies could benefit greatly by a thorough comparison of "study results vs. real world", especially since a current year baseline is part of the analysis. This would provide perhaps the strongest validation of the analytical methodology or otherwise give strong clues to adjustments that may be needed.	PacifiCorp agrees that the performance of the regulation reserve forecast developed in the FRS against future regulation reserve requirements would provide valuable feedback. This is an area for future work.

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 2017 through 2036, 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 2017 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.19 below.

Table F.19 - Reserve Requirements (MW)

	East Requirement			West Requirement		
Year	Spin (10-minute)	Non-spin (10-minute)	Regulation (30-minute)	Spin (10-minute)	Non-spin (10-minute)	Regulation (30-minute)
2017	195	195	387	88	88	229
2018	197	197	387	89	89	229
2019	198	198	390	91	91	231
2020	200	200	390	91	91	231
2021	203	203	454	92	92	230
2022	205	205	454	92	92	230
2023	207	207	454	93	93	230
2024	209	209	454	93	93	230
2025	212	212	454	94	94	230
2026	211	211	454	95	95	230
2027	213	213	454	95	95	230
2028	215	215	390	96	96	232
2029	218	218	390	96	96	235
2030	219	219	390	97	97	235
2031	222	222	398	97	97	233
2032	225	225	396	98	98	234
2033	227	227	398	98	98	232
2034	228	228	392	98	98	231
2035	231	231	401	99	99	231
2036	235	235	436	99	99	230

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.20 lists the annual reserve capability from resources in PacifiCorp's East and West balancing authority areas. 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.20 - Flexible Resource Supply Forecast (MW)

Year	East Supply (10-minute)	West Supply (10-minute)	East Supply (30-minute)	West Supply (30-minute)
2017	1,340	745	1,975	1,009
2018	1,340	751	1,975	1,015
2019	1,290	700	1,875	964
2020	1,290	743	1,875	1,007
2021	1,250	724	1,755	988
2022	1,250	684	1,755	948
2023	1,250	725	1,755	989
2024	1,250	725	1,755	989
2025	1,250	725	1,755	989
2026	1,250	724	1,755	988
2027	1,250	725	1,755	989
2028	1,169	726	1,675	990
2029	1,281	692	1,786	890
2030	1,231	968	1,656	1,166
2031	1,231	969	1,656	1,167
2032	1,231	970	1,657	1,168
2033	1,469	936	1,832	1,068
2034	1,469	935	1,832	1,067
2035	1,469	936	1,832	1,068
2036	1,469	937	1,833	1,069

Figure F.21 and Figure F.22 graphically display the balances of reserve requirements and capability of spinning reserve resources in PacifiCorp's East and West balancing authority areas respectively. The graphs demonstrate that PacifiCorp's system has sufficient resources to serve its reserve requirements throughout the IRP planning period.

Figure F.21 - Comparison of Reserve Requirements and Resources, East Balancing Authority Area (MW)

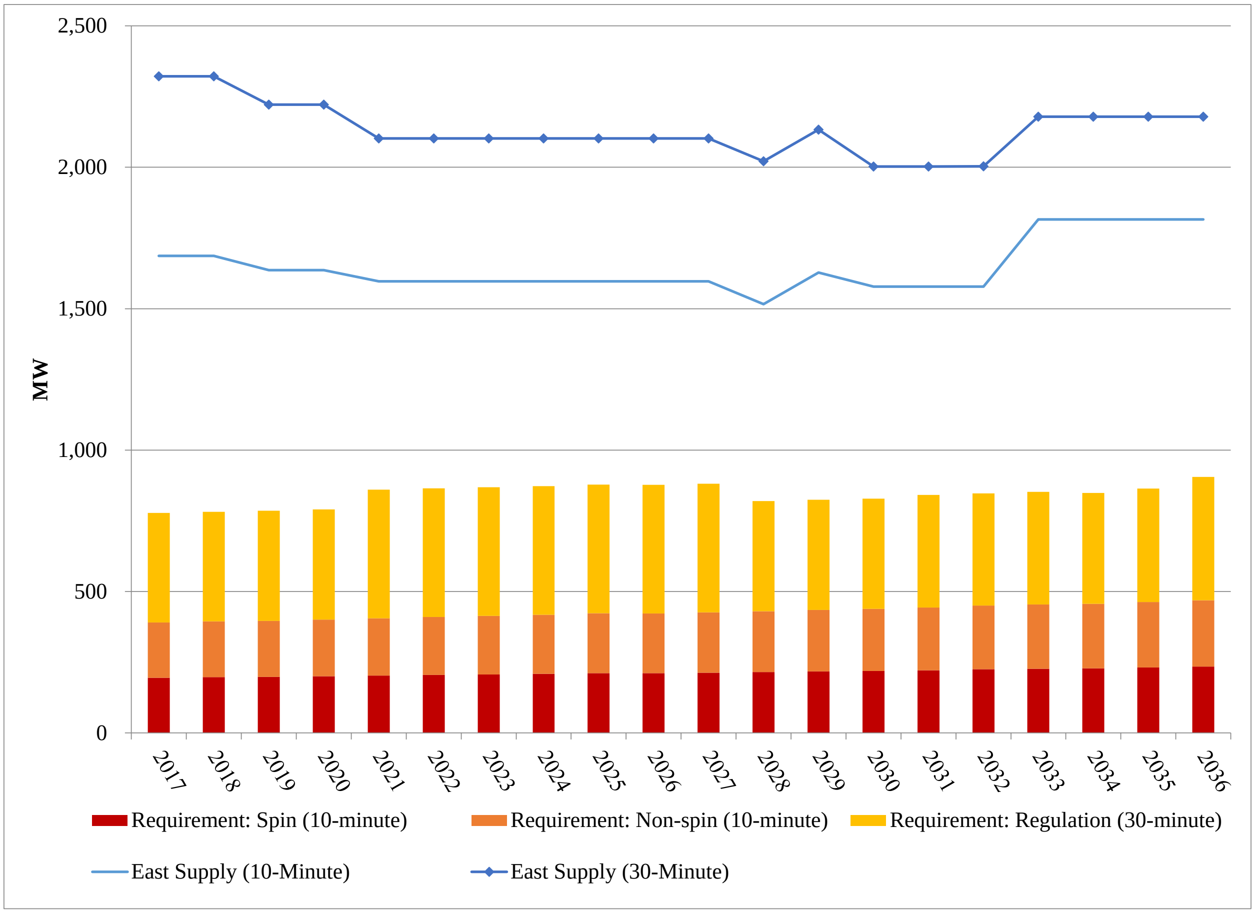
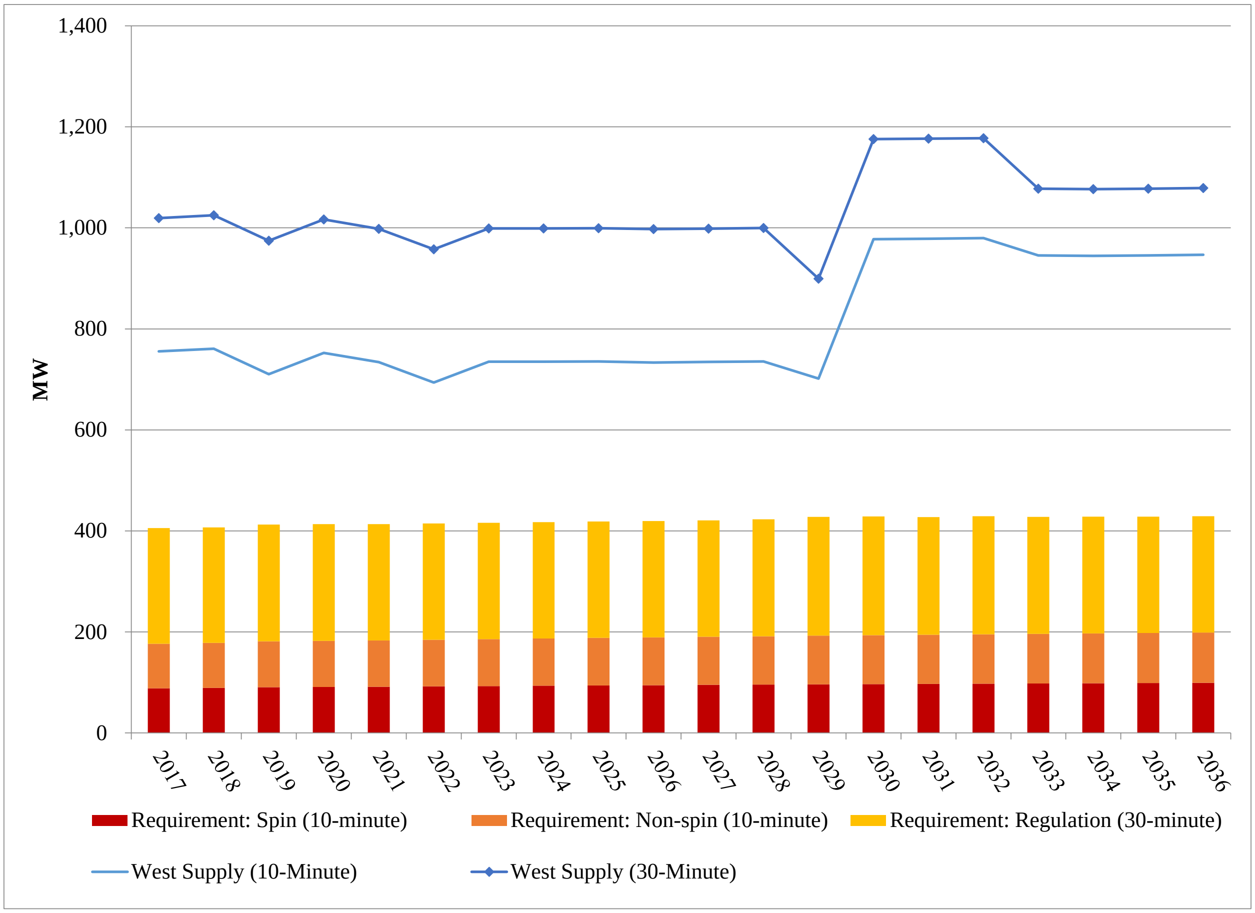


Figure F.22 - Comparison of Reserve Requirements and Resources, West Balancing Authority Area (MW)



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 has since expanded to include NV Energy, Arizona Public Service, and Puget Sound Energy, with several additional participants scheduled for entry between 2017 and 2019. 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 flexible ramping requirement for the entire EIM footprint can be less than the sum of individual BAAs' requirements. This difference is known as the "flexible ramping procurement diversity savings" in the EIM. This intra-hour 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 include whether electric vehicles could be used to meet future flexible resource needs.

Summary

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 and the cost of using day-ahead load, wind, and solar forecasts to commit gas units. 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.

PacifiCorp incorporated a revised methodology in the FRS compared to its 2014 Wind Integration Study. The FRS now 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 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 accounts for the diversity of using a single portfolio of regulation reserve resources to cover variations in load, wind, solar, and Non-VERs. The regulation reserve requirements for the various portfolios considered in the analysis and in the 2014 Wind Integration Study are shown in Table F.21.

Table F.21 – Portfolio Regulation Reserve Requirements, by Scenario

Case	Wind Capacity (MW)	Solar Capacity (MW)	Stand-alone Regulation Requirement (MW)	Portfolio Diversity Credit (%)	Regulation Requirement with Diversity (MW)
2014 WIS	2,543	n/a	n/a	n/a	626
2015 (No Solar)	2,588	0	900	37.5%	562
2017 Base Case	2,757	1,050	998	38.2%	617
Incremental Wind	3,007	1,050	1,023	38.3%	631
Incremental Solar 1	2,757	1,550	1,033	38.6%	635
Incremental Solar 2	2,757	2,050	1,074	39.2%	653

Two categories of flexible resource costs are estimated using the Planning and Risk (PaR) model: one for meeting intra-hour regulation reserve requirements, and one for inter-hour system balancing costs associated with committing gas plants using day-ahead forecasts of load, wind, and solar. Table F.22 provides the wind and solar costs on a dollar per megawatt-hour ($/MWh) of generation basis. The results of the 2014 Wind Integration Study are also included for comparison.

Table F.22 – 2017 FRS Flexible Resource Costs as Compared to 2014 WIS Costs, $/MWh

	Wind 2014 WIS (2015$)	**Wind 2017 FRS** (2017$)	**Solar 2017 FRS** (2017$)
Intra-hour Reserve	$2.35	$0.43	$0.46
Inter-hour/System Balancing	$0.71	$0.14	$0.14
Total Flexible Resource Cost	**$3.06**	**$0.57**	**$0.60**

The 2017 FRS results are applied in the 2017 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.

Reference Tables

Table F.23 - Wind

Resource ID	Nameplate Capacity (MW)	BAA	Grouping
DUNLAP_6_UNIT	111	PACE	Wind
FOOTECRE_7_UNITS	133.6	PACE	Wind
FREEZOUT_6_UNIT	118.5	PACE	Wind
GLENROCW_6_UNIT	138	PACE	Wind
HINSHAW_7_UNITS	144	PACE	Wind
HIPLAINS_7_UNITS	127.5	PACE	Wind
HORSEBU_7_UNIT	57.6	PACE	Wind
JOLLYHIL_1_GOSHEN	124.5	PACE	Wind
LATIGO_6_UNIT	99	PACE	Wind
MEADOWCR_6_UNIT	119.7	PACE	Wind
MOONSHIN_7_UNITS	45	PACE	Wind
MTWNDCOL_7_UNITS	140.7	PACE	Wind
RAWHIDE_6_UNIT	16.5	PACE	Wind
ROLLHILL_6_UNIT	99	PACE	Wind
SPNFKWND_7_UNIT	18.9	PACE	Wind
TOPWORLD_7_UNITS	200.2	PACE	Wind
WOLVERIN_7_UNITS	64.5	PACE	Wind
CAMPCOL_6_UNIT	98.9	PACW	Wind
COMBINEH_6_UNIT	41	PACW	Wind
DALREED_7_WIND	9.9	PACW	Wind
GOODNOEH_7_UNIT	94	PACW	Wind
HINKLE_6_UNIT	64.55	PACW	Wind
LEANJNPR_7_UNIT	100.5	PACW	Wind
MARENGO_6_UNITS	210.6	PACW	Wind
NINEMIL_7_UNIT 1	210	PACW	Wind
Total	**2587.65**		

Table F.24 – Non-VERs

Resource ID	Nameplate Capacity (MW)	BAA	Class
BONANZA_7_UNIT	458	PACE	Non-VER
DALTONU_7_UNIT	4.6	PACE	Non-VER
EXXON_7_UNITS	107.4	PACE	Non-VER
GEMSTATE_1_UNIT	23.4	PACE	Non-VER
MILLCRK_7_UNIT 1	40	PACE	Non-VER

MILLCRK_7_UNIT 2	40	PACE	Non-VER
NEBOPS_7_UNITS	140	PACE	Non-VER
PALISADI_7_UNIT 1	44	PACE	Non-VER
PALISADI_7_UNIT 2	44	PACE	Non-VER
PALISADI_7_UNIT 3	44	PACE	Non-VER
PALISADI_7_UNIT 4	44	PACE	Non-VER
SLENERGY_7_UNIT	3.2	PACE	Non-VER
SUNNYSIU_6_UNIT	53	PACE	Non-VER
TESORO_7_UNITS	25	PACE	Non-VER
USBRGATE_7_UNIT	4.5	PACE	Non-VER
WESTVALL_7_UNIT 1	40	PACE	Non-VER
WESTVALL_7_UNIT 2	40	PACE	Non-VER
WESTVALL_7_UNIT 3	40	PACE	Non-VER
WESTVALL_7_UNIT 4	40	PACE	Non-VER
WESTVALL_7_UNIT 5	40	PACE	Non-VER
BIOMAS_7_PACW	32.5	PACW	Non-VER
CAMASMI_7_UNIT	61.5	PACW	Non-VER
CLEARWA1_7_UNIT	17.9	PACW	Non-VER
CLEARWA2_7_UNIT	31	PACW	Non-VER
COID_7_UNITS	6	PACW	Non-VER
COLSTR_5_PACE	74	PACW	Non-VER
COLSTR_5_PACW	74	PACW	Non-VER
COPCO1_7_UNIT 1	14	PACW	Non-VER
COPCO1_7_UNIT 2	14	PACW	Non-VER
COPCO2_7_UNIT 1	17	PACW	Non-VER
COPCO2_7_UNIT 2	17	PACW	Non-VER
DALREED_7_BIO	4.8	PACW	Non-VER
EVERGBIO_6_BIO	10	PACW	Non-VER
FALLCREE_7_UNIT	2	PACW	Non-VER
FARMERS_6_UNIT	4.15	PACW	Non-VER
FISHCREO_7_UNIT	10.4	PACW	Non-VER
GRACE_7_UNIT 3	11	PACW	Non-VER
GRACE_7_UNIT 4	11	PACW	Non-VER
GRACE_7_UNIT 5	11	PACW	Non-VER
IRONGATE_7_UNIT	18.8	PACW	Non-VER
JCBOYLE_7_UNIT 1	40	PACW	Non-VER
JCBOYLE_7_UNIT 2	43	PACW	Non-VER
LEMOLO1_7_UNIT	32	PACW	Non-VER
LEMOLO2_7_UNIT	38.5	PACW	Non-VER
MERWIN_7_UNITS	150	PACW	Non-VER
OPALSPRI_7_UNIT	4.3	PACW	Non-VER

PELTONRE_7_UNIT	19.6	PACW	Non-VER
PENSTOCK_6_UNIT	5	PACW	Non-VER
PROSPEC2_7_UNIT 1	18	PACW	Non-VER
PROSPEC2_7_UNIT 2	18	PACW	Non-VER
PROSPEC3_7_UNIT	7.7	PACW	Non-VER
RFP_6_UNIT	10	PACW	Non-VER
ROSEBURL_7_LUMB	20	PACW	Non-VER
SLIDECRE_7_UNIT	18	PACW	Non-VER
SODA_7_UNIT 1	7	PACW	Non-VER
SODA_7_UNIT 2	7	PACW	Non-VER
SODASPRI_7_UNIT	11.6	PACW	Non-VER
TIETONHY_6_UNIT	13.8	PACW	Non-VER
TOKETEE_7_UNIT 1	15	PACW	Non-VER
TOKETEE_7_UNIT 2	15	PACW	Non-VER
TOKETEE_7_UNIT 3	15	PACW	Non-VER
WEBER_7_UNIT	2	PACW	Non-VER
Total	**2227.65**		

Table F.25 - Solar

Resource	Nameplate Capacity (MW)	BAA	Class
Beryl Solar	3	PACE	Solar
Buckhorn	3	PACE	Solar
Cedar Valley	3	PACE	Solar
Enterprise Solar I QF	80	PACE	Solar
Escalante Solar I QF	80	PACE	Solar
Escalante Solar II QF	80	PACE	Solar
Escalante Solar III QF	80	PACE	Solar
Fiddler's Canyon 1	3	PACE	Solar
Fiddler's Canyon 2	3	PACE	Solar
Fiddler's Canyon 3	3	PACE	Solar
Granite Mountain East Solar QF	80	PACE	Solar
Granite Mountain West Solar QF	50.4	PACE	Solar
Granite Peak	3	PACE	Solar
Greenville	2.2	PACE	Solar
Iron Springs Solar QF	80	PACE	Solar
Laho #1	3	PACE	Solar
Milford 2	2.97	PACE	Solar
Milford Flat	3	PACE	Solar

Pavant II Solar QF	50	PACE	Solar
Pavant III Solar	20	PACE	Solar
Quichapa 1	3	PACE	Solar
Quichapa 2	3	PACE	Solar
Quichapa 3	3	PACE	Solar
South Milford	2.93	PACE	Solar
Three Peaks Solar QF	80	PACE	Solar
Utah Pavant Solar QF	50	PACE	Solar
Utah Red Hills Solar QF	80	PACE	Solar
Adams Solar Center LLC	10	PACW	Solar
Beatty Solar	5	PACW	Solar
Black Cap	2	PACW	Solar
Black Cap II LLC	8	PACW	Solar
Bly Solar Center LLC	8.5	PACW	Solar
Chiloquin Solar	9.9	PACW	Solar
Collier Solar	9.9	PACW	Solar
Elbe Solar Center LLC	10	PACW	Solar
Ivory Pine Solar	10	PACW	Solar
Norwest Energy 2 LLC (Neff)	10	PACW	Solar
Old Mill Solar	5	PACW	Solar
OR Solar 2 (Agate Bay Solar)	10	PACW	Solar
OR Solar 3 (Turkey Hill Solar)	10	PACW	Solar
OR Solar 5 (Merrill)	8	PACW	Solar
OR Solar 6 (Lakeview)	10	PACW	Solar
OR Solar 7 (Jacksonville)	10	PACW	Solar
OR Solar 8 (Dairy)	10	PACW	Solar
Sprague River Solar	7	PACW	Solar
Tumbleweed Solar	9.9	PACW	Solar
Total	**1017.7**		