BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-76:
Western Pool Reserve Sharing Program

NWPP RSG
POWERED BY WPP

Northwest Power Pool
Reserve Sharing Program Documentation

NWPP Reserve Sharing Program 1.18.2006
RSG Committee Approved, effective: 10.1.2025

NWPP Reserve Sharing Documentation

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NWPP Reserve Sharing Program

A. INTRODUCTION AND OVERVIEW

Standards established by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC) require all Balancing Authorities to carry reserve for defined categories of contingencies. As permitted by NERC and WECC standards, Participating Balancing Authorities within the Northwest Power Pool (NWPP) have instituted the NWPP Reserve Sharing Program for Contingency Reserve.

By sharing Contingency Reserve, Participants are entitled to use not only their own "internal" reserve resources, but to call on other Participants for assistance if internal reserve does not fully cover a contingency. Except when communication links are down or the Reserve Sharing Computer System is not functioning, the NWPP Reserve Sharing Program is automated, operating through direct communication of data and Contingency Reserve deployment signals between the Reserve Sharing Computer System and the Participating Balancing Authorities. The WPP Staff is responsible for preparing and submitting required NERC and WECC compliance reports, and responding to compliance audits, on behalf of the NWPP Reserve Sharing Group for BAL-002. Participants are relieved of BAL-002 compliance reporting obligations, and do not report to NERC or WECC on BAL-002 compliance individually.

This document describes how the NWPP Reserve Sharing Program works. It covers:

- key terminology for the NWPP Reserve Sharing Program (Section B),
- an overview of the key elements of the NWPP Reserve Sharing Program (Section C),
- how much Contingency Reserve each participant is required to carry (Attachment A),
- what events allow participants to deploy their own Contingency Reserve, and, if necessary, request assistance reserve, how a participant may request assistance reserve from other participants (Attachment B and Section E),
- participants' obligations to supply assistance reserve (Section F),
- eligibility to participate in reserve sharing and how eligible Balancing Authorities become participants (Section G),
- the roles and responsibilities of participants, the WPP Staff, and others (Section H),
- general data requirements and the functions of the reserve sharing computer system (Section I),
- data requirements related to requests for assistance reserve (Section J),
- how participants settle when assistance reserve is supplied under the NWPP Reserve Sharing Program (Section K and Attachment D),

- tracking and reporting procedures related to the NWPP Reserve Sharing Program (Section L),
- identification of "zones" within the NWPP Reserve Sharing Group for delivering reserve energy, and the sequence in which assistance reserve from adjacent zones is deployed if the assistance reserve inside a given zone is insufficient to meet a contingency (Section M and Attachment C);
- backup procedures participants will use if the communication links that enable automated reserve sharing go down (Section N and Attachment E);
- procedures for addressing issues that affect the NWPP Reserve Sharing Program when the process under the *Agreement Appointing Agent and Establishing Responsibilities Related to Reserve Sharing Group Compliance with BAL-002* is insufficient (Section O);
- an explanation of why the NWPP Reserve Sharing Group does not activate Contingency Reserve during operation of BPA remedial action schemes that are designed to suspend automatic generation control (Attachment M),

This document includes several attachments, some of which have been noted above. The full set of attachments and their titles are as follows:

Attachment A – Calculation of Contingency Reserve Obligations; Requirements Related to WECC Operating Reserve - Supplemental

Attachment B – Qualifying Events

Attachment C – Reserve Sharing Zone and Levels

Attachment D – Process Chart

Attachment E – Backup Procedures for NWPP Reserve Sharing Program

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Attachment H – Balancing Authority Areas of Participating Balancing Authorities

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Attachment K – Typical Planning MSSC in Real Time, Jointly Owned Dynamic Generation Resources, Jointly Owned Static Generation Resources, and Multi Use Transformer(s) Tables

Attachment L – Cut Planes and Cut Plane Monitors Between Reserve Sharing Zones

Attachment M – Overview of BPA Remedial Action Schemes That Suspend Automatic Generation Control and Result in Expected Changes to NWPP Reserve Sharing Group Reporting ACE

Attachment N – Correlation Table of Participants, Reliability Coordinators, and Zones

B. KEY TERMINOLOGY

The terms identified below have the meanings given to them in this document for purposes of the NWPP Reserve Sharing Program. Most terms defined by NERC or the WECC are conformed to the NERC or WECC definitions, but some terms' definitions may not be identical to those established by NERC or the WECC.

ACE: Area Control Error, as defined in the NERC Glossary.

Actual Net Interchange (NI_A): Actual Net Interchange, as defined in the NERC Glossary.

Agency Agreement: The *Agreement Appointing Agent and Establishing Responsibilities Related to Reserve Sharing Group Compliance with BAL-002*, as initially effective on July 1, 2008, together with any subsequent amendments or restatements.

Assistance Reserve: Contingency Reserve of one Participant that is delivered to another Participant in response to a Reserve Sharing Request.

BAL-002: For the RSG, BAL-002 means:

- NERC Reliability Standards BAL-002 and BAL-002-WECC
- And with respect to a Participant, those provisions of the foregoing (or any substantially similar standard) applicable to the Participant by law or regulation.

Balancing Authority (BA): Balancing Authority, as defined in the NERC Glossary.

Balancing Authority Area (BAA): Balancing Authority Area, as defined in the NERC Glossary.

Balancing Authority Area MSSC: A NWPP Reserve Sharing Group Participant Balancing Authority and its Balancing Authority Area's real-time MSSC based on actual configurations and provided to the Reserve Sharing Computer System via ICCP in real time.

Balancing Contingency Event: Balancing Contingency Event, as defined in the NERC Glossary.

Contingency Event Recovery Period: Contingency Event Recovery Period, as defined in the NERC Glossary.

Contingency Reserve: Contingency Reserve, as defined in the NERC Glossary.

Contingency Reserve Available (CRA): Contingency Reserve committed by a Participating Balancing Authority, which the Participating Balancing Authority reports to the Reserve Sharing Computer Program, that:

- is fully deployable within ten minutes for use as Internal Reserve (except for amounts reported as already deployed for Qualifying Events);
- is fully deployable within ten minutes of an Assistance Reserve Sharing Request for delivery (except for amounts reported as already deployed for Qualifying Events); and
- is sustainable for 60 minutes from the time of a request for Assistance Reserves.

Subject to the foregoing requirements, a Participating Balancing Authority's Contingency Reserve Available:

- will, for monitoring purposes, be deemed to include a Participant's Contingency Reserve reported as available for deployment; and
- may include Contingency Reserve purchased or otherwise transferred to the Participating Balancing Authority. Reporting ACE transferred from one Participant to another Balancing Authority Area would be considered a transfer; and
    - if arranged from another entity from outside of the Participant's zone (as detailed in Attachment C) and deployed for a valid request, details of deployment shall be reported to the WPP Staff.
- may include load committed to be shed for Contingency Reserve if a Participant is in an EEA; and
- must exclude Contingency Reserve the Participating Balancing Authority has sold to any other party.

A Participating Balancing Authority's Contingency Reserve Available plus amounts reported as Used for internal Qualifying Events and the amount deployed in response to a request for Assistance Reserves must be equal to or greater than its Contingency Reserve Obligation.

Contingency Reserve Obligation (CRO): As specified in Attachment A to this document, Contingency Reserve Obligation is the minimum amount of Contingency Reserve that must be carried by a particular Participant for its Balancing Authority Area(s) or by the NWPP Reserve Sharing Group as a whole (as the context requires) to respond to Qualifying Events. Although the acronym "CRO," as used in this document, may sometimes designate base calculation of a Participating Balancing Authority's Contingency Reserve Obligation (before adjustments described in Attachment A), the written term "Contingency Reserve Obligation"

as used in this document refers to the total amount of Contingency Reserve that must be carried for a Participant's Balancing Authority Area(s) (or the NWPP Reserve Sharing Group as a whole), taking into account all applicable adjustments specified in Attachment A.

Firm Demand: Firm Demand, as defined in the NERC Glossary.

Internal Reserve: The Contingency Reserve of a Participating Balancing Authority when deployed to respond to a Qualifying Event on the Participating Balancing Authority's own system (as opposed to Contingency Reserve delivered as Assistance Reserve to another Participating Balancing Authority).

Long-Term Zonal MSSC Limit: An identified normal system MSSC documented in Attachment K.1. by each zone's Participant Balancing Authority/Balancing Authority Areas.

Most Severe Single Contingency (MSSC): The Most Severe Single Contingency, as defined in the NERC Glossary.

NERC Glossary: The NERC Glossary of Terms Used in Reliability Standards.

North American Electric Reliability Corporation (NERC): A self-regulatory nonprofit organization, subject to oversight by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada, whose mission is to ensure the reliability of the bulk power system in North America. NERC develops and enforces reliability standards, assesses reliability annually via 10-year and seasonal forecasts, monitors the bulk power system, and educates, trains, and certifies industry personnel.

Northwest Power Pool (NWPP): The geographic area encompassed by the electric systems of the NWPP Agreement Signatories. There is also a separate corporation named "Northwest Power Pool," which provides staffing and other resources to support implementation of the NWPP Agreement. In general, when this document refers to the Northwest Power Pool or the NWPP, it is referring to the geographic area and the associated electric power systems of the NWPP Agreement Signatories.

NWPP Agreement: A multilateral agreement to promote cooperation among participating organizations to achieve reliable operation, coordinate generation operation and power system planning, and assist in planning of transmission within the NWPP area.

NWPP Agreement Signatory (Signatory): An entity that is a party to the NWPP Agreement.

NWPP Reserve Sharing Group: The group composed of all Participants, collectively.

NWPP Reserve Sharing Group Long-Term MSSC Limit: The identified long-term maximum limit of the NWPP Reserve Sharing Group's MSSC is the largest Long-Term Zonal MSSC Limit as documented in Attachment K.1.

NWPP Reserve Sharing Group Reporting ACE: The algebraic sum of the Reporting ACE of the Participant(s) experiencing the RBCE (or multiple BCEs occurring within 60 seconds) and the Reporting ACE of those Participant(s) delivering Assistance Reserve to the Requesting Participant(s) -see Attachment C "Reserve Sharing Zones and Levels", including any Participant delivering transferred Assistance Reserve.

NWPP Reserve Sharing Program: The procedures, data, computer programs, and related information and requirements described in this document that enable Participants to request and provide Assistance Reserve as needed to respond to Qualifying Events.

Operating Plan: Operating Plan, as defined in the NERC Glossary.

Operating Process: Operating Process, as defined in the NERC Glossary.

Operating Reserve: Operating Reserve, as defined in the NERC Glossary.

Participating Balancing Authority or Participant: An entity that (a) operates one or more Balancing Authority Areas and (b) has become a participant in the NWPP Reserve Sharing Program as described in Section G.1. The terms "Participant" and "Participating Balancing Authority" are used interchangeably in this document. Attachment H contains a list of the Balancing Authority Areas of the current Participating Balancing Authorities.

Qualifying Event: Those events designated in Attachment B of this document as Qualifying Events.

Recovery Reporting ACE Target: The average value of a requesting Participant's Reporting ACE in the 16-second interval immediately prior to the start of the Qualifying Event (or zero, whichever is less) or the average value of a Participant's Reporting ACE that is providing Assistance Reserve in the 16-second interval immediately prior to the request of Assistance Reserves (or zero, whichever is less) based on EMS scan rate data.

Reliability Coordinator (RC): Any one or more organizations performing the NERC-registered function (or its equivalent in Canada) of reliability coordination within the Northwest Power Pool.

Reportable Balancing Contingency Event: Reportable Balancing Contingency Event, as defined in the NERC Glossary.

Reporting ACE: Reporting ACE, as defined in the NERC Glossary.

Reserve Sharing Computer System: The software and hardware used for automated reserve sharing under the NWPP Reserve Sharing Program.

Reserve Sharing Request: A request by Participating Balancing Authority that has satisfied the conditions specified in Section E.2 for delivery of Assistance Reserve.

Reserve Sharing Zone: A designated set of Balancing Authority Area(s) within the Reserve Sharing Group that is separated from other Balancing Authority Area(s) within the Reserve Sharing Group by transmission facilities that have been shown through studies to constrain reserve deliveries, at times, between the designated set and the other Balancing Authority Areas. Attachment C to this document identifies the Reserve Sharing Zones that have been established for the NWPP Reserve Sharing Program, together with the sequence through which Assistance Reserve is deployed for each Reserve Sharing Zone.

RSG Committee: The committee established under the terms of the NWPP Agreement to administer the NWPP Reserve Sharing Program.

Scheduled Net Interchange (NI_S): Scheduled Net Interchange, as defined in the NERC Glossary.

System Operator: System Operator, as defined in the NERC Glossary.

Third-Party Generation: Any generating resource that is within the metered boundaries of the Balancing Authority Area of a Participating Balancing Authority but is neither owned by nor under contract to that Participating Balancing Authority.

WECC Soft Price Cap: The price cap adopted by the Federal Energy Regulatory Commission in *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services*, 93 FERC ¶ 61,121 (2000) and *Western Electric Coordinating Council*, 133 FERC ¶ 61,026 (2010), subject to the guidance provided by the Federal Energy Regulatory Commission in *ConocoPhillips Company, et al*., 175 FERC ¶ 61,226 (2021)

WECC Operating Reserve - Supplemental: WECC Operating Reserve - Supplemental is the portion of Operating Reserve consisting of:

- generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Contingency Event Recovery Period following a contingency event; or
- load fully removable from the system within the Contingency Event Recovery Period following the contingency event;

provided, however, that for purposes of the NWPP Reserve Sharing Program (as required by WECC Standard BAL-002-WECC-3), WECC Operating Reserve - Supplemental must also be:

- capable of fully responding within ten minutes.

Western Electricity Coordinating Council (WECC): A nonprofit corporation with the mission to foster and promote reliability and efficient coordination in the Western Interconnection.

WPP Staff: The employees of the Northwest Power Pool Corporation doing business as the Western Power Pool.

C. OVERVIEW OF KEY RESERVE SHARING PROGRAM ELEMENTS

C.1. How Much Contingency Reserve a Participating Balancing Authority Must Carry (Contingency Reserve Obligation)

The processes for calculating how much Contingency Reserve each Participant must carry for its Balancing Authority Area(s), and the Contingency Reserve Obligation for the NWPP Reserve Sharing Group as a whole, are set forth in Attachment A to this document along with the process chart as reflected in Attachment D.

C.2. When a Participating Balancing Authority May Deploy Contingency Reserve and Request Assistance Reserve (Qualifying Events)

A Participating Balancing Authority must experience a "Qualifying Event" before it is entitled to deploy any portion of its Contingency Reserve Obligation (as Internal Reserve) or request Assistance Reserve. The definition of Qualifying Event is set forth in Attachment B to this document.

C.3. What a Participating Balancing Authority Must Do Before Requesting Assistance Reserve

A Participating Balancing Authority must fully commit an amount of its Balancing Authority Area's Internal Reserve that equals or exceeds the requesting Participant's CRO requirement to the NWPP before requesting Assistance Reserve to respond to a Qualifying Event. This requirement is more fully explained in Section E.2 of this document. There are also requirements concerning the timing and duration of Assistance Reserve Sharing Requests, which are set forth in Section E.3.

C.4. Where to Find Additional Information on Participant Eligibility and Obligations

Eligibility

Provisions governing eligibility to participate in the NWPP Reserve Sharing Program are in Section G of this document.

Additional Operating Reserve for R3 and R4 of WECC BAL-002-WECC-3

Section D.4 describes Participating Balancing Authorities' obligations to enable the NWPP Reserve Sharing Group to demonstrate compliance with Sections R3 and R4 of BAL-002-WECC-3.

Data Obligations

Section I contains information on the data requirements for the general operation of the NWPP Reserve Sharing Program, as well the functions of the Reserve Sharing Computer System. Section J describes data requirements for making and responding to Reserve Sharing Requests.

Providing Assistance Reserve

Participants' obligations to provide Assistance Reserve are explained in Section F.

Restoring Contingency Reserve Following Deployment

Section E.6 describes Participants' obligations to restore their Contingency Reserve following deployment (either as Internal Reserve or Assistance Reserve).

D. RESERVE REQUIREMENTS

D.1. How NWPP Reserve Sharing Program Rules Relate to BAL-002

The NWPP Reserve Sharing Program is intended to enable the NWPP Reserve Sharing Group to comply with BAL-002, as well as certain additional rules the NWPP Reserve Sharing Group has elected to adopt for itself.

Participants are required at all times to meet the requirements of BAL-002, as revised, supplemented, or superseded from time to time in accordance with applicable NERC, WECC, or regulatory procedures. BAL-002 constitutes the foundation on which the NWPP Reserve Sharing Group rules are built. Compliance with the NWPP Reserve Sharing Group rules for Contingency Reserve is intended to ensure compliance with the BAL-002, but cannot serve to excuse any compliance failure related to the NERC or WECC standards.

NERC Standard BAL-002-3 requires Balancing Authorities (or reserve sharing groups) to recover, within the Contingency Event Recovery Period, from Reportable Balancing Contingency Events (subject to certain exceptions).

WECC Standard BAL-002-WECC-3 governs Contingency Reserve, but also includes requirements (set forth in Sections R3 and R4 of BAL-002-WECC-3) for additional Operating Reserve that must be carried by Participants engaging in certain types of transactions involving purchases from units supplying Contingency Reserve or sales of Operating Reserve. This document addresses, at Section D.4, requirements for Participating Balancing Authorities to enable the NWPP Reserve Sharing Group to demonstrate compliance with Sections R3 and R4 of BAL-002-WECC-3.

D.2. Contingency Reserve Obligations and Associated Requirements Related to WECC Operating Reserve - Supplemental

Section 1 of Attachment A to this document provides a detailed explanation of how to calculate the Contingency Reserve Obligation for each Participating Balancing Authority. Section 1 also explains the manner in which the Participating Balancing Authorities' Contingency Reserve Obligations are combined to yield an aggregate obligation for the NWPP Reserve Sharing Group. Section 2 of Attachment A specifies what portion of Participating Balancing Authorities' Contingency Reserve Obligations must be carried as permitted sources of WECC Operating Reserve - Supplemental. Every Participating Balancing Authority must include in its operating procedures provisions that require it to:

a. maintain and have available an amount of Contingency Reserve Available that is equal to or greater than its Contingency Reserve Obligation,

b. perform such calculations as may be necessary (including consideration of transmission constraints) to ensure that it can deploy Contingency Reserve reported as available, and

c. deploy its Contingency Reserve Available for Qualifying Events as provided in this document.

Section 3 explains the Participating Balancing Authorities calculation of Contingency Reserve Obligation(s) when communications with the Reserve Sharing Computer System are disrupted.

D.3. Additional Policies Governing Contingency Reserve

a. <u>No Double Counting</u>

As expressed in the policies of the RSG Committee, multiple Participants may not count the same portion of resource capacity (*e.g.,* reserves from jointly owned generation) toward any portion of their Contingency Reserve Obligations, and the NWPP Reserve Sharing Group rules do not permit this.

b. <u>Contingency Reserve Available</u>

All Participants must continuously calculate and update their Contingency Reserve Available. A Participating Balancing Authority's Contingency

Reserve Available plus amounts reported as Used for internal Qualifying Events and the amount deployed in response to a request for Assistance Reserves must be equal to or greater than its Contingency Reserve Obligation.

c. Purchased Power

To provide flexibility in recovering from a Qualifying Event, any Participant may use power purchased from another Participant (or another supplier) to meet its Contingency Reserve Obligation. Any Participant that uses purchased power for recovery must report the source Balancing Authority(s) of the purchased power, the time the power was purchased, the start time and ramp rate for the mutually agreed-upon purchased power (or transaction). The WPP Staff will be responsible for determining whether a Participant providing purchased power fulfilled its obligations to deploy Contingency Reserve to enable the NWPP Reserve Sharing Group to comply with BAL-002. The requesting Participant must also arrange for transmission for delivery of the power. If the Balancing Authority from which the power was purchased is not a Participant in the NWPP Reserve Sharing Program, then any failure of the selling Balancing Authority to deliver the purchased power will be deemed, for purposes of the NWPP Reserve Sharing Program, as a failure to deliver of the Participant relying on the purchased power.

d. Aggregate Contingency Reserve Available

The aggregate Contingency Reserve Available for the NWPP Reserve Sharing Group (together with any Contingency Reserve deployed for Qualifying Events) must at all times equal or exceed both the NWPP Reserve Sharing Group's Most Severe Single Contingency and its combined Contingency Reserve Obligation.

e. RSG Committee Responsibilities; Monitoring and Follow-Up

The RSG Committee is responsible for developing guidelines and arranging for periodic reporting of the Contingency Reserve Obligation of the NWPP Reserve Sharing Group and the Contingency Reserve Available within the NWPP Reserve Sharing Group. WPP Staff monitors Participants' compliance with Contingency Reserve Obligations. The RSG Committee is responsible for addressing problems with deficient or poorly performing Participants, for developing remedies and proposed solutions, and for identifying and implementing any follow-up actions.

f. Determination of NWPP Reserve Sharing Group's Most Severe Single

Contingency

Each Participant is responsible for (i) determining, based on appropriate system modeling and applicable NERC definitions and guidelines, the Most Severe Single Contingency for its Balancing Authority Area(s), (ii) reporting its Most Severe Single Contingency determinations to the WPP Staff and making sure they are correctly reflected in Attachment K, and (iii) notifying WPP Staff whenever previously submitted Most Severe Single Contingency determinations need to be updated. The Most Severe Single Contingency for the NWPP Reserve Sharing Group at any given time is set by whichever of the Participants' Most Severe Single Contingencies is greatest at that time. The RSG Committee will review, at each of its meetings (and in any event no less than once a year), the NWPP Reserve Sharing Group's Operating Processes and its Most Severe Single Contingency to ensure the BAA MSSC's in Attachment K and other applicable tables are up to date and comply with applicable NERC and WECC requirements.

g. Participants' Monitoring of Real-Time Most Severe Single Contingencies

Every Participant is responsible for determining and telemetering to the Reserve Sharing Computer System, as provided in Section I.1.g, its Most Severe Single Contingency (and any adjustments upward or downward) based on real-time operating conditions. When determining Most Severe Single Contingencies in real time, each Participant must take into account its real-time generation output and its real-time generation and transmission outages. Real-time adjustments to a Participant's Most Severe Single Contingency should be captured and updated every data scan cycle.

h. All Participants' Contingency Reserve Available Constitutes NWPP Reserve Sharing Program Contingency Reserve Available

The amount of Contingency Reserve carried by the Participants to meet the requirements of NERC, WECC, and the NWPP Reserve Sharing Program is calculated so as to meet the needs of the NWPP Reserve Sharing Group as a whole and the Contingency Reserve Available reported by each Participant is deemed to be Contingency Reserve Available to the NWPP Reserve Sharing Program. Accordingly, if any Participant activates a portion of its Contingency Reserve to respond to a Qualifying Event, this will constitute activation of a portion of NWPP Reserve Sharing Program Contingency Reserve, including for purposes of calculating whether the Qualifying Event constitutes a Reportable Balancing Contingency Event, even if the activation of Contingency Reserve is not for a Reportable Balancing Contingency Event and even if the affected Participant does not

make a Reserve Sharing Request. Any Qualifying Event affecting any Participant constitutes a Qualifying Event for the NWPP Reserve Sharing Group, and therefore, unless at the time of the Qualifying Event the affected Participant is in "non-participating" status, recovery from the Qualifying Event will be determined with respect to the NWPP Reserve Sharing Group as a whole, and not the individual Participant.

i. Participant Obligation to Respond to Reportable Balancing Contingency Events

A Participant that has experienced a Qualifying Event (within its Balancing Authority Area):

- shall recover its ACE within the 15-minute Contingency Event Recovery Period for any loss greater than 50 MW, and
- must, if the Qualifying Event is equal to or greater than the threshold for Reportable Balancing Contingency Events, take all commercially reasonable actions that are necessary, in its good-faith judgment, to enable the NWPP Reserve Sharing Group to recover its Reporting ACE according to the requirements of BAL-002. To fulfill this obligation, the Participant is expected, among other things, to (i) deploy its Contingency Reserve, and (ii) if the Participant meets the conditions specified in Section E.2 and cannot fully recover from the Qualifying Event with reserve capability on its own system (and any purchased reserve rights), make a Reserve Sharing Request.

For Qualifying Events that result from the loss of a jointly owned facility, affected Participants must use the total MW of facility output lost to determine whether the Qualifying Event is equal to or greater than the threshold for Reportable Balancing Contingency Events (rather than whatever portion of the lost output a given Participant may have scheduled or been entitled to).

j. NWPP Reserve Sharing Program Automation and Exceptions.

Every Participant is always in active status with respect to the Reserve Sharing Program. All Participants must continuously and automatically telemeter to the Reserve Sharing Computer System the data specified in Section I.1, (unless unable to do so due to failure of communications capabilities between the Participant and the Reserve Sharing Computer System). Every Participant must also indicate (unless unable to do so) whether its participation is through automatic or manual capabilities. Valid reasons for Participants to indicate manual participation mode include, but are not limited to: failure of inter-control center

communications protocol (ICCP) links, suspension of automatic generation control (AGC), and system testing.

D.4. Additional Operating Reserve: Obligations Under R3 and R4 of WECC BAL-002-WECC-3 and Compliance Documentation

a. Participants Must Carry Required Additional Operating Reserve

Each Participating Balancing Authority must carry, in addition to its Contingency Reserve Obligation calculated in accordance with Attachment A, sufficient Operating Reserve to fulfill the requirements of R3 and R4 of BAL-002-WECC-3.

b. Participants Must Maintain and Provide Documentation to Demonstrate Compliance

Each Participating Balancing Authority must maintain appropriate documentation for any periods during which it has implemented

- any Interchange Transactions (as that term is defined by NERC) (i) with counterparties that are not Participants, (ii) for which it was the sink Balancing Authority, and (iii) that were designated as part of the source Balancing Authority's WECC Operating Reserve - Supplemental; or
- any Operating Reserve transactions (x) with counterparties that are not Participants, and (y) for which it was the source Balancing Authority.

The Participating Balancing Authority's documentation must be sufficient to demonstrate that, during all relevant periods, it maintained additional Operating Reserve as required by R3 and R4 of BAL-002-WECC-3.

Each Participating Balancing Authority must, on at least a quarterly basis, submit summaries to the WPP Staff of transactions subject to R3 and R4 of BAL-002-WECC-3, in the form specified by the WPP Staff (in consultation with the Participating Balancing Authorities). Participating Balancing Authorities that prefer to submit this information to the WPP Staff on a more frequent basis (including through the Reserve Sharing Computer System in real-time) may do so in coordination with the WPP Staff.

In addition, all Participating Balancing Authorities must supply copies of supporting documentation to the NWPP Reserve Sharing Group (or the WPP Staff) promptly upon request.

c. Deployment of Additional Operating Reserve Not Restricted to Qualifying Events

Because the additional Operating Reserve necessary to comply with R3 and R4 of BAL-002-WECC-3 is incremental to Participants' Contingency Reserve Obligations, Participants are not limited in their use of this additional Operating Reserve to Qualifying Events. Participants are entitled to deploy this additional Operating Reserve to respond to interruption of Interchange Transactions (as described in BAL-002-WECC-3 R3) or fulfillment of Operating Reserve transactions (as described in BAL-002-WECC-3 R4) even if these do not constitute Qualifying Events.

E. REQUESTING ASSISTANCE RESERVE

E.1. Qualifying Events

The Qualifying Events that permit Participants to deploy Internal Reserve, and, if the conditions specified in Section E.2 are satisfied, request Assistance Reserve, are specified in Attachment B to this document.

E.2. Action Required Before Requesting Assistance Reserve

If a Participant experiences a Qualifying Event (Attachment B parts A, B, or C), the requesting Participant is entitled to request and schedule Assistance Reserve (up to the amount lost minus their Contingency Reserve Obligation to fully recover from the Qualifying Event) through the NWPP Reserve Sharing Program **only** after the requesting Participant has made commitments to use an amount of Internal Reserve that equals or exceeds the requesting Participant's Contingency Reserve Obligation. A Participant experiencing a Qualifying Event from Attachment B part D is entitled to request Assistance Reserve to meet Firm Demand as necessary after committing to use ALL Internal Reserve. At the time of the Participant's request for Assistance Reserve, the fulfillment of the Participant's obligation to fully commit its Contingency Reserve Obligation will be evaluated taking into account any Internal Reserve lost because of the Qualifying Event (such as the loss of a generator on which reserve was being carried, whether due to conditions affecting the generator itself or due to loss of generator interconnection or transmission facilities necessary for delivery of output from the generator). The amount of Contingency Reserve carried by any unit that is lost due to the Qualifying Event will be considered deployed and added to the used Contingency Reserve reported.

If the requesting Participant improperly reflects their UsedCR less than their $TotCRO_{CA}$, the program will reduce the amount of Assistance Reserves provided (not including any rounding that occurs programmatically) by the amount that UsedCR is less than $TotCRO_{CA}$.

a. Response to an Energy Emergency Alert 3

A Participant may utilize Contingency Reserve to respond to an Energy Emergency Alert 3 (EEA 3), as described in Attachment B, Section D.

If time allows, the Participant will notify the Western Power Pool staff on the 24/7 support line 503.673.6744 of the situation, which will enable the staff to provide any clarification that may be needed.

E.3. Timing of Requests for Assistance Reserve

After experiencing a Qualifying Event as described in Attachment B parts A, B, or C and fulfilling the conditions specified in Section E.2, a Participant that requires Assistance Reserve may submit a Reserve Sharing Request, however, must do so within 60 minutes following the start of the Qualifying Event. Reserve Sharing Requests must be made in whole MWs.

Even though an eligible Participant may make a Reserve Sharing Request at any time within 60 minutes following that start of a Qualifying Event, the NWPP Reserve Sharing Group may, with respect to administering the terms of the Agency Agreement, differentiate between Reserve Sharing Requests submitted promptly—that is, within four minutes following the start of the Qualifying Event—and Reserve Sharing Requests that are delayed beyond four minutes. The "four-minute rule" does not affect Participants' obligations to deliver Assistance Reserve to other Participants that have made Reserve Sharing Requests, which, as stated in Section F, applies to all Reserve Sharing Requests made within 60 minutes following the start of the Qualifying Event.

If (a) a Reserve Sharing Request is made more than four minutes following the start of the Qualifying Event, and (b) the NWPP Reserve Sharing Group's Reporting ACE does not recover from the Qualifying Event within the applicable Contingency Event Recovery Period, then for purposes of any potential compliance consequences associated with the Qualifying Event, the matter will be addressed in accordance with Sections 7.2, 7.3, 8, and 9 of the Agency Agreement.

A Participant that has made a Reserve Sharing Request may rely on Assistance Reserve for a maximum period of 60 minutes from the time of the Qualifying Event.

The Qualifying Event outlined in Attachment B part D, allows for a request to be made at any time during the declared EEA 3 instead of immediately upon declaration of the EEA 3. An Assistance Reserve Request made for an EEA 3 allows the Participant to receive Assistance Reserve for up to 60 minutes from the time of the initial request. Subsequent hours of an EEA 3 are not additional Qualifying Events. If a participant is out of a declared EEA 3 for more than one hour before another EEA 3 is declared that next EEA 3 declaration will be considered a new Qualifying Event.

If another Qualifying Event occurs, it is a separate event, and the Participant may make an additional request for Assistance Reserve.

E.4. Performance Metric

Deployment of Contingency Reserve by a Participant requesting Assistance Reserve will be measured through evaluation of the Participant's Pre-Reporting Contingency Event ACE through the following criteria:

- In the first fifteen-minute period after the disturbance occurs, the Participant's Reporting ACE must be above their Recovery Reporting ACE Target for at least one scan; and
- Within nineteen minutes after the disturbance occurs and after the initial Reporting ACE recovery, the Participant's Reporting ACE must stay at or above their Recovery Reporting ACE Target minus 25% of their individual BAA's L_{10} value (as published by NERC) for at least five clock-minute average periods.
- If the request is not made within the required 4-minute period after the start of the Qualifying Event, the entity will be deemed to have not performed to the requirements of the program.

E.5. Accounting for Energy; Transmission for Delivery

Any Participant that requests Assistance Reserve must complete a NWPP RSG Verification Form and must account for scheduled receipt and delivery of Assistance Reserve energy as "Contingency Reserve." Tagging of Energy with respect to deliveries of Assistance Reserve energy is implemented as described in Section K.1.c. of this document.

The delivery of Assistance Reserve is exempt from any costs or charges associated with transmission wheeling or losses. The Reserve Sharing Computer System builds in sufficient transmission capacity for delivering Assistance Reserve (see Section M). There may be incremental transmission usage between some Reserve Sharing Zones, but this usage is effectively limited in real-time up to the current System Operating Limit (SOL) of the transmission facilities making up the cut planes between Reserve Sharing Zones (subject to certain further limitations with respect to particular cut planes as described the *NWPP RSG Cut Planes and Derivation Limits* document). Participants in the NWPP Reserve Sharing Program recognize the regional benefits associated with the NWPP Reserve Sharing Program and have agreed to waive any rights to financial settlement for any transmission needed to deliver Assistance Reserve to other Participants.

E.6. Restoring Reserves

If a Participant uses any portion of its Contingency Reserve Obligation in response to a Qualifying Event (whether use is limited to Internal Reserve or requires additional Assistance Reserve), the Participant should take appropriate action to restore Contingency Reserve Available on its system (to at least the level of its Contingency Reserve Obligation) as promptly as practicable. A Participant may not take longer than 60 minutes (measured from the start of the Qualifying Event) to restore Contingency Reserve Available on its system to at least the level of its

Contingency Reserve Obligation.

F. OBLIGATION TO PROVIDE ASSISTANCE RESERVE

Each Participant is obligated to deliver Assistance Reserve up to the full amount of its Balancing Authority Area's Contingency Reserve Obligation (after deducting for any capacity that has been deployed to respond to any Qualifying Events) in response to any Reserve Sharing Request that has met the requirements in Section E.2 and is made within 60 minutes following the start of the Qualifying Event.

Deployment of Contingency Reserve by a Participant providing Assistance Reserves will be measured through evaluation of the Participant's Reporting ACE through the following criteria:

- In the first ten-minute period after the request for Assistance Reserve, or any increase thereof, is received, the Participant's Reporting ACE must be above their Recovery Reporting ACE Target for at least one scan; and
- Within fifteen minutes of the request for Assistance Reserves and after the initial Reporting ACE recovery, the Participant's Reporting ACE must stay at or above their Recovery Reporting ACE Target minus 25% of their individual BAA's L_{10} value (as published by NERC) for at least five clock-minute average periods.

If a Participant has deployed all or a portion of its Balancing Authority Area's Contingency Reserve Obligation to respond to a Reserve Sharing Request by another Participant and then, while the deployment is still in effect, experiences its own Qualifying Event, the responding Participant may deploy whatever portion of its Contingency Reserve Obligation is required to recover from its own Qualifying Event. If the conditions necessary to receive Assistance Reserve are satisfied, the Participant may also make a Reserve Sharing Request even if one or more other Participants' Reserve Sharing Requests remain in effect. If the NWPP Reserve Sharing Group experiences sequential Qualifying Events that require one or more responding Participants to deploy Assistance Reserve that was being provided to other Participants, the Reserve Sharing Computer System will recalculate the distribution of Assistance Reserve and allocate to remaining Participants any amount necessary to replace the deployed Assistance Reserve.

G. ELIGIBILITY FOR AND PARTICIPATION IN RESERVE SHARING PROGRAM

G.1. Eligibility to Participate in the NWPP Reserve Sharing Program

All Balancing Authorities that operate Balancing Authority Areas located within the Northwest Power Pool and that elect to become NWPP Agreement Signatories must participate in the NWPP Reserve Sharing Program and must become parties to the Agency Agreement.

G.2. Treatment of Third-Party Generation

Each Participating Balancing Authority must, in calculating its Contingency Reserve Obligation, include all generation that is within its metered boundaries and for which the Participating Balancing Authority has an obligation or has agreed to provide Contingency Reserve. The term "Qualifying Event" with respect to a Participating Balancing Authority applies to any generation (including Third-Party Generation) that has been included in that Participating Balancing Authority's calculation of its Contingency Reserve Obligation.

H. ROLES AND RESPONSIBILITIES

H.1. Participant Responsibilities

Participants are responsible for abiding by the NWPP Reserve Sharing Group rules specified in this document, together with any corresponding policies adopted by the RSG Committee. These include requirements to meet Contingency Reserve Obligations, to provide Assistance Reserve when requested by another Participant, and to settle for deliveries of Assistance Reserve energy as provided in Section K.
Participants must also provide and receive data for the NWPP Reserve Sharing Program in accordance with Section I for general operation of the NWPP Reserve Sharing Program and Section J for making and responding to requests for Assistance Reserve.

a. Notifications

Participants must notify the WPP Staff and the NWPP Reserve Sharing Group Committee whenever a substantive change to the Participant's Balancing Authority Area is planned to occur. This would include, at a minimum, a change in Balancing Authority Area footprint or boundary, transfer of load or generation with another Balancing Authority Area, or any change that could have an impact to the deliverability of contingency reserves or the MSSC within the Participant's zone. This notification should occur prior to any changes being made to allow adequate time for appropriate impact studies to be completed and Program Document or computer program modifications, as needed.

The Participating Balancing Authorities are responsible to provide planned system failover notifications that may have an impact to data being telemetered to the Reserve Sharing Computer System to WPP Staff via an email to nwpprsg@westernpowerpool.org.

b. Program Monitoring

In addition, the Participating Balancing Authorities are responsible to monitor the NWPP Reserve Sharing Group "heartbeat" (as explained in Section I.1.n). If any Participating Balancing Authority discovers the NWPP Reserve Sharing Group heartbeat is inactive for a period of 10 minutes they should contact an adjacent Participating Balancing Authority to confirm this is a system-wide problem and not just a problem with their system or communication link. If the problem is believed to be system-wide that Participating Balancing Authority will contact the WPP Staff.

If a Participating Balancing Authority's heartbeat appears to be inactive at the time it needs to make a Reserve Sharing Request, it should initiate the Reserve Sharing Request as described in Attachment E – *Backup Procedures for NWPP Reserve Sharing Program*.

It is all Participating Balancing Authorities' responsibility to inform all other Participating Balancing Authorities and the WPP Staff if they have discovered a problem. In addition, Participating Balancing Authority System Operators and RSG Committee Representatives can e-mail or call with any questions or issues. WPP Staff will respond as soon as possible.

NWPP Reserve Sharing Group Program Support Contact Information:

- For immediate response the on-call support number at 503.673.6744.
- In addition, for non-urgent issues, you may email "nwpprsg@westernpowerpool.org". WPP Staff will respond to after-hours emails the next business day during normal work hours.

H.2. WPP Staff Monitoring and Reporting Responsibilities

The WPP Staff is responsible for monitoring Participants' compliance with Contingency Reserve Obligations. The RSG Committee is responsible for addressing problems related to Participant deficiencies or poor performance, for developing remedies and presenting proposed solutions, and for identifying and implementing any follow-up actions.

The WPP Staff is responsible for receiving NWPP RSG Verification Forms from Participants that have made Reserve Sharing Requests under the NWPP Reserve Sharing Program. The WPP Staff will perform analysis on each Reportable Balancing Contingency Event that the NWPP Reserve Sharing Group experiences with relationship to Participant's adherence to the Program Rules.

Subject to appropriate confidentiality and use restrictions (as determined by the WPP Staff), the WPP Staff may make available, to a Participant hosting implementation of an ACE Diversity Interchange arrangement, data related to the NWPP Reserve Sharing Program for the purpose of enabling the hosting Participant to harmonize the operation of the NWPP Reserve Sharing Program and the implementation of the ACE Diversity Interchange arrangement.

WPP Staff is responsible for monitoring and assisting in the implementation of the NWPP Reserve Sharing Program. While not staffed 24x7, WPP Staff will provide on-call 24x7 support as may be required. Although Participants are responsible for telemetering data to the Reserve Sharing Computer System as described in Sections I.1, and I.2, if WPP Staff notices missing information, WPP Staff will follow up with the affected Participant(s).

WPP Staff can review the status of each of the individual Participating Balancing Authority's data including heartbeats. If a WPP Staff member discovers a Participating Balancing Authority's heartbeat is inactive, he or she will follow up with the affected Participating Balancing Authority and document any findings by e-mail to all Participating Balancing Authorities.

H.3. RSG Committee Reporting Responsibilities

The RSG Committee is responsible for developing guidelines and arranging for periodic reports on the Contingency Reserve Obligation of the NWPP Reserve Sharing Group and Contingency Reserve Available within the NWPP Reserve Sharing Group as a whole.

I. GENERAL DATA REQUIREMENTS

This section describes data responsibilities for Participants in the NWPP Reserve Sharing Program. Although in general all required data are relayed automatically to the Reserve Sharing Computer System, all Participants must also have the capability to enter data manually if communications between Participating Balancing Authorities and the Reserve Sharing Computer System are interrupted.

I.1. Data Telemetered from Participating Balancing Authorities to the Reserve Sharing Computer System

Each Participant must telemeter the following data to the Reserve Sharing Computer System for each of its Balancing Authority Areas within the Northwest Power Pool:

a. the portion of its Contingency Reserve Available that is WECC Operating Reserve - Spinning ($TotCSR_{CA}$) ready for use as Internal Reserve or Assistance Reserve,

b. total Contingency Reserve Available ($TotAvailCR_{CA}$) ready for use as Internal Reserve or Assistance Reserve,

c. its total Balancing Authority Area Load (LOAD), as used to calculate its Contingency Reserve Obligation (CRO_{CA}) in accordance with Attachment A,

d. its total Balancing Authority Area Generation (GEN), as used to calculate its Contingency Reserve Obligation (CRO_{CA}) in accordance with Attachment A,

e. any portion of its reported Contingency Reserve Available already in use ($UsedCR_{CA}$),

f. its Reporting ACE (ACE_{raw}), as calculated according to the NERC glossary of terms,

g. its Most Severe Single Contingency ($MSSC_{CA}$),

h. Scheduled Net Interchange values (NET_SCHED_INT), as used to calculate an equivalent ACE,

i. Actual Net Interchange values (NET_ACTUAL_INT), as used to calculate an equivalent ACE,

j. its Reserve Sharing Request dynamic schedule ($RSReq_{CA}$),

k. request for Reserve Sharing Status Indication ($RSReq_Confirmd_{CA}$)

No Request = Status Open

Assistance Requested = Status Closed,

l. reserve sharing response (RSResp),

m. indication (manually entered) of availability to provide Assistance Reserve (Participating Balancing Authorities not available to provide Assistance Reserve can still receive Assistance Reserve) (BA_Participate)

Cannot Provide Assistance Reserve = Status Open

Can Provide Assistance Reserve = Status Closed,

n. status of the communications links that enable it to participate in the NWPP Reserve Sharing Program on an automated basis, also known as its “heartbeat” (signaled by continuing changes to indicator data not to exceed 999,999, which the Reserve Sharing Computer System monitors at 10-second intervals; if there is no change to the data for a period of 60 seconds, the Participating Balancing Authority is presumed to be able to participate in the NWPP Reserve Sharing Program only through manual action; when the indicator data begin to change again, the Participating Balancing Authority is presumed to have regained the ability to participate in the NWPP Reserve Sharing Program through automated action) (BA_heart_beat), and

o. its frequency bias setting. (BA_FBS)

p. its meter error term (BA_Ime)

q. its ATEC term (BA_ATEC)

r. its ADI term if not included in Scheduled Net Interchange or Actual Net Interchange values above (BA_ADI)

I.2. Cut Planes

Explanatory note: As used in this Section I.2, the term "cut plane" is intended generally to describe an imaginary line separating two areas within a transmission system (or two different transmission systems) to enable the evaluation of flow of electrical energy on multiple lines connecting these two areas (or systems). The cut planes referred to below are sets of multiple lines connecting Reserve Sharing Zones.

Participants that are operators of the major transfer facilities must telemeter to the Reserve Sharing Computer System actual flow ($ACTUAL_{PATHnn}$) and transfer limit ($LIMIT_{PATHnn}$) for each direction of flow for the cut planes, as identified in Attachment L, between Reserve Sharing Zones as described in the next Section I.3.e.

The RSG Committee maintains a separate document, *NWPP RSG Cut Planes and Derivation Limits*, that more fully details the major transfer facilities and any associated Participant derivation information, including applicable calculations for which the Participant that monitors that cut plane, address the evaluation of flow of electrical energy on multiple lines.

I.3 Functions of the Reserve Sharing Computer System

Except when communications links or the necessary computer capabilities are down, the Reserve Sharing Computer System performs the tasks listed below. WPP Staff is able to monitor the Reserve Sharing Computer System and receive all Participants' data described in Sections I.1 and I.2. If WPP Staff notices that there is missing information, WPP Staff will consult directly with any Participating Balancing Authorities for which information is missing to make any necessary corrections.

a. Determine the Most Severe Single Contingency for the NWPP as a whole ($MSSC_{NWPP}$).

b. Determine the aggregate Contingency Reserve Obligation for the NWPP as a whole ($TotCRO_{NWPP}$) to ensure that the Contingency Reserve Available within the NWPP Reserve Sharing Group is sufficient to cover the Contingency Reserve Obligation for the NWPP as a whole.

c. Determine the Contingency Reserve Obligation ($TotCRO_{CA}$) for each Participant's Balancing Authority Area(s), calculated in accordance with Attachment A.

d. Compute a pro rata allocation of any applicable adjustments to Contingency Reserve Obligations ($AdjCRO_MSSC_{CA}$ and $AdjCRO_ZONE_MSSC_{CA}$, which together are summed into $AdjCRO_{CA}$) for each Participant's Balancing Authority Area(s) to address shortages with respect to the MSSC for the NWPP Reserve Sharing Group or within a particular Reserve Sharing Zone.

e. In calculating any potential need to carry additional Contingency Reserve within a Reserve Sharing Zone, take into account transfer limits ($LIMIT_{Pathnn}$), actual flows ($ACTUAL_{Pathnn}$), and, where applicable, scheduled flows ($SCHED_{Pathnn}$) on

the transmission facilities connecting that Reserve Sharing Zone to its adjacent Reserve Sharing Zone(s). With respect to the facilities linking the Pacific Northwest-Montana Reserve Sharing Zone with the Northern California Reserve Sharing Zone, this also reflects limits on ownership rights.

f. Maintain a pro rata allocation of the Reserve Sharing delivery dynamic schedule based upon each $TotCRO_{CA}$ for each Participant's Balancing Authority Area(s) relative to the $TotCRO_{NWPP}$.

g. Upon receipt of a Reserve Sharing Request dynamic schedule from a Participating Balancing Authority that is requesting Assistance Reserve, validate and activate the pro rata sharing signal to all other Participating Balancing Authorities.

h. Whenever Assistance Reserve is being delivered across facilities connecting two different Reserve Sharing Zones, continue to monitor actual flows ($ACTUAL_{Pathnn}$) in comparison to transfer limits ($LIMIT_{Pathnn}$) between the Reserve Sharing Zones, and, to the extent actual flows fall below transfer limits, allow deliveries to increase if needed to fully respond to the Reserve Sharing Request.

i. Maintain hourly integrated Reserve Sharing Request dynamic schedules from each Participating Balancing Authority.

j. Calculate a NWPP Reserve Sharing Group ACE (TOTACE_POOL) for entire NWPP Reserve Sharing Group.

k. Calculate a NWPP Reserve Sharing Group Reporting ACE for each Requesting Zone and Level 1 (or Level 2 for NCAL) Participants (ZONEACE_XXX – See Attachment C).

Each Participating Balancing Authority should consistently review the Contingency Reserve Obligation (CRO_{CA}) value transmitted to it by the Reserve Sharing Computer System to confirm the accuracy of the calculation and should promptly contact WPP Staff if it suspects there may be an error in the Reserve Sharing Computer System's calculation.

I.4. Data Telemetered from the Reserve Sharing Computer System to Participating Balancing Authorities

The Reserve Sharing Computer System makes available to each Participant the following telemetered data:

a. The Reserve Sharing Computer System's calculation of total Contingency Reserve Obligation ($TotCRO_{CA}$) for the Participant's Balancing Authority Area(s), as described in Attachment A. This includes, as applicable,

- calculation of base Contingency Reserve Obligation based on three percent of load and three percent of generation (CRO_{CA}),

- any adjustment to address shortages with respect to the MSSC for the NWPP Reserve Sharing Group (AdjCRO_MSSC$_{CA}$),
- any adjustment to address shortages within a particular Reserve Sharing Zone (AdjCRO_ZONE_MSSC$_{CA}$), and
- combined adjustments to Contingency Reserve Obligation (AdjCRO$_{CA}$) to address shortages with respect to the MSSC for the NWPP Reserve Sharing Group or within a particular Reserve Sharing Zone.
- total Contingency Reserve Obligation (TotCRO$_{CA}$) as adjusted to address shortages with respect to the MSSC for the NWPP Reserve Sharing Group or within a particular Reserve Sharing Zone.

b. If the total Contingency Reserve Available within the NWPP Reserve Sharing Group (TotAvailCR$_{NWPP}$) is less than to total Contingency Reserve Obligation for the NWPP Reserve Sharing Group (TotCRO$_{NWPP}$), the NWPP Reserve Sharing Computer System calculates and telemeters necessary adjustments to total Contingency Reserve Obligation (TotCRO$_{CA}$) for each Participant's Balancing Authority Area(s) to reflect the shortfall in total Contingency Reserve Available within the NWPP Reserve Sharing Group (AdjCRO_SHORT$_{CA}$). Each Participant must carry this adjustment amount in addition to its TotCRO$_{CA}$.

c. If a Participant is in the penalty level 4 status, a flag (TBD) will be set by WPP Staff to communicate to the program and to the Participant that they are required to carry additional Contingency Reserves.

d. Reserve Sharing Delivery dynamic schedule (RSDel) for Participating Balancing Authority that is delivering Assistance Reserve:[1]

RSDel$_{CA(Level\ 1)}$ = RSReq$_{CA}$ * (TotCRO$_{CA}$ / S TotCRO$_{CA(Level\ 1)}$), limited to the portion of its Contingency Reserve Obligation (TotCRO$_{CA}$), if any, the Participating Balancing Authority is able to deliver at that time (after accounting for any portion of its TotCRO$_{CA}$ previously deployed)

Where,

RSReq$_{CA}$ £ MW$_{LOSS}$ - TotCRO$_{CA}$

- If S RSDel$_{CA(Level\ 1)}$ < RSReq$_{CA}$, then

[1] (All "$_{CA}$" designations in these formulas refer to the particular Participating Balancing Authority to which a given value applies. References to "Levels" are to the Levels related to the Reserve Sharing Zones, as identified in Attachment C.)

$RSReq_{Short} = RSReq_{CA} - S\ RSDel_{CA(Level\ 1)}$

and,

$RSDel_{CA(Level\ 2)} = RSReq_{Short} * (TotCRO_{CA} / S\ TotCRO_{CA(Level\ 2)})$.

- If the amount of Assistance Reserve that can be delivered from the Participating Balancing Authorities at Level 2 is insufficient to meet whatever portion of the Reserve Sharing Request remains after deliveries from Participating Balancing Authorities at Level 1, the process is repeated as described above for Level 3, and, if applicable, Level 4 and Level 5.
- If there are multiple requests for Assistance Reserve, the $RSDel_{CA}$ would be calculated to reflect the sum of all amounts to be delivered as Assistance Reserve to requesting Participants, but the Reserve Sharing Computer System separately tracks the amounts to be delivered to each of the requesting Balancing Authorities (so that payment and return energy obligations can be properly determined).
- Requests for Assistance Reserve are not allowed to exceed the Contingency Reserve Available for the NWPP Reserve Sharing Group as a whole.
- Transmission constraints are included the Reserve Sharing Computer System's calculation of how much Assistance Reserve can be delivered from each Level for each Reserve Sharing Zone, and so do not need to be separately computed and applied.

e. Delivery of Reserve Sharing Confirmation Flag ($RSDel_Confirmd_{CA}$),

No Request = Status Open

Assistance Requested = Status Closed

f. Reserve Sharing time remaining for the requesting Balancing Authority from the most recent request for Assistance Reserve (TimeLeft)

g. Number of active Reserve Sharing Requests (RSAct)

h. The MSSC for the NWPP Reserve Sharing Group as a whole ($MSSC_{NWPP}$)

i. The Contingency Reserve Obligation for the NWPP Reserve Sharing Group as a whole ($TotCRO_{NWPP}$)

j. The Contingency Reserve Available for the NWPP Reserve Sharing Group as a whole ($TotAvailCR_{NWPP}$)

k. NWPP Reserve Sharing Group Reporting ACE (ACE_{NWPP})

l. Reportable Balancing Contingency Event (RpDist)

Where,

RpDist = the lesser of (a) 0.8 * $MSSC_{NWPP}$ or 500 MW

m. Total number of minutes remaining since the most recent request for the NWPP (RSTimRem)

n. The indication that the Reserve Sharing Computer System and associated communication links are operational is also known as the NWPP Reserve Sharing Group "heartbeat."

o. When activity on the Reserve Sharing Computer System is due to testing rather than power system conditions, this is indicated by a testing flag. WPP Staff will arrange for this flag to be set while testing is underway, which may include helping a Participating Balancing Authority test its system(s). (The NWPP Reserve Sharing Program is fully operational while testing is in progress and Reserve Sharing Requests may be made normally. If there is a Reserve Sharing Request during testing, the test will be terminated.)

p. The Reserve Sharing Computer System's calculation for each Reserve Sharing Zone as reflected in Attachment C,

- The MSSC ($MSSC_{zone}$)
- The total Contingency Reserve within the zone ($TOTCR_{zone}$),
- Calculation of the zonal Contingency Reserve Obligation based on the zonal Participant(s) three percent of load and three percent of generation ($TOTCRO_{zone}$),
- The total Contingency Reserve Available to the zone ($TOTCRA_{zone}$),

q. The Reserve Sharing Computer System's information or calculation for each cut plane between Reserve Sharing Zones as reflected in in Section I.2.

- The actual flow ($ACTUAL_{PATHnn}$) and transfer limit ($LIMIT_{PATHnn}$) for each direction of flow
- The actual room ($ROOM_{PATHnn}$) and reserve ($RESERVE_{PATHnn}$) for each direction of flow

I.5. Informational Data Telemetered from the Reserve Sharing Computer System to the Reliability Coordinators

The Reserve Sharing Computer System telemeters to the Reliability Coordinators the following informational data:

a. The MSSC for the NWPP Reserve Sharing Group as a whole ($MSSC_{NWPP}$),

b. The Reserve Sharing Group Reporting ACE (ACE_{NWPP}),

c. The Contingency Reserve Obligation for the NWPP Reserve Sharing Group as a whole ($TotCRO_{NWPP}$), and

d. The Contingency Reserve Available for the NWPP Reserve Sharing Group as a whole ($TotAvailCR_{NWPP}$).

e. Data for each of the Reserve Sharing Zones as follows:
- The MSSC for the Reserve Sharing Zone,
- The Contingency Reserve Obligation for the Reserve Sharing Zone, and
- The Contingency Reserve Available for the Reserve Sharing Zone.

Attachment N is a correlation table of Participants, Reliability Coordinators, and Reserve Sharing Zones.

J. DATA REQUIREMENTS RELATED TO RESERVE SHARING REQUESTS

The general data requirements for Participants in the NWPP Reserve Sharing Program are described in Section I. The provisions below explain the steps for making and responding to Reserve Sharing Requests.

J.1. Requesting Participant

a. A Participant that has met the conditions to make a Reserve Sharing Request (as described in Section E.2) must calculate the amount of Assistance Reserve for which it is eligible, enter the deficient amount needed into a Reserve Sharing Request dynamic schedule, and send the request, at a zero-ramp span time, to the Reserve Sharing Computer System.

Where,

$RSReq_{CA}$ £ MW_{LOSS} – $TotCRO_{CA}$

RqstRSSI = 1.

At this point in time, the Participant's anticipated CR_{CA} should be zero if their CR_{CA} was equal to $TotCRO_{CA}$. If CR_{CA} was higher than $TotCRO_{CA}$, CR_{CA} should decrease by the amount shown as $UsedCR_{CA}$.

$TotCRO_{CA} – UsedCR_{CA} \leq 0$

c. Requesting Participants are expected to restore the Contingency Reserve Available on their systems, to at least the level of their Contingency Reserve Obligations, as promptly as practicable, but in no event longer than 60 minutes from the start of the Qualifying Event.

d. As a safeguard, the Reserve Sharing Computer System will remove the Reserve Sharing Request dynamic schedule within 65 minutes following the Reserve Sharing Request.

   $RSReq_{CA}$ = 0, ten-minute ramp to zero beginning at 55 minutes after the request first started.

   RqstRSSI = 0

e. If during the request the Requesting Participant detects a Reserve Sharing Computer System failure, it should assume that the Responding Participants will continue to deliver reserves for the full 65 minutes as called for in J.1.d.

f. If a Participant makes a Reserve Sharing Request for an initial Qualifying Event and, before the end of the 60 minutes during which the Participant is allowed to rely on Assistance Reserve (as provided in Section E.3 of this document), experiences one or more additional Qualifying Events for which it wishes to request Assistance Reserve, the Participant may initiate additional Reserve Sharing Requests by (1) activating the additional Reserve Sharing Request toggle on the Reserve Sharing Computer System (which indicates that the requesting Participant has two or more active Reserve Sharing Requests), then (2) revising the deficient amount needed, as calculated in accordance with Section J.1.a above, to include the additional amount of Assistance Reserve required for the additional Qualifying Event(s). The activation of any additional Reserve Sharing Request will re-set the overall event timer to 65 minutes (the permitted 60-minute reliance period plus an additional five minutes to complete ramping). While the Reserve Sharing Computer System continues to run separate event timers for each Qualifying Event, Participants are able to see only the time remaining for a Participant's last-initiated Reserve Sharing Request, and not for any of its previously initiated Reserve Sharing Requests.

J.2. Responding Participants

a. Responding Participants should initiate a response to a Reserve Sharing Delivery dynamic schedule from the Reserve Sharing Computer System by including $RSDel_{CA}$ in their ACE equation shown below. A security check on the Reserve Sharing Request dynamic schedule includes a crosscheck such that Reserve Sharing Status Indication = 1. The sign of the $RSDel_{CA}$ is negative for Participating Balancing Authorities requesting Assistance Reserve. The sign of the $RSDel_{CA}$ is positive for Participating Balancing Authorities providing Assistance Reserve.

   Where,

   $ACE_{CA} = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME} + I_{ATEC}$

   NI_S = S(adjacent Balancing Authority schedules) + S(dynamic schedules) + $RSDel_{CA}$

Each responding Participant will maintain an internal timer equal to $TotTmRem_{NWPP}$ and continue to count down this timer to zero if the value from the Reserve Sharing Computer System fails to decrement (indicating probable loss of data link). Whenever a responding Participant is operating in an assumed disconnected mode, $RSDel_{CA}$ is internally frozen. When the internal count-down timer reaches zero, the responding Participant should set $RSDel_{CA}$ to zero.

K. SETTLEMENT

A Participant that receives Assistance Reserve energy must compensate all Participants that deliver Assistance Reserve energy financially.

Participants may mutually agree to an alternate procedure, provided the affected Participants can account for the transaction appropriately.

This section explains how the data used for settlement is developed and the process through which Participants complete financial settlement. Attachment D includes a settlement process chart as reference of this process.

K.1. Settlement Data

Each hour, whether or not there has been a Reserve Sharing Request, the Reserve Sharing Computer System will transmit the hour-ending integrated dynamic schedule quantities (MWh) to all Participating Balancing Authorities. These data will be referred to as "Settlement Data" and will include source/sink energy information without consideration of transmission "wheeling" through intervening systems. Settlement Data are rounded and used to develop adjacent Balancing Authority interchange schedules. Settlement Data will be used to construct the official reserve sharing energy matrix (the "Matrix").

a. Rounding

Settlement Data are rounded to whole integers to accommodate scheduling and accounting systems:

- All Settlement Data quantities less than 1 MWh will be rounded to 0 MWh (e.g., 0.7 yields 0 MWh). This practice will reduce nuisance scheduling of small quantities.

- For quantities equal to or greater than 1 MWh, conventional rounding practices will apply. Fractional quantities less than 0.5 will be rounded down (*e.g.*, 27.2 yields 27 MWh) and fractional quantities of 0.5 or greater will be rounded up (*e.g.*, 27.9 yields 28 MWh). After rounding, Settlement Data are compiled into the matrix.

b. Mapping of Energy Schedules

Energy schedules must be mapped to adjacent Balancing Authorities to allow proper energy accounting consistent with existing reliability standards and regional business practices. The Participants have agreed to a pre-defined set of tag templates to account for the transmission mapping for the deliveries of Assistance Reserve Energy. This mapping includes wheeling parties between nonadjacent Balancing Authorities, and as further explained in Section K.1.c below, serves as the basis to create after-the-fact tags.

c. Automatic Tagging and Tag Templates

The Participants' tag templates reflect the transmission mapping for the delivery of Assistance Reserve energy between Participating Balancing Authorities. The Northwest Power Pool Corporation has a contract with Open Access Technology International, Inc. (OATI) to produce after-the-fact energy schedule tags for all deliveries of Assistance Reserve energy. These tags are provided to the Participants and the WECC Western Interchange Tool (WIT).

The WPP Staff is responsible for assisting with the maintenance of these tag templates used by OATI, and keeping them up-to-date in accordance with requests made by Participating Balancing Authorities. Attachment F describes the NWPP Reserve Sharing Group's procedures for revising the transmission mapping as reflected in the tag templates.

The Participants' tag templates are not publicly available and are only accessible to the RSG Representatives, their designated RSG Alternate Representatives and tagging personnel. The designated representatives may access and download the most current version of *NWPP RSG Tagging Templates.xls* on the Western Power Pool website (www.westernpowerpool.org) in the Reserve Sharing Group's Documents.

K.2. Financial Settlement

The NWPP Reserve Sharing Group utilizes the Intercontinental Exchange (ICE) day-ahead peak and off-peak index prices at the Mid-Columbia (Mid-C) and Palo Verde (PV) trading hubs, for the calculation of the settlement price as noted in subsection (a.) below.

A Participant will be financially reimbursed for providing Assistance Reserve energy.

For purposes of the NWPP Reserve Sharing Program, the "Settlement Price" for peak hours will be the average of the ICE day-ahead peak index prices for the Mid-C and PV trading hubs. The "Settlement Price" for off-peak hours will be the average of the ICE day-ahead off-peak index prices for the Mid-C and PV trading hubs, *provided, however*, that (a) if ICE does not publish a Day-Ahead Price for a relevant operating day or Request Hour, then the Settlement Price shall be the average of the other Day-Head Price for the Request Hour and (b) in no event will the Settlement

Price ($/MWh) be less than zero or greater than the WECC Soft Price Cap in accordance with regulations and orders of the Federal Energy Regulatory Commission (FERC).

Examples of settlement for 10 MWh of dispatched energy:

Example 1:
Index prices: Mid-C $50, PV $75
Calculation: ($50+$75)/2 = $62.50 settlement price x 10MWh = $625

Example 2:
Index prices: Mid-C $50, PV-No Trade.
Calculation: $50+ (excluded) = $50 settlement price x 10MWh = $500

Example 3:
Index prices: Mid-C $-20 (below price cap), PV $5,
Calculation: ($0 + $5)/2 = $2.50 Settlement Price x 10MWh = $25

Example 4:
Index prices: Mid-C $1035 (above WECC Soft Energy Price Cap), PV $750,
Calculation: ($1,000 + $750)/2 = $875*10MWh = $8,750

With respect to FERC-jurisdictional entities, the Settlement Price will be set forth in the Participant's individual tariff on file with and approved by FERC. In the event that the Settlement Price set forth in a. above is amended, such amended Settlement Price will not be effective until all FERC-jurisdictional entities have approved amended tariffs.

During the RSG Committee's third quarter meeting the RSG Committee (or a work group or task force appointed by the RSG Committee) will review the definition of "Settlement Price," to ensure the selected trading hubs and applicable day-ahead peak and off-peak index price continue to represent a fair value of energy within the NWPP Reserve Sharing Group footprint. The RSG Committee may elect to either maintain the current definition of "Settlement Price" or propose a modified definition to be considered for approval at the next meeting of the RSG Committee. The effective date of any modification to the definition of "Settlement Price" will be coordinated to allow Participants with applicable tariffs filed with FERC to make any necessary filings with FERC.

Unless the affected Participants have agreed otherwise, financial settlements will occur under the responding Participant's normal monthly billing cycle.

WPP Staff will be responsible for determining and posting Settlement Prices, calculated as described in subsection (a) above of this Section K.3, in accordance with the following procedures:

a. WPP Staff will use the day-ahead peak and off-peak prices posted by ICE at the end of each trading day to programmatically calculate and post the Settlement Price for all hours of the days for which prices were published (operating days).

b. In the first three (U.S.) business days following the first (U.S.) business day of each month (referred to in these procedures as the "lock down date"), WPP Staff may confer with designated Participants for assistance in validating the applicable prices posted by ICE for the preceding month and the computation of the Settlement Prices as necessary.

c. By the end of the third (U.S.) business day following the lock-down date, WPP Staff will post finalized Settlement Prices for all hours of the preceding month, computed as described in this subsection (e).

d. If, as of the lock-down date, information needed to compute one or more Settlement Prices has not yet been posted by ICE, WPP Staff will compute and post Settlement Prices for those applicable dates and hours within three (U.S.) business days following the date on which the necessary information is first posted by ICE.

e. Settlement Prices that have been posted by WPP Staff in accordance with the procedures set forth above will not be subject to further adjustment, except by agreement of all affected Participants.

L. INTERNAL NWPP RESERVE SHARING GROUP REPORTING

L.1 Obligation to Submit a NWPP RSG Verification Form

A Participant must, within two (U.S.) business days following the triggering event, prepare and submit to the WPP Staff a completed NWPP RSG Verification Form whenever any one of four conditions described below occurs:

a. The Participant makes a Reserve Sharing Request under the NWPP Reserve Sharing Program (including use of backup procedures specified in Section N if the automated process fails).

b. The Participant or the NWPP Reserve Sharing Group has experienced a Qualifying Event that is a Reportable Balancing Contingency Event (equal to or greater than the lesser of (i) 500 MW, or (ii) 80% of the Most Severe Single Contingency) for the NWPP Reserve Sharing Group at the time of the Qualifying Event.

c. The WPP Staff contacts the Participant requesting a NWPP RSG Verification Form because the Participant has ownership or contractual rights in a jointly owned facility and the WPP Staff is following up with the Participant as described in Section L.2.

d. The Participant has experienced a Reliability Coordinator declared Energy Emergency Alert (as described in NERC Standard EOP-011 or successor standard).

NWPP RSG Verification Forms are available on the WPP Website. The Participants will transmit completed forms via e-mail to nwpprsg@westernpowerpool.org. The Western Power Pool Corporation, in its capacity as agent for the NWPP Reserve Sharing Group, may request additional data and information as may be required and is responsible for submitting periodic reports to the WECC and NERC in accordance with their requirements.

L.2 Reporting Balancing Authority Obligation to Notify WPP Staff

A Participant that is the Reporting/Operating Balancing Authority (as specified in Attachment K) for a jointly owned facility must, as soon as feasible, but in any case within two (U.S.) business days following the triggering event, provide written notice to the WPP Staff (which may be by electronic mail) whenever the jointly owned facility for which it is the Reporting/Operating Balancing Authority has experienced a Qualifying Event that is a Reportable Balancing Contingency Event (equal to or greater than the lesser of (a) 500 MW, or (b) 80% of the Most Severe Single Contingency) for the NWPP Reserve Sharing Group at the time of the Qualifying Event.

The WPP Staff will promptly follow up with all other Participants that have ownership or contractual rights in the jointly owned facility to request that those Participants submit completed NWPP RSG Verification Forms.

M. RESERVE SHARING ZONES

The NWPP Reserve Sharing Program takes into account the effect constrained transmission facilities can have on the ability of Participants to deliver Assistance Reserve energy to one another. When a Participating Balancing Authority (or a group of Participating Balancing Authorities) is separated from remaining Participants by constrained transmission facilities, the effect of the constraint is reflected in the establishment of Reserve Sharing Zones. Attachment C to this document identifies the Reserve Sharing Zones for the NWPP Reserve Sharing Program, together with the sequence (levels) through which Assistance Reserve is deployed for each Reserve Sharing Zone.

The Long-Term Zonal MSSC Limits account for limitations, as determined by the Participant Balancing Authority(ies) of each zone as identified in Attachment K.1.

Proposed system changes that will result in an increase to a Long-Term Zonal MSSC as identified in Attachment K, must be approved by the Balancing Authorities of the impacted zone within 120 days of system change being identified.

In addition, any proposed change to the NWPP Reserve Sharing Group Long-Term MSSC Limit as identified in Attachment K, must be approved by the NWPP Reserve Sharing Group Committee.

N. BACKUP PROCEDURES

Reserve Sharing Requests and delivery of Assistance Reserve energy are normally implemented through the Reserve Sharing Computer System. When a Participant cannot access the Reserve Sharing Computer System (or the system is inoperable), the Participant should use the manual backup procedures as reflected in Attachment D's respective process chart and described in Attachment E and to make any Reserve Sharing Requests. In these circumstances, a responding Participant is obligated to provide Assistance Reserve only up to the amount of its available transmission capacity or its Contingency Reserve Obligation, whichever is smaller. The settlement process for delivery of Assistance Reserve energy using the backup procedure is the same as for the automated reserve sharing process, except that requesting and responding Participants must agree (on a case-by-case basis) to any reserve sharing transactions instead of obtaining the information from the Reserve Sharing Computer System. This process must be in accordance with Attachment G for production of after-the-fact tags and in accordance with existing reliability standards and regional business practices.

O. PROCEDURES FOR ADDRESSING ISSUES AFFECTING RESERVE SHARING PROGRAM WHEN AGENCY AGREEMENT PROCESS IS INSUFFICIENT

To facilitate reporting and compliance activities related to NERC or WECC reliability standards that may affect the NWPP Reserve Sharing Program, the Participating Balancing Authorities have entered into the Agency Agreement. All Participating Balancing Authorities, as well as the Northwest Power Pool Corporation, are parties to the Agency Agreement. The Agency Agreement contains provisions that enable Participating Balancing Authorities to call meetings on specified prior notice and make decisions about matters concerning the Agency Agreement or the NWPP Reserve Sharing Program. Any meeting or vote under the Agency Agreement requires at least 10 days' prior notice.

If an urgent matter related to NWPP Reserve Sharing Program arises, and the WPP Staff determines in good faith that either (1) there is insufficient time to address the matter through the procedures in the Agency Agreement or (2) the matter is outside the scope of the Agency Agreement, the WPP Staff will:

- make commercially reasonable efforts to promptly deliver electronic notice of the matter to each designated contact for notice under the Agency Agreement;
- convene a meeting by telephone conference (with the option of in-person attendance at the offices of the Northwest Power Pool Corporation if feasible) of all available Participating Balancing Authorities, giving as much advance notice and facilitating attendance of as many Participating Balancing Authorities as feasible in view of any need for prompt action;

- seek input from the Participating Balancing Authorities as to what action should be taken, and, if appropriate in the judgment of the WPP Staff or requested by any Participating Balancing Authority, take a vote of the Participating Balancing Authorities (on the basis that a vote of not less than two-thirds of the Participating Balancing Authorities present at the time the vote is taken will be necessary to approve an action or decision); and
- make commercially reasonable efforts to take follow-up action consistent with the input received or results of any vote taken in accordance with this Section O.

No vote of the Participating Balancing Authorities conducted in accordance with this Section O may have the effect of (a) amending this NWPP Reserve Sharing Program documentation, (b) amending the Agency Agreement, (c) authorizing settlement of any NERC or WECC compliance-related matter that will or could cause any party to incur violation(s), monetary penalties or other legal liability (unless the party or parties incurring violation(s), monetary penalties or legal liability have given their prior written consent); or (d) restricting the ability of any party to independently exercise whatever legal or procedural rights it may have to challenge action taken by or petition an Enforcement Authority (as that term is defined in the Agency Agreement) in connection with any NERC or WECC compliance-related matter.

P. PENALTIES FOR NON-PERFORMANCE (Effective July 1, 2024)

P.1 Grading

Events will be assessed shortly after they occur to provide feedback to the involved BAAs. Official grading for events will occur once that entity reaches the evaluation threshold. An entity may fail per the defined performance metrics and receive a score greater than 0%.

The evaluation threshold is any calendar quarter that the BAA participated in ten or more events. If an entity participates in fewer than ten events in any calendar quarter, that quarter will be considered a null quarter, and the events roll over to the next calendar quarter. Once ten events are accumulated, those events and any others during that quarter, will be evaluated and scored.

Each Assistance Reserve request and response will be evaluated and scored as follows:

For a Participant requesting Assistance Reserve:

- 50% for initial ACE Recovery in the first fifteen-minute period after the disturbance, plus
- 10% for each clock-minute average period sustained above Recovery Reporting ACE Target minus 25% of their individual BAA's L10 value (as published by NERC) in the first nineteen clock-minutes after the disturbance with a maximum of 50% for five or more sustained clock-minutes.
- With a total maximum score of 100%

If the request is not made within the required 4-minute period after the start of the Qualifying Event, the score will then be reduced by 10% for each minute (or portion thereof) beyond the 4-minute period the request is delayed. The minimum score a BAA may have is 0%.

For a Participant providing Assistance Reserve:

- 50% for initial ACE recovery in the first ten-minute period after the request for Assistance Reserve, plus
- 10% for each clock-minute average period sustained above Recovery Reporting ACE Target minus 25% of the individual BAA's L_{10} value (as published by NERC) in the first fifteen clock-minutes after the request for Assistance Reserve with a maximum of 50% for five or more sustained clock-minutes.
- With a total maximum score of 100%

All events for the quarter will be individually scored and averaged together and rounded to the nearest 0.1%, to provide a total score for the quarter. If a BAA receives a score of less than 95%, they will be determined to have failed the quarter. These scores will be reported to the RSG Committee at each meeting. If the BAA does not have any events for a quarter, that quarter will be considered a null quarter and not count as a "Pass" or a "Fail".

P.2 Edge Case Events Review and Final Determination

All RSG events will be reviewed by WPP Staff. Events that are found to have characteristics making them more difficult to respond to (ex. requests where the value is changing during the analysis period or coming in and out) will be flagged for further review. Any of these events where it is later determined that there is no impact to any member's quarterly grade (Pass/Fail) will be removed from the overall calculation. Any events with an impact will be brought to the Reserve Sharing Group Committee for final determination.

If a BAA believes that an event should be removed from consideration, they may present their case to the RSG Committee during a committee meeting. The committee will then make a determination and the quarterly score will be recalculated as necessary.

P.3 Penalties

Penalties will be assessed based on how many quarters a BAA has failed. All BAA's begin at Level 0 and increase one level from their current level with a failed quarter (ex. Q1). Penalties will be analyzed in the following quarter (ex. Q2) and any level changes implemented at 0600 pacific prevailing time the first NERC scheduling day of the quarter after that (ex. Q3). For example: Q1 will be analyzed in Q2 and any level changes implemented in Q3. Decreasing levels and null quarters are addressed in section P.4.

The penalty levels are:

Level 1:

- An official letter to the Participant RSG Representative(s) notifying them of the failed quarter
- The Participant RSG Representative(s) will present a Corrective Action Plan with milestones and completion dates to the RSG Committee
- The Participant RSG Representative(s) will designate a Company Executive to be notified if Level 2 is reached

Level 2:

- An official letter to the designated Company Executive notifying them of the failed quarter
- The Participant RSG Representative(s) will present a Corrective Action Plan with milestones and completion dates to the RSG Committee

Level 3:

- An official letter to the designated Company Executive notifying them of the failure and that their BAA will be required to carry additional Contingency Reserves with an additional failed quarter
- The Participant RSG Representative(s) will present a Corrective Action Plan with milestones and completion dates to the RSG Committee

Level 4:

- An official letter to the designated Company Executive notifying them of the failure and that their BAA is now required to carry additional Contingency Reserves
- The BAA will be required to carry additional reserves and be limited on the events that qualify for requesting Assistance Reserves the for one Quarter.
    - The BAA will be obligated to carry the lesser of their MSSC or 150% of their regularly calculated CRO
    - The BAA will be allowed to call on Assistance Reserve only if they experience a loss greater than their increased obligation
    - During this quarter, the BAA must still respond to requests for Assistance Reserves
    - The BAA must update their EMS or other impacted IT/OT applications to reflect these changes
    - Meet all financial obligations associated with RSG membership

- The Participant RSG Representative(s) will present a Corrective Action Plan with milestones and completion dates to the RSG Committee
- While in this level, an additional failed quarter will result in that BAA(s) triggering a vote to be removed from NWPP Reserve Sharing Group by the membership.

Level 0:

- An official letter to the Participant RSG Representative(s) notifying them of the return to Level 0 Operations
- Normal Operations – no restrictions

P.4 Reset

Each quarter a BAA passes will reduce the penalty level under which they are operating. A "null quarter" will keep the BAA at the level they were at for the previous quarter unless the BAA was at Level 4 in which case the BAA would go to Level 3 until they have passed two consecutive quarters excluding null quarters.

ATTACHMENTS

Attachment A – Calculation of Contingency Reserve Obligations; Requirements Related to WECC Operating Reserve - Supplemental

Attachment B – Qualifying Events

Attachment C – Reserve Sharing Zones and Levels

Attachment D – NWPP Process Charts

Attachment E – Backup Procedures for NWPP Reserve Sharing Program

Attachment F – Reserve Tagging Change Process

Attachment G – Backup Process for After-the-Fact Reserve Sharing Tags

Attachment H – Balancing Authority Areas of Participating Balancing Authorities

Attachment I – *Reserved for Future Use*

Attachment J – *Reserved for Future Use*

Attachment K – MSSC and Long-Term Zonal MSSC Limit, Jointly Owned Dynamic Generation Resources, and Multi Use Transformer(s) Tables

Attachment L – Cut Planes and Cut Plane Monitors Between Reserve Sharing Zones

Attachment M – Overview of BPA Remedial Action Schemes That Suspend Automatic Generation Control and Result in Expected Changes to NWPP Reserve Sharing Group Reporting ACE

Attachment N – Correlation Table of Participants, Reliability Coordinators, and Zones

Attachment A

Calculation of Contingency Reserve Obligations; Requirements Related to WECC Operating Reserve - Supplemental

1. Calculation of Participating Balancing Authority Contingency Reserve Obligation

The NWPP Reserve Sharing Group has determined that the Contingency Reserve Obligation for each Participant's Balancing Authority Area(s), as well as the Contingency Reserve Obligation for the NWPP Reserve Sharing Group as a whole, will be calculated as set forth below. The measure of the Contingency Reserve Obligation for each Participant's Balancing Authority Area(s), as well as the Contingency Reserve Obligation for the NWPP Reserve Sharing Group as a whole, will be based on real-time measurements of load and generation, which, for compliance purposes, will be used to calculate integrated hourly averages. These integrated hourly averages will be compared to hourly averages of Contingency Reserve Available (also based on real-time measurements) to determine whether the NWPP Reserve Sharing Group's Contingency Reserve Available was sufficient to meet the requirements of BAL-002. The amount of Contingency Reserve Available within the NWPP Reserve Sharing Group for each clock hour must be equal to or greater than the NWPP Reserve Sharing Group's Contingency Reserve Obligation during that same clock hour.

As described in detail in Section 1 of this Attachment A and reflected in Attachment D's process chart for Calculation of CRO, the Reserve Sharing Computer System uses a four-step process to determine the Contingency Reserve Obligation a Participating Balancing Authority is required to meet for its Balancing Authority Area(s) under normal circumstances, using real-time measurements as described above. The Reserve Sharing Computer System completes the calculations necessary for this process (with updated real-time measurements) every data scan cycle (that is, no less frequently than every six seconds).

These calculation processes can be summarized as follows:

First, the Reserve Sharing Computer System calculates three percent of load plus three percent of generation. Next, the Reserve Sharing Computer System sums of all Participants' Contingency Reserve calculations to see whether this calculated sum is at least equal to the Most Severe Single Contingency for the NWPP Reserve Sharing Group. If it is not, the Reserve Sharing Computer System allocates, on a pro rata basis, the additional amount of Contingency Reserve necessary to cover the NWPP Reserve Sharing Group's Most Severe Single Contingency and determines the Contingency Reserve Obligation for each Participant's Balancing Authority Area(s) as adjusted for the NWPP Reserve Sharing Group's Most Severe Single Contingency.

The third step calculates the amount of any additional Contingency Reserve that may be needed in a Reserve Sharing Zone to cover the Most Severe Single Contingency within that Reserve

Sharing Zone and determines each the Total Contingency Reserve Obligation for each Participant's Balancing Authority Area(s), reflecting both applicable adjustments for the NWPP Reserve Sharing Group's Most Severe Single Contingency and any adjustments necessary to address the Most Severe Single Contingency within a Reserve Sharing Zone.

The fourth step checks to make sure the aggregate amount of Contingency Reserve Available within the NWPP Reserve Sharing Group is at least equal to Contingency Reserve Obligation of the NWPP Reserve Sharing Group according to the requirements of BAL-002 (both the WECC and the NERC versions). If it is not, the Reserve Sharing Computer System allocates, on a pro rata basis, the additional amount of Contingency Reserve necessary to fully comply with the Contingency Reserve requirements of BAL-002. Each Participating Balancing Authority must add this adjustment amount to its total Contingency Reserve Obligations and stand ready to deploy this adjusted Contingency Reserve Obligation (excluding amounts already deployed to respond to Qualifying Events) at all times for use as Internal Reserve and Assistance Reserve.

Section 4 of this Attachment sets out the process a Participating Balancing Authority should follow to determine its Contingency Reserve Obligation(s) when communication links between the Participating Balancing Authority and the Reserve Sharing Computer System are down, or when the Reserve Sharing Computer System is unavailable.

Set forth below are explanations and formulas for each step in the process to determine the total amount of Contingency Reserve a Participating Balancing Authority is required to carry.[2] For any Participant that has more than one Balancing Authority Area within the Northwest Power Pool, the calculations below are done separately for each of its Balancing Authority Areas.

a. <u>Step One – Calculation of Participating Balancing Authority Base Contingency Reserve Obligation</u>:

   The base Contingency Reserve Obligation for each Participant's Balancing Authority Area(s), or "CRO_{CA}" (before the adjustments described in the remainder of Section 1 of this Attachment A), is the sum of (i) three percent of the Load (as defined below) for the Participant's Balancing Authority Area(s), plus (ii) three percent of the Generation (as defined below) for the Participant's Balancing Authority Area(s).

   $$\mathbf{CRO}_{CA} = (0.03 \times \text{Generation}) + (0.03 \times \text{Load}),$$

[2] For consistency with formulas used in the Reserve Sharing Computer System, individual Participating Balancing Authority obligations are designated by the subscript "$_{CA}$." This is because the formulas in the Reserve Sharing Computer System were established when the function roughly corresponding to a Balancing Authority was referred to as a control area.

Where,

- **CRO_{CA}** = base Contingency Reserve Obligation
- **Generation** = BAA Net Generation - Designated Dynamically Scheduled Exports + Designated Dynamically Scheduled Imports [*see* Note 1]
- **Load** = BAA Net Generation - Actual Net Interchange [*see* Notes 2 and 3]
- **BAA Net Generation** = the sum of Net Generation for all generating units (whether measured by individual units or at the plant level or both) inside the Balancing Authority Area
- **Net Generation** (whether for an individual generating unit or a generating plant) = the greater of (a) the gross metered generation minus station service load, or (b) zero
- **Actual Net Interchange (NI_A)** has the meaning given to this term in the NERC Glossary
- **Scheduled Net Interchange (NI_S)** has the meaning given to this term in the NERC Glossary
- **Designated Dynamically Scheduled Exports =** all Dynamically Scheduled exports for which the sink (receiving) Balancing Authority has agreed to carry Contingency Reserve, as reflected in the Balancing Authority Area's Scheduled Net Interchange value [*see* Note 4]
- **Designated Dynamically Scheduled Imports** for which the sink (receiving) Balancing Authority has agreed to carry Contingency Reserve, as reflected in the Balancing Authority Area's Scheduled Net Interchange value [*see* Note 4]
- **Dynamically Scheduled** corresponds to the term "Dynamic Schedule," as defined in the NERC Glossary

Note 1: All generation within the Balancing Authority Area's or the NWPP Reserve Sharing Group's metered boundaries should be included in this calculation, with the only exception being generation expressly permitted to be excluded by the terms of BAL-002-WECC-3 (or comparable standards in jurisdictions outside the United States). Generation within a Balancing Authority Area by Pseudo-Tie (as defined in the NERC Glossary) is considered within the metered boundaries of the Balancing Authority Area into which it is Pseudo-Tied and is included in its generation calculation.

Note 2: Generation within a Balancing Authority Area by Pseudo-Tie is reflected in Actual Net Interchange in the ACE equation.

Note 3: Load within a Balancing Authority Area by Pseudo-Tie is reflected in Actual Net Interchange in the ACE equation. Load within a Balancing Authority Area by Pseudo-Tie is considered within the metered boundaries of the Balancing Authority Area into which it is Pseudo-Tied and is included in its load calculation by virtue of its inclusion in the Actual Net Interchange equation.

Note 4: This term captures net generation responsibility transferred, reflecting that Dynamically Scheduled generation exports can be subtracted from the exporting Balancing Authority's generation obligation (except when the source Balancing Authority and sink Balancing Authority have agreed otherwise), and Dynamically Scheduled generation imports should be added to the importing Balancing Authority's generation obligation (except when the source Balancing Authority and sink Balancing Authority have agreed otherwise).

b. Step Two – Check for Deficiency Related to Most Severe Single Contingency for the NWPP:

Once the Participating Balancing Authorities' base Contingency Reserve Obligations have been calculated, the second step in the process is to check for any potential deficiency, should the Most Severe Single Contingency for the NWPP exceed the sum of the Participating Balancing Authorities' Contingency Reserve Obligations as calculated in step one.

The NWPP's Most Severe Single Contingency is compared to the sum of all Participating Balancing Authorities' base Contingency Reserve Obligations. If the Most Severe Single Contingency is greater, the difference between these two figures (the "shortfall") is allocated among the Participating Balancing Authorities in proportion to their relative shares of the NWPP Reserve Sharing Group's base Contingency Reserve Obligation, as calculated in step one. This results in an upward adjustment to the base Contingency Reserve Obligation for each Participant's Balancing Authority Area(s).

The formulas for this step are as follows:

If $S\ CRO_{CA} < MSSC_{NWPP}$, then

$$CRO_SHORT_{NWPP} = MSSC_{NWPP} - S\ CRO_{CA}$$

and

$$AdjCRO_MSSC_{CA} = CRO_SHORT_{NWPP} * CRO_{CA} / S\ CRO_{CA}$$

Where,

$S\ CRO_{CA}$ = sum of all Participating Balancing Authorities' base Contingency Reserve Obligations, as calculated through step one;

$MSSC_{NWPP}$ = the Most Severe Single Contingency for the NWPP Reserve Sharing Group, determined in accordance with the Typical Planning MSSC in real time table set forth in Attachment K;

CRO_SHORT_{NWPP} = the amount by which the Most Severe Single Contingency for the NWPP exceeds the sum of the Participating Balancing Authorities' base Contingency Reserve Obligations;

CRO_{CA} = the Participating Balancing Authority's base Contingency Reserve Obligation as calculated in step one;

$AdjCRO_MSSC_{CA}$ = the adjustment to the Participating Balancing Authority's base Contingency Reserve Obligation to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group.

$MSSC_{NWPP}$ is revised whenever the output of the generator (or loading of the transmission line) that sets the $MSSC_{NWPP}$ increases or decreases by one MW or more.

c. <u>Step Three – Check for Deficiency Related to Most Severe Single Contingency for a Reserve Sharing Zone and Sum of Adjustments</u>:

The third step in the process is to check for any potential deficiency within a Reserve Sharing Zone if the Zone's Most Severe Single Contingency exceeds the sum of (i) the Contingency Reserve Obligation for the Zone's Participating Balancing Authorities and (ii) the amount of Contingency Reserve that can be imported from adjacent Reserve Sharing Zones. This Zone adjustment is then summed with the adjustment from step two and added to the Participant's base Contingency Reserve Obligation to give Total Contingency Reserve Obligation.

The Reserve Sharing Computer System continuously monitors transfer limits ($LIMIT_{Pathnn}$), actual flows ($ACTUAL_{Pathnn}$), and, where applicable, scheduled flows ($SCHED_{Pathnn}$) on transmission facilities connecting Reserve Sharing Zones.

If, after accounting for Contingency Reserve Obligation that can be delivered from adjacent Reserve Sharing Zones, the combined Contingency Reserve Obligations within the Zone is less than the Zone's Most Severe Single Contingency, this shortfall is allocated among the Zone's Participating Balancing Authorities in proportion to their relative shares of the aggregate Contingency Reserve Obligations (as calculated through steps one and two) for the Reserve Sharing Zone.

The formulas for adjusting Contingency Reserve Obligations, if necessary, for the Most Severe Single Contingency for a Reserve Sharing Zone are as follows:

If $S\ (CRO_{CA} + AdjCRO_MSSC_{CA}) + ASDEL_{ZONE} < MSSC_{ZONE}$, then

$$CRO_SHORT_{ZONE} = MSSC_{ZONE} - (S\ (CRO_{CA} + AdjCRO_MSSC_{CA}) + ASDEL_{ZONE})$$

and

$$AdjCRO_ZONE_MSSC_{CA} = CRO_SHORT_{ZONE} * (CRO_{CA} + AdjCRO_MSSC_{CA}) / S\ (CRO_{CA} + AdjCRO_MSSC_{CA})$$

and

$$AdjCRO_{CA} = AdjCRO_MSSC_{CA} + AdjCRO_ZONE_MSSC_{CA}$$

and

$$TotCRO_{CA} = CRO_{CA} + AdjCRO_{CA}$$

Where,

$S\ CRO_MSSC_{CA}$ = the sum of Contingency Reserve Obligations for all Participating Balancing Authorities in the Reserve Sharing Zone (as calculated through steps one and two);

CRO_MSSC_{CA} = the Contingency Reserve Obligation for a Participating Balancing Authority in the Reserve Sharing Zone, as adjusted to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group;

$ASDEL_{ZONE}$ = the amount of Assistance Reserve that can be delivered to the Reserve Sharing Zone from adjacent Reserve Sharing Zones, after accounting for relevant transfer limits, actual flows, and if applicable, scheduled flows on transmission facilities connecting Reserve Sharing Zones;

$MSSC_{ZONE}$ = the Most Severe Single Contingency for the Reserve Sharing Zone;

CRO_SHORT_{ZONE} = the amount by which the Most Severe Single Contingency for the Reserve Sharing Zone exceeds the sum of (i) the aggregate Contingency Reserve Available of the Participating Balancing Authorities in the Reserve Sharing Zone (S CRO_MSSC_{ZONE}), plus (ii) amount of Assistance Reserve that can be delivered to the Reserve Sharing Zone from adjacent Reserve Sharing Zones ($ASDEL_{Lim}$);

CRO_{CA} = the Participating Balancing Authority's Contingency Reserve Obligation;

$AdjCRO_ZONE_MSSC_{CA}$ = the additional amount of Contingency Reserve a Participating Balancing Authority needs to carry to reflect the Most Severe Single Contingency for the Reserve Sharing Zone;

$AdjCRO_MSSC_{CA}$ = the adjustment to the Participating Balancing Authority's base Contingency Reserve Obligation to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group;

$AdjCRO_{CA}$ = the total adjustment amounts to be added to a Participant's base Contingency Reserve Obligation to reflect any applicable adjustments for the NWPP Reserve Sharing Group's Most Severe Single Contingency and the Most Severe Single Contingency for a Reserve Sharing Zone; and

$TotCRO_{CA}$ = the Participating Balancing Authority's Contingency Reserve Obligation as adjusted to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group and for its Reserve Sharing Zone.

$MSSC_{ZONE}$ is revised whenever the output of the generator (or loading of the transmission line) that sets the $MSSC_{ZONE}$ increases or decreases by one MW or more.

d. Step Four – Calculation of Aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group and Check for NWPP Reserve Sharing Group Shortfall:

The fourth step in the process calculates the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group and makes sure the total Contingency Reserve Available within the NWPP Reserve Sharing Group is at least equal to the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group.

The aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group is calculated by summing the total Contingency Reserve Obligations (as calculated in steps one through three) for all Participants' Balancing Authority Areas.

The formula for this step is as follows:

$$TotCRO_{NWPP} = S\ TotCRO_{CA}$$

Where,

$TotCRO_{NWPP}$ = the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group; and

$S\ TotCRO_{CA}$ = the sum of the total Contingency Reserve Obligations of all Participating Balancing Authorities, as adjusted to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group and for applicable Reserve Sharing Zones.

If the Contingency Reserve Available within the NWPP Reserve Sharing Group is less than the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group, the difference between these two figures (the "shortfall") is allocated among the Participating Balancing Authorities in proportion to their relative shares of the NWPP Reserve Sharing Group's Contingency Reserve Obligation (without factoring in adjustments for shortfalls within a Reserve

Sharing Zone). This results in an upward adjustment to the Contingency Reserve Obligation for each Participant's Balancing Authority Area(s).

The formulas for this final check are as follows:

If $TotAvailCR_{NWPP} < TotCRO_{NWPP}$, then

$TotCRO_SHORT_{NWPP} = TotCRO_{NWPP} - TotAvailCR_{NWPP}$

and

$AdjCRO_SHORT_{CA} = (TotCRO_SHORT_{NWPP} * (CRO_{CA} + AdjCRO_MSSC_{CA}) / S (CRO_{CA} + AdjCRO_MSSC_{CA}))$

Where,

$TotCRO_{NWPP}$ = the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group;

$TotAvailCR_{NWPP}$ = the total amount of Contingency Reserve Available in the NWPP Reserve Sharing Group;

$TotCRO_SHORT_{NWPP}$ = the amount by which the aggregate Contingency Reserve Obligation for the NWPP Reserve Sharing Group exceeds the total Contingency Reserve Available;

CRO_{CA} = the Participating Balancing Authority's base Contingency Reserve Obligation as calculated in steps one;

$AdjCRO_SHORT_{CA}$ = the adjustment to the Participating Balancing Authority's Contingency Reserve Obligation to reflect the shortfall in total Contingency Reserve Available; and

$AdjCRO_MSSC_{CA}$ = the adjustment to the Participating Balancing Authority's base Contingency Reserve Obligation to reflect the Most Severe Single Contingency for the NWPP Reserve Sharing Group.

Each Participant must add the adjustment amount ($AdjCRO_SHORT_{CA}$) to the total Contingency Reserve Obligation for its Balancing Authority Area(s) as calculated in step three ($TotCRO_{CA}$) and stand ready to deploy the combined amount of Contingency Reserve Available (excluding amounts already deployed to respond to a Qualifying Event) at all times for use as Internal Reserve and Assistance Reserve.

The NWPP Reserve Sharing Group will experience a shortfall only if one or more Participants have not fully met their Contingency Reserve Obligations.

2. Permitted Amounts and Types of WECC Operating Reserve - Supplemental

A Participating Balancing Authority's Contingency Reserve Obligation(s) may be met with WECC Operating Reserve - Supplemental, provided that any WECC Operating Reserve - Supplemental applied to a Participating Balancing Authority's Contingency Reserve Obligation can be made fully effective within 10 minutes.

Permitted Sources of WECC Operating Reserve - Supplemental

A Participating Balancing Authority is permitted to use WECC Operating Reserve - Supplemental to meet a portion of its Contingency Reserve Obligation(s) calculated in accordance with Section 1 of this Attachment A, the following may be used as sources of WECC Operating Reserve - Supplemental:

1. WECC Operating Reserve - Spinning,
2. WECC Operating Reserve - Supplemental,
3. Interchange Transactions designated by the Source Balancing Authority as WECC Operating Reserve - Supplemental,
4. Reserve held by other entities by agreement that is deliverable on Firm Transmission Service,
5. A resource, other than generation or load, that can provide energy or reduce energy consumption,
6. Load, including demand response resources, demand-side management resources, direct control load management, interruptible load or interruptible demand, or any other load made available for curtailment by the Participating Balancing Authority or the NWPP Reserve Sharing Group via contract or agreement, and

7. All other load, not identified in the foregoing items, once a Reliability Coordinator for the Northwest Power Pool has declared an energy emergency alert signifying that interruption of Firm Demand is imminent or in progress.

3. Participating Balancing Authority Calculation of Contingency Reserve Obligation(s) When Communications with Reserve Sharing Computer System Are Disrupted

During periods when communication links between a Participating Balancing Authority and the Reserve Sharing Computer System are down, or when the Reserve Sharing Computer System is unavailable, responsibility for calculating Contingency Reserve Obligations shifts to the Participating Balancing Authority. Any Participating Balancing Authority that is unable to access the Reserve Sharing Computer System's calculation of its Contingency Reserve Obligations should use good-faith estimates of the inputs needed to determine its Contingency Reserve Obligation, based on the last available input data known to be valid, and apply as many of the steps described in Section 1 of this Attachment A as it can, consistent with good utility practice. The Participating Balancing Authority should continue this process, adjusting as appropriate for relevant changes to system conditions, until availability of and communications with the Reserve Sharing Computer System are restored.

Attachment B

Qualifying Events

A "Qualifying Event" is any single event described in subsections (A), (B), (C), or (D) below, or any series of such otherwise single events, with each separated from the next by one minute or less. Any capitalized term used below that is not defined within this document has the meaning given to it in the NERC Glossary. This Attachment B may be modified from time to time by action of the RSG Committee.

(A) Sudden Loss of Generation

a. due to
    i. unit tripping (*see note 1 below), or*
    ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or
    iii. sudden unplanned outage of transmission Facility;
b. and, that causes an unexpected change to the responsible entity's ACE (*see note 2 below*)

(B) Sudden Loss of an Import

a. due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection. (*See note 3 below*).

(C) Sudden Restoration of Demand

a. that was used as a resource that causes an unexpected change to the responsible entity's ACE

(D) Energy Emergency Alert

a. where a Participating Balancing Authority's inability to meet Firm Demand such that the Participating Balancing Authority has requested its Reliability Coordinator to declare, and the Reliability Coordinator has declared an Energy Emergency Alert 3 (as described in NERC Standard EOP-011 or a successor standard) the Participant:
    i. May utilize its CRO to serve Firm Demand while the Participant is in an EEA 3;

ii. Must keep the RSG Computer System current with any portion of its Contingency Reserve Available already in use (UsedCR_{CA});

iii. Should reach out to neighboring BA's to verify no energy is available;

iv. Should reach out to cut-plane monitors for limit verification of any cut-planes with constraints impacting the BA's ability to receive Assistance Reserves;

v. May request Assistance Reserve through the NWPP Reserve Sharing Program for up to 60 minutes to prevent shedding Firm Demand, not to restore their Contingency Reserves.

1. Once the timeframe above has been depleted, then the Participant may continue to utilize its CRO to server Firm Demand. The Participant may need to shed Firm Demand to maintain Reporting ACE until the Participant is no longer in an EEA 3.

Note 1:

For purposes of this Attachment B, the term "unit tripping" means:

(1) the automatic operation of a device or capability designed to protect a power-producing resource from damage, or

(2) the unexpected failure of a power-producing resource to maintain, increase, or remain available due to equipment failure, or

(3) the unexpected failure of a power-producing resource to start (a) due to equipment failure, and (b) not associated with the failure to procure fuel,

which, in all cases, results in loss of MW output serving (or needed to serve) one or more Participants' Demand obligations.

Note 2:

The events described in Note 1 are Qualifying Events even when they do not result in an immediate change to the responsible entity's ACE.

Note 3:

Given typical operating practices followed in the Western Interconnection, the loss of an import would generally be expected to result in a corresponding adjustment to generation.

Attachment C

Reserve Sharing Zones and Assistance Reserve Responder Levels

Each Reserve Sharing Zone, as identified in the table below, has one or more Balancing Authority Participants.

Zones	Balancing Authority Participants
Alberta (AB)	AESO
Arizona -Nevada (AZNV)	AZPS, BNBA, DEAA, GRID, SRP, TEPC, WALC & NEVP
British Columbia (BC)	BCHA
Eastern Colorado (ECO)	PSCO
Mountain West (MTWEST)	IPCO & PACE
Northern California (NCAL)	BANC & TID
Pacific Northwest – Montana (PNWMT)	AVA, AVRN, BPA, CHPD, DOPD, GCPD, GRID, GWA, NWMT, PACW, PGE, PSEI, SCL, TPWR, & WAUW
Southern California (SCAL)	IID
Texas – New Mexico (TXNM)	EPE & PNM
Western Colorado (WCO)	WACM



Assistance Reserve Responder Levels

Each Reserve Sharing Zone has multiple levels for providing Assistance Reserve. Level 1 is the list of initial providers. If there is insufficient Assistance Reserve at Level 1 or there are transmission constraints between Reserve Sharing Zones, additional zones will be included by moving out one level at a time until there is sufficient Assistance Reserve or all Participating Balancing Authorities are included.

		Responding Zone									
		AB	AZNV	BC	ECO	MTWEST	NCAL	PNWMT	SCAL	TXNM	WCO
Requesting Zone	AB	-	4	1	6	3	3	2	5	5	5
	AZNV	5	1	4	3	2	4	3	1	1	2
	BC	1	3	-	5	2	2	1	4	4	4
	ECO	6	2	5	-	3	5	4	3	3	1
	MTWEST	3	2	2	4	1	2	1	3	3	3
	NCAL	4	4	3	6	2	1	2	5	5	5
	PNWMT	3	3	2	5	2	2	1	4	4	4
	SCAL	5	1	4	3	2	4	3	-	1	2
	TXNM	5	1	4	3	2	4	3	1	1	2
	WCO	6	2	5	1	3	5	4	3	3	-

Alberta Zone (AB)

Level 1: BC
Level 2: BC + PNWMT
Level 3: BC + PNWMT + MTWEST + NCAL
Level 4: BC + PNWMT + MTWEST + NCAL + AZNV
Level 5: BC + PNWMT + MTWEST + NCAL + AZNV+ SCAL + TXNM + WCO
Level 6: BC + PNWMT + MTWEST + NCAL + AZNV+ SCAL + TXNM + WCO + ECO

Arizona Nevada Zone (AZNV)

Level 1: AZNV + SCAL + TXNM
Level 2: AZNV + SCAL + TXNM + MTWEST + WCO
Level 3: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT
Level 4: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT + BC + NCAL
Level 5: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT + BC + NCAL + AB

British Columbia Zone (BC)

Level 1: AB + PNWMT
Level 2: AB + PNWMT + MTWEST + NCAL
Level 3: AB + PNWMT + MTWEST + NCAL + AZNV

Level 4: AB + PNWMT + MTWEST + NCAL + AZNV + SCAL + TXNM + WCO
Level 5: AB + PNWMT + MTWEST + NCAL + AZNV + SCAL + TXNM + WCO + ECO

Eastern Colorado Zone (ECO)
Level 1: WCO
Level 2: WCO + AZNV
Level 3: WCO + AZNV + MTWEST + SCAL + TXNM
Level 4: WCO + AZNV + MTWEST + SCAL + TXNM + PNWMT
Level 5: WCO + AZNV + MTWEST + SCAL + TXNM + PNWMT + BC
Level 6: WCO + AZNV + MTWEST + SCAL + TXNM + PNWMT + BC + AB

Mountain West Zone (MTWEST)
Level 1: MTWEST + PNWMT
Level 2: MTWEST + PNWMT + AZNV + BC + NCAL
Level 3: MTWEST + PNWMT + AZNV + BC + NCAL + AB + SCAL + TXNM + WCO
Level 4: MTWEST + PNWMT + AZNV + BC + NCAL + AB + SCAL + TXNM + WCO + ECO

Northern California Zone (NCAL)

Level 1: NCAL
Level 2: NCAL + MTWEST + PNWMT
Level 3: NCAL + MTWEST + PNWMT + BC
Level 4: NCAL + MTWEST + PNWMT + BC + AB + AZNV
Level 5: NCAL + MTWEST + PNWMT + BC + AB + AZNV + SCAL + TXNM + WCO
Level 6: NCAL + MTWEST + PNWMT + BC + AB + AZNV + SCAL + TXNM + WCO + ECO

Pacific Northwest-Montana Zone (PNWMT)

Level 1: PNWMT
Level 2: PNWMT + BC + MTWEST+ NCAL
Level 3: PNWMT + BC + MTWEST+ NCAL + AB + AZNV
Level 4: PNWMT + BC + MTWEST+ NCAL + AB + AZNV + SCAL + TXNM + WCO
Level 5: PNWMT + BC + MTWEST+ NCAL + AB + AZNV + SCAL + TXNM + WCO + ECO

Southern California Zone (SAL)

Level 1: AZNV + TXNM
Level 2: AZNV + TXNM+ MTWEST + WCO
Level 3: AZNV + TXNM+ MTWEST + WCO + ECO + PNWMT
Level 4: AZNV + TXNM+ MTWEST + WCO + ECO + PNWMT + BC + NCAL
Level 5: AZNV + TXNM+ MTWEST + WCO + ECO + PNWMT + BC + NCAL + AB

Texas New Mexico Zone (TXNM)

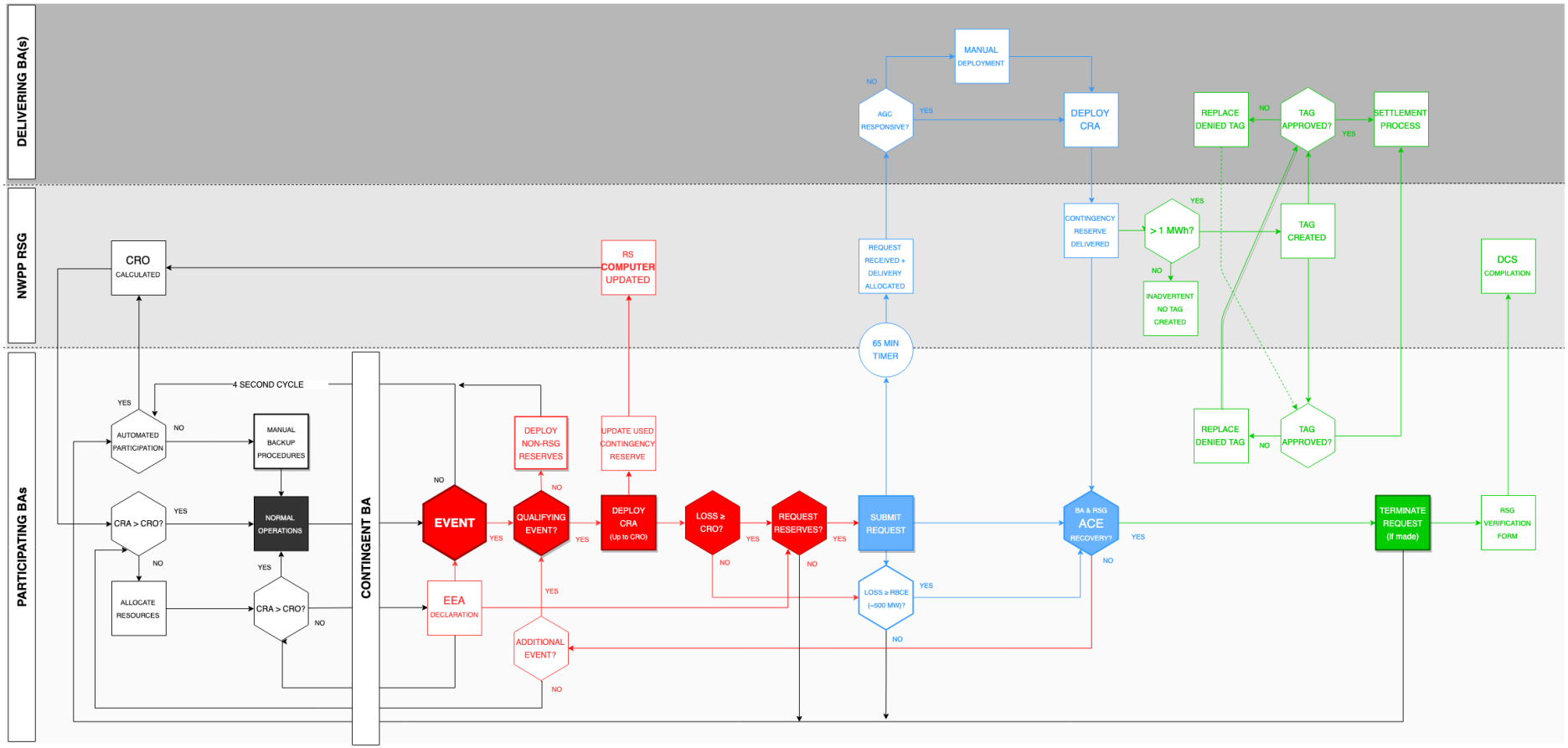
Level 1: AZNV + SCAL + TXNM
Level 2: AZNV + SCAL + TXNM + MTWEST + WCO
Level 3: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT
Level 4: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT + BC + NCAL
Level 5: AZNV + SCAL + TXNM + MTWEST + WCO + ECO + PNWMT + BC + NCAL + AB

Western Colorado Zone (WCO)

Level 1: ECO
Level 2: ECO + AZNV
Level 3: ECO + AZNV + MTWEST + SCAL + TXNM
Level 4: ECO + AZNV + MTWEST + SCAL + TXNM + PNWMT
Level 5: ECO + AZNV + MTWEST + SCAL + TXNM + PNWMT + BC + NCAL
Level 6: ECO + AZNV + MTWEST + SCAL + TXNM + PNWMT + BC + NCAL + AB

Attachment D

NWPP Process Charts



NORMAL OPERATIONS → DISTURBANCE → REQUEST → RESOLUTION

CONTINGENCY RESERVE OBLIGATION (CRO)

- Zonal MSSC
- 3% GENERATION + 3% LOAD

QUALIFYING EVENTS

- Sudden Loss of Generation
- Sudden Loss of an Import
- Sudden Restoration of a Demand
- Energy Emergency Alert

Four Minute Requirement

- 4 min allows adequate response time for ACE
- < 4 mins - RSG responsible
- > 4 mins - BA responsible if compliance failure occurs

RESERVE REQUESTS

- Request is optional
- **RBCE = Reportable Balancing Contingency Event**

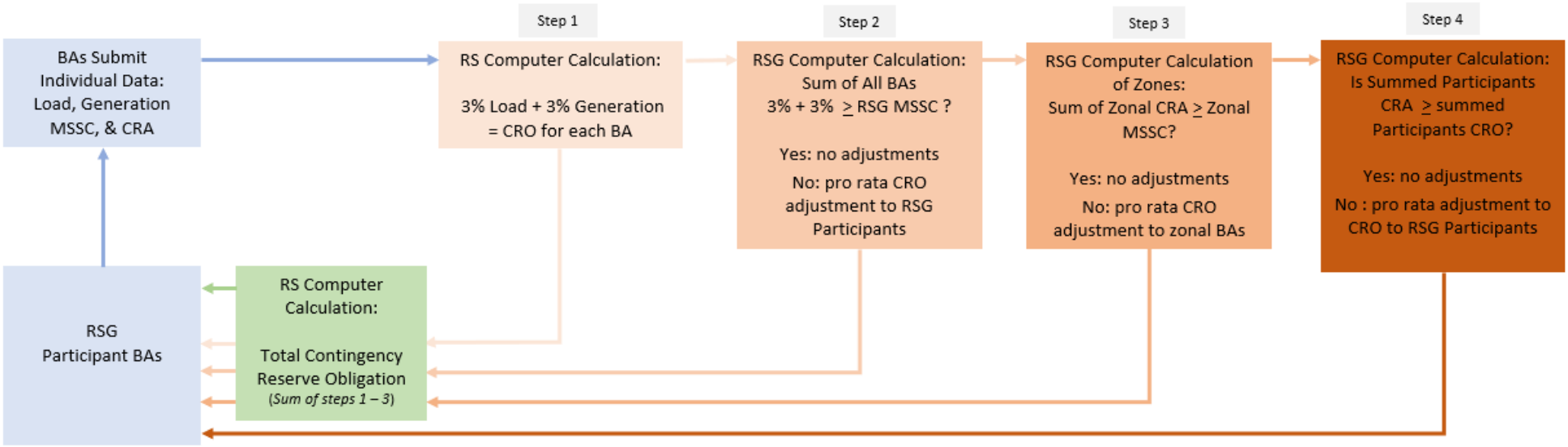
SETTLEMENT

- Powerdex Mid-Columbia Hourly Index

Northwest Power Pool
RESERVE SHARING PROGRAM
PROCESS CHART v19

NORTHWEST PowerPool

Attachment A – Calculation of CRO

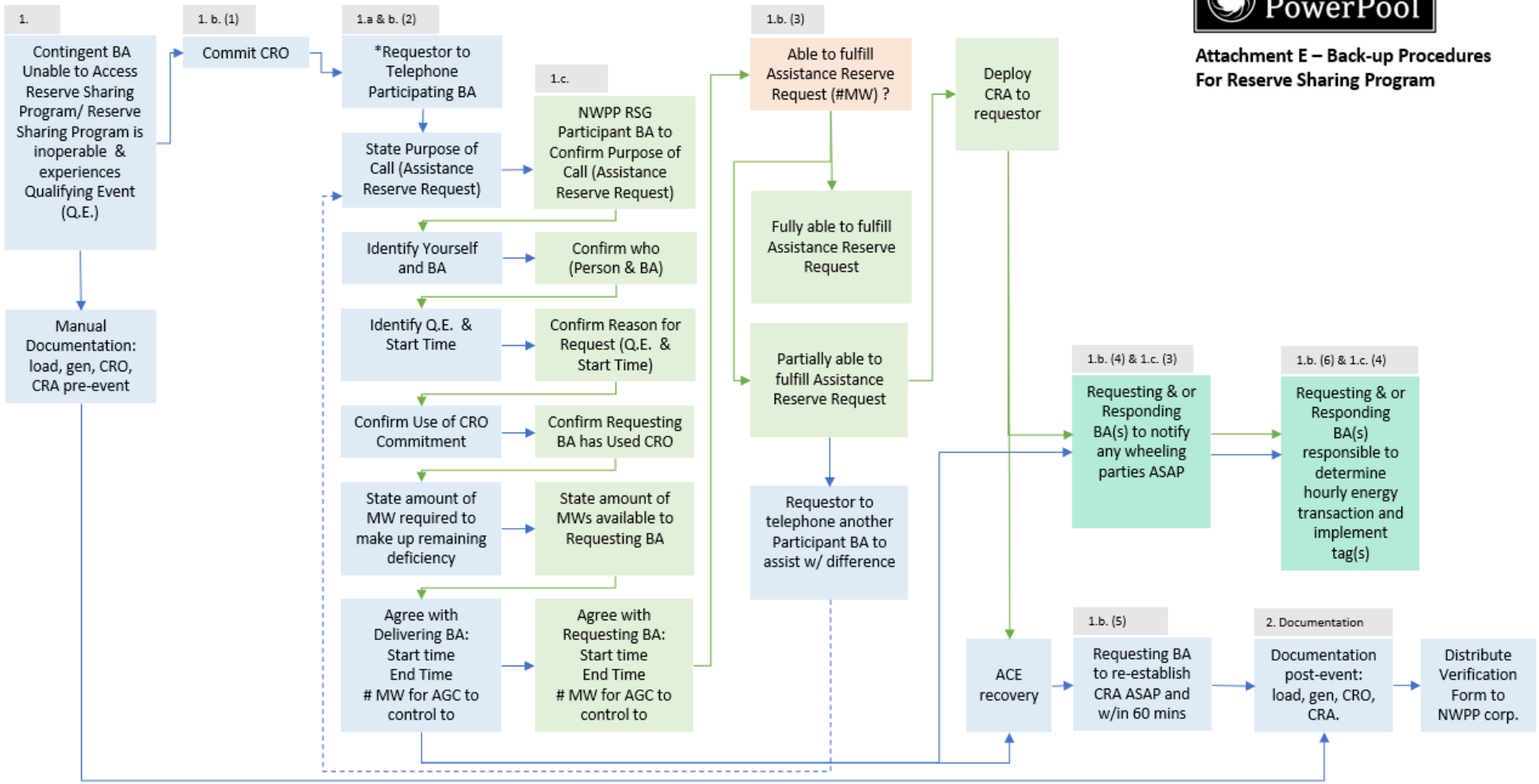


ICCP outputs for each step:
Step 1: BA-CRO
Step 2: BA-ADJ_MSSC_POOL
Step 3: BA-ADJ_MSSC_ZONE
Step 4: BA-ADJCRO_POOL

Total Contingency Reserve Obligation ICCP output: BA-TOTCRO

NORTHWEST PowerPool

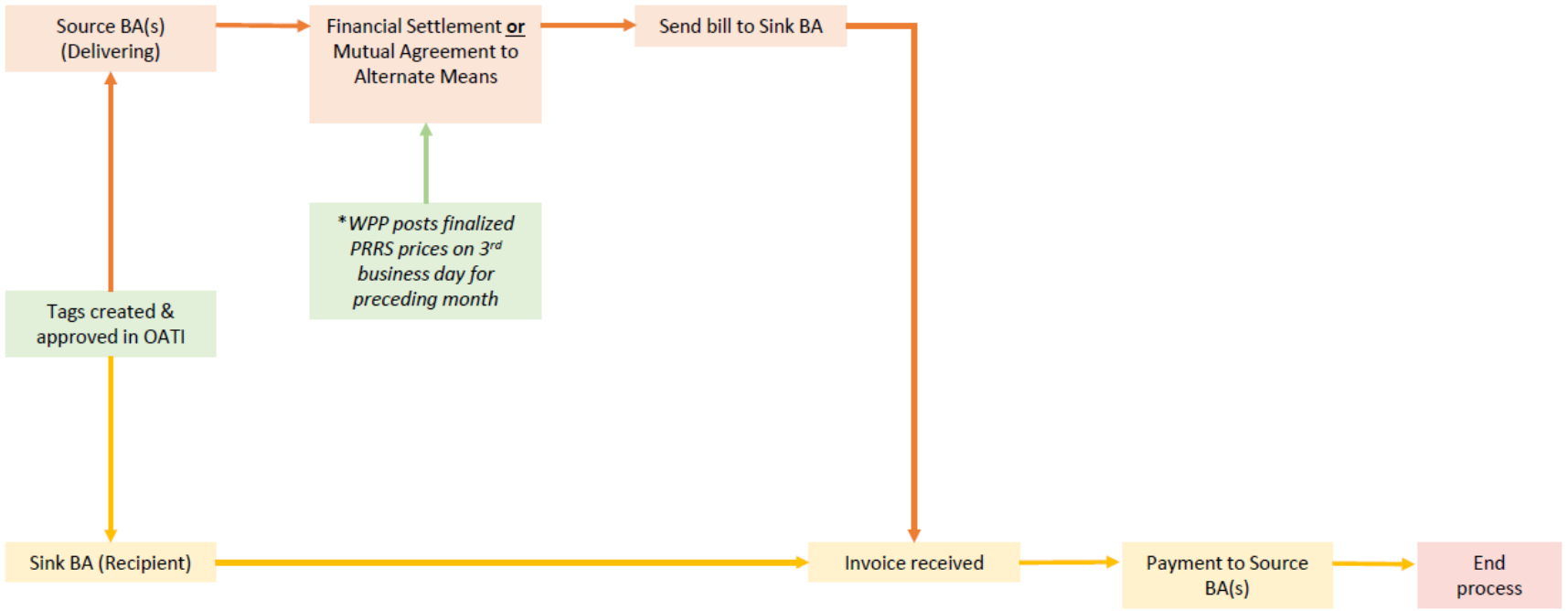
Attachment E – Back-up Procedures For Reserve Sharing Program



* To minimize potential transmission problems call adjacent BA first. If adjacent BA is unable to fulfill Assistance Reserve Request, contingent BA should move and call next adjacent BA. The process would be the same if the adjacent BA is able to partially fill request or unable to fill request.

NORTHWEST PowerPool

Section K – Settlement Process



Attachment E

BACKUP PROCEDURES FOR RESERVE SHARING PROGRAM

1. Participant Cannot Access Reserve Sharing Computer System or Reserve Sharing Computer System Is Inoperable

Reserve Sharing Requests and delivery of Assistance Reserve are normally implemented through the Reserve Sharing Computer System. When the Reserve Sharing Computer System is inoperable or inaccessible, a Participant that needs to make a Reserve Sharing Request should contact other Participants by telephone to request Assistance Reserve. Attachment D reflects the respective process described in this attachment. The provisions below (Sections 1.a, 1.b, and 1.c) will apply for the manual backup procedure. The settlement process for delivery of Assistance Reserve using the backup procedure is the same as for the automated reserve sharing process, except that requesting and responding Participants must agree (on a case-by-case basis) to any reserve sharing transactions instead of obtaining the information from the Reserve Sharing Computer System. This process must be in accordance with Attachment G for production of after-the-fact tags and in accordance with existing reliability standards and regional business practices.

a. Transmission Limitations; Adjacent Utilities

To minimize potential transmission problems, whenever possible a Participant that needs to request Assistance Reserve by telephone should contact an adjacent Participant first.

b. Backup Reserve Sharing Procedure – Telephone Requests

Because NERC BAL-002-3 requires recovery of Reporting ACE within 15 minutes, the number of telephoned assistance requests that a Participant's dispatcher can make is limited. To enhance Participants' ability to meet this standard, Participants may use the following procedure (and Participants may use any economic arrangements under existing contracts by mutual agreement at any point in the following sequence):

(1) As provided in Section E.2, a Participant must commit its Internal Reserve up to the full amount of its Contingency Reserve Obligation before requesting Assistance Reserve.

(2) If a Participant that has deployed its Contingency Reserve Obligation and needs additional capacity to meet the 15-minute criterion, that Participant may call another Participant for assistance. The responding Participant will make available its unused Contingency Reserve Available up to its Contingency Reserve Obligation.

The caller must:

(a) state that the purpose of the call is to make a Reserve Sharing Request,

(b) identify who is making the request,

(c) identify the Qualifying Event it has experienced and the start time of the event,

(d) confirm that it committed to use Contingency Reserve up to the full amount of its Contingency Reserve Obligation to respond to the event,

(e) state the amount of Assistance Reserve that is required to make up the remaining deficiency, and

(f) agree with the responding Participant on the amount, start-time, and end-time of the Contingency Reserve delivery to be entered into the AGC controller total. The end-time may be shortened thereafter, if the requesting Participant determines that it does not need Assistance Reserve through the original end-time.

(3) If the Assistance Reserve made available and delivered from the responding Participant is insufficient to cover the Qualifying Event, the requesting Participant will cover the remaining deficit by requesting Assistance Reserve from another Participant.

(4) As soon as possible, the requesting Participant must notify any intermediate wheeling Balancing Authority(s) of the scheduled delivery of Assistance Reserve and its duration. Each Participating Balancing Authority that is needed for intermediate wheeling will make transmission capacity available up to its maximum operating limit by any means necessary including the curtailment of interruptible schedules.

(5) The Participant requesting assistance must re-establish its Contingency Reserve Available that is ready for deployment (to at least the level of its Contingency Reserve Obligation) as soon as possible by adding generation, adjusting interchange schedules, or dropping load. As provided in Section F.3, a Participant that requests Assistance Reserve must relinquish the Assistance Reserve within 60 minutes following the start of the Qualifying Event.

(6) Any Participant that requests Assistance Reserve must contact the party within its organization that is responsible for energy scheduling and notify that party of the actions taken to request Assistance Reserve. The party responsible for scheduling must then contact its counterpart from the responding Participant to determine an agreed-upon hourly energy transaction and to agree on transaction wheeling amounts in accordance with the paths identified in the Participants pre-defined tag templates.

c. Backup Reserve Sharing Procedure – Telephone Responses

The following responses may be appropriate for a Participant that receives a Reserve Sharing Request by telephone:

(1) If a Participant that has deployed its Contingency Reserve needs additional capacity to meet the 15-minute criterion, that Participant may call another Participant for assistance.

The responding Participant will make available its unused Contingency Reserve up to its Contingency Reserve Obligation.

(2) The Participant that is being asked to provide Assistance Reserve may make the following responses:

(a) confirm that the purpose of the call is to make a Reserve Sharing Request,

(b) confirm who is making the request,

(c) confirm the reason for the request (*e.g.*, identify the Qualifying Event and the start time of the event),

(d) confirm that the requesting Participant has committed to use Contingency Reserve Available up to the full amount of its Contingency Reserve Obligation to respond to the event,

(e) state the amount of Assistance Reserve available to the requesting Participant,

(f) agree with the requesting Participant on the amount, start-time, and end-time of the Assistance Reserve to be entered into the AGC controller total.

(3) As soon as possible, the responding Participant should notify any intermediate wheeling Balancing Authority(s) of the scheduled delivery of Assistance Reserve energy and its duration. Each Participating Balancing Authority that is needed for intermediate wheeling will make transmission capacity available up to its maximum operating limit by any means necessary including the curtailment of interruptible schedules.

(4) Any Participant that provides Assistance Reserve must contact the party within its organization that is responsible for energy scheduling and notify that party of the actions taken to provide Assistance Reserve. The party responsible for scheduling must then contact its counterpart from the requesting Participant to determine an agreed-upon hourly energy transaction.

2. Documentation

Any Participant that requests Assistance Reserve using the backup procedures in this Attachment E must document its load, generation, Contingency Reserve Obligation, and Contingency Reserve Available immediately before the Qualifying Event. It must document the amount of its capacity lost or other characteristics of the Qualifying Event, the amount and components of Contingency Reserve deployed, and the amount of Assistance Reserve requested and received. The requesting Participant must also comply with Attachment G, Backup Process for After-the Fact Reserve Sharing Tags.

NWPP RSG Verification Forms are available on the WPP Website. The requesting Participant must send this documentation to all responding Participants, and to the WPP Staff, on the next working day.

Attachment F

TRANSMISSION MAPPING AND TAG TEMPLATE CHANGE PROCESS

A. Process for Changing Tagging Templates Delivery Paths Between NWPP Reserve Sharing Participants

1. Any Participant that wishes to request a change to the transmission mapping set forth in Participants' pre-defined tag templates must first obtain the agreement of all other Participants that would be affected by the requested change.
2. All affected Participants must be given adequate time to make any software changes to downstream or legacy scheduling systems.
3. Participant(s) requesting the change must complete any necessary registrations (or updates to registrations) related to the NAESB Electric Industry Registry (EIR) and Western Interchange Tool (WIT) Registry, or any successor industry registration systems.
4. Participants must submit requests for changes to the tag templates to the WPP Staff.
5. OATI will coordinate testing of the new or revised tag templates and confirm that the templates will pass WIT Registry validations.
6. WPP Staff and the affected Participants will coordinate with OATI to determine an implementation date and time for the new templates.
7. WPP Staff will advise all Participants of the implementation date for the revised templates.
8. OATI will make appropriate tag template changes effective as of the implementation date and time.

B. Process for Changing Tag Templates with No Change to Delivery Paths

(No Impact to Other Balancing Authorities)

1. The Participant with changes will notify the WPP Staff and provide WPP Staff with required changes to its tag templates.
2. The Participant with changes will complete any necessary EIR and WIT registrations or updates.
3. WPP Staff will communicate the requested changes to OATI.
4. OATI will coordinate testing of new or revised tag templates and confirm that the templates will pass WIT validations.

5. WPP Staff and the requesting Participant will determine an implementation date and time for the new tag templates.
6. OATI will make appropriate tag template changes effective as of the implementation date and time.
7. OATI will provide the WPP with the most current workbook of NWPP tag templates.

C. Process for Adding a New Participant to NWPP Reserve Sharing Program

1. WPP Staff will provide a newly admitted Participant(s) with the tag templates for further development to reflect the inclusion of the new Participant(s). If a new Reserve Sharing Zone is required, Attachment C will be revised to reflect the addition of a new Reserve Sharing Zone.
2. The New Participant(s) will provide WPP Staff with a workbook containing only their newly developed tag matrix (to and from each Participant BA) of completed tag templates.
3. WPP Staff will assist with distribution of these new tag templates to all Participants for review as required.
4. Participant(s) must review the new templates and implement any necessary changes to their own accounting and billing systems.
5. WPP Staff will communicate approved new tag templates to OATI.
6. OATI will coordinate testing of the new tag templates and confirm that the templates will pass WIT validations.
7. WPP Staff and all Participants will determine an implementation date and time for the new templates.
8. WPP Staff will advise all Participants of the implementation date and time for the new templates.
9. OATI will make the new tag templates effective as of the implementation date and time.

Attachment G

Backup Process for After-The-Fact Reserve Sharing Tags

A. Failure of Participant Internal Program or Reserve Sharing Computer System

If a Participant that has requested Assistance Reserve (or is providing Assistance Reserve) experiences a failure of any internal program related to reserve sharing, or if a Reserve Sharing Request is made or in effect during a time when the Reserve Sharing Computer System is not functioning, then the Participants receiving and providing Assistance Reserve energy will be responsible for all necessary after-the-fact tagging.

B. Failure of Automated After-the-Fact Tagging Process

If the automated tag creation process fails,

1. WPP Staff will
    a. contact OATI and coordinate the next possible time OATI can rerun automated tag creation for the event;
    b. make reasonable efforts (and request that OATI make reasonable efforts) to give Participants at least 24 hours' advance notice before the reissuing of the tags, and if this is not possible, attempt to give notice as far in advance as feasible; and
    c. notify Participants by e-mail distribution of the re-issuance of the tags.
2. If the affected Participants anticipate that the automated tag creation process will not be able to reissue the tags before the after-the-fact tagging deadline, the sink Participant will coordinate with the source Participants to facilitate the sink Participant's efforts to manually issue after-the-fact tags according to the most recent reserve sharing tag templates.
3. Participants shall contact WPP Staff to resolve failure of the automated tag creation process during normal business hours.

C. Replacing Denied Reserve Sharing Tags

1. If one Participant denies an after-the-fact the tag (properly or not), the denying Participant will coordinate with all other Participants to facilitate the denying Participant's efforts to manually reissue the after-the-fact tag(s).

a. If the problem with the original tag was due to an error in the tag template, the denying Participant will immediately notify all other Participants listed in the template of the necessary correction.

b. Participants needing to correct a tag template will follow the appropriate procedures specified in Attachment F to make changes to the tag template.

2. If more than one Participant denies a tag, the sink Participant will coordinate with all other affected Participants to facilitate the sink Participant's efforts to manually reissue the after-the-fact tag.

c. If the problem with the original tag was due to an error in the tag template, the denying Participants will immediately notify all other Participants listed in the template of the necessary correction.

d. Participants needing to correct a tag template will follow the appropriate procedures specified in Attachment F to make changes to the tag template.

Attachment H

Balancing Authority Areas of the
Participating Balancing Authorities

Alberta Electric System Operator (AESO)

Arizona Public Service Company (AZPS)

Arlington Valley, LLC (DEAA)

Avangrid Renewables, LLC (AVRN)

Avista Corporation (AVA)

Balancing Authority of Northern California (BANC)

British Columbia Hydro and Power Authority (BCHA)

Bonneville Power Administration (BPAT)

Chelan County Public Utility District (CHPD)

Douglas County Public Utility District (DOPD)

El Paso Electric Company (EPE)

First LightEnergy, LLC (BNBA)

Grant County Public Utility District (GCPD)

Gridforce Energy Management, LLC (GRID)

Idaho Power Company (IPCO)

Imperial Irrigation District (IID)

BHEM Power Watch, LLC (GWA)

Nevada Power (NEVP)

NorthWestern (NWMT)

PacifiCorp East (PACE)

PacifiCorp West (PACW)

Portland General Electric (PGE)

Public Service Company of Colorado (PSCo)

Public Service Company of New Mexico (PNM)

Puget Sound Energy (PSE)

Salt River Project Agriculture Improvement and Power District (SRP)

Seattle City Light (SCL)

Tacoma Power (TPWR)

Tucson Electric Power Company (TEPC)

Turlock Irrigation District (TID)

Western Area Power Administration – Desert Southwest Region (WALC)

Western Area Power Administration – Rocky Mountain Region (WACM)

Western Area Power Administration Upper Great Plains West (WAUW)

Attachment I

Reserved for Future Use

Attachment J

Reserved for Future Use

Attachment K

NWPP Reserve Sharing Group
MSSC and Long-Term Zonal MSSC Limit, Jointly Owned Dynamic Generation Resources, Jointly Owned Static Generation Resources, and Multi Use Transformer(s) Tables

1. Balancing Authority Area MSSC, NWPP Reserve Sharing Group Long-Term Zonal MSSC Limit, and NWPP Reserve Sharing Group Long-Term MSSC Limit.

The Participant Balancing Authorities have documented their BAA MSSCs in the table below which are used to derive the Long-Term Zonal MSSC Limit and the NWPP Reserve Sharing Group Long Term MSSC limit under normal system conditions.

Zone	Resource(s)	Reporting/ Operating BAA	Maximum Allowable Zonal MSSC MW	BAA System Normal MSSC MW	Plant Capability	Modeled Outage
Alberta	Genesse #3	AESO	466	466	1286	Loss of generation
Arizona - Nevada	Arlington Generation	AZPS	1122	565	600	Loss of transmission Line
	Arlington Valley	DEAA		580	600	Loss of transmission Line
	BrightNight PV Solar Project	BNBA		300	300	Loss of tie line
	Harquahala – Hassayampa Tie Line	SRP		975	1068	Loss of Transmission Line
	Gila River Blocks 2 &/ 3	TEPC		605	1100	Loss of generation
	Southpoint Energy Center	WALC		250	520	Loss of generation
	Silverhawk	NEVP		620	1055	Loss of transmission Line
British Columbia	Revelstoke – 3 Units	BCHA	1505	1505	2505	Revelstoke 500 kV main bus, three units (5MB2)
Eastern Colorado	Rush Creek Gen Tie	PSCO	1600	1600	1600	RAS Action
Southern California	El Centro Unit 3 / 230kV S-Line	IID	270	117/270	134	Loss of generation or line if scheduled greater than unit
Mountain West	Langley Gulch	IPC	1500	329	329	Unit trip of Langley Gulch – various issues
	Jim Bridger – 2 Units on RAS	PACE		1212	2120	RAS Action
Northern California	Consumnes	BANC	306	306	612	1X1 Generator outage, Gen Tie to plant
	Walnut Energy Center	TID		129	258	Loss of generation
Pacific Northwest - Montana	Noxon Plant RAS Trip	AVA	1500	540	550	Nox 239 East bus with RAS armed

	Schoolhouse	AVRN		598	598	Loss of John Day 239/500 kV transformer
	Columbia Generation Stn	BPAT		1180	1180	Loss of generation
	Rocky Reach – River Crossing 7-8-9	CHPD		410	1272	River crossing 7-8-9
	Wells	DOPD		168	840	Loss of generator step-up transformer (T1-T5) at Wells
	Wanapum – 4 Units	GCPD		440	1000	Trip of Wanapum Powerhouse #1 line or #2 line
	Centralia #2	GRID		710	710	Loss of generation
	BHE Power Watch	GWA		189	189	Loss of Hay Lakke-Rim Rock East & West 230 kV Generation Tie Line
	Clearwater	NWMT		750	1490	Loss of generation or generator lead line
	Chehalis	PACW		540	540	Loss of Napavine-Chehalis 500 kV line
	Carty	PGE		490	490	Loss of generation or generator lead line
	Penstemon Solar, Wild Horse Wind, Vantage Wind	PSE		382	382	230 kV Wind Ridge – Wanapum line
	Boundary Unit #55 or #56	SCL		234	1106	Loss of generation
	Mossyrock	TPWR		203	378	Generator – Transmission outage
	Fort Peck	WAUW		44	90	Loss of generation
Texas – New Mexico	Newman 5 in 2x1 configuration	EPE	900	228	268	Loss of generation
	Afton	PNM		235	235	Loss of generation
Western Colorado	Laramie River Station #2 or #3	WACM	570	570	570	Loss of generation

NWPP RSG Long-Term MSSC Limit	**Eastern Colorado Zone**		**1600**			

2. Jointly Owned Dynamic Generation Resources

This table below is a listing of jointly owned dynamic generation that could be considered a BCE under certain outage configurations.

Resource(s)	Reporting/ Operating BA	MSSC MW	Plant Capability	Balancing Authorities Participating in Jointly Owned Dynamic Generation	Capacity in MW as applicable
Four Corners 4	APS	770	1540	AZPS 70%	*
Four Corners 5		770		PNM 13%	*
				SRP 10%	*
				TEPC 7%	*
Pale Verde 1	APS	969	2907	APS	*
Pale Verde 2		969		EPE	*
Pale Verde 3		969		PNM	*
				SRP	*
Rock Island	CHPD	216	606	AVA 10%	*
				CHPD 50%	*
				PSE 40%	*
Rocky Reach – River Crossing 7-8-9	CHPD	410	1272	AVA 10%	*
				CHPD 44.46%	*
				DOPD 5.54%	*
				PSE 40%	*
Wells	DOPD	168	840	AVA	*
				CHPD	*
				DOPD	*
				PSE	`*

Resource(s)	Reporting/ Operating BA	MSSC MW	Plant Capability	Balancing Authorities Participating in Jointly Owned Dynamic Generation	Capacity in MW as applicable
Priest Rapids – 4 Units	GCPD	365	930	AVA	*
				GCPD	*
				PACW	*
				PGE	*
				PSE	*
				SCL	*
				TPWR	*
Wanapum - 4 units	GCPD	440	1000	AVA	*
				NWMT	*
				PACW	*
				PGE	*
				PSE	*
Colstrip 3 & 4	NWMT	740	1480	AVA	222
				NWMT	444
				PACW	148
				PGE	296
				PSE	370
					1480
Luna	PNM	570	570	PNM 66.33%	380
				TEPC 33.33 %	190
					570
Hermiston / Perennial	PACW	474	474	GRID	237
					237
					474

Resource(s)	Reporting/ Operating BA	MSSC MW	Plant Capability	Balancing Authorities Participating in Jointly Owned Dynamic Generation	Capacity in MW as applicable
Jim Bridger – RAS 2 Unit + Remote Wind	PACE	1212	2120	IPC	707
				PACE	1413
					2120
Gila River - *Blocks 1 & 4	SRP	550	2200	SRP 100%	1100
Gila River - *Blocks 2 & 3	TEPC	585		SRP 100%	1100
					2200
TEP and SRP have their own share based on blocks. *Under normal conditions this is not a JOU however SRP may report entire 2200MW based on N-4 conditions.*					
Springerville 1 & 2	**TEPC	450		TEP	*
Springerville 3	*PNM	458		PNM	*
				SRP	*
PNM does not own the generation, but PNM ACE is affected by the loss of generation and must request MW during disturbances to recover. **Under normal conditions this is not a JOU however TEP may report the entire amount based on potential N-4 conditions*					
Springerville 4	SRP	410		SRP	*

3. Jointly Owned Static Generation Resources

This table is a listing of jointly owned static generation that could be considered a BCE under certain outage configurations.

Resource(s)	Reporting/ Operating BA	MSSC MW	Plant Capability	Balancing Authorities Participating in Jointly Owned Dynamic Generation	Capacity in MW as applicable
Valmy	NEVP	268	395	IPC	134
				NEVP	261
					395

4. Multi Use Transformer(s)

This is a listing of transformers that are jointly utilized that could be a BCE under studied outage configurations.

Transformer(s)	Operating BA	Facility Rating	BA(s) with associated transformers	Generators	Generating Capacity in MW
John Day	BPA	1300 MVA	AVRN	Klondike I, II, III A, III GE, III Siemens, Starpoint, Hay Canyon, Golden Hills	809
			PGE	Biglow 1, Biglow 2, Biglow 3	450
					1259
Slatt	BPA	1300 MVA	AVRN	Montague Wind, Montague Solar	363
			BPA	Shepherds North (North Hurlburt)	265
			BPA	Shepherds South (South Hurlburt)	290
			BPA	Horseshoe Bend (Shepherds Central)	290
					1208
Rock Creek	BPA	1300 MVA	AVRN	Juniper Canyon, Lund Hil	299
			BPA	Windy Flats/Dooley	262
			BPA	White Creek Wind	205
			BPA	Harvest Wind	99
			PAC	Goodnoe Hills	150
					1015

Attachment L

Cut Planes and Cut Plane Monitors Between Reserve Sharing Zones

The following is a listing of the NWPP Reserve Sharing Group Participants that are monitors of the major transfer facilities and cut planes between Reserve Sharing Zones:

1) The Alberta Electric System Operator Balancing Authority (AESO) monitors the cut plane connecting the Alberta Reserve Sharing Zone with the British Columbia Reserve Sharing Zone,

2) The Bonneville Power Administration (BPA) Balancing Authority monitors the cut plane connecting the Pacific Northwest-Montana Reserve Sharing Zone with the British Columbia Reserve Sharing Zone,

3) The Idaho Power (IPC) Balancing Authority monitors the cut plane connecting the Mountain West Reserve Sharing Zone with the Pacific Northwest-Montana Reserve Sharing Zone,

4) The Balancing Authority of Northern California Balancing Authority (BANC) monitors the cut plane connecting the Pacific Northwest-Montana Reserve Sharing Zone with the Northern California Reserve Sharing Zone,

5) The PacifiCorp (PAC) Balancing Authority monitors the cut plane connecting the Mountain West Reserve Sharing Zone with the Arizona Nevada Reserve Sharing Zone,

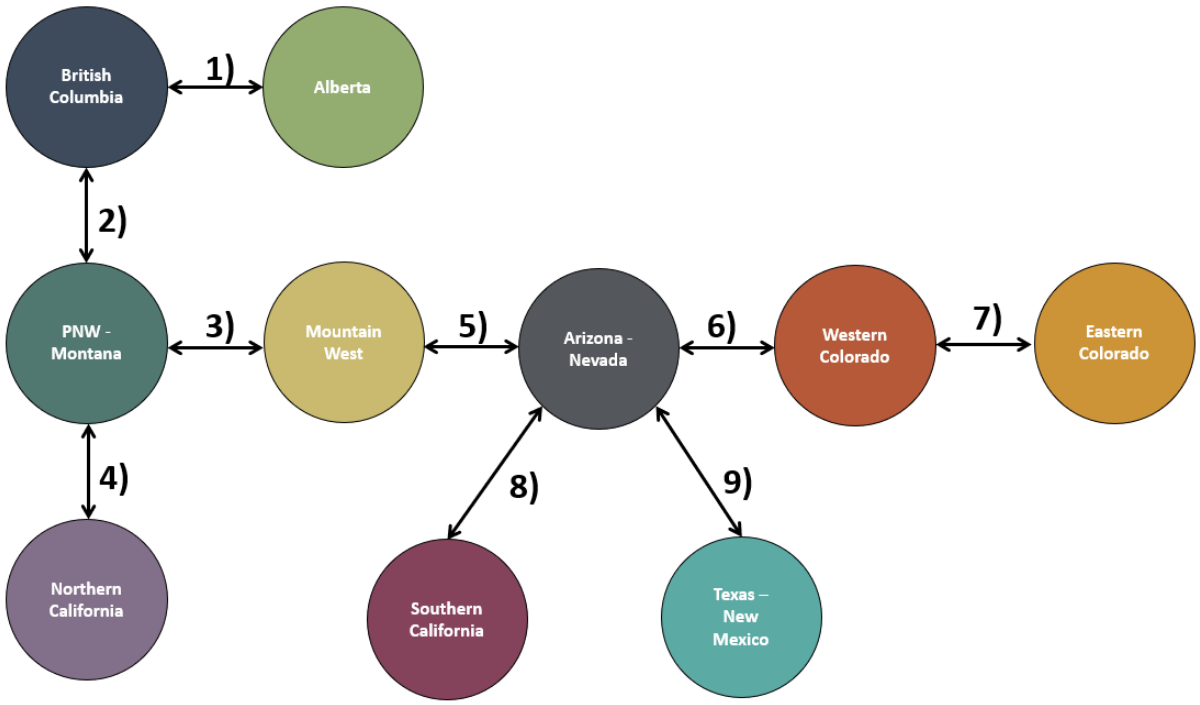
6) The Western Area Power Administration's Rocky Mountain Region (WACM) and Lower Colorado (WALC) Balancing Authorities monitor the cut plane connecting the Arizona Nevada Reserve Sharing Zone with the Western Colorado Reserve Sharing Zone,

7) The Western Area Power Administration's Rocky Mountain Region (WACM) Balancing Authority monitors the cut plane connecting the Western Colorado Reserve Sharing zone with the Eastern Colorado Reserve Sharing Zone,

8) The Imperial Irrigation District (IID) Balancing Authority monitors the cut plane connecting the Southern California Reserve Sharing zone with the Arizona Nevada Reserve Sharing Zone, and

9) The El Paso Electric Company (EPE) Balancing Authority monitors cut plane connecting the Arizona Nevada Reserve Sharing zone with the Texas New Mexico Reserve Sharing Zone.

See supporting picture of cut planes as identified above and represented between each of the zones:



Attachment M

Overview of BPA Remedial Action Schemes That Suspend Automatic Generation Control and Result in Expected Changes to NWPP Reserve Sharing Group Reporting ACE

Background:

This attachment (1) describes the operation and purposes of BPA Remedial Action Schemes (as defined in the NERC Glossary; also known as RAS) that are designed to drop generation and intentionally suspend Automatic Generation Control (AGC) actions to achieve the required flow mitigation effects of the RAS for transmission line outages that have large impacts to the integrity of the Western Interconnection, (2) explains why efforts by a Participating Balancing Authority or by the NWPP Reserve Sharing Group to immediately recover NWPP Reserve Sharing Group Reporting ACE following operation of this category of RAS would undermine the designed reliability benefits of the RAS, and (3) explains that the change in NWPP Reserve Sharing Group Reporting ACE that results from the planned, intentional generation dropping of these RAS is not unexpected and therefore does not meet the definition of a Balancing Contingency Event.

RAS Description:

For certain types of potential exceedances of System Operating Limits and Interconnection Reliability Operating Limits (SOL/IROL), BPA has designed RAS to intentionally drop generation and suspend related AGC actions. This category of RAS is intended to mitigate flow and stability impacts associated with various contingency events on transmission facilities. These transmission facilities are designed to operate at maximum transfer levels that rely on protection provided by the associated RAS. For example, RAS for the California-Oregon Intertie system (COI) and Pacific Direct Current Intertie system (PDCI) are in this category. There are other transmission facilities in the Northwest that also rely on this category of RAS to maximize transfer capability. Additional remedial actions for this category of RAS may include other actions such as fast switching of reactive devices and insertion of dynamic braking resistors.

This category of RAS intentionally suspends AGC within the BPA Balancing Authority and any other host Balancing Authorities of the associated generating units to avoid counteracting the intended flow mitigation benefit of the RAS. Even with AGC suspended, active governors of synchronized generators are expected to respond to the changed load-resource balance and resulting frequency drop. The Bulk Electric System within the Western Interconnection, including the affected areas, are expected to perform according to the BAL-003 requirements and immediately provide primary frequency control through governor action to arrest the frequency decline and stabilize the system.

Overall system recovery continues as the affected systems adjust transfers and generation or deploy contingency reserves, and the affected systems rebalance for the new level of transfers associated with the SOL/IROL. Each affected Balancing Authority restores its AGC once

transfers are adjusted. Generation then ramps up (receiving areas with imports curtailed) or down (sending areas with exports curtailed) to the new required levels, which enables each affected Balancing Authority to recover its Reporting ACE.

The Significance of BPA RAS in Relation to Reporting ACE:

Because certain planned generation dropping through RAS action is intended to protect affected transmission facilities within the NWPP from overloads, instability, or cascading outages, any action by Participants in the NWPP Reserve Sharing Group to immediately recover Reporting ACE following these specific RAS events may adversely affect reliability of the Bulk Electric System. Changes to the NWPP Reserve Sharing Group's Reporting ACE due to RAS actions are expected and, as such, are not Balancing Contingency Events. Generation is dispatched appropriately to accommodate the post-RAS system configuration, which may take more than 15 minutes.

BPA is responsible for notifying the WPP Staff whenever an event involving operation of this category of RAS has occurred, and therefore 15-minute recovery of NWPP Reserve Sharing Group Reporting ACE is not expected for that event.

Attachment N

Correlation Table of Participants, Reliability Coordinators, and Reserve Sharing Zones

Participant	Reliability Coordinator	Zone	Transfer Date
AESO	AESO	AB	N/A
AZPS	RC West	AZNV	11/1/2019
DEAA	SPP	AZNV	12/1/2019
AVA	RC West	PNWMT	11/1/2019
AVRN	RC West	PNWMT	11/1/2019
BANC	RC West	NCAL	7/1/2019
BCHA	BCHydro RC	BC	9/2/2019
BNBA	SPP	AZNV	7/1/2025
BPAT	RC West	PNWMT	11/1/2019
CHPD	RC West	PNWMT	11/1/2019
DOPD	RC West	PNWMT	11/1/2019
EPE	SPP	TXNM	12/13/2019
GCPD	RC West	PNWMT	11/1/2019
GRID (North)	SPP	PNWMT	12/3/2019
GRID (South)	SPP	AZNV	12/1/2019
GWA	RC West	PNWMT	11/1/20219
IID	RC West	SCAL	7/1/2019
IPC	RC West	ID	11/1/2019
NVE	RC West	HD	11/1/2019
NWMT	RC West	PNWMT	11/1/2019
PACE	RC West	PNWMT	11/1/2019

PACW	RC West	PNWMT	11/1/2019
PGE	RC West	PNWMT	11/1/2019
PSCO	SPP	ECO	12/3/2019
PNM	RC West	TXNM	11/1/2019
PSEI	RC West	PNWMT	11/1/2019
SRP	RC West	AZNV	11/1/2019
SCL	RC West	PNWMT	11/1/2019
TEP	SPP	AZNV	12/1/2019
TID	RC West	NCAL	7/1/2019
TPWR	RC West	PNWMT	11/1/2019
WACM	SPP	WCO	12/3/2019
WALC	SPP	AZNV	12/1/2019
WAUW	SPP	PNWMT	12/3/2019

DOCUMENTATION HISTORY

Updates:	Date:
NWPP Reserve Sharing Program	1-18-2006
Accommodation for new Balancing Authorities: SMUD & TID	6-07-2007
Combining of SPP and PACE zones into SPP-PACE zone	3-31-2008
Update of section D.3 for jointly owned generation	5-18-2008
Accommodation for new Balancing Authorities: GWA	10-13-2008
Updated terminology and addition of Attachments F, G, and H.	1-30-2009
Update of Attachment D to reflect tag template updates	3-31-2009
Update for requirement omission from 10-13-2008 version to 01-30-2009 version	3-31-2009
Clarity to sections I.5.l and H.2	4-8-2009
Update for computer failure, continuance to deliver reserve for full 60 minutes	4-8-2009
Clarification to Attachment B – Covered contingencies	5-12-2009
Update to Attachment B – Loss of wind generation due to temperature	7-1-2009
Grammar revision to definition of "Reportable Disturbance"	7-30-2009
Accommodation of information for the ACE Diversity Interchange (ADI) program	10-15-2009
Update of Attachment D – transmission mapping between NWMT and PGE	11-1-2009
Clarifying revisions and reorganization throughout; addition of language to Attachment B specifying Operating Committee authority to designate additional "Qualifying Events"; addition of Attachment K	10-18-2010
British Columbia Hydro and Power Authority NERC Registry acronym change from BCTC to BCHA	12-1-2010
Addition of definition of "RSG Committee"; replacement of most references to Operating Committee and all references to NWPP Reserve Sharing Subcommittee with references to RSG Committee; Updates of Attachment K	4-6-2011
Revision to Attachment B – addition of energy emergency as a Qualifying Event	10-5-2011
Update to section K.3. Financial Settlement with Powerdex Mid-Columbia Hourly	1-1-2012
Update to definition of Single Contingency, Section J.1.f with additional request language, and Section K.3. Financial Settlement clarification	6-7-2012
Revisions to Section 1.a of Attachment A to incorporate new requirements for photovoltaic and other types of generation; threshold in second bullet of	

definition of "Reportable Disturbance" lowered from 190 MW to 170 MW and updates to Attachment K Tables 1 and 3 1-10-2013

Clarifying updates throughout document including the addition of Section D.3.f, revisions to Sections E.2, E.4, F and updates to Attachments B, C, F and K 4-4-2013

Update to Attachment B and removal of (e) Unexpected loss of Contingency Reserve with new language to section (c) 6-6-2013

Updates to Attachments D, H, and K for incorporation of the NaturEner Wind Watch BA, WWA into program documentation 10-30-2013

Updates to Attachments D, H, and K for incorporation of the Constellation Energy Control and Dispatch BA, WWA into program documentation along with other clarifying updates throughout the document 11-25-2013

Updates to Attachments C, D, H, and K to reflect Nevada Power Company (NEVP), as operator of the consolidated Balancing Authority Area encompassing the Balancing Authority Areas previously operated separately by Sierra Pacific Power Company (SPPC) and Nevada Power Company (NEVP) 1-9-2014

Revisions throughout document to reflect implementation of WECC Standard BAL-002-WECC-2, to incorporate terms governing Loss of a Unit-Contingent Purchase, and to reflect the name change of the organization formerly known as Constellation Energy Control and Dispatch (CSTO) to Gridforce Energy Management, LLC (GRID) 8-15-2014 – Effective 10-1-2014

Revisions to incorporate language concerning RSG compliance with R3 and R4 of WECC BAL-002-WECC-2 8-22-2014 – Effective 10-1-2014

Clarifying revisions to the description of Contingency Reserve Obligation calculation in Attachment A, with conforming changes in body of document and other minor clean-up items 1-8-2015

Clarifying revisions to timing of requests for assistance reserve in section E.3; changes to section I.2, Major Transmission Facility Information; Attachment A, revisions regarding Balancing Authority Calculation of Contingency Reserve Obligation When Communications with Reserve Sharing Computer System Are Disrupted; and a new Attachment L, Transmission Facilities Making up Cut Planes Between Reserve Sharing Zones 4-2-2015

Clarifying revisions to section K.3.e to address how and when the NWPP Staff will complete and post calculations of applicable settlement prices 4-17-2015 – Effective 5-1-2015

Revisions to "Introduction and Overview" section to clarify that NWPP Staff are responsible for compliance reporting, not individual Participants; revisions to Section D.4.b to require at least quarterly reporting of data for R.3. and R.4 of WECC Standard BAL-002-WECC-2	10-8-2015
Addition and incorporation of the defined term "Contingency Reserve Available" and editorial cleanup revisions	4-1-2016
Clarifications related to NWPP Reserve Sharing Program participation status, determining real-time Most Severe Single Contingency, and reflection of NWPP Reserve Sharing Program requirements in Participant operating procedures	10-13-2016
Removal of language in Attachment B Qualifying Events, (d) Declaration of Energy Emergency Alert 2 or 3	05-12-2017
Effective May 12, 2017 - Participation in WECC Field Test Waiving Enforcement of BAL-002-WECC-2a, Requirement R2	05-12-2017
Revisions to harmonize definitions and other relevant provisions to NERC Standard BAL-002-2(i) and the NERC Glossary; miscellaneous cleanup and clarifying revisions	10-25-2017
Newly added definition for Operating Plan, clarifying changes to MSSC definition, and conforming changes sections D. 3., E.4. and L.	11-30-2017
Clarifying changes to term Reserve Sharing Zone, addition of terms: System Operator, BAA Net Generation, Net Generation, Actual Net Interchange, Scheduled Net Interchange; clarifying changes to Sections D.3.j, revisions to Section I.1,, addition of Section I.5.d., clarifying changes to Attachment A of BAA Net Generation, Net Generation, Actual Net Interchange, Scheduled Net Interchange; revisions to Attachments D, H, and K to reflect addition of Avangrid Renewables as a new Participant. Changes to update the WECC and NERC BAL-002 standards to conform through the entire document.	5-10-2018
Clarifying changes to section D.3.k. to clarify NWPP RSG procedures related to Energy Emergency Alerts. In addition, clarifying language was added to Section L. regarding Obligation to submit a NWPP RSG Verification Form and new Section L.2. added regarding Reporting Balancing Obligation to Notify NWPP Staff.	11-8-2018

New term added for NWPP Reserve Sharing Group Reporting ACE. In addition, new Attachment M – *Overview of BPA Remedial Action Schemes That Suspend Automatic Generation Control and Result in Expected Changes to NWPP Reserve Sharing Group Reporting ACE* and Attachment N -

Correlation Table of Participants, Reliability Coordinators and Zones. Clarifying changes to section I.5. regarding data telemetered from Reserve Sharing Program to the Reliability Coordinator with the addition of the NWPP RSG Reporting ACE and new Section I.6. – Management of Data Related to Reserve Sharing Zones. 2-14-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 2-14-2019

Clarifying notes to Attachment B - Qualifying Events with new *note 2* and formatting (similar to NERC Definition for Balancing Contingency Event). Additional housekeeping items to clarify front page with BAL-002-WECC-2a, Section H.3. with updated contact information, corrected bulleting in Attachment A, and updated Attachment L with appropriate AESO Cut Plane facilities. 5-16-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 5-16-2019

Clarification to WECC Waiver regarding BAL-002-WECC-2a R2. Balancing Contingent Event term added and conforming changes throughout document for a Reportable Balancing Contingent Event. Reporting ACE clarification to Section I.1.f. and J.2.a. Language added to section L.1 to address RSG reporting of EEAs. Clarification of zones to response levels to Attachment C, including new tables for zones and associated BAs along with responding levels. In addition, the removal of Attachment D with new reference to NWPP RSG Tag Templates and conforming changes. Housekeeping changes to conform document with Attachment N. 7-1-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 7-1-2019

Updates to address the addition of new BA Participants, WACM and PSCO for live operation 9-3-2019. Conforming changes throughout document (Section I.2., I.4.d., Attachment C, Attachment H, Attachment K, Attachment L, and Attachment N). 7-1-2019 – effective 9-3-2019

Revisions to Attachment M by removing "Reportable" from references to Balancing Contingency Event. 8-8-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 8-8-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 11-7-2019

Clarifications made to section E.3. Timing of Requests for Assistance Reserve. Additions to section H.3. with respect providing ICCP failover notifications to NWPP staff. Revisions to section I.5. regarding Data Telemetered to the RCs and elimination of section I.6 as it is all covered in the revised section I.5. Revisions to section K. Settlement with the elimination of Energy In-Kind settlement and conforming changes. 11-7-2019

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 2-6-2020

Housekeeping update to WECC Waiver extension to BAL-002-WECC-2a R2 on front page. 4-6-2020

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Housekeeping update to font formatting and indexing. Addition of Process Diagrams as Attachment D (General Process Diagram, Settlement Process, Calculation of CRO, and Back-up Procedures). Consistent naming of generator contingencies in Attachment K. 5-7-2020

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Revised Section B. term for *Participating Balancing Authority or Participant*. Revisions to Section C.3. to address Balancing Authority versus Balancing Authority Area and program functionality. Revisions to Section F. to further clarify program functionality for commitment of Contingency Reserve Obligation when requesting Assistance Reserve, including conforming changes to Section I.4.d. and elimination of Section 2. *Discretion of Participating BA to Carry More Contingency Reserve Than Required by Calculation of Minimum Contingency Reserve Obligation; Obligation to Make All Reported Contingency Reserve Available*. Section I.1. revision and addition of new data from Participant BAs to program (BA_FBS, BA_Ime, BA_ATEC, and BA_ADI). Updates to section L. as related to Internal RSG Reporting. Revisions to Attachment A, Section 1. to address program update to MSSC Deadbands. Attachment K MSSC Updates to PGE MSSC. 11-5-2020

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Housekeeping update to font formatting and indexing. Revisions to Section B. Terminology's *BAL-002* term. Revisions to Sections E.2. regarding actions required to respond to an EEA. Revisions to Section

E.3. regarding length of time for accessing Contingency Reserve to respond to EEAs. Conforming changes to address Section B. *Contingency Reserve Available* term relating to EEA. Last, updates to Section I.1. h. & i. to reflect correct use of NI_A and NI_S. 2-4-2021

Updated language to Section H.2. to for NWPP Staff to perform analysis on each Reportable Balancing Contingency Event that the NWPP RSG experiences. 3-30-2021

Updated cover page to reflect WECC-0115 BAL-002-WECC-2a, Requirement R2, Compliance Waiver Extension 4-6-2021

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Revisions to section D.2. to address appropriate reference to Attachment A and its sections. Revisions to Attachment A. 1 to remove the 1.5 shortfall multiplier to address the current functionality of computer program. 5-6-2021

RSGC approved updates (Feb. 4, 2021) to conform documentation with new Standard BAL-002-WECC-3, effective June 28, 2021 6-28-2021

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 8-5-2021

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Clarifying changes to Contingency Reserve Available (CRA) term, clarifying changes to NWPP Reserve Sharing Group Reporting ACE term, clarifying changes to Section D.3.i - ACE recovery period and size, clarifying changes to Section I.3.j. & k to address calculation of Reporting ACE, addition to Section F. regarding metrics for Deployment of Contingency Reserve, clarifying changes to Section H. regarding Participant responsibilities related BA footprint changes to MSSC (Unit configuration, RAS, etc.), and update to Section K.2.c. regarding annual review period. 11-5-2021

Updates to Section H. to address clarifications to Roles and Responsibilities of the Participant, NWPP Staff with on-call support 24x7, and RSG Committee. 1-12-2022

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Addition of new to Sections I.4. p. and I.4.q. as approved in 2018.11.09. 2-3-2022

Updated Attachment K Tables with new Table 4 to address AVRN's new Gold Hills Wind Project

connected to BPA transformer. 3-11-2022

Housekeeping from NWPP to WPP (*NWPP doing business as WPP*), including associated email addresses. Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 5-5-2022

Updated Attachment K Tables with PAC transfer of Jim Bridger from PACW to PACE BAA, updating new MSSCs for both, effective July 6, 2022 6-29-2022

More conforming updates to address NWPP to WPP. New Section E.3. and conforming changes to address performance metric for deployment of Contingency Reserve. Updates to Section K.2. Financial Settlement from use of Powerdex to the Intercontinental Exchange (ICE) in October 2022 (Mid-Columbia and Palo Verde). Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 8-4-2022

Section B. Clarifying updates CRA Definition and conforming updates to Section D.3.b., Section E.2. and Section J.1. Section B. new term: 'Recovery Reporting ACE Target'. Performance Metric updates to Section E.4 and F. Clarifying updates to section K.2.Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 11-3-2022

Attachment K Tables updated with GCPD MSSC to Tables 1 - Priest Rapids and Table 3 - Wanapum. 12-21-2022

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Attachment K Table 1 with GCPD MSSC and clarifying change to term 'Recovery Reporting ACE Target' 2-2-2023

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Attachment K Table 1 Colstrip Capacity Numbers, Table 2 Valmy Shares, and Table 3 AESO Plant Capability, 5-4-2023

Updated NaturEner Attachment H with NaturEner Balancing Authority Name change to BHEM Power Watch, LLC and BHEM Wind Watch, LLC 5-5-2023

Updated Qualifying Events from all EEAs to EEA3 only – Deleted previous section D.3.k (Script for talking to RC to prevent unnecessary EEAs). Clarifications to Sections E.2

., E.3. Attachment B.

6-8-2023

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 8-3-2023

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Attachment K Table 1 for PACE and GCPD along with Table 3 for PACE. 11-2-2023

Updates to conform documentation with zonal transition from Idaho and High Desert Zones to Mountain West and Arizona Nevada Zone to Section I.2., Attachments C, K, L & N. 1-24-2024

Clarifying language added to Section F, newly added Section P – Penalties for Non-Performance (Effective July 1, 2024), and conforming changes to Section I.4.c. In addition, reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Attachment K Table 1 Rocky Reach-River Crossing 7-8-9 Participants. 2-8-2024

Conforming changes with the addition of the new Balancing Authority Participants (AZPS, DEAA, EPE, IID, HGMA, PNM, SRP, TEPC, WALC) effective May 1, 2024 to Attachment C, Attachment H, Attachment K, Attachment L updates and conforming changes to Section I.2., and Attachment N. In addition, consistency with use of term 'RSG Committee', removal of standards documentation to Attachment I NERC BAL-002 and Attachment J BAL-002-WECC. 3-20-2024

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Attachment K Table 1 for BANC and TEPC 5-17-2024

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. 8-8-2024

Updates to Section P for a review process to allow for partial credit, to provide clarity that an entity may still receive credit for the "clock-minute averages" independently of meeting the Recovery Reporting ACE Target criteria. In addition, reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining

system reliability. 11-7-2024

Reviewed and updated the Operating Process (including all tables in Attachment K) to determine the NWPP's MSSC and make preparations to have Contingency Reserve equal to, or greater than the NWPP's MSSC available for maintaining system reliability. Updated Program Documentation with new terms: Balancing Authority Area MSSC, Long-Term Zonal MSSC Limit, and NWPP Reserve Sharing Group Long-Term MSSC Limit. Conforming changes to Section M to address MSSC limits, and conforming changes to Attachment K Table 1 with Maximum Allowable Zonal MSSC and NWPP RSG Long-Term MSSC Limit. 2-6-2025

Review and update to Attachment K, 1. column header from BAA MSSC MW to BAA System Normal MSSD MW. 2-12-2025

Conforming changes with the consolidation of HGMA BA into SRP BA, effective June 1, 2025, the addition of the new First LightEnergy, LLC BA (BNBA), effective July 1, 2024 to Attachment C, Attachment H, Attachment K, Attachment N. 7-1-2025

Updates to Attachment K, 1. BAA MSSC for NEVP and 2., adding back Jim Bridger for PACE and IPC. 9-23-2025

Conforming changes with the consolidation of BHE Montana's WWA BA into the GWA BA, effective October 1, 2025. 10-1-2025

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-77:
Western Frequency Response Sharing Group

WESTERN FREQUENCY RESPONSE SHARING GROUP

As permitted by the NERC Standard, BAL-003-2, many Balancing Authorities within the Northwest Power Pool Area have instituted the Western Frequency Response Sharing Group (WFRSG). By collectively participating in the WFRSG, participants are entitled to calculate their annual Frequency Response Measure (FRM) in aggregate to achieve an FRM that is equal to or more negative than its' (the WFRSG) FRO to assure sufficient Frequency Response is provided to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation.

MORE INFO

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WFRSG - WFRSGC

WFRSG Agenda and Meeting Materials

WFRSG Agenda and Meeting Materials

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WFRSG - WFRSGC

2024 Q3 Updates - FRS Form 1 and FRS Form 2

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WFRSG - WFRSGC

2024 Q2 Updates - FRS Form 1 and FRS Form 2

LOCKED

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WFRSG PARTICIPANTS

aeso ALBERTA ELECTRIC SYSTEM OPERATOR

AVANGRID

AVISTA

BANC

BHE MONTANA A BERKSHIRE HATHAWAY ENERGY COMPANY

Black Hills Energy

Bonneville POWER ADMINISTRATION

P.U.D. CHELAN COUNTY

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PGE

Xcel Energy

PSE PUGET SOUND ENERGY

SRP

Seattle City Light

SPP Southwest Power Pool

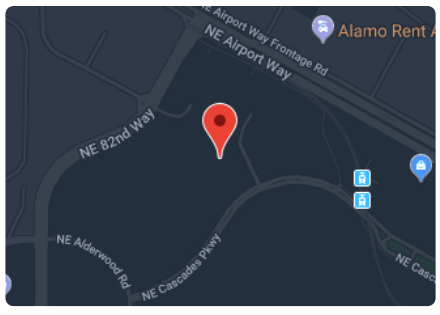
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7525 NE Ambassador Place, Suite M
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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-78:
WRAP Tariff

WESTERN RESOURCE ADEQUACY PROGRAM

TARIFF

OF

NORTHWEST POWER POOL

D/B/A

WESTERN POWER POOL

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SCHEDULE 1
WESTERN RESOURCE ADEQUACY PROGRAM ADMINISTATIVE COST RECOVERY CHARGE

ATTACHMENT A
Western Resource Adequacy Program Agreement

PART I GENERAL PROVISIONS

1. Definitions

Unless the context otherwise specifies or requires, capitalized terms used in this Tariff shall have the respective meanings assigned herein for all purposes of this Tariff (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Parts, Sections, Schedules, or Attachments, are to Parts, Sections, Schedules, or Attachments of this Tariff.

Applicable Price Index: A published index of wholesale electric prices, or Locational Marginal Prices duly calculated and posted by a FERC-regulated market operator, in either case as designated under Part III of this Tariff for use in connection with an identified Subregion.

Administration Charge or WRAP Administration Charge: The charge established under Schedule 1 of this Tariff for recovery of the costs of the WRAP.

Advance Assessment: Analyses and calculations of Participant load, resource, and other information performed in advance of each Binding Season as set forth in Part II of this Tariff.

Aggregate Capacity Deficiency: As to a Binding Season, the sum of the maximum Monthly Deficiencies of all Participants that submitted FS Submittals for such Binding Season, as determined following completion of the Cure Period for such Binding Season.

Available Transfer Capability ("ATC"): Transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains demand and resource balance within a Balancing Authority Area, and supports interconnection frequency in real time.

Balancing Authority Area: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

Base Charge: A component of the WRAP Administration Charge as established under Schedule 1 of this Tariff.

Base Costs: Base Costs shall have the meaning provided in Schedule 1 of this Tariff.

Base Services Cost Centers: The cost centers comprising the Base Charge as defined in Schedule 1 of this Tariff.

Base Services Percentage: Base Services Percentage shall have the meaning provided in Schedule 1 of this Tariff.

Binding Season: The Summer Season or the Winter Season.

Board of Directors or Board: The Board of Directors of the Northwest Power Pool d/b/a Western Power Pool.

Business Day: Any Day that is a Monday through Friday, excluding any holiday established by United States federal authorities.

Business Practice Manuals: The manuals compiling further details, guidance, and information that are appropriate or beneficial to the implementation of the rules, requirements, and procedures established by this Tariff. Business Practice Manuals do not include such internal rules or procedures as the Western Power Pool may adopt for its operation and administration, including but not limited to any corporate by-laws of the Western Power Pool, or for any services or functions provided by the Western Power Pool other than those established by this Tariff.

CAISO: The California Independent System Operator Corporation, a California nonprofit public benefit corporation.

Capacity Benefit Margin: An amount of transmission transfer capability permitted under open access transmission rules to be reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

Capacity Critical Hours ("CCH"): Those hours during which the net regional capacity need for the WRAP Region is expected to be above the 95th percentile, based on historical and synthesized data for the WRAP Region's gross load, variable energy resource performance, and interchange.

Capacity Deficiency: A shortfall in a Participant's Portfolio QCC relative to that Participant's FS Capacity Requirement, as further defined in Part II of this Tariff.

Cash Working Capital Fund: Cash Working Capital Fund shall have the meaning provided in Schedule 1 of this Tariff.

Cash Working Capital Support Charge: A charge assessed to Participants under Schedule 1 of this Tariff to fund the Cash Working Capital Fund.

Cash Working Capital Support Charge Rate: Cash Working Capital Support Charge Rate shall have the meaning provided in Schedule 1 of this Tariff.

Central Hub: A designated point or named group of points on the transmission system within a Subregion identified by the Program Administrator that permits energy deliveries from multiple points within such Subregion.

Cost of New Entry ("CONE"): The estimated cost of new entry of a new peaking natural gas-fired generation facility, as determined under, and used in, Part II of this Tariff.

CONE Factor: A factor employed in the calculation of Deficiency Charges under Part II of this Tariff, to reflect whether, and the extent to which, the WRAP Region as a whole is expected to have a capacity deficiency during the period for which the Deficiency Charge is being calculated or a factor employed when a Participant has had repeated deficiencies in sequential years.

Committee of State Representatives ("COSR"): Committee of State Representatives, as established in Part I of this Tariff.

Contingency Reserve: As more fully described in the NERC WECC reliability standards, a quantity of reserves, consisting of generation, load, interchange, or other resources, that are deployable within ten minutes, equal to the greater of (i) the MW quantity of the loss of the most severe contingency and (ii) the megawatt quantity equal to the sum of 3% of hourly integrated load plus 3% of hourly integrated generation.

Critical Mass: *The threshold level of participation in a Subregion, as established in the Business Practice Manuals, below which each Participant of such Subregion may elect to participate as a Non-Binding Participant.*

Cumulative Delivery Failure Period: Any period of five consecutive years, ending with and including the most recent Energy Delivery Failure as of the time of determination of a possible Delivery Failure Charge.

Day: A calendar day.

Day-Ahead Price: A price for wholesale electric transactions designated as a day-ahead price in an Applicable Price Index.

Default Allocation Assessment: A charge assessed on non-defaulting Participants to recover the costs associated with a default by a Participant, as set forth in Part I of this Tariff.

Deficiency Charge: A charge assessed for a Capacity Deficiency or Transmission Deficiency, as set forth in Part II of this Tariff.

Delivery Failure Charge: A charge assessed for a Participant's failure to deliver a required Energy Deployment, as set forth in Part III of this Tariff.

Delivery Failure Charge Rate: A rate employed in the determination of a Delivery Failure Charge as more fully set forth in Part III of this Tariff.

Delivery Failure Factor: A factor used in the determination of a Delivery Failure Charge to recognize the relative severity or impact of an Energy Delivery Failure, as set forth in Part III of this Tariff.

Demand Response: A quantifiable load reduction or otherwise controllable load for which a Participant has two mutually-exclusive options to use to affect its FS Capacity Requirements in a FS for a Binding Season: (1) leave the effects of historically deployed demand response as part of its load provided for the Advance Assessment; or (2) utilize as a Demand Response Capacity Resource.

Demand Response Capacity Resource: A Qualifying Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements established under Part II of this Tariff utilized to meet a Participant's FS Capacity Requirement.

Demonstrated FS Transmission: A Participant's demonstration in its Forward Showing Submittal that it has secured firm transmission service rights of the type and quantity sufficient to provide reasonable assurance, as of the time of the Forward Showing Submittal, of delivery of

capacity from the Qualifying Resources and the resources associated with the power purchase agreements in the Participant's Portfolio QCC.

Discounted Deficiency Change: *A reduced Deficiency Charge during the Transition Period that enables a deficient Participant that demonstrates commercially reasonable efforts but is unable to cure deficiencies to access Operations Program capacity.*

Dual Benefit Cost Centers: Dual Benefit Cost Centers shall have the meaning provided in Schedule 1 of this Tariff.

Effective Load Carrying Capability ("ELCC"): A methodology employed to determine the Qualified Capacity Contribution of certain types of Qualifying Resources, as more fully set forth in Part II of this Tariff.

Energy Declined Settlement Price: A pricing component used as part of the calculation of settlements for Holdback Requirements and Energy Deployments under Part III of this Tariff.

Energy Delivery Failure: A failure by a Participant to provide an Energy Deployment assigned to such Participant under Part III of this Tariff.

Energy Deployment: A delivery of energy that a Participant is required to provide during an Operating Day, as set forth in Part III of this Tariff.

Energy Storage Resource: A resource, not including a Storage Hydro Qualifying Resource, designed to capture energy produced at one time for use at a later time.

Excused Transition Deficit: A Participant's inability during the Transition Period to demonstrate full satisfaction of the Participant's FS Capacity Requirement, which, under certain conditions and limitations prescribed by Part II of this Tariff, permits *the Participant to pay a Discounted* Deficiency Charge.

Federal Power Marketing Administration: A United States federal agency that operates electric systems and sells the output of federally owned and operated hydroelectric dams located in the United States.

FERC: The Federal Energy Regulatory Commission.

Forced Outage Factor: The factor resulting from dividing the number of hours a generating unit or set of generating units is not synchronized to the grid system, not in reserve shutdown state and considered to be out of service for unplanned outages—or a startup failure, by the number of total hours in the period multiplied by 100% or a Program Administrator calculated equivalent forced outage factor that reflects the likelihood and extent to which a resource will be unavailable from time to time due to factors outside management control.

Forward Showing Program: The program and requirements as set forth in Part II of this Tariff.

Forward Showing Submittal ("FS Submittal"): The submissions a Participant is required to submit in advance of each Binding Season to demonstrate its satisfaction of the FS Capacity Requirement and FS Transmission Requirement, as set forth in Part II of this Tariff.

Forward Showing Year: A period consisting of a Summer Season and the immediately succeeding Winter Season.

FS Capacity Requirement: The minimum quantity of capacity a Participant is required to demonstrate for a Binding Season, as set forth in Part II of this Tariff.

FS Deadline: The deadline for Participants' submissions of their FS Submittals for a Binding Season, as established under Part II of this Tariff.

FS Planning Reserve Margin ("FSPRM"): An increment of resource adequacy supply needed to meet conditions of high demand in excess of the applicable peak load forecast and other conditions such as higher resource outages, or lower availability of resources, expressed as a percentage of the applicable peak load forecast, as determined in accordance with Part II of this Tariff.

FS Transmission Requirement: The minimum quantity of transmission service rights a Participant is required to demonstrate for a Binding Season, as set forth in Part II of this Tariff.

High-Priced Day: The most recent day in the CAISO in which prices in the day-ahead market were at least $200/MWh.

Holdback Capacity: Capacity that is voluntarily supplied or is the result of a positive Sharing Calculation result that is bindingly committed to the WRAP after it is claimed by one or more Participants with a negative Sharing Calculation result.

Holdback Requirement: A MW quantity, as determined on a Preschedule Day, that a Participant is required to be capable of converting into an Energy Deployment on a given hour of the succeeding Operating Day, as more fully set forth in Part III of this Tariff.

ICE Index: A wholesale electric price index prepared and published by the Intercontinental Exchange.

Incremental Cash Working Capital Support Charge: Incremental Cash Working Capital Support Charge shall have the meaning provided in Schedule 1 of this Tariff.

Independent Evaluator: An independent entity engaged to provide an independent assessment of the performance of the WRAP and any potential beneficial design modifications, as set forth in Part I of this Tariff.

Installed Capacity: Nameplate capacity adjusted for conditions at the site of installation.

International Power Marketing Entity: An entity that (i) owns, controls, purchases and/or sells resource adequacy supply and is responsible under the WRAP program for meeting LRE obligations associated with one or more loads physically located outside the United States.

Legacy Agreement: A power supply agreement entered into prior to October 1, 2021.

Load Charge: A component of the WRAP Administration Charge as established under Schedule 1 of this Tariff.

Load Charge Rate: Load Charge Rate shall have the meaning provided in Schedule 1 of this Tariff.

Load Services Costs: Load Services Costs shall have the meaning provided in Schedule 1 of this Tariff.

Load Services Cost Centers: Load Services Cost Centers shall have the meaning provided in Schedule 1 of this Tariff.

Load Services Percentage: Load Services Percentage shall have the meaning provided in Schedule 1 of this Tariff.

Load Responsible Entity ("LRE"): An LRE is an entity that (i) owns, controls, purchases and/or sells resource adequacy supply, or is a Federal Power Marketing Administration or an International Power Marketing Entity, and (ii) has full authority and capability, either through statute, rule, contract, or otherwise, to:

(a) submit capacity and system load data to the WRAP Program Operator at all hours;

(b) submit Interchange Schedules within the WRAP Region that are prepared in accordance with all NERC and WECC requirements, including providing E-Tags for all applicable energy delivery transactions pursuant to WECC practices and as required by the rules of the WRAP Operations Program;

(c) procure and reserve transmission service rights in support of the requirements of the WRAP Forward Showing Program and Operations Program; and

(d) track and bilaterally settle holdback and delivery transactions.

Subject to the above-mentioned criteria, an LRE may be a load serving entity, may act as an agent of a load serving entity or multiple load serving entities, or may otherwise be responsible for meeting LRE obligations under the WRAP.

Locational Marginal Price: The cost of delivering an additional unit of energy to a given node, as calculated under a FERC-regulated wholesale electric tariff.

Loss of Load Expectation ("LOLE"): An expression of the frequency with which a single event of failure, due to resource inadequacy, to serve firm load would be expected (based on accepted reliability planning analysis methods) to result from a given FS Planning Reserve Margin.

Make Whole Adjustment: A component used as part of the calculation of settlements for Holdback Requirements and Energy Deployments under Part III of this Tariff.

Maximum Base Charge: The maximum amount prescribed in Schedule 1 of the Tariff that the Base Charge cannot exceed.

Maximum Load Charge Rate: The maximum rate prescribed in Schedule 1 of the Tariff that the Load Charge Rate cannot exceed.

Median Monthly P50 Peak Loads: Median Monthly P50 Peak Loads has the meaning prescribed by Schedule 1 of this Tariff.

Month: A calendar month.

Monthly Capacity Deficiency: A Participant's Capacity Deficiency for a given Month.

Monthly Deficiency: An identification under Part II of this Tariff whether, and the extent to which, a Participant's need for capacity or transmission for a given Month is greater than the capacity or transmission, respectively, the Participant can demonstrate for such Month.

Monthly FS Capacity Requirement: FS Capacity Requirement determined as to a Month.

Monthly FSPRM: The FS Planning Reserve Margin applicable to a given Month of a given Binding Season, as determined in accordance with Part II of this Tariff.

Monthly Transmission Deficiency: A Participant's Transmission Deficiency for a given Month.

Monthly Transmission Demonstrated: A Participant's Demonstrated FS Transmission for a given Month.

Monthly Transmission Exceptions: Exceptions from the FS Transmission Requirement approved under Part II of this Tariff for a Participant for a given Month.

Multi-Day-Ahead Assessment: A period of days preceding each Operating Day, and ending on the Preschedule Day, during which Sharing Calculations are successively performed based in each case on Operating Day conditions expected at the time of calculation.

North American Electric Reliability Corporation ("NERC"): A not-for-profit international regulatory authority that serves as the designated electric reliability organization for the continental United States, Canada, and a portion of Mexico.

Net Contract QCC: The QCC, which may be a positive or negative value, calculated, in sum and on net, for a Participant's power purchase agreements and power sale agreements, in accordance with Part II of this Tariff.

Non-Binding Season: As to a Participant, *any* Binding Season during which the *provisions of Section 15A.1* of this Tariff *apply*.

Non-Binding Participant: For any Binding Season, a Participant that has made an election by which such Binding Season is a Non-Binding Season for that Participant.

Open Access Transmission Tariff: A governing document on file with FERC establishing the rates, terms, and conditions of open access transmission service, or equivalent tariff of a transmission service provider that is not required to file its transmission service tariff with FERC.

Operating Day: A current Day of actual electric service from resources to load, for which Sharing Events are determined and Energy Deployments may be required, as set forth in Part III of this Tariff.

Operations Program: The program and requirements set forth in Part III of this Tariff.

P50 Peak Load Forecast: A peak load forecast prepared on a basis, such that the actual peak load is statistically expected to be as likely to be above the forecast as it is to be below the forecast.

Participant: A Load Responsible Entity that is a signatory to the WRAPA.

Portfolio QCC: As to a Participant, the sum of the Resource QCC provided by all of a Participant's Qualifying Resources plus the Net Contract QCC of such Participant, as adjusted to reflect RA Transfers as described in Section 16.2 7 and Planned Outages as described in Section 16.2.8.

Preschedule Day: The applicable scheduling Day for a given Operating Day as defined in scheduling calendar established by WECC.

Program Administrator: The Western Power Pool, in its role as the entity responsible for administering the WRAP.

Program Operator: A third party that has contracted with the Program Administrator to provide technical, analytical, and implementation support to the Program Administrator for the WRAP.

Program Review Committee ("PRC"): The stakeholder sector committee as established in Section 4.2 of this Tariff.

Pure Capacity: A MW quantity of capacity without any assigned forced outage rate employed in ELCC determinations under Part II of this Tariff.

Qualifying Capacity Contribution ("QCC"): The MW quantity of capacity provided by a resource, contract, or portfolio which qualifies to help satisfy a Participant's FS Capacity Requirement, as determined in accordance with Part II of this Tariff.

Qualifying Resource: A generation or load resource that meets the qualification and accreditation requirements established by and under Part II of this Tariff.

Real-Time Price: A price for wholesale electric transactions designated as a real-time price in an Applicable Price Index.

Resource Adequacy Participant Committee ("RAPC"): The committee comprised of representatives from each Participant as established in Part I of this Tariff.

Resource QCC: The QCC provided by a Qualifying Resource, as determined in accordance with Part II of this Tariff.

Run-of-River Qualifying Resource ("ROR"): A hydro-electric power project that does not have the capability to store a sufficient volume of water to support continuous generation at the project's stated maximum capacity for a period of one hour. Resource does not meet the definition of a Storage Hydro Qualifying Resource.

Safety Margin: An additional factor allocated among Participants with positive sharing calculations when warranted by certain conditions as prescribed by Part III of this Tariff.

Senior Official Attestation: A signed statement of a senior official of a Participant attesting that it has reviewed such Participant's information submission required under this Tariff, that the statements therein are true, correct and complete to the best of such official's knowledge and belief following due inquiry appropriate to the reliability and resource adequacy matters addressed therein, and containing such further statements as required by this Tariff or the applicable Business Practice Manual for the information submission at issue.

Sharing Calculation: A calculation used in the Operations Program under Part III of this Tariff to identify any hour in which any Participant is forecast to have a capacity deficit.

Sharing Event: An hour or hours of an Operating Day for which one or more Participants has a negative Sharing Calculation result, as determined in accordance with Part III of this Tariff.

Storage Hydro Qualifying Resource: A hydro-electric power project with an impoundment or reservoir located immediately upstream of the powerhouse intake structures that can store a sufficient volume of water to support continuous generation at the project's stated maximum capacity for a period of one hour or longer.

Subregion: An area definition approved by the Board of Directors and identified in the Business Practice Manuals, that is wholly contained within the WRAP Region, which is separated from one or more other Subregions by transmission constraints on capacity imports or on capacity exports that result, or are expected to result, in differing FSPRM determinations for that Subregion relative to such other Subregion.

Summer Season: A period of time that commences on June 1 of a Year and terminates on September 15 of the same Year.

System Sale: A bilateral agreement that conveys generating capacity from a group of generating resources from one party to another.

Transition Period: The Binding Seasons within the time period from June 1, 2025, through March 15, *2029*, plus the time period required to implement the requirements and procedures of Part II of this Tariff applicable to such Binding Seasons.

Transmission Deficiency: A shortfall in a Participant's demonstration of secured transmission service rights, after accounting for any approved transmission exceptions, relative to that Participant's FS Transmission Requirement, as further defined in Part II of this Tariff.

Unforced Capacity: The percentage of Installed Capacity available after a unit's forced outage rate is taken into account.

Variable Energy Resource ("VER"): An electric generation resource powered by a renewable energy source that cannot be stored by the facility owner or operator and that has variability that is beyond the control of the facility owner or operator, including but not limited to a solar or wind resource.

VER Zone: A geographic area delineated in accordance with Section 16.2.5.2 of this Tariff for a given type of VER, where each VER of that type located in such area is anticipated to be comparably affected by meteorological or other expected conditions in such area to a degree that warrants distinct calculation of ELCC allocations for such VERs of that type in such area.

Voluntary Holdback: Capacity that is offered to the Operations Program by a Participant with excess supply that is not obligated to the WRAP through a positive Sharing Calculation result, some or all of which can used as part of the offering Participant's Holdback Requirement. For a Participant in a Subregion without a Central Hub, Voluntary Holdback for an hour must additionally include a total quantity for all identified points from Section 19.4 at which it can deliver that is no less than the amount of the Voluntary Holdback capacity for such hour.

Western Electricity Coordinating Council ("WECC"): A non-profit corporation that has been approved by FERC as the regional entity for the western interconnection and that also has NERC delegated authority to create, monitor, and enforce reliability standards.

Western Resource Adequacy Program Agreement ("WRAPA"): The participation agreement for the Western Resource Adequacy Program, as set forth as Attachment A to this Tariff, or as set forth for an individual Participant in a non-conforming version of such participation agreement accepted by FERC.

Western Resource Adequacy Program ("WRAP"): The Western Resource Adequacy Program, as established under this Tariff.

Western Power Pool ("WPP"): Northwest Power Pool, d/b/a Western Power Pool, which serves as Program Administrator for the WRAP under this Tariff and holds exclusive rights under section 205 of the Federal Power Act to file amendments to this Tariff.

Winter Season: A period of time that commences on November 1 of a Year and terminates on March 15 of the immediately following Year.

WRAP Cost Assignment Matrix: The matrix set forth in Schedule 1 of this Tariff to identify which WRAP costs are assessed to the Base Charge and the Load Charge components of the WRAP Administration Charge.

WRAP Region: The area comprising, collectively, (i) the duly recognized and established load service areas of all loads in the United States that all Participants are responsible for serving, (ii) the duly recognized and established load service areas of all loads in the United States that all load serving entities, on whose behalf a Participant acts in accordance with this Tariff, are responsible for serving, and (iii) the applicable location(s) on the United States side of the United States

international border that form the basis for an International Power Marketing Entity's participation under the WRAP, in all cases excluding, for any Binding Season, any loads permitted by this Tariff to be excluded from Participants' Forward Showing Submittal for such Binding Season.

Year: A calendar year.

2. Role of Western Power Pool

2.1 WPP, acting under the direction of its Board of Directors, shall administer the WRAP as Program Administrator. Except as specified in Section 3 of this Tariff, WPP, as authorized by its Board of Directors, shall have the sole authority to submit to FERC amendments to the rates, terms, and conditions set forth in this Tariff under section 205 of the Federal Power Act, 16 U.S.C. § 824d. Nothing contained herein shall be construed as affecting in any way the right of any Participant or any other entity to apply to FERC for amendments to the rates, terms, and conditions contained herein under section 206 of the Federal Power Act, 16 U.S.C. § 824e, or any other applicable provision of that Act.

2.1.1 WPP president and staff shall support the Board of Directors in overseeing all aspects of the WRAP, including oversight and management of the Program Operator(s) in accordance with any Program Operator agreement(s) entered into by WPP under Section 2.2 of this Tariff.

2.1.2 WPP and its staff shall provide all legal, regulatory, and accounting support for the WRAP, including support for making filings with FERC as authorized by the Board of Directors.

2.1.3 WPP staff shall provide all logistical support necessary to facilitate implementation of the WRAP and specifically all logistical needs of the Board of Directors and reasonable logistical assistance to facilitate meetings and activities of the RAPC, PRC, and all subordinate organizational groups.

2.2 As Program Administrator, WPP shall undertake all actions as necessary to implement and administer the WRAP, including but not limited to engaging one or more Program Operator(s) to perform technical operations of the WRAP including both the Forward Showing Program and Operations Program. Except as otherwise provided herein, WPP may contract for certain activities required by this Tariff to be provided by one or more Program Operator(s) subject to oversight by the Board of Directors, provided, however, that the Program Operator shall operate solely as a contractor under the oversight of WPP, and WPP shall remain the sole point of compliance with this Tariff. WPP shall have the sole authority to enter into contracts for such engagements and is responsible for providing support and compensation for such Program Operator(s) pursuant to any contract(s).

2.2.1 WPP will contract with Program Operator(s) to assist WPP with providing reasonable technical support and expertise to all WRAP organizational groups as governed by the Program Operator’s contract with WPP.

3. Role of the Board of Directors and Limitations on Board Authority

3.1 Authority: Ultimate authority over all aspects of the WRAP as established under this Tariff shall be vested in the independent Board of Directors. Each member of the Board of Directors shall at all times exhibit financial independence from all Participants and classes of Participants, as further provided in the WPP Bylaws and policies. As set forth in Section 2.1 of this Tariff, the Board of Directors shall have the exclusive authority to approve and direct WPP to file amendments to this Tariff with FERC under section 205 of the Federal Power Act, 16 U.S.C. § 824d, subject to the limitations and prohibitions imposed under Section 3.4 of this Tariff. The Board of Directors shall also have the exclusive authority to approve the Business Practice Manuals and any amendments to the Business Practice Manuals, subject to the terms, conditions, and limitations imposed under this Tariff.

3.2 The Board of Directors generally shall meet in open session for all matters related to the WRAP; however, the Board of Directors may meet in closed session as the chair deems necessary to safeguard the confidentiality of sensitive information, including but not limited to discussing matters related to personnel, litigation, or proprietary, confidential, or security sensitive information. The Board of Directors shall not take action on any proposed amendment to this Tariff or the Business Practice Manuals in closed session. During open session, the chair of the Board of Directors will reasonably accommodate stakeholder requests to address the Board within the discretion of the chair.

3.3 The Board of Directors shall only consider amendments to this Tariff or the Business Practice Manuals after such amendments are first acted upon by the RAPC, subject to the following additional conditions:

3.3.1 In the event that the RAPC has voted to reject or has not voted to support a proposed amendment to this Tariff or the Business Practice Manuals, any stakeholder may appeal such decision to the Board of Directors, and the Board of Directors shall consider the appeal.

3.3.2 In the event that the RAPC has voted to reject or has not voted to support a proposed amendment to this Tariff or the Business Practice Manuals and a stakeholder has not appealed such decision, the Board of Directors may, on its own motion or motion of any member of the Board of Directors, consider the proposed amendment.

3.3.3 In the event that the COSR as a body opposes or appeals a RAPC decision to the Board of Directors regarding an amendment to this Tariff or the Business Practice Manuals, the process set forth in Section 4.3.3 of this Tariff shall apply prior to the Board of Directors' consideration of the RAPC decision.

3.3.4 In the event that the Board of Directors wishes to initiate an amendment to this Tariff or the Business Practice Manuals that has not undergone PRC

and RAPC review, the Board of Directors shall first submit such proposed amendment to the PRC for review under the processes set forth in Sections 4.1 and 4.2 of this Tariff.

3.3.5 Expedited Review Process: In the event that the RAPC determines that an expedited review process is necessitated by an exigent circumstance as set forth in Section 4.1.3.1.1 of this Tariff, the Board of Directors shall review the RAPC's recommended Tariff or Business Practice Manual amendment expeditiously and invite comment from the PRC, COSR, and stakeholders concurrently with its consideration of the RAPC proposal.

3.4 WPP is specifically prohibited from amending this Tariff to:

3.4.1 Alter, usurp, control, or otherwise materially modify the Participants' existing functional control and responsibility over their generation and transmission assets, including but not limited to planning and operation of such assets, Open Access Transmission Tariff administration, interfering with Balancing Authority duties and responsibilities, or imposing a must-offer requirement on any specific generation resources.

3.4.2 Administer Open Access Transmission Tariff service, engage in Balancing Authority operations, impose transmission planning requirements, or assume any transmission planning responsibilities with regard to any of the Participant's transmission assets.

3.4.3 Form any type of organized market, including but not limited to a capacity market, a regional transmission organization, a real-time market, or any other type of FERC-approved regional construct, unless such action is also approved by the RAPC under its voting procedures set forth in Section 4.1.6 of this Tariff.

3.4.4 Impose any requirements on Participants beyond the assessment of financial charges as specified in this Tariff or suspension or termination of participation for failure to meet any WRAP requirements.

3.4.5 Amend in any way this Section 3 of this Tariff without the approval of the RAPC under its voting procedures set forth in Section 4.1.6 of this Tariff.

3.4.6 Amend the RAPC voting thresholds set forth in Section 4.1.6 of this Tariff.

3.5 Subject to the limitations and prohibitions imposed under Section 3.4 of this Tariff, if the Board of Directors votes to file at FERC to expand the WRAP to include market optimization or transmission planning services, WPP will initiate a formal process with COSR and other stakeholders to conduct a full review of governance structures and procedures, including the role of states. If COSR does not support any revised governance structure that emerges from such WPP review process, the WPP will file, along with any WPP governance proposal to FERC, an alternative

governance structure on behalf of the COSR so long as such COSR alternative governance structure is supported by 75% of the COSR.

4. Organizational Groups for the WRAP

4.1 Resource Adequacy Participants Committee

4.1.1 Authority and Purpose: The RAPC shall be the highest level of authority for representation by Participants in the WRAP governance structure and shall represent the interests of Participants directly to the Board of Directors.

4.1.2 Composition: The RAPC shall be composed of one representative from each Participant. Such representative shall be a senior management official with binding decision-making authority on behalf of the Participant, or a designated representative of a Participant's senior management official. A designated representative shall be required to have binding decision-making authority on behalf of the Participant and shall have all voting rights delegated from the senior management official. Participant shall appoint a designated representative no less than one Business Day in advance of a meeting for that designated representative to be eligible to vote during the meeting.

4.1.3 Functions: The RAPC:

4.1.3.1 Shall consider and recommend that the Board of Directors approve or reject all proposed amendments to this Tariff or Business Practice Manuals prior to the Board of Directors considering such amendments, including any amendments reviewed and referred by the PRC.

4.1.3.1.1 Exigent Circumstances: When the RAPC determines that an amendment to the Tariff or the Business Practice Manuals requires expedited Board of Directors review due to exigent circumstances, it may propose such amendment directly to the Board of Directors without awaiting review by other committees and stakeholders. Exigent circumstances include: (i) a FERC-mandated amendment to this Tariff or the Business Practice Manuals; (ii) an amendment to this Tariff or the Business Practice Manuals to address an immediate reliability impact; or (iii) an amendment to this Tariff or the Business Practice Manuals that the RAPC has determined has significant impacts to utility service.

4.1.3.2 Shall consider and vote to recommend that the Board of Directors approve or reject any proposed amendments to this Tariff or the Business Practice Manuals.

4.1.3.3 May provide input to the Board of Directors on any proposed WPP rules that apply both to the WRAP and other WPP services.

4.1.3.4 May evaluate and provide input to the Board of Directors on the WRAP administration budget and budget allocation to Participants, including amendments to the WRAP Administration Charge as calculated in accordance with Schedule 1 of this Tariff.

4.1.3.5 Shall form and organize all of the organizational groups under its responsibilities.

4.1.3.6 May take other actions reasonably related to its role as the senior-level Participant advisory committee to the Board of Directors regarding WRAP matters.

4.1.4 Leadership: The RAPC shall select from among its members a chair and vice chair.

4.1.5 Meetings:

4.1.5.1 Meetings of the RAPC will generally be open to all stakeholders. WPP shall provide advanced written notice of the date, time, place, and purpose of each RAPC meeting. All RAPC decisional items shall be placed on the open meeting agenda and allotted adequate time for public comment and deliberation.

4.1.5.1.1 The RAPC may meet in closed session as the RAPC chair deems necessary; provided, however, that the RAPC shall allow the designated COSR support staff member as specified in Section 4.3 of this Tariff to attend any closed meeting. The RAPC shall not take action on any proposed amendment to this Tariff or the Business Practice Manuals in closed session.

4.1.5.2 The quorum for a meeting of the RAPC or any organizational group organized under it shall be one-half of the representatives thereof, but not less than three representatives, provided that a lesser number may serve as a quorum for the sole purpose of voting to adjourn the meeting to a later time.

4.1.6 Voting:

4.1.6.1 Each RAPC representative shall have one vote.

4.1.6.2 Voting in the RAPC shall utilize a “House and Senate” model.

4.1.6.2.1 Each Participant’s “House” vote shall represent the proportion of the Participant’s Median Monthly P50 Peak Load, as described in Section 2 of Schedule 1 of this Tariff, compared to the sum of all Participants’ Median Monthly P50 Peak Loads. A Participant may choose to divide its

House vote but is responsible for announcing such at the time of voting.

4.1.6.2.2 Each Participant shall receive a single, non-weighted "Senate" vote.

4.1.6.2.3 For an action to be approved by the RAPC, it must pass both "House" and "Senate" votes as follows. For purposes of voting, the percentages identified below specify the percentage threshold of the entire RAPC (whether in attendance or not) that is needed for passage of an action.

4.1.6.2.3.1 Actions to amend any of the limitations on Board authority set forth in Section 3.4 of this Tariff require an 80% affirmative approval by both the House and the Senate vote tallies to be approved.

4.1.6.2.3.2 Actions brought before the RAPC that have been approved by the PRC require a 67% affirmative approval by both the House and Senate vote tallies to be approved.

4.1.6.2.3.3 All other actions not specified in this Section 4.1.6.2.3 require a 75% affirmative approval by both the House and Senate vote tallies to be approved.

4.1.6.2.4 If at any time a single Participant's P50 load for voting purposes would result in that Participant possessing a veto over any votes taken under Section 4.1.5.2.3, such Participant's House vote shall be capped at 1% below the amount that would convey such a veto, such that no single Participant will possess a veto over any action taken under Section 4.1.6.2.3.

4.2 Program Review Committee

4.2.1 Authority and Purpose: The PRC is a sector-representative group comprised in accordance with Section 4.2.2 of this Tariff. The PRC is responsible for receiving, considering, and proposing amendments to this Tariff and the Business Practice Manuals. The PRC shall serve as a clearinghouse of all recommended amendments to this Tariff or the Business Practice Manuals, except for those designated by the RAPC as involving an exigent circumstance under Section 4.1.3.1.1 of this Tariff, amendments to Schedule 1 of this Tariff and cost allocation for the WRAP, and amendments to the WRAPA set forth as Attachment A of this Tariff. The PRC shall serve in an advisory capacity to the RAPC and, when applicable, the Board of Directors.

4.2.1.1 The PRC shall present all proposals received to the RAPC, along with the PRC's recommendation and summaries of all comments and feedback received.

4.2.1.2 The PRC's decisions are advisory-only and are not binding on the RAPC, the Board of Directors, or WPP.

4.2.2 Composition: The PRC shall be composed of up to twenty representatives from the following ten sectors: four representatives of RAPC Participant investor-owned utilities; four representatives of RAPC Participant publicly-owned (consumer or municipal) utilities; two representatives of RAPC Participant retail competition load serving entities; two representatives from RAPC Participant Federal Power Marketing Administrations; two representatives of independent power producers; two representatives of public interest organizations; one representative of retail consumer advocacy groups; one representative of industrial customer advocacy groups; one representative of load serving entities with loads in the WRAP that are represented by other LREs and are not otherwise eligible for any other sector; a representative from the COSR. Expectations for sectors to consider regional, operational, geographic, demographic, and other forms of diversity in selecting their sector representatives are set forth in more detail in the PRC charter, which shall be posted and maintained on the WRAP website or other appropriate public location.

4.2.3 The PRC shall establish a process and criteria for receiving and reviewing proposed amendments to this Tariff and the Business Practice Manuals. Such review will include procedures for stakeholder comment.

4.2.4 Meetings: The PRC shall meet primarily in open session; provided that the PRC may schedule closed meetings if it determines that doing so would be beneficial to safeguard the confidentiality of sensitive information. The PRC shall not take action on any proposed amendment to this Tariff or the Business Practice Manuals in closed session.

4.2.5 Voting: The PRC shall endeavor to operate by consensus. When voting is necessary, voting shall consist of one sector one vote, with an affirmative vote of six sectors (as specified in Section 4.2.2 of this Tariff) constituting approval of an action before the PRC.

4.2.5.1 For sectors with four seats, three sector representatives must agree with the action for the sector to be considered an affirmative vote for the action.

4.2.5.2 For sectors with two seats, both sector representatives must agree with the action for the sector to be considered an affirmative vote for the action.

4.2.6 Participants and other entities shall participate in no more than one PRC sector. If a Participant or other entity is eligible to participate in more than one sector, such Participant or other entity shall declare in which sector it will participate.

4.3 Committee of State Representatives

4.3.1. Composition: The COSR is a committee composed of one representative from each state or provincial jurisdiction (either public utility commission or state/provincial energy office) that regulates at least one Participant.

4.3.2 Leadership: The COSR shall determine its leadership, including a chair and vice chair. The chair or vice chair will be requested to attend all open sessions of the RAPC to provide input and advice.

4.3.2.1 The COSR shall designate a COSR support staff member to attend and audit closed meetings of the RAPC under a non-disclosure agreement.

4.3.3 Authority:

4.3.3.1 If the COSR determines that a proposal approved by the RAPC is substantially different from the proposal submitted to the RAPC by the PRC, the COSR may engage in additional public review and comment before the RAPC decision is presented to the Board of Directors; provided that this additional public review and comment does not unreasonably delay presentation to the Board of Directors.

4.3.3.2 If the COSR as a body opposes or appeals a RAPC decision to the Board of Directors, the Board of Directors will not consider the RAPC's decision until the RAPC engages with the COSR to discuss, in at least two public discussions, to attempt to reach a mutually agreeable solution.

4.3.3.2.1 If the appeal relates to an amendment that the RAPC designated as involving an exigent circumstance under Section 4.1.3.1.1 of this Tariff, COSR can require no more than one public discussion, provided that such additional discussion does not unreasonably hinder the timeline for Board of Directors consideration of the proposed amendment.

4.3.4 Voting, Meetings, and Quorum: The COSR may develop its own rules governing voting, meetings, and quorum for action. COSR shall be responsible for its own costs.

5. Independent Evaluator

5.1 WPP shall engage an Independent Evaluator to provide an independent assessment of the performance of the WRAP and any potential beneficial design modifications. The Independent Evaluator shall report directly to the Board of Directors.

5.2 The Independent Evaluator shall conduct an annual review of the WRAP, including but not limited to analyzing prior year program performance, accounting and settlement, and program design.

5.3 The Independent Evaluator shall prepare an annual report of its findings, and any recommended modifications to WRAP design, and present its findings to the WRAP committees and the Board of Directors, subject to any necessary confidentiality considerations. Any data included in the Independent Evaluator's report shall be reported on an aggregated basis as applicable to preserve confidentiality. The Independent Evaluator's annual reports shall be available to the public, except to the extent they contain information designated as confidential under this Tariff, or information designated as confidential by the Independent Evaluator.

5.4 The Independent Evaluator shall not:

5.4.1 Evaluate individual Participants.

5.4.2 Possess any decision-making authority regarding the WRAP or design modifications.

5.4.3 Evaluate WPP's day-to-day operations of the WRAP (except as part of review of prior year program performance).

6. WPP Invoicing and Settlement

6.1 WPP shall be responsible for issuing invoices to, and collecting from, Participants all charges under Schedule 1 of this Tariff for recovery of all WPP costs associated with administering the WRAP.

6.2 WPP shall be responsible for invoicing, collecting, and (as applicable) distributing revenues from Deficiency Charges under Part II of this Tariff and Delivery Failure Charges under Part III of this Tariff.

6.3 Participants are not required to provide credit assurances to WPP to cover charges under Schedule 1 of this Tariff, Deficiency Charges under Part II of this Tariff, or Delivery Failure Charge under Part III of this Tariff.

6.4 Participants shall make full payment of all invoices rendered by WPP for which payment is required to WPP within thirty calendar days following the receipt of the WPP invoice, notwithstanding any disputed amount, but any such payment shall not be deemed a waiver of any right with respect to such dispute. Any Participant that fails to make full and timely payment to WPP of amounts owed upon expiration of the cure period specified in Section 6.4.1 of this Tariff will be in default.

6.4.1 If a Participant fails to make timely payment as required by Section 6.4, WPP shall so notify such Participant. The notified Participant may remedy such asserted breach by paying all amounts due, along with interest on such amounts calculated in accordance with the methodology specified for interest on refunds in FERC's regulations at 18 C.F.R. § 35.19a(a)(2)(iii); provided, however, that any such payment may be subject to a reservation of rights, if any, to refer such matter to dispute resolution procedures under Section 9 of this Tariff. If the Participant has not remedied such asserted breach by 5:00 p.m. Pacific Prevailing Time on the second Business Day following WPP's issuance of a written notice of breach, then the Participant shall be in default.

6.4.2 In the event of a Participant's default under Section 6.4.1 of this Tariff, WPP in its discretion may pursue collection through such actions, legal or otherwise, as it reasonably deems appropriate, including but not limited to the prosecution of legal actions and assertion of claims in the state and federal courts as well as under the United States Bankruptcy Code. After deducting any costs associated with pursuing such claims, any amounts recovered by WPP with respect to defaults for which there was a Default Allocation Assessment shall be distributed to the Participants who have paid their Default Allocation Assessment in proportion to the Default Allocation Assessment paid by each Participant, as calculated pursuant to Section 6.4.3 of this Tariff. In addition to any amounts in default, the defaulting Participant shall be liable to WPP for all reasonable costs incurred in enforcing the defaulting Participant's obligations.

6.4.3 In the event of a Participant's default with respect to an invoice issued by WPP for charges under Schedule 1 of this Tariff, in order to ensure that WPP remains revenue neutral, the Board of Directors may assess against, and collect from, the Participants not in default a Default Allocation Assessment to recover the costs associated with the default. Such assessment shall in no way relieve the defaulting Participant of its obligations.

6.4.3.1 The Default Allocation Assessment shall be equal to:

(20% × (1/N) + (80% × (Participant Median Monthly P50 Peak Load / Sum Participants Median Monthly P50 Peak Load)

where:

N = the total number of Participants, calculated as of the date WPP declares a Participant in default.

Participant Median Monthly P50 Peak Load = for each Participant included in factor "N" above, the Participant's Median Monthly P50 Peak Load as determined in Section 2 of Schedule 1 of this Tariff, recalculated on the day the WPP declares a Participant in default.

All Participants Median Monthly P50 Peak Load = the sum of the Participant Median Monthly P50 Peak Load values for all Participants included in factor "N" above.

7. Credit Requirements and Settlement for Holdback and Delivered Energy

7.1 Credit and Settlement for Holdback and Delivered Energy: Settlement of holdback and delivered energy shall be completed bilaterally between Participants, subject to the following:

7.1.1 Neither WPP nor the Program Operator(s) shall take title to energy or be party to any settlement of holdback or delivered energy.

7.1.2 Participants shall establish credit with each other through one of the following mechanisms. Neither WPP nor the Program Operator(s) shall be involved in the calculation of credit or credit limits.

7.1.2.1 Establish credit directly with each Participant: Participants may establish credit directly with other Participants from whom they may receive delivered energy.

7.1.2.1.1 Such credit should be established in advance of the applicable season.

7.1.2.1.2 The amount of such credit and any credit limit shall be at the discretion of each Participant.

7.1.2.2 WPP shall conduct a competitive solicitation process to identify a third-party service provider to serve as central credit organization and clearing house for credit and settlement. Once such central credit organization is selected, Participants that have not already directly established credit with all other Participants under Section 7.2.2.1 of this Tariff shall establish credit with the central credit organization.

7.1.2.2.1 WPP will provide the central credit organization any Operations Program related information necessary for them to perform their obligations as set forth in the agreement between WPP and the central credit organization.

7.1.2.2.2 All costs associated with the central credit organization service shall be borne by Participants as established in the agreement between WPP and the central credit organization and either billed directly on a transactional basis or else recovered under Schedule 1 of this Tariff.

7.1.2.3 The obligation to arrange sufficient credit shall at all times be on the deficient Participant (i.e., a Participant with a negative sharing calculation in the Operations Program). If a deficient Participant has not made good faith and commercially reasonable efforts to

obtain sufficient credit with a delivering Participant, such delivering Participant shall so notify WPP and shall be excused from any obligation to deliver to such deficient Participant. Nothing in this Section 7 requires a Participant to violate its written risk or credit policy.

7.2 All settlement pricing calculated under this Tariff shall be final and no adjustments to settlement prices shall be allowed after the later of: (1) ninety Days after such settlement prices are posted by WPP; or (2) the final outcome of any dispute resolution process that is initiated by a Participant to dispute a settlement price pursuant to the Dispute Resolution Procedures set forth in Section 9 of this Tariff.

7.2.1 A Participant may invoke the Dispute Resolution Procedures set forth in Section 9 of this Tariff to address calculation errors in any settlement price, but may not invoke the Dispute Resolution Procedures to dispute data sources or to request the use of alternative data sources.

8. Force Majeure, Limitation of Liability, and Indemnification

8.1 Force Majeure: An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, pandemic, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation, or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither WPP nor the Participant will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff. Notwithstanding the foregoing, the physical inability to perform because of an event of Force Majeure shall not relieve the party of any financial obligations incurred under this Tariff or as a result of the Force Majeure event, unless, and to the extent, such financial obligation is waived or excused under provisions of Part II or Part III of this Tariff expressly providing for such waiver or excuse.

8.2 Limitation of Liability:

8.2.1 Neither WPP nor the Program Operator shall be liable, whether based on contract, indemnification, warranty, tort, strict liability or otherwise, to any Participant, other entity owning a Qualifying Resource, third party, or other person for any damages whatsoever, including, without limitation, direct, incidental, consequential, punitive, special, exemplary, or indirect damages arising or resulting from any act or omission in any way associated with service provided under this Tariff or any agreement hereunder, including, but not limited to, any act or omission that results in an interruption, deficiency or imperfection of service, except to the extent that the damages are direct damages that arise or result from the gross negligence or intentional misconduct of WPP or Program Operator, in which case WPP shall only be liable for direct damages.

8.2.2 Neither WPP nor the Program Operator shall be liable for damages arising out of services provided under this Tariff or any agreement entered into hereunder, including, but not limited to, any act or omission that results in an interruption, deficiency, or imperfection of service, occurring as a result of conditions or circumstances beyond the control of WPP, or resulting from electric system design common to the domestic electric utility industry or electric system operation practices or conditions common to the domestic electric utility industry.

8.2.3 To the extent that a Participant or other person has a claim against WPP, the amount of any judgment or arbitration award on such claim entered in favor of such entity shall be limited to the value of WPP's assets. No party may seek to enforce any claims under this Tariff or any Agreements entered into

hereunder against the directors, managers, members, shareholders, officers, employees, or agents of WPP, or against the Program Operator, who shall have no personal liability for obligations of WPP by reason of their status as directors, managers, members, shareholders, officers, employees, or agents of WPP or by virtue of their status as Program Operator.

8.2.4 To the extent that WPP is required to pay any money damages or compensation or pay amounts due to its indemnification of any other party as it relates to any services provided, acts, or omissions under this Tariff or any agreement entered into hereunder, WPP shall be allowed to recover any such amounts under Schedule 1 of this Tariff as part of the WRAP Administration Charge. Notwithstanding the foregoing, WPP shall be prohibited from recovering under this Tariff any costs associated with any damages, compensation, or indemnification costs that arise: (i) with regard to any acts or omissions that occur outside of this Tariff and any agreements entered into hereunder, or (ii) if a court of competent jurisdiction determines that the damages are direct damages that arise or result from the gross negligence or intentional misconduct of WPP or the Program Operator.

8.2.5 A Participant's liability to another Participant under this Tariff for failure to comply with obligations under this Tariff shall be limited to any charges or payments calculated pursuant to this Tariff; provided, however, that nothing in this Section 8.2.5 shall limit or is intended to foreclose any Participant's liability that may arise under any bilateral agreements between Participants.

8.3 Indemnification: The Participants shall at all times indemnify, defend, and save WPP (and any of its Program Operator(s), agents, consultants, directors, officers, or employees) harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties arising out of or resulting from the performance of activities under this Tariff by WPP, any Program Operator(s), or agents, consultants, directors, officers, or employees of WPP, except in cases of gross negligence or intentional wrongdoing by WPP or the Program Operator. WPP shall credit any proceeds from insurance or otherwise recovered from third parties to Participants who have paid to indemnify WPP under this Section 8.3.

8.4 Actions upon Unavailability of Program Operator(s): In the event that the Program Operator(s) become(s) unwilling, unable, or otherwise unavailable to perform contractual duties necessary for WPP to discharge its obligations under this Tariff and WPP’s agreement(s) with the Program Operator(s), WPP shall engage with Participants as soon as practicable to determine what actions to take, including but not limited to filing with FERC a request to waive one or more provisions of this Tariff up to and including immediate suspension of all rights and obligations under this Tariff until a replacement Program Operator(s) can assume all relevant Program Operator functions.

9. Dispute Resolution Procedures

9.1 Internal Dispute Resolution Procedures: Subject to the limitations set forth in Section 7.2.1 of this Tariff, any dispute between a Participant and WPP under the Tariff (excluding amendments to the Tariff or to any agreement entered into under the Tariff, which shall be presented directly to the FERC for resolution) shall be referred to a designated senior representative of WPP and a senior representative of the Participant for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty days (or such other period as the parties may agree upon) by mutual agreement, such dispute shall then be referred to the chief executive officer or comparable executive of each party for resolution. In the event that the executives are unable to resolve the dispute within thirty days (or such other period as the parties may agree upon), such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

9.2 External Arbitration Procedures: Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the parties to the dispute. If the parties fail to agree upon a single arbitrator within ten days of the referral of the dispute to arbitration, each party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable FERC regulations.

9.3 Arbitration Decisions: Unless otherwise agreed by the parties, the arbitrator(s) shall render a decision within ninety days of appointment and shall notify the parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and/or any agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the FERC if it affects jurisdictional rates, terms and conditions of service or facilities.

9.4 Costs: Each party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (i) the cost of the arbitrator chosen by the party to sit on the three-member panel and one half of the

cost of the third arbitrator chosen; or (ii) one half the cost of the single arbitrator jointly chosen by the Parties.

9.5 Rights Under the Federal Power Act: Nothing in this section shall restrict the rights of any person to file a complaint with the FERC under relevant provisions of the Federal Power Act or of WPP to file amendments to this Tariff under the relevant provisions of the Federal Power Act.

10. Treatment of Confidential and Commercially Sensitive Information of Participants

10.1 Terms: For purposes of this Section 10 only, the term "WPP" shall also include, as applicable, any directors, officers, employees, agents, or consultants of WPP, the Independent Evaluator established under Section 5 of this Tariff, and any central credit organization established under Section 7 of this Tariff. WPP shall be bound by the rights, obligations, and conditions set forth in this Section 10. For purposes of this Section 10, the term "Disclosing Entity" shall include any Participant that discloses information to WPP that the Disclosing Entity deems and identifies as confidential or commercially sensitive. WPP's collection and handling of non-Participant data shall be governed by separate non-disclosure agreements with such non-Participants.

10.2 Treatment of Confidential or Commercially Sensitive Information: WPP shall identify in the Business Practice Manuals categories of Participant-specific data and information received from Participants that shall be treated as confidential or commercially-sensitive, which WPP shall not disclose publicly or to any other Participant or other entity except as provided for in this Section 10. In addition, WPP shall maintain the confidentiality of all of the documents, data, and information provided to it by any Participant that such disclosing Participant deems and specifically identifies as confidential or commercially sensitive. Notwithstanding the foregoing, WPP need not keep confidential: (i) information that is publicly available or otherwise in the public domain; or (ii) information that is required to be disclosed under this Tariff or any applicable legal or regulatory requirement (subject to the procedures set forth in Section 10.4 of this Tariff).

10.2.1 WPP staff may develop and release publicly composite or aggregated data based upon Participant confidential or commercially sensitive information, provided that such composite or aggregated data cannot be used to identify or attribute a disclosing Participant's confidential or commercially sensitive data. Such release of composite or aggregated data shall be governed by the following process.

10.2.1.1 Prior to the initial release of such composite or aggregated data, WPP staff shall present the form and format of such data to each Participant whose confidential information or data will be used to create the composite or aggregated data. If any such Participant objects to the form and format as revealing or allowing for attribution of confidential or commercially sensitive Participant-specific data, WPP staff shall determine whether to modify the form and format or to retain the proposed form and format for release. If WPP staff elects to retain the proposed form and format, the Participant shall have the right to appeal to the RAPC and WPP staff shall be prohibited from releasing the composite or aggregated data in the proposed form and format until the Participant's appeal rights as specified in this Section 10.2.1

are exhausted.

10.2.1.2 If a Participant appeals a WPP staff decision regarding the form and format of composite or aggregated data to the RAPC, the RAPC shall consider whether the form and format reveals or allows for attribution of confidential or commercially sensitive Participant-specific data. If the RAPC determines that the proposed form and format is sufficient to protect against the release of confidential or commercially sensitive Participant-specific data, WPP staff is authorized to release the composite or aggregated data in the proposed form and format unless the Participant timely appeals the RAPC decision to the Board of Directors.

10.2.1.3 If a Participant appeals a RAPC decision regarding the form and format of composite or aggregated data to the Board of Directors, the Board of Directors shall consider whether the form and format is sufficient to protect against the release or attribution of confidential or commercially sensitive Participant-specific data. If the Board of Directors determines that the proposed form and format is sufficient to protect against the release of confidential or commercially sensitive Participant-specific data, WPP staff is authorized to release the composite or aggregated data in the proposed form and format.

10.2.1.4 Once a proposed form and format of composite or aggregated data is approved by the WPP staff and is not appealed or appeals are unsuccessful, such form and format may be used for all future disclosures of composite or aggregate information and no Participant may dispute such release. If WPP staff proposes to alter the form and format, including but not limited to changing the granularity of data, WPP staff shall be required to follow the process set forth in this Section 10.2.1 and Participants shall have the right to appeal such changes in form and format as set forth herein. Notwithstanding the foregoing, if the composition of Participants in the WRAP changes in such a way that the form and format of composite or aggregated data is no longer sufficient to protect against disclosure or attribution of confidential or commercially sensitive Participant-specific data, an aggrieved Participant shall have a one-time right to raise the issue promptly with WPP Staff for presentation to and review by the Board of Directors, and the Board of Directors in its sole discretion shall decide whether the change in composition results in the form and format of the composite or aggregated data becoming insufficient to

protect against the release or attribution of confidential or commercially sensitive Participant-specific data; provided, however, that if an aggrieved Participant does not raise its concerns with the Board of Directors promptly following the change in composition, such Participant shall have waived its right to contest the release of such composite or aggregated data.

10.2.2 Notwithstanding anything to the contrary in this Section 10.2, if the RAPC unanimously votes to disclose publicly any particular category of Participant-specific data, such data shall no longer be deemed confidential regardless of any such designation by a disclosing Participant, and this election shall be binding on any current and future Participants until such time as the RAPC votes unanimously to prohibit public release of such category of data. A list of the categories of Participant-specific data that the RAPC unanimously votes to make public shall be included in the Business Practice Manuals.

10.3 Access to Confidential or Commercially Sensitive Information: Except as otherwise provided in Section 10.2 of this Tariff, no Participant, entity owning a Qualifying Resource, or any third party shall have the right hereunder to receive from WPP or to otherwise obtain access to any documents, data or other information that has been identified as or deemed to be confidential or commercially sensitive under Section 10.2 of this Tariff by a disclosing Participant. The provisions of this Section 10.3 do not apply to WPP (including any Independent Evaluator, member of the Board of Directors, or any WPP officer, employee, agent, or consultant that requires access to confidential or commercially sensitive information); provided that access to Participant-specific confidential or commercially sensitive information shall be solely for the purpose of performing the duties or functions under this Tariff or otherwise advising or assisting WPP. WPP shall develop internal policies and controls governing the handling and protection of confidential or commercially sensitive Participant-specific data by members of the Board of Directors, officers, employees, agents, consultants, or any Independent Evaluator.

10.4 Exceptions: Notwithstanding anything in this Section 10 to the contrary:

10.4.1 If WPP is required by applicable laws or regulations, or in the course of administrative or judicial proceedings, to disclose information that is otherwise required to be maintained in confidence pursuant to this Section 10, WPP may disclose such information; provided, however, that as soon as practicable after WPP learns of the disclosure requirement and prior to making such disclosure, WPP shall notify any affected disclosing Participant of the requirement and the terms thereof. Any such disclosing Participant may, at its sole discretion and own cost, direct any challenge to or defense against the disclosure requirement and WPP shall cooperate with such disclosing Participant to take all reasonable available steps to oppose

or otherwise minimize the disclosure of the information permitted by applicable legal and regulatory requirements. WPP shall further cooperate with such disclosing Participant to the extent reasonably practicable to obtain proprietary or confidential treatment of confidential or commercially sensitive information by the person to whom such information is disclosed prior to any such compelled disclosure.

10.4.2 WPP may disclose confidential or commercially sensitive information, without notice to any affected disclosing Participant(s), in the event that FERC, during the course of an investigation or otherwise, requests information that is confidential or commercially sensitive. In providing the information to FERC, WPP shall take action, consistent with 18 C.F.R. §§ 1b.20 and/or 388.112, to request that the information be treated by FERC as confidential and non-public and, if appropriate, as Critical Energy Infrastructure Information and that the information be withheld from public disclosure. WPP shall provide the requested information to FERC within the time provided for in the request for information. WPP shall notify any affected disclosing Participant(s) within a reasonable time after WPP is notified by FERC that a request for disclosure of, or decision to disclose, the confidential or commercially sensitive information has been received, at which time WPP and any affected disclosing Participant may respond before such information would be made public.

10.5 Notwithstanding any efforts undertaken pursuant to Section 10.4 to prevent or limit the release of a Participant's confidential or commercially sensitive information, in the event that FERC or a court of competent jurisdiction orders or otherwise permits the public release of a Participant's confidential or commercially sensitive information, the affected Participant shall have a one-time right to elect to terminate its participation in the WRAP under the expedited termination provisions set out in Section 11.2 of the WRAPA.

10.6 WPP shall handle any information identified or deemed to be Controlled Unclassified Information/Critical Energy Infrastructure Information in accordance with FERC's regulations set forth at 18 C.F.R. § 388.113 and any applicable FERC policies or other regulations, including but not limited to restricting access to such information on a password-protected portion of WPP's website or similar precautions.

10.7 Nothing in this Section 10 is intended to limit a Participant's ability to disclose or release publicly its own confidential or commercially sensitive information or data, or to limit a Participant's ability to authorize WPP's disclosure of such material to a specified recipient.

11. Timing

11.1 In the event that any deadline specified in this Tariff shall fall on a day that is not a Business Day, the deadline shall be extended to the next Business Day.

12. Application and Registration

12.1 Any entity wishing to participate in the WRAP must submit an application and registration in accordance with the Business Practices Manuals and must execute the WRAPA as set forth in Attachment A of this Tariff, or a non-conforming version of such participation agreement that is approved by FERC for an individual Participant. Such application and registration must be submitted in accordance with the timelines set forth in the Business Practices Manuals in advance of the next Binding Season.

12.2 Each Participant must register all of its resources and loads, regardless of whether such resources will be used to satisfy the WRAP requirements and regardless of whether certain loads will be subject to the requirements of the WRAP. Participants may modify their registration of resources and loads in accordance with the timing procedures set forth in the Business Practices Manuals.

12.3 In the event that more than one Participant attempts to register the same resource or load, the following procedure will be used to assign the resource or load to a Participant:

12.3.1 If a Participant attempts to register a load or resource that has already been registered by a different Participant, the resource or load will remain registered by the original Participant registering the resource or load until such time as both Participants mutually inform WPP that a change to the registration is required.

12.3.2 If two or more Participants attempt to register the same resource or load during the same registration window, WPP shall request that the Participants determine among themselves the appropriate registration of the resource or load before that resource or load is included in the WRAP.

PART II FORWARD SHOWING PROGRAM

13. Overview

13.1 In the Forward Showing Program, as set forth in this Part II of the Tariff, and as further detailed in the Business Practice Manuals, each Participant shall, in advance of each Binding Season, show as to such Binding Season: (i) the total capacity, referred to and defined herein as the FS Capacity Requirement, required by the provisions of this Tariff for such Binding Season for reliable service to the loads for which such Participant is responsible; (ii) the demonstration of capacity, referred to and defined herein as the Qualifying Capacity Contribution, or QCC, provided by the Qualifying Resources the Participant provides or procures to meet its FS Capacity Requirement; and (iii) at least the minimum level of firm transmission service, referred to and defined herein as the FS Transmission Requirement, needed for reliable delivery of the QCC of the Participant's Qualifying Resources from such resources to the loads for which the Participant is responsible.

13.2 As also set forth in this Part II of the Tariff, and as further detailed in the Business Practice Manuals: (i) WPP shall, in advance of each Binding Season, review the Forward Showing Submittals of each Participant for such Binding Season; (ii) WPP shall identify to the Participant any deficiencies in the Participant's Portfolio QCC (whether as to contracts or directly owned or controlled resources) relative to the FS Capacity Requirement, and any deficiencies in the identified firm transmission service relative to the FS Transmission Requirement, within sixty days of the Forward Showing Submittal deadline; (iii) the Participant shall have an opportunity to cure such deficiencies, within sixty days of notification of deficiency; and (iv) if the Participant fails to cure all such deficiencies on or before the deadlines prescribed herein, the Participant shall be assessed a Forward Showing Deficiency Charge.

14. Forward Showing Program Process and Timeline

14.1 The Forward Showing Program has two Binding Seasons, defined as the Summer Season and the Winter Season. The Summer Season is the period beginning on June 1 of each Year and ending on September 15 of that same Year. The Winter Season is the period beginning on November 1 of each Year and ending on March 15 of the succeeding Year. This Tariff does not establish resource or showing obligations outside the periods defined by the Summer Season and Winter Season.

14.2 Each Participant shall submit its Forward Showing Submittals for each Month of each Binding Season, with all required supporting materials and information as detailed in the Business Practice Manuals, on or before the FS Deadline for the Binding Season. The FS Deadline for each Binding Season shall be seven months before the start of such Binding Season.

14.2.1 Forward Showing Submittal:

14.2.1.1 Absent the exception in Section 14.2.1.2, each Participant shall submit a separate Forward Showing Submittal for loads for which it is responsible if transmission constraints between areas where its loads are located, including, without limitation, when Participant is responsible for loads in more than one Subregion, prevent application, in the manner more fully described in the Business Practice Manuals, of Resource QCC or Net Contract QCC from one load area to the FS Capacity Requirement of another load area.

14.2.1.2 Notwithstanding Section 14.2.1.1, a Participant responsible for loads in two Subregions may submit for a given Month a single Forward Showing Submittal for such loads, and may employ for determination of its FS Capacity Requirement for such Month the lower of the two FSPRM values determined for the Subregions where its loads are located, if the Participant demonstrates in such Forward Showing Submittal, in accordance with the procedures and requirements set forth in the Business Practice Manuals, transmission service rights of the type required by the FS Transmission Requirement, in a quantity, in addition to that required by the FS Transmission Requirement, equal to the difference in the two FSPRM values multiplied by the Participant's P50 Peak Load Forecast for such Month, with a point of delivery in the Subregion with the higher FSPRM value and the point of receipt in the Subregion with the lower FSPRM value. Each such showing shall identify the MW quantity, Month of service, point of receipt, and point of delivery of such transmission service rights, and such other information as specified in the Business Practice Manuals, and shall verify that the offered rights are NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service.

14.2.2 Each Participant's Forward Showing Submittal shall include a Senior Official Attestation.

14.3 The FSPRM values used in the Forward Showing Submittals for a Binding Season shall be those values approved by the Board of Directors as the culmination of an Advance Assessment process. No later than twelve months before the FS Deadline for each Binding Season, WPP will determine and post the recommended FSPRM for each Subregion for each Month of such Binding Season. Participants shall provide their load, resource and other information reasonably required to perform the analyses and calculations required for the Advance Assessment, in accordance with the Advance Assessment information submission details and schedule specified in the Business Practice Manuals. No later than nine months before the FS Deadline for such Binding Season, the Board of Directors shall take its final action regarding approval of the FSPRM values for each Month of such Binding Season.

14.3.1 In connection with an Advance Assessment process, or otherwise in connection with consideration of a change to the Business Practice Manuals, the Board of Directors may determine that designation of Subregions would encourage the relief, in whole or part, of transmission constraints on the transfer of capacity within the WRAP Region (whether through development or commitment of transmission, of Qualifying Resources, or by other means) to the benefit of the WRAP Region and the advancement of the objectives of the WRAP. Each such Subregion shall be identified in the Business Practice Manuals.

14.3.2 Any Participant may choose to offer in the Advance Assessment process transmission service rights owned or controlled by such Participant for firm delivery of capacity from one Subregion to another Subregion, for use by other Participants under the terms of Part III of this Tariff during any or all identified Months of the applicable Binding Season. Each such offer shall identify the MW quantity, Month of service, point of receipt, and point of delivery of such transmission service rights, and such other information as specified in the Business Practice Manuals, and shall verify that the offered rights are NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service. No Participant is obligated to offer any such transmission service rights in the Advance Assessment process, but any offer so made and not withdrawn before the deadline during the Advance Assessment process specified in the Business Practice Manuals shall be considered a binding offer of the identified transmission service rights which may not be withdrawn before the end of the last Day of the Month for which such transmission service is offered. WPP shall take account of such offered transmission service rights, along with other transmission deliverability reasonably anticipated to be available for use by Participants for WRAP purposes during the applicable Binding Season in its determination of the recommended FSPRM values for each Month of the

applicable Binding Season for the WRAP Region and for each affected Subregion.

14.4 No later than sixty Days after the FS Deadline for a Binding Season, WPP will (i) provide the values of the Participant's FS Capacity Requirement and FS Transmission Requirement for each Month of the Binding Season; (ii) affirm that the Portfolio QCC of such Participant for each Month of the Binding Season equals or exceeds the FS Capacity Requirement of such Month for such Participant or notify such Participants of any deficiencies in the Forward Showing Submittal that result in a failure to demonstrate satisfaction of the FS Capacity Requirement; and (iii) affirm that the Demonstrated FS Transmission plus approved Monthly Transmission Exceptions of such Participant for each Month of the Binding Season equals or exceeds the FS Transmission Requirement of such Month for such Participant or notify such Participants of any deficiencies in the Forward Showing Submittal that result in a failure to demonstrate satisfaction of the FS Transmission Requirement.

14.5 Within 120 Days after the FS Deadline, the Participant shall (i) submit revisions to its Forward Showing Submittal, including, without limitation, additions or revisions to the Participant's Resource QCC, Net Contract QCC, or Demonstrated FS Transmission; (ii) in order to fully cure all identified deficiencies and demonstrate that such Participant's Portfolio QCC for each Month of the Binding Season equals or exceeds its FS Capacity Requirement; and (iii) fully provide Demonstrated FS Transmission for each Month of the Binding Season that equals or exceeds its FS Transmission Requirement for the same Month of the Binding Season where WPP identified deficiencies.

14.5.1 Any Participant that fails to cure identified deficiencies in its Forward Showing Submittal within the period prescribed above shall be assessed a Deficiency Charge.

15. Transition Period

15.1 Except as specified in Section 15.1.1, the Binding Season beginning November 1, 2027, will be the first Binding Season for which all Participants will assume the obligations of demonstrating capacity and making surplus capacity available to other Participants and will receive the benefits of reliance upon other Participants' surplus capacity. Any Binding Season during the Transition Period occurring before November 1, 2027, shall be a Non-Binding Season, as specified in Section 15A of this Tariff.

15.1.1 No later than January 15, 2026, a Participant may elect the Binding Season beginning June 1, 2027, as the first Binding Season for which it will assume the obligations of demonstrating capacity and making surplus capacity available to other Participants and will receive the benefits of reliance upon other Participants' surplus capacity by providing written notice of its election.

15.2 Within two years prior to the start of the first Binding Season of the WRAP, a Participant who has elected to participate in the first Binding Season may request a vote of all Participants who have elected to participate in the first Binding Season to delay implementation of the first Binding Season for up to two Seasons. Delayed implementation of the first Binding Season shall be approved if 75% of the Participants who elected to participate in the first Binding Season vote in favor of such delay, with approval requiring a vote of 75% of both the House and Senate vote tallies (as described in Sections 4.1.6.2.1 and 4.1.6.2.2 of this Tariff) of all Participants who elected to participate in the first Binding Season.

15.2.1 The deferral vote may only occur for the first Binding Season of the WRAP. If the Participants who elected to participate in the first Binding Season of the WRAP vote to delay implementation of the first Binding Season, all compliance charges for the Forward Showing Program and Operations Program are automatically deferred; except that the Participants may vote to delay implementation only of the Operations Program portion of the first Binding Season and retain the binding Forward Showing Program portion of the first Binding Season.

15A. Non-Binding Seasons

15A.1 A Participant will participate as a Non-Binding Participant for certain Binding Seasons in the Transition Period, as detailed in Section 15.1 of this Tariff, and when Critical Mass is not achieved for a given Binding Season, as detailed in Section 15A.2 of this Tariff. As to a Non-Binding Season, the Participant:

15A.1.1 Shall not be subject to Deficiency Charges, Transmission Deficiency Charges, Holdback Requirements, Energy Deployment obligations, or Delivery Failure Charges;

15A.1.2 Shall submit Forward Showing Submittals but shall not be required to cure deficiencies;

15A.1.3 Shall not have a mandatory Holdback Requirement as a result of the Sharing Calculation;

15A.1.4 May only receive Holdback Capacity offered voluntarily by other Participants in accordance with Part III of this Tariff; and

15A.1.5 Shall have all rights and be subject to all obligations under Part I of this Tariff and the Participant's WRAPA, including, without limitation, voting rights, committee participation, and the obligation to pay the WRAP Administration Charge.

15A.2 Once WPP has given notice to Participants that their Subregion does not have Critical Mass for a given Binding Season, each such Participant will have 30 days to provide notice to WPP if it intends to participate as a Non-Binding Participant for that Binding Season. Such notice and election will be given similarly for each season without Critical Mass participation.

16. Components of the Forward Showing

16.1 FS Capacity Requirement. The FS Capacity Requirement shall be determined for each Participant on a monthly basis by applying the applicable Monthly FSPRM for a Month to such Participant's peak load forecast for that Month. The Participant's peak load forecast for a given Month of a Binding Season will be the P50 Peak Load Forecast for the Binding Season multiplied by a shaping factor based on the historical relationship, for such Participant, of the seasonal peak for the Winter Season or Summer Season, as applicable, and the monthly peaks for the Months in such season, as more fully described in the Business Practice Manuals.

16.1.1 P50 Peak Load Forecast. The P50 Peak Load Forecast is a peak load forecast prepared on a basis, such that the actual peak load is statistically expected to be as likely to be above the forecast as it is to be below the forecast. The Business Practice Manuals shall specify an approved load forecasting methodology for use by all Participants for their WRAP-required load forecasts which shall include (i) a base monthly peak derived from a recent historical period that recognizes additions and removals of load during the historical period, (ii) adjustments for known additions and removals of load during the forecast window; and (iii) a specified load growth factor.

16.1.2 FS Planning Reserve Margin

16.1.2.1 The FSPRM is an increment of resource adequacy supply needed to meet conditions of high demand in excess of the applicable peak load forecast and other conditions such as higher resource outages, expressed as a percentage of the applicable peak load forecast. The FSPRM shall be determined based on probabilistic analysis, taking account of uncertainties in generation and load, as the margin above peak load that provides an expectation of no more than a single event-day of loss of load in ten years (sometimes referred to herein as the "1-in-10 LOLE") for each Binding Season. The FSPRM shall be determined in a manner that accounts for the governing principles of QCC value determinations set forth in Section 16.2.5 of this Tariff and shall employ the applicable peak load for the applicable Binding Season and Months. Additional details, assumptions, methodologies, and procedures for determination of the FSPRM shall be as set forth in the Business Practice Manuals.

16.1.2.2 WPP shall calculate in the Advance Assessment process the recommended Monthly FSPRM for each Month of each Binding Season, for approval by the Board of Directors as set forth in this Part II.

16.1.2.3 The FSPRM shall employ (i) a simulated resource stack using capacity accreditation principles consistent with those used for WRAP QCC determinations; (ii) an adjustment in the total WRAP-required QCC value as needed to meet a 1-in-10 LOLE for each Binding Season, and (iii) while maintaining the 1-in-10 LOLE for each Binding Season in (ii), include a monthly reduction of capacity to ensure that each Month has at least 0.01 annual LOLE. The FSPRM for a Month shall be the simulated QCC as adjusted to meet the 1-in-10 LOLE for each Binding Season minus the P50 Peak Load Forecast for the Month, divided by the P50 Peak Load Forecast for the Month.

16.1.2.4 The FSPRM shall include an approximation of Contingency Reserves as set forth in the Business Practice Manuals.

16.1.3 Contingency Reserves Adjustment. A Participant's FS Capacity Requirement will be adjusted as set forth in the Business Practice Manuals to account for changes in Contingency Reserve requirements resulting from energy contract purchases and contract sales.

16.1.4 A Participant responsible for loads located in a Subregion for which an FSPRM value has been determined that is higher than the FSPRM value determined for a different Subregion may, in lieu of demonstrating a MW increment of Portfolio QCC otherwise required to satisfy such Participant's FS Capacity Requirement for a given Month, demonstrate in its Forward Showing Submittal, in accordance with the procedures and requirements set forth in the Business Practice Manuals, transmission service rights of the type required by the FS Transmission Requirement, in a quantity, in addition to that required by the FS Transmission Requirement, that is no greater than the difference in the two FSPRM values multiplied by the Participant's P50 Peak Load Forecast, with the point of delivery in the Subregion with the higher FSPRM value and the point of receipt in the Subregion with the lower FSPRM value. The MW quantity of the additional transmission so demonstrated shall reduce for such Month, by the same MW quantity, the Portfolio QCC the Participant would otherwise be required to demonstrate to satisfy its FS Capacity Requirement for such Month. Each such demonstration shall identify the MW quantity, Month of service, point of receipt, and point of delivery of such transmission service rights, and such other information as specified in the Business Practice Manuals, and shall verify that the offered rights are NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service.

16.2 Qualified Capacity Contribution

16.2.1 For each Participant and each Binding Season, the Forward Showing shall show and support the Portfolio QCC, which shall be the sum of the QCC of the Participant's Qualifying Resources ("Resource QCC"), the QCC of its

contracted capacity ("Net Contract QCC"), and any transfers of capacity already accredited by another Participant ("Total RA Transfer," which could be positive or negative). The Portfolio QCC effective for a Binding Season shall be the value determined by WPP.

16.2.2 A resource will not be assigned a Resource QCC or counted toward Portfolio QCC unless it is a Qualifying Resource. Qualifying Resources are those that, before they are included in a Forward Showing Submittal, are first registered with WPP. A Participant seeking registration of a resource must submit a request for registration providing the resource information described in the Business Practice Manuals.

16.2.3 The minimum resource size for registration of a resource is 1 MW, provided, however, that Participants with responsibility for individual resources of less than 1 MW may aggregate them to meet the 1 MW minimum requirement, under the conditions and limitations specified in the Business Practice Manuals.

16.2.4 A Participant may include in its Forward Showing Submittal a request for an exception from its FS Capacity Requirement for an insufficiency of its Portfolio QCC solely due to (i) a catastrophic failure of one or more Qualifying Resources due to an event of Force Majeure as defined by Section 8.1 of this Tariff that (ii) the Participant is unable to replace on commercially reasonable terms prior to the FS Deadline as a result of the timing and magnitude of such catastrophic failure and its consequences. As more fully set forth in the Business Practice Manuals, such exception request shall be supported by a Senior Official Attestation. The exception request must include complete information on the nature, causes and consequences of the catastrophic failure, and must describe the Participant's specific, concrete efforts prior to the FS Deadline to secure replacement Qualifying Resources for the applicable Binding Season. WPP will consider the exception criteria established by this section, the information provided in the exception request, the completeness of the exception request, and other relevant data and information, in determining whether to grant or deny an FS Capacity Requirement exception request. WPP shall provide such determination no later than sixty days after submission of such Participant's FS Submittal containing such FS Capacity Requirement exception request. A Participant granted an exception hereunder must complete a monthly exception check report demonstrating that either the circumstances necessitating the exception have not changed; or that Qualifying Resources have become available, and the Participant has acquired them and no longer requires the exception. Failure to timely submit a required monthly report will result in assessment of a Deficiency Charge, unless the deficiency is cured within seven days of notice of non-compliance. A Participant denied an exception request hereunder may appeal such denial to the Board of Directors in accordance with the procedures and deadlines set forth in the Business Practice Manuals. In

such event, the requested exception shall be denied or permitted as, when and to the extent permitted by the Board, in accordance with the procedures and timing set forth in the Business Practice Manuals. WPP shall give notice of any exception granted hereunder in the time and manner provided by the Business Practice Manuals.

16.2.5 QCC: WPP shall determine QCC values for the resource types specified below in accordance with the governing principles specified below for each resource type, and consistent with further details specified for each resource type in the Business Practice Manuals.

16.2.5.1 For resources that use conventional thermal fuels, including but not limited to, coal, natural gas, nuclear, and biofuel, WPP will determine QCC based on an Unforced Capacity methodology that employs resource-specific capability testing and capability requirements to determine an Installed Capacity value, and a forced outage calculation methodology based on historical performance during Capacity Critical Hours over a specified multi-year period (excluding outages properly reported as "outside management control"), or based on class-average forced outage data, as specified in the Business Practice Manuals, if there is insufficient data on historical performance.

16.2.5.2 For resources that are Variable Energy Resources, including, but not limited to, wind and solar resources, WPP will determine QCC based on an ELCC methodology, that accounts for synergistic portfolio effects within and among VER types at different resource penetration levels that influence the extent to which the WRAP Region can rely on those VER categories to meet overall capacity needs.

16.2.5.2.1 For such purpose, a separate ELCC value will be calculated in the aggregate for all VER resources of a given type in an identified VER Zone, to be delineated in the Business Practice Manuals based on factors such as geography, performance, meteorological considerations, and penetration.

16.2.5.2.2 As more fully described in the Business Practice Manuals, the zonal aggregate VER-resource-type value will be calculated by (i) conducting a benchmark LOLE study that includes all resource types except the VER resource type being studied, employing a model and assumptions consistent with those used to calculate FSPRM, and adding, or subtracting, the same MW quantity of Pure Capacity to every hour of the applicable Binding Season until,

respectively, an initial LOLE value above 0.1 day per Binding Season becomes 0.1 day per Binding Season, or an initial LOLE value below 0.1 day per Binding Season becomes 0.1 day per Binding Season; (ii) conducting an LOLE study that includes all resource types including the VER resource type being studied, employing a model and assumptions consistent with those used to calculate FSPRM, and adding, or subtracting, the same MW quantity of Pure Capacity to every hour of the applicable Binding Season until, respectively, an initial LOLE value above 0.1 day per Binding Season becomes 0.1 day per Binding Season, or an initial LOLE value below 0.1 day per Binding Season becomes 0.1 day per Binding Season; and (iii) subtracting the Pure Capacity value determined under subpart (ii) from the Pure Capacity value determined under subpart (i) (for which calculation a Pure Capacity value subtracted from each hour in either subpart (i) or subpart (ii) will be assigned a negative value; (iv) repeating steps (i) through (iii) for each Binding Season of the study period employing historical, or as necessary, synthesized, data; and (v) basing the aggregate value of the studied VER resource type for the studied VER Zone on the results of the calculation in step (iii) for the Binding Seasons studied, which may include differential weighting of the Binding Seasons studied as appropriate to improve the quality and predictive capacity of the final result.

16.2.5.2.3 The aggregate capacity calculated for each VER resource type in each VER Zone will then be allocated to VERs of that type in that VER Zone based on each such resource's average historical performance if at least three years of historical performance or three years of synthesized forecast data during the WRAP Region's CCH is available at the time of such allocation. If three years historical performance or synthesized forecast data is not then available, the average ELCC from the VER Zone will be assigned.

16.2.5.3 For resources that are Energy Storage Resources, WPP will determine QCC based on an ELCC methodology comparable to that used for VERs. The ELCC methodology will model Energy Storage Resources at the level of their usable capacity that can

be sustained for a minimum duration of four hours. An Energy Storage Resource need not have a nameplate rating that assumes a minimum of four hours in order to receive a QCC determination, but the QCC in that case will be scaled to reflect the capability that can be sustained for four hours, as more fully described in the Business Practice Manuals.

16.2.5.4 A Participant's Demand Response used as a Demand Response Capacity Resource must be controllable and dispatchable by the Participant or by the host utility, and must have met certain testing requirements consistent with Business Practice Manuals. WPP will determine Demand Response Load Modifier QCC by multiplying the load reduction in MWs by the number of hours the resource can demonstrate load reduction capability (for a period of up to five continuous hours) divided by five. The effects of Demand Response used as a Demand Response Capacity Resource must not be included in load provided for a Participant's Advance Assessment.

16.2.5.5 For Storage Hydro Qualifying Resources, the Participant will calculate a QCC based on a methodology detailed in the Business Practice Manuals that: (i) considers each resource's actual generation output, residual generating capability, water in storage, reservoir levels, and flow or project constraints over the previous ten-year historical period; (ii) determines the project's QCC by assessing the historical generation during CCHs on any given day and ability to increase generation during CCHs on the same day, subject to useable water in storage, inflows/outflows, and expected project operating parameters/constraints and limitations; (iii) incorporates forced outage rates; and (iv) determines QCC as average contribution to the CCH for each Winter Season and Summer Season over the previous ten years. If ten years of historical data is not available for the Storage Hydro Qualifying Resource, the Participant may alternatively employ data on the same metrics from a demonstrably comparable facility or apply another method that provides reasonable confidence in the reliability of the predicted values, as more fully set forth in the Business Practice Manuals. The Participant's QCC calculation shall be subject to review and validation by WPP. In connection with such review, the Participant shall provide WPP with the following information necessary to calculate a QCC for Storage Hydro Qualifying Resources: (i.a) historical reservoir elevation levels; (ii.a) historical plant generation; (iii.a) elevation versus capacity curves; (iv.a) any minimum or maximum reservoir level constraints; (v.a) forced outage rates; (vi.a) volume of water

versus reservoir elevation storage tables; and (vii.a) turbine discharge versus generation efficiency curve.

16.2.5.6 For Run of River Qualifying Resources, WPP will determine QCC based on the monthly average performance of such resource during Capacity Critical Hours, as further specified in the Business Practice Manuals

16.2.5.7 For resources that (i) are not within the meaning of any of Sections 16.2.5.1 through 16.2.5.5, and that (ii) either (a) are not dispatchable; or (b) require the purchaser of energy from the resource to take energy as available from such resource, including but not limited to a qualifying facility as defined under the Public Utility Regulatory Policies Act of 1978, WPP will determine QCC based on the monthly average performance of such resource during Capacity Critical Hours, as further specified in the Business Practice Manuals.

16.2.6 Net Contract QCC: WPP shall determine Net Contract QCC for the agreement types specified below in accordance with the governing principles specified below for each agreement type, and consistent with further details specified for each agreement type in the Business Practice Manuals. Net Contract QCC may be either positive or negative, to take account of, for example, a Participant's agreements for the sale of capacity to any other party.

16.2.6.1 Absent one of the exceptions described and limited below, capacity supply agreements qualifying for a Net Contract QCC in the WRAP must be resource specific, and therefore must include, among other requirements, an identified source, an assurance that the capacity is not used for another entity's resource adequacy requirements, an assurance that the seller will not fail to deliver in order to meet other supply obligations, and affirmation of NERC Priority 6 or 7 firm point-to-point transmission service rights or network integration transmission service rights from the identified resource to the point of delivery/load. The specific resources identified in a capacity supply agreement qualifying for Net Contract QCC shall meet the same Resource QCC accreditation requirements for the given resource type, as specified in Section 16.2.5.

16.2.6.2 A system sales contract can qualify for a Net Contract QCC value, provided that if the seller is not a Participant, the system capacity that is the subject of the agreement must be deemed surplus to the seller's estimated needs, there must be an assurance that the seller will not fail to deliver in order to meet other commercial obligations, and there must be NERC Priority

6 or 7 firm point-to-point transmission service rights or network integration transmission service rights from the identified resource to the point of delivery/load. Surplus status may be demonstrated by a Senior Official Attestation with pertinent supporting details for such surplus status, including written assent of the non-Participant Seller, secured by the purchasing Participant. Such attestation is not required if the seller is a Participant, because the information needed to verify surplus status is already available.

16.2.6.3 A supply agreement entered into prior to October 1, 2021 ("Legacy Agreement") can qualify for a Net Contract QCC value; provided that where a legacy agreement does not identify the source, it must be possible for WPP to presume a source or sources for the contract, including with the written assent of the supplier under such Legacy Agreement, conveyed in the form and manner set forth in the Business Practice Manuals. A Legacy Agreement for which such resource determination cannot be reasonably made will not be counted as adding to the Portfolio QCC.

16.2.7 Total RA Transfer: A Participant may agree with another Participant on a transfer of a portion of its Portfolio QCC to meet the other's FS Capacity Requirement ("RA Transfer"), provided that the details and duration of such transfer are reported to WPP for validation in accordance with procedures and information requirements specified in the Business Practice Manuals. Where such transfers have been duly reported and validated, an RA Transfer will be added to the purchasing Participant's Portfolio QCC and subtracted from the selling Participant's Portfolio QCC.

16.2.8 Planned Outages: Participants shall include in their Forward Showing Submittal for a Binding Season information on all Qualifying Resources that are currently out of service with a scheduled return date that falls during the Binding Season or after the Binding Season. Capacity associated with such resources must be deducted from Participants' Portfolio QCC as specified in the Business Practice Manuals to ensure no credit is granted for such resources during the planned outage. The aggregate of any additional outages that are planned to occur during the Binding Season but have not yet begun at the time of submission must be within the Participant's remaining surplus (or replaced with other supply). Participants may provide information on all Qualifying Resources that are planned to be out of service but if such data cannot be supplied with reasonable specificity, a Participant may provide a Senior Official Attestation at the time of the submission of its FS Submittal that it expects the sum of planned outages to be equal to or less than the surplus stated in its FS Submittal throughout the Binding Season.

16.2.8.1 If a Qualifying Resource is planned to return to service within the first five days of a Binding Season, WPP may approve a qualified acceptance of the FS Submittal, provided the deficiency is less than 500 MW.

16.2.8.2 A planned outage shall not justify a waiver of or exception to a Participant's holdback or energy delivery obligations under Part III of this Tariff. Participants will be expected to procure the necessary capacity or energy to meet the Operations Program requirements, regardless of planned outage schedules or FS Submittal acceptance.

16.3 FS Transmission Requirement

16.3.1 As part of its Forward Showing Submittal for a Binding Season, each Participant must demonstrate, as specified in the Business Practice Manuals, that it has secured firm transmission service rights, including under supply arrangements with a third party that holds or has committed transmission service rights, sufficient to deliver a MW quantity equal to at least 75% of the MW quantity of its FS Capacity Requirement. To the extent a Participant holds transmission service rights with a point of receipt at a Qualifying Resource, or in connection with an RA Transfer to such Participant, any such rights from such point in a MW quantity, respectively, in excess of the QCC of such Qualifying Resource, or in excess of the value of such RA Transfer, shall not contribute toward satisfaction of such Participant's FS Transmission Requirement. The FS Transmission Requirement must be met with NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service or network integration transmission service, from such Participant's Qualifying Resource(s) or from the delivery points for the resources identified for its Net Contract QCC or for its RA Transfer to such Participant's load. Notwithstanding the foregoing, authorized use of Capacity Benefit Margin will satisfy the FS Transmission Requirement. Demonstration of the FS Transmission Requirement shall not, in and of itself, relieve any Participant of responsibility for a Delivery Failure Charge as determined under Section 20.7 if such Participant's failure to obtain or maintain firm transmission service of the type and quantity expected by the Operations Program, as described in Section 20.6 of this Tariff, caused or contributed to an Energy Delivery Failure.

16.3.2 A Participant may include in its Forward Showing Submittal a request for an exception from a limited part of its FS Transmission Requirement, provided the exception request meets the terms, conditions, and limitations of one or more of the following four exception categories below. As more fully set forth in the Business Practice Manuals, such exceptions may be subject to overall WRAP limits, and shall be supported by a Senior Official Attestation. WPP will consider the exception category terms, conditions and limitations set forth below, and may consider the completeness of the

exception request, information from transmission service providers, OASIS data, and data readily available to WPP from other reliable and validated sources concerning the duration, timing, firmness and quantity of available transmission service or equivalent options (including transmission construction), in determining whether to grant or deny a transmission exception request. WPP shall provide such determination no later than sixty days after submission of such Participant's FS Submittal containing such transmission exception request. A Participant denied an exception request hereunder may appeal such denial to the Board of Directors in accordance with the procedures and deadlines set forth in the Business Practice Manuals. In such event, the requested exception shall be denied or permitted as, when and to the extent permitted by the Board, in accordance with the procedures and timing set forth in the Business Practice Manuals. WPP shall give notice of any exception granted hereunder in the time and manner provided by the Business Practice Manuals. A Participant granted a transmission exception under either Section 16.3.2.1 or Section 16.3.2.2 must complete a monthly transmission exception check report demonstrating that either (i) the circumstances necessitating the exception have not changed; (ii) transmission has become available and the Participant has acquired it; or (iii) the Participant has acquired a different resource, and associated transmission service rights, and no longer requires the exception. Failure to timely submit a required monthly report will result in assessment of a Deficiency Charge, unless the deficiency is cured within seven days of notice of non-compliance.

16.3.2.1 Enduring Constraints. Participant is unable to demonstrate sufficient NERC Priority 6 or NERC Priority 7 firm point-to-point or network integration transmission service rights on any single segment of a source to sink path for a Qualifying Resource; and Participant demonstrates that no ATC for such transmission service rights is available (either from the transmission service provider or through a secondary market) at the FS Deadline on the applicable segment for the Month(s) needed (for a duration of one year or less) at the applicable Open Access Transmission Tariff rate or less; and Participant submits a Senior Official Attestation that Participant has taken commercially reasonable efforts to procure firm transmission service rights, and that Participant has posted Firm Transmission Requirements on a relevant bulletin board prior to the FS Deadline. In the event such transmission service rights are only available for a duration of more than one year (whether from the transmission service provider or through a secondary market) at the FS Deadline on the applicable segment for the Month(s) needed at the applicable Open Access Transmission Tariff rate or less, a Participant is not required to obtain such service in order to qualify for the Enduring Constraints exception hereunder. Notwithstanding the foregoing, if such Participant declines to obtain such available service and is granted the exception hereunder, such Participant shall not qualify

for an exception hereunder for the same path (or across the same constraint) for the same season of the subsequent year if the Participant again declines to obtain such transmission service rights that are available for a duration of more than one year. In addition to the foregoing, Participant must further demonstrate that there was remaining available transmission transfer capability (i.e., non-firm ATC after the fact) for all CCHs in the same season of the most recent year for which CCHs have been calculated; or, if the path was constrained in at least one CCH of the CCHs in the same season of the most recent year for which CCHs have been calculated, Participant in that case must demonstrate either that it is constructing or contracting for a new local resource for at least the amount of the exception requested, or that it is pursuing long-term firm transmission service rights by entering the long-term queue and taking all appropriate steps to obtain at least the amount of the exception requested.

16.3.2.2 Future Firm ATC Expected. Participant demonstrates that ATC for NERC Priority 6 or NERC Priority 7 firm point-to-point or network integration transmission service rights is not posted or available prior to the FS Deadline (for a duration of one year or less) at the applicable Open Access Transmission Tariff rate or less, and that the transmission service provider has, after the FS Deadline, released additional ATC for such transmission service rights in every one of the CCHs of the most recent year for which CCHs have been calculated on the applicable path. In the event ATC for such transmission service rights is only posted or available prior to the FS Deadline for a duration of more than one year (whether from the transmission service provider or through a secondary market) on the applicable segment for the Month(s) needed at the applicable Open Access Transmission Tariff rate or less, a Participant is not required to obtain such service in order to qualify for the Future Firm ATC Expected exception hereunder. Notwithstanding the foregoing, if such Participant declines to obtain such available service and is granted the exception hereunder, such Participant shall not qualify for an exception hereunder for the same path (or across the same constraint) for the same season of the subsequent year if the Participant again declines to obtain such transmission service rights that are available for a duration of more than one year. The Participant must also demonstrate that the exception request meets volume and duration limitations specified in the Business Practice Manuals.

16.3.2.3 Transmission Outages and Derates. Participant demonstrates that an applicable segment of its existing transmission service rights from its source to sink path for its Qualifying Resource is expected to be derated or out-of-service and the ATC

for NERC Priority 6 or NERC Priority 7 firm point-to-point or network integration transmission service rights is not otherwise available, and that the exception request meets volume and duration limitations specified in the Business Practice Manuals.

16.3.2.4 Counterflow of a Qualifying Resource. Participant demonstrates that either: (i) Participant's use of firm transmission service in connection with the delivery of capacity from Participant's Qualifying Resource (or from the resource associated with its Net Contract QCC) to Participant's load (or other qualifying delivery point permitted by the WRAP) or (ii) a second Participant's use of firm transmission service in connection with the delivery of capacity from the second Participant's Qualifying Resource (or from the resource associated with its Net Contract QCC) to the second Participant's load (or other qualifying delivery point permitted by the WRAP) provides a direct and proportional counterflow transmission that supports the first Participant's delivery of capacity from the first Participant's Qualifying Resource (or from the resource associated with its Net Contract QCC) to the first Participant's load (or other qualifying delivery point permitted by the WRAP) Qualifying Resource to their load. If the exception is requested under subpart (ii) of this subsection, the Participant requesting the exception shall include a written acknowledgement from the second Participant that it is aware of such exception request.

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16.3.3 To the extent a Participant does not demonstrate satisfaction of its FS Transmission Requirement by the FS Deadline, the Participant may correct any such deficiency on or before the end of the cure period prescribed by Section 14.5 of this Tariff to avoid a Deficiency Charge.

16.3.4. Any deficiency of transmission service rights ultimately determined by WPP will be treated, for purposes of Deficiency Charge determinations, as in conjunction with, and not additive to, any deficiencies of QCC determined pursuant to Section 16.2.

17. Forward Showing Deficiency Charge

17.1 If a Participant fails during the cure period to demonstrate that it has resolved any identified deficiencies in either or both of its FS Capacity Requirement and its FS Transmission Requirement, the Participant will be assessed a Deficiency Charge for each Month for which a deficiency is identified in accordance with this section. In such case, the deficiency for which the Participant will be assessed a Deficiency Charge will be calculated in accordance with the following:

Participant's Monthly Capacity Deficiency = Maximum of (Monthly FS Capacity Requirement – Monthly Portfolio QCC, 0)

Participant's Monthly Transmission Deficiency (MW) = Maximum of ((75% × Monthly FS Capacity Requirement) – (Monthly Transmission Demonstrated + Approved Monthly Transmission Exemptions), 0)

Where Monthly Transmission Demonstrated is the amount of transmission service rights submitted by a Participant per the requirements in Section 16.3 and validated by WPP for each month.

Monthly Deficiency (MW) = Maximum of (Monthly Capacity Deficiency, Monthly Transmission Deficiency)

17.2 A Participant's Deficiency Charges shall be calculated as set forth in this Section 17.2, subject to the Transition Period rules in Section 17.3, and shall take account of multiple Monthly Deficiencies within a Forward Showing for a single Binding Season, multiple Deficiencies across a Forward Showing Year, consisting of a Summer Season and the immediately succeeding Winter Season, and any Monthly Deficiencies in a previous Forward Showing Year, in accordance with the following:

17.2.1 The Monthly Deficiency with the highest MW value in a Forward Showing for a Summer Season shall be assessed a Deficiency Charge equal to:

Max Summer Deficiency (MW) × Annual CONE ($/kW-year) × 1000 × Summer Season Annual CONE Factor

17.2.2 Any other Monthly Deficiency in the Participant's Forward Showing for the same Summer Season shall be assessed a Deficiency Charge equal to:

Additional Summer Deficiency (MW) × (Annual CONE ($/kW-year)/12) × 1000 × 200%

17.2.3 Any Monthly Deficiency in the Forward Showing for the immediately succeeding Winter Season with a higher MW value than the highest MW value of the Monthly Deficiency in the Summer Season shall be assessed a Deficiency Charge on the incremental MW value above the Summer Season equal to:

Maximum of (Max Winter Deficiency – Max Summer Deficiency, 0) (MW) × Annual CONE ($/kW-year) × 1000 × Winter Season Annual CONE Factor

and in such case where there is a Monthly Deficiency in the Winter Season with a higher MW value than the highest MW value of any Monthly Deficiency in the Summer Season, the Monthly Deficiency with the highest MW value in the Summer Season shall be assessed an additional Deficiency Charge calculated in accordance with Section 17.2.2.

17.2.4 Any other Monthly Deficiency in the Participant's Forward Showing Submittal for the same Winter Season shall be assessed a Deficiency Charge equal to:

Additional Winter Capacity Deficiency × (Annual CONE/12) × 1000 × 200%

17.2.5 For purposes of the above, CONE is the estimated cost of new entry of a new peaking natural gas-fired generation facility. The CONE estimate shall be based on publicly available information relevant to the estimated annual capital and fixed operating costs of a hypothetical natural gas-fired peaking facility. The CONE estimate shall not consider the anticipated net revenue from the sale of capacity, energy, or ancillary services from the hypothetical facility, nor shall it consider variable operating costs necessary for generating energy.

17.2.6 WPP shall review the CONE estimate annually for a possible update. Any proposed changes in the CONE estimate shall be subject to review through the stakeholder process for program rule changes.

17.2.7 The Summer Season Annual CONE Factor shall vary based on the ratio ("Summer % Deficit") of the Aggregate Capacity Deficiency for the WRAP as a whole for that Summer Season, divided by the P50 Peak Load Forecast for the Summer Season, as follows:

If the Summer % Deficit is less than or equal to 1%, the Summer Season Annual CONE Factor = 125%

If the Summer % Deficit is greater than 1% but less than or equal to 2%, the Summer Season Annual CONE Factor = 150%

If the Summer % Deficit is greater than 2% but less than or equal to 3%, the Summer Season Annual CONE Factor = 175%

If the Summer % Deficit is greater than 3%, the Summer Season Annual CONE Factor = 200%

17.2.8 The Winter Season Annual CONE Factor shall vary based on the ratio ("Winter % Deficit") of the Aggregate Capacity Deficiency for the WRAP as a whole for that Winter Season, divided by the P50 Peak Load Forecast for the Winter Season, as follows:

If the Winter % Deficit is less than or equal to 1%, the Winter Season Annual CONE Factor = 125%

If the Winter % Deficit is greater than 1% but less than or equal to 2%, the Winter Season Annual CONE Factor = 150%

If the Winter % Deficit is greater than 2% but less than or equal to 3%, the Winter Season Annual CONE Factor = 175%

If the Winter % Deficit is greater than 3%, the Winter Season Annual CONE Factor = 200%

17.2.9 Notwithstanding Sections 17.2.7 and 17.2.8, if a *Participant incurred any FS Deficiency Charges* in a Forward Showing Year *after the Transition Period*, then for the immediately following Forward Showing Year, both the Summer Season Annual CONE Factor and the Winter Season Annual CONE Factor shall be 200% *for such Participant*.

17.2.10. Subject to the Transition Period rules in Section *15A.1*, revenues from the payment of Deficiency Charges as to a Binding Season shall be allocated among those Participants with no Deficiency Charges for that Binding Season, pro rata based on each Participant's share of all such Participants' Median Monthly P50 Peak Loads for such Binding Season.

17.3 During the Transition Period, Deficiency Charges otherwise calculated under Section 17.2 shall be reduced as, when, and to the extent, and subject to the conditions, provided in Section 17.3.2; and revenue allocations otherwise calculated under Section 17.2 shall be adjusted as, when, and to the extent, and subject to the conditions, provided in Section 17.3.4.

17.3.1. During the Transition Period, a Participant with a Monthly Capacity Deficiency can pay a *Discounted* Deficiency Charge for so much of such Monthly Capacity Deficiency as was due to an Excused Transition Deficit. To obtain an Excused Transition Deficit for a Binding Season, the Participant must provide a Senior Official Attestation attesting that the Participant *or a relevant third party servicing load for which the Participant is the LRE* has made commercially reasonable efforts to secure Qualifying Resources in the quantity needed to satisfy the Participant's FS Capacity Requirement for the Binding Season, but is unable to obtain Qualifying Resources in the quantity required for the Binding Season because the supply of such resources on a timely basis and on commercially reasonable

terms is at that time inadequate. *If the attestation relates to a third-party servicing load for which the Participant is the LRE, the Senior Official Attestation may be signed by a Senior Official of the third party load service provider, as further detailed in the Business Practices.* Excused Transition Deficits are not resource specific, relate to a MW quantity of the Participant's FS Capacity Requirement, and are limited for each Participant as to a Binding Season during the Transition Period to a maximum permissible MW quantity equal to a percentage value times the FSPRM applicable to such Participant for all Forward Showing Submittals submitted by such Participant for such Binding Season. For purposes of such calculation, the percentage value is*: 200*% for each of the *2027* Summer Season and *2027-2028* Winter Season*; and 100*% for each of the *2028* Summer Season and *2028-2029* Winter Season.

17.3.2 A Participant will pay a *Discounted* Deficiency Charge as to the portion of its Monthly Capacity Deficiency for which it obtained an Excused Transition Deficit. The *FS* Deficiency Charge otherwise applicable to such Participant under Section 17.2 shall be reduced by a percentage value equal to 75% for each of the *2027* Summer Season and *2027-2028* Winter Season*; and* 50% for each of the *2028* Summer Season and *2028-2029* Winter Season. The Participant will be assessed a*n FS* Deficiency Charge calculated under Section 17.2, without reduction or adjustment, for any of its Monthly Capacity Deficiency that is in excess of the amount of such deficiency for which it obtained an Excused Transition Deficit.

17.3.3 Whether or not a Participant obtains an Excused Transition Deficit as to a Binding Season, the Participant may reduce a Monthly Capacity Deficiency otherwise calculated under Section 17.1 for a Binding Season during the Transition Period to the extent such deficiency is due to the Participant's inability to obtain assent from the supplier under a Legacy Agreement to the accreditation required for such Legacy Agreement under Part II of this Tariff and the Business Practice Manuals. To obtain such relief, the Participant must provide a Senior Official Attestation attesting that the Participant made commercially reasonable efforts to execute the required accreditation form with the supplier under the Legacy Agreement, but the supplier was unable or unwilling to counter sign the accreditation form. The reduction in Monthly Capacity Deficiency permitted by this Section 17.3.3 as to any Participant for all Forward Showing Submittals submitted by such Participant for any Binding Season during the Transition Period shall not exceed a MW quantity equal to 25% times the FSPRM applicable for such Participant for such Binding Season. To the extent a Participant reduces a Monthly Capacity Deficiency under this subsection, the percentage of the Participant's FSPRM corresponding to the reduction hereunder shall reduce the maximum permissible percentage of FSPRM reduction allowed under Section 17.3.1 for Excused Transition Deficits for the same Binding Season.

17.3.4 A Participant that, as a result of application of this Section 17.3, pays no Deficiency Charge as to a Binding Season, shall not be deemed a "Participant[ ] with no Deficiency Charges" for purposes of Section 17.2.10, and shall not receive an allocation of revenues from the payment of Deficiency Charges as to such Binding Season.

PART III OPERATIONS PROGRAM

18. Operations Program Overview

18.1 The Operations Program facilitates access to collective capacity made available through regional load and resource diversity of all Participants under the terms of this Part III.

18.2 The Operations Program evaluates forecasted system conditions across the seven-day period ("Multi-Day-Ahead Assessment") preceding the Operating Day, commencing at the outset of the assessment period with an initial Sharing Calculation and initial identification of potential Sharing Events for the Operating Day. The assessment is refined as forecasted conditions for the Operating Day are revised and established on the Preschedule Day, a Holdback Requirement for any Sharing Events is then identified. To the extent a Sharing Event continues to be identified for the Operating Day, Holdback Requirements shall be converted into Energy Deployments on the Operating Day.

18.3 The Operations Program prescribes pricing designed to incent Participants to resolve any forecast Operating Day deficiencies before the Operating Day, including through transactions outside the Operations Program, and to fully compensate Participants that provide support through the Operations Program to Participants with Operating Day deficiencies.

19. Operations Program Timeline and Supporting Information

19.1 The Operations Program includes a Multi-Day Ahead Assessment that looks ahead at the next seven Operating Days by performing an indicative Sharing Calculation from Participant forecast data for each future Operating Day up until the Preschedule Day. The Sharing Calculation for the Preschedule Day is not indicative but is binding, subject to Sections 20.2.4 and 20.3. Participants shall provide WPP with forecasts for the next seven Operating Days of expected (i) load, (ii) output of VERs, (iii) output of RORs, (iv) Contingency Reserves, and (v) forced outages, including outages on transmission facilities the Participant utilized to meet its Forward Showing Capacity Requirement, as further described in the Business Practice Manuals. WPP shall utilize the forecast data obtained in the Multi-Day-Ahead Assessment to calculate or revise the indicative Sharing Calculations for each day thereafter, up until the Preschedule Day, and will use such forecast data to revise the indicative Sharing Calculation hourly during the Operating Day. Such forecast data will also be used to calculate the binding Sharing Calculation for the Preschedule Day.

19.2 The Operations Program, during any Binding Season, shall rely on and employ (among other data) the following information from the Forward Showings for such Binding Season: (i) the P50 Peak Load Forecast for each Participant; (ii) the Monthly FSPRMs for each Participant during such Binding Season; (iii) expected performance by Qualifying Resource type and any RA Transfers; (iv) expected forced outage rates by resource type; (v) expected Contingency Reserves; and (vi) firm transmission service rights made available for purposes of regional diversity sharing under the WRAP, permitted under Part II of this Tariff, which shall be assumed to be available for all hours of each Month for which such firm transmission service rights were made available.

19.3 To facilitate WPP's conduct of the Multi-Day-Ahead Assessment, each Participant shall provide the Program Operator information relevant to the Participant's expected demand and supply conditions on each Operating Day, of the type, in the manner, and with the frequency, specified in the Business Practice Manuals.

19.4 Each Participant in any Subregion identified in the Business Practice Manuals as not containing a central transmission hub permitting energy deliveries to that hub from any point within such Subregion, shall, in addition to providing the information required by Section 19.3, identify, on or before the deadline during the Preschedule Day specified in the Business Practice Manuals, for each Hour of the Operating Day each point to which it can deliver energy, each point at which it can take receipt of energy, the quantity it can deliver or receive at each such point, and a numeric factor intended to prioritize use of transmission made available by Participants with positive Sharing Calculations and needed by Participants with negative Sharing Calculations for each such hour. A Participant with a positive Sharing Calculation for an hour must provide a total quantity for all identified points at which it can deliver that is no less than the amount of its positive Sharing Calculation for such hour (adjusted as necessary for any RA Transfer in accordance

with Section 20.1.2). A Participant with a negative Sharing Calculation for an hour must provide a total quantity for all identified points at which it can take receipt that is no less than the amount of its negative Sharing Calculation for such hour (adjusted as necessary for any RA Transfer in accordance with Section 20.1.2). Participants shall provide this same information for each Operating Day on an expected or preliminary basis on each day of the Multi-Day-Ahead Assessment following, and based on, the expected Holdback Requirement estimates provided on each such day for the Operating Day.

19.5 Any Participant with excess supply that is not obligated to the WRAP through a positive Sharing Calculation result may, at its sole election, offer such supply to the WRAP as Voluntary Holdback. If the offering Participant has a positive Sharing Calculation result, the offered capacity shall be in addition to that Sharing Calculation result; if the offering Participant has a negative Sharing Calculation result, the offered capacity will only be included in the allocation of Holdback Requirement so long as the offering Participant did not confirm a need for Holdback Capacity for such hour. Such offers must be submitted within the time window identified in the Business Practice Manuals, must include the information identified in Sections 19.3 and 19.4, as applicable, and must conform to the format and content identified in the Business Practice Manuals. An offer of Voluntary Holdback may become part of the Participant's Holdback Requirement when it is included in the allocation on the Preschedule Day prescribed by Section 20.2.

20. Components of the Operations Program

20.1 Sharing Calculation

20.1.1 WPP shall implement, as more fully described in the Business Practice Manuals, with respect to each Forward Showing Submittal accepted by WPP for a Participant under Part II of this Tariff, or with respect to each Subregion in which the Participant is responsible for load regardless of whether the Participant submitted a single Forward Showing Submittal encompassing its loads in both Subregions, the following Sharing Calculation to identify any hour in which any Participant is forecast to have a capacity deficit (known as a "Sharing Event"). This calculation takes into account changes in a Participant's resource availability, resource performance, forecast load, and Contingency Reserve relative to the Forward Showing, plus an Uncertainty Factor. The Sharing Calculation is equal to:

[(P50) * (1 + FSPRM) + Contingency Reserve Adjustment] – [Load Forecast – Demand Response Capacity Resources + Contingency Reserve Obligation + Uncertainty Factor] + [ΔForced Outages + ΔRoR Performance + ΔVER Performance]

Where:

P50 refers to the Participant's Monthly P50 Peak Load for that Binding Season's Month;

FSPRM, as described in Section 16.1.2, is an increment of resource adequacy supply needed to meet conditions of high demand in excess of the applicable peak load forecast and other conditions such as higher resource outages and is expressed as a percentage of the applicable Participant P50 Peak Load Forecast for that Binding Season's month;

Contingency Reserve Adjustment accounts for changes in Contingency Reserve expectations (relative to the 6% Contingency Reserve assumed in the FSPRM) resulting from energy contract purchases and contract sales as set forth in the Business Practice Manuals;

Load Forecast refers to the forecast of expected load for the subject hour for the loads for which the Participant is the Load Responsible Entity and that have not been excluded from WRAP participation;

Demand Response Capacity Resource as described in Section 16.2.5.4.

Contingency Reserve Obligation refers to the amount of Contingency Reserve the Participant is carrying during the operating hour equal to (i) 3% of Load Forecast for which the Participant is the WRAP LRE and maintains

its Contingency Reserve, (ii) plus 3% of WRAP load for which the Participant is not the LRE but has assumed the Contingency Reserve through a contractual arrangement, (iii) plus 3% of generation used to meet any load for which the Participant is the LRE and maintains the Contingency Reserve, (iv) plus 3% of generation utilized to meet WRAP Load for which the Participant is not the LRE but has assumed the Contingency Reserve through a contractual arrangement;

Uncertainty Factor refers to a factor determined by WPP, as more fully set forth in the Business Practice Manuals, to account for the potential variance between forecasts of load, solar resources, wind resources, and run-of-river resources, and the Operating Day conditions of such load and resources;

Δ Forced Outages refers, for the subject hour, to the sum of:

(i) any change in forced outages of any of the thermal resources included in the Participant's Portfolio QCC, relative to the forced outages assumed in the Forward Showing Submittal by application of the Forced Outage Factor; plus

(ii) any change in forced outages of any of the Storage Hydro Qualifying Resources relative to the forced outages assumed in the calculation of the Participant's Resource QCC as more fully described in the Business Practice Manuals; plus

(iii) any reduction in output capability of any of the Energy Storage Resources due to equipment failure or protection
   a. In the first four (4) hours the Forced Outages MWs that can be claimed are equal to [(charge MW x duration)/4]
   b. For all hours beyond four (4) hours, the Forced Outages MW amount that can be claimed for an Energy Storage Resource shall not be greater than the monthly QCC; plus

(iv) any impacts of transmission conditions on previously acquired firm transmission service rights that result in capacity reductions up to the level of the Resource QCC of the associated Qualifying Resource;

ΔRoR Performance refers to any change, for the subject hour, in expected performance of any of the run-of-river resources in the Participant's Portfolio QCC relative to the QCC of those Qualifying Resources; and

ΔVER Performance refers to any change, for the subject hour, in expected performance of the VER Resources in the Participant's Portfolio QCC relative to the QCC of those Qualifying Resources;

20.1.2 In addition to the foregoing, the Sharing Calculation for a Participant that is a purchaser of an RA Transfer shall be performed in two passes, with and without such purchase. If the result of assuming in the first pass that the Participant had not purchased the RA Transfer is that the Participant has a

negative Sharing Calculation, then the Participant that sold the RA Transfer must agree, for the time period addressed by the Sharing Calculation, to an energy delivery to the Participant that purchased the RA Transfer, in an amount equal to the lesser of: (i) the MW quantity needed to result in a net zero Sharing Calculation for the Participant that purchased the RA Transfer; and (ii) the MW amount of the RA Transfer. If the result of recognizing the Participant's purchase of the RA Transfer in the second pass is that the Participant has a positive Sharing Calculation, then the Participant that sold the RA Transfer must assume a share of the purchasing Participant's resulting obligation to the Operations Program in an amount equal to the MW quantity of the RA Transfer, minus the MW quantity of the delivery made by the seller of the RA Transfer to the purchaser of the RA Transfer as a result of the first pass.

20.1.3 The Sharing Calculation of any Participant that was found to have a Monthly Capacity Deficiency under Sections 16.1 and 16.2, for which such Participant paid a Deficiency Charge, including any Deficiency Charge reduced by application of Section 17.3 during the Transition Period, shall be reduced by the MW quantity of such Monthly Deficiency.

20.2 Holdback Requirement

To the extent that: (i) WPP's application of the Sharing Calculation identifies on the Preschedule Day a Sharing Event for any hour(s) of the Operating Day; and (ii) the Participant(s) found to be deficient for such hour(s) by the Sharing Calculation confirms to WPP on the Preschedule Day, in accordance with notification and confirmation procedures set forth in the Business Practice Manuals, such Participant's need for capacity for such hour(s), then WPP shall determine the Participants having a Holdback Requirement for such hour(s) and the quantity of the Holdback Requirement for each such Participant in accordance with this Section 20.2. The Operations Program will prioritize offers of Voluntary Holdback in the allocation and assignment of Holdback Requirements. Holdback Requirements shall be expressed as whole MWs for each hour for which they are estimated or established and shall not be specific to any Qualifying Resource.

20.2.1 Subregion with Central Hub

For any hour, as to any Subregion identified in the Business Practice Manuals as containing a central transmission hub permitting energy deliveries to that hub from any point within such Subregion ("Central Hub"), the aggregate of the holdback needed to meet the requirements of all Participants with negative Sharing calculation results that have confirmed their need for holdback will be allocated and assigned first among offers of Voluntary Holdback, and second, to the extent such needs remain unmet, among Participants with positive Sharing Calculation results.

20.2.1.1 Allocation of Voluntary Holdback: Voluntary Holdback will be allocated in one of three alternative ways, based on comparing the aggregate confirmed need for holdback among Participants with negative Sharing Calculation results against the aggregate of all offers for Voluntary Holdback.

20.2.1.1.1 If the total MW quantity of all Voluntary Holdback offered is equal to the total MW quantity of all deficient Participants' confirmed requests for holdback, then each Participant that offered Voluntary Holdback is assigned its offered Voluntary Holdback as its Holdback Requirement.

20.2.1.1.2 If the total MW quantity of all Voluntary Holdback offered is more than the total MW quantity of all deficient Participants' confirmed requests for holdback, then each Participant that offered Voluntary Holdback is assigned as its Holdback Requirement a percentage of the total confirmed need for holdback based on the ratio of the Participant's MWs of offered Voluntary Holdback to the sum of all Participants' MWs of offered Voluntary Holdback.

20.2.1.1.3 If the total MW quantity of all Voluntary Holdback offered is less than the total MW quantity of all deficient Participants' confirmed requests for holdback, then each Participant's Holdback Requirement is determined as set forth in section 20.2.1.2.

20.2.1.2 Allocation of Remaining Holdback Requirement: Sharing Calculation Results

If the total MW quantity of all Voluntary Holdback offered is less than the total MW quantity of all deficient Participants' confirmed requests for holdback, then the maximum Voluntary Holdback offered is used as the first term in the Holdback Requirement. The remaining term of the Holdback Requirement is met by application of the Sharing Calculation, and the results of the two terms are summed for each Participant. The remaining need for holdback that is not met by Voluntary Holdback is allocated among all Participants with positive Sharing Calculation results pro rata based on the ratio for each Participant of the Participant's positive Sharing Calculation result to the sum of the positive Sharing Calculation results. The

sum of these two values for each applicable Participant is the Holdback Requirement for that Participant.

20.2.2 Subregion without Central Hub

For any hour, any Subregion not containing a Central Hub, the Program Operator shall conduct an optimization-based allocation to pair surplus and deficient Participants. The allocation methodology will utilize the points at which surplus Participants can deliver their Holdback Requirement, the points at which deficient Participants can take receipt of their allocation of the total Holdback Capacity, and the transfer capability that exists to the points at which surplus Participants can deliver and the points at which deficient Participants can take receipt.

The optimization will generally attempt to prioritize (i) Voluntary Holdback; (ii) Holdback Capacity matched pursuant to the information provided per Section 19.4 on a nearest neighbor and cluster basis, allocated pro rata among Participants within such cluster; (iii) Holdback Capacity matched pursuant to the information provided and allocated among Participants within the same Subregion to the extent not matched and allocated under category (ii); and finally (iv) Holdback Capacity from Participants in another Subregion, paired with any transmission service per Section 14.3.2.

20.2.3 Absent a Holdback Requirement Transfer as described below, a Participant's Holdback Requirement for any hour of an Operating Day shall not exceed the level first set by WPP on the Preschedule Day for that Participant for that hour.

20.2.4 Any Participant may agree with any other Participant for the first Participant to transfer to the second Participant some or all of the Holdback Requirement established for the first Participant for any hour on any Operating Day. Any such Holdback Requirement Transfer shall be a bilateral arrangement settled outside the Operations Program, provided, however, that both Participants must timely notify WPP, by the time and in the manner described in the Business Practice Manuals, of such Holdback Requirement Transfer. Any necessary transmission arrangements and any transaction settlements shall be the sole responsibility of the Participants that are the parties to such bilateral arrangement.

20.2.4.1 No Holdback Requirement transfer for any hour shall be permitted if notice of such bilateral transaction is not fully reported to WPP, in the form required by the Business Practice Manuals, by 120 minutes before the start of such hour.

20.3 Release of Surplus Capacity

20.3.1 As detailed in the Business Practice Manuals, WPP will review the indicative Sharing Calculation results from the Multi-Day Ahead Assessment and to the extent the WPP determines any indicative Sharing Calculations can be reduced, it may release all or a portion of Participants' future Holdback Requirements. WPP may permit a release of future Holdback Requirements to the extent WPP has not applied a Safety Margin for such hour and (i) WPP's continued Sharing Calculations determine that no Participant has a negative indicative Sharing Calculation result for such hour; and (ii) WPP determines there is a low probability of a Sharing Event for the hour; or (iii) WPP grants a Participant's request for extenuating circumstances of all or any portion of that Participant's future Holdback Requirement for the hour.

20.3.2 Upon release of all or any portion of a future Holdback Requirement, the quantity of future Holdback Requirement so released shall no longer be subject to an Energy Deployment requirement under the Operations Program for the subject hour.

20.4 Energy Deployment

20.4.1 Participants shall provide energy during an hour, in support of any Participants with a negative Sharing Calculation result and a confirmed need for energy under the Operations Program for such hour, in accordance with WPP's calculation of the Energy Deployment for such hour. The total Energy Deployment required of all Participants that are subject to Energy Deployment shall equal the sum, in MWh for that hour, of the energy confirmed as being needed in that hour by Participants in such Subregion with negative Sharing Calculation results in such hour, to the extent that can be supported by the Program. The Energy Deployment assigned to each Participant shall not exceed that Participant's Holdback Requirement calculated on the Preschedule Day, adjusted for any applicable transfer of Holdback Requirement as allocated and assigned for the Preschedule Day, and, as further adjusted to reflect the election, made after the Preschedule Day, of any Participant with a negative Sharing Calculation result on the Preschedule Day to decline all or any part of the Holdback Capacity to which it would have been entitled based on the Holdback Requirements determined on the Preschedule Day.

20.4.1.1 In Subregions with a Central Hub, Energy Deployments required hereunder shall be delivered to the Central Hub in such Subregion, or to an alternate delivery point mutually agreed by the parties to a specific Energy Deployment, provided both parties to the transaction report such alternative delivery arrangements to WPP in the form and manner described in the Business Practice Manuals.

20.4.1.2 In Subregions without a Central Hub, Energy Deployments required hereunder shall be delivered to the receipt point and delivery point as indicated by the optimization allocation, or to an alternate delivery point mutually agreed by the parties to a specific Energy Deployment, provided both parties to the transaction report such alternative delivery arrangements to WPP in the form and manner described in the Business Practice Manuals.

20.4.2 The Energy Deployment a Participant may receive for any hour shall be no greater than the negative Sharing Calculation result calculated for such Participant for such hour. Such Participant shall confirm, by no later than 85 minutes before the start of such hour, the quantity of Energy Deployment for which it requires delivery for such hour, through the procedures outlined in the Business Practice Manuals. Any Participant that does not confirm required Energy Deployment deliveries for such hour by such deadline will be deemed to waive all deliveries of Energy Deployment under the Operations Program for such hour.

20.4.3 The Energy Deployment a Participant can be required to supply for an hour shall not exceed the final Holdback Requirement calculated for such Participant on Preschedule Day, including any duly reported exchange of Holdback Requirement, as of 85 minutes before the start of such hour.

20.4.4 WPP shall advise each Participant with a required Energy Deployment for an hour of the required MWh quantity and delivery point of such Energy Deployment by no later than 80 minutes before the start of such hour.

20.5 Safety Margin

20.5.1 WPP may establish on the Preschedule Day a Safety Margin for the WRAP Region or any identified Subregion thereof for any hour of an Operating Day when warranted by such circumstances as potential large resource trips, heavy transmission outage conditions, significant environmental conditions, or other similar regional or subregional conditions, as more fully set forth in the Business Practice Manuals.

20.5.2 Any Safety Margin so determined for an hour shall be allocated pro rata among Participants with a positive Sharing Calculation result, based on their relative shares of the sum of all positive Sharing Calculation results for such hour, provided, however, that the Safety Margin allocated to a Participant may not result in a Holdback Requirement for such Participant greater than such Participant's Sharing Calculation result. A Participant allocated holdback for a Safety Margin hereunder does not receive compensation under this Tariff for such allocation of holdback.

20.5.3 WPP shall notify all Participants of application of a Safety Margin for any hour, including in such notice the total timeframe, the MW amount, and the rationale for such Safety Margin.

20.6 Operations Program Transmission Service Requirements

Participant shall have in place, prior to the Operating Day, transmission service satisfying NERC Priority 6 or 7 for each hour of such Operating Day for which a Sharing Event has been established, in a quantity sufficient for deliveries from the Qualifying Resources relied upon in such Participant's Forward Showing Submittal to demonstrate satisfaction of such Participant's FS Capacity Requirement (or from replacement Qualifying Resources) to serve such Participant's loads during such hours. In the event a Participant has an Energy Delivery Failure, the review associated with the possible assessment of a Delivery Failure Charge on such Participant shall, as further described in the Business Practice Manuals, include whether a failure to secure sufficient NERC Priority 6 or Priority 7 firm transmission service rights caused or contributed to such Energy Delivery Failure. For such purpose, the Participant will have been expected to have complied with the transmission service requirement stated in this subsection.

20.7 Failure to Deliver Energy Deployments

20.7.1 A Participant assigned a required Energy Deployment pursuant to Section 20.4.4 of this Tariff for any hour that fails to deliver the specified energy during such hour, and that does not obtain a waiver of its Energy Deployment obligation, shall be assessed a Delivery Failure Charge.

20.7.2 A Participant shall be deemed to have an Energy Delivery Failure if Participant fails to deliver the Energy Deployment quantity established under Section 20.4.1, absent grant of a waiver pursuant to Section 20.7.3 of this Tariff.

20.7.3 A Participant anticipating an Energy Delivery Failure should provide WPP notice of such expected Energy Delivery Failure as soon as practicable after becoming aware of the anticipated failure. Whether anticipated or not, a Participant may request a waiver of an Energy Deployment obligation after an Energy Delivery Failure has occurred. The WPP shall review all such waiver requests and shall determine whether the Participant's justification for the Energy Delivery Failure is valid and warrants waiver of its Energy Deployment obligation. The WPP also shall consider whether the Participant knew in advance, or reasonably should have known in advance, of an Energy Delivery Failure, and what efforts the Participant took to notify the WPP in advance of such Energy Delivery Failure. The procedures for addressing such waiver requests, including a non-exclusive list of valid justifications for an Energy Delivery Failure shall be set forth in the Business Practice Manuals. A Participant denied a waiver request hereunder may appeal such denial to the Board of Directors in accordance

with the procedures and deadlines set forth in the Business Practice Manuals. In such event, the requested waiver shall be denied or permitted as, when and to the extent permitted by the Board, in accordance with the procedures and timing set forth in the Business Practice Manuals. WPP shall report on the disposition of each waiver request received.

20.7.4 The Delivery Failure Charge for each hour shall be the Charge Rate applicable for such hour times the MWhs of energy that were required to be, but were not, delivered pursuant to an Energy Deployment during such hour. The Charge Rate shall be the higher of the Day-Ahead price or Real-Time price provided by the Day-Ahead Applicable Price Index and Real-Time Applicable Price Index as specified in the Business Practice Manuals for the Subregion applicable to the location of the delivering entity, applicable to the day and hour of the energy delivery, respectively, for the hour, times a Delivery Failure Factor, as follows:

20.7.4.1 If the deficit is fully covered by other Participants through the Operations Program, in each instance of failure, the Delivery Failure Factor shall be five for the first non-waived Energy Delivery Failure in a Cumulative Delivery Failure Period; ten for the second non-waived Energy Delivery Failure in a Cumulative Delivery Failure Period; and twenty for the third and subsequent non-waived Energy Delivery Failures in a Cumulative Delivery Failure Period. For purposes of applying the Delivery Failure Factors under this Section 20.7.4 or the review referenced in Section 20.7.5, multiple Energy Delivery Failures occurring in one day shall be treated as a single instance of failure.

20.7.4.2 If the deficit is not fully covered by other Participants through the Operations Program, the Delivery Failure Factor is twenty-five for the first non-waived Energy Delivery Failure in a Cumulative Delivery Failure Period; and fifty for the second and subsequent non-waived Energy Delivery Failures (regardless of whether the prior instance(s) of delivery failure were fully covered by other Participants) in a Cumulative Delivery Failure Period.

20.7.4.3 Revenues from Delivery Failure Charges assessed in cases where the deficit was fully satisfied by other Participants will be used to reduce WPP costs that are recovered under Schedule 1, WRAP Administration Charge. Revenues from Delivery Failure Charges assessed in cases where the deficit was not fully met by other Participants will be collected by the WPP and provided to the Participant that had an unserved deficit.

20.7.4.4 Notwithstanding anything to the contrary in this Section 20.7.4, the Delivery Failure Charges assessed on a Participant, regardless of application of the Delivery Failure Factor, shall not

exceed, over the course of a Summer Season and the immediately succeeding Winter Season, the dollar amount that, as more fully detailed in the Business Practice Manuals, would have been assessed cumulatively under Section 17 as Deficiency Charges if the Participant had one or more Forward Showing Capacity Deficiencies over the course of such Summer Season and Winter Season in the same MW amounts as the highest MW amount of Delivery Failure experienced by such Participant in each Month of such Summer Season and Winter Season. The maximum dollar amount described herein shall be calculated on an ongoing basis during such Summer Season and Winter Season, and increased or reduced accordingly, without awaiting the end of the combined period of such Summer Season and Winter Season.

20.7.5 In addition to assessment of the Delivery Failure Charge, a third or subsequent instance of non-waived delivery failure, when all such delivery failures are fully covered by other Participants, or a second or subsequent instance of non-waived delivery failure when such instance is not fully covered by other Participants, will subject the Participant to review for expulsion from the WRAP.

20.8 Voluntary Response to Increased Deficiencies Identified After Preschedule Day

20.8.1 A Participant that identifies an unmet need for energy for any hour of an Operating Day that is outside of assistance provided or to be provided by Holdback Requirements or Energy Deployments established hereunder may, in accordance with procedures specified in the Business Practice Manuals, notify WPP of the need for such assistance. WPP will establish a portal or other procedure, as specified in the Business Practice Manuals, to facilitate provision of assistance, on a voluntary, bilateral basis, by other Participants to the Participant that identified the unmet need. Compensation, terms, and conditions of any resulting bilateral transactions will be determined by the affected parties outside of this Tariff. While Participant response to any such notification is voluntary, Participants are encouraged to provide assistance to other Participants in the circumstances described in this subsection, in consideration of the mutual support each Participant has agreed to provide to each other Participant by its agreement to participate in the WRAP, including this Operations Program.

21. Operations Program Settlements

21.1 Nature of Operation Program Settlements

21.1.1 Operations Program settlements are bilateral transactions; they are not purchases from or sales to a central market.

21.1.2 Operations Program transactions use existing transaction systems and processes.

21.1.3 The WPP will calculate and post settlement quantities and prices based on the Energy Deployment and Holdback Requirement, in accordance with procedures specified in the Business Practice Manuals for provision of transaction information by and among Participants and WPP, but WPP has no role in the transaction itself. WPP is not a settlement entity.

21.1.4 Settlement Prices calculated under Section 21.2 shall recognize pricing differences among Subregions. Where the seller and buyer are located in the same Subregion, the Applicable Price Index shall be the price index specified for that Subregion in the Business Practice Manuals. Where the seller and buyer are located in different Subregions, the following components of the settlement price calculation in Section 21.2 will be calculated using the Applicable Price Index for the Subregion that provides the higher index price: (i) Possible Block Sale Revenue; (ii) Total Settlement Price; (iii) Energy Declined Settlement Price; and (iv) Realtime Value of Unheld Energy. If a third participant is involved by providing transmission service rights between Subregions, the Participant that provided holdback or Energy Deployment shall receive the settlement price of the Subregion from which the holdback or Energy Deployment was sourced, and the Participant that provided Subregion to Subregion transmission service rights pursuant to Section 19.4 shall receive the difference between each Subregion's Total Settlement Price, or zero, whichever is greater.

21.2 Settlement Price Calculation. Settlement prices shall be calculated in accordance with the following, as more fully set forth in the Business Practice Manuals.

21.2.1 A Participant assigned a Holdback Requirement on a Preschedule Day for any hour of an Operating Day shall be paid the Holdback Settlement Price times the MW quantity of the Holdback Requirement. A Participant that provides energy to another Participant pursuant to an Energy Deployment shall be paid the Energy Declined Settlement Price, defined in Section 21.2.4, times the MWhs of energy provided to such other Participant, and its total payments shall be reduced by the Energy Declined Settlement Price times the MWhs of energy that would have been provided under a Holdback Requirement but were declined by the other Participant. A Participant

assigned a Holdback Requirement also shall be paid, when applicable, a Make Whole Adjustment, as provided below in Section 21.2.5.

21.2.2 A Participant that had a negative Sharing Calculation result for any hour of an Operating Day, which was incorporated in the calculation of Holdback Requirements of any Participants for such hour, determined as of the Preschedule Day, shall pay the Holdback Settlement Price times the MW quantity of such negative Sharing Calculation result. In addition, any Participant that had a negative Sharing Calculation result that was incorporated in the calculation of a Holdback Requirement shall contribute to the payment of the Make Whole Adjustment based on its negative Sharing Calculation. A Participant that declines energy that would have been provided under a Holdback Requirement shall be credited the Energy Declined Settlement Price times the MWhs of energy declined by such Participant.

21.2.3 The Holdback Settlement Price shall equal the Total Settlement Price minus the Energy Declined Settlement Price.

21.2.4 The Energy Declined Settlement Price shall equal the Applicable Real-Time Index Price for the hour.

21.2.5 The Make Whole Adjustment is applied in the event that the settlement revenue and the estimated value of the non-dispatched energy is less than the estimated revenues the selling entity would have received had such entity not been subject to a Holdback Requirement and had sold a day-ahead block of energy with a MW value equal to the maximum amount of Holdback Requirement for the hours in the block. The Make Whole Adjustment has a minimum value of zero and is determined as follows:

Make Whole Adjustment (when applicable) =
Maximum of (Possible Block Sale Revenue
– Final Settlement Revenue
– Realtime Value of Declined Energy
– Realtime Value of Unheld Energy, 0)

Where:

Realtime Value of Declined Energy = Energy Declined × Energy Declined Settlement price

provided that Declined Energy is only applicable to those hours where there was a positive Holdback Requirement.

Realtime Value of Unheld Energy = (Maximum Holdback MW in Block – Holdback MW Requested) × Applicable Index Price

21.2.6 The Total Settlement Price used in the above calculations shall be determined in accordance with the following formula:

Total Settlement Price = Maximum of (Minimum of (Hourly Shaping Factor × Day Ahead Applicable Index Price × 110%, 2000 $/MWh), 0)

where:

Hourly Shaping Factor is based on the most recent High-Priced Day for the relevant season, defined as a day in which at least one hour has a system marginal energy cost ("SMEC") greater than $200/MWh, and shall be calculated as follows:

1 + {[CAISO Hourly Day Ahead SMEC - CAISO Average Day Ahead SMEC (on- or off-peak hours)] / [CAISO Average Day Ahead SMEC (on- or off-peak hours)]}

Day-Ahead Applicable Index Price is the day-ahead heavy load/light load ICE Index price that is specified in the Business Practice Manuals for the Subregion applicable to the location of the delivering entity, applicable to the day and hour of the energy delivery. If transmission via Section 14.3.2 was used to facilitate holdback, the Applicable Index Price shall be the higher of the two subregional day-ahead index prices for that portion of the holdback.

Real-Time Applicable Index Price is the real-time index price that is specified in the Business Practice Manuals for the Subregion applicable to the location of the delivering entity, applicable to the day and hour of the energy delivery.

SCHEDULE 1

WESTERN RESOURCE ADEQUACY PROGRAM ADMINISTATIVE COST RECOVERY CHARGE

The Western Power Pool's Costs of administering and operating the Western Resource Adequacy Program including, without limitation, all costs incurred or obligated by WPP as Program Administrator, all costs paid or payable by WPP to the Program Operator or other service providers, all costs of the Board of Directors in directing, supervising, or overseeing the WRAP, and the costs of maintaining a reasonable reserve as provided in Section 1 of this Schedule 1, shall be recovered from Participants pursuant to the charges set forth in this Schedule 1.

Section 1. WRAP Costs

1. As used herein, Costs shall mean WPP's costs, expenses, disbursements and other amounts incurred (whether paid or accrued) or obligated of administering and operating the WRAP as described above, including, without limitation, operating expenses, general and administrative expenses, costs of outside services, taxes, fees, capital costs, depreciation expense, interest expense, working capital expense, any costs of funds or other financing costs, and the costs of a reasonable reserve as provided herein.
2. The Costs included in a WRAP Administration Charge assessed for a Month shall be the Costs determined as being incurred for that Month, including, without limitation, for each Month, one-twelfth of any annual charge(s).

3. The Costs included in the WRAP Administration Charge for a reasonable reserve shall be those designed to establish over the first twelve months that this WRAP Administration charge is in effect an amount equal to 6% of the expected Costs, exclusive of such reserve, for one year; and to maintain such reserve thereafter at an amount equal to 6% of the expected Costs, exclusive of such reserve for the then-current year. WPP shall record on its income statement deferred regulatory expense, and WPP's balance sheet will reflect as a cumulative deferred regulatory liability, revenues collected under this Schedule 1 that are in excess of the Costs exclusive of such reserve and taking account of and including any accrued tax expense effects of this regulatory liability. The deferred regulatory liability will be reduced when after-tax WPP revenues collected under this Schedule 1 during any Month are less than the Costs exclusive of such reserve. Within thirty days after the end of each Year, to the extent WPP determines that the deferred regulatory liability exceeds 6% of WPP's revenues that were collected under this Schedule 1 during such Year, such excess amounts in the deferred regulatory liability shall be refunded evenly over the applicable billing determinant volumes in the remainder of the subsequent Year through credits to charges to then-current customers under this Schedule 1.

Section 2. WRAP Administration Charge

Each Participant shall be assessed each Month a WRAP Administration Charge equal to the sum of the Base Charge and the Load Charge,

where:

The Base Charge for each Participant equals the Base Costs divided by the number of Participants being assessed the Base Charge for the Month for which the WRAP Administration Charge is being calculated;

The Load Charge for each Participant equals the Load Charge Rate of the Load Services Costs divided by the sum of the Median Monthly P50 Peak Loads of the Participants being assessed the Load Charge for the Month for which the WRAP Administration Charge is being calculated, times that Participant's Median Monthly P50 Peak Load;

And where:

Base Costs means the Costs for the Month of the Base Services Cost Centers shown in the WRAP Cost Assignment Matrix, plus the Base Services Percentage times the Costs for that Month of the Dual Benefit Cost Centers shown below in Section 4: WRAP Cost Assignment Matrix;

Load Services Costs means the Costs for the Month of the Load Services Cost Centers shown in the WRAP Cost Assignment Matrix, plus the Load Services Percentage times the Costs for that Month of the Dual Benefit Cost Centers shown in the WRAP Cost Assignment Matrix; and

Median Monthly P50 Peak Loads means, for each Participant, the median of the Monthly P50 Peak Loads used in the FS Capacity Requirement of such Participant for two Binding Seasons corresponding to the two FS Submittal most recently validated by WPP.

If before or during a Binding Season, a Participant has need to update their Monthly P50 Peak Load for allowable reasons, those updated Monthly P50 Peak Loads will be replaced and the Median Monthly P50 Peak Load value recalculated upon validation of the change in participating load.

A Participant joining the Program will supply data such that WPP can validate Monthly P50 Peak Loads for the first two Binding Seasons for which the Participant will submit an FS Submittal for use in calculating Load Services Costs until these FS Submittals are submitted and reviewed in the normal timeframe.

Section 3. Maximum Charge Rates

3.1 Notwithstanding anything to the contrary in this Schedule 1, the sum of the Base Charges for all Months in a Year shall not exceed the Annual Maximum Base Charge of $59,000/Year, and the sum of the Load Charge Rates for all Months in a Year shall not exceed the Annual Maximum Load Charge Rate of $199/MW. WPP shall, to the extent reasonably practicable, provide two-months' notice prior to WPP's filing at FERC of an application to change the Maximum Base Charge or the Maximum Load Charge Rate, provided that nothing herein shall limit the Board of Director's authority and discretion to seek at FERC a change in the maximum rates in the time and manner the Board determines in the best interests of the Western Resource Adequacy Program. For purposes of clarity, these specified maximum rates on the Base Charge and the Load Charge do not limit the level of the Cash Working Capital Support Charge established under Section 5 of this Schedule 1, nor do they limit the amount of the default Allocation assessment provided under Part I of this Tariff.

3.2 To facilitate Participant planning, the WPP shall prepare, and provide to the RAPC, good faith, non-binding estimates of: (i) reasonably anticipated WRAP budgets for three Years beyond the most recently approved WRAP budget, including sensitivity analyses for reasonably identified major contingencies; (ii) reasonably anticipated numbers of Participants and MWs of Winter and Summer P50 Loads for each such Year; and (iii) reasonably anticipated highest monthly Base Charges and Load Charge Rates for each such Year. All assumptions and estimates in such forecasts and analyses shall be in WPP's sole discretion, which may be informed by RAPC discussion of such topics.

Section 4. WRAP Cost Assignment Matrix

	BASE COSTS	LOAD COSTS	DUAL BENEFIT
PROGRAM ADMINISTRATION (NON-PARTICIPANT)		100%	
PROGRAM ADMINISTRATION (PARTICIPANT ENGAGEMENT, RAPC FACILITATION)	100%		
WRAP PORTION OF WPP BOD COSTS			50%/50%
PROGRAM OPERATIONS STAFFING AND OVERHEAD		100%	
PROGRAM OPERATIONS TECHNOLOGY		100%	

LEGAL SERVICES	100%
INDEPENDENT EVALUATOR	100%

Section 5. Cash Working Capital Support Charge

5.1 In addition to the WRAP Administration Charge, each Participant shall be assessed a Cash Working Capital Support Charge, to support WPP's maintenance of sufficient funds on hand to make payments required for the operation and administration of the WRAP on a timely basis. Cash Working Capital Support Charges shall be designed to maintain a Cash Working Capital Fund that, at its maximum level over a twelve-month cycle, equals approximately nine-twelfths of the expected annual payment due from the WPP to the Program Operator for its Program Operator services.

5.2 A Participant shall pay a Cash Working Capital Support Charge no later than thirty days after that Participant executes a WRAPA. The Cash Working Capital Support Charge due following WRAPA execution equals the Cash Working Capital Support Charge Rate, calculated as the Cash Working Capital Fund at its required maximum twelve-month cycle level divided by the sum of the Median Monthly P50 Peak Loads of all Participants, times that Participant's Median Monthly P50 Peak Load.

5.3 To the extent the Cash Working Capital Fund is adequately funded at the time a new Participant executes a WRAPA, the revenue from such Participant's payment of the Cash Working Capital Support Charge shall be distributed to all Participants that previously have paid a Cash Working Capital Support Charge, pro rata based on the Median Monthly P50 Peak Loads of all Participants that have previously paid such charge.

5.4 To the extent, and at such time, WPP determines that an incremental addition to the Cash Working Capital Fund is needed due to such causes as, for example, an expected increase in the annual payment to the Program Operator, each Participant shall be assessed an Incremental Cash Working Capital Support Charge equal to the desired incremental addition, divided by the sum of the Median Monthly P50

Peak Loads of all Participants being assessed the Incremental Cash Working Capital Support Charge for the Month for which the Incremental Cash Working Capital Support Charge is being calculated, times that Participant's Median Monthly P50 Peak Load.

ATTACHMENT A

Western Resource Adequacy Program Agreement

This Western Resource Adequacy Program Agreement ("Agreement") dated as of _____ ("Effective Date") is entered into by and between Western Power Pool Corporation ("WPP") and _____ ("Participant"). WPP and Participant are each sometimes referred to in the Agreement as a "Party" and collectively as the "Parties."

In consideration of the mutual promises contained herein, and other good and valuable consideration, the receipt of which is hereby acknowledged, the Parties agree as follows:

1. The Parties agree that this agreement shall be governed by the rates, terms, and conditions of the Western Resource Adequacy Program Tariff ("Tariff") and all such rates, terms, and conditions contained therein are expressly incorporated by reference herein. All capitalized terms that are not otherwise defined herein shall have the meanings ascribed by the Tariff.

2. Participant wishes to participate in the Western Resource Adequacy Program ("WRAP") administered by WPP under the Tariff.

3. Participant certifies that it satisfies all of the following qualifications:

    3.1 Participant is a Load Responsible Entity as that term is defined in the Tariff.

    3.2 Participant commits to complying with all applicable terms and conditions of WRAP participation as set forth in the Tariff and Business Practice Manuals adopted thereunder, including all Forward Showing Program and Operations Program requirements.

4. Participant will register all resources and supply contracts and shall disclose any other obligations associated with those resources and supply contracts.

5. Participant represents and warrants that it is authorized by all relevant laws and regulations governing its business to enter into this Agreement and assume all rights and obligations thereunder.

6. It is understood that, in accordance with the Tariff, WPP, as authorized by its independent Board of Directors, may amend the terms and conditions of this Agreement or the Tariff by notifying the Participant in writing and making the appropriate filing with FERC, subject to any limitations on WPP's authority to amend the Tariff as set forth therein.

7. Participant agrees to pay its share of all costs associated with the WRAP, as calculated pursuant to Schedule 1 of the Tariff. The manner and timing of such payment shall be as specified in Schedule 1 of the Tariff.

8. WPP agrees to provide all services as set forth in the Tariff.

9. Term and termination. This Agreement shall commence upon the Effective Date and shall continue in effect until terminated either by WPP by vote of its Board of Directors or by Participant's withdrawal as set forth herein. WPP and Participant agree that participation in the WRAP is voluntary, subject to the terms and conditions of this Agreement and the Tariff. The date upon which a Participant's withdrawal is effective and its participation in the program terminates is referred to as the "Withdrawal Date."

9.1 Normal Withdrawal: In general, Participant may withdraw from this Agreement by providing written notice to WPP no less than twenty-four months prior to commencement of the next binding Forward Showing Program period. Once notice has been properly given, Participant remains in a "Withdrawal Period" until the Withdrawal Date.

9.1.1 During Participant's Withdrawal Period, Participant remains subject to all requirements and obligations imposed by the Tariff and this Agreement, including but not limited to all obligations imposed in the Forward Showing Program and Operations Program and obligation to pay Participant's share of all costs associated with the WRAP.

9.1.2 All financial obligations incurred prior to and during the Withdrawal Period are preserved until satisfied.

9.1.3 During the Withdrawal Period, Participant is not eligible to vote on any actions affecting the WRAP that extend beyond the Withdrawal Period.

9.2 Expedited Withdrawal: Participant may withdraw from this agreement with less than the required twenty-four month notice as set forth below. Participant shall negotiate with WPP regarding the timing of the Expedited Withdrawal.

9.2.1 Extenuating Circumstances: The following such events and circumstances shall constitute "extenuating circumstances" justifying a withdrawal on less than twenty-four months. Participant invoking an extenuating circumstance shall negotiate with WPP regarding potential ways to minimize the impact of the expedited withdrawal on all other Participants and WPP. Such extenuating circumstances and any mitigation plan to minimize the impact of the expedited withdrawal must be reviewed and approved by the Board of Directors prior to termination of Participant's WRAP obligations. Regardless of the extenuating circumstance, all financial obligations incurred prior to the Withdrawal Date remain in effect until satisfied.

9.2.1.1 A governmental authority takes an action that substantially impairs Participant's ability to continue to

participate in the WRAP to the same extent as previously; provided, however, that Participant shall be obligated to negotiate with WPP regarding potential ways to address the impact of the regulatory action without requiring a full withdrawal of Participant from the WRAP if possible.

9.2.1.2 Continued participation in the WRAP conflicts with applicable governing statutes or other applicable legal authorities or orders.

9.2.1.3 Participant voted against a RAPC determination and disagreed with a Board of Directors decision to release composite or aggregated data under Section 10.2.1 of the Tariff, provided that such right to expedited withdrawal is exercised promptly after the first time that the Board of Directors determines that the form and format of composite or aggregated data sufficiently protects against the release of confidential or commercially sensitive Participant data. Failure to exercise this right promptly upon the first occurrence of the Board of Directors voting on a specific form and format of composite or aggregated data shall constitute a waiver of the right to expedited withdrawal for any future disclosures of composite or aggregated data in the same or substantially similar form and format.

9.2.1.4 FERC or a court of competent jurisdiction requires the public disclosure of a Participant's confidential or commercially sensitive information, as further described in Section 10.5 of the Tariff; provided however that such right to expedited withdrawal shall be exercised promptly upon the exhaustion of all legal or administrative remedies aimed at preventing the release.

9.2.2 Exit Fee: If the impact of Participant's withdrawal on WRAP operations can calculated with a high degree of confidence and mitigated by the payment of an "exit fee" to be calculated by WPP, an expedited withdrawal will be permitted. Such exit fee shall include (but not be limited to): (i) any unpaid WRAP fees or charges; (ii) Participant's share of all WRAP administrative costs incurred up to the next Forward Showing Program period; (iii) any costs, expenses, or liabilities incurred by WPP and/or the Program Operator directly resulting from Participant's withdrawal; and (iv) any costs necessary to hold other participants harmless from the voluntary expedited withdrawal. The exit fee may be waived to the extent that it would violate any federal, state, or local statute, regulation, or ordnance or exceed the statutory authority of a federal

agency. The exit fee shall be paid in full prior to the Withdrawal Date.

9.2.3 Amendments to Section 3.4 of the Tariff: In the event that amendments to Section 3.4 of the Tariff are approved by the RAPC and Board of Directors, a Participant that voted against such a change may withdraw with less than the required twenty-four month notice, provided that the Participant satisfy all obligations in the Forward Showing Program and Operations Program and satisfy all other financial obligations incurred prior to the date that the amendments to Section 3.4 of the Tariff are made effective by FERC.

9.2.4 Expulsion: The Board of Directors, in its sole discretion, may terminate Participant's participation in the WRAP and may terminate this Agreement with Participant for cause, including but not limited to material violation of any WPP rules or governing documents or nonpayment of obligations. Prior to exercising such right to terminate, the Board of Directors shall provide notice to Participant of the reasons for such contemplated termination and a reasonable opportunity to cure any deficiencies. Such Board of Directors termination shall be after an affirmative vote consistent with the Board of Directors standard voting procedures. Such termination shall not relieve the Participant of any financial obligations incurred prior to the termination date, and WPP may take all legal actions available to recover any financial obligations from Participant.

10. No Waiver of Non-FERC-Jurisdictional Status. If Participant is not subject to the jurisdiction of FERC as a public utility under the Federal Power Act, Participant shall not be required to take any action or participate in any filing or appeal that would confer FERC jurisdiction over Participant that does not otherwise exist. Participant acknowledges that FERC has jurisdiction over the WRAP, including Participant's activities in the WRAP.

[SIGNATURE BLOCKS]

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-79:
WRAP Notice

WESTERN RESOURCE ADEQUACY PROGRAM

WPP Notice to WRAP Resource Adequacy Participants Committee

Oct. 31, 2025, 9:42 a.m. by Rebecca Sexton | Last modified Oct. 31, 2025, 12:54 p.m.

On Friday, October 31, WPP Chief Strategy Officer Rebecca Sexton sent this notice to members of the WRAP Resource Adequacy Participants Committee, regarding participants committed to WRAP binding operations in Winter 2027/2028:

Today is the deadline set in the tariff for Western Resource Adequacy Program (WRAP) participants to notify us if they plan to exit the program before binding operations start in Winter 2027/2028.

As of the deadline there are 16 current participants that will remain in the program for binding operations, including five in addition to the 11 who sent a commitment letter last month, and we expect more companies to join in the future. The committed participants bring significant load (over 58,000 MW in peak load) and resources and a large, diverse geographic footprint, making WRAP one of the largest RA programs in the country and giving us critical mass for a binding program. The group includes members committed to or leaning toward both EDAM and Markets+, as well as some who have not indicated they will join a day-ahead market. The committed participants are:

- Arizona Public Service Company
- Avista Corp
- Bonneville Power Administration
- PUD No. 1 of Chelan County
- Clatskanie People's Utility District
- Constellation
- PUD #2 of Grant County
- Idaho Power
- NorthWestern Energy
- Powerex Corp.
- Puget Sound Energy
- Salt River Project Agricultural Improvement and Power District
- Seattle City Light
- Tacoma Power
- The Energy Authority, Inc.
- Tucson Electric Power

The following companies provided formal notice of intent to exit:

- Calpine Energy Solutions
- Eugene Water & Electric Board
- NV Energy
- PacifiCorp
- Portland General Electric Company
- Public Service Company of New Mexico

To all participants, thank you for your efforts in the last six years to build WRAP into a program that can help the region tackle the significant challenge of resource adequacy.

To our exiting participants, over the next two years, we encourage you to stay engaged in committees, task forces, and the stakeholder process to continue to evolve and improve WRAP and potentially resolve the concerns that prevented you from committing to binding operations at this time. As we have communicated previously, should your concerns be resolved, you have the option to rejoin the program and can commit to the Winter 2027/2028 season as late as September 15, 2026.

We have received a lot of positive outreach and support as we neared this deadline, and I will share just one example - part of a note we received from Lauren Tenney Denison, Director of Market Policy & Grid Strategy for Public Power Council. She wrote, "You have designed a remarkable program, from the ground up. WRAP has forever changed the way the West approaches markets and regional programs. There is a large and diverse footprint of entities committed to the binding season. That is a lot to be excited about."

I wanted you all to see this too because the congratulations for designing this program are for all of us and because there is a lot of progress to be excited about.

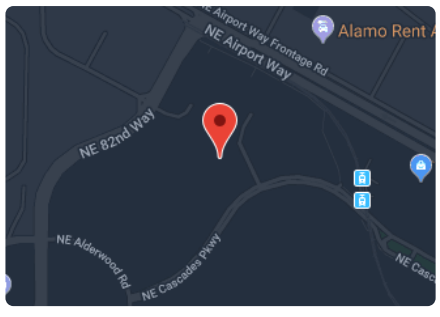
We look forward to continuing to work collaboratively to support reliability and resource adequacy across the West.



Rebecca Sexton
Chief Strategy Officer
WPP | 253-279-3002
rebecca.sexton@westernpo...

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-80:
Fisheries Report

Final Report

SKOOKUMCHUCK-HANAFORD CREEK FISHERIES INVESTIGATIONS

State of Washington
DEPARTMENT OF FISHERIES
Management and Research Division

Earl L. Finn, Jr.
Fisheries Biologist

March 1973

Financed by:
Pacific Power and Light Company
Contract No. 001-01-022-0190

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16.	Skookumchuck River average mean daily flow in cfs (1940 through 1965).	81

INTRODUCTION

On June 1, 1967, the Washington Department of Fisheries, under contract with Pacific Power and Light Company, began an investigation to determine the effects of the proposed Centralia steam-electric project on the fisheries resource and what measures, if any, should be taken to protect, preserve, or replace fish life. The initial contract expired December 31, 1969, and this report fulfills the Department of Fisheries obligations.

Project Description

The Centralia Steam-electric Power plant is located in the Hanaford Creek Valley in Lewis County. The ultimate plant operation will require 81 cubic ft per second (cfs) of water from the Skookumchuck River, a tributary to the Chehalis River. Initially, two generating units of 700,000 kw each are scheduled for completion in 1971 and 1972. If a third unit is built, the existing 81 cfs water right will be sufficient to meet the total requirements. A dam on the Skookumchuck River, some 1,500 ft upstream from the confluence with Bloody Run Creek, will provide water storage to augment the natural flow of the river to supply the necessary water to the plant. The plant water, 27 cfs for the first unit, 54 cfs for the scheduled two units, and a total of 81 cfs, if the third unit is built, will be diverted from the river about 15 miles downstream from the dam and pumped 3.2 miles to the plant. Fuel to fire the steam plant will be sub-bituminous coal from fields primarily in the Hanaford Creek drainage. The coal will be strip-mined and washed before use.

Consumptive uses of the water consists of moisture on the refuse from coal washing, moisture on the processed coal, domestic water for the plant, and the remainder released as vapor to the atmosphere from the cooling towers. No water will be returned directly to the drainage.

Objectives

The objectives of this investigation were to (1) determine what anadromous species utilize the Skookumchuck Basin and their relative abundance in the sections of the river and tributaries affected by the project, (2) to forecast net gain or loss in spawning and rearing habitat after project development in each section of the Skookumchuck Basin, and (3) to determine the most practical and effective measures for the preservation of fish life. The sections of the river under investigation are the headwaters (RM 43.9) to the main falls (RM 30.6), the main falls to the upper end of the reservoir (RM 27.6), the upper end of the reservoir to the dam (RM 22.9), the dam to the diversion (RM 7.8), the diversion to the mouth (RM 0.0), and Hanaford Creek (Figure 1).

Skookumchuck Basin

The Skookumchuck River flows generally westward from its headwaters on the westerly slopes of Huckleberry Mountain and Lookout Peak. The total watershed is about 183 sq miles and the total river length is 43.9 miles The upstream 20 miles of river flow through heavily forested hills and the remainder flows through a broad, flat valley to its confluence with the Chehalis River. The river drops 1,950 ft between RM 43.9 (elevation 2,950) and RM 35.7. It drops 300 ft between RM 35.7 and RM 30.6, the main falls. It drops 400 ft between the falls and the dam and 120 ft from the dam to the mouth (elevation 180).

Mean annual flow of the Skookumchuck River at the USGS gage (Skookumchuck River near Centralia) is about 240 cfs with minimum and maximum recorded discharges of 15.5 and 6,710 cfs, respectively. Stream flow in the Skookumchuck River is primarily from rainfall runoff. Mean annual precipitation in the Skookumchuck Basin varies from 44 inches at the mouth to 86 inches in the headwaters, with a resulting average annual runoff of about 30 inches at the mouth and 80 inches in the extreme headwaters.

History

Existing salmon runs in the Skookumchuck River have been greatly depressed by a combination of factors including three dams on the river, illegal fisheries (gaffing), log jams, poor water quality in the Chehalis River and Grays Harbor, and coal mining activities in Hanaford Creek Basin. The abuses to salmon runs in the river are well documented in the Department files back to 1914.

Turvey Dam (RM 23.8) was built about 1924 and either completely or partially blocked upstream migrations of salmonids until 1938. The Bucoda Dam (RM 11.5) was build prior to 1914 and presented both a partial block to salmonids and a very serious gaffing problem in the fishways until it was removed in 1946. Agnew Dam (RM 3.7) existed from the early 1900's to 1969, when the Department of Fisheries removed it. It partially to totally blocked salmon runs both to the main river and Hanaford Creek during this period. One report from Department files in 1932 documented that all three dams on the river were blocking fish and between 50 and 75 gaffers were working in the fishways at Agnew Dam alone.

Between 1878 and 1969, more than 9 million tons of coal were mined in Hanaford Creek drainage, primarily North Hanaford and Packwood Creeks (Beikman, Gower, and Dana, 1961). Local residents report that spawning area was lost due to these mining activities. Mine tailings are presently found in Packwood Creek, and the upper part of North Hanaford Creek flows through an old strip mine.

PHYSICAL HABITAT

To forecast changes in the river affecting fish life which may develop from the project, it was necessary to examine the physical fish production habitat within each section of the basin. Watershed areas were determined with a planimeter and river lengths with a map measure or dividers from USGS quadrangle maps. Discharge measurements were made in Hanaford Creek with a Price-type AA current meter, using standard stream gaging procedures. Discharge data for the main river are from USGS publications. The river was surveyed on foot from the falls during summer low flow (RM 30.6), to the mouth to determine the physical characteristics of the streambed. Riffle lengths and rapid lengths were estimated by eye while river widths were measured with a tape at a flow of about 40 cfs every 550 ft of stream. Some error was probably involved estimating lengths but any error should be consistent between sections. Pool lengths were calculated from total river less combined rapid and riffle lengths. Per cent boulder (over 12 inches), rubble (6 to 12 inches), gravel (1 to 6 inches), and sand (under 1 inch) in each riffle was also determined by eye. The tributaries were surveyed on foot to determine fish utilization, production potential, and upper limits of accessibility. Spawning habitat is confined to riffles, and rearing habitat includes all waters.

The Skookumchuck Basin contains 183 sq miles of watershed and 221 miles of total stream (including tributaries) of which about 74 miles are accessible and used by salmon. The river below the falls and excluding tributaries contains 341 riffles and the riffle: pool: rapid ratio is about 36:61:3 (Table 1). At a flow of 40 cfs, there are about 350,000 sq yards of riffles which contain about 230,000 sq yards of gravel (Table 2). At a pre-project flow of 40 cfs in August, there are about 1 million sq yards of available rearing area.

Headwaters to Falls

This area contains about 40 sq miles of drainage area, and none of the 53.6 miles of total stream (including tributaries) are accessible to salmon. The area consists of many rapids, a few riffles with limited salmon spawning potential, and a few pools. Eleven Creek (RM 33.4) and Twelve Creek (RM 35.4) have resident and anadromous trout populations. All other tributaries in this section have impassable falls at their mouths.

Falls to Reservoir

This area contains about 10 sq miles of drainage area, and about 3.5 miles of 14.0 miles of total stream (tributary and main river) are accessible and used by coho. No chinook have been observed, and the canyon at the lower end of the section is probably a low flow block during upstream migration. This section contains 43

riffles and the riffle: pool: rapid ratio is about 79:4:18 (Table 1). At a flow of 40 cfs, there are about 59,000 sq yards of riffles which contain about 37,000 sq yards of spawning gravel (Table 2). This comprises about 16% of the total available gravel in the river below the falls. At a flow of 40 cfs in August, there are about 75,000 sq yards of available rearing area. Pheeny Creek (RM 28.0) has about 1/2 mile of accessibility to salmon, and all other tributaries have impassable falls at their mouths.

Future Reservoir

This area contains about 13 sq miles of drainage area, and about 4.3 miles of the 14.0 miles of total stream (including tributaries) are accessible and used by coho, spring chinook, and fall chinook. This section contains 90 riffles, and the riffle: pool: rapid ratio is about 60:30:10 (Table 1). At a flow of 40 cfs, there are about 100,000 sq yards of riffles which contain about 78,000 sq yards of spawning gravel comprising about 34% of the total available gravel in the river (Table 2). At a flow of 40 cfs in August, there are about 166,000 sq yards of available rearing area. There are no tributaries in this section except for a few feet of Fall Creek (RM 24.9) available to salmon because of falls.

Dam to Diversion

This area contains about 49 sq miles of drainage area, and about 27.4 miles of the 58.8 miles of total stream (including tributaries) are accessible and used by coho, spring chinook, and fall chinook. This section contains 149 riffles and the riffle: pool: rapid ratio is about 25:75:0 (Table 1). At a flow of 40 cfs, there are about 126,000 sq yards of riffle area which contains about 76,000 sq yards of spawning gravel, comprising about 33% of the total available in the river (Table 2). At a flow of 40 cfs in August, there is about 511,000 sq yards of available rearing area. After project completion, assuming an August flow of about 115 cfs, there would be an increase in total wetted area of about 8,500 sq yards. Thompson (RM 19.5), Johnson (RM 19.3), and Salmon Creeks (RM 19.3) are the only tributaries in this section utilized by a few coho. All other tributaries are dry most of the year.

Diversion to Mouth Excluding Hanaford Creek

This area contains about 15 sq miles of drainage area, and about 7.8 miles of the 20.8 miles of total stream (including tributaries) are accessible and used by coho, spring chinook, and fall chinook. This section contains 59 riffles and the riffle: pool: rapid ratio is 24:76:0 (Table 1). At a flow of 40 cfs, there are about 71,000 sq yards of riffles which contain about 40,000 sq yards of spawning gravel

comprising about 17% of the total available in the river (Table 2). We do not yet know what the flow will be in this section after project completion, but any reduction below natural flow would reduce the amount of presently available spawning area. At an average mean monthly flow of 40 cfs in August, there would be about 297,000 sq yards of available rearing area. Rearing area would be lost in this section if flows are reduced by the project below natural river flow at this point. Hanaford Creek (RM 4.1) is the only tributary in this section not dry most of the year.

Hanaford Creek Drainage

The Hanaford Creek Basin contains about 56 sq miles of drainage area, and about 31.3 miles of the 60.2 miles of total stream (including tributaries) are accessible and used by coho. Chum reportedly have been observed in good numbers in the 1940's. The lower 9 miles of the main creek has been channelized but the upper 8 miles is some of the best coho spawning and rearing habitat in the entire Chehalis Basin. The riffle:pool ratio in the upper section is about 60:40, and most of the bottom material is superb coho spawning gravel. The measured flow in 1967-1968, a low water year, ranged from about 95 to 3 cfs, and the estimated stream width at low flow is about 5 yards (Figure 3). Additional width and water flow measurements should be taken if a dam is built on this creek. The entire main stream has an estimated 150,000 sq yards of rearing area, and an estimated 84,500 sq yards of spawning gravel is confined to the upper section. The channelized section contains no spawning area, however, it is used for transportation of young and adults. Packwood, Coal, and Overburden Creeks are the only tributaries with coho. All tributaries to lower Hanaford Creek have been altered by man to an extent that they either do not have or support only remnant populations of coho.

SALMON DISTRIBUTION

Stream surveys on foot or by boat were conducted to determine what species utilize the basin, what time of year they are present, and their distribution. In 1969, spawning velocity and depth measurements were made at the head end of a few new, active redds to substantiate work done by other workers in other watersheds. In 1968, sampling for juvenile salmonids with inclined plane screen traps and broomstick seines was conducted between March and July. The broomstick seines were used in side channels and small tributaries. Trap sites included upper Hanaford Creek, Packwood Creek, upper Skookumchuck River at the new USGS gage above the falls (RM 38.8), lower Skookumchuck River below North Pearl Street Bridge (RM 2.3) and (RM 9.0) above the diversion site. A 40-ft beach seine was used in May, June, and July when flows were reduced to allow efficient sampling. Additional data on distribution were supplied by the Department of Game.

Juveniles

Coho fry (35 to 50 mm fork length) populations were found in the main river from below the falls (RM 29) to just above the mouth (RM 4.0). Chinook fry (40 to 50 mm fork length) were collected from the Bucoda bridge (RM 11.5) to the mouth (RM 0.0). The absence of chinook from samples above Bucoda is attributed to high flows in April and May which prevented effective seining and does not demonstrate that the river above Bucoda is not used for rearing. Few yearling coho were collected because of escapement under the seines and avoidance of the traps. No attempt was made to estimate either total or relative abundance of juveniles because of high costs involved and lack of adequate seeding during the study.

Fingerling coho were found in Hanaford, Packwood, Overburden, Coal, Salmon, Johnson, Thompson, and Pheeny Creeks. Yearling coho were found in Johnson, Salmon, and Hanaford Creeks and at the dam site during construction activities in 1969. No coho or chinook juveniles were found in the main river above the falls, North Hanaford, Fall, or Snyder Creeks. All other tributaries have inaccessible falls or are dry most of the year.

1967 Adult Surveys

About 20 spawning ground surveys were conducted between September 15 and December 22, 1967. The results are presented in Tables 3 through 7. No chinook and only one coho redd was observed above the reservoir.

In the reservoir area, only 4 live chinook and 11 redds were observed, and the live fish were seen September 15, 1967 (spring chinook). A total of 8 live, 2 dead, and 7 coho redds were observed in this section. The peak coho live count was on December 18, 1967.

Between the dam and diversion, a maximum of 18 live, 7 dead, and 87 chinook redds were observed, and peak of spawning was probably mid-October. A maximum of 4 live, 2 dead, and 3 coho redds were observed in late November. Agnew Dam probably had an effect on timing in 1967 because flows were low in the fall migration period.

Below the diversion, 5 live, 22 dead, and 47 chinook redds were observed. The only live chinook were seen October 17, 1967. No coho were observed.

A maximum of 31 live, 9 dead, and 47 coho redds were observed in Hanaford Creek, and the peak live count was in mid-December. Fry collected in the spring of 1968 in Packwood, Coal, Johnson, and Thompson Creeks indicated coho spawned in these streams as well. No chinook were seen in any tributary surveyed.

1968 Adult Surveys

Thirty spawning ground surveys were conducted between September 10 and December 31, 1968. The results are presented in Tables 8 through 12. The 1968 surveys were disrupted by continual floods in November and most of December. No chinook and only one coho redd was observed between the falls and the reservoir.

On November 1, only 3 live, 1 dead chinook, and 2 redds were observed in the reservoir area. Fourteen live, and 8 coho redds were observed December 21, 1968. The peak of coho spawning was missed because of the flooding river.

Between the dam and diversion, the peak spring chinook count was 6 live and 7 redds on September 12, 1968. Fall chinook spawning peaked in late October when 14 live and 12 redds were observed. All but 1 fish was observed between RM 15.5 and RM 7.7. Only 1 live coho was observed in this section in 1968.

Below the diversion, no spring chinook and 16 live, 3 dead, and 29 fall chinook redds were observed. Peak of spawning was late October. The area was not surveyed for coho because of poor visibility and high water.

Conditions in Hanaford Creek were good for surveying in November but impossible because of high water most of December. Maximum coho counts in late November were 116 live, 11 dead, and 112 distinct redds. Redd counts were minimal because of mass spawning. Coho counts in other tributaries were 2 live and 3 redds in Johnson Creek, 3 redds in Thompson Creek, 4 live and 7 redds in Salmon Creek, 3 live, 1 dead, and 6 redds in Thompson Creek, and 5 live and 3 redds in Coal Creek. No chinook were observed in any tributary in 1968.

1969 Adult Surveys

Thirty-three spawning ground surveys on the main river were conducted between September 2, and December 1. About 6 additional surveys were conducted on tributaries. River flow was low except for one freshet between November 4, and 9, 1969.

The section between the main falls and the upper end of the canyon was surveyed twice but no fish were observed that year (Table 13).

The future reservoir area was surveyed 11 times (Table 14). Spring chinook were observed in deep pools in early September, began spawning in mid-September, and peaked spawning about September 24, 1969 when 65 live and 20 redds were counted. Spring chinook spawning was over about the first of October and no fall chinook were observed in 1969. Coho spawned in this section and a maximum of 9 fish and 10 redds were observed.

Fourteen surveys were conducted on the section between the dam and the diversion site (Table 15). Spring chinook counts peaked in late September with 32 live, 2 dead, and 7 redds, and spawning was essentially over by the first of October. Fall

chinook counts peaked between October 20 and 22, 1969 with 27 live, 7 dead, and 16 redds and spawning was over by mid-November. High water turbidities hampered fall chinook counts. Coho spawned in this section and a maximum of 12 live, 1 dead, and 30 redds were observed. The low fish to redd ratio suggests peak of spawning was missed and probably occurred between November 14 and 26, 1969.

The river from diversion site to the mouth was surveyed six times (Table 16). Turbidities were periodically high in this section from several sources including construction work at Skookumchuck Dam, Hanaford Creek, Agnew Dam, and a temporary gravel operation in the lower river. A peak spring chinook redd count of 12 was observed October 7, 1969 after peak of spawning. It is estimated that about 40 spring chinook utilized this section in 1969. Fall chinook spawning peaked in late October, early November. Peak redd count was October 29, 1969 with 4 live, 3 dead, and 10 redds. On November 10, 1969, 4 live, 5 dead, and 5 redds were observed in highly turbid water below Hanaford Creek. On the same survey, 9 live coho on 4 redds were observed. On November 20, 1969, 3 live coho and 8 redds were observed.

Coho were first observed in Hanaford Creek October 9, 1969, and peak counts were observed November 21, 1969 with 30 live, 5 dead, and 22 redds (Table 17). Coho were still spawning on December 19, 1969.

TIMING OF SALMON RUNS AND AREAS UTILIZED

The general results of the biological surveys were reviewed to determine timing of salmon runs and spawning areas. The results are presented on Table 18.

Spring Chinook

Based on the Indian fishery in the Chehalis River, spring chinook enter the river between early March and July, peaking in May (Figure 2). Spawning extends from early September to early October, peaking in late September. Peak of spring chinook spawning is considerably earlier, late August to mid-September, in other western Washington streams. The later spawning period for the Skookumchuck River may be the result of river flow and temperature in August and early September during the years 1967 through 1969. The data show heaviest spawning in the reservor area and between the diversion and mouth.

Fall Chinook

Fall chinook enter the river between July and late November, peaking in October. Spawning extends from early October to early December, peaking in late October and early November. Spawning is well distributed from the dam to diversion and diversion to mouth.

Coho

Coho enter the river between August and January, peaking in late October and early November. Spawning extends from late October to early January. In 1967, peak spawning occurred in mid-December and in 1968 and 1969 occurred in late November. No late-run coho, January and February spawners, were observed during the study. In 1967 and 1968, the heaviest spawning was located in Hanaford Creek and the reservoir area. In 1969, spawning was well distributed through the river.

Chum

No chum were observed during the investigations, but historically, chum were found in the river. They entered the river between September and December, peaking in late October, early November. Spawning probably extended from mid-October through December, peaking in November based on data from other Chehalis River tributaries. Seaward migration probably occurred during February, March, and April.

CROSS-SECTION STUDY

Introduction

A cross-section study was conducted to predict the affect of project flows on fish life below the dam and below the diversion. Several definitions are required. Optimum spawning flow is defined as that single flow which provides the most habitat for spawning at a selected cross section on a single spawning riffle (Figure 4). The criteria used for spawning habitat shown in Figure 5 were depths between 1.00 ft and 1.75 ft, and water velocities (measured 0.4 ft from the bottom) between 1.0 and 2.25 ft per second (Chambers, 1956). Minimum acceptable spawning flow is that single flow which, if reduced, would cause severe reductions in suitable spawning depth and velocity on a selected cross section on a single spawning riffle. Minimum rearing flow is that single flow which, if reduced, would affect severe losses in wetted perimeter. Minimum incubation flow is that single flow which insures at least 0.5 ft of water over spawning gravel.

Methods and Materials

Five cross sections were selected above the diversion (Sections 1, 2, 3, 4, and 5) and two below (Sections 6 and 7). River stage measurement markers were established along with initial points from which to measure the distance to water edge and sampling points in the river channel for each set of measurements in the study

(Figure 4). All cross sections were measured initially with a surveyor's transit and level rod. After establishing the study cross sections, five sets of depth and water velocity measurements were made along with discharge measurements by the velocity-area method over a range of flows from 30 to 230 cfs. All velocity measurements were made with a Price-type AA current meter, depth measurements were made with the current meter suspension rod, and distance measurements from the initial point were made with a standard stream gaging tag line graduated at 2-ft intervals for the first 50-ft and 5-ft intervals for the next 100 ft. For each set of measurements, the river stage at each section was measured based on the assumed datum at the section. Gage readings were also taken at three USGS gages below the dam.

The collected data were reduced to graphical plots as shown in Figure 5 which is a typical plot of the depth and water velocity data at a hypothetical flow. All sections were plotted for each set of measurements, and the amount of section width containing optimum conditions of depth, water velocity, and a combination of depth and water velocity scaled off. The resulting measurements were then substituted in the formulas in Figure 5 and the information plotted in Figures 6 and 7.

Results

Figure 8 shows the river discharge at each section for each set of measurements. The discharges for each date are connected to show the discharge profile for the stream. There was little or no diurnal flow fluctuations during each set of measurements. The profiles show the effect of conveyance loss to irrigation and change in intragravel flow at the sections during the study. The results are not exact and are presented to indicate that the channel does have losses to surface flow during the months of low flows, and that tributary inflow is not always significant below the dam.

Figure 6 shows the spawning characteristic curves for each cross section reference line. Optimum spawning flows for cross sections 1 through 5 (above the diversion) are about 150, 120, 165, 75, and 160 cfs, respectively (average of 134 cfs). Optimum flow for cross section 6 (below the diversion) is about 160 cfs. Cross section 7 data were not applicable to the criteria and were not used. Minimum acceptable spawning flows for cross sections 1 through 5 are about 110, 110, 120, 40, and 80 cfs, respectively (average of 92 cfs). Minimum acceptable spawning flow for cross section 6 is about 110 cfs.

Figure 7 shows the rearing characteristic (P_w) and incubation characteristic (W_d) curves. Minimum acceptable rearing flows for cross section 1 through 5 (above

the diversion) are about 30, 35, 40, 45, and 45 cfs, respectively. Minimum acceptable rearing flows for cross sections 6 and 7 are about 40 and 45 cfs, respectively. Minimum acceptable incubation flows for cross sections 1 through 7 are about 80 to 90 cfs.

Data on spawning depth and velocity used by chinook were collected from 10 redds to determine the ranges used in the Skookumchuck River and if they were comparable to the criteria used in the cross section study. Only new, fresh redds with active fish were used and the velocities were measured with a current meter set 0.4 ft from the bottom immediately upstream from the pot. Water depths were read from the current meter rod. Depths for spawning spring chinook ranged from 0.8 to 1.3 ft and averaged 1.0 ft at flows of 80 cfs (Table 19). Velocities ranged from 3.05 to 0.65 fps. The high value was from a redd in the middle of a riffle and the average velocity of all redds was 1.49 fps. Excluding the high value, the average velocity was 1.18 fps. Spawning depths for fall chinook ranged from 1.0 to 1.8 ft and averaged 1.4 ft at about 80 cfs. Velocity ranged from 1.79 to 1.17 fps and averaged 1.51 fps. Except for the one high velocity measurement, the data were comparable to the criteria used in the cross-section study.

The spawning riffle above the North Pearl Street Bridge historically has been one of the most heavily spawned in the river and was number 7 in our cross-section study. October 24, 1969 depths and velocity measurements were made on the cross section and also about 100 ft upstream where a pair of fall chinook were spawning. The flow was 82.5 cfs and the data are presented in Table 20. The gravel on cross-section 7 ranged from 1 to 3 inches in diameter and the mean depth and velocity was 0.8 ft and 1.96 fps, respectively. The depth ranged from 1.1 to 0.6 ft and the velocity ranged from 2.33 to 1.47 fps and no redds were observed. The material on the cross section being utilized by the chinook was 1 to 8 inches in diameter and considerable rubble was present. The mean depth and velocity in this cross section were 1.4 ft and 1.21 fps, respectively. The depth ranged from 0.9 to 1.8 ft and the velocity ranged from 1.29 to 1.05 fps. The depth and velocity at the immediate head end of the redd were 1.8 ft and 1.17 fps, respectively.

These data indicate that there was insufficient depth for chinook spawning on cross section 7 at a flow of 82 cfs and the chinook chose to spawn in gravel not considered good for this section of the river. On November 10, 1969 at a flow of 218 cfs, coho were spawning immediately on cross section 7 which suggest that an increasing hydrograph for the Skookumchuck River is more important than a single fixed flow to utilize more riffle area for spawning and to reduce superimposition of spawning. From these data and general observations of Rothfus and Thompson at 105 cfs, it is concluded that at flows of 82 cfs, the spawning area is limited in extent. This causes fish to be more heavily concentrated than at higher flows.

WATER QUALITY

Introduction

To forcast changes in water quality from the proposed strip mining operation, it was necessary to examine the literature to determine what factors should be measured and to determine existing levels of these in the Skookumchuck River and its tributaries before full scale mining commenced. The literature survey revealed the following determinations to be measured: temperature, dissolved oxygen (DO), turbidity, settleable matter, sulfate, hydrogen iron concentration (pH), total acidity, free acidity, total alkalinity, free alkalinity, and iron content. The latter five determinations were analyzed by the Washington Water Pollution Control Commission (WWPCC).

Methods and Materials

Methods for the sulfate determination are outlined in APHA (1965), and a Hellige nephelometer was used for the determination. Both a turbidity and a reagent blank were used to correct for interference. Highly turbid samples were filtered and samples with sulfate in excess of 100 milligrams per liter (mg/l) were diluted before analysis. Turbidity was determined with a Hellige turbidimeter and settleable matter with 1-liter Imhoff cones as outlined above. Methods for DO and pH are standard procedures as outlined by Strickland and Parsons (1965). A temperature compensating Beckman Model G pH meter with external electrodes was employed for pH determinations. A clinical grade 3-inch emersion thermometer was used to estimate temperatures to 0.01 centigrade (C). Water samples were collected with either a 3-liter Van Dorn bottle or with a plastic aspirator bottle. All samples were taken just below the surface of the water.

A total of 29 sampling trips were conducted during the investigation between June 1968 and December 1969. The latter 15 trips included the samples for analysis by WWPCC between December 1968 and December 1969. A maximum of 14 stations were sampled but the number was reduced to 11 after preliminary analysis of data. The description and location of the stations are on Table 21. Continual recording thermograph data were collected at the Bloody Run Gage (RM 23.7), the Connor Road Gage (RM 6.8), Upper Hanaford Creek (RM 10) and Hanaford Creek at the plant site (RM 4).

Upper Hanaford Creek

The data are presented on Table 22. The DO ranged from a high of 13.26 ppm on February 25, 1969 to a low of 8.60 ppm on June 19, 1969. The DO was higher in the winter and lower in the summer being inversely related to temperature. The pH

ranged from a high of 7.89 on September 22, 1969 to a low of 6.58 on March 18, 1969. The pH was inversely related to river stage and turbidity. Turbidity ranged from a high of 36.50 JTU on December 3, 1969 to a low of 0.52 JTU on August 8, 1968. Turbidity was related to flow. The sulfate content remained below 5 ppm during the period. The iron content ranged from a high of 4.6 ppm on December 3, 1969 to lows of 0.4 ppm on June 19 and August 13, 1969. Total alkalinity ranged from a high of 85 ppm as $CaCO_3$ on September 22, 1969 to a low of 7.9 ppm as $CaCO_3$ on January 7, 1969. Free alkalinity and total acidity fluctuated little averaging around 15 and 5 ppm as $CaCO_3$, respectively.

Mid-Hanaford Creek

The data are presented in Table 23. The DO ranged from a high of 13.04 ppm on March 18, 1969 to a low of 8.41 ppm on September 22, 1969. The DO was higher in winter being inversely related to temperature, and low in the early fall being also related to low flow in Hanaford Creek. The pH ranged from a high of 7.53 on September 22, 1969 to a low of 5.91 on October 15, 1969. The determination on the low value was duplicated with another water sample to confirm reliability. The latter pH was the lowest found for all stations except the coal pile drainage area. The reason is unexplainable being non-typical for the station. The values below and above this station on that date were pH 6.98 and pH 6.87, respectively. The next lowest value was pH 6.49 on June 3, 1968. Turbidity ranged from a high of 36.50 JTU on January 7, 1969 to a low of 3.50 JTU on July 16, 1968. Turbidity was related to flow. The sulfate content remained below 5 ppm during the period. The iron content ranged from a high of 4.0 ppm on January 7, 1969 to a low of 0.5 ppm on February 25, 1969. Total alkalinity ranged from a high of 35.5 ppm as $CaCO_3$ on April 1, 1969 to a low of 3.1 ppm as $CaCO_3$ on January 7, 1969. Free alkalinity and total acidity fluctuated little averaging around 15 and 5 ppm as $CaCO_3$, respectively.

Packwood Creek

The data are presented in Table 24. The DO ranged from a high of 12.92 ppm on February 25, 1969 to a low of 5.02 ppm on June 19, 1969. DO was below 6 ppm on two other occasions, July 8, 1968 and July 31, 1968. All low DO values occurred when the flow was extremely low. The pH ranged from a high of 7.41 on December 10, 1969 to a low of 6.10 on March 18, 1969. During winter and early spring, the pH was below 7.00 much of the time. Extensive coal mine drainage at the headwaters may be responsible for the low pH. Turbidity ranged from a high of 142 JTU on September 22, 1969 to a low of 5.20 on January 1, 1969. There is no explanation for the high turbidity. The sulfate content remained about 6 ppm during the period. The iron content ranged

from a high of 5.2 ppm on September 22, 1969 to a low of 0.5 ppm on February 25, 1969. Iron content was higher during low flow months. Total alkalinity peaked twice, once at 41.5 ppm as $CaCO_3$ on April 1, 1969 and again at 51.0 ppm as $CaCO_3$ on August 13, 1969. The lowest total alkalinity was 2.0 ppm as $CaCO_3$ on May 22, 1969. Total acidity peaked twice at 10.7 ppm as $CaCO_3$ on April 1, 1969 and June 19, 1969. The lowest total acidity was 2.6 ppm as $CaCO_3$ on December 3, 1968. Free alkalinity ranged from a high of 68.0 ppm as $CaCO_3$ on August 13, 1969 to a low of 6.0 ppm as $CaCO_3$ on January 7, 1969. The alkalinity values peaked during low flow conditions.

Overburden Creek

The data are presented in Table 25. The DO ranged from a high of 12.98 ppm on February 25, 1969 to lows of 5.50, 5.37, and 6.19 ppm on August 8, 1968, August 22, 1968, and September 22, 1969, respectively. At this time, there is no explanation for the low DO. The pH ranged from a high of about 7.51 on July 16 and 31, 1968 to a low of 6.31 on March 18, 1969. The pH was below 7.00 during months of high flows. The test coal mine might be the source of the low pH. Turbidity ranged from 1,180 JTU on December 3, 1968 to a low or 3.15 JTU on October 15, 1969. Extreme fluctuation of turbidities occurred with every rainfall and 10 of 27 turbidity measurements during the period were in excess of 25 JTU. The high turbidities were related to excessive siltation from the test coal mine operation. The sulfate content ranged from a high of 61.60 ppm on December 3, 1968 to a low of 0.00 from July 1, 1968 to August 21, 1968. Sulfate content was also low in the summer of 1969. There was little or no moving water in the creek during the periods of low sulfate content. The iron content ranged from a high of 27.2 ppm on December 3, 1968 to a low of 1.0 ppm on February 25, 1969. Other high iron values of 6.3, 7.5, and 2.3 ppm on January 7, June 19, and September 22, 1969. The total alkalinity peaked three times at 59.5, 40.1, and 86.0 ppm as $CaCO_3$ on December 3, 1968, April 1, 1969, and August 13, 1969, respectively. The lowest total alkalinity measured was 3.6 ppm as $CaCO_3$ on January 7, 1969. Correspondingly, the free alkalinity peaked twice at 28.0 and 105.0 ppm as $CaCO_3$ on April 1 and August 13, 1969. The lowest free alkalinity measured was 4.3 as $CaCO_3$ on January 7, 1969. Total acidity ranged from a high of 16.0 ppm as $CaCO_3$ on May 22, 1969 to a low of 2.9 on December 17, 1968. The pH was above 7.00 only during periods of alkalinity in excess of 20 ppm as $CaCO_3$.

Coal Pile Drainage

The data are presented in Table 26. The DO ranged from a supersaturated high of about 20 ppm on April 1, 1969 to lows less than 0.3 ppm on August 13, 1969 and December 10, 1969. The pH was 7.19 on June 19, 1969 and 6.32 on October 16, 1968.

The pH was below 5.99 on all other sampling trips. The lowest pH was 5.12 on October 15, 1969. Data on turbidity are not included because the extreme amount of color in the samples negated precision in the determinations. The sulfate content ranged from highs of 381 ppm on January 7, 1969, 334 ppm on September 25, 1968, and 265 ppm on December 17, 1968 to a low of 45 ppm on June 19, 1969. The sulfate content ranged between 50 and 70 ppm on all other samples. The iron content ranged from a high of 73.0 ppm on December 10, 1969 to a low of 1.7 ppm on September 22, 1969. The iron content ranged between 10 and 26 ppm on the other trips. Total alkalinity, free alkalinity, and total acidity further demonstrated classic acid mine water conditions by the total acidity exceeding total alkalinity on numerous occasions and the total alkalinity being negative on four occasions.

South Hanaford Creek

The data are presented in Table 27. The DO ranged from a high of about 11 ppm on February 25, 1969 to a low of 0.12 ppm on June 19, 1969. The DO was below 5 ppm on all trips between May and September. During this period, the creek stops flowing, is filled with rooted floating emergent aquatics which completely shade the water, and a high BOD and lack of primary productivity in the water are probably responsible for the low DO. The pH ranged from a high of 7.07 on August 8, 1969 and June 19, 1969 to a low of 6.18 on February 25, 1969. The pH was below 7.00 on all trips except above. The low pH is probably caused by the swampy, nonproductive nature of the stream. Fortunately, the relative flow of this tributary is very small to Hanaford Creek at their confluence. The sulfate content was below 10 ppm except on August 22, 1968 when it reached 22 ppm. No samples were collected for analysis by WWPCC because of the stream's lack of salmonids.

North Hanaford Creek

The data are presented in Table 28. The DO ranged from a high of 11.29 on April 23, 1969 to a low of 7.23 on September 22, 1969. The DO was inversely related to temperatures. The pH ranged from a high of 7.69 on July 31, 1968 to a low of 6.41 on February 25, 1969. The pH was above 7.00 only during low flow months. The turbidity ranged from a high of 23.00 JTU on January 7, 1969 to a low of 0.51 JTU on July 16, 1968. Turbidity was related to flow. The sulfate content ranged from a high of 68.40 ppm on June 19, 1969 to a low of 21.30 on January 7, 1969. The sulfate content was generally higher during low flow months. The iron content remained below 2 ppm and fluctuated little during the period. Alkalinities fluctuated to higher levels than any other station sampled. Free alkalinities were greater than 125 ppm as $CaCo_3$ on seven occasions and peaked August 13, 1969 at 311 ppm as $CaCO_3$. Total

alkalinity peaked at 192 ppm on $CaCO_3$ on October 15, 1969. Total acidity peaked August 13, 1969 at 61 ppm as $CaCO_3$ and was above 10 ppm as $CaCO_3$ during the spring and summer.

Lower Hanaford Creek

The data are presented in Table 29. The DO ranged from a high of 10.82 ppm on January 21, 1969 to a low of 6.02 ppm on August 8, 1969. The DO was frequently below 7.0 ppm during low water and warm temperature. The pH ranged from a high of 7.24 on August 13, 1969 to a low of 6.28 on June 3, 1968. The pH was below 7.0 all months except January, June, July, August, and December. Turbidity ranged from a high of 27 ppm on June 3, 1968 to a low of 4.1 on July 16, 1968. Turbidity was related to construction activity at the plant site and flow. The sulfate content fluctuated between 1 and 10 ppm except for January 7, 1969 when it reached 27.4 ppm. The iron content ranged from a high of 2.8 ppm on June 19, 1969 to lows of about 1.0 ppm during high water. Total alkalinity ranged from a high of 41.5 on April 1, 1969 to a low of 6.2 on February 12, 1969. Free alkalinity ranged from a high of 47 ppm as $CaCO_3$ on June 19, 1969 to a low of 7.1 on February 12, 1969. Total acidity fluctuated between 5 and 10 ppm as $CaCO_3$ during the period.

Upper River

The data are presented in Table 30. The DO ranged from a high of 13.13 ppm on December 10, 1969 to a low of 8.88 ppm on September 22, 1969. The DO was higher in winter and lower in summer being inversely related to temperature. The pH ranged from a high of 7.89 on July 31, 1968 to a low of 6.90 on March 18, 1969. The pH was inversely related to river stage and turbidity. The turbidity ranged from highs of 41.0 JTU on January 7, and February 12, 1969 to a low of 0.3 JTU on July 1, 1968. Turbidity was related to flow. The sulfate content remained below 2.00 ppm during the period. The iron content ranged from a high of 4.6 ppm on December 3, 1968 to a low less than 0.5 ppm through much of the period. Total alkalinity ranged from a high of 32.5 ppm as $CaCO_3$ on April 1, 1969 to a low of 3.1 ppm as $CaCO_3$ on January 7, 1969. Free alkalinity and total acidity fluctuated little averaging around 20 ppm as $CaCo_3$, respectively.

Bucoda

The data are presented in Table 31. The DO ranged from a high of 12.76 ppm on February 25, 1969 to a low of 8.53 ppm on September 22, 1969. The DO was higher in winter and lower in summer being inversely related to temperature. The pH was

usually higher in summer and lower in winter being inversely related to flow and turbidity. The turbidity ranged from a high of 28.5 JTU on February 12, 1969 to a low of 0.1 JTU on July 31, 1968. Turbidity was related to flow. The sulfate content remained below 2.5 ppm during the period. The iron content ranged from a high of 5.0 ppm on January 7, 1969 to lows less than 0.4 ppm through much of the period. Total alkalinity ranged from a high of 57.7 ppm as $CaCO_3$ on January 21, 1969 to a low of 21.1 ppm as $CaCO_3$ on January 7, 1969. Total acidity ranged from a high of 17.2 ppm as $CaCO_3$ on April 1, 1969 to a low of 0.0 on December 3, 1968 and August 13, 1969. Free alkalinity ranged from a high of 30.0 ppm as $CaCO_3$ on August 13, 1969 to a low of 4.3 ppm as $CaCO_3$ on January 7, 1969.

Skookumchuck River

(0.8 miles upstream from Hanaford Creek)

The data are presented in Table 32. The DO ranged from a high of 12.18 ppm on January 21, 1969 to a low of 7.68 ppm on July 31, 1969. The DO was higher in winter and lower in summer being inversely related to temperature. The pH ranged from a high of 7.59 on August 21, 1968 to a low of 6.83 on March 18, 1969. The pH fluctuated little being above 7.00 except during high flows. The turbidity ranged from a high of 37.0 JTU on January 7, 1969 to a low of 0.8 JTU on September 22, 1969. Turbidity was related to flow. The sulfate content remained below 2.5 ppm during the period. The iron content ranged from a high of 4.1 ppm on January 7, 1969 to a low of 0.1 ppm on June 19, 1969, and remained below 0.5 ppm during low flow periods. Total alkalinity ranged from a high of 31.4 ppm as $CaCO_3$ on April 1, 1969 to a low of 7.8 ppm as $CaCO_3$ on June 19, 1969. Total acidity ranged from a high of 10.2 ppm as $CaCO_3$ on April 23, 1969 to lows of 0.0 ppm as $CaCO_3$ on December 12, 1968 and September 22, 1969. Free alkalinity ranged from a high of 28.5 ppm as $CaCO_3$ on June 19, 1969 to a low of 10.3 on January 7, 1969.

Skookumchuck River

(1.6 miles downstream from Hanaford Creek)

The data are presented in Table 33. The DO ranged from a high of 12.56 ppm on February 25, 1969 to a low of 7.60 ppm on September 22, 1969. The DO was higher in winter and lower in summer being inversely related to temperature. The pH ranged from a high of 7.56 on August 8, 1968 to a low of 6.69 on June 3, 1968. Turbidity ranged from a high of 42.5 JTU on January 7, 1969 to a low of 1.0 JTU on August 13, 1969. Turbidity was related to flow except September 22, 1969 when the turbidity exceeded 30 JTU from uncertain work in the stream. The sulfate content remained

below 3.7 ppm during the period. The iron content ranged from a high of 7.0 on January 7, 1969 to a low of less than 0.5 ppm on several occasions. Total alkalinity ranged from a high of 30.4 ppm as $CaCO_3$ on April 1, 1969 to a low of 8.0 on April 22, 1969. Free alkalinity and total acidity fluctuated little averaging around 25 ppm as $CaCO_3$ and 5 ppm as $CaCO_3$ during the period.

Riverside Park

The data are presented in Table 34. The DO ranged from a high of 12.69 ppm on February 25, 1969 to a low of 8.00 ppm on June 19, 1969. The DO was high in winter and lower in summer being inversely related to temperature. The pH ranged from a high of 7.87 on February 12, 1969 to a low of 6.82 on June 3, 1968. The pH was above 7.00 on all other occasions. The turbidity ranged from about 35 JTU to less than 1 JTU being related to flow. The sulfate content was below 10 ppm during the period. No samples were taken for analysis by WWPCC.

Water Temperatures

The monthly range and mean temperatures for the four thermograph sites are presented in Figures 9, 10, 11, and 12. Temperatures generally increased slowly from February to April, increased rapidly to maximums in July, and decreased at a rate proportionate to river flow. Monthly ranges in temperature below the diversion were in error during the winter of 1968-1969 after the probe became badly silted.

Spawning Temperatures

In 1969, daily maximum temperatures at Bloody Run were compared to spawning activity by species and race in Figure 13. In general, spring chinook spawned when temperatures dropped below 60 F, fall chinook spawned when temperatures dropped below 50 F, and coho spawned when the temperature dropped to about 45 F.

Temperature Forecast

A report forecasting discharge temperatures below Bloody Run Dam was completed by Water Research Associates for Pacific Power and Light Company. Forecasts for a median flow year and a critical flow year are presented in Figures 14 and 15. In general, maximum summer temperatures will be reduced and the maximum will occur in late July, August. Several alternate thermographs are possible depending on the water year and operation of the outlet gates at the dam.

Live Box Tests

Fingerling coho from upper Hanaford Creek were used for live box testing of coal mine drainage water in March, May, and June 1969 at several key sites in the Hanaford Creek drainage. Stations included upper Hanaford Creek (control), mid-Hanaford Creek, lower Hanaford Creek, Overburden Creek, North Hanaford Creek, the coal pile drainage ditch, and the new lake in the test coal mine. The stations on Hanaford Creek had two surface and two deep live boxes each, while the other stations had only one surface box each. Temperatures were recorded and dead fish counted at all stations after 24, 48, and 96 hours when the tests were terminated. The results were clouded by mortalities in the controls, due to transportation, and vandalism in the experimental units. Mortalities were higher in the coal pile drainage and the lake in the test mine (Tables 35, 36, and 37).

CALCULATED NET LOSS OF SALMON PRODUCTION POTENTIAL

Introduction

One of the objectives of the study was to determine the numbers of fish utilizing the sections of the Skookumchuck Basin affected by the Centralia project. Unfortunately, existing salmon runs are so greatly depressed that few conclusions can be made from the field observations. Therefore, it was necessary to calculate the production potential of the sections of the river to predict the net gain or loss caused by the project.

Methods

A total of 12 methods of calculating potential production were attempted for the Skookumchuck Basin. Four compared watershed size to predetermined adult production figures and eight compared rearing habitat to juvenile production.

Smoker (1954) related total square miles of watershed for all western Washington to total salmon catch. His catch figures of 50.4 chinook, 110.0 coho, and 65.4 chum per square mile of watershed were adjusted to escapement figure of 12.59 chinook, 36.65 coho, and 32.72 chum spawners per square mile of watershed. In all cases, catch to escapement figures of 4:1 for chinook, 3:1 for coho and 1:1 for chum were used (Table 38).

Laramie (personal communication) related total square miles watershed in the Puget Sound region to total natural production (catch plus escapement) and his total production figures were 15.6 chinook, 97.2 coho per square mile of watershed. Pratt (personal communication) supplied chum catch figures for Puget Sound. Calculated escapement figures per square mile of watershed for Puget Sound are 3.12 chinook, 24.30 coho, and 36.20 chum spawners (Table 39).

Deschamps (personal communication) supplied annual salmon production figures for Grays Harbor (1960-1969) of about 77,000 chinook, 250,000 coho, and 25,000 chum. Calculated escapement figures per square mile of watershed are 6.06 chinook, 25.19 coho, and 5.00 chum spawners (Table 40).

Shapovalov and Taft (1954) described coho runs in Waddell Creek, California and calculated an average escapement of 247 adult coho per year between 1934 and 1942. Waddell Creek has a 26 sq mile watershed and the calculated escapement of adult per square mile of watershed is 9.5. This latter figure was not used for the Skookumchuck Basin because production in Waddell Creek is limited largely by lack of spawning area and the intermittent closing and opening of a sand bar at the mouth of the stream causing delays in upstream and downstream migrations.

Chapman (1965) determined that about 35 coho smolts were produced per 100 sq yards of rearing area in three small Oregon streams. Walker and Lister (1965) determined that about 16 coho smolts were produced per 100 sq yards of rearing area in the Big Qualicum River, B. C. Salo and Bayliff (1958) found Minter Creek, Washington capable of producing 25,000 to 35,000 yearlings. Minter Creek has about 60,500 sq yards of accessible rearing area and combining these data, smolt production ranges from 41.3 to 57.9 and averages about 49.5 smolts per 100 sq yards of rearing area. Rothfus (personal communication) revealed that Speelyai Creek, Washington produced about 15,000 coho smolts, was about 8 yards wide at low summer flow, and 4 miles long. Speelyai Creek is capable of producing at least 26.6 smolts per 100 sq yards of rearing area or 2.13 smolts per linear yard of stream. The Department of Fisheries of Canada (1966) suggests rearing capacity for coho is more closely associated with length of stream than surface area in Big Qualicum River B.C. Their smolt output was 2 smolts per linear yard or about 3,500 per mile of stream.

Pearson, Conover, and Sams (1969) determined numbers of rearing coho per surface area in 19 Oregon streams. Their average figure was 52.2 fingerling coho per 100 sq yards of rearing area. These data will not be used in evaluating the Skookumchuck Basin because the survival from fingerling to outmigrant is not known.

Ruggles (1966) at Robertson Creek B.C. determined that rearing coho prefer pools, fish food production is higher in riffles, and the most smolt production occurs in a channel with a 50:50 pool ratio. Unfortunately, smolt production for riffle pool ratios of 75:25, 60:40, and 25:75, similar to various sections of the Skookumchuck River, were not measured.

Results

The calculated number of spawners for the main Skookumchuck River (127 sq mile watershed) are presented in Table 41. These totals were related to the available spawning gravel below the falls to determine the number of adult salmon spawners by river section and the loss of potential salmon production after project development (Table 42). Losses above the dam based on calculated escapements and on present utilization are about 1,800 adult coho, 371 adult fall chinook, and 2,100 adult chum. Losses below the diversion are uncertain until flows are established for this section. If the flow is about 65 cfs during spawning about 50% of the spawning area will be lost (Figure 6, Section 6) and on this basis losses would be about 96 chinook, 317 coho, and 325 chum. Losses between the dam and diversion are impossible to calculate because the production calculations assume an average, normal hydrograph during spawning months (Figure 16) which reduces superimposition of spawning by fluctuating spawning depths and velocities on each spawning riffle causing later spawning fish to choose different spawning sites than earlier fish on the same riffle.

Potential coho smolt production was calculated for each section of the river by six methods and is shown in Table 43. Table 44 shows net gain and loss of coho production (adult returns 1% of wild smolt production assumed) after project development based on rearing area. Minter Creek data were used above the dam and Big Qualicum data below because the riffle pool ratios of about 60:40 in the former and 30:70 in the latter were similar to the appropriate sections in the Skookumchuck. An estimated loss of one-half the total potential production will probably occur below the diversion during fluctuation in stage when generation units at the plant are shut down for maintenance and then restarted. Based on rearing area, 1,364 smolts (13 spawners) will be produced above natural production between the pump and dam at sustained minimum flows of 115 cfs and 143,446 (1,434 spawners) will be lost because of the dam and fluctuation on river stage below the pump. The net loss is predicted to be 142,082 smolts or 1,421 spawners based on rearing area alone.

CONCLUSIONS

Changes in Physical Habitat and Potential Fish Production

It is concluded that the Centralia project will alter over one-half of the present salmon spawning habitat in the main Skookumchuck River. The direct loss of spawning habitat correlated with a total potential production constitutes a median potential loss of 467 fall chinook, 2,133 coho, and 1,583 chum spawners. It is further concluded that the Centralia Project will alter over one-half of the potential coho rearing habitat based on both quality and quantity of rearing

area and that this loss represents 142,082 wild migrants. It is recognized that some benefits of increased coho rearing area (increased wetted perimeter in July and August most years) may be realized between the dam and diversion at project flows, but the gain will be minimal because of the cross section and profile of the lower river and present temperatures which are conducive to good production. This section is not considered optimum coho rearing area, and present utilization is very low. The loss of coho, considering losses in spawning and rearing area, is forecasted to be about 1,800 adults, the average of the methods presented in Tables 42 and 44. No method was available to calculate potential spring chinook production, however, general observations on present run size and distribution along with general physical features of the river indicate a potential loss or redistribution of about 500 adult spawners.

It is concluded that, based on observed distribution of spawners, fall chinook will not be as adversely affected by the project as spring chinook and coho. It is also concluded that the minimum project flow will be greater than natural flow below the dam during spring chinook spawning which should provide the increased spawning habitat in the first few miles below the dam necessary to replace that lost in the reservoir. This is contingent on the behavior of the adult spring chinook, and that fall chinook and coho can be prevented from spawning on top of spring chinook redds.

It is further concluded that hatchery production of 300,000 coho smolts averaging 17 fish/lb. would be compensation for lost coho production in the Skookumchuck River. These coho should be planted in upper Chehalis River tributaries to reduce the adult return problem at the dam and to maintain production levels to the fisheries. These conclusions assume that no dam will be built on Hanaford Creek.

As no chum were observed during the study, it is concluded that this species is no longer viable in the Skookumchuck River and special considerations are unnecessary.

Water Quality

It is concluded that present water quality in the Skookumchuck River, Hanaford Creek, and Packwood Creek is generally excellent for salmonid production. Lower Hanaford Creek is an exception being good only for transportation water, and poor for spawning and egg incubation.

It is also concluded that coal fields in Hanaford Valley can form both very dangerous acid mine water and highly alkaline drainage water but, at present, discharge of these waters is not of a magnitude to be detected in fish carrying waters. The acid water has the capacity to be directly toxic to fish life and even with dilution it can destroy or reduce the natural alkalinity of the receiving water.

No conclusions can be drawn of the affect of acid or alkaline mine water being added to very marginal water quality presently existing in the lower Chehalis River and Grays Harbor.

RECOMMENDATIONS

Minimum Flow Released at Dam

To provide for the maintenance of the salmon resource downstream from the dam, it is recommended that minimum flow releases should be provided according to the schedule depicted in Exhibit A, attached, until such time that water in excess of 54 cfs is diverted from the river for plant operation. Before the latter date, sufficient information will have been obtained to re-evaluate the effect of flow releases from the dam on the fisheries resource and to establish final flow requirements under a 3-unit plant operation.

Exhibit A provides that between September 10 and the end of the chinook spawning season or approximately November 5, the minimum release from the dam should be 140 cfs. Additional releases could be requested by the Department during this period if some storage was available to augment spawning flows below the diversion and to aid adult transportation if found necessary. The yearly termination date would be determined by field inspection and after consultation between Pacific Power and Light Company and Department representatives.

After completion of spawning and at an agreed-upon date as noted above, the minimum flow from the dam could be reduced to 95 cfs with this requirement remaining in effect until April 1 to provide for egg incubation. From April 1 to September 9, the minimum flow released from the dam should be 95 cfs or the natural river flow (reservoir inflow) plus 54 cfs, whichever is less. This would provide minimum rearing flows for juvenile fish below the diversion.

Flow reductions, accomplished in accordance with agreed schedules, should be made gradually to reduce the possibility of stranding juvenile fish.

Water Temperatures

The owners have installed multiple level gates designed to permit the release of water from different levels in the reservoir and at different temperatures, and the Department has approved said design. It is recommended that the Department, from time to time, advise the owners which gates are to be operated in order to provide desired water temperatures.

Coho

It is recommended that the predicted loss of coho production in the Skookumchuck River be replaced by the artificial production of 300,000 coho smolts (17/lb.) annually at owner's expense. The coho smolts produced should be released into the Skookumchuck River and other tributaries of the Chehalis River upstream of the Chehalis Indian Reservation at the Department's discretion to maintain production to the various fisheries.

Chinook

It is recommended that adult spring chinook be allowed to redistribute and to spawn naturally below the dam and that minimum spawning flows be as noted above. To prevent superimposition of fall chinook spawning on top of spring chinook redds, it is recommended that the owners construct a temporary fish weir to segregate the spawning grounds of these two races. The weir should be installed prior to the arrival of fall chinook and should remain in place until stream flows make it impractical to maintain, as agreed upon by the Department and the owners, each year.

To prevent superimposition of spawning by coho, it is recommended that they be collected at the dam, after removal of the weir, for redistribution for natural spawning or for artificial propagation.

Mine Drainage

As a minimum, it is recommended that existing water quality as appended in this report be maintained. It has been recommended to the Department of Ecology that discharge, or drainage from coal mining activities entering streams have the following minimum standards and that these standards be written into any waste discharge permits issued at the stream plant and coal mine:

1. The iron content shall not exceed that of the receiving water.
2. The total acidity shall not exceed the total alkalinity.
3. The dissolved oxygen shall not be less than 8 ppm and shall not exceed saturation as a function of temperature.
4. The pH shall be between 6.50 and 8.00.
5. The turbidity and sediment load shall not exceed that of the receiving water.
6. Concentrations of toxic or deleterious material including free carbon dioxide shall be less than those that affect the aquatic environment.

Hanaford Creek Dam

These foregoing recommendations do not provide for protection of the salmon resource of Hanaford Creek in the event that the proposed dam is built as indicated by owners of the Centralia project in 1967. The proposed reservoir would inundate much of the spawning area and if the dam is to be build in the future, it is recommended that additional studies be undertaken to define the effect of the dam and to determine the appropriate compensatory measures necessary to protect the resource.

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GLOSSARY

EXPLANATION OF SYMBOLS AND DATA HEADINGS IN APPENDIX I

Temp:	Water temperature in degrees centigrade (Celsius)
DO:	Dissolved oxygen in milligrams per liter
Turb:	Turbidity in Jackson turbidity units
pH:	Negative logarithm of hydrogen ion concentration
Fe:	Total iron content in milligrams per liter
SO_4:	Total sulfate precipitated by barium chloride in acid solution in milligrams per liter
Total Alka.:	Phenolphthalein alkalinity at boiling temperature as milligrams per liter calcium carbonate
Total Acid:	Phenolphthalein acidity at boiling temperature as milligrams per liter calcium carbonate
Free Alka.:	Methyl red alkalinity as milligrams per liter calcium carbonate

A P P E N D I X I

Tables 1 through 44

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Table 1. Skookumchuck River riffle, pool, rapid composition at assumed mean low summer flows before and after project development, 1968.[1/]

Section	August		Riffle		Pool		Rapids		Total River		Per cent of total		
	Flow cfs	Width yard	Length yard	Area sq yd	Length yard	Area sq yd	Length yard	Area sq yd	Length yard	Area sq yd	Riffle	Pool	Rapid
Falls to upper end reservoir RM 30.60 - 27.60	40	14.3	4,149	59,331	198	2,831	933	13,342	5,280	75,504	78.6	3.8	17.7
Reservoir RM 27.60 - 22.85	40	19.9	5,016	99,818	2,464	49,034	880	17,512	8,360	166,364	60.0	29.5	10.5
Subtotal RM 30.60 - 22.85	40	-	9,165	159,149	2,662	51,865	1,813	30,854	13,640	241,868	67.2	19.5	13.3
Dam to diversion	40	19.3	6,557	126,550	19,931	384,668	0	0	26,488	511,218	24.8	75.2	0.0
RM 22.85 - 7.80	115	2/	6,557	135,074	19,931	384,668	0	0	26,488	519,742	24.8	75.2	0.0
Diversion to mouth RM 7.80 - 0.00	40	21.6	3,293	71,129	10,435	225,396	0	0	13,728	296,525	24.0	76.0	0.0
Total RM 30.60 - 0.00	Pre-project	-	19,015	356,828	33,028	661,929	1,813	30,854	53,856	1,049,611	35.5	61.0	3.4
	Post-project	-	19,015	365,352	33,028	661,929	1,813	30,854	53,856	1,058,135	33.5	61.0	3.4

1/ Based on 20 years of gage records and information provided by Pacific Power and Light Company.

2/ Riffle width 20.6 yd based on 6.9% increase from cross-section study and pool width 19.3 yds.

Table 2. Skookumchuck River, per cent spawning gravel by section at 40 cfs.

Section	Riffle area sq yds	Per cent composition 1/				Calculated composition in sq yd				Per cent gravel by area
		Boulder	Rubble	Gravel	Sand	Boulder	Rubble	Gravel	Sand	
Falls to Reservoir	59,331	3.4	26.6	62.5	7.5	2,017	15,782	37,082	4,450	16.0
Reservoir	99,818	7.2	8.0	78.3	6.5	7,187	7,985	78,157	6,488	33.7
Subtotal dam to falls	159,149	-	-	-	-	9,204	23,767	115,239	10,938	49.8
Dam to diversion	156,550	5.2	16.4	60.0	18.4	6.581	20,754	75,930	23,285	32.8
Diversion to mouth	71,129	0.0	17.2	56.7	26.1	0.0	12,234	40,330	18.565	17.4
Total	356,828	-	-	-	-	15,785	56,755	231,499	52,788	100.0
Total excl. above reservoir	297,497	-	-	-	-	13,768	40,973	194,417	48,338	84.0
1/2 diversion to mouth	35,565	-	-	-	-	0.0	6,117	20,165	9,283	8.7
Loss above dam & below diversion	194,714	-	-	-	-	9,204	29,884	135,404	20,221	58.5
Loss in reservoir & below diversion	135,383	-	-	-	-	7,187	14,104	98,322	15,771	42.5

1/ Boulder - over 12 inch; rubble - 6-12 inch; gravel - 1-6 inch; sand - less than 1 inch.

Table 3. 1967 adult salmon counts above reservoir limit (RM 34.4 to 27.6).

Date	Chinook			Coho			Net miles surveyed	Area surveyed
	Live	Dead	Redds	Live	Dead	Redds		
October 25, 1967	0	0	0	0	0	0	0.3	Eleven Creek RM 32.3
December 8, 1967	0	0	0	0	0	0	0.5	Twelve Creek RM 34.4
December 8, 1967	0	0	0	0	0	0	0.3	Eleven Creek RM 32.2
December 8, 1967	0	0	0	0	0	1	0.8	Pheeny Creek RM 26.6
December 12, 1967	0	0	0	0	0	0	2.0	Twelve Creek RM 34.3
December 22, 1967	0	0	0	0	0	0	-	Below Falls (spot check) RM 29.2

Table 4. 1967 Adult salmon counts in reservoir (RM 27.3 to 22.8).

Date	Chinook			Coho			Net miles surveyed	Area surveyed
	Live	Dead	Redds	Live	Dead	Redds		
September 15, 1967	4	0	2	0	0	0	3.6	Canyon to Gauge RM 25.7 to 22.1
October 24, 1967	0	0	5	0	0	0	0.5	Gauge to Bloody Run RM 22.1 to 21.6
November 1, 1967	0	0	6	2	0	1	0.5	End of road to Turvey Dam RM 24.5 to 24.0
December 18, 1967	0	0	0	4	0	1	1.2	Quarry to end of road RM 25.7 to 24.5
December 21, 1967	0	0	0	2	2	5	2.9	End of road to Bloody Run RM 24.5 to 21.6
December 22, 1967	0	0	0	0	0	1	0.5	Pheeny Creek to canyon RM 26.6 to approximately 26.1

Table 5. 1967 adult salmon counts between dam and diversion (RM 22.8 to 7.8).

Date	Chinook			Coho			Net miles surveyed	Area surveyed
	Live	Dead	Redds	Live	Dead	Redds		
October 4, 1967	2	0	0	0	0	0	3.5	Bloody Run to Johnson Creek RM 21.6 to 18.1
October 9, 1967	16	1	19	0	0	0	4.8	Tyrell Bridge to Bucoda RM 15.8 to 11.0
October 24, 1967	0	1	42	0	0	0	3.5	Bloody Run to Johnson Creek RM 21.6 to 18.1
November 29, 1967	0	0	26	2	0	2	3.5	Bucoda to pump RM 11.0 to 7.5
November 30, 1967	0	5	21	2	0	1	3.5	Bloody Run to Johnson Creek RM 21.6 to 18.1
December 21, 1967	0	0	0	0	2	0	3.5	Bloody Run to Johnson Creek RM 21.6 to 18.1

Table 6. 1967 adult salmon counts below diversion (RM 7.8 to 0.0).

Date	Chinook			Coho			Net miles surveyed	Area surveyed
	Live	Dead	Redds	Live	Dead	Redds		
October 17, 1967	5	1	5	0	0	0		Spot check RM 2.3
November 28, 1967	0	21	42	0	0	0	7.5	Entire section RM 7.5 to 0.0

Table 7. 1967 adult salmon counts, Hanaford Creek.

Date	Chinook			Coho			Net miles surveyed	Area surveyed
	Live	Dead	Redds	Live	Dead	Redds		
October 27, 1967	0	0	0	2	0	1	1.0	1 mile above road end
December 4, 1967	0	0	0	0	1	1	1.0	1 mile above road end
December 13, 1967	0	0	0	18	3	25	1.5	End of road to forks
December 14, 1967	0	0	0	11	5	22	3.9	Farm to end of road

Table 8. 1968 adult salmon counts above reservoir limit (RM 30.6 to 27.6).

Date	Chinook			Coho			Net miles surveyed	Area surveyed
	Live	Dead	Redds	Live	Dead	Redds		
September 16, 1968	0	0	0	0	0	0	2.0	Old Weyerhauser Bridge to log jam
December 31, 1968	0	0	0	1	0	1	1.2	Lower Falls to Run Creek

Table 9. 1968 adult salmon counts in reservoir (RM 27.3 to 22.8).

Date	Chinook			Coho			Net miles surveyed	Area surveyed
	Live	Dead	Redds	Live	Dead	Redds		
September 30, 1968	0	0	0	0	0	0	2.0	Above Fall Creek to Bloody Run Creek
November 1, 1968	3	1	2	6	0	4	3.1	Turvey Dam to rock quarry
December 21, 1968	0	0	0	14	0	8	3.0	Turvey Dam to below rock quarry

Table 10. 1968 adult salmon counts between dam and diversion (RM 22.8 to 7.8).[1/]

Date	Chinook			Coho			Net miles surveyed	Area surveyed
	Live	Dead	Redds	Live	Dead	Redds		
September 11, 1968	0	1	2	0	0	0	3.8	Bucoda (RM 11.5) to pump (RM 7.7)
September 13, 1968	3	0	1	0	0	0	5.4	Tyrell Bridge (RM 16.9) to Bucoda (RM 11.5)
September 30, 1968	0	0	0	0	0	0	1.0	Bloody Run Creek (RM 22.9) to Pease Ranch
October 1, 1968	1	0	0	0	0	0	6.0	Bloody Run Creek (RM 22.9) to Tyrell Bridge (RM 16.9)
October 10, 1968	1	0	2	0	0	0	3.8	Bucoda (RM 11.5) to pump (RM 7.7)
October 29, 1968	13	0	12	0	0	0	7.8	Skookumchuck Bridge #1 (RM 15.5) to pump (RM 7.7)
October 30, 1968	1	0	1	0	0	0	7.4	Bloody Run (RM 22.9) to Skookumchuck Bridge (RM 15.5)
November 4, 1968	2	2	4	1	0	0	7.4	Bloody Run (RM 22.9) to Skookumchuck Bridge #1 (RM 15.5)
November 22, 1968	0	0	0	2	0	3	0.2	Johnson Creek (RM 19.3)
November 25, 1969	0	0	0	0	0	3	1.0	Thompson Creek (RM 19.5)
November 25, 1968	0	0	0	4	0	7	1.0	Salmon Creek (RM 19.3)
December 5, 1968	0	0	0	3	1	6	0.75	Thompson Creek (RM 19.5)

[1/] Helicopter flight September 12, 1968 tallied 6 live and 7 chinook redds.

Table 11. 1968 adult salmon counts below diversion (RM 7.8 to 0.0).

Date	Chinook			Coho			Net miles surveyed	Area surveyed
	Live	Dead	Redds	Live	Dead	Redds		
September 10, 1968	0	0	0	0	0	0	4.9	507 bridge #2 (RM 4.9) to mouth (RM 0.0)
September 11, 1968	0	0	0	0	0	0	2.8	Pump (RM 7.7) to 507 bridge #2 (RM 4.9)
September 25, 1968	7	0	4	0	0	0	6.8	507 bridge #3 (RM 6.8) to mouth (RM 0.0)
October 10, 1968	0	0	0	0	0	0	0.9	Pump (RM 7.7) to 507 #3 (RM 6.8)
October 28, 1968	16	3	29	0	0	0	7.9	Pump (RM 7.7 to mouth (RM 0.0)

Table 12. 1968 adult salmon counts, Hanaford Creek.

Date	Chinook			coho			Net miles surveyed	Area surveyed
	Live	Dead	Redds	Live	Dead	Redds		
November 6, 1968	0	0	0	8	1	16	3.0	Road end to just above swamp
November 8, 1968	0	0	0	9	1	10	1.8	Road end to halfway between Coal Creek and farm
November 18, 1968	0	0	0	7	0	13	0.4	"Y" in road to bridge above Coal Creek
November 18, 1968	0	0	0	5	0	3	Spot check	Coal Creek
November 20, 1968	0	0	0	42	5	33	3.0	Road end to swamp
November 21, 1968	0	0	0	66	3	69	0.9	Bridge above Coal Creek to road end
November 21, 1968	0	0	0	8	3	10	0.9	First discharge station to bridge above Coal Creek

Table 13. 1969 adult salmon counts above reservoir (RM 30.6 to 27.6).

Date	Flow cfs	Visibility	Section surveyed	Chinook			Coho			Remarks
				Live	Dead	Redds	Live	Dead	Redds	
October 1, 1969	302	Good	Entire	0	0	0	0	0	0	
November 24, 1969		Good	Entire	0	0	0	0	0	0	

Table 14. 1969 adult salmon counts in reservoir (RM 27.3 to 22.8).

Date	Flow cfs	Visibility	Section surveyed	Chinook			Coho			Remarks
				Live	Dead	Redds	Live	Dead	Redds	
July 23, 1969				8	0	0	0	0	0	Fish salvage during diversion
September 3, 1969	25-30	Excellent	Entire	19	0	0	0	0	0	Fish in pools
September 10, 1969		Poor	"	4	0	0	0	0	0	" "
September 17-18, 1969		Poor	"	13	0	1	0	0	0	Fish exploring riffles
September 24, 1969	200	Poor	"	65	0	20	0	0	0	Active spawning
October 6, 1969	115	Good	"	3	1	21	0	0	0	Spawning complete (spring chinook)
October 15, 1969		Good	"	0	0	14	0	0	0	Hamilton and Vaughan
October 23, 1969		Excellent	"	0	0	0	0	0	0	New Bloody Run gage 3.77 ft
October 30, 1969		Excellent	Fall Ck to dam	0	0	0	0	0	0	Hamilton and Vaughan
November 12, 1969	155	Good	Entire	0	0	1	4	0	1	Chinook redd was new
November 19, 1969		Good	"	0	0	0	8	1	5	
November 25, 1969	170	Good	"	0	0	0	7	1	10	
December 3, 1969	145	Fair	"	0	0	0	4	0	8	

Table 15. 1969 adult salmon counts dam to diversion (RM 22.8 to 7.8).

Date	Flow cfs	Visibility	Section surveyed	Chinook			Coho			Remarks
				Live	Dead	Redds	Live	Dead	Redds	
September 2, 1969	25-30	Excellent	RM 22.8 - 15.6	1	2	0	0	0	0	
September 25, 1969	127	Poor[1/]	RM 22.8 - 15.6	24	0	7	0	0	0	Siltation from settling pond
September 25, 1969	127	Poor[1/]	RM 15.6 - 7.8	0	0	0	0	0	0	" " "
September 29, 1969	80	Good	RM 22.8 - 15.6	32	2	7	0	0	0	Spawning essentially over
October 13, 1969		Good	RM 22.8 - 15.6	1	0	8	0	0	0	Hamilton and Vaughan
October 14, 1969		Good	RM 15.6 - 7.8	7	2	15	0	0	0	" "
October 20, 1969	78	Poor[1/]	RM 22.8 - 15.6	8	5	9	0	0	0	3 new fall chinook redds
October 22, 1969		Poor[1/]	RM 15.6 - 7.8	19	2	7	0	0	0	
October 29, 1969		Excellent	RM 15.6 - 7.8	3	0	11	0	0	0	Hamilton and Vaughan
October 30, 1969		Excellent	RM 22.8 - 15.6	0	1	4	0	0	0	" "
November 13, 1969	150	Good	RM 15.6 - 7.8	1	7	8	7	0	4	
November 14, 1969	130	Good	RM 22.8 - 15.6	0	2	0	8	1	5	
November 26, 1969	145	Good	RM 22.8 - 15.6	0	0	0	7	1	20	
November 28, 1969		Fair	RM 15.6 - 7.8	0	0	0	5	0	10	

[1/] Siltation from settling pond.

Table 16. 1969 adult salmon counts diversion to mouth (RM 7.8 to 0.0).

Date	Flow cfs	Visibility	Section surveyed	Chinook			Coho			Remarks
				Live	Dead	Redds	Live	Dead	Redds	
September 26, 1969	127	Poor	Entire	8	0	2	0	0	0	Visibility very poor below Agnew Dam
October 7, 1969	120	Excellent	Entire	40[1/]	-	12	0	0	0	Spawning over
October 14-15, 1969			RM 7.8 to 0.9	1	0	7	1	0	0	Hamilton and Vaughan
October 27-29, 1969		Good	RM 7.8 to 0.9	4	3	10	0	0	0	" "
November 10, 1969	218	Fair	Entire	4	5	5	9	0	4	Visibility very poor below Hanaford Creek
November 20, 1969		Fair	Entire	0	0	1	3	0	8	

1/ Fish count calculated using 3.3 chinook per redd as observed in other sections of river.

Table 17. 1969 adult coho - Hanaford Creek.

Date	Creek condition			Live	Dead	Total	Redds	Remarks
	Flow	Temp.	Visibility					
October 9, 1969				1	0	1	0	Jack, caught while electro fishing
November 21, 1969	Low	44°	Excellent	30	5	35	22	14 redds, 14 live, 3 dead in index
December 1, 1969	Low	35°	Excellent	13	6	19	10	Index area - Jensen
December 10, 1969		42°	Fair	4	2	6	16	Index area - Jensen
December 15, 1969	Rising	40°	Fair	3	1	4	12	Index area - Jensen
December 18, 1969	High	44°	Fair	3	0	3	5	Electro-fishing area - Jensen and Fenton
December 19, 1969	High	44°	Good	6	1	7	5	" " " " "
December 22, 1969	High	41°	Poor	0	0	0	0	Index area visibility poor - Jensen
January 2, 1970	Low	41°	Excellent	0	2	2	0	No new redds spotted (Index area)

Table 18. Summary of timing of runs and major spawning areas for salmon in the Skookumchuck River.

Race and species	Upstream migration period	Upstream migration peak	Spawning period	Spawning peak	Major spawning areas
Spring chinook	Early March to July	May	Early Sept. to mid-Oct.	Late Sept.	1967: Reservoir 1968: Dam to diversion 1969: Reservoir and diversion to mouth
Fall chinook	July to late Nov.	Oct.	Early Oct. to early Dec.	Late Oct. and Nov.	1967: Dam to diversion and diversion to mouth 1968: Diversion to mouth and dam to diversion 1969: Dam to diversion and diversion to mouth
Coho	August to Jan.	Late Oct. Early Nov.	Late Oct. Early Jan.	Late Nov. mid-Dec.	1967: Reservoir and Hanaford Ck. 1968: Reservoir and Hanaford Ck. 1969: Reservoir, dam to diversion, diversion to mouth and Hanaford Creek
Chum[1/]	Sept. to Dec.	Late Oct. Early Nov.	Mid-Oct. through Dec.	Nov.	

1/ None observed but migration period from Chehalis River net fishery and spawning from Wynoochee River data.

Table 19. Skookumchuck River chinook spawning depth and velocity.

Date	Race	Location RM	Flow cfs	Depth ft	Velocity ft/sec.
September 26, 1969	Spring	4.8	127	1.3	1.61
September 29, 1969	"	21.2	80	1.3	1.53
September 29, 1969	"	20.3	80	0.8	0.87
September 29, 1969	"	18.5	80	1.0	0.65
September 29, 1969	"	17.3	80	0.9	1.23
September 29, 1969	"	17.2	80	0.9	3.05
Average including high velocity				1.0	1.49
Average excluding high velocity				1.0	1.18
October 22, 1969	Fall	14.2	80	1.6	1.75
October 22, 1969	"	13.7	80	1.3	1.79
October 22, 1969	"	10.0	80	1.0	1.32
October 24, 1969	"	2.8	83	1.8	1.17
Average	"			1.4	1.51

Table 20. North Pearl Street riffle, October 24, 1969 (flow = 82 cfs).

Location	Distance from right bank, ft	Depth ft	Velocity ft/sec.	Remarks
Cross section 7	5	0.7	2.19	Gravel size is 1 to 3 inches in diameter
" "	15	1.0	2.19	
" "	25	1.1	1.95	
" "	35	0.7	2.33	
" "	45	0.6	1.65	
" "	55	0.7	1.47	
Average		0.8	1.96	
100 ft upstream	5	0.9	1.23	Gravel size is 1 to 8 inches in diameter
" "	15	1.6	1.21	
" "	25	1.8	1.21	
" "	30	1.8	1.05	
" "	35	1.8	1.17	Head of redd
" "	45	1.1	1.29	
" "	50	1.0	1.29	
Average		1.4	1.21	

Table 21. Water sampling stations.

Station	Location
Upper Hanaford Creek	Above last farm in valley
Mid-Hanaford Creek	Second bridge crossing creek above mouth
Packwood Creek	Hanaford Valley road bridge
Overburden Creek	Hanaford Valley road bridge
Coal Pile Drainage	Existing coal storage area
South Hanaford Creek	About 1/2 mile upstream from mouth
North Hanaford Creek	Tona Road bridge
Lower Hanaford Creek	First bridge above mouth
Upper Skookumchuck River	Several sites between old and new U.S.G.S. gages "near Centralia"
Skookumchuck River at Bucoda	Tono Road bridge
Skookumchuck River 0.8 mile upstream from Hanaford Creek	Same
Skookumchuck River 1.6 mile downstream from Hanaford Creek	Same
Skookumchuck River near mouth	Riverside Park in Centralia

Table 22. Upper Hanaford Creek water sampling data, June 3, 1968 through December 10, 1969.

Date	Time	Temp.	DO	Turb.	pH	SO_4	Fe.	Total alka.	Total acid	Free alka.
June 3, 1968	1250	10.56	10.68	11.5	6.84					
June 24, 1968	1325	15.50	9.60	3.0	7.46	0.0				
July 1, 1968	1135	13.90	9.98	2.0	7.51	0.0				
July 8, 1968	1130	16.20	9.57		7.54					
July 16, 1968	1135	13.70	10.32	0.8	7.56	0.7				
July 23, 1968	1150	13.85	10.37	2.3	7.36	0.8				
July 31, 1968	1215	17.35	9.29	3.0	7.56	1.5				
August 8, 1968	1200	14.55	10.10	0.5	7.66	0.2				
August 21, 1968	1245	14.20	9.98	1.1	7.51					
September 4, 1968	1230	13.96	9.62	3.8	7.43					
September 25, 1968	1225	12.23	10.64	1.1	7.36					
October 16, 1968	1330	9.43	9.99	10.3	6.89	0.3				
November 13, 1968	1320	8.25	11.28	7.5	7.09	1.6				
December 3, 1968	1300	8.19	11.09	36.5	7.09	3.3	4.6	10.4	1.8	
December 17, 1968	1220	6.10	11.61	12.5	7.02	0.0	0.9	12.5	1.2	12.8
January 7, 1969	1250	5.78	11.92	32.5	6.71	0.0	4.0	4.1	6.0	7.9
January 21, 1969	1205	2.88	12.64	7.5	6.98	0.0	0.7	10.6	3.9	11.8
February 12, 1969	1125	4.80	12.53	13.8	7.00	0.0	1.3	7.5	4.7	7.1
February 25, 1969	1250	3.52	13.26	5.9	7.03	2.3	0.4	9.5	4.3	15.0
March 18, 1969	1142	6.10	11.96	25.0	6.58	0.0	2.2	21.5	5.4	12.0
April 1, 1969	1304	7.90	11.70	4.1	7.12	0.0	0.4	37.9	5.9	19.0
April 23, 1969	1207	10.28	11.14	14.7	7.10	0.0	1.6	7.0	5.0	
May 22, 1969	1232	14.12	9.98	3.4	7.36	0.2	0.5	17.0	7.0	21.0
June 19, 1969	1205	17.16	8.60	3.5	7.48	0.9	0.4	15.5	11.6	23.0
August 13, 1969	1220	14.86	9.51	3.8	7.57	0.0	0.4	19.0	5.0	25.0
September 22, 1969	1108	13.55	8.61	4.8	7.89	1.1	0.8	85.0	4.4	24.9
October 15, 1969	1214	5.40	11.57	3.4	6.98	0.6	0.5	22.9	4.0	17.4
December 10, 1969	1140	4.85	12.03	11.0	7.22	0.6	1.1	17.8	7.4	16.9

Table 23. Mid-Hanaford Creek water sampling data, June 3, 1968 through December 10, 1969.

Date	Time	Temp.	DO	Turb.	pH	SO_4	Fe.	Total alka.	Total acid	Free alka.
June 3, 1968	1145	11.60	10.00	35.0	6.49					
June 24, 1968	1155	15.31	9.28	4.5	7.09	0.6				
July 1, 1968	1105	14.98	9.27	4.5	7.33	1.5				
July 8, 1968	1100	17.55	8.76		7.39					
July 16, 1968	1105	14.38	9.69	3.50	7.41	2.6				
July 23, 1968	1115	14.35	9.60	4.10	7.42	3.9				
July 31, 1968	1145	18.00	8.48	6.0	7.49	4.4				
August 8, 1968	1131	15.20	9.28	7.5	7.41	5.8				
August 15, 1968	1345	15.30	8.69	5.55	7.10	4.6				
August 21, 1968	1226	14.20	9.63	1.11	7.43					
September 4, 1968	1140	14.24	9.32	4.15	7.29					
September 25, 1968	1148	12.75	9.99	4.15	7.18					
October 6, 1968	1300	9.00	9.57	12.95	6.69	0.5				
November 13, 1968	1240	8.50	10.57	13.80	6.53	0.3				
December 3, 1968	1230	7.76	10.77	27.50	7.04	2.0	3.9	11.5	2.8	
December 17, 1968	1205	5.92	11.25	14.25	6.76	0.3	1.1	13.6	1.9	12.2
January 7, 1969	1230	5.59	11.62	36.50	6.50	0.0	4.0	3.1	6.5	5.4
January 21, 1969	1150	2.55	12.33	9.90	6.79	0.3	1.0	12.2	4.8	10.2
February 12, 1969	1107	4.80	12.32	26.00	6.89	0.0	1.6	7.5	5.6	9.5
February 25, 1969	1308	3.82	13.04	7.50	6.88	0.6	0.5	12.5	3.2	15.0
March 18, 1969	1123	5.95	11.67	30.00	6.50	0.0	2.5	22.5	6.5	11.0
April 1, 1969	1229	7.98	11.48	7.50	7.00	1.1	0.7	35.5	9.7	20.0
April 23, 1969	1152	10.58	10.80	14.25	6.79	0.6	1.6	12.0	7.0	15.0
May 22, 1969	1222	15.75	9.37	7.85	7.12	1.3	0.9	15.0	6.0	22.0
June 19, 1969	1148	18.02	8.43	5.90	7.40	2.3	0.8	18.4	6.8	27.0
August 13, 1969	1205	15.98	9.25	5.55	7.56	2.9	0.8	19.0	5.0	25.0
September 22, 1969	1129	13.72	8.41	7.10	7.53	4.4	1.0	19.5	3.5	25.9
October 15, 1969	1155	5.38	11.41	7.10	5.91	1.6	0.6	22.0	4.4	21.0
December 10, 1969	1125	4.42	11.67	14.25	7.00	0.6	1.6	18.8	7.4	15.7

Table 24. Packwood Creek water sampling data, June 3, 1969 through December 10, 1969.

Date	Time	Temp.	DO	Turb.	pH	SO_4	Fe.	Total alka.	Total acid	Free alka.
June 3, 1968	1130	11.91	9.46	15.0	6.32					
June 24, 1968	1140	15.28	8.66	9.3	6.80	1.8				
July 1, 1968	1053	14.70	7.83	8.3	6.98	0.4				
July 8, 1968	1050	18.45	5.49		7.00					
July 16, 1968	1055	15.52	6.60	8.60	7.17	3.9				
July 23, 1968	1105	15.35	7.14	13.30	7.24	3.6				
July 31, 1968	1135	18.35	5.84	22.00	7.24	0.0				
August 8, 1968	1119	15.38	7.02	27.50	7.39	1.6				
August 15, 1968	1355	15.80	7.26	39.50	7.10	20.7				
August 21, 1968	1145	15.95	6.78	25.00	7.31					
September 4, 1968	1103	13.93	8.38	7.85	6.88					
September 25, 1968	1140	13.10	9.40	5.95	6.62					
October 6, 1968	1225	9.30	8.74	9.90	6.45	7.6				
November 13, 1968	1235	8.65	9.85	8.30	6.50	5.3				
December 3, 1968	1215	7.54	10.09	25.00	6.80	2.3	2.4	7.9	2.6	
December 17, 1968	1145	5.80	10.91	5.95	6.56	4.8	0.6	10.0	3.3	12.5
January 7, 1969	1215	5.38	11.28	28.50	6.28	4.4	2.3	3.6	6.3	6.0
January 21, 1969	1137	2.35	12.29	5.20	6.50	4.9	0.7	8.3	5.8	9.7
February 12, 1969	1055	4.70	12.00	11.60	6.61	3.8	0.8	9.8	4.0	5.7
February 25, 1969	1321	3.82	12.92	5.95	6.59	4.2	0.5	12.0	5.4	12.0
March 18, 1969	1113	6.32	11.17	8.65	6.10	5.2	0.9	12.0	6.5	15.0
April 1, 1969	1215	9.00	11.48	6.30	6.74	4.1	0.9	41.5	10.7	22.0
April 23, 1969	1141	11.00	10.95	5.60	6.61	5.0	1.0	13.0	8.0	27.0
May 22, 1969	1205	15.90	9.97	7.10	7.01	3.2	1.5	2.0	10.0	27.0
June 19, 1969	1131	19.00	5.02	13.80	7.03	0.0	4.0	18.4	10.7	44.5
August 13, 1969	1153	16.48	6.53	15.10	6.94	0.0	2.4	51.0	5.0	68.0
September 22, 1969	1252	14.22	6.11	142.00	7.27	0.0	5.2	34.2	6.6	30.7
October 15, 1969	1143	5.52	10.74	9.10	6.52	12.4	1.2	17.6	5.3	15.6
December 10, 1969	1108	4.42	11.07	21.50	7.41	5.9	2.2	16.7	6.3	10.8

Table 25. Overburden Creek water sampling data, June 3, 1969 through December 10, 1969.

Date	Time	Temp.	DO	Turb.	pH	SO_4	Fe.	Total alka.	Total acid	Free alka.
June 3, 1968	1120	14.42	8.90	42.0	6.67					
June 24, 1968	1130	20.25	7.78	7.0	7.18	0.6				
July 1, 1968	1045	18.87	8.11	9.4	7.42	0.0				
July 8, 1968	1045	17.30	7.58		7.37					
July 16, 1968	1050	15.35	8.89	14.50	7.51	0.0				
July 23, 1968	1100	14.00	8.14	21.00	7.40	0.0				
July 31, 1968	1125	19.60	7.69	22.00	7.50	0.0				
August 8, 1968	1111	14.80	5.50	7.32	7.32	0.0				
August 15, 1968	1405	15.45	6.58	38.00	7.20	0.0				
August 21, 1968	1137	14.25	5.37	38.00	7.04	1.6				
September 4, 1968	1053	16.20	8.02	5.20	6.92					
September 25, 1968	1120	14.48	9.24	6.30	7.00					
October 16, 1968	1215	8.98	9.02	13.35	6.58					
November 13, 1968	1212	7.90	10.27	37.50	6.33	15.8				
December 3, 1968	1145	7.48	10.13	1180.00	6.38	61.5	27.2	59.5	5.8	
December 17, 1968	1110	5.30	11.17	21.00	6.94	16.2	1.5	10.3	2.9	12.3
January 7, 1969	1145	5.08	11.51	112.00	6.44	3.0	6.3	3.6	7.1	4.3
January 21, 1969	1115	2.02	12.18	11.20	6.75	5.7	1.2	9.3	2.9	11.5
February 12, 1969	1029	4.40	12.24	32.50	6.63	9.0	2.1	6.2	4.1	6.2
February 25, 1969	1332	5.70	12.98	9.50	6.70	3.8	1.0	12.5	4.4	15.0
March 18, 1969	1051	6.62	11.11	29.00	6.31	15.4	2.5	21.0	7.5	17.0
April 1, 1969	1154	10.32	12.04	9.50	7.06	5.6	1.7	40.1	6.5	28.0
April 23, 1969	1117	12.68	11.14	26.00	6.82	13.9	2.3	13.0	9.0	17.0
May 22, 1969	1154	20.55	8.73	8.25	7.00	3.2	2.4	24.0	16.0	31.0
June 19, 1969	1112	18.40	6.82	11.20	7.48	0.3	7.5	49.5	12.1	50.5
August 13, 1969	1130	16.91	7.06	4.85	7.30	1.2	1.9	86.0	4.0	105.0
September 22, 1969	1300	14.75	6.19	38.50	7.02	4.5	3.2	38.6	6.2	41.3
October 15, 1969	1117	6.20	9.83	3.15	6.61	44.2	1.5	7.9	7.0	19.2
December 10, 1969	1044	3.90	11.15	9.50	6.66	25.2	1.8	20.9	5.2	16.9

Table 26. Coal Pile Drainage water sampling data, September 25, 1968 through December 10, 1969.

Date	Time	Temp.	DO	Turb.	pH	SO_4	Fe.	Total alka.	Total acid	Free alka.
September 25, 1968	1130	17.65	2.75	35.05	5.41	333.8				
October 16, 1968	1230	8.36	8.88	13.40	6.32					
November 13, 1968	1220	7.83	7.62	26.00	5.58	221.7				
December 3, 1968	1200	7.48	8.87	39.50	5.36	57.8	9.4	28.0	5.2	
December 17, 1968	1130	7.05	3.18	12.00	5.71	264.6	36.5	-22.2	17.5	47.3
January 7, 1969	1200	6.23	7.85	30.00	5.49	381.0	5.9	4.1	5.9	0.0
January 21, 1969	1130	4.62	2.68	9.50	5.72	65.4	25.0	-	16.5	12.6
February 12, 1969	1045	7.00	5.11	13.40	5.98	60.9	13.2	9.8	9.9	23.6
February 25, 1969	1348	14.30	7.01	19.00	5.58	62.9	13.0	30.0	6.4	37.0
March 18, 1969	1103	8.85	3.49	9.90	5.58	62.4	17.0	25.0	50.0	50.0
April 1, 1969	1206	11.65	20.45	26.00	5.79	51.7	12.6	15.3	66.7	36.0
April 23, 1969	1123	16.50	8.17	9.90	5.58	62.4	10.8	23.0	12.0	25.0
May 22, 1969	1147	22.10	5.28	9.90	5.78	60.1	14.0	2.0	32.0	16.0
June 19, 1969	1120	20.18	6.10	27.50	7.19	45.1	21.1	46.6	16.5	48.0
August 13, 1969	1145	21.02	0.00	6.30	6.10	57.2	10.0	23.0	39.0	3.0
September 22, 1969	1320	15.88	4.67	5.85	5.51	72.1	1.7	-12.7	14.9	0.0
October 15, 1969	1123	5.98	5.93	12.50	5.12	54.5	26.4	-11.9	22.9	0.0
December 10, 1969	1055	6.82	0.23	78.50	5.82	68.5	73.0	17.8	30.5	0.0

Table 27. South Hanaford Creek water sampling data, June 3, 1968 through June 19, 1969.

Date	Time	Temp.	DO	Turb.	pH	SO_4
June 3, 1968	1105	13.18	5.96	23.0	6.26	
June 24, 1968	1113	16.69	4.03	8.2	6.39	4.3
July 1, 1968	1030	16.51	2.66	6.3	6.58	6.3
July 8, 1968	1025	19.20	0.86		6.73	
July 16, 1968	1030	15.80	1.47	0.61	6.78	2.9
July 23, 1968	1040	15.48	1.38	3.50	6.73	6.5
July 31, 1968	1105	19.30	0.22	6.30	6.85	0.0
August 8, 1968	1054	14.35	0.79	13.35	7.07	1.3
August 15, 1968	1420	15.00	0.43	7.10	6.80	0.0
August 21, 1968	1120	15.45	2.47	3.80	6.79	22.2
September 4, 1968	1034	15.56	4.27	4.15	6.41	
September 25, 1968	1055	13.90	5.56	4.50	6.32	
October 16, 1968	1200	8.70	5.64	10,30	6.40	
November 13, 1968	1155	7.70	7.23	9.50	6.49	7.1
December 3, 1968	1120	7.32	8.54	5.55	6.53	4.6
December 17, 1968	1055	5.10	8.54	6.70	6.78	5.4
January 7, 1969	1125	4.99	9.49	14.70	6.41	0.0
January 21, 1969	1055	2.08	10.44	5.20	6.55	5.3
February 12, 1969	1012	4.88	8.59	7.45	6.73	1.1
February 25, 1969	1402	4.60	11.63	6.70	6.18	7.3
March 18, 1969	1033	6.30	8.28	12.95	6.25	3.6
April 1, 1969	1136	9.50	8.47	5.95	6.41	7.2
April 23, 1969	1101	11.42	8.52	5.60	6.32	5.9
May 22, 1969	1117	16.20	4.18	4.15	6.45	5.4
June 19, 1969	1058	19.22	0.12	7.10	7.07	2.9

Table 28. North Hanaford Creek water sampling data, June 3, 1968 through December 10, 1969.

Date	Time	Temp.	DO	Turb.	pH	SO_4	Fe.	Total alka.	Total acid	Free alka.
June 3, 1968	1330	13.03	9.24	12.0	6.55	37.0				
June 24, 1968	1410	19.10	9.56	3.5	7.09	50.8				
July 1, 1968	1300	18.85	8.69	3.1	7.31	33.8				
July 8, 1968	1210	20.75	7.82		7.33					
July 16, 1968	1305	17.24	8.45	0.51	7.31	44.4				
July 23, 1968	1255	17.30	8.40	2.30	7.68	55.8				
July 31, 1968	1422	21.70	7.74	3.00	7.69	48.4				
August 8, 1968	1328	18.25	8.48	2.80	7.64	57.5				
August 15, 1968	1334	17.85	7.71	2.80	7.40	60.8				
August 21, 1968	1310	16.45	8.50	1.36	7.63					
September 4, 1968	1252	16.51	8.14	1.11	7.35					
September 25, 1968	1405	14.80	9.40	3.65	7.30					
October 16, 1968	1345	9.95	9.16	12.50	6.90	31.1				
November 13, 1968	1405	9.15	7.66	14.65	6.57	25.8				
December 3, 1968	1335	8.55	8.37	21.00	6.58	32.8	1.7	62.4	0.0	
December 17, 1968	1300	7.35	9.01	9.50	6.59	44.2	1.0	62.0	0.0	68.1
January 7, 1969	1330	6.22	10.13	23.00	6.47	21.3	1.9	29.8	5.9	29.9
January 21, 1969	1225	5.02	9.03	7.30	6.61	44.0	1.2	34.5	5.8	38.6
February 12, 1969	1145	5.92	9.43	12.90	6.72	28.2	1.3	52.0	3.7	51.1
February 25, 1969	1235	7.18	8.08	6.70	6.41	53.1	0.8	70.0	21.4	126.0
March 18, 1969	1206	7.10	10.06	13.80	6.44	28.4	1.5	54.0	11.0	64.0
April 1, 1969	1324	9.98	10.01	7.10	6.82	41.13	0.8	120.7	10.2	124.0
April 23, 1969	1229	11.45	11.29	7.50	6.70	41.2	0.8	65.0	10.0	66.0
May 22, 1969	1317	18.45	9.67	2.85	7.08	61.3	0.2	90.0	10.0	151.0
June 19, 1969	1224	20.18	8.62	1.36	7.33	68.4	0.2	73.7	16.5	204.5
August 13, 1969	1238	17.22	7.30	7.10	7.21	45.0	0.5	72.0	61.0	311.0
September 22, 1969	1047	14.92	7.23	3.50	7.31	61.7	0.3	171.4	0.0	210.0
October 15, 1969	1249	6.42	8.40	4.50	7.02	40.0	0.3	191.8	0.0	169.3
December 10, 1969	1158	5.38	10.31	7.85	6.86	37.7	1.4	96.5	7.4	92.8

Table 29. Lower Hanaford Creek water sampling data, June 3, 1968 through December 10, 1969.

Date	Time	Temp.	DO	Turb.	pH	SO_4	Fe.	Total alka.	Total acid	Free alka.
June 3, 1968	1055	13.31	6.07	27.00	6.28					
June 24, 1968	1055	17.02	6.36	10.50	6.61	2.8				
July 1, 1968	1015	16.75	6.47	7.30	6.97	2.2				
July 8, 1968	1015	20.55	5.34		7.14					
July 16, 1968	1020	16.85	7.23	4.10	7.09	5.0				
July 23, 1968	1030	16.68	7.33	6.70	7.11	5.4				
July 31, 1968	1050	20.39	5.62	6.50	7.10	5.0				
August 8, 1968	1043	16.85	6.02	8.20	7.10	4.5				
August 15, 1968	1430	17.40	4.90	10.30	6.80	6.7				
August 21, 1968	1110	16.15	7.27	9.10	7.11					
September 4, 1968	1022	15.79	6.37	8.25	6.79					
September 25, 1968	1045	13.50	7.48	7.10	6.72					
October 16, 1968	1145	8.13	7.49	12.00	6.64					
November 13, 1968	1140	7.86	6.80	12.05	6.52	10.1				
December 3, 1968	1110	7.49	9.41	11.20	6.80	3.6	1.7	7.2	4.5	
December 17, 1968	1037	5.50	9.43	9.90	7.11	4.8	1.0	12.6	2.4	14.2
January 7, 1969	1115	5.26	9.29	14.70	6.50	27.4	1.5	8.3	7.5	7.9
January 21, 1969	1045	2.22	10.82	8.30	7.09	6.8	1.0	10.8	11.6	15.1
February 12, 1969	1002	5.08	9.94	23.50	7.06	2.8	1.4	6.2	5.6	7.1
March 18, 1969	1022	6.38	9.82	25.00	6.53	4.0	1.9	21.5	9.7	19.0
April 1, 1969	1126	8.78	9.80	7.50	6.78	4.4	1.2	41.5	10.7	26.0
April 23, 1969	1050	11.10	8.76	14.25	6.63	5.4	2.0	16.0	10.8	18.0
May 22, 1969	1104	15.60	6.22	9.10	6.88	2.4	1.8	24.0	6.0	29.0
June 19, 1969	1045	21.25	5.05	7.50	7.01	3.7	2.8	32.0	11.2	47.0
August 13, 1969	1110	16.77	5.21	6.30	7.24	6.1	1.7	27.0	8.0	30.0
September 22, 1969	1326	14.50	5.63	12.45	6.55	14.4	1.5	19.0	4.4	26.4
October 15,1969	1101	6.00	9.54	8.60	6.87	8.1	1.0	22.0	5.7	18.8
December 10, 1969	1026	4.70	10.24	13.80	6.72	5.8	1.8	17.8	6.3	22.9

Table 30. Upper Skookumchuck River water sampling data, June 3, 1968 through December 10, 1969.

Date	Time	Temp.	DO	Turb.	pH	SO_4	Fe.	Total alka.	Total acid	Free alka.
June 3, 1968	1430	11.36	11.02	12.00	7.51					
June 24, 1968	1505	16.35	9.92	1.6	7.52	0.0				
July 1, 1968	1400	16.80	9.94	0.3	7.70	0.0				
July 8, 1968	1320	18.75	9.40		7.70					
July 16, 1968	1404	15.15	10.17	0.25	7.61	1.8				
July 23, 1968	1400	16.05	10.31	1.30	7.71	0.4				
July 31, 1968	1530	20.55	-	0.3	7.89	0.0				
August 8, 1968	1435	17.30	9.77	0.47	7.74	0.3				
August 15, 1968	1230	15.00	9.12	0.38	-	0.3				
August 21, 1968	1404	15.20	10.32	0.38	7.73					
September 4, 1968	1400	14.11	10.29	0.29	7.80					
September 25, 1968	1500	11.78	11.24	0.38	7.76					
October 16, 1968	1420	8.30	10.64	7.10	7.23	0.3				
November 13, 1968	1500	7.90	11.67	11.15	7.20	1.1				
December 3, 1968	1430	7.48	11.48	27.50	7.26	1.9	4.6	10.6	0.6	
December 17, 1968	1350	5.80	-	7.90	7.26	0.0	0.5	12.3	0.5	13.6
January 7, 1969	1410	5.68	12.05	41.00	6.98	0.0	4.0	3.1	6.3	10.9
January 21, 1969	1323	2.95	12.59	5.20	7.20	0.4	0.4	17.1	3.9	17.9
February 12, 1969	1235	4.88	12.48	41.00	7.25	0.0	1.8	7.8	5.0	10.4
February 25, 1969	1125	3.82	13.03	4.15	7.25	0.3	0.4	12.0	2.8	19.0
March 18, 1969	1305	5.45	12.26	12.50	6.90	0.0	0.9	24.0	5.4	15.0
April 1, 1969	1435	7.15	12.08	3.45	7.26	1.0	0.2	32.5	7.5	20.0
April 23, 1969	1337	8.65	11.76	12.50	7.42	0.0	0.9	8.0	7.0	17.0
May 22, 1969	1421	14.45	10.68	0.83	7.63	0.0	0.1	12.0	4.0	21.0
June 19, 1969	1307	16.80	9.28	1.36	7.50	0.3	0.1	7.8	4.9	15.0
August 13, 1969	1355	18.91	10.05	4.15	7.76	0.0	0.1	22.0	0.0	27.0
September 22, 1969	1010	13.20	8.88	3.85	7.86	1.8	0.2	24.0	3.5	25.9
October 15, 1969	1331	6.98	11.99	3.65	7.41	0.6	0.1	24.6	2.2	16.5
December 10, 1969	1322	5.15	13.13	5.20	7.32	0.3	0.5	24.1	5.2	19.3

Table 31. Skookumchuck River at Bucoda water sampling data, June 3, 1968 through December 10, 1969.

Date	Time	Temp.	DO	Turb.	pH	SO_4	Fe.	Total alka.	Total acid	Free alka.
June 3, 1968	1345	11.02	10.76	14.20	6.88					
June 24, 1968	1430	17.30	10.12	2.10	7.36	0.0				
July 1, 1968	1320	17.15	9.92	0.60	7.61	0.0				
July 8, 1968	1225	19.55	9.32		7.59					
July 16, 1968	1325	15.98	10.68	0.33	7.64	0.7				
July 23, 1968	1320	16.15	10.80	1.51	7.75	0.2				
July 31, 1968	1440	22.00	9.70	0.10	7.82	0.6				
August 8, 1968	1343	17.40	10.67	0.47	7.98	1.7				
August 15, 1968	1328	16.20	8.87	0.38	7.30	0.0				
August 21, 1968	1340	15.45	10.35	0.94	7.65					
September 4, 1968	1317	15.69	9.74	0.72	7.52					
September 25,1968	1420	13.50	10.61	0.77	7.67					
October 16, 1968	1400	8.15	10.45	6.85	7.30	0.3				
November 13, 1968	1420	7.78	11.14	13.20	7.03	1.1				
December 3, 1968	1350	7.43	11.26	14.70	7.09	1.5	2.1	14.3	0.0	
December 17, 1968	1320	5.95	11.61	6.35	7.14	0.0	0.5	11.2	2.3	15.3
January 7, 1969	1345	5.55	11.88	27.00	7.06	0.0	5.0	2.1	5.8	8.2
January 21, 1969	1300	3.18	12.25	3.80	7.18	1.8	0.5	57.7	3.9	17.9
February 12, 1969	1204	4.90	12.45	28.50	7.41	0.0	1.6	11.3	5.0	10.4
February 25, 1969	1205	4.38	12.76	3.80	6.91	0.3	0.3	20.5	1.6	20.0
March 18, 1969	1241	5.65	12.17	14.70	6.97	0.0	1.3	26.0	5.4	14.0
April 1, 1969	1407	7.05	12.01	4.15	7.37	0.7	0.2	36.8	17.2	21.0
April 23, 1969	1244	9.05	11.64	4.85	7.31	0.8	0.4	10.0	5.0	16.0
May 22, 1969	1343	15.70	10.68	1.30	7.56	0.5	0.3	18.0	5.0	20.0
June 19, 1969	1239	18.60	9.14	0.83	7.64	0.8	0.1	18.4	5.8	26.5
August 13, 1969	1320	17.08	9.99	2.50	7.81	2.3	0.1	22.0	0.0	30.0
September 22, 1969	1031	13.60	8.53	1.47	7.60	0.3	0.2	23.5	2.2	25.4
October 15, 1969	1305	6.60	11.44	3.80	7.60	1.2	0.2	21.5	2.64	16.5
December 10, 1969	1214	4.82	12.07	6.70	7.48	0.0	0.6	25.1	6.3	20.5

Table 32. Skookumchuck River 0.8 miles upstream from Hanaford Creek water sampling data, June 3, 1968 through December 10, 1969.

Date	Time	Temp.	DO	Turb.	pH	SO_4	Fe.	Total alka.	Total acid	Free alka.
June 3, 1968	1030	11.29	10.44	32.00	6.84					
June 24, 1968	1035	15.85	9.19	2.2	7.22	0.0				
July 1, 1968	1000	15.90	9.06	0.5	7.42	0.0				
July 8, 1968	1000	19.92	8.06		7.35					
July 16, 1968	1005	15.98	9.27	0.21	7.43	0.6				
July 23, 1968	1020	16.15	9.05	0.94	7.42	0.4				
July 31, 1968	1040	19.65	7.68	0.55	7.34	0.0				
August 8, 1968	1030	16.45	8.61	0.42	7.48	1.0				
August 15, 1968	1450	17.65	8.63	0.47	7.30	0.4				
August 21, 1968	1100	15.50	9.27	0.47	7.59					
September 4, 1968	1010	15.42	9.02	0.94	7.35					
September 25, 1968	1030	12.85	10.07	0.72	7.32					
October 16, 1968	1135	8.15	10.18	9.10	6.95					
November 13, 1968	1050	7.70	10.93	14.25	6.90	2.1				
December 3, 1968	1050	7.19	11.30	8.25	7.29	0.9	1.3	14.8	0.5	
December 17, 1968	1022	5.85	11.39	7.50	7.30	0.3	0.6	15.1	0.0	18.9
January 7, 1969	1100	5.50	11.23	37.00	6.78	0.0	4.1	9.9	5.9	10.3
January 21, 1969	1027	3.08	12.18	5.55	7.11	1.5	0.5	18.5	4.8	21.6
February 12, 1969	0945	4.70	12.37	26.00	7.23	0.0	1.8	9.5	5.2	11.4
March 18, 1969	1008	5.60	11.99	26.00	6.83	2.4	1.7	23.0	5.4	15.0
April 1, 1969	1112	7.30	11.67	3.80	7.10	0.6	0.6	31.4	4.3	21.0
April 23, 1969	1031	9.15	11.22	3.85	7.13	0.6	0.5	12.0	10.2	15.0
May 22, 1969	1047	14.42	9.95	2.50	7.46	0.7	0.3	11.0	3.0	23.0
June 19, 1969	1032	19.72	7.75	0.42	7.42	0.4	0.1	7.8	4.9	28.5
August 13, 1969	1053	16.59	8.82	0.88	7.48	0.0	0.2	23.0	5.0	28.0
September 22, 1969	1351	14.48	8.36	0.82	7.11	0.9	0.1	23.5	0.0	25.4
October 15, 1969	1045	5.68	11.40	3.80	7.18	0.3	0.3	18.5	5.72	18.8
December 10, 1969	1005	4.88	11.90	5.95	7.27	0.8	0.8	25.1	3.2	15.7

Table 33. Skookumchuck River 1.6 miles downstream from Hanaford Creek water sampling data, June 3, 1968 through December 10, 1969.

Date	Time	Temp.	DO	Turb.	pH	SO_4	Fe.	Total alka.	Total acid	Free alka.
June 3, 1968	1015	11.68	9.60	35.00	6.69					
June 24, 1968	1020	16.00	9.27	2.80	7.04	0.5				
July 1, 1968	0945	15.90	9.23	1.10	7.38	0.0				
July 8, 1968	0945	23.00	8.29		7.28					
July 16, 1968	0950	16.49	9.47	0.40	7.45	2.4				
July 23, 1968	1000	16.48	9.32	0.72	7.51	0.3				
July 31, 1968	1020	20.65	8.12	0.55	7.48	1.5				
August 8, 1968	1015	17.55	9.27	0.37	7.56	0.5				
August 15, 1968	1500	17.70	9.12	0.67		0.3				
August 21, 1968	1045	15.95	9.43	0.94	7.43					
September 4, 1968	0952	15.49	8.99	1.95	7.29					
September 25, 1968	1015	13.23	10.10	1.05	7.31					
October 16, 1968	1115	8.50	9.85	11.60	7.19					
November 13, 1968	1040	7.78	10.08	13.35	6.93	2.4				
December 3, 1968	1030	7.13	11.03	14.70	7.18	1.2	2.5	15.3	2.4	
December 17, 1968	1010	5.95	11.11	9.10	7.23	1.4	0.8	13.15	1.0	18.0
January 7, 1969	1045	5.93	11.35	42.50	6.79	0.0	7.0	8.8	5.8	9.3
January 21, 1969	1010	2.95	12.03	6.70	6.96	2.6	0.8	15.1	4.8	18.9
February 12, 1969	0922	4.82	12.08	21.00	7.42	0.0	1.9	7.8	4.1	9.5
February 25, 1969	0905	3.95	12.56	4.50	7.28	2.7	0.6	19.5	3.2	24.0
March 18, 1969	0952	5.92	11.70	27.50	6.72	1.2	1.9	21.5	5.4	14.0
April 1, 1969	1048	7.75	11.52	1.42	7.28	2.2	0.5	30.4	4.3	23.0
April 23, 1969	1017	9.65	10.99	5.20	7.12	1.3	0.6	8.0	10.0	18.0
May 22, 1969	1031	15.03	9.91	3.15	7.42	0.7	0.5	13.0	4.0	24.0
June 19, 1969	1015	20.20	7.75	0.99	7.38	0.5	0.3	11.6	5.8	26.5
August 13, 1969	1035	17.38	9.34	0.99	7.28	0.0	0.3	19.0	5.0	29.0
September 22, 1969	1407	14.60	7.60	31.50	7.15	1.9	2.7	19.0	4.4	21.1
October 15, 1969	1028	5.82	11.37	5.20	7.12	2.0	0.5	23.7	4.84	21.9
December 10, 1969	0945	4.85	11.65	10.30	7.34	3.7	1.2	22.0	3.2	20.5

Table 34. Skookumchuck River near mouth water sampling data, June 3, 1968 through June 19, 1969.

Date	Time	Temp.	DO	Turb.	pH	SO_4
June 3, 1968	0945	11.99	9.73	32.00	6.82	
June 24, 1968	1003	15.85	9.41	3.00	7.24	2.9
July 1, 1968	0930	15.65	9.45	1.20	7.34	2.0
July 8, 1968	0930	23.00	8.67		7.33	
July 16, 1968	0925	16.45	9.84	0.55	7.62	0.5
July 23, 1968	0940	16.38	9.16	0.88	7.48	1.4
July 31, 1968	1002	20.30	8.23	0.70	7.47	0.6
August 8, 1968	0950	17.15	9.00	0.82	7.58	2.5
August 15, 1968	1545	17.85	9.83	0.52	7.40	0.4
August 21, 1968	1030	16.01	9.68	0.72	7.42	
September 4, 1968	0933	15.44	9.09	1.42	7.35	
September 25, 1968	0955	13.10	10.21	1.29	7.30	
October 16, 1968	1100	8.55	9.81	13.80	7.47	
November 13, 1968	1025	7.85	10.12	14.25	7.53	3.9
December 3, 1968	1010	7.01	11.05	26.00	7.10	0.0
December 17, 1968	0955	5.95	11.37	7.10	7.32	1.5
January 7, 1969	1025	5.95	11.37	34.00	7.06	8.7
January 21, 1969	0955	2.85	12.15	5.55	7.32	2.0
February 12, 1969	0910	4.85	11.98	22.50	7.87	0.0
February 25, 1969	0923	4.05	12.69	5.20	7.04	1.6
March 18, 1969	0945	6.05	11.64	34.00	7.11	1.3
April 1, 1969	1044	7.88	11.52	3.50	7.37	5.6
April 23, 1969	1000	9.70	11.03	4.85	7.19	0.6
May 22, 1969	1019	15.05	10.19	3.45	7.21	0.8
June 19, 1969	1007	20.38	8.00	0.62	7.30	0.5

Table 35. Results of live box tests in Hanaford Valley, March 14 through 18, 1969.

Station	Box[1/]	Number fish	Cumulative number dead			Cumulative per cent dead			Temp. range	
			24 hours	48 hours	96 hours	24 hours	48 hours	96 hours	Maximum	Minimum
Upper Hanaford Creek	Surface	25	0	0	0	0	0	0		
	Bottom	25	0	0	0	0	0	0	48°	48°
	Combined	50	0	0	0	0	0	0		
Mid Hanaford Creek	Surface LB	25	0	0	0	0	0	0		
	Surface RB	25	0	0	0	0	0	0		
	Bottom LB	25	0	0	0	0	0	0	49°	49°
	Bottom RB	25	0	0	0	0	0	0		
	Combined	100	0	0	0	0	0	0		
Lower Hanaford Creek	Surface LB	25	0	0	0	0	0	0		
	Surface RB	25	0	0	0	0	0	0		
	Bottom LB	25	0	0	0	0	0	0	49°	49°
	Bottom RB	25	0	0	0	0	0	0		
	Combined	100	0	0	0	0	0	0		
No. Hanaford	Surface	17	0	0	0	0	0	0	51°	49°
Overburden Cr.	Surface	25	-	0	0	-	0	0	52°	52°
Coal Pile	Surface	25	-	0	0	-	0	0	54°	53°
Coal Pit	Surface	25	-	-	-	-	-	-	-	-

[1/] LB = Left Bank, RB = Right Bank.

Table 36. Results of live box tests in Hanaford Valley, May 19 through 23, 1969.

Station	Box[1/]	Number fish	Cumulative number dead			Cumulative per cent dead			Temp. range	
			24 hours	48 hours	96 hours	24 hours	48 hours	96 hours	Maximum	Minimum
Upper Hanaford Creek	Surface	15	0	10	10	0	66.7	66.7		
	Bottom	15	0	3	3	0	20.0	20.0	61°	54°
	Combined	30	0	13	13	0	43.3	43.3		
Mid Hanaford Creek	Surface LB	25	0	2	3	0	8.0	12.0		
	Surface RB	25	0	2	2	0	8.0	8.0		
	Bottom LB	25	0	1	4	0	4.0	16.0	62°	54°
	Bottom RB	25	0	0	0	0	0.0	0.0		
	Combined	100	0	5	9	0	5.0	9.0		
Lower Hanaford Creek	Surface LB	25								
	Surface RB	25								
	Bottom LB	25	Fish released by unknown person							
	Bottom RB	25								
	Combined	100								
Overburden Cr.	Surface	25	0	1	1	0	4.0	4.0	74°	59°
Coal Pile	Surface	25	7	12	14	28.0	48.0	56.0	85°	62°
Coal Pit	Surface	25	5	8	10	20.0	32.0	40.0		
	3 feet	25	7	9	11	28.0	36.0	44.0	74°	64°
	Combined	50	12	17	21	24.0	34.0	42.0		

[1/] LB = Left Bank, RB = Right Bank.

Table 37. Results of live box tests in Hanaford Valley, June 16 through 20, 1969.

Station	Box[1/]	Number fish	Cumulative number dead			Cumulative per cent dead			Temp. range	
			24 hours	48 hours	96 hours	24 hours	48 hours	96 hours	Maximum	Minimum
Upper Hanaford Creek[2/]	Surface LB	8	4	4	4	50.0	50.0	50.0		
	Surface RB	8	0	0	0					
	Bottom LB	8	2	2	3	25.0	25.0	37.5	63°	63°
	Bottom RB	8	0	0	0					
	Combined	16	6	6	7	37.5	37.5	43.7		
Mid Hanaford Creek	Surface LB	8	5	5	7	62.5	62.5	87.5		
	Surface RB	8	3	3	8	37.5	37.5	100.0		
	Bottom LB	8	5	5	7	62.5	62.5	87.5	66°	65°
	Bottom RB	-	-	-	-					
	Combined	24	13	13	22	54.2	54.2	91.7		
Lower Hanaford Creek	Surface LB	8	1	1	7	12.5	12.5	87.5		
	Surface RB	8	6	7	7	75.0	87.5	87.5		
	Bottom LB	8	4	4	5	50.0	50.0	62.5	66°	65°
	Bottom RB	8	5	6	8	62.5	75.0	100.0		
	Combined	32	16	18	27	50.0	56.3	84.4		
Overburden Cr.	Surface	8	2	4	4	25.0	50.0	50.0	69°	66°
Coal Pile	Surface	8	8	8	8	100.0	100.0	100.0	77°	77°
Coal Pit	Surface	8	8	8	8	100.0	100.0	100.0		
	Bottom	8	3	3	6	26.7	26.7	75.0	76°	74°
	Combined	16	11	11	14	68.7	68.7	87.5		

[1/] LB = Left Bank, RB = Right Bank.
[2/] Right Bank boxes not used in combined data.

Table 38. Western Washington salmon production per square mile drainage area (watershed).

Species	Commercial catch	Sport catch	Total catch	Spawners[1/] per square mile watershed
Chinook	34.23	16.12	50.35	12.59
Coho	81.73	28.22	109.95	36.65
Chum	65.44	0.00	65.44	32.72

1/ Catch to escapement ratio 4:1 chinook, 3:1 coho, 1:1 chum.

Table 39. Puget Sound salmon spawners per square mile drainage area (watershed).

Species	Square miles watershed	Total production	Catch	Escapement	Spawners per square mile watershed
Chinook	12,154	189,360[1/]	151,488	37,872	3.12
Coho	12,154	1,181,420[1/]	886,065	295,355	24.30
Chum	12,154	879,874[2/]	439,937	439,937	36.20

1/ Based on Puget Sound Basin Study (1968) and catch to escapement ratios of 4:1 for chinook and 3:1 for coho.

2/ Based on 1946 through 1966 average Puget Sound net catch of 439,937 chum and catch to escapement ratio of 1:1.

Table 40. Grays Harbor salmon spawners per square mile drainage area (watershed).

Species	Square miles watershed	Total[1/] production	Catch	Escapement	Spawners per square mile watershed
Chinook	2,547	76,990	61,592	15,398	6.06
Coho	2,547	256,600	192,450	64,150	25.19
Chum	2,547	25,494	12,747	12,747	5.00

1/ Based on 10-year average (1960 through 1969) by Deschamps and catch to escapement ratios of 4:1, 3:1, and 1:1 for chinook, coho, and chum, respectively.

Table 41. Skookumchuck River, less Hanaford Creek, total salmon spawners based on calculated escapements for Western Washington, Puget Sound, and Grays Harbor.

Species	Spawners per square mile watershed			Skookumchuck River calculated number of spawners based on 127 square miles watershed			
	Western Washington	Puget Sound	Grays Harbor	Western Washington data	Puget Sound data	Grays Harbor data	Average
Chinook	12.59	3.12	6.06	1,599	396	770	922
Coho	36.65	24.30	25.19	4,655	3,086	3,199	3,647
Chum	32.72	36.20	5.00	4,155	4,597	635	3,129

Table 42. Distribution of salmon spawners in the Skookumchuck River based on available spawning gravel and total escapement figures of 922 fall chinook, 3,647 coho, and 3,129 chum.

Section	Available spawning gravel sq yards	Per cent spawning gravel by section	Coho numbers of fish	Available spawning gravel excluding falls to reservoir sq yards	Per cent available spawning gravel by section	Fall chinook numbers of fish	Chum numbers of fish
Falls to reservoir	37,082	16.0	583	-	-	-	-
Reservoir	78,157	33.8	1,233	78,157	40.2	371	1,258
Loss above dam	115,239	49.8	1,816	78,157	40.2	371	1,258
Dam to diversion	75,930	32.8	1,196	75,930	39.1	360	1,223
Diversion to mouth	40,330	17.4	635	40,330	20.7	191	648
50% below diversion	20,165	8.7	317	20,165	10.4	96	325
Total	231,499	100.0	3,647	194,417	100.0	922	3,129
Total loss	135,404	58.5	2,133	98,322	50.6	467	1,583

Table 43. Skookumchuck River, less Hanaford Creek, potential coho smolt production by section at 40 cfs.

Section	August flow cfs	Rearing area in sq yd in Aug.	Minter Creek 49.5 smolts per 100 sq yd	Alsea Streams 35 smolts per 100 sq yd	Speelyai Creek 26.6 smolts per 100 sq yd	Big Qualicum 1965 16 smolts per 100 sq yd	Speelyai Creek 2.13 smolts per linear yd of stream	Big Qualicum 1966 2 smolts per linear yd of stream
Falls to reservoir RM 30.60-27.60	40	75,504	37,374	26,426	20,084	12,081	11,246	10,560
Reservoir RM 26.60-22.85	40	166,364	82,350	58,227	44,253	26,618	17,807	16,720
Dam to diversion RM 22.85-7.80	40	511,218	253,053	178,926	135,984	81,795	56,419	52,976
	115	519,742	257,272	181,910	138,251	83,159	56,419	52,976
Diversion to mouth RM 7.80-0.00	40	296,525	146,780	103,784	78,876	47,444	29,241	27,456
Total at 40 cfs	40	1,049,611	519,557	367,364	279,196	167,938	114,713	107,712

Table 44. Skookumchuck River, less Hanaford Creek, net loss of coho production after project development based on loss of rearing area.

Section	August flow cfs	Riffle: Pool: Rapid ratio	Method	Gain		Loss	
				Smolts	Adults	Smolts	Adults
Falls to reservoir	40	79:4:18	Minter Creek			37,374	374
Reservoir	40	60:30:10	Minter Creek			82,350	823
Dam to diversion	115	25:75:0	Big Qualicum 1965	1,364	13		
Diversion to mouth	40	24:76:0	1/2 Big Qualicum 1965			23,722	237
Total				1,364	13	143,446	1,434
Net loss						142,082	1,421

A P P E N D I X II

Figures 1 through 16

Pages 66 through 81

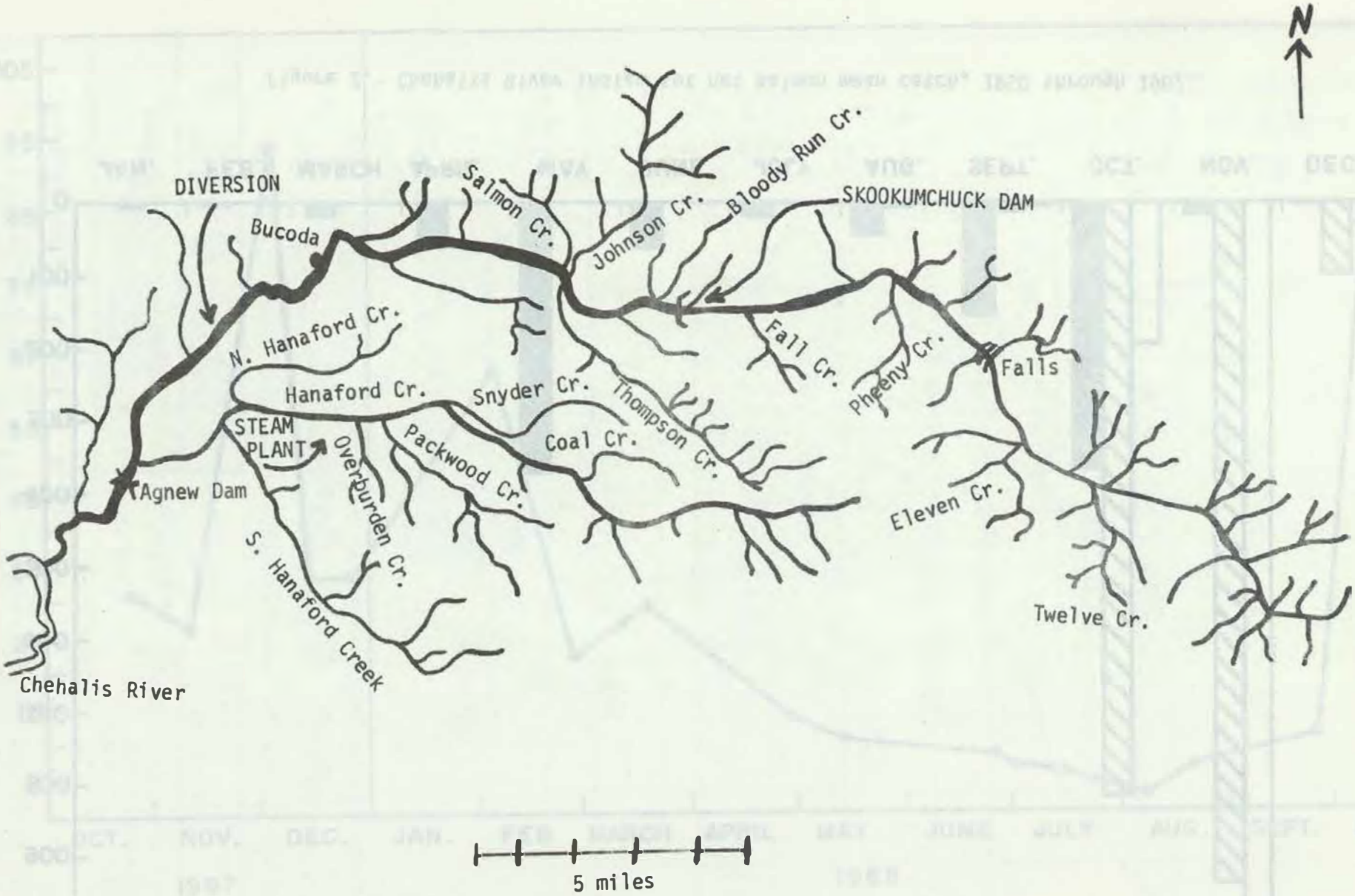


Figure 1. Sketch of Skookumchuck River and features mentioned in text.

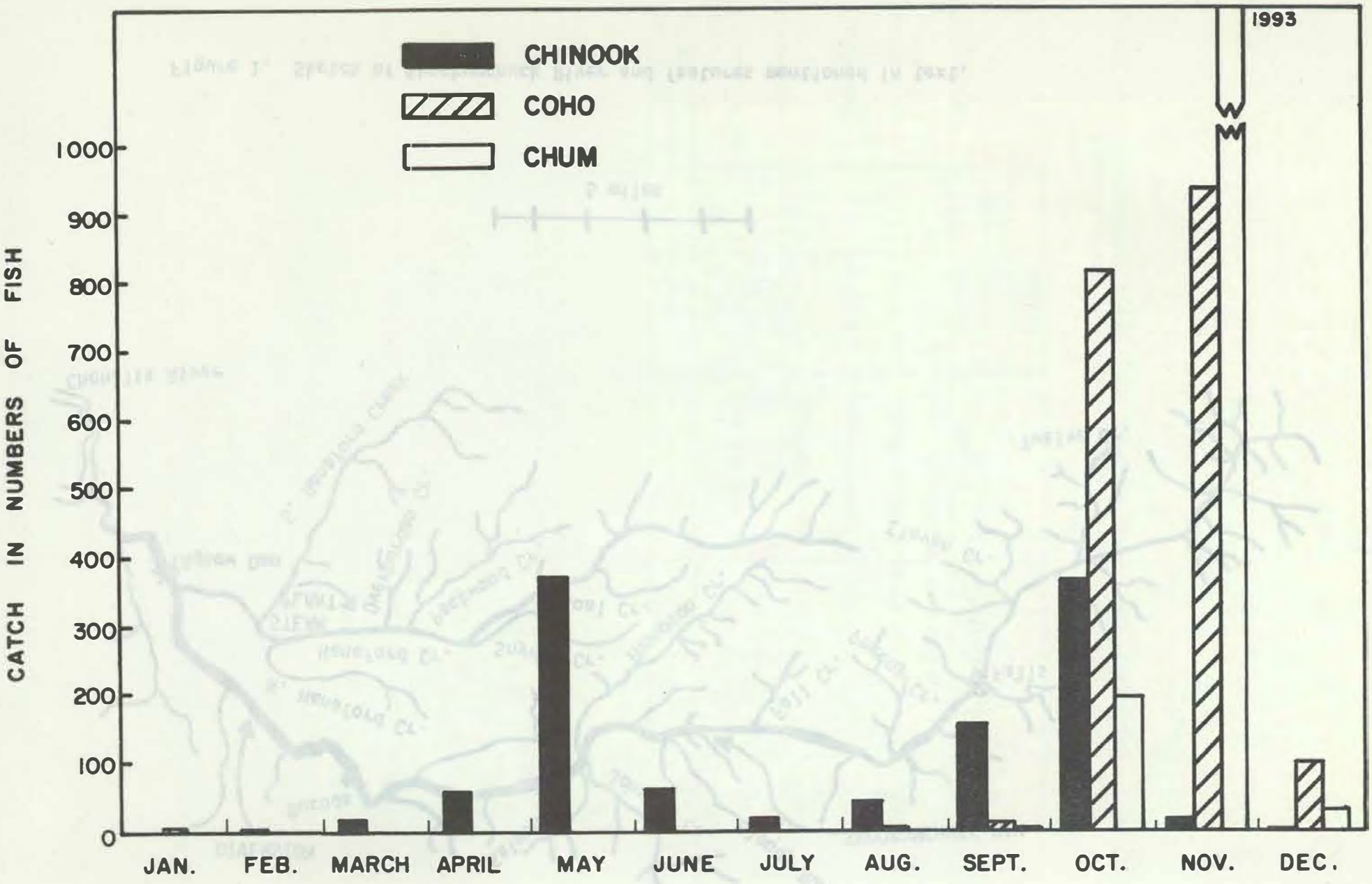


Figure 2. Chehalis River Indian set net salmon mean catch, 1950 through 1967.

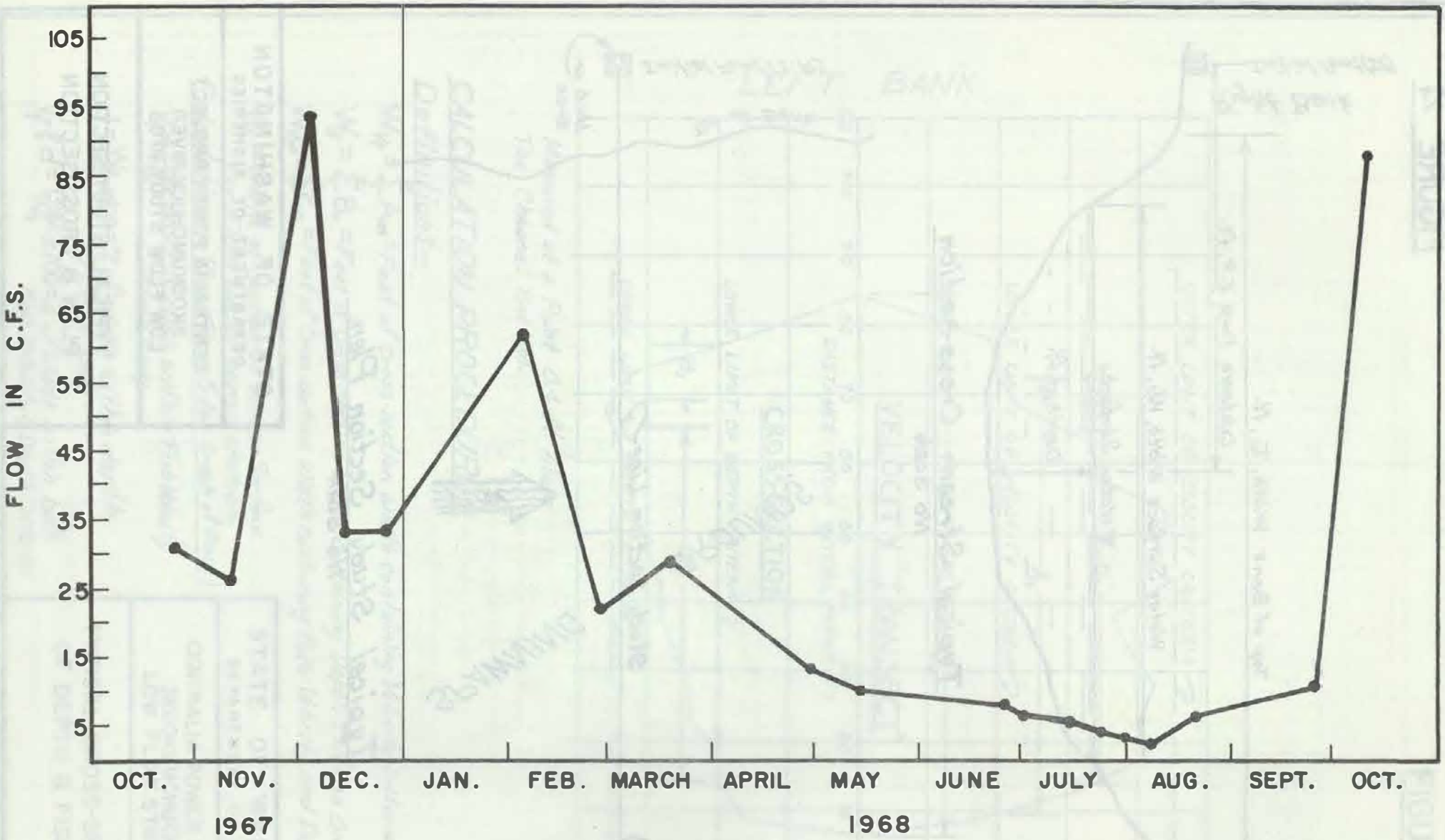
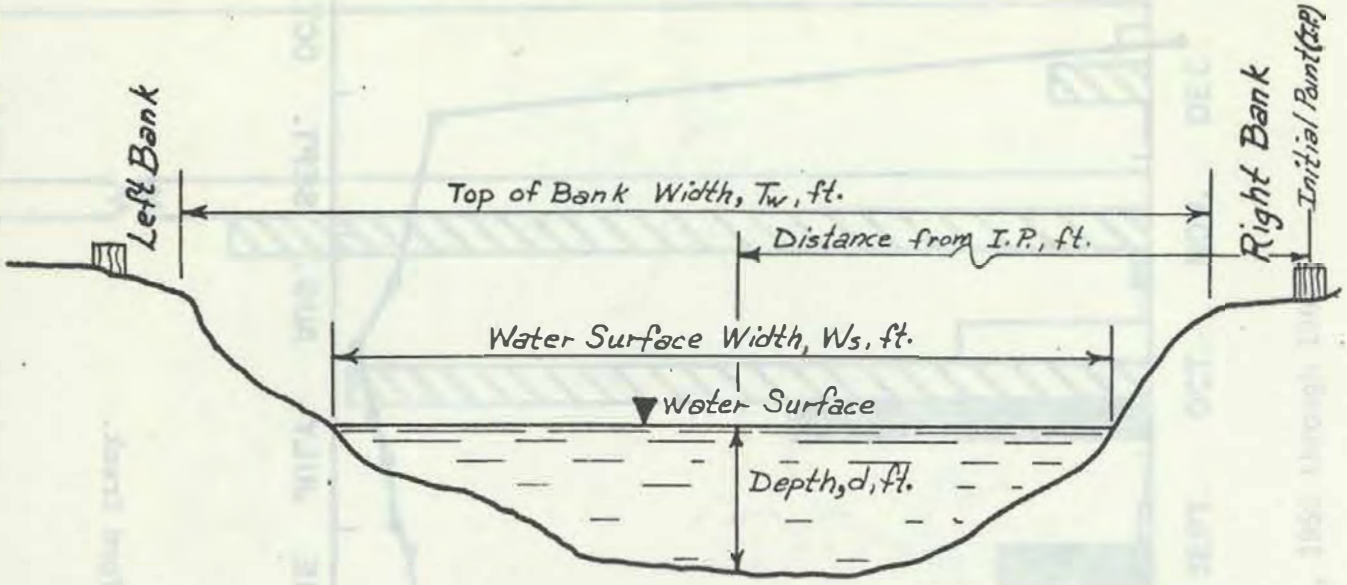


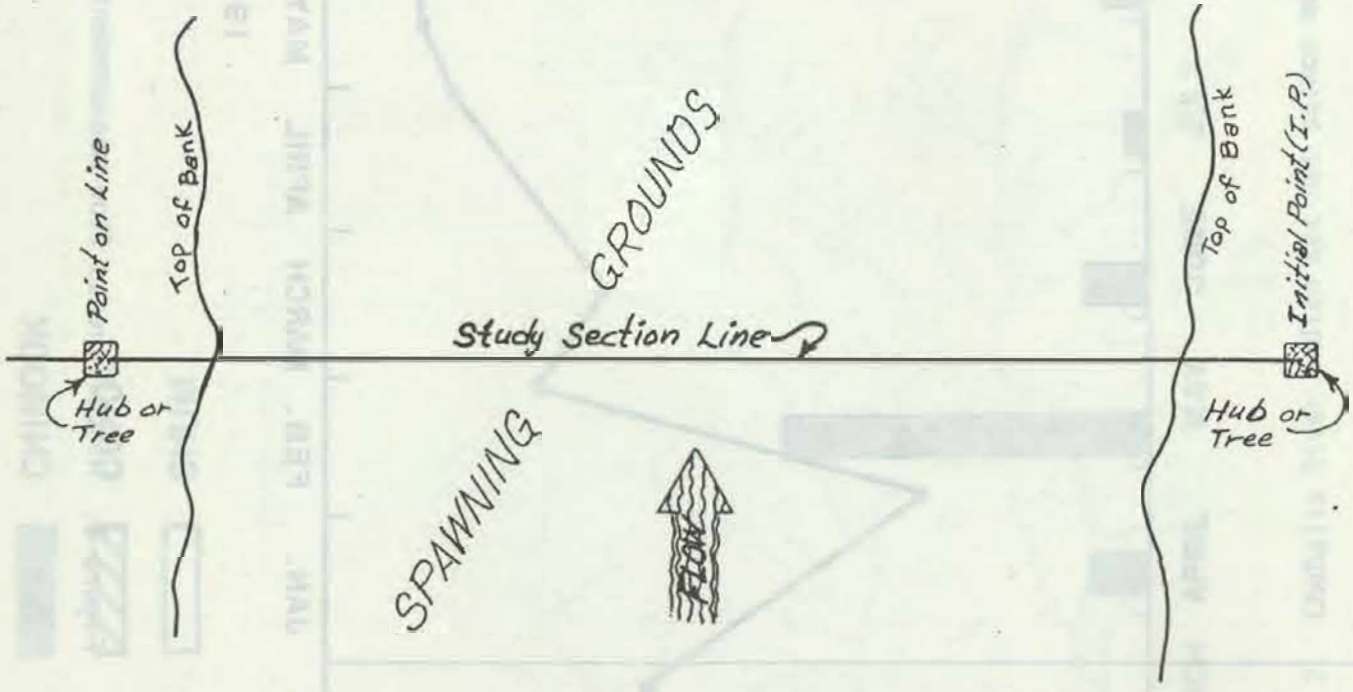
Figure 3. Miscellaneous flow measurements - Hanaford Creek.

FIGURE 4



Typical Stream Cross-section

No Scale

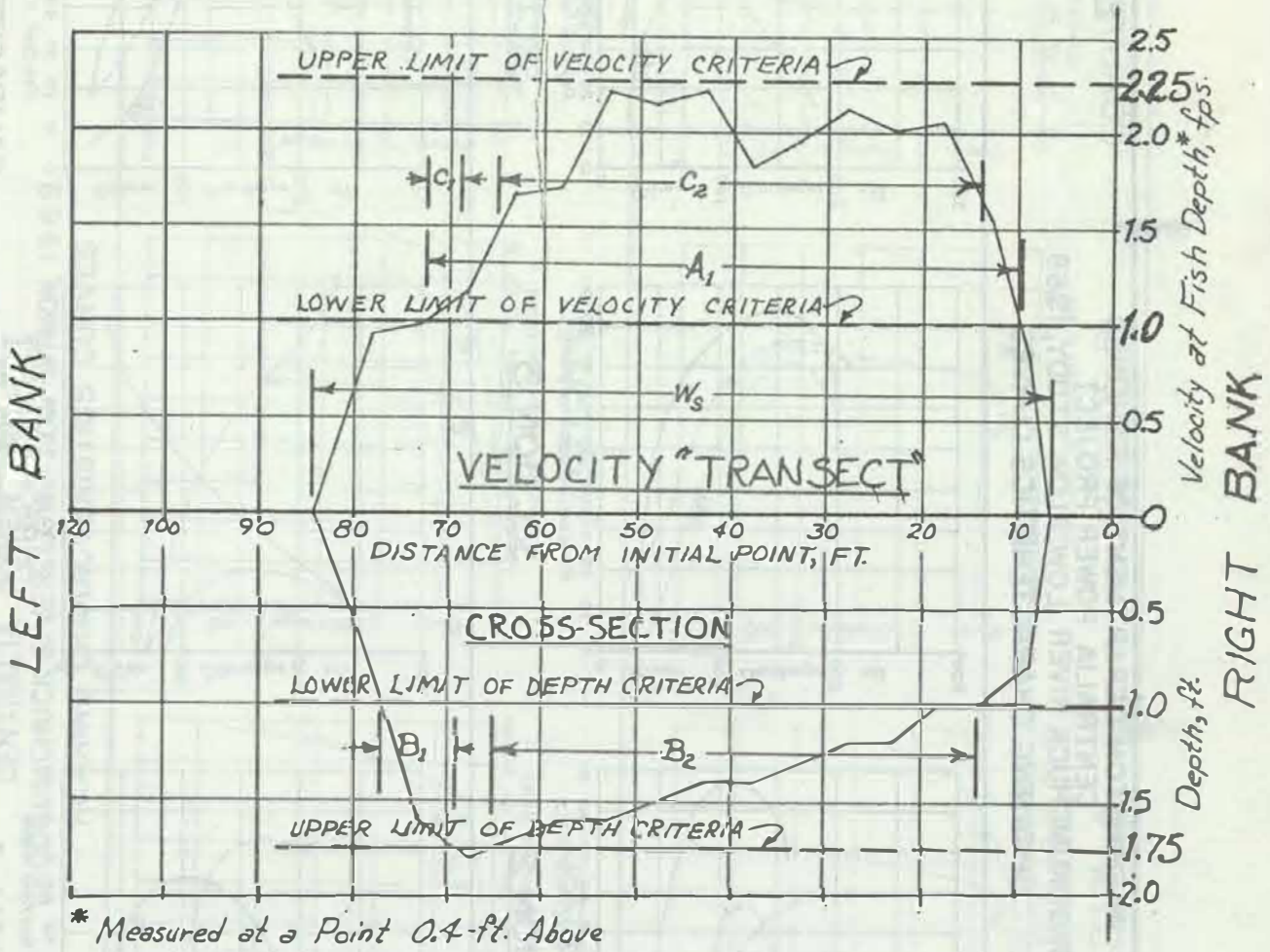


Typical Study Section Plan

No Scale

STATE OF WASHINGTON DEPARTMENT OF FISHERIES
CENTRALIA POWER PROJECT SKOOKUMCHUCK RIVER LOW FLOW STUDY, 1968
TYPICAL STUDY SECTION PLAN & CROSS-SECTION

FIGURE 5



* Measured at a Point 0.4-ft. Above The Channel Bottom.

CALCULATION PROCEDURE-

Definitions-

$W_{V_f} = \sum_{1}^{m} A_m$ = Feet of cross-section width containing Velocity Criteria Only.

$W_d = \sum_{1}^{n} B_n$ = Feet of cross-section width containing Depth Criteria Only.

$W_{V_f d} = \sum_{1}^{p} C_n$ = Feet of Cross-section Width containing Both Velocity and Depth Criteria

W_s = Width of Section at Water Surface for Flow under consideration.

Calculations- (See Figure 5 for Graph of Result)

$V_f = \frac{W_{V_f}}{W_s} \times 100$ = % of width within Fish Velocity Criteria only.

$d = \frac{W_d}{W_s} \times 100$ = % of width within depth Criteria only.

$V_f \& d = \frac{W_{V_f d}}{W_s} \times 100$ = % of Width within both Fish Velocity & Depth Criteria.

STATE OF WASHINGTON
DEPARTMENT OF FISHERIES

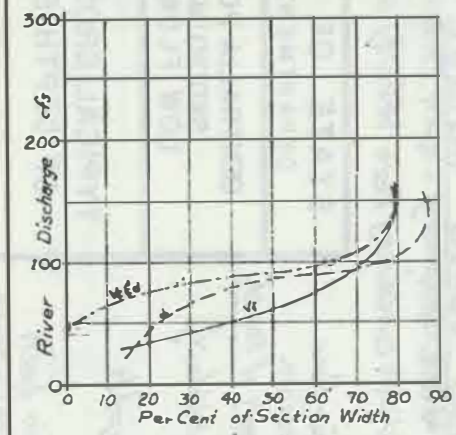
CENTRALIA POWER PROJECT
SKOOKUMCHUCK RIVER
LOW FLOW STUDY, 1968

TYPICAL CROSS-SECTION PLOT OF DEPTH & FISH VELOCITY

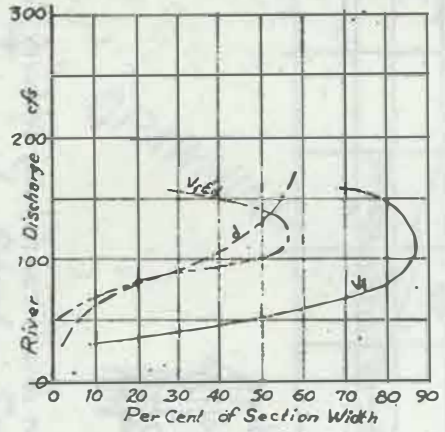
SYMBOLS——
V_f — Fish Velocity Criteria Only*
d — Depth Criteria Only*
V_f & d - Combination of Fish Velocity & Depth Criteria*
* See Figures 2 3 4 5

WASHINGTON DEPARTMENT OF FISHERIES
CENTRALIA POWER PROJECT
SKOOKUMCHUCK RIVER LOW FLOW STUDY, 1968
SPAWNING CHARACTERISTICS CURVES

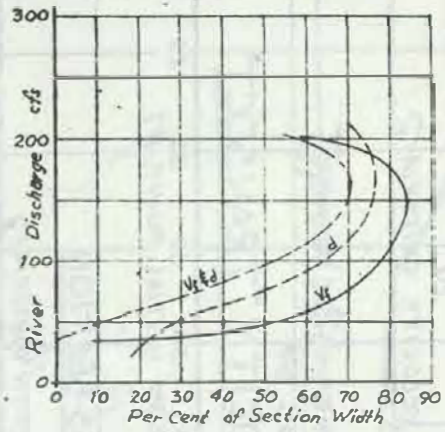
FIGURE 6



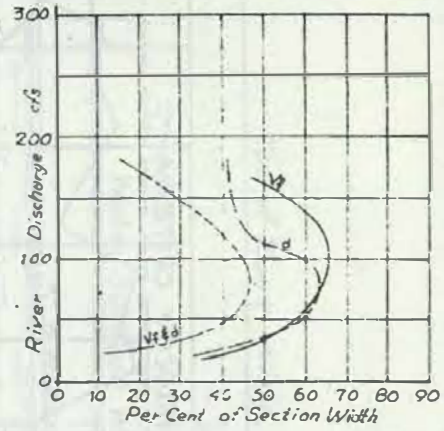
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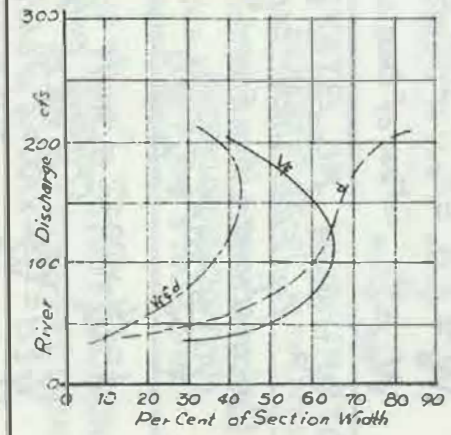
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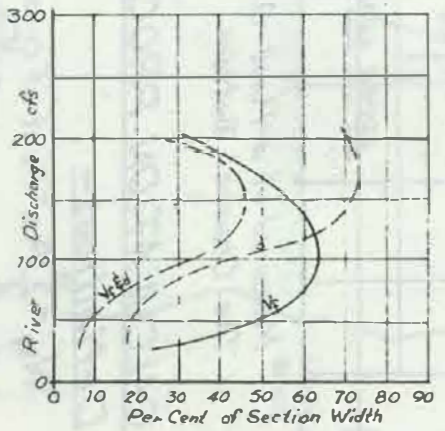
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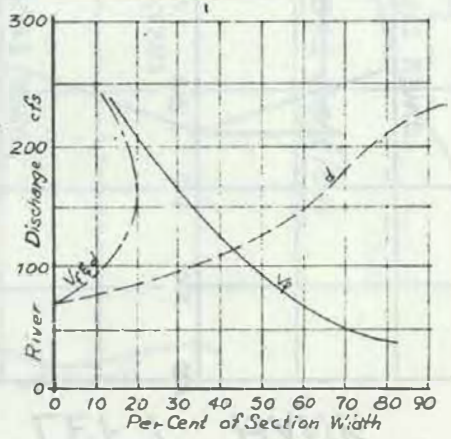
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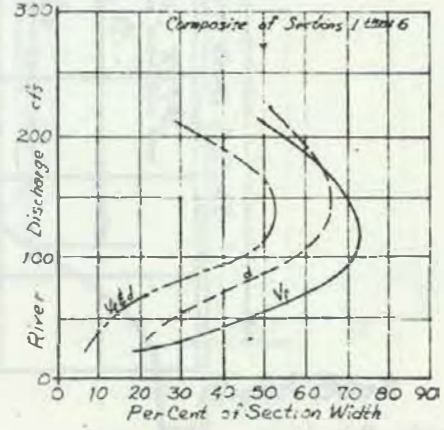
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SECTION 6



SECTION 7

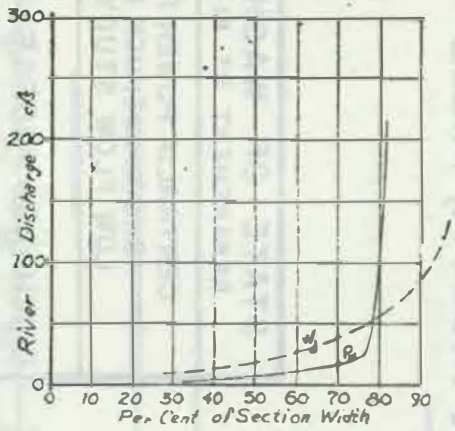


COMPOSITE SECTION

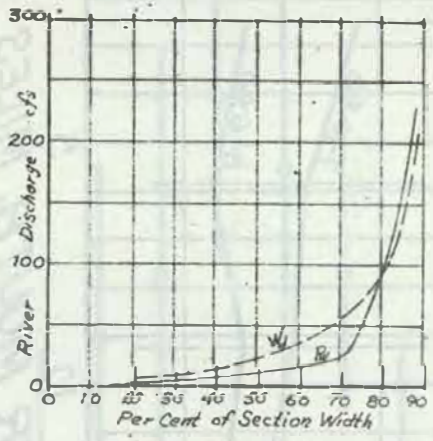
SYMBOLS——
P_w — Wetted Perimeter Criteria, Based on T_w*
W_d — Minimum Depth Criteria, Based on W_s*
*See Figure 4

WASHINGTON DEPARTMENT OF FISHERIES
CENTRALIA POWER PROJECT
SKOOKUMCHUCK RIVER LOW FLOW STUDY, 1968
REARING CHARACTERISTICS CURVES

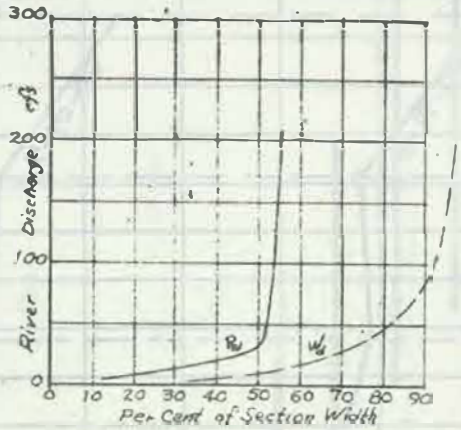
FIGURE 7



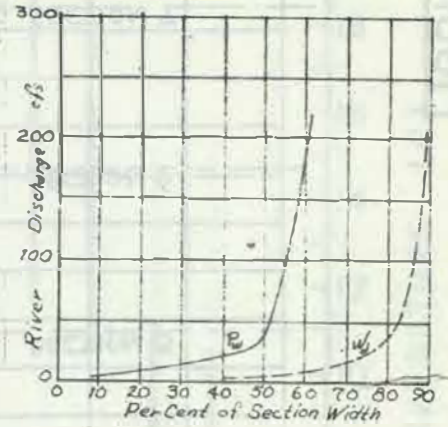
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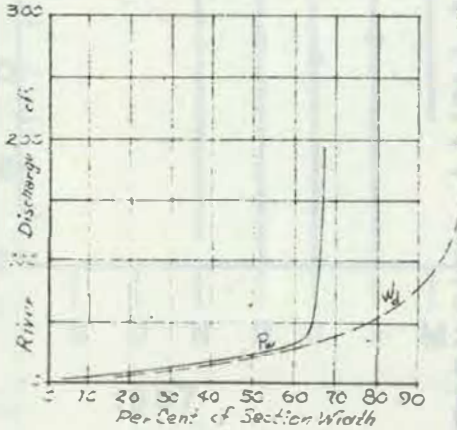
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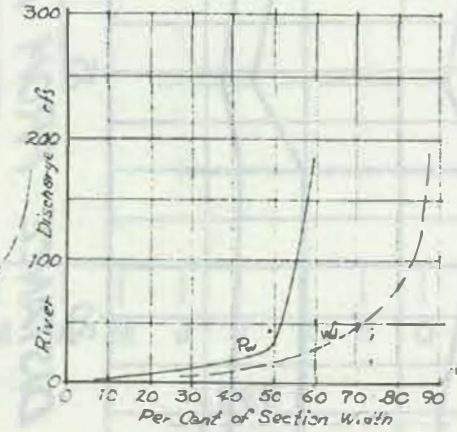
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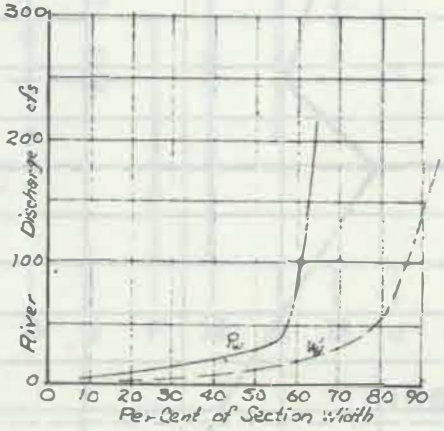
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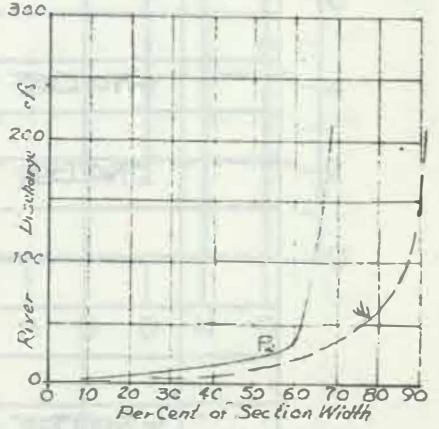
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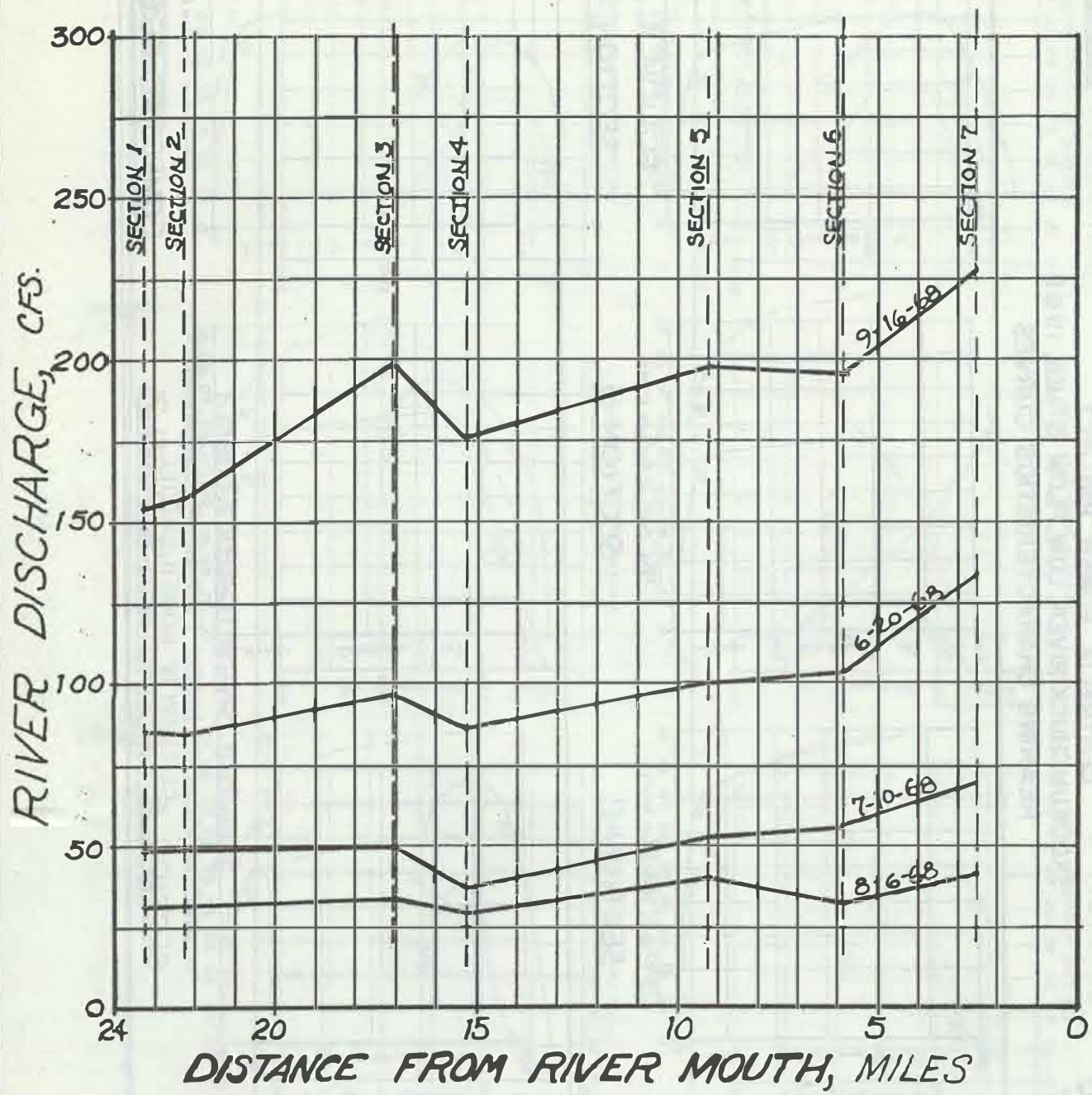


SECTION 7



COMPOSITE SECTION

FIGURE 8



STATE OF WASHINGTON DEPARTMENT OF FISHERIES
CENTRALIA POWER PROJECT SKOOKUMCHUCK RIVER LOW FLOW STUDY, 1968
DISCHARGE PROFILES OBSERVED 6-20-68 THRU 9-16-68

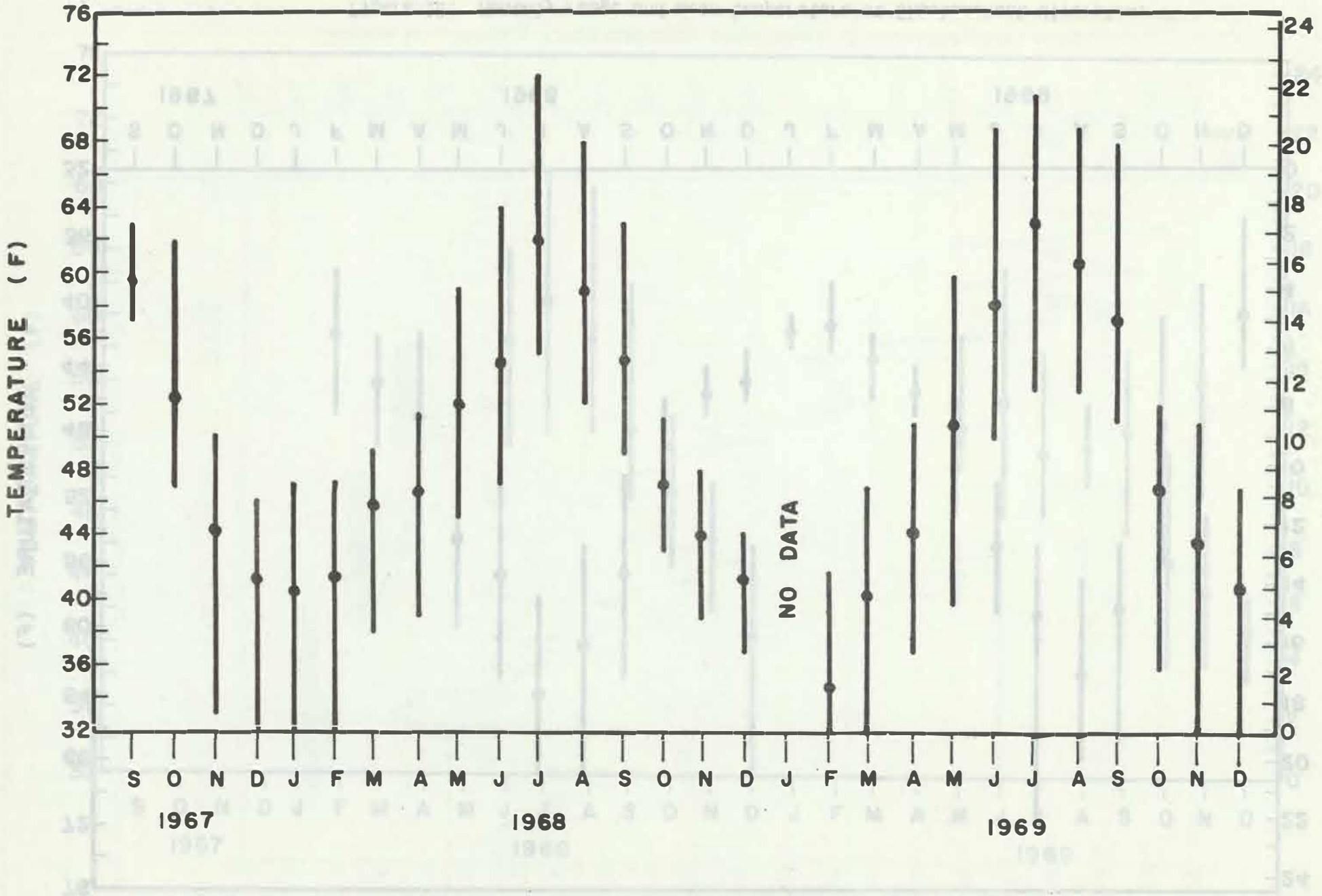


Figure 9. Monthly range and mean temperature at Skookumchuck dam site.

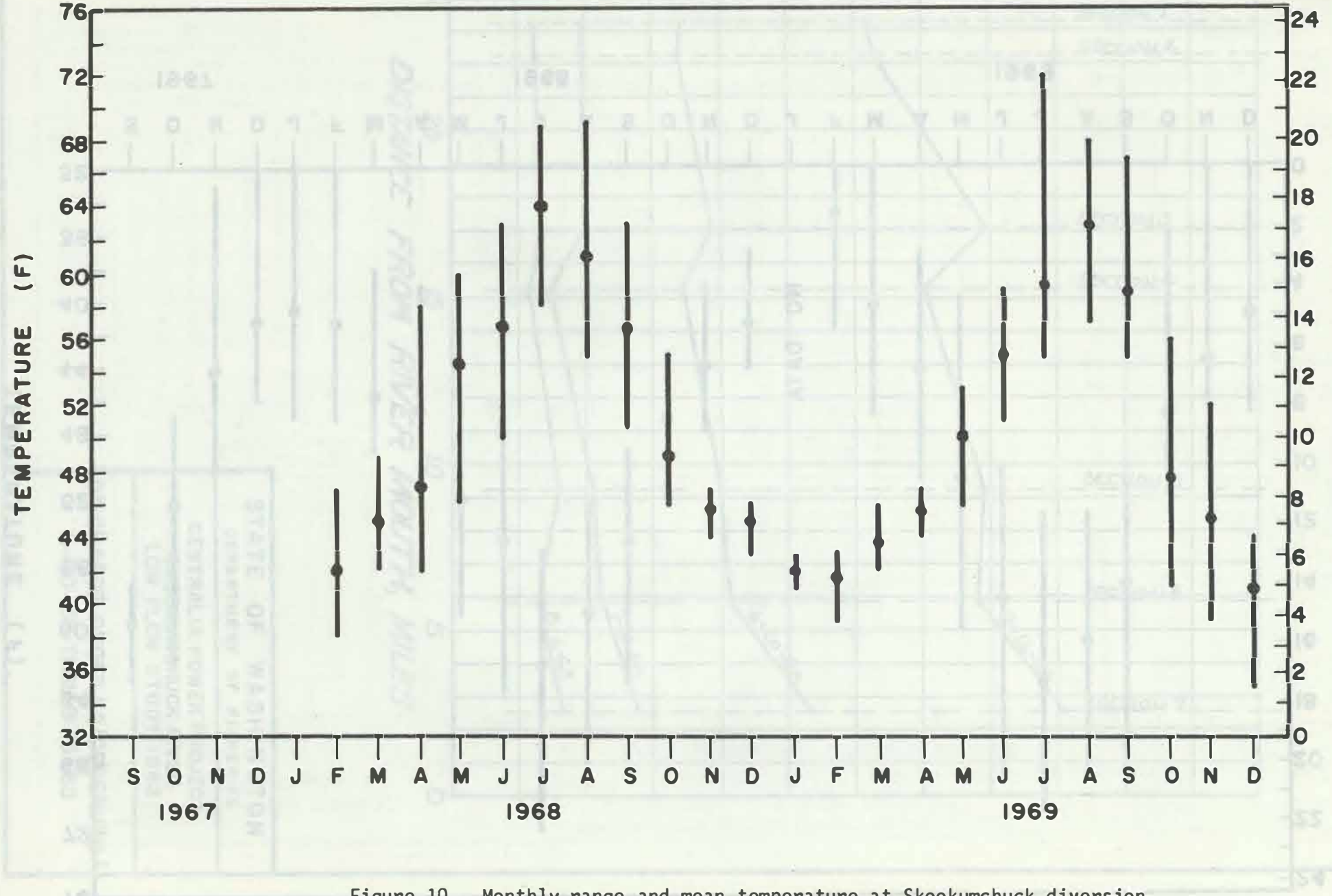


Figure 10. Monthly range and mean temperature at Skookumchuck diversion.

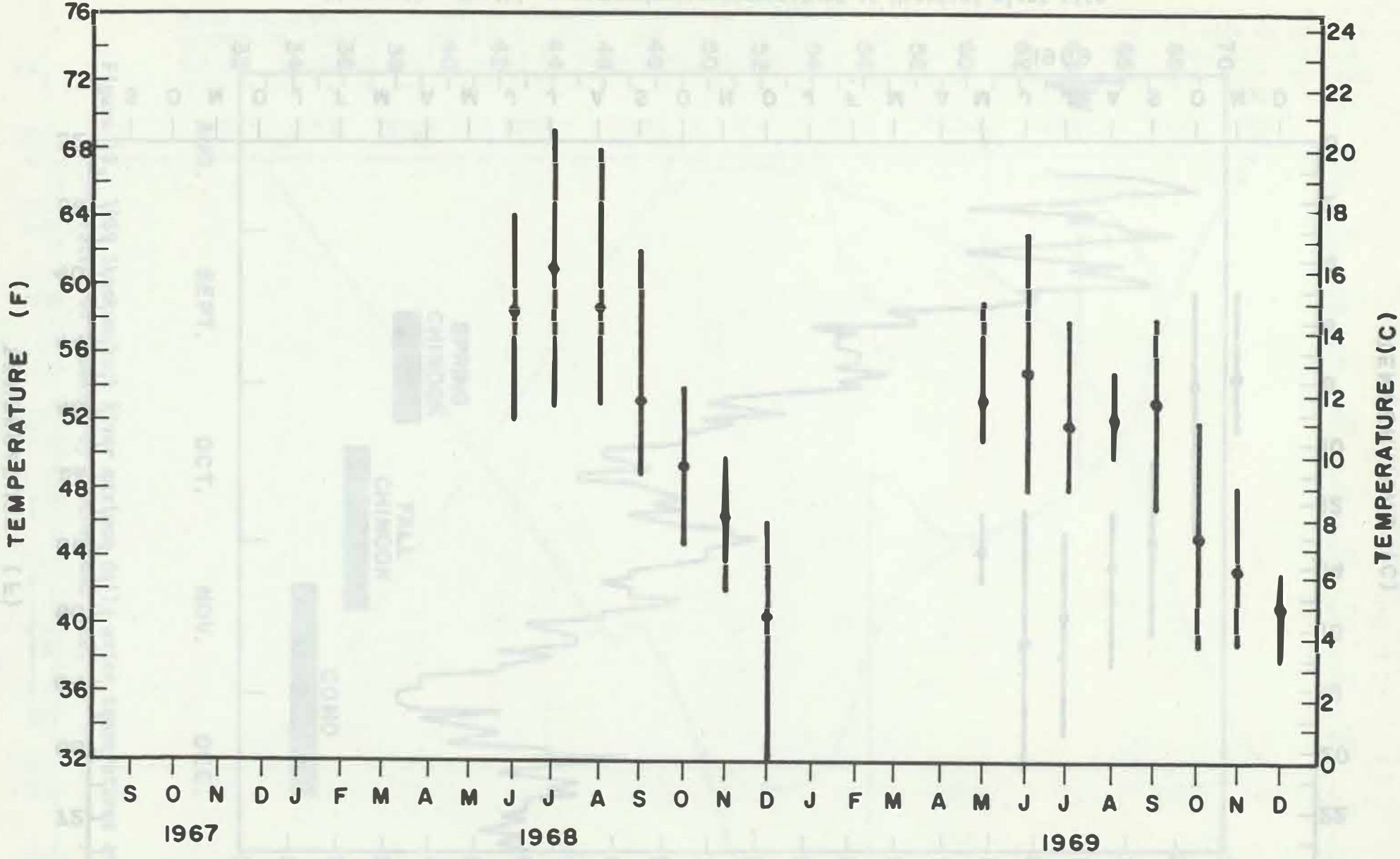


Figure 11. Monthly range and mean temperature at Hanaford dam site.

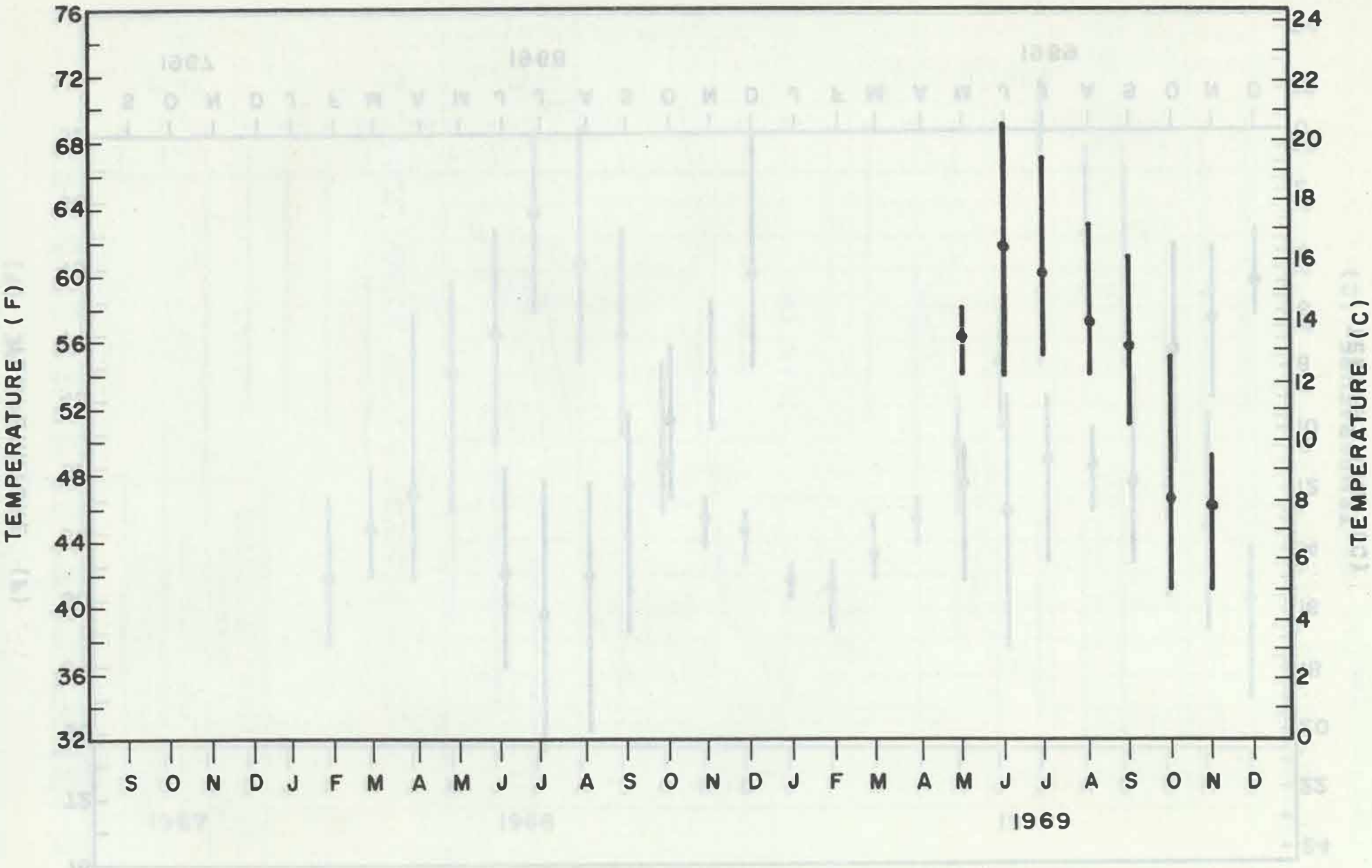


Figure 12. Monthly range and mean temperature at Hanaford plant site.

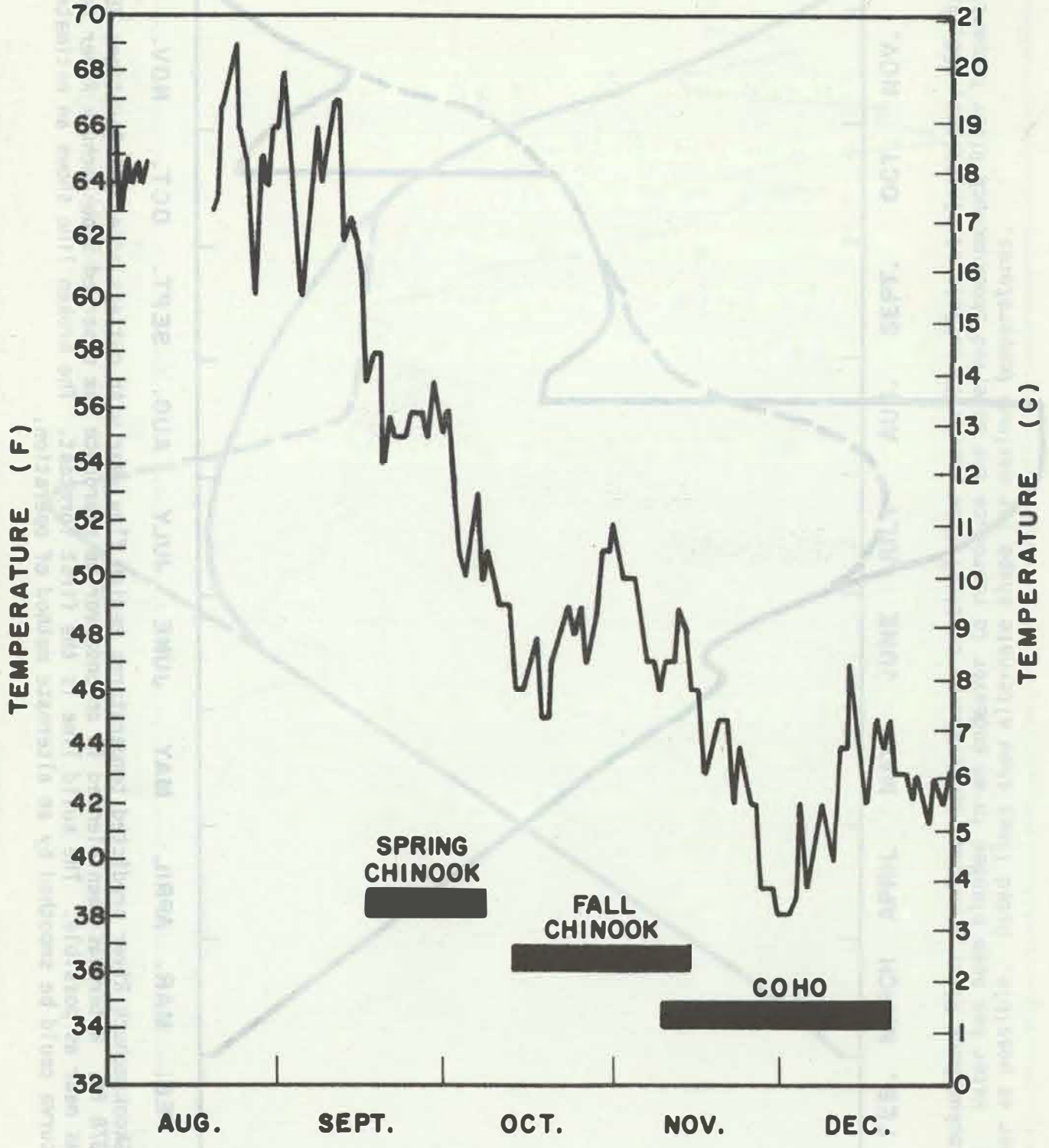


Figure 13. 1969 Skookumchuck River maximum daily water temperatures and duration of spawning by species and race.

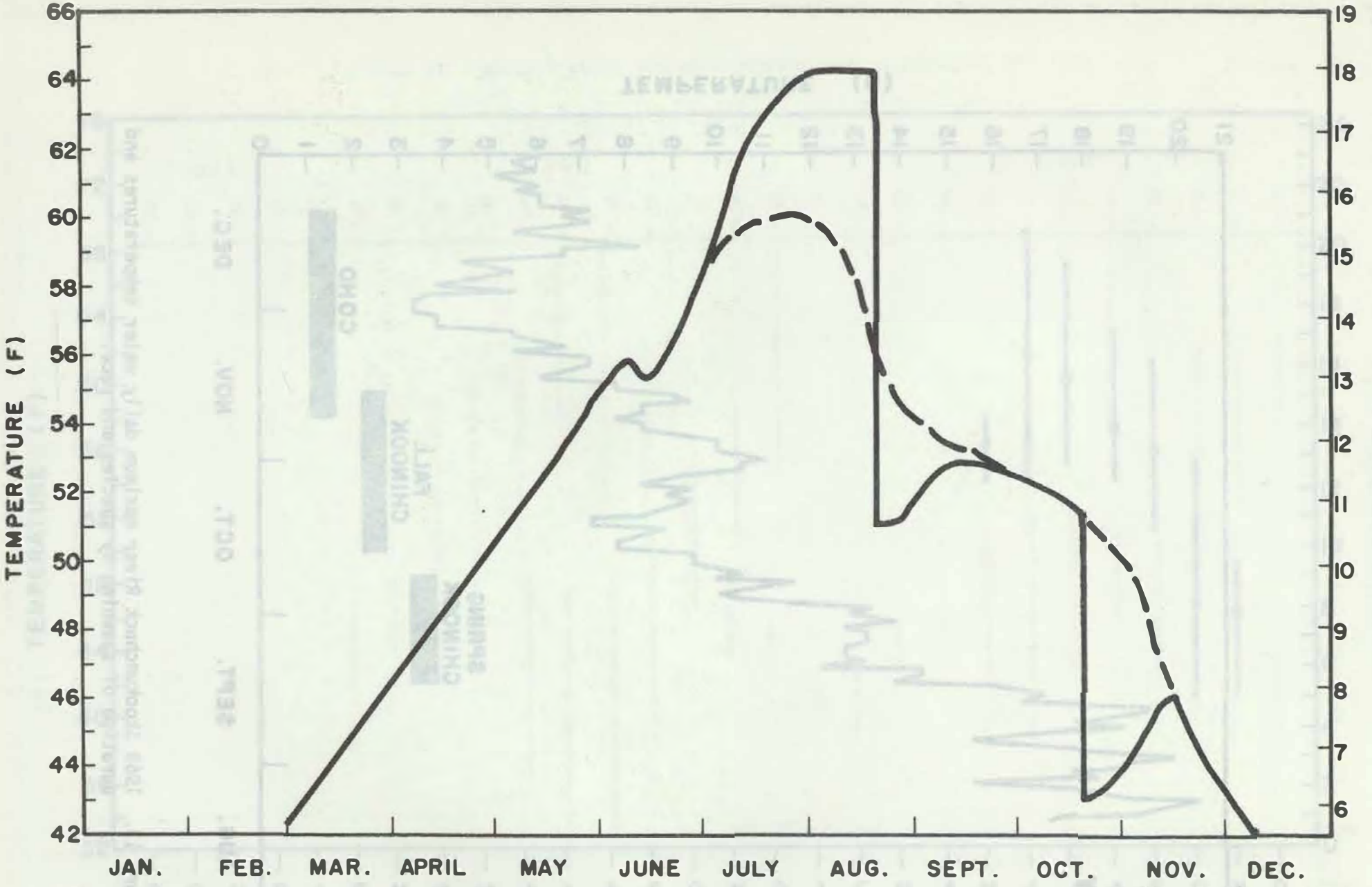


Figure 14. Skookumchuck River predicted temperatures median flow year with outlets added at elevations 450, 420, and 378 ft. Water has been blended in an endeavor to reproduce the observed Skookumchuck River temperatures as near as possible. The solid line is the first forecast. The broken line shows an estimate of how the curve could be smoothed by an alternate method of operation.

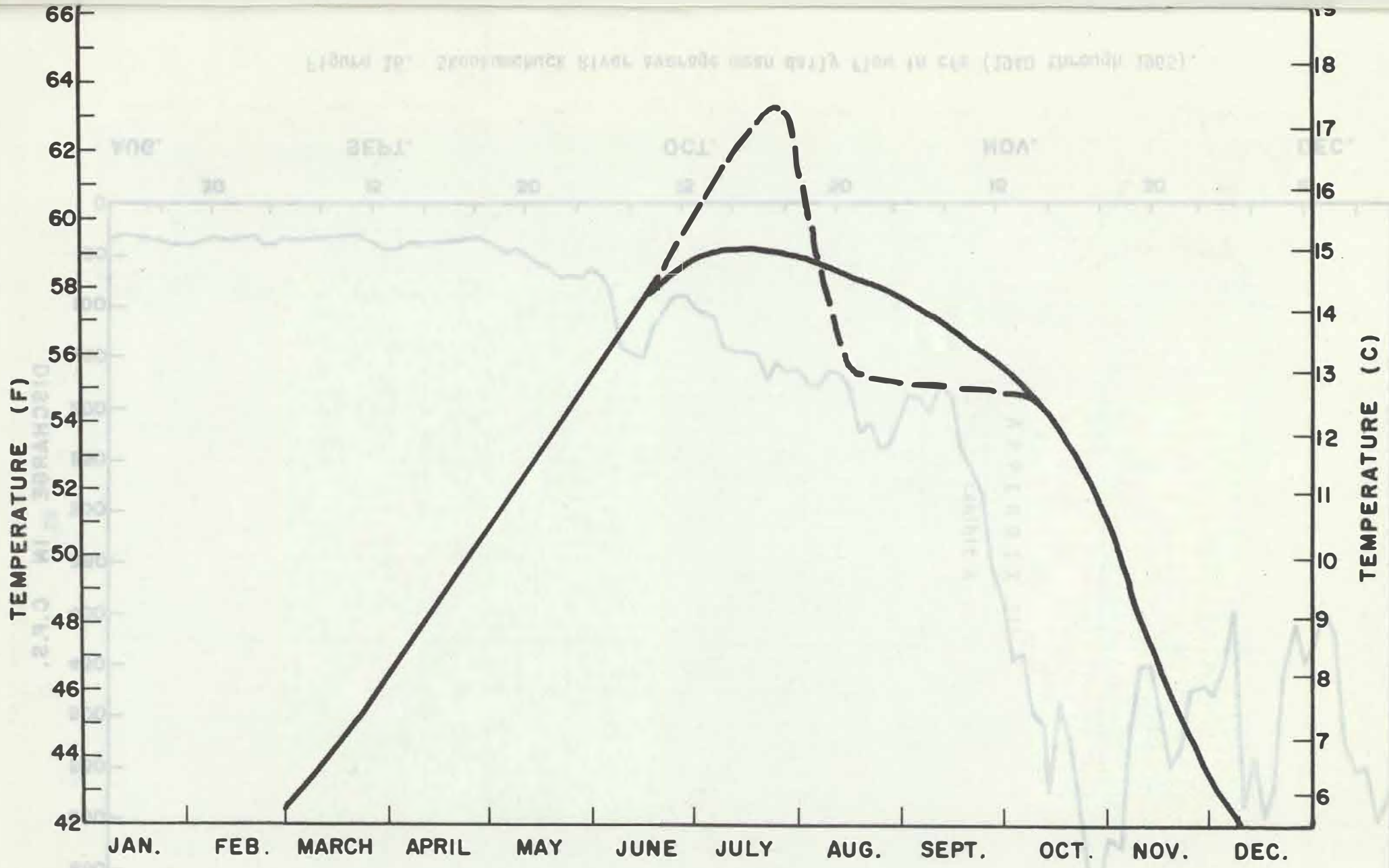


Figure 15. Skookumchuck River predicted temperatures critical flow year with outlets at elevations, 450, 420, and 378 ft Water has been blended in an endeavor to reproduce the observed Skookumchuck River temperatures as near as possible. Dated lines show alternate shape for maximum temperatures.

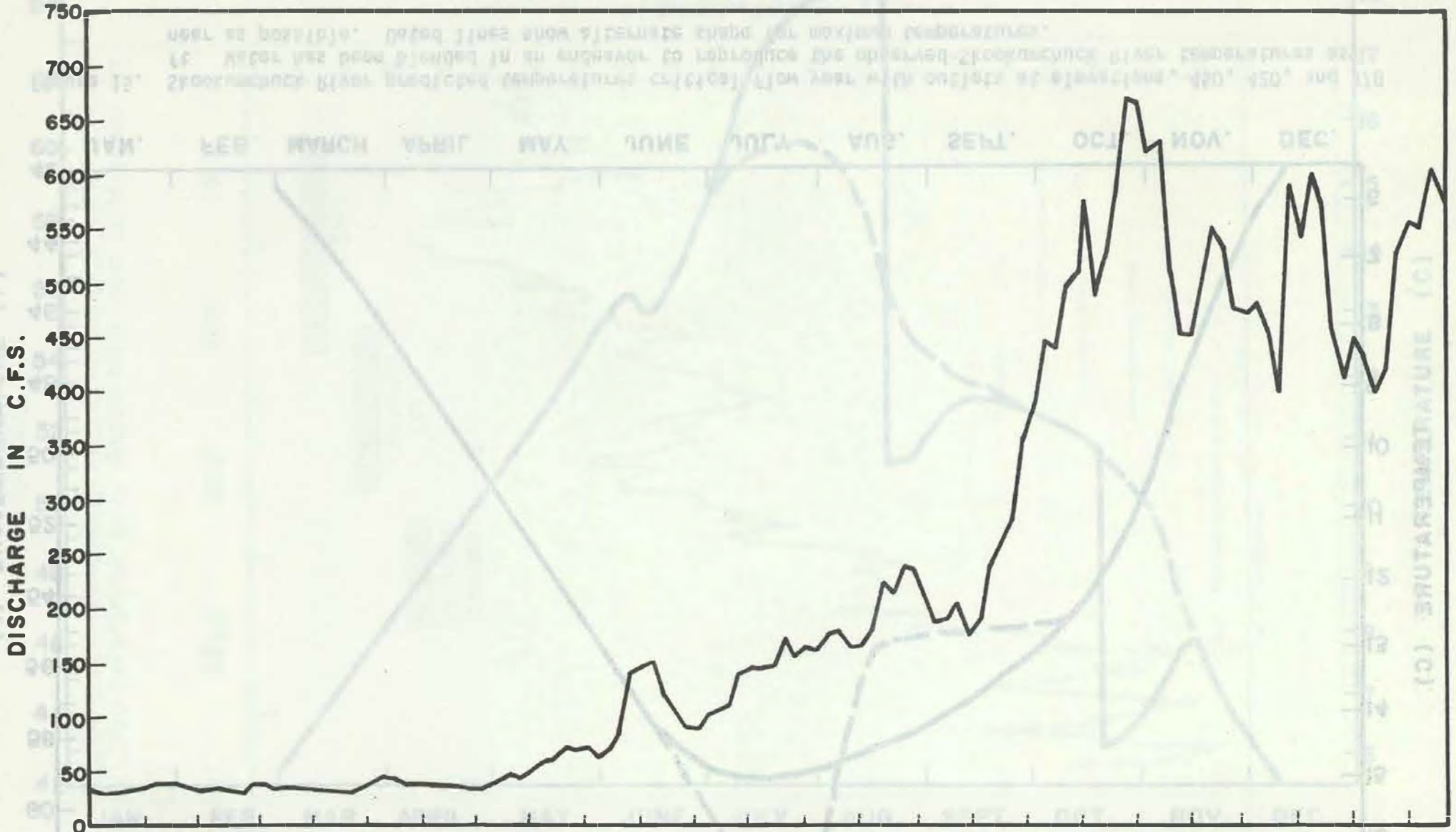


Figure 16. Skookumchuck River average mean daily flow in cfs (1940 through 1965).

A P P E N D I X III

Exhibit A

KEUFFEL & ESSER CO. MADE IN U. S. A.
CALENDAR YEAR

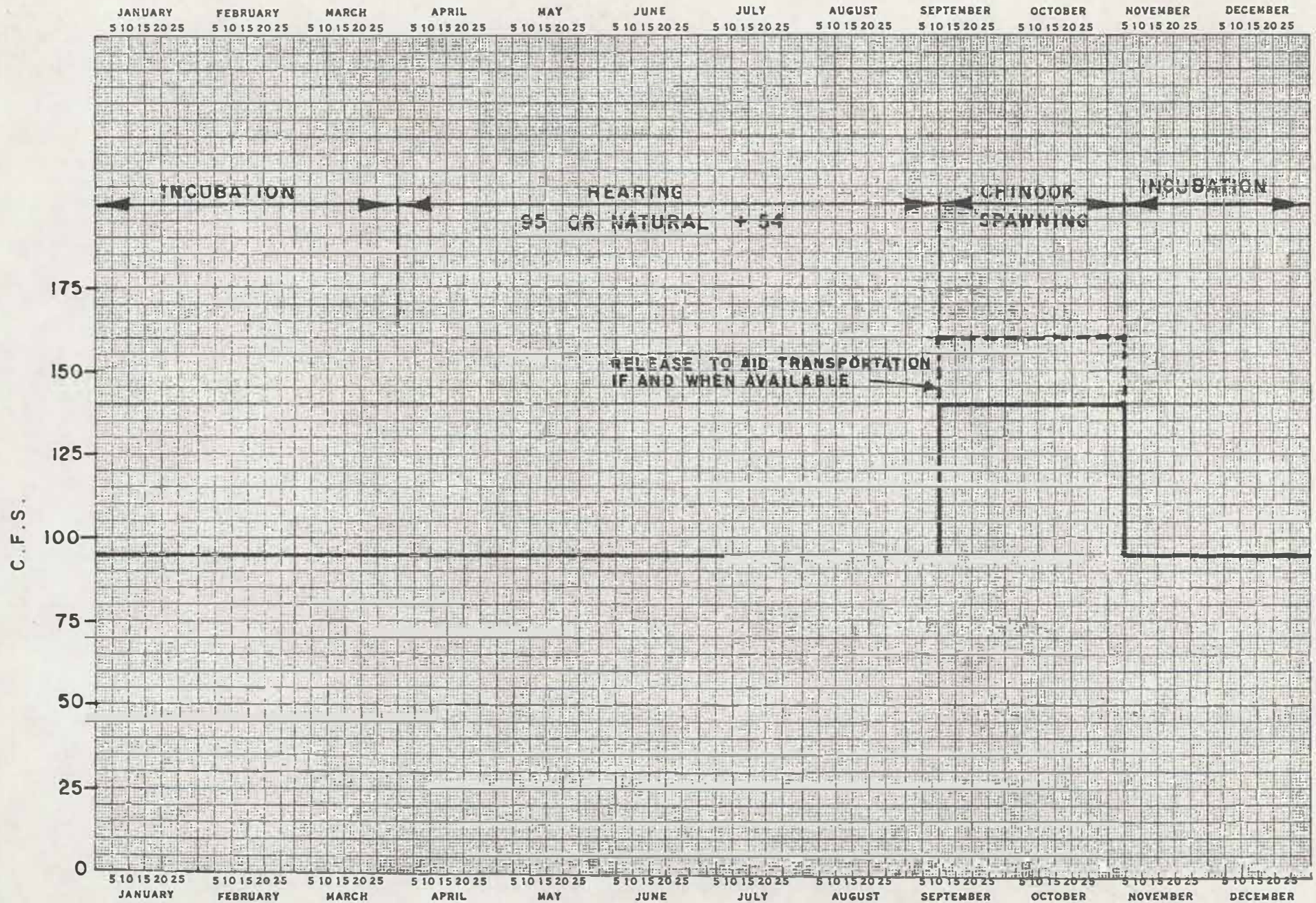


EXHIBIT A. MINIMUM RELEASE IN C.F.S. AT SKOOKUMCHUCK DAM FOR PROTECTION OF FISHERIES RESOURCE DURING 54 C.F.S. DIVERSION AT STEAM PLANT INTAKE.

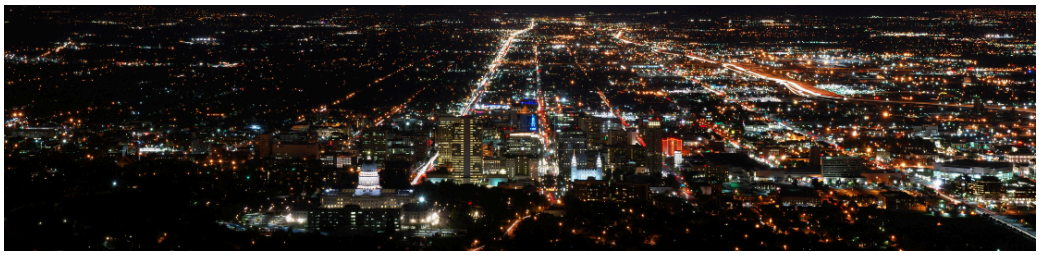
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-81:
"About WECC" Webpage

LOGIN



About WECC

The Western Electricity Coordinating Council (WECC) is a non-profit corporation that exists to ensure a reliable Bulk Electric System in the geographic area known as the Western Interconnection. WECC has been approved by the Federal Energy Regulatory Commission (FERC) as the Regional Entity for the Western Interconnection. The North American Electric Reliability Corporation (NERC) delegated some of its authority to create, monitor, and enforce reliability standards to WECC through a Delegation Agreement.



WECC promotes bulk power system reliability and security in the Western Interconnection. WECC is the Regional Entity responsible for compliance monitoring and enforcement and oversees reliability planning and assessments. In addition, WECC provides an environment for the development of Reliability Standards and the coordination of the operating and planning activities of its members as set forth in the WECC Bylaws.

There are six Regional Entities given authority by NERC and FERC. Of those six entities, WECC oversees the largest and most geographically diverse region, known as the Western Interconnection. WECC's footprint

extends from Canada to Mexico and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between.

Membership in WECC is open to all entities that meet the qualifications in the WECC Bylaws. WECC strives for transparency and open participation in all of its meetings and processes.

2024 State of the Interconnection Report

Our History

@ 2026 WECC

LEGAL

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-82:
NERC Rules of Procedure

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rules of Procedure

Effective: November 28, 2023

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SECTION 100 — APPLICABILITY OF RULES OF PROCEDURE

NERC and NERC Members shall comply with these Rules of Procedure. Each Regional Entity shall comply with these Rules of Procedure as applicable to functions delegated to the Regional Entity by NERC or as required by an Applicable Governmental Authority or as otherwise provided.

Each Bulk Power System owner, operator, and user shall comply with all Rules of Procedure of NERC that are made applicable to such entities by approval pursuant to applicable legislation or regulation, or pursuant to agreement.

Any entity that is unable to comply or that is not in compliance with a NERC Rule of Procedure shall immediately notify NERC in writing, stating the Rule of Procedure of concern and the reason for not being able to comply with the Rule of Procedure.

NERC shall evaluate each case and inform the entity of the results of the evaluation. If NERC determines that a Rule of Procedure has been violated, or cannot practically be complied with, NERC shall notify the Applicable Governmental Authorities and take such other actions as NERC deems appropriate to address the situation.

NERC shall comply with each approved Reliability Standard that identifies NERC or the Electric Reliability Organization as a responsible entity. Regional Entities shall comply with each approved Reliability Standard that identifies Regional Entities as responsible entities. A violation by NERC or a Regional Entity of such a Reliability Standard shall constitute a violation of these Rules of Procedure.

SECTION 200 — DEFINITIONS OF TERMS

Definitions of terms used in the NERC Rules of Procedure are set forth in **Appendix 2**, *Definitions Used in the Rules of Procedure*.

SECTION 300 — RELIABILITY STANDARDS DEVELOPMENT

301. General

NERC shall develop and maintain Reliability Standards that apply to Bulk Power System owners, operators, and users and that enable NERC and Regional Entities to measure the reliability performance of Bulk Power System owners, operators, and users; and to hold them accountable for Reliable Operation of the Bulk Power Systems. The Reliability Standards shall be technically excellent, timely, just, reasonable, not unduly discriminatory or preferential, in the public interest, and consistent with other applicable standards of governmental authorities.

302. Essential Attributes for Technically Excellent Reliability Standards

1. **Applicability** — Each Reliability Standard shall clearly identify the functional classes of entities responsible for complying with the Reliability Standard, with any specific additions or exceptions noted.[1] Each Reliability Standard shall also identify the geographic applicability of the Reliability Standard, such as the entire North American Bulk Power System, an Interconnection, or within a Region. A Reliability Standard may also identify any limitations on the applicability of the Reliability Standard based on electric Facility characteristics.

2. **Reliability Objectives** — Each Reliability Standard shall have a clear statement of purpose that shall describe how the Reliability Standard contributes to the reliability of the Bulk Power System. The following general objectives for the Bulk Power System provide a foundation for determining the specific objective(s) of each Reliability Standard:

    2.1 **Reliability Planning and Operating Performance** — Bulk Power Systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.

    2.2 **Frequency and Voltage Performance** — The frequency and voltage of Bulk Power Systems shall be controlled within defined limits through the balancing of Real and Reactive Power supply and demand.

    2.3 **Reliability Information** — Information necessary for the planning and operation of reliable Bulk Power Systems shall be made available to those entities responsible for planning and operating Bulk Power Systems.

    2.4 **Emergency Preparation** — Plans for emergency operation and system restoration of Bulk Power Systems shall be developed, coordinated, maintained, and implemented.

[1] When a Reliability Standard identifies a class of entities to which it applies, that class must be defined in the Glossary of Terms Used in NERC Reliability Standards.

2.5 **Communications and Control** — Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of Bulk Power Systems.

2.6 **Personnel** — Personnel responsible for planning and operating Bulk Power Systems shall be trained and qualified, and shall have the responsibility and authority to implement actions.

2.7 **Wide-Area View** — The reliability of the Bulk Power Systems shall be assessed, monitored, and maintained on a Wide-Area basis.

2.8 **Security** — Bulk Power Systems shall be protected from malicious physical or cyber attacks.

3. **Performance Requirement or Outcome** — Each Reliability Standard shall state one or more performance Requirements, which if achieved by the applicable entities, will provide for a reliable Bulk Power System, consistent with good utility practices and the public interest. Each Requirement is not a "lowest common denominator" compromise, but instead achieves an objective that is the best approach for Bulk Power System reliability, taking account of the costs and benefits of implementing the proposal.

4. **Measurability** — Each performance Requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that Requirement. Each performance Requirement shall have one or more associated measures used to objectively evaluate compliance with the Requirement. If performance can be practically measured quantitatively, metrics shall be provided to determine satisfactory performance.

5. **Technical Basis in Engineering and Operations** — Each Reliability Standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field.

6. **Completeness** — Reliability Standards shall be complete and self-contained. The Reliability Standards shall not depend on external information to determine the required level of performance.

7. **Consequences for Noncompliance** — In combination with guidelines for Penalties and sanctions, as well as other ERO and Regional Entity compliance documents, the consequences of violating a Reliability Standard are clearly presented to the entities responsible for complying with the Reliability Standards.

8. **Clear Language** — Each Reliability Standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practices, are able to arrive at a consistent interpretation of the required performance.

9. **Practicality** — Each Reliability Standard shall establish Requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.

10. **Consistent Terminology** — To the extent possible, Reliability Standards shall use a set of standard terms and definitions that are approved through the NERC Reliability Standards development process.

303. Relationship between Reliability Standards and Competition

To ensure Reliability Standards are developed with due consideration of impacts on competition, to ensure Reliability Standards are not unduly discriminatory or preferential, and recognizing that reliability is an essential requirement of a robust North American economy, each Reliability Standard shall meet all of these market-related objectives:

1. **Competition** — A Reliability Standard shall not give any market participant an unfair competitive advantage.

2. **Market Structures** — A Reliability Standard shall neither mandate nor prohibit any specific market structure.

3. **Market Solutions** — A Reliability Standard shall not preclude market solutions to achieving compliance with that Reliability Standard.

4. **Commercially Sensitive Information** — A Reliability Standard shall not require the public disclosure of commercially sensitive information or other Confidential Information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with Reliability Standards.

5. **Adequacy** — NERC shall not set Reliability Standards defining an adequate amount of, or requiring expansion of, Bulk Power System resources or delivery capability.

304. Essential Principles for the Development of Reliability Standards

NERC shall develop Reliability Standards in accordance with the NERC *Standard Processes Manual*, which is incorporated into these Rules of Procedure as **Appendix 3A**. Appeals in connection with the development of a Reliability Standard shall also be conducted in accordance with the NERC *Standard Processes Manual*. Any amendments or revisions to the NERC *Standard Processes Manual* shall be consistent with the following essential principles:

1. **Openness** — Participation shall be open to all Persons and who are directly and materially affected by the reliability of the North American Bulk Power System. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in NERC or any other organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

2. **Transparency** — The process shall be transparent to the public.

3. **Consensus-building** —The process shall build and document consensus for each Reliability Standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.

4. **Fair Balance of Interests** — The process shall fairly balance interests of all stakeholders and shall not be dominated by any two Segments as defined in **Appendix 3D**, *Development of the Registered Ballot Body*, of these Rules of Procedure, and no single Segment, individual or organization shall be able to defeat a matter.

5. **Due Process** — Development of Reliability Standards shall provide reasonable notice and opportunity for any Person with a direct and material interest to express views on a proposed Reliability Standard and the basis for those views, and to have that position considered in the development of the Reliability Standards.

6. **Timeliness** — Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the Bulk Power System.

305. Registered Ballot Body

NERC Reliability Standards shall be approved by a Registered Ballot Body prior to submittal to the Board and then to Applicable Governmental Authorities for their approval, where authorized by applicable legislation or agreement. This Section 305 sets forth the rules pertaining to the composition of, and eligibility to participate in, the Registered Ballot Body.

1. **Eligibility to Vote on Reliability Standards** — Any person or entity may join the Registered Ballot Body to vote on Reliability Standards, whether or not such person or entity is a Member of NERC.

2. **Inclusive Participation** — The Segment qualification guidelines are inclusive; i.e., any entity with a legitimate interest in the reliability of the Bulk Power System that can meet any one of the eligibility criteria for a Segment is entitled to belong to and vote in each Segment for which it qualifies, subject to limitations defined in Sections 305.3 and 305.5.

3. **General Criteria for Registered Ballot Body Membership** — The general criteria for membership in the Segments are:

    3.1 **Multiple Segments** — A corporation or other organization with integrated operations or with affiliates that qualifies to belong to more than one Segment (e.g., Transmission Owners and Load-Serving Entities) may join once in each Segment for which it qualifies, provided that each Segment constitutes a separate membership and the organization is represented in

each Segment by a different representative. Affiliated entities are collectively limited to one membership in each Segment for which they are qualified.

3.2 **Withdrawing from a Segment or Changing Segments** — After its initial registration in a Segment, each registered participant may elect to withdraw from a Segment at any time or apply to change Segments as described in the *Development of the Registered Ballot Body* in **Appendix 3D**. In the event a change in corporate or organizational structure results in merged or affiliated entities having more than one membership in a particular Segment, the merged or affiliated entities shall withdraw the additional memberships before joining any new ballot pools or voting on any standards action as part of an existing ballot pool.

3.3 **Review of Segment Criteria** — The Board shall review the qualification guidelines and rules for joining Segments periodically to ensure that the process continues to be fair, open, balanced, and inclusive. Public input will be solicited in the review of these guidelines.

4. **Proxies for Voting on Reliability Standards** — Any registered participant may designate an agent or proxy to vote on its behalf. There are no limits on how many proxies an agent may hold. However, for the proxy to be valid, NERC must have in its possession written documentation signed by the representative of the registered participant that the voting right by proxy has been transferred from the registered participant to the agent.

5. **Segments** — The specific criteria for membership in each Registered Ballot Body Segment are defined in the *Development of the Registered Ballot Body* in **Appendix 3D.**

6. **Review of Segment Entries** — NERC shall review all applications for joining the Registered Ballot Body, and shall make a determination of whether the applicant's self-selection of a Segment satisfies at least one of the guidelines to belong to that Segment. The entity shall then become eligible to participate as a voting member of that Segment. The Standards Committee shall resolve disputes regarding eligibility for membership in a Segment, with the applicant having the right of appeal to the Board.

306. Standards Committee

The Standards Committee shall provide oversight of the Reliability Standards development process to ensure stakeholder interests are fairly represented. The Standards Committee shall not under any circumstance change the substance of a draft or approved Reliability Standard.

1. **Membership** — The Standards Committee is a representative committee comprising representatives of two members of each of the Segments in the

Registered Ballot Body and two officers elected to represent the interests of the industry as a whole.

2. **Elections** — Standards Committee members are elected for staggered (one per Segment per year) two-year terms by the respective Segments in accordance with the *Procedure for the Election of Members of the NERC Standards Committee*, which is incorporated into these Rules of Procedure as **Appendix 3B**. Segments may use their own election procedure if such a procedure is ratified by two-thirds of the members of a Segment and approved by the Board.

3. **Canadian Representation**

   The Standards Committee will include Canadian representation as provided in **Appendix 3B**, *Procedure for the Election of Members of the NERC Standards Committee*.

4. **Open Meetings** — All meetings of the Standards Committee shall be open and publicly noticed on the NERC website.

307. Standards Process Management

NERC standards staff shall be responsible for ensuring that the development and revision of Reliability Standards are in accordance with the NERC *Standard Processes Manual* and shall work to achieve the highest degree of integrity and consistency of quality and completeness of the Reliability Standards. NERC staff shall coordinate with any Regional Entities that develop Regional Reliability Standards to ensure those Regional Reliability Standards are effectively integrated with the NERC Reliability Standards.

308. Steps in the Development of Reliability Standards

1. **Procedure** — NERC shall develop Reliability Standards through the process set forth in the NERC *Standard Processes Manual* (**Appendix 3A**). The NERC *Standard Processes Manual* includes provisions for developing Reliability Standards that can be completed using expedited processes, including a process to develop Reliability Standards to address national security situations that involve confidential issues.

2. **Board Adoption** — Reliability Standards or revisions to Reliability Standards approved by the ballot pool in accordance with the NERC *Standard Processes Manual* shall be submitted for adoption by the Board. No Reliability Standard or revision to a Reliability Standard shall be effective unless adopted by the Board.

3. **Governmental Approval** — After Board adoption, a Reliability Standard or revision to a Reliability Standard shall be submitted to all Applicable Governmental Authorities in accordance with Section 309. No Reliability Standard or revision to a Reliability Standard shall be effective within a geographic area over which an Applicable Governmental Authority has jurisdiction unless it is approved by such Applicable Governmental Authority or

is otherwise made effective pursuant to the laws applicable to such Applicable Governmental Authority.

309. Filing of Reliability Standards for Approval by Applicable Governmental Authorities

1. **Filing of Reliability Standards for Approval** — Where authorized by applicable legislation or agreement, NERC shall file with the Applicable Governmental Authorities each Reliability Standard, modification to a Reliability Standard, or withdrawal of a Reliability Standard that is adopted by the Board. Each filing shall be in the format required by the Applicable Governmental Authority and shall include: a concise statement of the basis and purpose of the Reliability Standard; the text of the Reliability Standard; the implementation plan for the Reliability Standard; a demonstration that the Reliability Standard meets the essential attributes of Reliability Standards as stated in Section 302; the drafting team roster; the ballot pool and final ballot results; and a discussion of public comments received during the development of the Reliability Standard and the consideration of those comments.

2. **Remanded Reliability Standards and Directives to Develop New or Modified Reliability Standards** — If an Applicable Governmental Authority remands a Reliability Standard to NERC, NERC shall within five (5) business days notify all other Applicable Governmental Authorities. Reliability Standards that are directed by an Applicable Governmental Authority shall be developed using the NERC *Standard Processes Manual*. The waiver provisions of the NERC *Standard Processes Manual* may be applied if necessary to meet a timetable for action required by the Applicable Governmental Authority, respecting to the extent possible the provisions in the *NERC Standard Processes Manual* for reasonable notice and opportunity for public comment, due process, openness, and a balance of interest in developing Reliability Standards. If the Board of Trustees determines that the standards process did not result in a Reliability Standard that adequately addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply.

3. **Directives to Develop Reliability Standards under Extraordinary Circumstances** — An Applicable Governmental Authority may, on its own initiative, determine that extraordinary circumstances exist requiring expedited development of a Reliability Standard. In such a case, the Applicable Governmental Authority may direct the development of a Reliability Standard within a certain deadline. NERC staff shall prepare the Standards Authorization Request. The proposed Reliability Standard will then proceed through the Reliability Standards development process, using the waiver provisions of the NERC *Standard Processes Manual* as necessary to meet the specified deadline. The timeline will be developed to respect, to the extent possible, the provisions in the Reliability Standards development process for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests

in developing Reliability Standards. If the Board of Trustees determines that the standards process did not result in a Reliability Standard that adequately addresses a specific matter that is identified in a directive issued by an Applicable Governmental Authority, then Rule 321 of these Rules of Procedure shall apply, with appropriate modification of the timeline.

310. Annual Reliability Standards Development Plan

NERC shall develop and provide an annual Reliability Standards Development Plan for development of Reliability Standards to the Applicable Governmental Authorities. NERC shall consider the comments and priorities of the Applicable Governmental Authorities in developing and updating the annual Reliability Standards Development Plan. Each annual Reliability Standards Development Plan shall include a progress report comparing results achieved to the prior year's Reliability Standards Development Plan.

311. Regional Entity Standards Development Procedures

1. **NERC Approval of Regional Entity Reliability Standards Development Procedure** — To enable a Regional Entity to develop Regional Reliability Standards that are to be recognized and made part of NERC Reliability Standards, a Regional Entity may request NERC to approve a Regional Reliability Standards development procedure.

2. **Public Notice and Comment on Regional Reliability Standards Development Procedure** — Upon receipt of such a request, NERC shall publicly notice and request comment on the proposed Regional Reliability Standards development procedure, allowing a minimum of 45 days for comment. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to withdraw the request, revise the Regional Reliability Standards development procedure and request another posting for comment, or submit the Regional Reliability Standards development procedure, along with its consideration of any objections received, for approval by NERC.

3. **Evaluation of Regional Reliability Standards Development Procedure** — NERC shall evaluate whether a Regional Reliability Standards development procedure meets the criteria listed below and shall consider stakeholder comments, any unresolved stakeholder objections, and the consideration of comments provided by the Regional Entity, in making that determination. If NERC determines the Regional Reliability Standards development procedure meets these requirements, the Regional Reliability Standards development procedure shall be submitted to the Board for approval. The Board shall consider the recommended action, stakeholder comments, any unresolved stakeholder comments, and the Regional Entity consideration of comments in determining whether to approve the Regional Reliability Standards development procedure.

    3.1 **Evaluation Criteria** — The Regional Reliability Standards development procedure shall be:

3.1.1 **Open** — The Regional Reliability Standards development procedure shall provide that any person or entity who is directly and materially affected by the reliability of the Bulk Power Systems within the Regional Entity shall be able to participate in the development and approval of Reliability Standards. There shall be no undue financial barriers to participation. Participation shall not be conditional upon membership in the Regional Entity, a Regional Entity or any organization, and shall not be unreasonably restricted on the basis of technical qualifications or other such requirements.

3.1.2 **Inclusive** — The Regional Reliability Standards development procedure shall provide that any Person with a direct and material interest has a right to participate by expressing an opinion and its basis, having that position considered, and appealing through an established appeals process if adversely affected.

3.1.3 **Balanced** — The Regional Reliability Standards development procedure shall have a balance of interests and shall not permit any two interest categories to dominate a matter or any single interest category to defeat a matter.

3.1.4 **Due Process** — The Regional Reliability Standards development procedure shall provide for reasonable notice and opportunity for public comment. At a minimum, the Regional Reliability Standards development procedure shall include public notice of the intent to develop a Regional Reliability Standard, a public comment period on the proposed Regional Reliability Standard, due consideration of those public comments, and a ballot of interested stakeholders.

3.1.5 **Transparent** — All actions material to the development of Regional Reliability Standards shall be transparent. All Regional Reliability Standards development meetings shall be open and publicly noticed on the Regional Entity's website.

3.1.6 **Accreditation of Regional Standards Development Procedure** — A Regional Entity's Regional Reliability Standards development procedure that is accredited by the American National Standards Institute shall be deemed to meet the criteria listed in this Section 311.3.1, although such accreditation is not a prerequisite for approval by NERC.

3.1.7 **Use of NERC Procedure** — A Regional Entity may adopt the NERC *Standard Processes Manual* as the Regional Reliability Standards development procedure, in which case the Regional

Entity's Regional Reliability Standards development procedure shall be deemed to meet the criteria listed in this Section 311.3.1.

4. **Revisions of Regional Reliability Standards Development Procedures** — Any revision to a Regional Reliability Standards development procedure shall be subject to the same approval requirements set forth in Sections 311.1 through 311.3.

5. **Duration of Regional Reliability Standards Development Procedures** — The Regional Reliability Standards development procedure shall remain in effect until such time as it is replaced with a new version approved by NERC or it is withdrawn by the Regional Entity. The Regional Entity may, at its discretion, withdraw its Regional Reliability Standards development procedure at any time.

312. Regional Reliability Standards

1. **Basis for Regional Reliability Standards** — Regional Entities may propose Regional Reliability Standards that set more stringent reliability requirements than the NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard. Such Regional Reliability Standards shall in all cases be submitted to NERC for adoption and, if adopted, made part of the NERC Reliability Standards and shall be enforceable in accordance with the delegation agreement between NERC and the Regional Entity or other instrument granting authority over enforcement to the Regional Entity. No entities other than NERC and the Regional Entity shall be permitted to develop Regional Reliability Standards that are enforceable under statutory authority delegated to NERC and the Regional Entity.

2. **Regional Reliability Standards That are Directed by a NERC Reliability Standard** — Although it is the intent of NERC to promote uniform Reliability Standards across North America, in some cases it may not be feasible to achieve a reliability objective with a Reliability Standard that is uniformly applicable across North America. In such cases, NERC may direct Regional Entities to develop Regional Reliability Standards necessary to implement a NERC Reliability Standard. Such Regional Reliability Standards that are developed pursuant to a direction by NERC shall be made part of the NERC Reliability Standards.

3. **Procedure for Developing an Interconnection-wide Regional Standard** — A Regional Entity organized on an Interconnection-wide basis may propose a Regional Reliability Standard for approval as a NERC Reliability Standard to be made mandatory for all applicable Bulk Power System owners, operators, and users within that Interconnection.

   3.1 **Presumption of Validity** — An Interconnection-wide Regional Reliability Standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities, shall be adopted as a NERC Reliability Standard. NERC shall

rebuttably presume that a Regional Reliability Standard developed, in accordance with a Regional Reliability Standards development process approved by NERC, by a Regional Entity organized on an Interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with such other applicable standards of governmental authorities.

3.2 **Notice and Comment Procedure for Interconnection-wide Regional Reliability Standard** — NERC shall publicly notice and request comment on the proposed Interconnection-wide Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to resolve any objections identified in the comments and may choose to comment on or withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for approval by NERC.

3.3 **Adoption of Interconnection-wide Regional Reliability Standard by NERC** — NERC shall evaluate and recommend whether a proposed Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections that could serve as a basis for rebutting the presumption of validity of the Regional Reliability Standard. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning the proposed Regional Reliability Standard, shall have the option of presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, NERC's recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

3.4 **Applicable Governmental Authority Approval** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

3.5 **Enforcement of Interconnection-wide Regional Reliability Standard** — An Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or

is otherwise made effective within Canada as mandatory within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

4. **Procedure for Developing Non-Interconnection-Wide Regional Reliability Standards** — Regional Entities that are not organized on an Interconnection-wide basis may propose Regional Reliability Standards to apply within their respective Regions. Such Regional Reliability Standards may be developed through the NERC Reliability Standards development procedure, or alternatively, through a Regional Reliability Standards development procedure that has been approved by NERC.

4.1 **No Presumption of Validity** — Regional Reliability Standards that are not proposed to be applied on an Interconnection-wide basis are not presumed to be valid but may be demonstrated by the proponent to be valid.

4.2 **Notice and Comment Procedure for Non-Interconnection-wide Regional Reliability Standards** — NERC shall publicly notice and request comment on the proposed Regional Reliability Standard, allowing a minimum of 45 days for comment. NERC may publicly notice and post for comment the proposed Regional Reliability Standard concurrent with similar steps in the Regional Entity's Regional Reliability Standards development process. The Regional Entity shall have an opportunity to comment on or resolve any objections identified in the comments and may choose to withdraw the request, revise the proposed Regional Reliability Standard and request another posting for comment, or submit the proposed Regional Reliability Standard along with its consideration of any objections received, for adoption by NERC.

4.3 **NERC Adoption of Non-Interconnection-wide Regional Reliability Standards** — NERC shall evaluate and recommend whether a proposed non-Interconnection-wide Regional Reliability Standard has been developed in accordance with all applicable procedural requirements and whether the Regional Entity has considered and resolved stakeholder objections. The Regional Entity, having been notified of the results of the evaluation and recommendation concerning proposed Regional Reliability Standard, shall have the option of presenting the proposed Regional Reliability Standard to the Board for adoption as a NERC Reliability Standard. The Board shall consider the Regional Entity's request, the recommendation for action on the Regional Reliability Standard, any unresolved stakeholder comments, and the Regional Entity's consideration of comments, in determining whether to adopt the Regional Reliability Standard as a NERC Reliability Standard.

4.4 **Applicable Governmental Authority Approval** — A non-Interconnection-wide Regional Reliability Standard that has been adopted

by the Board shall be filed with the Applicable Governmental Authorities for approval, where authorized by applicable legislation or agreement, and shall become effective when approved by such Applicable Governmental Authorities or on a date set by the Applicable Governmental Authorities.

4.5 **Enforcement of Non-Interconnection-wide Regional Reliability Standards** — A non-Interconnection-wide Regional Reliability Standard that has been adopted by the Board and by the Applicable Governmental Authorities or is otherwise made effective within Canada as mandatory within a particular Region shall be applicable and enforced as a NERC Reliability Standard within the Region.

5. **Appeals** — A Regional Entity shall have the right to appeal NERC's decision not to adopt a proposed Regional Reliability Standard or Variance to the Commission or other Applicable Governmental Authority.

313. Other Regional Criteria, Guides, Procedures, Agreements, Etc.

1. **Regional Criteria** — Regional Entities may develop Regional Criteria that are necessary to implement, to augment, or to comply with NERC Reliability Standards, but which are not Reliability Standards. Regional Criteria may also address issues not within the scope of Reliability Standards, such as resource adequacy. Regional Criteria may include specific acceptable operating or planning parameters, guides, agreements, protocols or other documents used to enhance the reliability of the Bulk Power System in the Region. These documents typically provide benefits by promoting more consistent implementation of the NERC Reliability Standards within the Region. These documents are not NERC Reliability Standards, Regional Reliability Standards, or regional Variances, and therefore are not enforceable under authority delegated by NERC pursuant to delegation agreements and do not require NERC approval.

2. **Catalog of Regional Criteria** — Each Regional Entity that has Regional Criteria shall maintain a publicly-available, current catalog of its Regional Criteria. Regional Entities shall provide any Regional Criteria to NERC upon written request.

314. Conflicts with Statutes, Regulations, and Orders

Notice of Potential Conflict — If a Bulk Power System owner, operator, or user determines that a NERC or Regional Reliability Standard may conflict with a function, rule, order, tariff, rate schedule, legislative requirement or agreement that has been accepted, approved, or ordered by a governmental authority affecting that entity, the entity shall expeditiously notify the governmental authority, NERC, and the relevant Regional Entity of the conflict.

1. **Determination of Conflict —** NERC, upon request of the governmental authority, may advise the governmental authority regarding the conflict and

propose a resolution of the conflict, including revision of the Reliability Standard if appropriate.

2. **Regulatory Precedence** — Unless otherwise ordered by a governmental authority, the affected Bulk Power System owner, operator, or user shall continue to follow the function, rule, order, tariff, rate schedule, legislative requirement, or agreement accepted, approved, or ordered by the governmental authority until the governmental authority finds that a conflict exists and orders a remedy and such remedy is affected.

315. Revisions to NERC Standard Processes Manual

Any person or entity may submit a written request to modify NERC *Standard Processes Manual*. Consideration of the request and development of the revision shall follow the process defined in the NERC *Standard Processes Manual*. Upon approval by the Board, the revision shall be submitted to the Applicable Governmental Authorities for approval. Changes shall become effective only upon approval by the Applicable Governmental Authorities or on a date designated by the Applicable Governmental Authorities or as otherwise applicable in a particular jurisdiction.

316. Reserved

317. Periodic Review of Reliability Standards

NERC shall complete a periodic review of each NERC Reliability Standard in accordance with the NERC *Standard Processes Manual*. As a result of this review, the NERC Reliability Standard shall be reaffirmed, revised, or withdrawn. If the review indicates a need to revise or withdraw the Reliability Standard, a request for revision or withdrawal shall be prepared, submitted and addressed in accordance with the NERC *Standard Processes Manual*.

318. Coordination with the North American Energy Standards Board

NERC shall maintain a close working relationship with the North American Energy Standards Board and ISO/RTO Council to ensure effective coordination of wholesale electric business practice standards and market protocols with the NERC Reliability Standards.

319. Archived Standards Information

NERC shall maintain a historical record of Reliability Standards information that is no longer maintained on-line. For example, Reliability Standards that have been retired may be removed from the on-line system. Archived information shall be retained indefinitely as practical, but in no case less than six years or one complete Reliability Standards review cycle from the date on which the Reliability Standard was no longer in effect. Archived records of Reliability Standards information shall be available electronically within 30 days following the receipt by NERC staff of a written request.

320. Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels

1. **Development of Violation Risk Factors and Violation Severity Levels** — NERC shall follow the process for developing Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) as set forth in the Standard Processes Manual, Appendix 3A to these Rules of Procedure.

2. **Remands of Directed Revision of VRFs and VSLs by Applicable Governmental Authorities** — If an Applicable Governmental Authority remands or directs a revision to a Board-approved VRF or VSL assignment, the NERC director of standards, after consulting with the standard drafting team, Standards Committee, and the NERC director of compliance operations, will recommend to the Board one of the following actions: (1) filing a request for clarification; (2) filing for rehearing or for review of the Applicable Governmental Authority decision; or (3) approval of the directed revisions to the VRF or VSL. If and to the extent time is available prior to the deadline for the Board's decision, an opportunity for interested parties to comment on the action taken will be provided.

3. **Alternative Procedure for Developing and Approving Violation Risk Factors and Violation Severity Levels** — In the event the Reliability Standards development process fails to produce Violation Risk Factors or Violation Severity Levels for a particular Reliability Standard in a timely manner, the Board of Trustees may approve Violation Risk Factors or Violation Severity Levels for that Reliability Standard after notice and opportunity for comment. In approving VRFs and VSLs, the Board shall consider the inputs of the Member Representatives Committee, affected stakeholders and NERC staff.

321. Special Rule to Address Certain Regulatory and Board of Trustees Directives

In circumstances where this Rule 321 applies, the Board of Trustees shall have the authority to take one or more of the actions set out below. The Board of Trustees shall have the authority to choose which one or more of the actions are appropriate to the circumstances and need not take these actions in sequential steps; provided that the Board of Trustees shall, to the extent feasible and consistent with its obligations and established deadlines, choose actions that seek to maximize stakeholder participation.

1. The Standards Committee shall have the responsibility to ensure that standards drafting teams address specific matters that are identified in directives issued by Applicable Governmental Authorities or by the NERC Board of Trustees pursuant to its authority in Section 322. If the Board of Trustees is presented with a proposed Reliability Standard that fails to adequately address such directives, the Board of Trustees has the authority to remand, with instructions (including establishing a timetable for action), the proposed Reliability Standard to the Standards Committee.

2. Upon a written finding by the Board of Trustees that a ballot pool has failed to approve a proposed Reliability Standard that contains a provision to adequately address a specific matter identified in a directive issued by an Applicable Governmental Authority or by the NERC Board of Trustees pursuant to its

authority in Section 322, the Board of Trustees has the authority to remand the proposed Reliability Standard to the Standards Committee, with instructions to (i) convene a public technical conference to discuss the issues surrounding the regulatory or Board directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified; (ii) working with NERC staff, prepare a memorandum discussing the issues, an analysis of the alternatives considered and other appropriate matters; (iii) use the input from the technical conference to revise the proposed Reliability Standard, as appropriate; and (iv) re-ballot the proposed Reliability Standard one additional time, with such adjustments in the schedule as are necessary to meet the deadline contained in paragraph 2.1 of this Rule.

2.1 Such a re-ballot shall be completed within forty-five (45) days of the remand. The Standards Committee memorandum shall be included in the materials made available to the ballot pool in connection with the re-ballot.

2.2 In any such re-ballot, negative votes without comments related to the proposal shall be counted for purposes of establishing a quorum, but only affirmative votes and negative votes with comments related to the proposal shall be counted for purposes of determining the number of votes cast and whether the proposed Reliability Standard has been approved.

3. If the re-balloted proposed Reliability Standard achieves at least an affirmative two-thirds majority vote of the weighted Segment votes cast, with a quorum established, then the proposed Reliability Standard shall be deemed approved by the ballot pool and shall be considered by the Board of Trustees for approval.

4. If the re-balloted proposed Reliability Standard fails to achieve at least an affirmative two-thirds majority vote of the weighted Segment votes cast, but does achieve at least a sixty percent affirmative majority of the weighted Segment votes cast, with a quorum established, then the Board of Trustees has the authority to consider the proposed Reliability Standard for approval under the following procedures:

4.1 The Board of Trustees shall issue notice of its intent to consider the proposed Reliability Standard and shall solicit written public comment particularly focused on the technical aspects of the provisions of the proposed Reliability Standard that address the specific matter identified in the regulatory or Board directive, including whether or not the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, in the public interest, helpful to reliability, practical, technically sound, technically feasible, and cost-justified.

4.2 The Board of Trustees may, in its discretion, convene a public technical conference to receive additional input on the matter.

4.3 After considering the developmental record, the comments received during balloting and the additional input received under paragraphs 4.1 and 4.2 of this Rule, the Board of Trustees has authority to act on the proposed Reliability Standard.

4.3.1 If the Board of Trustees finds that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to approve the proposed Reliability Standard and direct that it be filed with Applicable Governmental Authorities with a request that it be made effective. In addition, the Board of Trustees may direct further revisions in accordance with Rule 322.

4.3.2 If the Board of Trustees is unable to find that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is helpful to reliability, practical, technically sound, technically feasible, and cost-justified, then it has authority to take one of the following actions:

4.3.2.1 For a regulatory directive, the Board of Trustees may treat the proposed Reliability Standard as a draft Reliability Standard and direct that the draft Reliability Standard and complete developmental record, including the additional input received under paragraphs 4.1 and 4.2 of this Rule, be filed with the Applicable Governmental Authorities as a compliance filing in response to the order giving rise to the regulatory directive, along with a recommendation that the Reliability Standard not be made effective and an explanation of the basis for the recommendation.

4.3.2.2 For a Board directive, the Board of Trustees may remand the proposed Reliability Standard and direct further work under this Section.

5. Upon a written finding by the Board of Trustees that standard drafting team has failed to develop, or a ballot pool has failed to approve, a proposed Reliability Standard that contains a provision to adequately address a specific matter identified in a directive issued by an Applicable Governmental Authority or the Board of Trustees, the Board of Trustees has the authority to direct the Standards Committee (with the assistance of stakeholders and NERC staff) to prepare a draft Reliability Standard that addresses the regulatory or Board directive, taking account of the entire developmental record pertaining to the matter. If the Standards Committee fails to prepare such draft Reliability Standard, the Board of

Trustees may direct NERC management to prepare such draft Reliability Standard.

5.1 The Board of Trustees may, in its discretion, convene a public technical conference to receive input on the matter. The draft Reliability Standard shall be posted for a 45-day public comment period.

5.2 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees finds that the draft Reliability Standard, with such modifications as the Board of Trustees determines are appropriate in light of the comments received, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to approve the draft Reliability Standard and direct that the proposed Reliability Standard be filed with Applicable Governmental Authorities with a request that the proposed Reliability Standard be made effective. In addition, the Board of Trustees may direct further work in accordance with Rule 322.

5.3 If, after considering the entire developmental record (including the comments received under paragraph 5.1 of this Rule), the Board of Trustees is unable to find that the draft Reliability Standard, even with modifications, is just, reasonable, not unduly discriminatory or preferential, and in the public interest, considering (among other things) whether it is practical, technically sound, technically feasible, cost-justified and serves the best interests of reliability of the Bulk Power System, then the Board of Trustees has the authority to take one of the following actions:

5.3.1 For a regulatory directive, the Board of Trustees may direct that the draft Reliability Standard and complete developmental record be filed as a compliance filing in response to the regulatory directive with the Applicable Governmental Authority issuing the regulatory directive, with a recommendation that the draft Reliability Standard not be made effective.

5.3.2 For a Board directive, the Board of Trustees may remand the proposed Reliability Standard and direct further work under this Section.

5.4 The filing of the Reliability Standard under either paragraph 5.2 or paragraph 5.3 of this Rule shall include an explanation of the basis for the decision by the Board of Trustees.

6. NERC shall on or before March 31st of each year file a report with Applicable Governmental Authorities on the status and timetable for addressing each outstanding directive to address a specific matter received from an Applicable Governmental Authority.

322. Special Authority to Address Reliability Matters Necessary to Maintain the Reliability of the Bulk Power System

To meet NERC's statutory responsibility under Section 215 of the Federal Power Act to develop Reliability Standards that provide for an adequate level of reliability for the Bulk Power System, the Board of Trustees shall have the authority to direct the development of a new or revised Reliability Standard. The Board of Trustees will only exercise this authority in extraordinary circumstances, where the Board determines a directive is essential to provide for an adequate level of reliability for the Bulk Power System consistent with Section 215 of the Federal Power Act. This authority shall be in addition to the Board of Trustees' other authorities regarding Reliability Standards as provided in these Rules of Procedure and the Bylaws. In issuing such directives, the following process shall be used:

1. The Board of Trustees shall provide public notice of its intent to direct the development of a new or revised Reliability Standard to address a matter it has deemed essential to provide for an adequate level of reliability for the Bulk Power System. This notice shall take the form of a written document that includes, at a minimum, the following:

    1.1 the proposed date for issuing the proposed directive, which shall be no earlier than 60 days from the date of the notice, and the period for public comment, which shall be no less than 45 days;

    1.2 a description of the proposed directive, including any deadlines for standards development;

    1.3 the reliability basis for the proposed directive;

    1.4 the reasons why the Board has preliminarily determined that extraordinary circumstances exist, and that the proposed directive is essential to assure the reliable operation of the Bulk Power System;

    1.5 identification of any past, current, or planned stakeholder-initiated standards development projects to address the reliability matter addressed by the proposed directive; and

    1.6 An explanation of why the Board has preliminarily determined that the reliability matter cannot be addressed adequately or in a timely manner through stakeholder-initiated projects or a project initiated by NERC Staff.

2. NERC shall publicly post the notice and set a public comment period for the time described in the notice.

3. The Board of Trustees may direct the development of a new or revised Reliability Standard, as originally proposed or with modifications, if it determines that such action is just, reasonable, not unduly discriminatory, and in the public interest. This action shall take the take the form of a written determination containing, at a minimum, the following:

    1.1 the effective date of the directive;

    1.2 a description of the directive, including any deadlines for standards development;

    1.3 the reliability basis for the directive;

    1.4 the reasons why the Board has determined that extraordinary circumstances exist, and that the directive is essential to assure the reliable operation of the Bulk Power System;

    1.5 identification of any past, current, or planned stakeholder-initiated standards development projects to address the reliability matter addressed by the proposed directive;

    1.6 An explanation of why the Board has determined that the reliability matter cannot be addressed adequately or in a timely manner through stakeholder-initiated projects or a project initiated by NERC Staff; and

    1.7 a description of how the Board of Trustees considered any advice provided by the Member Representatives Committee, or any comments provided by the public, NERC standing committees, Applicable Governmental Authorities or other regulatory authorities, the Regional Entities, or NERC management.

4. Any person or entity with directly and materially affected interests in the subject of a Board of Trustees directive, including any nonprofit association representing members with such interests, may request the Board of Trustees reconsider or clarify its determination. Such request shall be submitted in writing within 30 calendar days of the issuance of the determination and contain, at a minimum, a description of the matter for which the entity is seeking reconsideration or clarification, the reasons therefor, and the interests that would be affected if the requested reconsideration or clarification is not granted. If the Board of Trustees does not act on the request within 30 days, it may be deemed denied. Unless

otherwise directed by the Board of Trustees, no deadline for action shall be stayed pending the disposition of any request for reconsideration or clarification.

5. NERC shall publicly post all Board of Trustees directives and any supporting documentation. This information shall become part of the record of development for the resulting Reliability Standard.

6. Where the Board of Trustees has determined to direct the development of a new or revised Reliability Standard, NERC Staff shall prepare a Standards Authorization Request for submission to the Standards Committee.

7. Reliability Standards that are directed by the Board of Trustees shall be developed using the NERC Standard Processes Manual. The waiver provisions of the NERC *Standard Processes Manual* may be applied if necessary to meet a timetable for action required by the Board of Trustees, respecting to the extent possible the provisions in the *NERC Standard Processes Manual* for reasonable notice and opportunity for public comment, due process, openness, and a balance of interest in developing Reliability Standards. If the Board of Trustees determines that the process did not result in a Reliability Standard that addresses a specific matter that is identified in its directive, then the Board of Trustees may, in its discretion, apply Rule 321 of these Rules of Procedure.

SECTION 400 — COMPLIANCE MONITORING AND ENFORCEMENT

401. Scope of the Compliance Monitoring and Enforcement Program

1. **Components of the Compliance Monitoring and Enforcement Program** — NERC shall develop and implement a Compliance Monitoring and Enforcement Program (CMEP) to promote the reliability of the Bulk Power System by enforcing compliance with approved Reliability Standards in those regions of North America in which NERC and/or a Regional Entity (pursuant to a delegation agreement with NERC or other legal instrument approved by an Applicable Governmental Authority) has been given enforcement authority.

2. **Who Must Comply** — Where required by applicable legislation, regulation, rule or agreement, all Bulk Power System owners, operators, and users are required to comply with all approved Reliability Standards at all times. Regional Reliability Standards and Variances approved by NERC and the Applicable Governmental Authority shall be considered Reliability Standards and shall apply to all Bulk Power System owners, operators, or users responsible for meeting those Reliability Standards within the Regional Entity boundaries, whether or not the Bulk Power System owner, operator, or user is a member of the Regional Entity.

3. **Data Access** — All Bulk Power System owners, operators, and users shall provide to NERC or the Compliance Enforcement Authority (CEA) such Documents, data, and information as is necessary to monitor and enforce compliance with the Reliability Standards. NERC and the CEA will define the data retention and reporting requirements.

4. **Role of Regional Entities in the Compliance Monitoring and Enforcement Program** — Each Regional Entity that has been delegated authority through a delegation agreement or other legal instrument approved by the Applicable Governmental Authority shall, in accordance with the terms of the approved delegation agreement, administer the CMEP provided in these Rules of Procedure.

5. **Program Continuity** — NERC will ensure continuity of compliance monitoring and enforcement within the geographic boundaries of a Regional Entity if NERC does not have a delegation agreement with a Regional Entity, the Regional Entity or NERC terminates the delegation agreement, or the Regional Entity does not administer the CMEP in accordance with the delegation agreement or other applicable requirements.

   5.1 In the circumstances outlined above, the following will apply:

      1. This monitoring and enforcement can be coordinated with staff from another approved Regional Entity.

2. If an existing delegation agreement with a Regional Entity is terminating, the Regional Entity shall promptly provide to NERC all relevant information regarding Registered Entities in the geographic footprint or for which the Regional Entity has CMEP responsibilities under coordinated oversight of Registered Entities, as specified in a termination agreement.

3. NERC will levy and collect all Penalties directly and will utilize any Penalty monies consistent with Section 1107 of the Rules of Procedure.

5.2 Should a Regional Entity seek to withdraw from its delegation agreement, NERC will seek agreement from another Regional Entity to amend its delegation agreement with NERC to extend that Regional Entity's boundaries for compliance monitoring and enforcement. In the event no Regional Entity is willing to accept this responsibility, NERC will administer the CMEP within the geographical boundaries of the Regional Entity seeking to withdraw from the delegation agreement, in accordance with Section 401.5.1.

6. **Risk Elements** — NERC, with input from the Regional Entities, stakeholders, and regulators, shall at least annually identify ERO and Regional Entity-specific risk elements, together with related Reliability Standards and Requirements are to be considered to prioritize CMEP activities. NERC coordinates with the Regional Entities to identify the risk elements using data including, but not limited to: compliance findings; event analysis experience; data analysis; and the expert judgment of NERC and Regional Entity staff, committees, and subcommittees. Compliance is required, and NERC and the Regional Entities have authority to monitor compliance, with all applicable Reliability Standards whether or not they are identified as areas of focus to be considered for compliance oversight in the annual ERO CMEP Implementation Plan or are included in a Regional Entity's oversight plan for the Registered Entity.

7. **Penalties, Sanctions, and Remedial Action Directives** — NERC and Regional Entities will apply Penalties, sanctions, and Remedial Action Directives that bear a reasonable relation to the seriousness of a violation and take into consideration timely remedial efforts as defined in the NERC *Sanction Guidelines*, which are incorporated into these rules as **Appendix 4B**.

8. **Multiple Enforcement Actions** – A Registered Entity shall not be subject to an enforcement action by NERC and a Regional Entity, or by more than one Regional Entity (unless the Registered Entity is registered in more than one Region in which the violation occurred), for the same violation.

9. **Records** — NERC and Regional Entities shall coordinate to maintain a record of each compliance submission, including potential noncompliance with approved

Reliability Standards; associated Penalties, sanctions, Remedial Action Directives, and settlements; and the status of Mitigating Activities.

10. **Confidential Information** — The types of CMEP information that will be considered confidential and will not (subject to statutory and regulatory requirements) be disclosed in any public information reported by NERC are identified in Section 1500.

    The disclosure by the CEA or NERC of any CMEP Confidential Information shall follow Section 1500.

11. **Public Posting** — When the affected Bulk Power System owner, operator, or user either agrees with the resolution of a potential noncompliance with a Reliability Standard(s) or a report of a Compliance Audit or Compliance Investigation, or enters into a settlement agreement concerning a potential noncompliance or Alleged Violation(s), or the time for submitting an appeal is passed, or all appeals processes are complete, NERC shall, subject to the requirements, rules, and regulations of the Applicable Governmental Authority and the confidentiality requirements of these Rules of Procedure, publicly post information on each such noncompliance, Penalty or sanction, settlement agreement, and final Compliance Audit or Compliance Investigation, on its website. As required by an Applicable Governmental Authority, NERC will also post information concerning noncompliance disposed of as Compliance Exceptions, subject to Section 1500 of these Rules of Procedure.

    11.1 Each Bulk Power System owner, operator, or user may provide NERC with a statement to accompany the publicly posted information. The statement must be on company letterhead and include a signature, as well as the name and title of the person submitting the information.

    11.2 Subject to the disclosure requirements of the Applicable Governmental Authority and redaction of Critical Energy Infrastructure Information, Critical Electric Infrastructure Information, or other Confidential Information, for each resolved noncompliance submitted to the Applicable Governmental Authority, the public posting shall include: a) the name of any relevant entity, b) the nature, time period, and circumstances of the noncompliance, c) any Mitigation Plan or other Mitigating Activities to be implemented by the Registered Entity, and d) sufficient facts to assist owners, operators and users of the Bulk Power System to evaluate whether they have engaged in or are engaging in similar activities.

12. **Review of Noncompliance** — NERC staff shall periodically review and analyze reports of noncompliance to identify trends and other pertinent reliability issues.

402. NERC Oversight of the Compliance Monitoring and Enforcement Program

1. **Oversight** — NERC shall oversee each Regional Entity that has been delegated authority. The objective of this oversight is to ensure that the Regional Entity

carries out its obligations under the CMEP in accordance with these Rules of Procedure and the terms of the delegation agreement, and to ensure consistency and fairness of the Regional Entity's execution of the CMEP. Oversight by NERC shall be accomplished through an annual Compliance Monitoring and Enforcement Program review, program audits, regular evaluations of Regional Entity Compliance Monitoring and Enforcement Program performance metrics, risk-based monitoring activities, and performance reports. Through this oversight, NERC evaluates the Regional Entity's effectiveness and implementation of the CMEP using, among other things, the criteria developed by the NERC Compliance and Certification Committee.

1.1 **Annual ERO CMEP Implementation Plan** — NERC and the Regional Entities will maintain and update an ERO CMEP Implementation Plan. The ERO CMEP Implementation Plan reflects ERO and Regional Entity-specific risk elements that CEAs should prioritize for oversight of Registered Entities.

1.2 **Regional Entity Compliance Monitoring and Enforcement Program Evaluation** — NERC shall annually evaluate the goals, tools, and procedures of each Regional Entity Compliance Monitoring and Enforcement Program to determine the effectiveness of each Regional Entity Compliance Monitoring and Enforcement Program, using criteria developed by the NERC Compliance and Certification Committee.

1.3 **Regional Entity Compliance Monitoring and Enforcement Program Audit** — At least once every five years, NERC shall conduct an audit to evaluate how each Regional Entity implements the CMEP. The audit shall be based on these Rules of Procedure, including Appendix 4C, the delegation agreements, directives in effect pursuant to the delegation agreements, the approved annual ERO CMEP Implementation Plan, required CMEP attributes, and NERC CMEP guidance and procedures. The audit shall be provided to the Applicable Governmental Authorities to demonstrate the effectiveness of each Regional Entity. In addition, audits of Cross-Border Regional Entities shall cover applicable requirements imposed on the Regional Entity by statute, regulation, or order of, or agreement with, provincial governmental and/or regulatory authorities for which NERC has auditing responsibilities over the Regional Entity's compliance with such requirements within Canada or Mexico. Participation of a representative of an Applicable Governmental Authority shall be subject to the limitations of sections 4.1.4 and 8.0 of Appendix 4C of these Rules of Procedure regarding disclosures of non-public compliance information related to other jurisdictions. NERC shall maintain an audit procedure containing the requirements, steps, and timelines to conduct an audit of each Regional Entity.

1.3.1. NERC shall establish a program to audit bulk power system owners, operators, and users operating within a regional entity to

verify the findings of previous compliance audits conducted by the regional entity to evaluate how well the regional entity compliance enforcement program is meeting its delegated authority and responsibility.

1.4 Applicable Governmental Authorities will be allowed to participate as an observer in any audit conducted by NERC of a Regional Entity's implementation of the CMEP.

2. **Consistency in Regional Implementation of the Compliance Monitoring and Enforcement Program** — To provide for consistency and fairness of the processes used for Regional Entity findings of compliance and noncompliance and the application of Penalties and sanctions for all Bulk Power System owners, operators, and users required to comply with approved Reliability Standards, NERC shall maintain a single CMEP, which is incorporated into these Rules of Procedure as **Appendix 4C**. Any differences in CMEP methods, including determination of noncompliance and Penalty assessment, shall be justified on a case-by-case basis and fully documented in each Regional Entity delegation agreement.

2.1 NERC shall periodically conduct Regional Entity CMEP manager meetings. These meetings shall identify and resolve CMEP differences into a set of best practices over time.

3. **Information Collection and Reporting** — NERC and the Regional Entities shall implement data management procedures that address data reporting requirements, data integrity, data retention, data security, and data confidentiality.

4. **Noncompliance Disclosure** — NERC shall follow the process in **Appendix 4C**.

5. **Authority to Determine Noncompliance, Levy Penalties and Sanctions, and Issue Remedial Action Directives** — The CEA shall have the authority and responsibility to make initial determinations of compliance or noncompliance, and where authorized by the Applicable Governmental Authorities or where otherwise authorized, to determine Penalties and sanctions for noncompliance with a Reliability Standard, and issue Remedial Action Directives. Remedial Action Directives may be issued by a CEA that is aware of a Bulk Power System owner, operator, or user that is, or is about to engage in an act or practice that would result, in noncompliance with a Reliability Standard, where such Remedial Action Directive is immediately necessary to protect the reliability of the Bulk Power System from an imminent or actual threat. If, after receiving such a Remedial Action Directive, the Bulk Power System owner, operator, or user does not take appropriate action to avert noncompliance with a Reliability Standard, NERC may petition the Applicable Governmental Authority to issue a compliance order.

6. **Due Process** — NERC shall establish and maintain a fair, independent, and nondiscriminatory appeals process. The appeals process is set forth in Sections

408-410. The process shall allow Bulk Power System owners, operators, and users to appeal the Regional Entity's findings of noncompliance and to appeal Penalties, sanctions, and Remedial Action Directives that are levied by the Regional Entity. Appeals beyond the NERC process will be heard by the Applicable Governmental Authority.

7. **Conflict Disclosure** — NERC shall disclose to the Applicable Governmental Authority any potential conflicts between a market rule and the enforcement of a Reliability Standard.

8. **Confidentiality** — To maintain the integrity of the CMEP, NERC and Regional Entities, Compliance Audit team members, and committee members shall maintain the confidentiality of information obtained and shared during CMEP activities.

    8.1 NERC and the Regional Entity shall have in place appropriate codes of conduct and confidentiality agreements for all participants in CMEP activities.

    8.2 A participant's failure to follow the code of conduct or Confidential Information provisions of these Rules of Procedure may result in that person and any member organization with which the person is associated losing access to Confidential Information on a temporary or permanent basis and being subject to appropriate action by the Regional Entity or NERC, including prohibiting participation in future CMEP activities. Nothing in Section 1500 precludes an entity whose information was improperly disclosed from seeking a remedy in an appropriate court.

9. **Auditor Training** — NERC shall develop and provide training in auditing skills to participants in NERC and Regional Entity Compliance Audits. Training for NERC and Regional Entity personnel and others who serve as Compliance Audit team leaders shall be more comprehensive than training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

403. Required Attributes of Regional Entity Implementation of the Compliance Monitoring and Enforcement Program

Each Regional Entity shall (i) conform to and comply with the CMEP, **Appendix 4C** to these Rules of Procedure, except to the extent of any deviations that are stated in the Regional Entity's delegation agreement, and (ii) meet all of the attributes set forth in this Section 403.

Program Structure

1. **Independence** — Each Regional Entity's governance of its CMEP activities shall exhibit independence, meaning the Regional Entity shall be organized so that its CMEP activities are carried out separately from other activities of the Regional

Entity. The CMEP activities shall not be unduly influenced by the Bulk Power System owners, operators, and users being monitored. Regional Entities must include rules providing that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

2. **Exercising Authority** — Each Regional Entity shall exercise the responsibility and authority in carrying out the delegated functions of the CMEP in accordance with delegation agreements and **Appendix 4C**.

3. **Delegation of Authority** — To maintain independence, fairness, and consistency in the CMEP, a Regional Entity shall not sub-delegate its CMEP duties to entities or persons other than the Regional Entity Staff, unless (i) required by statute or regulation in the applicable jurisdiction, or (ii) by agreement with express approval of NERC and of FERC or other Applicable Governmental Authority, to another Regional Entity.

4. **Hearings of Contested Findings or Sanctions —** Unless the Regional Entity has elected to participate in the Consolidated Hearing Process, the Regional Entity board or compliance panel reporting directly to the Regional Entity board will designate a Hearing Body (with appropriate recusal procedures) that will be vested with the authority for conducting all compliance hearings, pursuant to the hearing process selected under Section 403.15, in which any Bulk Power System owner, operator, or user provided a Notice of Alleged Violation may present facts and other information to contest a Notice of Alleged Violation or any proposed Penalty, sanction, any Remedial Action Directive, or any Mitigation Plan component. Compliance hearings shall be conducted in accordance with the Hearing Procedures set forth in Attachment 2 to **Appendix 4C**. If a stakeholder body serves as the Hearing Body, no two industry sectors may control any decision and no single sector may veto any matter related to compliance after recusals.

Program Resources

5. **Regional Entity Staff** — Each Regional Entity shall have sufficient resources to meet delegated compliance monitoring and enforcement responsibilities, including the necessary professional staff to manage and implement the CMEP.

6. **Regional Entity Staff Independence** — The Regional Entity Staff, collectively, shall be capable and required to: a) make all determinations of compliance and noncompliance; b) determine Penalties, sanctions, and Remedial Action Directives; and c) review and accept Mitigation Plans and other Mitigating Activities.

    6.1 Regional Entity Staff shall not have a conflict of interest, real or perceived, in the outcome of compliance monitoring and enforcement processes, reports, or sanctions. The Regional Entity shall have in effect a conflict of interest policy.

6.2 Regional Entity Staff shall have the authority and responsibility to carry out compliance monitoring and enforcement processes, make determinations of compliance or noncompliance, and levy Penalties and sanctions without interference or undue influence from Regional Entity members and their representative or other industry entities.

6.3 Regional Entity Staff may call upon independent technical subject matter experts who have no conflict of interest in the outcome of the compliance monitoring and enforcement process to provide technical advice or recommendations in the determination of compliance or noncompliance.

6.4 Regional Entity Staff shall abide by the confidentiality requirements contained in Section 1500 and **Appendix 4C** of these Rules of Procedure and the delegation agreement

6.5 Contracting with independent consultants or others working for the Regional Entity shall be permitted provided the individual has not received compensation from a Bulk Power System owner, operator, or user being monitored for a period of at least the preceding six months and owns no financial interest in any Bulk Power System owner, operator, or user being monitored for compliance to the Reliability Standard, regardless of where the Bulk Power System owner, operator, or user operates. Any such individuals shall be considered as augmenting Regional Entity Staff under these Rules of Procedure.

7. **Use of Industry Subject Matter Experts and Regional Entity Members** — Industry experts and Regional Entity members may be called upon to provide their technical expertise in CMEP activities.

7.1 The Regional Entity shall have procedures defining the allowable involvement of industry subject matter experts and Regional Entity members. The procedures shall address applicable antitrust laws and conflicts of interest.

7.2 Industry subject matter experts and Regional Entity members shall have no conflict of interest or financial interests in the outcome of their activities.

7.3 Regional Entity members and industry subject matter experts, as part of teams or Regional Entity committees, may provide input to the Regional Entity so long as the authority and responsibility for (i) evaluating and determining compliance or noncompliance and (ii) levying Penalties, sanctions, or Remedial Action Directives shall not be delegated to any person or entity other than Regional Entity staff. Industry subject matter experts, Regional Entity members, or Regional Entity committees shall not make determinations of noncompliance or levy Penalties, sanctions, or Remedial Action Directives. Any committee involved shall be organized

so that no two industry sectors may control any decision and no single segment may veto any matter related to compliance.

7.4 Industry subject matter experts and Regional Entity members shall sign a confidentiality agreement appropriate for the activity being performed.

7.5 All industry subject matter experts and Regional Entity members participating in Compliance Audits and Compliance Investigations shall successfully complete auditor training provided by NERC or the Regional Entity prior to performing these activities

Program Design

8. **Antitrust Provisions** — Each Regional Entity's CMEP activities shall be structured and administered to abide by United States antitrust law and Canadian competition law.

9. **Information Submittal** — All Bulk Power System owners, operators, and users responsible for complying with Reliability Standards within the Regional Entity shall submit timely and accurate Documents, data, and information when requested by the Regional Entity or NERC. Where appropriate, Submitting Entities should comply with the requirements of Section 1500 in submitting such Documents, data, and information. NERC and the Regional Entities shall preserve any mark of confidentiality on information submitted pursuant to Section 1502.1.

9.1 Each Regional Entity has the authority to collect the necessary Documents, data, and information to determine compliance and shall develop processes for gathering Documents, data, and information from the Bulk Power System owners, operators, and users the Regional Entity monitors.

9.2 The Regional Entity or NERC has the authority to request information from Bulk Power System owners, operators, and users pursuant to Section 401.3 or this Section 403.9 without invoking a specific compliance monitoring and enforcement process in **Appendix 4C**, for purposes of determining whether to pursue one such process in a particular case and/or validating in the enforcement phase of a matter the conclusions reached through the compliance monitoring and enforcement process(es).

9.3 When required or requested, the Regional Entities shall report information to NERC promptly and in accordance with **Appendix 4C** and other NERC procedures.

9.4 Regional Entities shall notify NERC of noncompliance with Reliability Standards by Registered Entities over which the Regional Entity has compliance monitoring and enforcement authority, in accordance with **Appendix 4C**.

9.5 As requested by the CEA, a Bulk Power System owner, operator, or user found in noncompliance with a Reliability Standard shall submit a Mitigation Plan or conduct Mitigating Activities in accordance with **Appendix 4C**. The Regional Entity Staff shall review and accept the Mitigation Plan in accordance with **Appendix 4C**.

9.6 An officer of a Bulk Power System owner, operator, or user shall certify as accurate all Self-Reports to the Regional Entity, including Documents, data, and information provided with the Self-Report.

9.7 Regional Entities shall develop and implement procedures to verify the compliance information submitted by Bulk Power System owners, operators, and users.

10. **Compliance Monitoring of Bulk Power System Owners, Operators, and Users** — Each Regional Entity will maintain and implement a program for risk-based compliance monitoring, to include Compliance Audits of Bulk Power System owners, operators, and users responsible for complying with Reliability Standards, in accordance with **Appendix 4C**.

10.1 For an entity registered as a Balancing Authority, Reliability Coordinator, or Transmission Operator, the Compliance Audit will be performed at least once every three years.

11. **Confidentiality of Compliance Monitoring and Enforcement Processes** — All compliance monitoring and enforcement processes, and Documents, data, and information obtained from such processes, are to be non-public and treated in accordance with Section 1500 and **Appendix 4C** of these Rules of Procedure, unless NERC, the Regional Entity, or FERC or another Applicable Governmental Authority with jurisdiction determines a need to conduct a Compliance Monitoring and Enforcement Program process on a public basis. Advance authorization from the Applicable Governmental Authority is required to make public any compliance monitoring and enforcement process or any information relating to a compliance monitoring and enforcement process, or to permit interventions when determining whether to impose a Penalty. This prohibition on making public any compliance monitoring and enforcement process does not prohibit NERC or a Regional Entity from publicly disclosing (i) the initiation of or results from an analysis of a significant system event under Section 807 or of off-normal events or system performance under Section 808, or (ii) information of general applicability and usefulness to owners, operators, and users of the Bulk Power System concerning reliability and compliance matters, so long as such disclosures are in accordance with Section 1500 and Appendix 4C of these Rules of Procedure.

12. **Critical Energy Infrastructure Information and Critical Electric Infrastructure Information** — Information that would jeopardize Bulk Power System reliability, including information relating to a Cyber Security Incident will

be identified and protected from public disclosure as Confidential Information. In accordance with Section 1500, information deemed by a Bulk Power System owner, operator, or user, Regional Entity, or NERC as Critical Energy Infrastructure Information or Critical Electric Infrastructure Information shall be redacted according to NERC procedures and shall not be released publicly.

13. **Penalties, Sanctions, and Remedial Action Directives** — Each Regional Entity will apply all Penalties, sanctions, and Remedial Action Directives in accordance with the approved *Sanction Guidelines*, **Appendix 4B** to these Rules of Procedure. Any changes to the *Sanction Guidelines* to be used by any Regional Entity must be approved by NERC and submitted to the Applicable Governmental Authority for approval. All Confirmed Violations, Penalties, and sanctions, including Confirmed Violations, Penalties, and sanctions specified in a Regional Entity Hearing Body decision, will be provided to NERC for review and filing with Applicable Governmental Authorities as a Notice of Penalty, in accordance with **Appendix 4C**.

14. **Hearing Process** — Each Regional Entity shall adopt either the Regional Entity Hearing Process (Section 403.15A) or the Consolidated Hearing Process (403.15B) and conduct all hearings pursuant to the selected process. In either case, the selected hearing process shall be a fair, independent, and nondiscriminatory process for hearing contested violations and any Penalties or sanctions levied, in conformance with Attachment 2 to **Appendix 4C** to these Rules of Procedure and any deviations therefrom that are set forth in the Regional Entity's delegation agreement. The hearing process shall allow Bulk Power System owners, operators, and users to contest findings of compliance violations, any Penalties and sanctions that are proposed to be levied, proposed Remedial Action Directives, and components of proposed Mitigation Plans. The hearing process shall (i) include provisions for recusal of any members of the Hearing Body with a potential conflict of interest, real or perceived, from all compliance matters considered by the Hearing Body for which the potential conflict of interest exists and (ii) provide that no two industry sectors may control any decision and no single sector may veto any matter brought before the Hearing Body after recusals.

    A Regional Entity may modify its selection of hearing process by giving notice to NERC six (6) months prior to such modification becoming effective. Hearings will be conducted pursuant to the process in effect at the Regional Entity at the time of the submission of the hearing request by the registered entity.

    Each Regional Entity will notify NERC of all hearings and NERC may observe any of the proceedings. Each Regional Entity will notify NERC of the outcome of all hearings.

    If a Bulk Power System owner, operator, or user or a Regional Entity has completed the Regional Entity Hearing Process or the Consolidated Hearing Process and desires to appeal the outcome of the hearing, the Bulk Power System

owner, operator, or user or the Regional Entity shall appeal to NERC in accordance with Section 409 of these Rules of Procedure, except that a determination of violation or Penalty that has been directly adjudicated by an Applicable Governmental Authority shall be appealed with that Applicable Governmental Authority.

14A. **Regional Entity Hearing Process** — The Regional Entity Hearing Process shall be conducted before a Hearing Body composed of the Regional Entity board or a balanced committee established by and reporting to the Regional Entity board as the final adjudicator at the Regional Entity level, provided, that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions.

14B. **Consolidated Hearing Process** — The Consolidated Hearing Process shall be conducted before a Hearing Body composed of five members, unless a smaller number is necessary, as discussed below. The Hearing Body will issue a final decision, provided that Canadian provincial regulators may act as the final adjudicator in their respective jurisdictions. Up to two members will be appointed by the Regional Entity from which the case originates. If stakeholder members are appointed, the stakeholders shall not represent the same industry sector. Should a Regional Entity choose to appoint one or no representative, then the NERC Board of Trustees Compliance Committee ("Compliance Committee") will select additional representatives to fill those vacancies. The Compliance Committee will appoint the NERC representatives to the Hearing Body, chosen among NERC trustees not serving on the Compliance Committee at the time of the request for hearing. The Regional Entity and NERC members appointed to the Hearing Body will appoint an additional member to the Hearing Body, chosen among NERC trustees not serving on the Compliance Committee at the time of the request for hearing or from the Regional Entity from which the case originates. If the Hearing Body does not select a NERC trustee or a regional representative, the Hearing Body will appoint an additional member in accordance with the criteria specified in Appendix 4C, Attachment 2, Section 1.4.3(a). In the event a Regional Entity chooses not to appoint representatives to the Hearing Body and there are not five NERC trustees available to participate on the Hearing Body, as determined by the Compliance Committee, the Hearing Body may be composed of three members (three NERC trustees not serving on the Compliance Committee). The Hearing Body will appoint a Hearing Officer to preside over the hearing.

404. NERC Monitoring of Compliance for Bulk Power System Owners, Operators, or Users

1. **NERC Obligations** —NERC will directly monitor Bulk Power System owners, operators, and users for compliance with Reliability Standards in any geographic area for which there is not a delegation agreement in effect with a Regional Entity, in accordance with **Appendix 4C**. In such cases, NERC will serve as the CEA described in **Appendix 4C**. Compliance matters contested by Bulk Power

System owners, operators, and users in such an event will be heard by the NERC Compliance and Certification Committee.

2. **Appeals Process** — Any Bulk Power System owner, operator or user found by NERC to be in noncompliance with a Reliability Standard may appeal the findings of noncompliance with Reliability Standards and any sanctions or Remedial Action Directives that are issued by, or Mitigation Plan components imposed by, NERC, pursuant to the processes described in Sections 408 through 410.

405. Monitoring NERC's Compliance with the Rules of Procedure

The Compliance and Certification Committee shall monitor NERC's compliance with its Rules of Procedure for the Reliability Standards Development, Compliance Monitoring and Enforcement, and Organization Registration and Certification Programs in accordance with this section and Section 506. The Compliance and Certification Committee's monitoring shall not be used to circumvent the appeals processes established for those programs. The Compliance and Certification Committee shall use independent expert monitors with no conflict of interest, real or perceived. Compliance and Certification Committee findings shall be addressed with the NERC Board of Trustees and other appropriate Board committees.

406. Independent Audits of the Compliance Monitoring and Enforcement Program

NERC shall provide for an independent audit of the Compliance Monitoring and Enforcement Program at least once every three years, or more frequently as determined by the NERC Board of Trustees in coordination with the Compliance and Certification Committee. The audit shall be conducted by independent expert auditors as selected by the NERC Board of Trustees. The independent audit shall meet the following minimum requirements and any other requirements established by the NERC Board of Trustees.

1. **Effectiveness** — The audit shall evaluate the success and effectiveness of the Compliance Monitoring and Enforcement Program in achieving its mission.

2. **Relationship** — The audit shall evaluate the relationship between NERC and the Regional Entities in implementing the Compliance Monitoring and Enforcement Program and the effectiveness of the program in ensuring reliability.

3. **Final Report Posting** — The final report shall be posted by NERC for public viewing in accordance with Appendix 4C.

4. **Response to Recommendations** — If the audit report includes recommendations to improve the Compliance Monitoring and Enforcement Program, the administrators of the Compliance Monitoring and Enforcement Program shall provide a written response and plan to the NERC Board of Trustees within 30 days of the release of the final audit report to the NERC Board of Trustees or other appropriate Board committee. NERC will post the written response and plan for public viewing when authorized by the NERC Board of Trustees or other

appropriate Board committee. NERC will post the written response and plan for public viewing.

407. Penalties, Sanctions, and Remedial Action Directives

1. **NERC Review of Regional Entity Penalties and Sanctions —** NERC shall review all Penalties, sanctions, and Remedial Action Directives imposed by each Regional Entity for violations of Reliability Standards, including Penalties, sanctions, and Remedial Action Directives that are specified by a Hearing Body final decision issued pursuant to Attachment 2 to **Appendix 4C**, to determine if the Regional Entity's determination: a) is supported by a sufficient record compiled by the Regional Entity; b) is consistent with the *Sanction Guidelines* incorporated into these Rules of Procedure as **Appendix 4B** and with other directives, guidance, and directions issued by NERC pursuant to the delegation agreement; and c) is consistent with Penalties, sanctions, and Remedial Action Directives imposed by the Regional Entity and by other Regional Entities for violations involving the same or similar facts and circumstances.

2. **Developing Penalties and Sanctions** — The Regional Entity Staff shall use the *Sanction Guidelines*, which are incorporated into these Rules of Procedure as **Appendix 4B**, to develop an appropriate Penalty, sanction, or Remedial Action Directive for a violation, and shall notify NERC of the Penalty, sanction, or Remedial Action Directive.

3. **Effective Date of Penalty** — Where authorized by applicable legislation or agreement, no Penalty imposed for a violation of a Reliability Standard shall take effect until the thirty-first day after NERC files, with the Applicable Governmental Authority, a Notice of Penalty and the record of the proceedings in which the violation and Penalty were determined, or such other date as ordered by the Applicable Governmental Authority.

408. Review of NERC Decisions

1. **Scope of Review** — A Registered Entity wishing to challenge a finding of noncompliance and the imposition of a Penalty for a compliance measure directly administered by NERC, or a Regional Entity wishing to challenge a Regional Entity audit finding, may do so by filing a notice of the challenge with NERC's Director of Enforcement no later than 30 days after issuance of the notice of finding of violation or audit finding. Appeals by Registered Entities or Regional Entities of decisions of Hearing Bodies shall be pursuant to Section 409.

2. **Contents of Notice** — The notice of challenge shall include the full text of the decision that is being challenged, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief.

3. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 30 days after receiving a copy of the notice of challenge, the NERC

Director of Enforcement may file with the Hearing Panel a response to the issues raised in the notice, with a copy to the Regional Entity.

4. **Hearing by Compliance and Certification Committee** — For matters subject to its review, the Compliance and Certification Committee shall provide representatives of the Regional Entity or Registered Entity and the NERC Compliance Monitoring and Enforcement Program an opportunity to be heard and shall decide the matter based upon the filings and presentations made, with a written explanation of its decision.

5. **Appeal** — The Regional Entity or Registered Entity may appeal the decision of the Compliance and Certification Committee by filing a notice of appeal with NERC's Director of Enforcement no later than 21 days after issuance of the written decision by the Compliance and Certification Committee. The notice of appeal shall include the full text of the written decision of the Compliance and Certification Committee that is being appealed, a concise statement of the error or errors contained in the decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief. No factual material shall be presented in the appeal that was not presented to the Compliance and Certification Committee.

6. **Response by NERC Compliance Monitoring and Enforcement Program** — Within 21 days after receiving a copy of the notice of appeal, NERC may file its response to the issues raised in the notice of appeal, with a copy to the entity filing the notice.

7. **Reply** — The entity filing the appeal may file a reply within 7 days.

8. **Decision** — The Board of Trustees Compliance Committee shall decide the appeal, in writing, based upon the notice of appeal, the record, the response, and any reply. At its discretion, the Board of Trustees Compliance Committee may invite representatives of the Regional Entity or Registered Entity and the NERC Compliance Monitoring and Enforcement Program to appear before the Board of Trustees Compliance Committee. Decisions of the Board of Trustees Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

9. **Impartiality** — No member of the Compliance and Certification Committee or the Board of Trustees Compliance Committee having an actual or perceived conflict of interest in the matter may participate in any aspect of the challenge or appeal except as a party or witness.

10. **Expenses** — Each party in the challenge and appeals processes shall pay its own expenses for each step in the process.

11. **Non-Public Proceedings —** All challenges and appeals shall be closed to the public to protect Confidential Information.

409. Appeals from Final Decisions of Hearing Bodies

1. **Time for Appeal** — A Regional Entity acting as the CEA, or an owner, operator, or user of the Bulk Power System, shall be entitled to appeal from a final decision of a Hearing Body concerning an Alleged Violation of a Reliability Standard, a proposed Penalty or sanction for violation of a Reliability Standard, a proposed Mitigation Plan, or a proposed Remedial Action Directive, by filing a notice of appeal with NERC's Director of Enforcement, with copies to the Clerk, the Regional Entity, and any other Participants in the Hearing Body proceeding, no later than 21 days after issuance of the final decision of the Hearing Body. The Board of Trustees Compliance Committee shall render its decision within 180 days following the receipt by NERC's Director of Enforcement of the notice of appeal. The Board of Trustees Compliance Committee may extend this deadline for good cause and shall provide written notice of any extension to all Participants.

2. **Contents** — The notice of appeal shall include the full text of the final decision of the Hearing Body that is being appealed, a concise statement of the error or errors contained in the final decision, a clear statement of the relief being sought, and argument in sufficient detail to justify such relief. No factual material shall be presented in the appeal that was not first presented during the proceeding before the Hearing Body.

3. **Response to Notice of Appeal** — Within 21 days after the date the notice of appeal is filed, the Clerk shall file the entire record of the Hearing Body proceeding with NERC's Director of Enforcement, with a copy to all Participants. Within 35 days after the date of the notice of appeal, all Participants in the proceeding before the Hearing Body, other than the Participant filing the notice of appeal, shall file their responses to the issues raised in the notice of appeal.

4. **Reply** — The party filing the appeal may file a reply to the responses within 7 days.

5. **Decision** — The Board of Trustees Compliance Committee shall decide the appeal, in writing, based upon the notice of appeal, the record of the proceeding before the Hearing Body, the responses, and any reply filed with NERC. The Board of Trustees Compliance Committee shall review the appealed issue(s) under a *de novo* standard. At its discretion, the Board of Trustees Compliance Committee may invite representatives of the entity making the appeal and the other Participants in the proceeding before the Hearing Body to appear before the Board of Trustees Compliance Committee. Decisions of the Board of Trustees Compliance Committee shall be final, except for further appeal to the Applicable Governmental Authority.

6. **Expenses** — Each party in the appeals process shall pay its own expenses for each step in the process.

7. **Non-Public Proceedings** — All appeals shall be closed to the public to protect Confidential Information.

8. **Appeal of Hearing Body Decisions Granting or Denying Motions to Intervene** — This section is not applicable to an appeal of a decision of a Hearing Body granting or denying a motion to intervene in the Hearing Body proceeding. Appeals of decisions of Hearing Bodies granting or denying motions to intervene in Hearing Body proceedings shall be processed and decided pursuant to Section 414.

410. Hold Harmless

A condition of invoking the challenge or appeals processes under Section 408 or 409 is that the entity requesting the challenge or appeal agrees that neither NERC (defined to include its Members, Board of Trustees, committees, subcommittees, staff and industry subject matter experts), any person assisting in the challenge or appeals processes, nor any company employing a person assisting in the challenge or appeals processes, shall be liable, and they shall be held harmless against the consequences of: a) any action or inaction; b) any agreement reached in resolution of the dispute; or c) any failure to reach agreement as a result of the challenge or appeals proceeding. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

411. Requests for Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Reliability Standards

A Registered Entity that is subject to an Applicable Requirement of a NERC Critical Infrastructure Protection Standard for which Technical Feasibility Exceptions are permitted, may request a Technical Feasibility Exception to the Requirement. The request will be reviewed, approved or disapproved, and if approved, implemented, in accordance with the NERC *Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standards*, Appendix 4D to these Rules of Procedure.

412. Certification of Questions from Hearing Bodies for Decision by the NERC Board of Trustees Compliance Committee

1. A Hearing Body that is conducting a hearing concerning a disputed compliance matter pursuant to Attachment 2, Hearing Procedures, of Appendix 4C, may certify to the Board of Trustees Compliance Committee, for decision, a significant question of law, policy, or procedure, the resolution of which may be determinative of the issues in the hearing in whole or in part, and as to which there are other extraordinary circumstances that make prompt consideration of the question by the Board of Trustees Compliance Committee appropriate, in accordance with Section 1.5.12 of the Hearing Procedures. All questions certified by a Hearing Body to the Board of Trustees Compliance Committee shall be considered and disposed of by the Board of Trustees Compliance Committee.

2. The Board of Trustees Compliance Committee may accept or reject a certification of a question for decision. If the Board of Trustees Compliance Committee rejects the certified question, it shall issue a written statement that the certification is rejected.

3. If the Board of Trustees Compliance Committee accepts the certification of a question for decision, it shall establish a schedule by which the Participants in the hearing before the Hearing Body may file memoranda and reply memoranda stating their positions as to how the question certified for decision should be decided by the Board of Trustees Compliance Committee. The Board of Trustees Compliance Committee may also request, or provide an opportunity for, the NERC Compliance department, the NERC Enforcement department, and/or the NERC general counsel to file memoranda stating their positions as to how the question certified for decision should be decided. After receiving such memoranda and reply memoranda are filed in accordance with the schedule, the Board of Trustees Compliance Committee shall issue a written decision on the certified question.

4. Upon receiving the Board of Trustees Compliance Committee's written decision on the certified question, the Hearing Body shall proceed to complete the hearing in accordance with the Board of Trustees Compliance Committee's decision.

5. The Board of Trustees Compliance Committee's decision, if any, on the certified question shall only be applicable to the hearing from which the question was certified and to the Participants in that hearing.

413. Review and Processing of Hearing Body Final Decisions that Are Not Appealed

NERC shall review and process all final decisions of Hearing Bodies issued pursuant to Attachment 2 to Appendix 4C concerning an Alleged Violation, proposed Penalty or sanction, or proposed Mitigation Plan that are not appealed pursuant to Section 409, as though the determination had been made by the Regional Entity. NERC shall review and process such final decisions, and may require that they be modified by the Regional Entity, in accordance with, as applicable to the particular decision, Sections 5.8, 5.9, and 6.5 of Appendix 4C.

414. Appeals of Decisions of Hearing Bodies Granting or Denying Motions to Intervene in Hearing Body Proceedings

1. **Time to Appeal** — An entity may appeal a decision of a Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** denying the entity's motion to intervene in a Hearing Body proceeding, and the Regional Entity Staff or any other Participant in the Hearing Body proceeding may appeal a decision of the Hearing Body under Section 1.4.4 of Attachment 2 of **Appendix C** granting or denying a motion to intervene in the Hearing Body proceeding, in either case by filing a notice of appeal with the NERC Director of Enforcement, with copies to the Clerk of the Hearing Body, the Hearing Body, the Hearing Officer, the Regional Entity Staff, and all other Participants in the Hearing Body proceeding,

no later than seven (7) days following the date of the Hearing Body decision granting or denying the motion to intervene.

2. **Contents of Notice of Appeal** — The notice of appeal shall set forth information and argument to demonstrate that the decision of the Hearing Body granting or denying the motion to intervene was erroneous under the grounds for intervention specified in Section 1.4.4 of Attachment 2 of **Appendix 4C** and that the entity requesting intervention should be granted or denied intervention, as applicable. Facts alleged in, and any offers of proof made in, the notice of appeal shall be supported by affidavit or verification. The notice of appeal shall include a copy of the original motion to intervene and a copy of the decision of the Hearing Body granting or denying the motion to intervene.

3. **Responses to Notice of Appeal** — Within ten (10) days following the date the notice of appeal is filed, the Clerk shall transmit to the NERC Director of Enforcement copies of all pleadings filed in the Hearing Body proceeding on the motion to intervene. Within fourteen (14) days following the date the notice of appeal is filed, the Hearing Body, the Regional Entity Staff, and any other Participants in the Hearing Body proceeding, may each file a response to the notice of appeal with the NERC Director of Enforcement. Within seven (7) days following the last day for filing responses, the entity filing the notice of appeal, and any Participant in the Hearing Body proceeding that supports the appeal, may file replies to the responses with the NERC Director of Enforcement.

4. **Disposition of Appeal** — The appeal shall be considered and decided by the Board of Trustees Compliance Committee. The NERC Director of Enforcement shall provide copies of the notice of appeal and any responses and replies to the Board of Trustees Compliance Committee. The Board of Trustees Compliance Committee shall issue a written decision on the appeal; provided, that if the Board of Trustees Compliance Committee does not issue a written decision on the appeal within forty-five (45) days following the date of filing the notice of appeal, the appeal shall be deemed denied and the decision of the Hearing Body granting or denying the motion to intervene shall stand. The NERC Director of Enforcement shall transmit copies of the Board of Trustees Compliance Committee's decision, or shall provide notice that the forty-five (45) day period has expired with no decision by the Board of Trustees Compliance Committee, to the Clerk, the Hearing Body, the entity filing the notice of appeal, the Regional Entity Staff, and any other Participants in the Hearing Body proceeding that filed responses to the notice of appeal or replies to responses.

5. **Appeal of Board of Trustees Compliance Committee Decision to FERC or Other Applicable Governmental Authority** — Any entity aggrieved by the decision of the Board of Trustees Compliance Committee on an appeal of a Hearing Body decision granting or denying a motion to intervene in a Hearing Body proceeding (including a denial of such appeal by the expiration of the forty-five (45) day period as provided in Section 414.4) may appeal or petition for review of the decision of the Board of Trustees Compliance Committee to FERC

or to another Applicable Governmental Authority having jurisdiction over the matter, in accordance with the authorities, rules, and procedures of FERC or such other Applicable Governmental Authority. Any such appeal or petition for review shall be filed within the time period, if any, and in the form and manner, specified by the applicable statutes, rules, or regulations governing proceedings before FERC or the other Applicable Governmental Authority.

SECTION 500 — ORGANIZATION REGISTRATION AND CERTIFICATION

501. Scope of the Organization Registration and Organization Certification Programs

The purpose of the Organization Registration Program is to clearly identify those entities that are responsible for compliance with the FERC approved Reliability Standards. Organizations that are registered are included on the NERC Compliance Registry (NCR) and are responsible for knowing the content of and for complying with all applicable Reliability Standards. Registered Entities are not and do not become Members of NERC or a Regional Entity, by virtue of being listed on the NCR. Membership in NERC is governed by Article II of NERC's Bylaws; membership in a Regional Entity or regional reliability organization is governed by that entity's bylaws or rules.

The purpose of the Organization Certification Program is to ensure that the new entity (i.e., applicant to be an RC, BA, or TOP that is not already performing the function for which it is applying to be certified as) has the tools, processes, training, and procedures to demonstrate their ability to meet the Requirements/sub-Requirements of all of the Reliability Standards applicable to the function(s) for which it is applying thereby demonstrating the ability to become certified and then operational.

Organization Registration and Organization Certification may be delegated to Regional Entities in accordance with the procedures in this Section 500; the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into these Rules of Procedure as **Appendix 5A**; and, approved Regional Entity delegation agreements or other applicable agreements.

1. **NERC Compliance Registry** — NERC shall establish and maintain the NCR of the Bulk Power System owners, operators, and users that are subject to approved Reliability Standards.

   1.1 (a) The NCR shall set forth the identity and functions performed for each organization responsible for meeting Requirements/sub-Requirements of the Reliability Standards. Bulk Power System owners, operators, and users (i) shall provide to NERC and the applicable Regional Entity information necessary to complete the Registration, and (ii) shall provide NERC and the applicable Regional Entity with timely updates to information concerning the Registered Entity's ownership, operations, contact information, and other information that may affect the Registered Entity's Registration status or other information recorded in the Compliance Registry.

   (b) Entities may address registration obligations for applicable function types using a Joint Registration Organization (JRO), in lieu of each of the JRO's parties'entities being registered individually for one or more functions. Refer to Section 507.

   (c) Entities may each register using a Coordinated Functional Registration

(CFR) for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function pursuant to a written agreement for the division of compliance responsibility. Refer to Section 508.

1.2 In the development of the NCR, NERC and the Regional Entities shall determine which organizations should be placed on the NCR based on the criteria provided in the NERC *Statement of Compliance Registry Criteria* which is incorporated into these Rules of Procedure as **Appendix 5B**.

1.3 NERC and the Regional Entities shall use the following rules for establishing and maintaining the NCR based on the Registration criteria as set forth in **Appendix 5B** *Statement of Compliance Registry Criteria*:

1.3.1 NERC shall notify each organization that it is on the NCR. The Registered Entity is responsible for compliance with all the Reliability Standards applicable to the functions for which it is registered from the time it receives the Registration notification from NERC.

1.3.2 Any organization receiving such a notice may challenge its placement on the NCR according to the process in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section V.

1.3.3 The Compliance Committee of the Board of Trustees shall promptly issue a written decision on the challenge, including the reasons for the decision.

1.3.4 The decision of the Compliance Committee of the Board of Trustees shall be final unless, within 21 days of the date of the Compliance Committee of the Board of Trustees decision, the organization appeals the decision to the Applicable Governmental Authority.

1.3.5 Each Registered Entity identified on the NCR shall notify its corresponding Regional Entity(s) of any corrections, revisions, deletions, changes in ownership, corporate structure, or similar matters that affect the Registered Entity's responsibilities with respect to the Reliability Standards. Failure to notify will not relieve the Registered Entity from any responsibility to comply with the Reliability Standards or shield it from any Penalties or sanctions associated with failing to comply with the Reliability Standards applicable to its associated Registration.

1.4 For all geographical or electrical areas of the Bulk Power System, the Registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and required by the Reliability

Standards to the fullest extent practical, and (2) there is no unnecessary duplication of such coverage or of required oversight of such coverage. In particular the process shall:

1.4.1 Ensure that all areas are under the oversight of one and only one Reliability Coordinator.

1.4.2 Ensure that all Balancing Authorities and Transmission Operator entities[2] are under the responsibility of one and only one Reliability Coordinator.

1.4.3 Ensure that all transmission Facilities of the Bulk Power System are the responsibility and under the control of one and only one Transmission Planner, Planning Authority, and Transmission Operator.

1.4.4 Ensure that all Loads and generators are under the responsibility and control of one and only one Balancing Authority.

1.5 NERC shall maintain the NCR of organizations responsible for meeting the Requirements/sub-Requirements of the Reliability Standards currently in effect on its website and shall update the NCR monthly.

1.6 With respect to: (i) entities to be registered for the first time; (ii) currently-registered entities or (iii) previously-registered entities, for which registration status changes are sought, including availability and composition of a sub-set list of applicable Reliability Standards (which specifies the Reliability Standards and may specify Requirements/sub-Requirements), the registration process steps in Section III of **Appendix 5A** apply.

1.7 NERC shall establish a NERC-led, centralized review panel, comprised of a NERC lead with Regional Entity participants, in accordance with **Appendix 5A**, *Organization Registration and Organization Certification Manual*, Section III.D and **Appendix 5B**, *Statement of Compliance Registry Criteria*.

2. **Entity Certification** — NERC shall provide for Certification of all entities with primary reliability responsibilities requiring Certification. The NERC programs shall:

[2] Some organizations perform the listed functions (e.g., Balancing Authority, Transmission Operator) over areas that transcend the Footprints of more than one Reliability Coordinator. Such organizations will have multiple Registrations, with each such Registration corresponding to that portion of the organization's overall area that is within the Footprint of a particular Reliability Coordinator.

2.1 Evaluate the entity's tools, personnel, facilities, and processes used to perform the duties and tasks identified in and required by the Reliability Standards. The entities currently requiring Certification include Reliability Coordinators, Transmission Operators, and Balancing Authorities.

2.2 Certify each applicant's ability to perform the function for a specified Area.[3]

2.3 Maintain process documentation.

2.4 Maintain records of currently certified entities.

2.5 Issue a Certification document to the applicant that successfully demonstrates its competency to perform the evaluated functions.

3. **Delegation and Oversight**

3.1 NERC may delegate responsibilities for Organization Registration and Organization Certification to Regional Entities in accordance with requirements established by NERC. Delegation will be via the delegation agreement between NERC and the Regional Entity or other applicable agreement. The Regional Entity shall administer Organization Registration and Organization Certification Programs in accordance with such delegations to meet NERC's programs goals and requirements subject to NERC oversight.

3.2 NERC shall develop and maintain a plan to ensure the continuity of Organization Registration and Organization Certification within the geographic or electrical boundaries of a Regional Entity in the event that no entity is functioning as a Regional Entity for that Region, or the Regional Entity withdraws as a Regional Entity, or does not operate its Organization Registration and Organization Certification Programs in accordance with delegation agreements.

3.3 NERC shall develop and maintain a program to monitor and oversee the NERC Organization Registration and Organization Certification Programs activities that are delegated to each Regional Entity through a delegation agreement or other applicable agreement.

3.3.1 This program shall monitor whether the Regional Entity carries out those delegated activities in accordance with NERC requirements,

[3] When the term "Area" is used and capitalized it is being used in the certification context, and is inclusive of terms currently defined in NERC Glossary of Terms and Appendix 2 of the ROP, specifically, "Balancing Authority Area," "Reliability Coordinator Area," or "Transmission Operator Area."

and whether there is consistency, fairness of administration, and comparability.

3.3.2 Monitoring and oversight shall be accomplished through direct participation in the Organization Registration and Organization Certification Programs with periodic reviews of documents and records of both programs.

502. Organization Registration and Organization Certification Program Requirements

1. NERC shall maintain the Organization Registration and Organization Certification Programs.

   1.1 The roles and authority of Regional Entities in the programs are delegated from NERC pursuant to the Rules of Procedure through regional delegation agreements or other applicable agreements.

   1.2 Processes for the programs shall be administered by NERC and the Regional Entities. Materials that each Regional Entity uses are subject to review and approval by NERC.

   1.3 The appeals process for the Organization Registration and Organization Certification Programs are identified in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Sections VI and VII, respectively.

   1.4 The Certification Team membership is identified in **Appendix 5A** *Organization Registration and Organization Certification Manual*, Section IV.

2. To ensure consistency and fairness of the Organization Registration and Organization Certification Programs, NERC shall develop procedures to be used by all Regional Entities and NERC in accordance with the following criteria:

   2.1 NERC and the Regional Entities shall have data management processes and procedures that provide for confidentiality, integrity, and retention of data and information collected.

   2.2 Documentation used to substantiate the conclusions of the Regional Entity/ NERC related to Registration and/or Certification must be retained by the Regional Entity for (6) six years, unless a different retention period is otherwise identified, for the purposes of future audits of these programs.

   2.3 To maintain the integrity of the NERC Organization Registration and Organization Certification Programs, NERC, Regional Entities, Certification Team members, program audit team members (Section 506), and committee members shall maintain the confidentiality of information provided by an applicant or entities.

2.2.1 NERC and the Regional Entities shall have appropriate codes of conduct and confidentiality agreements for staff, Certification Team, Certification related committees, and Certification program audit team members.

2.2.2 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall maintain the confidentiality of any Registration or Certification-related discussions or documents designated as confidential (see Section 1500 for types of Confidential Information).

2.2.3 NERC, Regional Entities, Certification Team members, program audit team members and committee members shall treat as confidential the individual comments expressed during evaluations, program audits and report-drafting sessions.

2.2.4 Copies of notes, draft reports, and other interim documents developed or used during an entity Certification evaluation or program audit shall be destroyed after the public posting of a final, uncontested report.

2.2.5 Information deemed by an applicant, entity, a Regional Entity, or NERC as confidential, including Critical Energy Infrastructure Information, shall not be released publicly or distributed outside of a committee or team.

2.2.6 In the event that an individual violates any of the confidentiality rules set forth above, that individual and any member organization with which the individual is associated will be subject to immediate dismissal from the audit team and may be prohibited from future participation in Compliance Monitoring and Enforcement Program activities by the Regional Entity or NERC.

2.2.7 NERC shall develop and provide training in auditing skills to all individuals prior to their participation in Certification evaluations. Training for Certification Team leaders shall be more comprehensive than the training given to industry subject matter experts and Regional Entity members. Training for Regional Entity members may be delegated to the Regional Entity.

2.4 An applicant that is determined to be competent to perform a function after completing all Certification requirements shall be deemed certified by NERC to perform that function for which it has demonstrated full competency.

2.4.1 All NERC certified entities shall be included on the NCR.

503. Regional Entity Implementation of Organization Registration and Organization Certification Program Requirements

1. **Delegation** — Recognizing the Regional Entity's knowledge of and experience with its members, NERC may delegate responsibility for Organization Registration and Organization Certification to the Regional Entity through a delegation agreement.

2. **Registration** — The following Organization Registration activities shall be managed by the Regional Entity per the NERC *Organization Registration and Organization Certification Manual*, which is incorporated into the Rules of Procedure as Appendix 5A *Organization Registration and Organization Certification Manual*:

   2.1 Regional Entities shall verify that all Reliability Coordinators, Balancing Authorities, and Transmission Operators meet the Registration requirements of Section 501(1.4).

3. **Certification —** The following Organization Certification activities shall be managed by the Regional Entity in accordance with an approved delegation agreement or another applicable agreement:

   3.1 An entity seeking Certification to perform one of the functions requiring Certification shall contact the Regional Entity for the Region(s) in which it plans to operate to apply for Certification.

   3.2 An entity seeking Certification and other affected entities shall provide all information and data requested by NERC or the Regional Entity to conduct the Certification process.

   3.3 Regional Entities shall notify NERC of all Certification applicants.

   3.4 NERC and/or the Regional Entity shall evaluate the competency of entities requiring Certification to meet the NERC Certification requirements.

   3.5 NERC or the Regional Entity shall establish Certification procedures to include evaluation processes, schedules and deadlines, expectations of the applicants and all entities participating in the evaluation and Certification processes, and requirements for Certification Team members.

      3.5.1 The NERC / Regional Entity Certification procedures will include provisions for on-site visits to the applicant's facilities to review the data collected through questionnaires, interviewing the operations and management personnel, inspecting the facilities and equipment (including requesting a demonstration of all tools identified in the Certification process), reviewing all necessary documents and data (including all agreements, processes, and procedures identified in the Certification process), reviewing

Certification documents and projected system operator work schedules, and reviewing any additional documentation needed to support the completed questionnaire or inquiries arising during the site visit.

3.5.2 The NERC/ Regional Entity Certification procedures will provide for preparation of a written report by the Certification Team, detailing any deficiencies that must be resolved prior to granting Certification, along with any other recommendations for consideration by the applicant, the Regional Entity, or NERC.

504. Appeals

1. NERC shall maintain an appeals process to resolve any disputes related to Registration or Certification activities per the *Organization Registration and Organization Certification Manual,* which is incorporated in these Rules of Procedure as Appendix 5A.

2. The Regional Entity Certification appeals process shall culminate with the Regional Entity board or a committee established by and reporting to the Regional Entity board as the final adjudicator, provided that where applicable, Canadian provincial governmental authorities may act as the final adjudicator in their jurisdictions. NERC shall be notified of all appeals and may observe any proceedings **(Appendix 5A** *Organization Registration and Organization Certification Manual*).

505. Program Maintenance

NERC shall maintain its program materials, including such manuals or other documents as it deems necessary, of the governing policies and procedures of the Organization Registration and Organization Certification Programs.

506. Independent Audit of NERC Organization Registration and Organization Certification Program

1. NERC, through the Compliance and Certification Committee, shall provide for an independent audit of its Organization Registration and Organization Certification Programs at least once every three years, or more frequently, as determined by the Board. The audit shall be conducted by independent expert auditors as selected by the Board.

2. The audit shall evaluate the success, effectiveness and consistency of the NERC Organization Registration and Organization Certification Programs.

3. The final report shall be provided to the NERC Board of Trustees or its appropriate committees, and posted for public viewing. Confidential Information shall be handled in accordance with the NERC Rules of Procedure Section 1500, *Confidential Information*.

4. If the audit report includes recommendations to improve the program, the administrators of the program shall provide a written response to the Board within 30 days of the final report, detailing the disposition of each and every recommendation, including an explanation of the reasons for rejecting a recommendation and an implementation plan for the recommendations accepted.

507. Provisions Relating to Joint Registration Organizations (JRO)

1. In addition to registering as the entity responsible for all function type(s) that it performs itself, an entity may execute an agreement to register as a Lead Entity of a JRO on behalf of one or more parties to the agreement for one or more function type(s) for which such parties would otherwise be required to register. The Lead Entity thereby, accept on behalf of such parties all compliance responsibility for the function types(s) covered by the JRO registration, including all reporting requirements. The Lead Entity of a JRO must execute a written agreement with the parties on whose behalf it registers that: (1) governs the relationship between the parties; (2) addresses the function type(s) described within Appendix 5B for which the Lead Entity is registering for and taking responsibility, and which would otherwise be the responsibility of one or more of the other parties to the JRO; (3) identifies which entity is the Lead Entity and a point of contact within the Lead Entity; and (4) identifies a point of contact for each of the parties to the JRO.

2. For every JRO, the written agreement must be submitted to the appropriate Regional Entity for its retention. Neither NERC nor the Regional Entity shall be parties to any such agreement. Neither NERC nor the Regional Entity shall have responsibility for reviewing or approving any such agreement, other than to verify that the agreement addresses the function type(s) consistent with the Lead Entity's Registration.

3. The JRO Registration data must include all Registration and Certification information as needed by the Regional Entity to complete the Registration process and to perform assessments of compliance. All Compliance Monitoring and Enforcement related communications shall be directed to the primary compliance contact identified for the Lead Entity of the JRO.[4]

4. The Regional Entity shall notify NERC when it registers a Lead Entity of a JRO. The notification will identify the point of contact and the function type(s) for which the Lead Entity of the JRO is registered on behalf of the JRO parties and a point of contact for each of the JRO parties.

[4] The primary compliance contact for the Lead Entity of a JRO can be the same person who serves as the point of contact for the Lead Entity of the JRO. However, it is not required that the same person serve as both the primary compliance contact and the point of contact.

5. For purposes of Compliance Audits, the Regional Entity shall keep a list of all JROs, the Lead Entities, the JRO parties,es and the function type(s) for which the Lead Entity of the JRO has registered for each partythat. It is the responsibility of the Lead Entity of the JRO to provide the Regional Entity with this information as well as the applicable JRO agreement(s).

6. The Regional Entity can request clarification of any list submitted to it that identifies the parties to the JRO and can request such additional information as the Regional Entity deems appropriate.

7. The Regional Entity's acceptance of a Lead Entity's registration as part of a JRO shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded that the registration of the Lead Entity of the JRO meets the Registration requirements of Section 501(1.4).

8. NERC shall maintain, and post on its website, a listing of all JROs, Lead Entities, JRO parties, and the function type(s) for which the Lead Entity of the JRO has registered for each party.

9. The Lead Entity of the JRO shall inform the Regional Entity of any changes to an existing JRO. The Regional Entity shall promptly notify NERC of each such revision.

10. Nothing in Section 507 shall preclude any party to a JRO from registering on its own behalf and undertaking full compliance responsibility for the function type(s) for which the Lead Entity of the JRO has registered. Such registration shall include submission of data or information that includes any documentation that the agreement supporting the JRO has been terminated as to the registering party. In addition to any notification requirements contained within the written agreement, a JRO party, that registers as responsible for any function type(s) for which the Lead Entity of a JRO was previously responsible shall inform the Lead Entity of the JRO and/or other parties once its Registration has been accepted by the Regional Entity.

508. Provisions Relating to Coordinated Functional Registration (CFR) Entities

1. In addition to registering as an entity responsible for all functions that it performs itself, multiple entities using a CFR must register for the function associated with the CFR. The CFR submission to the Regional Entity must include a written agreement that: (1) governs itself; (2) specifies the entities' respective compliance responsibilities; (3) identifies which entity is the Lead Entity, a point of contact within the Lead Entity, and a point of contact for each of the parties to the CFR The Lead Entity identified for each CFR is responsible for providing the written agreement between the parties, including submitting updates for currently active CFRs to the Regional Entity related to the CFR Registration; and (4) lists one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function type.

2. Neither NERC nor the Regional Entity shall be parties to any such agreement. Neither NERC nor the Regional Entity have responsibility for reviewing or approving any such agreement, other than to verify that the agreement provides for an allocation or assignment of responsibilities consistent with the function type for which the parties are registered and the responsibility(ies) which are addressed through the CFR.

3. The CFR Registration data must include all Registration and Certification information and data, as needed by the Regional Entity to complete the Registration process and to perform assessments of compliance, as it relates to the CFR. All Compliance Monitoring and Enforcement related communications shall be directed to the primary compliance contact(s) identified for each of the CFR parties.

4. Each party to a CFR shall have compliance responsibility for those Reliability Standards and/or Requirements/sub-Requirements for which it has registered pursuant to the CFR.

5. The Regional Entity shall notify NERC of each CFR that the Regional Entity accepts, and the notification shall include identification of the Lead Entity of a CFR, the function type that the CFR addresses, a point of contact for each of the CFR parties, and any updates to currently active CFRs.

6. For purposes of Compliance Audits, the Regional Entity shall keep a list of all CFRs, the Lead Entities, the CFR parties, the function type that the CFR addresses, and the responsibilities assigned to each of the CFR parties.

7. The Regional Entity can request clarification of any list submitted to it that identifies the parties to the CFR and can request such additional information as the Regional Entity deems appropriate.

8. The Regional Entity's acceptance of a Lead Entity's registration as part of a CFR shall be a representation by the Regional Entity to NERC that the Regional Entity has concluded that the registration of the CFR meets the Registration requirements of Section 501(1.4).

9. NERC shall maintain, and post on its website, a listing of all CFRs, the Lead Entity of CFRs, CFR parties, the function type that the CFR addresses, and the responsibilities assigned to each of the CFR parties. The posting shall clearly list all the Reliability Standards or Requirements/sub-Requirements thereof for which each entity of the CFR is responsible for under the CFR.

10. Any noncompliance shall be investigated in accordance with the NERC Rules of Procedure Section 400, *Compliance Enforcement*.

11. Nothing in Section 508 shall preclude a party to a CFR from registering on its own behalf and undertaking full compliance responsibility including reporting Requirements for the Reliability Standards to which a CFR is applicable. Such

registration shall include submission of data or information that includes any documentation that the agreement supporting the CFR has been terminated or revised as to the Reliability Standards for which the registering party is now taking compliance responsibility. In addition to any notification requirements contained within the written agreement, an entity registered in a CFR that registers as responsible for any Reliability Standard or Requirement/sub-Requirement of a Reliability Standard shall inform the Lead Entity of the CFR and/or other parties once its Registration has been accepted by the Regional Entity.

509. Exceptions to the Definition of the Bulk Electric System

An Element is considered to be (or not be) part of the Bulk Electric System by applying the BES Definition to the Element (including the inclusions and exclusions set forth therein). Appendix 5C sets forth the procedures by which (i) an entity may request a determination that an Element that falls within the definition of the Bulk Electric System should be exempted from being considered a part of the Bulk Electric System, or (ii) an entity may request that an Element that falls outside of the definition of the Bulk Electric System should be considered part of the Bulk Electric System.

SECTION 600 — PERSONNEL CERTIFICATION AND CREDENTIAL MAINTENANCE PROGRAM

601. Scope of Personnel Certification and Credential Maintenance Program

Maintaining the reliability of the Bulk Power System through implementation of the Reliability Standards requires skilled, and qualified personnel, including system operators. NERC shall develop a Personnel Certification and Credential Maintenance Program to:

1. provide the mechanism to determine system operators' essential knowledge relating to NERC Reliability Standards as well as principles of Bulk Power System operations;

2. administer a system operator Certification exam;

3. award the system operator Certification Credential to individuals who pass the exam; and,

4. prescribe requirements for System Operators to maintain their Certification Credential.

The NERC Personnel Certification and Credential Maintenance Program shall be international in scope consistent with the ERO's international regulatory responsibility for the reliability of the Bulk Power System in North America.

NERC Reliability Standards define which system operators require certification pursuant to the NERC Personnel Certification Program.

The NERC Personnel Certification Governance Committee (PCGC) is the governing body that both establishes the policies, sets fees, and monitors the performance of the Personnel Certification and Credential Maintenance Program for system operators.

602. Structure of ERO Personnel Certification and Credential Maintenance Program

1. PCGC shall develop a system operator program manual, approved by the NERC Board of Directors, which outlines the following:

   1.1 requirements for administering the system operator examinations;

   1.2 requirements for exam eligibility;

   1.3 requirements for awarding the Certification Credential;

   1.4 requirements for Certification Credential maintenance;

   1.4.1 NERC requires a system operator to earn CE Hours in NERC-Approved Learning Activities within the three-year period preceding

the expiration date of his/her certificate as determined by the PCGC and posted in the NERC System Operator Program Manual.

1.4.2 NERC requires a system operator to request a renewal and submit the appropriate fee for Certification renewal evaluation.

1.5 dispute resolution procedures; and

1.6 disciplinary action guidelines.

2. PCGC shall develop a Credential Maintenance Program and maintain an accompanying manual, which outlines the following:

2.1 requirements for approving contining education Providers and Learning Activities;

2.2 requirements for auditing continuing education Providers and Learning Activities;

2.3 multi-layer review process for disputed application reviews, interpretations of guideline and standards, probation or suspension of NERC-approved Provider status, and credential maintenance disputes; and,

2.4 requirements on fees for continuing education Providers and Learning Activities.

603. Examination and Maintenance of NERC System Operator Certification Credentials

1. System operators seeking to obtain a Credential must pass an examination to earn the Credential.

2. A certificate will be issued to successful candidates which is valid for three years.

3. A system operator must earn Continuing Education Hours (CE Hours) in NERC-Approved Learning Activities within the three-year period preceding the expiration date of his/her certificate as determined by the PCGC and posted in the NERC System Operator Program Manual. A system operator must request a renewal and submit the appropriate fee for Certification renewal evaluation.

4. The Credential of a certified system operator who does not accumulate the required number and balance of CE Hours within the three-year period will be Suspended. A system operator with a Suspended certificate cannot perform any task that requires an operator to be NERC-certified. The system operator with a Suspended Credential will have up to twelve months to acquire the necessary CE Hours.

4.1 During the time of suspension, the original anniversary date will be maintained. Therefore, should the system operator accumulate the

required number of CE Hours within the twelve month suspension period, he/she will be issued a certificate that will be valid for three years from the previous expiration date.

4.2 At the end of the twelve-month suspension period, if the system operator has not accumulated the required number of CE Hours, the Credential will be Revoked and all CE Hours earned will be forfeited. After a Credential is Revoked, the system operator will be required to pass an examination to become certified.

5. Hardship: Due to unforeseen events and extenuating circumstances, a certified system operator may be unable to accumulate the necessary CE Hours in the time frame required by the Personnel Certification Program to maintain the Credential. In such an event, the individual must submit a written request containing a thorough explanation of the circumstances and supporting information to the NERC Personnel Certification Manager. The PCGC retains the right to invoke this hardship clause as it deems appropriate to address such events or circumstances.

604. Dispute Resolution Process

1. Any dispute arising under the NERC agreement establishing the *NERC Personnel Certification Program* or from the establishment of any NERC rules, policies, or procedures dealing with any segment of the Certification process shall be subject to the NERC System Operator Certification Dispute Resolution Process. The Dispute Resolution Process is for the use of persons who hold an operator Certification or persons wishing to be certified to dispute the validity of the examination, the content of the test, the content outlines, or the Registration process.

2. Dispute Resolution Process consists of three steps.

2.1. Notify NERC Personnel Certification Program Staff: This first step can usually resolve the issues without further actions. It is expected that most disputes will be resolved at this step. If the issue(s) is not resolved to the satisfaction of the parties involved in the first step, the issue can be brought to the PCGC Dispute Resolution Task Force.

2.2. PCGC Dispute Resolution Task Force: If the NERC staff did not resolve the issue(s) to the satisfaction of the parties involved, a written request must be submitted to the chairman of the PCGC through NERC staff explaining the issue(s) and requesting further action. Upon receipt of the letter, the PCGC chairman will present the request to the PCGC Dispute Resolution Task Force for action. This task force consists of three current members of the PCGC. The PCGC Dispute Resolution Task Force will investigate and consider the issue(s) presented and make a decision. This decision will then be communicated to the submitting party, the PCGC

chairman, and the NERC staff within 45 calendar days of receipt of the request.

3. Personnel Certification Governance Committee: If the PCGC Dispute Resolution Task Force's decision did not resolve the issue(s) to the satisfaction of the parties involved, the final step in the process is for the issue(s) to be brought before the PCGC. Within 45 days of the date of the Task Force's decision, the disputing party shall submit a written request to the PCGC chairman through NERC staff requesting that the issue(s) be brought before the PCGC for resolution. The chairman shall see that the necessary documents and related data are provided to the PCGC members as soon as practicable. The PCGC will then meet or conference to discuss the issue(s) and make their decision within 60 calendar days of the chairman's receipt of the request. The decision will be provided to the person bringing the issue(s) and the NERC staff. The PCGC is the governing body of the Certification program and its decision is final.

4. Dispute Resolution Process Expenses: All individual expenses associated with the Dispute Resolution Process, including salaries, meetings, or consultant fees, shall be the responsibility of the individual parties incurring the expense.

5. Decision Process: Robert's Rules of Order shall be used as a standard of conduct for the Dispute Resolution Process. A majority vote of the members present will decide all issues. The vote will be taken in a closed session. No member of the PCGC may participate in the Dispute Resolution Process, other than as a party or witness, if he or she has an interest in the particular matter.

    5.1 A stipulation of invoking the Dispute Resolution Process is that the entity invoking the Dispute Resolution Process agrees that neither NERC (its members, Board of Trustees, committees, subcommittees, and staff), any person assisting in the Dispute Resolution Process, nor any company employing a person assisting in the Dispute Resolution Process, shall be liable, and they shall be held harmless against the consequences of or any action or inaction or of any agreement reached in resolution of the dispute or any failure to reach agreement as a result of the Dispute Resolution Process. This "hold harmless" clause does not extend to matters constituting gross negligence, intentional misconduct, or a breach of confidentiality.

605. Disciplinary Action

1. Disciplinary action may be necessary to protect the integrity of the system operator Credential. The PCGC may initiate disciplinary action should an individual act in a manner that is inconsistent with expectations, including but not limited to:

    1.1. Willful, gross, and/or repeated violation of the NERC Reliability Standards as determined by a NERC investigation.

1.2. Willful, gross, and/or repeated negligence in performing the duties of a certified system operator as determined by a NERC investigation.

1.3. Intentional misrepresentation of information provided on a NERC application for a system operator Certification exam or to maintain a system operator Credential using CE Hours.

1.4. Intentional misrepresentation of identification in the exam process, including a person identifying himself or herself as another person to obtain Certification for the other person.

1.5. Any form of cheating during a Certification exam, including, but not limited to, bringing unauthorized reference material in the form of notes, crib sheets, or other methods of cheating into the testing center.

1.6. A certified system operator's admission to or conviction of any felony or misdemeanor directly related to his/her duties as a system operator.

2. Hearing Process: Upon report to NERC of a candidate's or certified system operator's alleged misconduct, the NERC PCGC Credential Review Task Force will convene for the determination of facts. An individual, government agency, or other investigating authority can file a report. Unless the Task Force initially determines that the report of alleged misconduct is without merit, the candidate or certified system operator will be given the right to notice of the allegation. A hearing will be held and the charged candidate or certified system operator will be given an opportunity to be heard and present further relevant information. The Task Force may seek out information from other involved parties. The hearing will not be open to the public, but it will be open to the charged candidate or certified system operator and his or her representative. The Task Force will deliberate in a closed session, but the Task Force cannot receive any evidence during the closed session that was not developed during the course of the hearing.

3. Task Force's decision: The Task Force's decision will be unanimous and will be in writing with inclusion of the facts and reasons for the decision. The Task Force's written decision will be delivered to the PCGC and by certified post to the charged candidate or certified system operator. In the event that the Task Force is unable to reach a unanimous decision, the matter shall be brought to the full committee for a decision.

3.1. No Action: Allegation of misconduct was determined to be unsubstantiated or inconsequential to the Credential.

3.2. Probation: A letter will be sent from NERC to the offender specifying:

3.2.1. The length of time of the probationary period (to be determined by the PCGC).

3.2.2. Credential will remain valid during the probationary period.

3.2.3. The probationary period does not affect the expiration date of the current certificate.

3.2.4. During the probationary period, a subsequent offense of misconduct, as determined through the same process as described above, may be cause for more serious consequences.

3.3. Revoke for Cause: A letter will be sent from NERC to the offender specifying:

3.3.1. The length of time of the probationary period (to be determined by the PCGC).

3.3.2. Credential is no longer valid.

3.3.3. Successfully passing an exam will be required to become recertified.

3.3.4. An exam will not be authorized until the revocation period expires

3.4. Termination of Credential: A letter will be sent from NERC to the offender specifying permanent removal of Credential.

4. Credential Review Task Force: The Credential Review Task Force shall be comprised of three active members of the PCGC assigned by the Chairman of the PCGC on an ad hoc basis. No one on the Credential Review Task Force may have an interest in the particular matter. The Task Force will meet in a venue determined by the Task Force chairman.

5. Appeal Process: The decision of the Task Force may be appealed using the NERC System Operator Certification Dispute Resolution Process.

606. Candidate Testing

1. The PCGC shall develop exams to evaluate individual competence in a manner that is objective, and fair to all candidates, and to determine essential knowledge relating to NERC Reliability Standards as well as principles of the Bulk Power System operations.

2. The PCGC shall oversee exam administration as follows:

1.1 Adopt and implement a formal policy of periodic review of exams to assess ongoing relevance to knowledge and skill needed in the discipline; and

1.2 Conduct ongoing studies to substantiate the reliability and validity of exams.

3. The PCGC shall develop and utilize policies and procedures to ensure the integrity and security of exams and the transparency of test administration consistent with the following:

    1.1 The PCGC shall establish pass/fail levels that protect the public with a method that is based on competence and generally accepted standards in the psychometric community as being fair and reasonable;

    1.2 The PCGC shall conduct ongoing studies to substantiate the reliability and validity of the exams;

    1.3 The PCGC shall dictate how long examination records are kept in their original format; and

    1.4 The PCGC shall demonstrate that different revisions of the exams assess equivalent content.

607. Public Information About the Personnel Certification Program

The PCGC shall maintain and publish the following:

1. a summary of the information, knowledge, or functions covered by each examination administered pursuant to the Personnel Certification Program; and

2. an annual summary of Certification activities for the Personnel Certification Program, including, the number of examinations delivered, the number of applicants who passed, the number of applicants who failed, and the number of applicants certified.

608. Responsibilities to Applicants for Certification or Re-Certification

The PCGC shall adhere to the following with respect to personnel applicants:

1. comply with all requirements of applicable federal and state/provincial laws with respect to all Certification and re-Certification activities, and shall require compliance of all contractors and/or providers of services;

2. make available to all applicants copies of formalized procedures for application for, and attainment of, personnel Certification and re-Certification and shall uniformly follow and enforce such procedures for all applicants;

3. implement a formal policy for the periodic review of eligibility criteria and application procedures for fairness;

4. provide competently proctored examination sites; and

5. uniformly provide applicants with examination results and give content summary after the examination.

609. Responsibilities to Employers of Certified Personnel

The PCGC shall adhere to the following with respect to certified personnel:

1. demonstrate that the exams adequately measure essential knowledge relating to NERC Reliability Standards as well as principles of Bulk Power System operations;

2. award Certification and re-Certification only after the skill and knowledge of the individual have been evaluated and determined to be acceptable;

3. maintain, in an electronic format, a current list of those personnel certified in the programs and have policies and procedures that delineate what information about a Certification Credential holder may be made public and under what circumstances; and

4. develop formal policies and procedures for discipline of a Certification Credential holder, including the revocation of the certificate, for conduct deemed harmful to the public or inappropriate to the discipline (e.g., incompetence, unethical behavior, physical or mental impairment affecting performance). These procedures shall incorporate due process.

610. [PLACEHOLDER]

SECTION 700 — RELIABILITY READINESS EVALUATION AND IMPROVEMENT AND FORMATION OF SECTOR FORUMS

701. Confidentiality Requirements for Readiness Evaluations and Evaluation Team Members

1. All information made available or created during the course of any reliability readiness evaluation including, but not limited to, data, Documents, observations and notes, shall be maintained as confidential by all evaluation team members, in accordance with the requirements of Section 1500.

2. Evaluation team members are obligated to destroy all confidential evaluation notes following the posting of the final report of the reliability readiness evaluation.

3. NERC will retain reliability readiness evaluation-related documentation, notes, and materials for a period of time as defined by NERC.

4. These confidentiality requirements shall survive the termination of the NERC Reliability Readiness Evaluation and Improvement Program.

702. Formation of Sector Forum

1. NERC will form a sector forum at the request of any five members of NERC that share a common interest in the safety and reliability of the Bulk Power System. The members of sector forum may invite such others of the members of NERC to join the sector forum as the sector forum deems appropriate.

2. The request to form a sector forum must include a proposed charter for the sector forum. The Board must approve the charter.

3. NERC will provide notification of the formation of a sector forum to its membership roster. Notices and agendas of meetings shall be posted on NERC's website.

4. A sector forum may make recommendations to any of the NERC committees and may submit a Standards Authorization Request to the NERC *Reliability Standards Development Procedure*.

SECTION 800 — RELIABILITY ASSESSMENT AND PERFORMANCE ANALYSIS

801. Objectives of the Reliability Assessment and Performance Analysis Program

The objectives of the NERC Reliability Assessment and Performance Analysis Program are to: (1) conduct, and report the results of, an independent assessment of the overall reliability and adequacy of the interconnected North American Bulk Power Systems, both as existing and as planned; (2) analyze off-normal events on the Bulk Power System; (3) identify the root causes of events that may be precursors of potentially more serious events; (4) assess past reliability performance for lessons learned; (5) disseminate findings and lessons learned to the electric industry to improve reliability performance; and (6) develop reliability performance benchmarks. The final reliability assessment reports shall be approved by the Board for publication to the electric industry and the general public.

802. Scope of the Reliability Assessment Program

1. The scope of the Reliability Assessment Program shall include:

    1.1 Review, assess, and report on the overall electric generation and transmission reliability (adequacy and operating reliability) of the interconnected Bulk Power Systems, both existing and as planned.

    1.2 Assess and report on the key issues, risks, and uncertainties that affect or have the potential to affect the reliability of existing and future electric supply and transmission.

    1.3 Review, analyze, and report on Regional Entity self-assessments of electric supply and bulk power transmission reliability, including reliability issues of specific regional concern.

    1.4 Identify, analyze, and project trends in electric customer demand, supply, and transmission and their impacts on Bulk Power System reliability.

    1.5 Investigate, assess, and report on the potential impacts of new and evolving electricity market practices, new or proposed regulatory procedures, and new or proposed legislation (e.g. environmental requirements) on the adequacy and operating reliability of the Bulk Power Systems.

2. The Reliability Assessment Program shall be performed in a manner consistent with the Reliability Standards of NERC including but not limited to those that specify reliability assessment Requirements.

803. Reliability Assessment Reports

The number and type of periodic assessments that are to be conducted shall be at the discretion of NERC. The results of the reliability assessments shall be documented in three reports: the long-term and the annual seasonal (summer) and the annual seasonal (winter) assessment reports. NERC shall also conduct special reliability assessments from time to time as circumstances warrant. The reliability assessment reports shall be reviewed and approved for publication by the Board. The three regular reports are described below.

1. **Long-Term Reliability Assessment Report** — The annual long-term report shall cover a ten-year planning horizon. The planning horizon of the long-term reliability assessment report shall be subject to change at the discretion of NERC. Detailed generation and transmission adequacy assessments shall be conducted for the first five years of the review period. For the second five years of the review period, the assessment shall focus on the identification, analysis, and projection of trends in peak demand, electric supply, and transmission adequacy, as well as other industry trends and developments that may impact future electric system reliability. Reliability issues of concern and their potential impacts shall be presented along with any mitigation plans or alternatives. The long-term reliability assessment reports will generally be published in the fall (September) of each year. NERC will also publish electricity supply and demand data associated with the long-term reliability assessment report.

2. **Summer Assessment Report** — The annual summer seasonal assessment report typically shall cover the four-month (June–September) summer period. It shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected summer peak demands. It shall also identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may include possible mitigation alternatives. The report will generally be published in mid-May for the upcoming summer period.

3. **Winter Assessment Report** — The annual winter seasonal assessment report shall cover the three-month (December–February) winter period. The report shall provide an overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected winter peak demands. Similar to the summer assessment, the winter assessment shall identify reliability issues of interest and regional and subregional areas of concern in meeting projected customer demands and may also include possible mitigation alternatives. The winter assessment report will generally be published in mid-November for the upcoming winter period.

4. **Special Reliability Assessment Reports** — In addition to the long-term and seasonal reliability assessment reports, NERC shall also conduct special reliability assessments on a regional, interregional, and Interconnection basis as conditions warrant, or as requested by the Board or governmental authorities. The teams of reliability and technical experts also may initiate special assessments of key

reliability issues and their impacts on the reliability of a regions, subregions, or Interconnection (or a portion thereof). Such special reliability assessments may include, among other things, operational reliability assessments, evaluations of emergency response preparedness, adequacy of fuel supply, hydro conditions, reliability impacts of new or proposed environmental rules and regulations, and reliability impacts of new or proposed legislation that affects or has the potential to affect the reliability of the interconnected Bulk Power Systems in North America.

804. Reliability Assessment Data and Information Requirements

To carry out the reviews and assessments of the overall reliability of the interconnected Bulk Power Systems, the Regional Entities and other entities shall provide sufficient data and other information requested by NERC in support of the annual long-term and seasonal assessments and any special reliability assessments.

Some of the data provided for these reviews and assessment may be considered confidential from a competitive marketing perspective, a Critical Energy Infrastructure Information perspective, or for other purposes. Such data shall be treated in accordance with the provisions of Section 1500 – Confidential Information.

While the major sources of data and information for this program are the Regional Entities, a team of reliability and technical experts is responsible for developing and formulating its own independent conclusions about the near-term and long-term reliability of the Bulk Power Systems.

In connection with the reliability assessment reports, requests shall be submitted to each of the Regional Entities for required reliability assessment data and other information, and for each Regional Entity's self-assessment report. The timing of the requests will be governed by the schedule for the preparation of the assessment reports.

The Regional Entity self-assessments are to be conducted in compliance with NERC Reliability Standards and the respective regional planning criteria. The team(s) of reliability and technical experts shall also conduct interviews with the Regional Entities as needed. The summary of the Regional Entity self-assessments that are to be included in the assessment reports shall follow the general outline identified in NERC's request. This outline may change from time to time as key reliability issues change.

In general, the Regional Entity reliability self-assessments shall address, among other areas, the following topics: demand and Net Energy for Load; assessment of projected resource adequacy; any transmission constraints that may impact bulk transmission adequacy and plans to alleviate those constraints; any unusual operating conditions that could impact reliability for the assessment period; fuel supply adequacy; the deliverability of generation (both internal and external) to Load; and any other reliability issues in the Region and their potential impacts on the reliability of the Bulk Power Systems.

805. Reliability Assessment Process

Based on their expertise, the review of the collected data, the review of the Regional Entity self-assessment reports, and interviews with the Regional Entities, as appropriate, the teams of reliability and technical experts shall perform an independent review and assessment of the generation and transmission adequacy of each Region's existing and planned Bulk Power System. The results of the review teams shall form the basis of NERC's long-term and seasonal reliability assessment reports. The review and assessment process is briefly summarized below.

1. **Resource Adequacy Assessment** — The teams shall evaluate the regional demand and resource capacity data for completeness in the context of the overall resource capacity needs of the Region. The team shall independently evaluate the ability of the Regional Entity members to serve their obligations given the demand growth projections, the amount of existing and planned capacity, including committed and uncommitted capacity, contracted capacity, or capacity outside of the Region. If the Region relies on capacity from outside of the Region to meet its resource objectives, the ability to deliver that capacity shall be factored into the assessment. The demand and resource capacity information shall be compared to the resource adequacy requirements of the Regional Entity for the year(s) or season(s) being assessed. The assessment shall determine if the resource information submitted represents a reasonable and attainable plan for the Regional Entity and its members. For cases of inadequate capacity or reserve margin, the Regional Entity will be requested to analyze and explain any resource capacity inadequacies and its plans to mitigate the reliability impact of the potential inadequacies. The analysis may be expanded to include surrounding areas. If the expanded analysis indicates further inadequacies, then an interregional problem may exist and will be explored with the applicable Regions. The results of these analyses shall be described in the assessment report.

2. **Transmission Adequacy and Operating Reliability Assessment** — The teams shall evaluate transmission system information that relates to the adequacy and operating reliability of the regional transmission system. That information shall include: regional planning study reports, interregional planning study reports, and/or regional operational study reports. If additional information is required, another data request shall be sent to the Regional Entity. The assessment shall provide a judgment on the ability of the regional transmission system to operate reliably under the expected range of operating conditions over the assessment period as required by NERC Reliability Standards. If sub-areas of the regional system are especially critical to the Reliable Operation of the regional bulk transmission system, these Facilities or sub-areas shall be reviewed and addressed in the assessment. Any areas of concern related to the adequacy or operating reliability of the system shall be identified and reported in the assessment.

3. **Seasonal Operating Reliability Assessment** — The team(s) shall evaluate the overall operating reliability of the regional bulk transmission systems. In areas with potential resource adequacy or system operating reliability problems,

operational readiness of the affected Regional Entities for the upcoming season shall be reviewed and analyzed. The assessment may consider unusual but possible operating scenarios and how the system is expected to perform. Operating reliability shall take into account a wide range of activities, all of which should reinforce the Regional Entity's ability to deal with the situations that might occur during the upcoming season. Typical activities in the assessment may include: facility modifications and additions, new or modified operating procedures, emergency procedures enhancement, and planning and operating studies. The teams shall report the overall seasonal operating reliability of the regional transmission systems in the annual summer and winter assessment reports.

4. **Reporting of Reliability Assessment Results** — The teams of reliability and technical experts shall provide an independent assessment of the reliability of the Regional Entities and the North American interconnected Bulk Power System for the period of the assessment. While the Regional Entities are relied upon to provide the information to perform such assessments, the review team is not required to accept the conclusions provided by the Regional Entities. Instead, the review team is expected, based on their expertise, to reach their own independent conclusions about the status of the adequacy of the generation and bulk power transmission systems of North America.

   The review team also shall strive to achieve consensus in their assessments. The assessments that are made are based on the best information available at the time. However, since judgment is applied to this information, legitimate differences of opinion can develop. Despite these differences, the review team shall work to achieve consensus on their findings.

   In addition to providing long-term and seasonal assessments in connection with the Reliability Assessment Program, the review team of experts shall also be responsible for recommending new and revised Reliability Standards related to the reliability assessments and the reliability of the Bulk Power Systems. These proposals for new or revised Reliability Standards shall be entered into NERC's Reliability Standards development process.

   Upon completion of the assessment, the team shall share the results with the Regional Entities. The Regional Entities shall be given the opportunity to review and comment on the conclusions in the assessment and to provide additional information as appropriate. The reliability assessments and their conclusions are the responsibility of NERC's technical review team and NERC.

   The preparation and approval of NERC's reliability assessment reports shall follow a prescribed schedule including review, comment, and possible approval by appropriate NERC committees. The long-term and seasonal (summer and winter) reliability assessment reports shall be further reviewed for approval by the Board for publication to the electric industry.

806. Scope of the Reliability Performance and Analysis Program

The components of the program will include analysis of large-scale outages, disturbances, and near misses to determine root causes and lessons learned; identification and continuous monitoring of performance indices to detect emerging trends and signs of a decline in reliability performance; and communications of performance results, trends, recommendations, and initiatives to those responsible to take actions; followed with confirmation of actions to correct any deficiencies identified. Within NERC, the reliability performance program will provide performance results to the Reliability Standards Development and Compliance Monitoring and Enforcement Programs to make the necessary adjustments to preserve reliability based on a risk-based approach.

807. Analysis of Major Events

Responding to major events affecting the Bulk Power System such as significant losses of Load or generation, significant Bulk Power System disturbances, or other emergencies on the Bulk Power System, can be divided into four phases: situational assessment and communications; situation tracking and communications; data collection, investigation, analysis, and reporting; and follow-up on recommendations.

1. NERC's role following a major event is to provide leadership, coordination, technical expertise, and assistance to the industry in responding to the major event. Working closely with the Regional Entities and Reliability Coordinators, and other appropriate Registered Entities, NERC will coordinate and facilitate efforts among industry participants, and with state, federal, and provincial governments in the United States and Canada to support the industry's response.

2. When responding to any major event where physical or cyber security is suspected as a cause or contributing factor to the major event, NERC will immediately notify appropriate government agencies and coordinate its activities with them.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator of the Bulk Power System shall also provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entity as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

4. During the conduct of NERC analyses, assistance may be needed from government agencies. This assistance could include: authority to require data reporting from affected or involved parties; communications with other agencies of government; investigations related to possible criminal or terrorist involvement in the major event; resources for initial data gathering immediately after the major

event; authority to call meetings of affected or involved parties; and technical and analytical resources for studies.

5. NERC shall work with all other participants to establish a clear delineation of roles, responsibilities, and coordination requirements among industry and government for the investigation and reporting of findings, conclusions, and recommendations related to major events with the objective of avoiding, to the extent possible, multiple investigations of the same major event. If the major event is confined to a single Regional Entity, NERC representatives will participate as members of the Regional Entity analysis team. NERC will establish, maintain, and revise from time to time as appropriate based on experience, a manual setting forth procedures and protocols for communications and sharing and exchange of information between and among NERC, the affected Regional Entity or Entities, and relevant governmental authorities, industry organizations and Bulk Power System user, owners, and operators concerning the investigation and analysis of major events.

6. NERC and applicable entity(s) will apply, as appropriate to the circumstances of the major event, the NERC *Blackout and Disturbance Response Procedures*, which are incorporated into these Rules of Procedure as **Appendix 8**. These procedures provide a framework to guide NERC's response to major events that may have multiregional, national, or international implications. Experienced industry leadership shall be applied to tailor the response to the specific circumstances of the major event. In accordance with those procedures, the NERC president will determine whether the major event warrants analysis at the NERC level. A Regional Entity may request that NERC elevate any analysis of a major event to the NERC level.

7. NERC will screen and analyze the findings and recommendations from the analysis, and those with generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

808. Analysis of Off-Normal Occurrences, Bulk Power System Performance, and Bulk Power System Vulnerabilities

1. NERC and Regional Entities will analyze Bulk Power System and equipment performance occurrences that do not rise to the level of a major event, as described in Section 807. NERC and Regional Entities will also analyze potential vulnerabilities in the Bulk Power System that they discover or that are brought to their attention by other sources including government agencies. The purpose of these analyses is to identify the root causes of occurrences or conditions that may be precursors of major events or other potentially more serious occurrences, or that have the potential to cause major events or other more serious occurrences, to assess past reliability performance for lessons learned, and to develop reliability performance benchmarks and trends.

2. NERC and Regional Entities will screen and analyze off-normal occurrences, Bulk Power System performance, and potential Bulk Power System vulnerabilities for significance, and information from those indicated as having generic applicability will be disseminated to the industry through various means appropriate to the circumstances, including in accordance with Section 810.

3. To the extent that a Reliability Standard sets forth specific criteria and procedures for reporting the Bulk Power System disturbances and events described in that Reliability Standard, all Registered Entities that are subject to the Requirements of that Reliability Standard must report the information required by that Reliability Standard within the time periods specified. In addition to reporting information as required by applicable Reliability Standards, each user, owner, and operator, of the Bulk Power System shall provide NERC and the applicable Regional Entities with such additional information requested by NERC or the applicable Regional Entities as is necessary to enable NERC and the applicable Regional Entities to carry out their responsibilities under this section.

809. Reliability Benchmarking

NERC shall identify and track key reliability indicators as a means of benchmarking reliability performance and measuring reliability improvements. This program will include assessing available metrics, developing guidelines for acceptable metrics, maintaining a performance metrics "dashboard" on the NERC website, and developing appropriate reliability performance benchmarks.

810. Information Exchange and Issuance of NERC Advisories, Recommendations and Essential Actions

1. Members of NERC and Bulk Power System owners, operators, and users shall provide NERC with detailed and timely operating experience information and data.

2. In the normal course of operations, NERC disseminates the results of its events analysis findings, lessons learned and other analysis and information gathering to the industry. These findings, lessons learned and other information will be used to guide the Reliability Assessment Program.

3. When NERC determines it is necessary to place the industry or segments of the industry on formal notice of its findings, analyses, and recommendations, NERC will provide such notification in the form of specific operations or equipment Advisories, Recommendations or Essential Actions:

   3.1 Level 1 (Advisories) – purely informational, intended to advise certain segments of the owners, operators and users of the Bulk Power System of findings and lessons learned;

   3.2 Level 2 (Recommendations) – specific actions that NERC is recommending be considered on a particular topic by certain segments of

owners, operators, and users of the Bulk Power System according to each entity's facts and circumstances;

3.3 Level 3 (Essential Actions) – specific actions that NERC has determined are essential for certain segments of owners, operators, or users of the Bulk Power System to take to ensure the reliability of the Bulk Power System. Such Essential Actions require NERC Board approval before issuance.

4. The Bulk Power System owners, operators, and users to which Level 2 (Recommendations) and Level 3 (Essential Actions) notifications apply are to evaluate and take appropriate action on such issuances by NERC. Such Bulk Power System owners, operators, and users shall also provide reports of actions taken and timely updates on progress towards resolving the issues raised in the Recommendations and Essential Actions in accordance with the reporting date(s) specified by NERC.

5. NERC will advise the Commission and other Applicable Governmental Authorities of its intent to issue all Level 1 (Advisories), Level 2 (Recommendations), and Level 3 (Essential Actions) at least five (5) business days prior to issuance, unless extraordinary circumstances exist that warrant issuance less than five (5) business days after such advice. NERC will file a report with the Commission and other Applicable Governmental Authorities no later than thirty (30) days following the date by which NERC has requested the Bulk Power System owners, operators, and users to which a Level 2 (Recommendation) or Level 3 (Essential Action) issuance applies to provide reports of actions taken in response to the notification. NERC's report to the Commission and other Applicable Governmental Authorities will describe the actions taken by the relevant owners, operators, and users of the Bulk Power System and the success of such actions taken in correcting any vulnerability or deficiency that was the subject of the notification, with appropriate protection for Confidential Information or Critical Energy Infrastructure Information.

811. Equipment Performance Data

Through its Generating Availability Data System (GADS), NERC shall collect operating information about the performance of electric generating equipment; provide assistance to those researching information on power plant outages stored in its database; and support equipment reliability as well as availability analyses and other decision-making processes developed by GADS subscribers. GADS data is also used in conducting assessments of generation resource adequacy.

SECTION 900 — TRAINING AND EDUCATION

901. Scope of the Training and Education Program

Assuring the Reliable Operation of the North American Bulk Power System requires informed knowledgeable and skilled personnel. NERC shall oversee the coordination and delivery of learning materials, resources, and activities to allow for training and education of:

1. ERO Enterprise staff supporting statutory and delegation-related activities; and

2. Bulk Power System industry participants consistent with ERO functional program requirements.

902. [PLACEHOLDER]

SECTION 1000 — SITUATION AWARENESS AND INFRASTRUCTURE SECURITY

1001. Situation Awareness

NERC shall through the use of Reliability Coordinators and available tools, monitor present conditions on the Bulk Power System and provide leadership coordination, technical expertise, and assistance to the industry in responding to events as necessary. To accomplish these goals, NERC will:

1. Maintain real-time situation awareness of conditions on the Bulk Power System;

2. Notify the industry of significant Bulk Power System events that have occurred in one area, and which have the potential to impact reliability in other areas;

3. Maintain and strengthen high-level communication, coordination, and cooperation with governments and government agencies regarding real-time conditions; and

4. Enable the Reliable Operation of interconnected Bulk Power Systems by facilitating information exchange and coordination among reliability service organizations.

1002. Reliability Support Services

NERC may assist in the development of tools and other support services for the benefit of Reliability Coordinators and other system operators to enhance reliability, operations and planning. NERC will work with the industry to identify new tools, collaboratively develop requirements, support development, provide an incubation period, and at the end of that period, transition the tool or service to another group or owner for long term operation of the tool or provision of the service. To accomplish this goal, NERC will:

1. Collaborate with industry to determine the necessity of new tools or services to enhance reliability;

2. For those tools that the collaborative process determines should proceed to a development phase, provide a start-up mechanism and development system;

3. Implement the tool either on its own or through an appropriate group or organization; and

4. Where NERC conducts the implementation phase of a new tool or service, develop a transition plan to turn maintenance and provision of the tool or service over to an organization identified in the development stage.

In addition to tools developed as a result of a collaborative process with industry, NERC may develop reliability tools on its own, but will consult with industry concerning the need for the tool prior to proceeding to development.

Tools and services being maintained by NERC as of January 1, 2012, will be reviewed and, as warranted, transitioned to an appropriate industry group or organization. NERC will develop and maintain a strategic reliability tools plan that will list the tools and services being maintained by NERC, and, where applicable, the plans for transition to an appropriate industry group or organization.

1003. Infrastructure Security Program

NERC shall participate in and, where appropriate, coordinate electric industry activities to promote Critical Infrastructure protection of the Bulk Power System in North America. NERC shall, where appropriate, take a leadership role in Critical Infrastructure protection of the electricity sector to help reduce vulnerability and improve mitigation and protection of the electricity sector's Critical Infrastructure. To accomplish these goals, NERC shall perform the following functions.

1. Electricity Information Sharing and Analysis Center (E-ISAC)

    1.1 NERC shall operate the E-ISAC on behalf of the electricity sector. In 1998, the U.S. Secretary of Energy asked NERC to serve as the information sharing and analysis center for the electricity sector, in implementation of Presidential Decision Directive 63, as part of a public/private partnership to deal with matters related to infrastructure security.

    1.2 The E-ISAC gathers and analyzes security information, coordinates incident management, and communicates mitigation strategies with stakeholders within the electricity sector, across interdependent sectors, and with government partners. The E-ISAC, in collaboration with the United States Department of Energy (DOE) and the Electricity Subsector Coordinating Council (ESCC), serves as the primary security communications channel for the electricity sector and enhances the sector's ability to prepare for and respond to cyber and physical threats, vulnerabilities, and incidents.

    1.3 NERC shall improve the capability of the E-ISAC to fulfill its mission.

    1.4 NERC shall work closely with governmental agencies, including, among others, DOE, the United States Department of Homeland Security, Natural Resources Canada, and Public Safety Canada.

    1.5 NERC shall strengthen and expand these functions and working relationships with the electricity sector, other Critical Infrastructure industries, governments, and government agencies throughout North America to ensure the protection of the infrastructure of the Bulk Power System.

    1.6 NERC shall coordinate with the ESCC and the Government Coordinating Council.

1.7 NERC shall coordinate with other Critical Infrastructure sectors through active participation with the other Sector Coordinating Councils, other ISACs, and the National Infrastructure Advisory Council.

1.8 NERC shall encourage and participate in coordinated Critical Infrastructure protection exercises, including interdependencies with other Critical Infrastructure sectors.

1.9 As part of the E-ISAC's efforts to fulfill its mission, it may issue, as circumstances warrant, written communications, referred to as All Points Bulletins (APBs), to disseminate critical security information rapidly to electricity sector asset owners and operators as security threats and attacks develop, and critical, time-sensitive security information becomes available. The E-ISAC shall share all APBs with Federal Energy Regulatory Commission staff no later than at the time of issuance.

2. Security Planning

2.1 NERC shall take a risk management approach to Critical Infrastructure protection, considering probability and severity, through identification, protection, detection, response, and recovery functions.

2.2 NERC shall consider security along-side considerations of reliability and resiliency of the Bulk Power System.

2.3 NERC shall keep abreast of the changing threat environment through collaboration with appropriate government agencies.

2.4 NERC shall develop criteria to identify critical physical and cyber assets, assess security threats, identify risk assessment methods, and assess effectiveness of physical and cyber protection measures.

2.5 NERC shall support implementation of the Critical Infrastructure Protection Standards through education and outreach.

2.6 NERC shall review and improve existing security guidelines, develop new security guidelines to meet the needs of the electricity sector, and consider whether any guidelines should be developed into Reliability Standards.

2.7 NERC shall conduct education and outreach initiatives to increase awareness of security matters and respond to the security needs of the electricity sector.

2.8 NERC shall strengthen relationships with federal, state, and provincial government agencies on Critical Infrastructure protection matters.

2.9 NERC shall maintain and endeavor to improve mechanisms for the sharing of sensitive or classified information with federal, state, and provincial government agencies on Critical Infrastructure protection matters.

2.10 NERC shall improve methods to assess the impact of a possible physical attack on the Bulk Power System and means to deter, mitigate, and respond following an attack.

SECTION 1100 — ANNUAL NERC BUSINESS PLANS AND BUDGETS

1101. Scope of Business Plans and Budgets

The Board shall determine the content of the budgets to be submitted to the Applicable Governmental Authorities with consultation from the members of the Member Representatives Committee, Regional Entities, and others in accordance with the Bylaws. The Board shall identify any activities outside the scope of NERC's statutory reliability functions, if any, and the appropriate funding mechanisms for those activities.

1102. NERC Funding and Cost Allocation

1. In order that NERC's costs shall be fairly allocated among Interconnections and among Regional Entities, the NERC funding mechanism for all statutory functions shall be based on Net Energy for Load (NEL).

2. NERC's costs shall be allocated so that all Load (or, in the case of costs for an Interconnection or Regional Entity, all Load within that Interconnection or Regional Entity) bears an equitable share of such costs based on NEL.

3. Costs shall be equitably allocated between countries or Regional Entities thereof for which NERC has been designated or recognized as the Electric Reliability Organization.

4. Costs incurred to accomplish the statutory functions for one Interconnection, Regional Entity, or group of entities will be directly assigned to that Interconnection, Regional Entity, or group of entities provided that such costs are allocated equitably to end-users based on Net Energy for Load.

1103. NERC Budget Development

1. The NERC annual budget process shall be scheduled and conducted for each calendar year so as to allow a sufficient amount of time for NERC to receive Member inputs, develop the budget, and receive Board and, where authorized by applicable legislation or agreement, Applicable Governmental Authority approval of the NERC budget for the following fiscal year, including timely submission of the proposed budget to FERC for approval in accordance with FERC regulations.

2. The NERC budget submittal to Applicable Governmental Authorities shall include provisions for all ERO functions, all Regional Entity delegated functions as specified in delegation agreements and reasonable reserves and contingencies.

3. The NERC annual budget submittal to Applicable Governmental Authorities shall include description and explanation of NERC's proposed ERO program activities for the year; budget component justification based on statutory or other authorities; explanation of how each budgeted activity lends itself to the accomplishment of the statutory or other authorities; sufficiency of resources provided for in the budget to carry out the ERO program responsibilities;

explanation of the calculations and budget estimates; identification and explanation of changes in budget components from the previous year's budget; information on staffing and organization charts; and such other information as is required by FERC and other Applicable Governmental Authorities having authority to approve the proposed budget.

4. NERC shall develop, in consultation with the Regional Entities, a reasonable and consistent system of accounts, to allow a meaningful comparison of actual results at the NERC and Regional Entity level by the Applicable Governmental Authorities.

1104. Submittal of Regional Entity Budgets to NERC

1. Each Regional Entity shall submit its proposed annual budget for carrying out its delegated authority functions as well as all other activities and funding to NERC in accordance with a schedule developed by NERC and the Regional Entities, which shall provide for the Regional Entity to submit its final budget that has been approved by its board of directors or other governing body no later than July 1 of the prior year, in order to provide sufficient time for NERC's review and comment on the proposed budget and approval of the Regional Entity budget by the NERC Board of Trustees in time for the NERC and Regional Entity budgets to be submitted to FERC and other Applicable Governmental Authorities for approval in accordance with their regulations. The Regional Entity's budget shall include supporting materials in accordance with the budget and reporting format developed by NERC and the Regional Entities, including the Regional Entity's complete business plan and organization chart, explaining the proposed collection of all dues, fees, and charges and the proposed expenditure of funds collected in sufficient detail to justify the requested funding collection and budget expenditures.

2. NERC shall review and approve each Regional Entity's budget for meeting the requirements of its delegated authority. Concurrent with approving the NERC budget, NERC shall review and approve, or reject, each Regional Entity budget for filing.

3. NERC shall also have the right to review from time to time, in reasonable intervals but no less frequently than every three years, the financial books and records of each Regional Entity having delegated authority in order to ensure that the documentation fairly represents in all material aspects appropriate funding of delegated functions.

1105. Submittal of NERC and Regional Entity Budgets to Governmental Authorities for Approval

1. NERC shall file for approval by the Applicable Governmental Authorities at least 130 days in advance of the start of each fiscal year. The filing shall include: (1) the complete NERC and Regional Entity budgets including the business plans and organizational charts approved by the Board, (2) NERC's annual funding

requirement (including Regional Entity costs for delegated functions), and (3) the mechanism for assessing charges to recover that annual funding requirement, together with supporting materials in sufficient detail to support the requested funding requirement.

2. NERC shall seek approval from each Applicable Governmental Authority requiring such approval for the funding requirements necessary to perform ERO activities within their jurisdictions.

1106. NERC and Regional Entity Billing and Collections

1. NERC shall request the Regional Entities to identify all Load-Serving Entities[5] within each Regional Entity and the NEL assigned to each Load-Serving Entity, and the Regional Entities shall supply the requested information. The assignment of a funding requirement to an entity shall not be the basis for determining that the entity must be registered in the Compliance Registry.

2. NERC shall accumulate the NEL by Load-Serving Entities for each Applicable Governmental Authority and submit the proportional share of NERC funding requirements to each Applicable Governmental Authority for approval together with supporting materials in sufficient detail to support the requested funding requirement.

3. NEL reported by Balancing Authorities within a Region shall be used to rationalize and validate amounts allocated for collection through Regional Entity processes.

4. The billing and collection processes shall provide:

   4.1 A clear validation of billing and application of payments.

   4.2 A minimum of data requests to those being billed.

   4.3 Adequate controls to ensure integrity in the billing determinants including identification of entities responsible for funding NERC's activities.

   4.4 Consistent billing and collection terms.

5. NERC will bill and collect all budget requirements approved by Applicable Governmental Authorities (including the funds required to support those functions assigned to the Regional Entities through the delegation agreements) directly from the Load-Serving Entities or their designees or as directed by particular Applicable Governmental Authorities, except where the Regional Entity is required to collect the budget requirements for NERC, in which case the Regional

[5] A Regional Entity may allocate funding obligations using an alternative method approved by NERC and by FERC and other Applicable Governmental Authorities, as provided for in the regional delegation agreement.

Entity will collect directly from the Load-Serving Entities or as otherwise provided by agreement and submit funds to NERC. Alternatively, a load-serving entity may pay its allocated ERO costs through a Regional Entity managed collection mechanism.

6. NERC shall set a minimum threshold limit on the billing of small LSEs to minimize the administrative burden of collection.

7. NERC shall pursue any non-payments and shall request assistance from Applicable Governmental Authorities as necessary to secure collection.

8. In the case where a Regional Entity performs the collection for ERO, the Regional Entity will not be responsible for non-payment in the event that a user, owner or operator of the Bulk Power System does not pay its share of dues, fees and charges in a timely manner, provided that such a Regional Entity shall use reasonably diligent efforts to collect dues, fees, and other charges from all entities obligated to pay them. However, any revenues not paid shall be recovered from others within the same Region to avoid cross-subsidization between Regions.

9. Both NERC and the Regional Entities also may bill members or others for functions and services not within statutory requirements or otherwise authorized by the Applicable Governmental Authorities. Costs and revenues associated with these functions and services shall be separately identified and not commingled with billings associated with the funding of NERC or of the Regional Entities for delegated activities.

1107. Penalty Applications

1. Where NERC or a Regional Entity initiates a compliance monitoring and enforcement process that leads to imposition of a Penalty, the entity that initiated the process shall receive any Penalty monies imposed and collected as a result of that process, unless a different disposition of the Penalty monies is provided for in the delegation agreement, or in a contract or a disposition of the violation that is approved by NERC and FERC.

2. All funds from financial Penalties assessed in the United States received by the entity initiating the compliance monitoring and enforcement process shall be applied as a general offset to the entity's budget requirements for the subsequent fiscal year, if received by July 1, or for the second subsequent fiscal year, if received on or after July 1. Funds from financial Penalties shall not be directly applied to any program maintained by the entity conducting the compliance monitoring and enforcement process. Funds from financial Penalties assessed against a Canadian entity shall be applied as specified by legislation or agreement.

3. In the event that a compliance monitoring and enforcement process is conducted jointly by NERC and a Regional Entity, the Regional Entity shall receive the Penalty monies and offset the Regional Entity's budget requirements for the subsequent fiscal year.

4. Exceptions or alternatives to the foregoing provisions will be allowed if approved by NERC and by FERC or any other Applicable Governmental Authority.

1108. Special Assessments

On a demonstration of unforeseen and extraordinary circumstances requiring additional funds prior to the next funding cycle, NERC shall file with the Applicable Governmental Authorities, where authorized by applicable legislation or agreement, for authorization for an amended or supplemental budget for NERC or a Regional Entity and, if necessary under the amended or supplemental budget, to collect a special or additional assessment for statutory functions of NERC or the Regional Entity. Such filing shall include supporting materials to justify the requested funding, including any departure from the approved funding formula or method.

SECTION 1200 — REGIONAL DELEGATION AGREEMENTS

1201. Pro Forma Regional Delegation Agreement

NERC shall develop and maintain a pro forma Regional Entity delegation agreement, which shall serve as the basis for negotiation of consistent agreements for the delegation of ERO functions to Regional Entities.

1202. Regional Entity Essential Requirements

NERC shall establish the essential requirements for an entity to become qualified and maintain good standing as a Regional Entity.

1203. Negotiation of Regional Delegation Agreements

NERC shall, for all areas of North America that have provided NERC with the appropriate authority, negotiate regional delegation agreements for the purpose of ensuring all areas of the North American Bulk Power Systems are within a Regional Entity Region. In the event NERC is unable to reach agreement with Regional Entities for all areas, NERC shall provide alternative means and resources for implementing NERC functions within those areas. No delegation agreement shall take effect until it has been approved by the Applicable Governmental Authority.

1204. Conformance to Rules and Terms of Regional Delegation Agreements

NERC and each Regional Entity shall comply with all applicable ERO Rules of Procedure and the obligations stated in the regional delegation agreement.

1205. Sub-delegation

The Regional Entity shall not sub-delegate any responsibilities and authorities delegated to it by its regional delegation agreement with NERC except with the approval of NERC and FERC and other Applicable Governmental Authorities. Responsibilities and authorities may only be sub-delegated to another Regional Entity. Regional Entities may share resources with one another so long as such arrangements do not result in cross-subsidization or in any sub-delegation of authorities.

1206. Nonconformance to Rules or Terms of Regional Delegation Agreement

If a Regional Entity is unable to comply or is not in compliance with an ERO Rule of Procedure or the terms of the regional delegation agreement, the Regional Entity shall immediately notify NERC in writing, describing the area of nonconformance and the reason for not being able to conform to the Rule of Procedure. NERC shall evaluate each case and inform the affected Regional Entity of the results of the evaluation. If NERC determines that a Rule of Procedure or term of the regional delegation agreement has been violated by a Regional Entity or cannot practically be implemented by a Regional Entity, NERC shall notify the Applicable Governmental Authorities and take any actions necessary to address the situation.

1207. Regional Entity Audits

Approximately every five years and more frequently if necessary for cause, NERC shall audit each Regional Entity to verify that the Regional Entity continues to comply with NERC Rules of Procedure and the obligations of NERC delegation agreement. Audits of Regional Entities shall be conducted, to the extent practical, based on professional auditing standards recognized in the U.S., including Generally Accepted Auditing Standards, Generally Accepted Government Auditing Standards, and standards sanctioned by the Institute of Internal Auditors, and if applicable to the coverage of the audit, may be based on Canadian or other international standards. The audits required by this Section 1207 shall not duplicate the audits of Regional Entity Compliance Monitoring and Enforcement Programs provided for in **Appendix 4A**, Audit of Regional Compliance Programs, to these Rules of Procedure.

1208. Process for Considering Registered Entity Requests to Transfer to Another Regional Entity

1. A Registered Entity that is registered in the Region of one Regional Entity and believes its registration should be transferred to a different Regional Entity may submit a written request to both Regional Entities requesting that they process the proposed transfer in accordance with this section. The Registered Entity's written request shall set forth the reasons the Registered Entity believes justify the proposed transfer and shall describe any impacts of the proposed transfer on other Bulk Power System owners, operators, and users.

2. After receiving the Registered Entity's written request, the two Regional Entities shall consult with each other as to whether they agree or disagree that the requested transfer is appropriate. The Regional Entities may also consult with affected Reliability Coordinators, Balancing Authorities and Transmission Operators as appropriate. Each Regional Entity shall post the request on its website for public comment period of 21 days. In evaluating the proposed transfer, the Regional Entities shall consider the location of the Registered Entity's Bulk Power System facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators; and users, the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments to other Load-Serving Entities of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity would be transitioned from the current Regional Entity to the transferee Regional Entity; along with any other reasons for the proposed transfer stated by the Registered Entity and any other reasons either Regional Entity considers relevant. The Regional Entities may request that the Registered Entity provide additional data and information concerning the proposed transfer for the Regional Entities' use in their evaluation. The Registered Entity's current Regional Entity shall notify the Registered Entity

in writing as to whether (i) the two Regional Entities agree that the requested transfer is appropriate, (ii) the two Regional Entities agree that the requested transfer is not appropriate and should not be processed further, or (iii) the two Regional Entities disagree as to whether the proposed transfer is appropriate.

3. If the two Regional Entities agree that the requested transfer is appropriate, they shall submit a joint written request to NERC requesting that the proposed transfer be approved and that the delegation agreement between NERC and each of the Regional Entities be amended accordingly. The Regional Entities' joint written submission to NERC shall describe the reasons for the proposed transfer; the location of the Registered Entity's Bulk Power System Facilities in relation to the geographic and electrical boundaries of the respective Regions; the impacts of the proposed transfer on other Bulk Power System owners, operators, and users; the impacts of the proposed transfer on the current and future staffing, resources, budgets and assessments of each Regional Entity, including the sufficiency of the proposed transferee Regional Entity's staffing and resources to perform compliance monitoring and enforcement activities with respect to the Registered Entity; the Registered Entity's compliance history with its current Regional Entity; and the manner in which pending compliance monitoring and enforcement matters concerning the Registered Entity will be transitioned from the current Regional Entity to the transferee Regional Entity. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

4. If the two Regional Entities do not agree with each other that the proposed transfer is appropriate, the Regional Entity supporting the proposed transfer shall, if requested by the Registered Entity, submit a written request to NERC to approve the transfer and the related delegation agreement amendments. The Regional Entity's written request shall include the information specified in Section 1208.3. The Regional Entity that does not believe the proposed transfer is appropriate will be allowed to submit a written statement to NERC explaining why the Regional Entity believes the transfer is not appropriate and should not be approved. The NERC Board of Trustees shall consider the proposed transfer based on the submissions of the Regional Entities and any other information the Board considers relevant, and shall approve or disapprove the proposed transfer and the related delegation agreement amendments. The NERC Board may request that the Regional Entities provide additional information, or obtain additional information from the Registered Entity, for the use of the NERC Board in making its decision. If the NERC Board approves the proposed transfer, NERC shall file the related delegation agreements with FERC for approval.

5. Prior to action by the NERC Board of Trustees on a proposed transfer of registration under Section 1208.3 or 1208.4, NERC shall post information concerning the proposed transfer, including the submissions from the Regional Entities, on its website for at least twenty-one (21) days for the purpose of receiving public comment.

6. If the NERC Board of Trustees disapproves a proposed transfer presented to it pursuant to either Section 1208.3 or 1208.4, the Regional Entity or Regional Entities that believe the transfer is appropriate may, if requested to do so by the Registered Entity, file a petition with FERC pursuant to 18 C.F.R. section 39.8(f) and (g) requesting that FERC order amendments to the delegation agreements of the two Regional Entities to effectuate the proposed transfer.

7. No transfer of a Registered Entity from one Regional Entity to another Regional Entity shall be effective (i) unless approved by FERC, and (ii) any earlier than the first day of January of the second calendar year following approval by FERC, unless an earlier effective date is agreed to by both Regional Entities and NERC and approved by FERC.

SECTION 1300 — COMMITTEES

1301. Establishing Standing Committees

The Board may from time to time create standing committees. In doing so, the Board shall approve the charter of each committee and assign specific authority to each committee necessary to conduct business within that charter. Each standing committee shall work within its Board-approved charter and shall be accountable to the Board for performance of its Board-assigned responsibilities. A NERC standing committee may not delegate its assigned work to a member forum, but, in its deliberations, may request the opinions of and consider the recommendations of a member forum.

1302. Committee Membership

Each committee shall have a defined membership composition that is explained in its charter. Committee membership may be unique to each committee, and can provide for balanced decision-making by providing for representatives from each Sector or, where Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area, by bringing together a wide diversity of opinions from industry experts with outstanding technical knowledge and experience in a particular subject area. Committee membership shall also provide the opportunity for an equitable number of members from the United States and Canada, based approximately on proportionate Net Energy for Load. All committees and other subgroups (except for those organized on other than a Sector basis because Sector representation will not bring together the necessary diversity of opinions, technical knowledge and experience in a particular subject area) must ensure that no two stakeholder Sectors are able to control the vote on any matter, and no single Sector is able to defeat a matter. With regard to committees and subgroups pertaining to development of, interpretation of, or compliance with Reliability Standards, NERC shall provide a reasonable opportunity for membership from Sectors desiring to participate. Committees and subgroups organized on other than a Sector basis shall be reported to the NERC Board and the Member Representatives Committee, along with the reasons for constituting the committee or subgroup in the manner chosen. In such cases and subject to reasonable restrictions necessary to accomplish the mission of such committee or subgroup, NERC shall provide a reasonable opportunity for additional participation, as members or official observers, for Sectors not represented on the committee or subgroup.

1303. Procedures for Appointing Committee Members

Committee members shall be nominated and selected in a manner that is open, inclusive, and fair. Unless otherwise stated in these Rules of Procedure or approved by the Board, all committee member appointments shall be approved by the board, and committee officers shall be appointed by the Chairman of the Board.

1304. Procedures for Conduct of Committee Business

1. Notice to the public of the dates, places, and times of meetings of all committees, and all nonconfidential material provided to committee members, shall be posted on NERC's website at approximately the same time that notice is given to

committee members. Meetings of all standing committees shall be open to the public, subject to reasonable limitations due to the availability and size of meeting facilities; provided that the meeting may be held in or adjourn to closed session to discuss matters of a confidential nature, including but not limited to personnel matters, compliance enforcement matters, litigation, or commercially sensitive or Critical Energy Infrastructure Information of any entity.

2. NERC shall maintain a set of procedures, approved by the Board, to guide the conduct of business by standing committees.

1305. Committee Subgroups

Standing committees may appoint subgroups using the same principles as in Section 1302.

SECTION 1400 — AMENDMENTS TO THE NERC RULES OF PROCEDURE

1401. Proposals for Amendment or Repeal of Rules of Procedure

In accordance with the Bylaws of NERC, requests to amend or repeal the Rules of Procedure may be submitted by (1) any fifty Members of NERC, which number shall include Members from at least three membership Sectors, (2) the Member Representatives Committee, (3) a committee of NERC to whose function and purpose the Rule of Procedure pertains, or (4) an officer of NERC.

1402. Approval of Amendment or Repeal of Rules of Procedure

Amendment to or repeal of Rules of Procedure shall be approved by the Board after public notice and opportunity for comment in accordance with the Bylaws of NERC. In approving changes to the Rules of Procedure, the Board shall consider the inputs of the Member Representatives Committee, other ERO committees affected by the particular changes to the Rules of Procedure, and other stakeholders as appropriate. After Board approval, the amendment or repeal shall be submitted to the Applicable Governmental Authorities for approval, where authorized by legislation or agreement. No amendment to or repeal of the Rules of Procedure shall be effective until it has been approved by the Applicable Governmental Authorities.

SECTION 1500 — CONFIDENTIAL INFORMATION

1501. Definitions

1. **Confidential Information** means (i) Confidential Business and Market Information; (ii) Critical Electric Infrastructure Information; (iii) Critical Energy Infrastructure Information; (iv) personnel information that identifies or could be used to identify a specific individual, or reveals personnel, financial, medical, or other personal information; (v) work papers, including any records produced for or created in the course of an evaluation or audit; (vi) investigative files, including any records produced for or created in the course of an investigation; or (vii) Cyber Security Incident Information; provided, that public information developed or acquired by an entity shall be excluded from this definition.

2. **Confidential Business and Market Information** means any information that pertains to the interests of any entity, that was developed or acquired by that entity, and that is proprietary or competitively sensitive.

3. **Critical Electric Infrastructure** means a system or asset of the bulk power system, whether physical or virtual, the incapacity or destruction of which would negatively affect national security, economic security, public health or safety, or any combination of such matters.

4. **Critical Electric Infrastructure Information** means information related to proposed or existing Critical Electric Infrastructure. Such term includes information that qualifies as Critical Energy Infrastructure Information as defined herein.

5. **Critical Energy Infrastructure Information** means specific engineering, vulnerability, or detailed design information about proposed or existing Critical Infrastructure that (i) relates details about the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on Critical Infrastructure; and (iii) does not simply give the location of the Critical Infrastructure.

6. **Critical Infrastructure** means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.

7. **Cyber Security Incident Information** means any information related to, describing, or which could be used to plan or cause a Cyber Security Incident.

1502. Protection of Confidential Information

1. **Identification of Confidential Information** — An owner, operator, or user of the Bulk Power System and any other party (the "Submitting Entity") shall mark as confidential any information that it submits to NERC or a Regional Entity (the

"Receiving Entity") that it reasonably believes contains Confidential Information as defined by these Rules of Procedure, indicating the category or categories defined in Section 1501 in which the information falls, and by adding any labels required by rules or regulations of an Applicable Governmental Authority. If the information is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the Submitting Entity shall so indicate and provide supporting references and details.

2. **Confidentiality** — Except as provided herein, a Receiving Entity shall keep in confidence and not copy, disclose, or distribute any Confidential Information or any part thereof without the permission of the Submitting Entity, except as otherwise legally required.

3. **Information no longer Confidential –** If a Submitting Entity concludes that information for which it had sought confidential treatment no longer qualifies for that treatment, the Submitting Entity shall promptly so notify NERC or the relevant Regional Entity.

1503. Requests for Information

1. **Limitation** — A Receiving Entity shall make information available only to one with a demonstrated need for access to the information from the Receiving Entity. Commission regulations regarding access to Critical Electric Infrastructure Information or Critical Energy Infrastructure Information will also apply as appropriate when the Commission is the Submitting Entity.

2. **Form of Request** — A person with such a need may request access to information by using the following procedure:

   2.1 The request must be in writing and clearly marked "Request for Information."

   2.2 The request must identify the individual or entity that will use the information, explain the requester's need for access to the information, explain how the requester will use the information in furtherance of that need, and state whether the information is publicly available or available from another source or through another means. If the requester seeks access to information that is subject to a prohibition on public disclosure in the Commission-approved rules of a regional transmission organization or independent system operator or a similar prohibition in applicable federal, state, or provincial laws, the requester shall describe how it qualifies to receive such information.

   2.3 The request must stipulate that, if the requester does not seek public disclosure, the requester will maintain as confidential any information received for which a Submitting Party has made a claim of confidentiality

in accordance with NERC's rules. As a condition to gaining access to such information, a requester shall execute a non-disclosure agreement provided by NERC.

3. **Notice and Opportunity for Comment** — Prior to any decision to disclose information marked as confidential, the Receiving Entity shall provide written notice to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed. Failure to provide such comments or otherwise respond is not deemed waiver of the claim of confidentiality.

4. **Determination by ERO or Regional Entity** — Based on the information provided by the requester under Rule 1503.2, any comments provided by the Submitting Entity, and any other relevant available information, the chief executive officer or his or her designee of the Receiving Entity shall determine whether to disclose such information.

5. **Appeal** — A person whose request for information is denied in whole or part may appeal that determination to the President of NERC (or the President's designee) within 30 days of the determination. Appeals filed pursuant to this Section must be in writing, addressed to the President of NERC (or the President's designee), and clearly marked "Appeal of Information Request Denial."

   NERC will provide written notice of such appeal to the Submitting Entity and an opportunity for the Submitting Entity to either waive objection to disclosure or provide comments as to why the Confidential Information should not be disclosed; provided that any such comments must be received within 30 days of the notice and any failure to provide such comments or otherwise respond is not deemed a waiver of the claim of confidentiality.

   The President of NERC (or the President's designee) will make a determination with respect to any appeal within 30 days. In unusual circumstances, this time limit may be extended by the President of NERC (or the President's designee), who will send written notice to the requester setting forth the reasons for the extension and the date on which a determination on the appeal is expected.

6. **Disclosure of Information** — In the event the Receiving Entity, after following the procedures herein, determines to disclose information designated as Confidential Information, it shall provide the Submitting Entity no fewer than 21 days' written notice prior to releasing the Confidential Information in order to enable such Submitting Entity to (a) seek an appropriate protective order or other remedy, (b) consult with the Receiving Entity with respect to taking steps to resist or narrow the scope of such request or legal process, or (c) waive compliance, in whole or in part, with the terms of this Section. Should a Receiving Entity be required to disclose Confidential Information, or should the Submitting Entity waive objection to disclosure, the Receiving Entity shall furnish only that portion

of the Confidential Information which the Receiving Entity's counsel advises is legally required.

7. **Posting of Determinations on Requests for Disclosure of Confidential Information** — Upon making its determination on a request for disclosure of Confidential Information, NERC or the Regional Entity, as applicable, shall (i) notify the requester that the request for disclosure is granted or denied, (ii) publicly post any determination to deny the request to disclose Confidential Information, including in such posting an explanation of the reasons for the denial (but without in such explanation disclosing the Confidential Information), and (iii) publicly post any determination that information claimed by the Submitting Entity to be Confidential Information is not Confidential Information (but without in such posting disclosing any information that has been determined to be Confidential Information).

1504. Employees, Contractors and Agents

A Receiving Entity shall ensure that its officers, trustees, directors, employees, subcontractors and subcontractors' employees, and agents to whom Confidential Information is exposed are under obligations of confidentiality that are at least as restrictive as those contained herein.

1505. Provision of Information to FERC and Other Governmental Authorities

1. **Request** — A request from FERC for reliability information with respect to owners, operators, and users of the Bulk Power System within the United States is authorized by Section 215 of the Federal Power Act. Other Applicable Governmental Authorities may have similar authorizing legislation that grants a right of access to such information. Unless otherwise directed by FERC or its staff or the other Applicable Governmental Authority requesting the information, upon receiving such a request, a Receiving Entity shall provide contemporaneous notice to the applicable Submitting Entity. In its response to such a request, a Receiving Entity shall preserve any mark of confidentiality and shall notify FERC or other Applicable Governmental Authorities that the Submitting Entity has marked the information as confidential.

2. **Continued Confidentiality** — Each Receiving Entity shall continue to treat as confidential all Confidential Information that it has submitted to NERC or to FERC or another Applicable Governmental Authority, until such time as FERC or the other Applicable Governmental Authority authorizes disclosure of such information.

1506. Permitted Disclosures

1. **Resolved Noncompliance** — Nothing in this Section 1500 shall prohibit the disclosure of a noncompliance at the point when the matter is filed with an Applicable Governmental Authority, a Registered Entity admits to the violation, or the Registered Entity and the CEA resolve the noncompliance in accordance with Appendix 4C.

2. **Information Exchange** — NERC and the Regional Entities are authorized to exchange Confidential Information to perform their respective statutory and delegated functions, including, but not limited to, evaluations, Compliance Audits, and Compliance Investigations in furtherance of the Compliance Monitoring and Enforcement Program, on condition they continue to maintain the confidentiality of such information consistent with the delegation agreement.

1507. Remedies for Improper Disclosure

Any person engaged in NERC or Regional Entity activity under Section 215 of the Federal Power Act or the equivalent laws of other Applicable Governmental Authorities who improperly discloses Confidential Information may lose access to Confidential Information on a temporary or permanent basis and may be subject to adverse personnel action, including suspension or termination. Nothing in Section 1500 precludes an entity whose information was improperly disclosed from seeking a remedy in an appropriate court.

SECTION 1600 — REQUESTS FOR DATA OR INFORMATION

1601. Scope of a NERC or Regional Entity Request for Data or Information

Within the United States, NERC and Regional Entities may request data or information that is necessary to meet their obligations under Section 215 of the Federal Power Act, as authorized by Section 39.2(d) of the Commission's regulations, 18 C.F.R. § 39.2(d). In other jurisdictions NERC and Regional Entities may request comparable data or information, using such authority as may exist pursuant to these Rules of Procedure and as may be granted by Applicable Governmental Authorities in those other jurisdictions. The provisions of Section 1600 shall not apply to Requirements contained in any Reliability Standard to provide data or information; the Requirements in the Reliability Standards govern. The provisions of Section 1600 shall also not apply to data or information requested in connection with a compliance or enforcement action under Section 215 of the Federal Power Act, Section 400 of these Rules of Procedure, or any procedures adopted pursuant to those authorities, in which case the Rules of Procedure applicable to the production of data or information for compliance and enforcement actions shall apply.

1602. Procedure for Authorizing a NERC Request for Data or Information

1. NERC shall provide a proposed request for data or information or a proposed modification to a previously-authorized request, including the information specified in Section 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability at least twenty-one (21) days prior to initially posting the request or modification for public comment. Submission of the proposed request or modification to the Office of Electric Reliability is for the information of the Commission. NERC is not required to receive any approval from the Commission prior to posting the proposed request or modification for public comment in accordance with Section 1602.2 or issuing the request or modification to Reporting Entities following approval by the Board of Trustees.

2. NERC shall post a proposed request for data or information or a proposed modification to a previously authorized request for data or information for a forty-five (45) day public comment period.

    2.1. A proposed request for data or information shall contain, at a minimum, the following information: (i) a description of the data or information to be requested, how the data or information will be used, and how the availability of the data or information is necessary for NERC to meet its obligations under applicable laws and agreements; (ii) a description of how the data or information will be collected and validated; (iii) a description of the entities (by functional class and jurisdiction) that will be required to provide the data or information ("Reporting Entities"); (iv) the schedule or due date for the data or information; (v) a description of any restrictions on disseminating the data or information (e.g., "Confidential Information," "Critical Energy Infrastructure Information," "aggregating"

or "identity masking"); and (vi) an estimate of the relative burden imposed on the Reporting Entities to accommodate the data or information request.

2.2. A proposed modification to a previously authorized request for data or information shall explain (i) the nature of the modifications; (ii) an estimate of the burden imposed on the Reporting Entities to accommodate the modified data or information request, and (iii) any other items from Section 1602.2.1 that require updating as a result of the modifications.

3. After the close of the comment period, NERC shall make such revisions to the proposed request for data or information as are appropriate in light of the comments. NERC shall submit the proposed request for data or information, as revised, along with the comments received, NERC's evaluation of the comments and recommendations, to the Board of Trustees.

4. In acting on the proposed request for data or information, the Board of Trustees may authorize NERC to issue it, modify it, or remand it for further consideration.

5. NERC may make minor changes to an authorized request for data or information without Board approval. However, if a Reporting Entity objects to NERC in writing to such changes within 21 days of issuance of the modified request, such changes shall require Board approval before they are implemented.

6. Authorization of a request for data or information shall be final unless, within thirty (30) days of the decision by the Board of Trustees, an affected party appeals the authorization under this Section 1600 to the Applicable Governmental Authority.

1603. Owners, Operators, and Users to Comply

Owners, operators, and users of the Bulk Power System registered on the NERC Compliance Registry shall comply with authorized requests for data and information. In the event a Reporting Entity within the United States fails to comply with an authorized request for data or information under Section 1600, NERC may request the Commission to exercise its enforcement authority to require the Reporting Entity to comply with the request for data or information and for other appropriate enforcement action by the Commission. NERC will make any request for the Commission to enforce a request for data or information through a non-public submission to the Commission's enforcement staff.

1604. Requests by Regional Entity for Data or Information

1. A Regional Entity may request that NERC seek authorization for a request for data or information to be applicable within the Region of the Regional Entity, either as a freestanding request or as part of a proposed NERC request for data or information. Any such request must be consistent with this Section 1600.

2. A Regional Entity may also develop its own procedures for requesting data or information, but any such procedures must include at least the same procedural

elements as are included in this Section 1600. Any such Regional Entity procedures or changes to such procedures shall be submitted to NERC for approval. Upon approving such procedures or changes thereto, NERC shall file the proposed procedures or proposed changes for approval by the Commission and any other Applicable Governmental Authorities applicable to the Regional Entity. The Regional Entity procedures or changes to such procedures shall not be effective in a jurisdiction until approved by, and in accordance with any revisions directed by, the Commission or other Applicable Governmental Authority.

1605. Confidentiality

If the approved data or information request includes a statement under Section 1602.1.1(v) that the requested data or information will be held confidential or treated as Critical Energy Infrastructure Information, then the applicable provisions of Section 1500 will apply without further action by a Submitting Entity. A Submitting Entity may designate any other data or information as Confidential Information pursuant to the provisions of Section 1500, and NERC or the Regional Entity shall treat that data or information in accordance with Section 1500. NERC or a Regional Entity may utilize additional protective procedures for handling particular requests for data or information as may be necessary under the circumstances.

1606. Expedited Procedures for Requesting Time-Sensitive Data or Information

1. In the event NERC or a Regional Entity must obtain data or information by a date or within a time period that does not permit adherence to the time periods specified in Section 1602, the procedures specified in Section 1606 may be used to obtain the data or information. Without limiting the circumstances in which the procedures in Section 1606 may be used, such circumstances include situations in which it is necessary to obtain the data or information (in order to evaluate a threat to the reliability or security of the Bulk Power System, or to comply with a directive in an order issued by the Commission or by another Applicable Governmental Authority) within a shorter time period than possible under Section 1602. The procedures specified in Section 1606 may only be used if authorized by the NERC Board of Trustees prior to activation of such procedures.

2. Prior to posting a proposed request for data or information, or a modification to a previously-authorized request, for public comment under Section 1606, NERC shall provide the proposed request or modification, including the information specified in paragraph 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability. The submission to the Commission's Office of Electric Reliability shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information. The submission shall be made to the Commission's Office of Electric Reliability as far in advance, up to twenty-one (21) days, of the posting of the proposed request or modification for public comments as is reasonably possible under the circumstances, but in no event less than two (2) days in advance of the public posting of the proposed request or modification.

3. NERC shall post the proposed request for data or information or proposed modification to a previously-authorized request for data or information for a public comment period that is reasonable in duration given the circumstances, but in no event shorter than five (5) days. The proposed request for data or information or proposed modification to a previously-authorized request for data or information shall include the information specified in Section 1602.2.1 or 1602.2.2, as applicable, and shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information.

4. The provisions of Sections 1602.3, 1602.4, 1602.5 and 1602.6 shall be applicable to a request for data or information or modification to a previously-authorized request for data or information developed and issued pursuant to Section 1606, except that (a) if NERC makes minor changes to an authorized request for data or information without Board approval, such changes shall require Board approval if a Reporting Entity objects to NERC in writing to such changes within five (5) days of issuance of the modified request; and (b) authorization of the request for data or information shall be final unless an affected party appeals the authorization of the request by the Board of Trustees to the Applicable Governmental Authority within five (5) days following the decision of the Board of Trustees authorizing the request, which decision shall be promptly posted on NERC's website.

SECTION 1700 — CHALLENGES TO DETERMINATIONS

1701. Scope of Authority

Section 1702 sets forth the procedures to be followed for Registered Entities to challenge determinations made by Planning Coordinators under Reliability Standard PRC-023. Section 1703 sets forth the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

1702. Challenges to Determinations by Planning Coordinators Under Reliability Standard PRC-023

1. This Section 1702 establishes the procedures to be followed when a Registered Entity wishes to challenge a determination by a Planning Coordinator of the sub-200 kV circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers (defined as "Registered Entities" for purposes of this Section 1702) must comply with the requirements of Reliability Standard PRC-023.

2. Planning Coordinator Procedures

    2.1 Each Planning Coordinator shall establish a procedure for a Registered Entity to submit a written request for an explanation of a determination made by the Planning Coordinator under PRC-023.

    2.2 A Registered Entity shall follow the procedure established by the Planning Coordinator for submitting the request for explanation and must submit any such request within 60 days of receiving the determination under PRC-023 from the Planning Coordinator.

    2.3 Within 30 days of receiving a written request from a Registered Entity, the Planning Coordinator shall provide the Registered Entity with a written explanation of the basis for its determination under PRC-023, unless the Planning Coordinator provided a written explanation of the basis for its determination when it initially informed the Registered Entity of its determination.

3. A Registered Entity may challenge the determination of the Planning Coordinator by filing with the appropriate Regional Entity, with a copy to the Planning Coordinator, within 60 days of receiving the written explanation from the Planning Coordinator. The challenge shall include the following: (a) an explanation of the technical reasons for its disagreement with the Planning Coordinator's determination, along with any supporting documentation, and (b) a copy of the Planning Coordinator's written explanation. Within 30 days of receipt of a challenge, the Planning Coordinator may file a response to the Regional Entity, with a copy to the Registered Entity.

4. The filing of a challenge in good faith shall toll the time period for compliance with PRC-023 with respect to the subject facility until such time as the challenge is withdrawn, settled or resolved.

5. The Regional Entity shall issue its written decision setting forth the basis of its determination within 90 days after it receives the challenge and send copies of the decision to the Registered Entity and the Planning Coordinator. The Regional Entity may convene a meeting of the involved entities and may request additional information. The Regional Entity shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

6. A Planning Coordinator or Registered Entity affected by the decision of the Regional Entity may, within 30 days of the decision, file an appeal with NERC, with copies to the Regional Entity and the Planning Coordinator or Registered Entity. The appeal shall state the basis of the objection to the decision of the Regional Entity and shall include the Regional Entity decision, the written explanation of the Planning Coordinator's determination under PRC-023, and the documents and reasoning filed by the Registered Entity with the Regional Entity in support of its objection. The Regional Entity, Planning Coordinator or Registered Entity may file a response to the appeal within 30 days of the appeal.

7. The Board of Trustees shall appoint a panel to decide appeals from Regional Entity decisions under Section 1702.5. The panel, which may contain alternates, shall consist of at least three appointees, one of whom must be a member of the NERC staff, who are knowledgeable about PRC-023 and transmission planning and do not have a direct financial or business interest in the outcome of the appeal. The panel shall decide the appeal within 90 days of receiving the appeal from the decision of the Regional Entity and shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

8. The Planning Coordinator or Registered Entity affected by the decision of the panel may request that the Board of Trustees review the decision by filing its request for review and a statement of reasons with NERC's Chief Reliability Officer within 30 days of the panel decision. The Board of Trustees may, in its discretion, decline to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. Within 90 days of the request for review under this Section 1702.8, the Board of Trustees may either (a) issue a decision on the merits, which shall be the final NERC decision, or (b) issue a notice declining to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. If no written decision or notice declining review is issued within 90 calendar days, the appeal shall be deemed to have been denied by the Board of Trustees and this will have the same effect as a notice declining review.

9. The Registered Entity or Planning Coordinator may appeal the final NERC decision to the Applicable Governmental Authority within 30 days of receipt of

the Board of Trustees' final decision or notice declining review, or expiration of the 90-day review period without any action by NERC.

10. The Planning Coordinator and Registered Entity are encouraged, but not required, to meet to resolve any dispute, including use of mutually agreed to alternative dispute resolution procedures, at any time during the course of the matter. In the event resolution occurs after the filing of a challenge, the Registered Entity and Planning Coordinator shall jointly provide to the applicable Regional Entity a written acknowledgement of withdrawal of the challenge or appeal, including a statement that all outstanding issues have been resolved.

1703. Challenges to NERC Determinations of BES Exception Requests Under Section 509

1. This Section 1703 establishes the procedures to be followed when a Submitting Entity or Owner wishes to challenge a determination by NERC to approve or to disapprove an Exception Request or to terminate an Exception under Section 509.

2. A Submitting Entity (or Owner if different) aggrieved by the decision of NERC to approve or disapprove an Exception Request or to terminate an Exception with respect to any Element may, within 30 days following the date of the decision, file a written challenge to the decision with the NERC director of compliance operations, with copies to the Regional Entity and the Submitting Entity or Owner if different. The challenge shall state the basis of the objection to the decision of NERC. The Regional Entity, and the Submitting Entity or Owner if different, may file a response to the challenge within 30 days following the date the challenge is filed with NERC.

3. The challenge shall be decided by the Board of Trustees Compliance Committee. Within 90 days of the date of submission of the challenge, the Board of Trustees Compliance Committee shall issue its decision on the challenge. The decision of the Board of Trustees Compliance Committee shall be the final NERC decision; provided, that the Board of Trustees Compliance Committee may extend the deadline date for its decision to a date more than 90 days following submission of the challenge, by issuing a notice to the Submitting Entity, the Owner (if different) and the Regional Entity stating the revised deadline date and the reason for the extension.

4. The Submitting Entity, or Owner if different, may appeal the final NERC decision to, or seek review of the final NERC decision by, the Applicable Governmental Authority(ies), in accordance with the legal authority and rules and procedures of the Applicable Governmental Authority(ies). Any such appeal shall be filed within thirty (30) days following the date of the decision of the Board of Trustees Compliance Committee, or within such other time period as is provided for in the legal authority, rules or procedures of the Applicable Governmental Authority.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-83:
WECC Contingency Reserve Whitepaper



WECC

WECC-0142 BAL-002-WECC-3

Contingency Reserve

Request to Retire

WECC-0142 Drafting Team

01/21/2025

Executive Summary

This document supports and requests full retirement of WECC Regional Reliability Standard (RRS) BAL-002-WECC-3, Contingency Reserve.

In FERC Order No. 672, when considering approval of RRSs, FERC agreed to accept two kinds of regional differences: (1) a regional difference that is more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; and (2) an RRS that is necessitated by a physical difference in the Bulk-Power System.[1]

Order 672 also provides authority to retire an RRS.

Since the start of BAL-002-WECC-3 and its predecessors (2007), the original standard and each subsequent iteration have continued as more stringent than the continent-wide equivalent, NERC BAL-002-X, Disturbance Control Standard. Among other things, WECC's BAL-002-WECC has always required most WECC entities to hold more reserves than the continent-wide equivalent. Specifically, BAL-002-WECC-3, Requirement R1.1.1 requires the applicable entity to hold the greater of, either the amount of Contingency Reserve equal to the loss of the most severe single contingency or the amount of Contingency Reserve equal to the sum of 3% of hourly integrated load and 3% of hourly integrated generation.

Though Requirement R1.1.1 was approved in BAL-002-WECC-1, that approval was predicated on distributing burden and the availability of deliverability.[2] There has never been a technical study proving that holding reserves more than required under NERC BAL-002-X enhances the reliability of the Western Interconnection.

By contrast, as variable generation is added to the Interconnection, there is increasing evidence that holding excess reserves may be inhibiting reliability across the interconnection. FERC's recent Order 901 echoes these concerns, addressing operational and performance concerns for variable resources.

Restated, within the Western Interconnection, applicable entities are holding more reserves than the rest of the continent, even though there is no technical basis for doing so. In FERC Order 693, in which NERC BAL-002-1 was first approved, at P341, FERC states:

> 341. We believe a continent-wide contingency reserves policy would assure [sic] that there are adequate magnitude and frequency responsive contingency reserves in each Balancing

[1] Order No. 672 at P 331. See also FERC Order 740, P 4 and P 23. https://www.nerc.com/pa/Stand/Resources/Documents/FERC'S_Criteria_for_Approving_Reliability_Standards_from_Order_672.pdf

[2] FERC Order 740, Remand.

> Authority. This will improve performance so that no Balancing Authority will be doing *less than its fair share*." (Emphasis added.)

By extension, retiring BAL-002-WECC-3 in favor of NERC BAL-002-3, ensures that no Balancing Authority will be doing **more** than its fair share.

Further, requiring Balancing Authorities to hold that excess may be inhibiting the integration and use of variable generation. As a result, BAL-002-WECC-3 creates a mandated scenario in which reserves are used inefficiently and withheld from the marketplace.

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Introduction

Per the Standard Authorization Request (SAR) for WECC-0142,[3] this document explores the full retirement of WECC RRS BAL-002-WECC-3, Contingency Reserve.

The following will show that, if the standard is retired, reliability will continue to be maintained through NERC BAL-002-3, and may be enhanced as resources being held for contingency reserves may be used more efficiently to support variable generation.

By retiring BAL-002-WECC-3 in favor of NERC BAL-002-3:

- Dispatchable resources can be used to support variable generation, addressing issues raised by FERC in Order 901.
- A more efficient use of resources should negate any current negative impacts on the market, thereby enhancing vital public interests.

As the Procedural History and Development History sections note, BAL-002-WECC-3 is an evolution of pre-standards originating in the 1990s. Never during the estimated 30 years of its existence has there been a technical justification for the values and procedures required in the standard. Rather, the stated values and procedures are the result of generalized negotiations taking place between the parties. Because these values and procedures are negotiated, the content of BAL-002-WECC-3 is the lowest common denominator and does not meet the requirements of FERC Order 672.[4]

Because BAL-002-WECC-2a, Contingency Reserve, Request to Retire Requirement R2 provided the technical support for retiring Requirement R2, arguments in that filing are not revisited here.[5]

[3] See WECC-0142 BAL-002-WECC-3, Contingency Reserve, Request to Retire, home page, at the SAR accordion.
[4] FERC Order 672, P329 and P330.
[5] Approved by the NERC Board of Trustees on August 15, 2019, filed with FERC on September 9, 2019.

Standard of Review

While the Commission may approve an RRS that is more stringent than a parallel continent-wide standard, the Commission may also retire such a standard.[6]

> "While a Regional Entity may propose regional Reliability Standards that address specific, unique regional conditions and circumstances, *such regional Reliability Standards can be retired if those justifications are no longer relevant.* Accordingly, the Commission may approve retirement of a more stringent regional requirement "if the Regional Entity demonstrates that the continent-wide Reliability Standard is sufficient to ensure the reliability of that region."[7] (Emphasis added.)

In doing so, the Commission must give due weight to the technical expertise of a Regional Entity, like WECC, that is organized on an interconnection-wide basis with respect to the regional differences applicable to the Western Interconnection.

The technical qualifications of the subject matter experts compiling this paper are provided with this filing, as presented and approved by the WECC Standards Committee (WSC).

[6] The Commission approves regional differences proposed by Regional Entities, such as Regional Reliability Standards and Variances, if the regional difference is just, reasonable, not unduly discriminatory or preferential, and in the public interest. 16 U.S.C. § 824o(d)(2) and 18 C.F.R. § 39.5(a). (See also) Additionally, Commission Order No. 672 requires further criteria for regional differences. A regional difference from a continent-wide Reliability Standard must either be:
(1) more stringent than the continent-wide Reliability Standard, including a regional difference that addresses matters that the continent-wide Reliability Standard does not; or is,
(2) necessitated by a physical difference in the Bulk-Power System.

[7] Version One Regional Reliability Standard for Resource and Demand Balancing,
Order No. 740, 75 FR 65964 (Oct. 27, 2010), 133 FERC ¶ 61,063, P 30 (2010). See also: FERC, 18 CFR Part 40, Docket No. RM19-20-000, WECC Regional Reliability Standard BAL-002-WECC-3 (Contingency Reserve), p.5

Procedural History

In 1996, the Western Systems Coordinating Council (WSCC)[8] adopted the WSCC Reliability Criteria, Minimum Operating Reliability Criteria (MORC). The MORC prescribed levels of reserves that became BAL-002-WECC-3, effective 2021.

In 1999, the MORC became the WECC Reliability Management System (RMS), a contract-based system of accountability that pre-dated mandatory standards.

As the industry approached the onset of mandatory standards (2007) and memorialization of legacy operating practices, the content of the RMS was adapted and approved as BAL-STD-002-0, Operating Reserves (2007). That standard was an attempt to translate the substantive content of the RMS into the sought-after NERC/FERC format of today's reliability standards. The *content* was accepted "as is" with its origins in the 1996 MORC; albeit, the early standard was remanded for remediation, largely on *format* and structural grounds.

In 2013, FERC accepted remediations to BAL-002-WECC-2.

In 2017, an interpretation was added (BAL-002-WECC-2a) and later incorporated into BAL-002-WECC-3, in which Requirement R2 was approved for retirement, with an effective date of August 15, 2019.

In 2025, the Western Interconnection still adheres to similar levels of reserves as it did in 1996. This means that, for over 28 years, the Western Interconnection has held more reserves than the rest of the continent (NERC BAL-002-3) even though there has never been technical justification to do so.

[8] The Western Systems Coordinating Council (WSCC) was formed in 1967 by 40 power systems to coordinate the planning and operations of the electric system in western North America. The WSCC's goal was to provide reliable power to the public.

Development History (Before 1996 to 2024)

Before 1996, members of the WSCC voluntarily operated the Western Interconnection according to the MORC.[9] Although the MORC contained provisions for generation control, generation performance, and Contingency Reserve, the MORC provided no technical support for the reserve thresholds and characteristics it set.[10] Rather, the operating thresholds were established by negotiation—not technical analysis. If this approach were adopted today, FERC would likely deny approval of the standard as contrary to FERC Order 672, P329.[11]

In July and August of 1996, the Western Interconnection experienced two widespread outages resulting from improper vegetation management. The resulting outage reports[12] [13] made several recommendations that would later be adopted in the 1999 WECC RMS.[14] [15] The WECC Operating Committee's recommendation produced portions of the RMS that later evolved into WECC Standard BAL-STD-002-0, Operating Reserves and, ultimately, BAL-002-WECC-3. Like the other initial

[9] MORC, Maintenance Coordination: 1. Sharing information. The security and reliability of the interconnected power system depends upon periodic inspection and adequate maintenance of generators, transmission lines and associated equipment, control equipment, communication equipment, relaying equipment, and other system facilities. Entities and coordinated groups of entities must establish procedures and responsibility for disseminating information on scheduled outages and for coordinating scheduled outages of major facilities which affect the security and reliability of the interconnected power system.

[10] Minimum Operating Reliability Criterion, Section 1, Generation Control and Performance

[11] FERC Order 672. P329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice—the so-called "lowest common denominator"—if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

[12] The outage reports are available upon request. Western Systems Coordinating Council (WSCC) Disturbance Report for the Power System Outage that Occurred on the Western Interconnection August 10, 1996, as approved by the WSCC Operations Committee on October 18, 1996

[13] "f. The WSCC Operations Committee shall assess whether the levels and allocation of operating reserves contributed to the severity of this disturbance and implement corrective measures as appropriate." Western System Coordinating Council Disturbance Report, For the Power System Outages that Occurred on the Western Interconnection on 2 JUL 1996. Approved by the WSCC Operations Committee on September 19, 1996. RMS Outage Report, page 14.

[14] The RMS was approved 1 SEP 1999. WECC Comment Report – WECC Tier 1- RMS Standard – (BAL-STD-002-0) Question 4, Attachment 2, page 9.

[15] "The majority of these standards were specifically developed to address and mitigate main causes of the two major system outages that occurred in the Western Interconnection in July and August of 1996." Agenda Item 3, Board of Trustees Meeting, March 12, 2007, page 4

standards, the language of the original standard was a translation of the language contained in the RMS.[16]

In March 1997, noting that federal remedial legislation could take years to enact, the WSCC trustees created the WSCC RMS Policy Group[17] establishing a contract-based operational system known as the RMS.[18] [19] In establishing the RMS, the WSCC RMS Policy Group reviewed all NERC and WECC reliability criteria, identified specific criteria deemed critical for reliability management, then moved those criteria into the RMS through a three-phase implementation plan.[20]

On April 14, 1999, FERC asserted jurisdiction over the RMS.

Between September 1998 and February 2000 (phase two of the three-phase RMS implementation), the WSCC turned the content of the RMS into the first mandatory reliability standards (aka Version Zero, 2007). BAL-SDT-002-0, Contingency Reserve was part of that translation.

On December 22, 2006, WECC submitted a request to NERC to approve, and send to FERC for approval, eight proposed RRSs. WECC referred to the eight proposed standards as its Tier One

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[16] WECC states that the proposed regional Reliability Standards, which are exact translations of existing regional criteria, either address matters not addressed in the Commission-approved ERO Reliability Standards or contain more stringent requirements than the ERO standards. (FERC accepted Tier One standards evolving from the RMS. AKA: Tier One Order.) FERC, 119 FERC ¶ 61,260 United States of America, Federal Energy Regulatory Commission, Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications (Issued June 8, 2007), page 19.

[17] Following the enactment of EPAct 2005 and the establishment of mandatory Reliability Standards applicable to all owners, operators, and users of the BPS, WECC sought to translate certain of its existing practices under its RMS reliability criteria into regional Reliability Standards to supplement the continent-wide Reliability Standards the Commission approved in Order No. 693. To that end, WECC established a task force to identify criteria in the RMS that should be binding on all BPS users, owners, and operators in the Western Interconnection, not just the Transmission Operators subject to the RMS. The task force chose eight of the identified criteria, which had the highest priority and could be implemented in the near term for translation into regional Reliability Standards. United States of America Before the Federal Energy Regulatory Commission, North American Electric Reliability Corporation (NERC), Docket No. RM16-10-000, Supplemental Information for Petition of the NERC and WECC for Approval of retirement of Regional Reliability Standard TOP-007-WECC-1a, page 5.

[18] Hearing

[19] Electric Reliability Corporation, Helping Owners, Operators, and Users of the Bulk Power System Assure Reliability and Security for More Than 50 Years, By David Nevius, Senior Vice President 1979–2012, Page 40-41.

[20] Hearing

standards originating from the RMS because the proposed standards were translations of standards that were already mandatory within the Western Interconnection as part of the RMS.[21]

Those eight standards—that included Tier One WECC-BAL-STD-002-0 (Operating Reserves)—were near-exact translations of existing WECC criteria that FERC earlier accepted as part of the WECC RMS program.[22] Because the content was a near-exact translation, the format did not match that required by NERC/FERC. This would later lead to a remand of BAL-002-WECC-1 to ensure conformity.

On January 9, 2007, NERC provided WECC with a report of its preliminary findings about the request from December 22, 2006, and provided WECC with a list of required remediations.[23] The request largely addressed styles, formats, and corrections to compliance sections. The NERC Board of Trustees approved the Tier One request subject to remediation and sent the eight proposed standards to FERC with a request for approval.

In June 2007, FERC approved WECC's submittal of eight reliability-crucial Tier One standards, thereby transitioning from the RMS system to that of FERC-approved NERC Reliability Standards.[24] Although earlier versions lacked technical support, FERC agreed with

> "WECC, WIRAB [Western Interconnection Regional Advisory Board] and NERC that approval of [WECC's early BAL] under section 215 would enhance reliability in the Western Interconnection **by making WECC's current practices binding** on all relevant entities in the region and **by strengthening WECC's compliance and enforcement authority.**"[25]

[21] North American Electric Reliability Corporation, Docket No. RR07-___-000, III. BACKGROUND ON THE DEVELOPMENT OF THE WECC REGIONAL RELIABILITY STANDARDS, Debra A. Palmer of Schiff/Hardin (1666 K STREET N.W., SUITE 300, WASHINGTON, DC 20006) on March 26, 2007.
[22] Loc. Cit. IV. Overview of the Proposed WECC Regional Reliability Standards, page 6.
[23] NERC DECISION APPROVING, WITH CONDITIONS, RELIABILITY STANDARDS PROPOSED BY WESTERN ELECTRICITY COORDINATING COUNCIL, page 2. (Approved by Board of Trustees March 12, 2007)
[24]FERC Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications, Docket No. RR07-11-000, (Issued June 8, 2007)
[25] Tier One Order, p. 43. See also, "The proposed regional Reliability Standards would make eight of those RMS criteria binding on the applicable subset of users, owners and operators of the Bulk-Power System in the United States portion of the Western Interconnection, as identified in each proposed standard. The regional Reliability Standards would supplement rather than replace the Commission-approved Reliability Standards developed by the ERO that will take effect in June 2007. Tier One, p. 10.

Structural Overview of BAL-002-WECC-3

Purpose

The Purpose of currently effective RRS BAL-002-WECC-3—Contingency Reserve is to provide an RRS specifying "the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions."[26]

The NERC Glossary defines Contingency Reserve as:

"The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard). A Balancing Authority may include in its restoration of Contingency Reserve readiness to reduce Firm Demand and include it if, and only if, the Balancing Authority:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert level and is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan.
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan."

Applicability

BAL-002-WECC-3 applies to Balancing Authorities (BA), unless the BA is a member of a Reserve Sharing Group (RSG), in which case the RSG becomes the applicable entity.

Requirements

The standard consists of four requirements.

Requirement R1

- Provides that each BA and RSG must maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserves, and that the Contingency Reserve must consist of any combination of a list of specified reserve types.

Requirement R2

- Reserved. Retired, subject to cyclical field tests.

[26] BAL-002-WECC-3, Contingency Reserve, Purpose.

Requirement R3

- Each Sink BA and RSG must maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve in Requirement R1, equal to the amount of Operating Reserve–Supplemental for any Interchange Transaction designated as part of the Source Balancing Authority's Operating Reserve–Supplemental or source Reserve Sharing Group's Operating Reserve–Supplemental, except within the first sixty minutes following an event requiring the activation of Contingency Reserve.

Requirement R4

- Each Source BA and RSG must maintain an amount of Operating Reserve, in addition to the minimum Contingency Reserve amounts identified in Requirement R1, equal to the amount and type of Operating Reserves for any Operating Reserve transactions for which it is the Source BA or RSG.

Reliability will be Maintained

Upon retirement of BAL-002-WECC-3, reliability will be maintained by NERC BAL-002-3, Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event, reinforced by the enhanced availability of resources currently unavailable under BAL-002-WECC-3.

Replacing BAL-002-WECC-3 with NERC BAL-002-3 Mitigates Reliability Gaps associated with Variable Generation

As highlighted by FERC in its Order 901, with the growing amount of variable generation replacing more responsive and dispatchable resources, the industry faces the dilemma of how to support these new resources.[27] Unlike traditional resources, much of the new variable generation cannot be quickly dispatched, thus creating a gap in reliability. FERC acknowledged that gap, noting that neither business as usual nor existing reliability standards will remedy this concern. Finally, FERC also recognizes the value that steps taken must apply on a continent-wide basis.[28]

Replacing BAL-002-WECC-3 with the continent-wide NERC BAL-002-3 takes immediate steps towards meeting FERC's concerns.

In Order 901, FERC states:

> "[W]e continue to find that as the resource mix trends towards higher penetrations of IBRs, the need to reliably integrate these resources into the Bulk-Power System is expected to grow, and that the currently effective Reliability Standards do not adequately address IBR reliability risks. *The continuing risks that the increasing penetration of IBRs pose to the reliable operation of the Bulk-Power System underscore the need for mandatory Reliability Standards to address these issues on a nationwide basis*." (Emphasis added.) Order 901, P24.

When BAL-002-WECC-3 is retired and replaced with NERC BAL-002-3, the amount and type of reserves required to be held back within the Western Interconnection will decrease. That frees those resources to be plied against load. Within the Western Interconnection, a vast majority of these sequestered resources are immediately dispatchable (such as hydro), thus serving as the perfect resource to match the less predictable response of variable generation.

[27] FERC Order 901, P11-15, 185 FERC ¶ 61,042, United States of America, Federal Energy Regulatory Commission (FERC), 18 CFR Part 40, Docket No. RM22-12-000; Reliability Standards to Address Inverter-Based Resources, October 19, 2023. Hereafter: Order 901

[28] Order 901, P24.

By making these dispatchable resources more operationally available, the secondary benefits may be to bolster the supply of generation to the market. This potential secondary benefit directly addresses vital public interests.[29]

Dispatchable Resources Contribute Significantly to Essential Reliability Services (ERS) [30]

ERSs consist of frequency control, ramping capability, and voltage control.

Frequency control is necessary because the electric grid is designed to operate at a frequency of 60 hertz (Hz). Deviations from 60 Hz can have destructive effects on generators, motors, and equipment of all sizes and types. It is critical to maintain and restore frequency after a disturbance such as the loss of generation. This requires an instantaneous (inertial) response from some resources and a fast response from other resources to slow the rate of fall during the arresting period, a fast increase in power output during the rebound period to stabilize the frequency, and a more prolonged contribution of additional power to compensate for lost resources and bring system frequency back to the normal level. Two NERC Reliability Standards address this:

- BAL-002-3 Disturbance Control Standard—Contingency Reserve from a Balancing Contingency Event
- BAL-003-2 Frequency Response and Frequency Bias Setting

Adequate ramping capability (the ability to match load and generation at all times) is necessary to maintain system frequency. Changes to the generation mix or the system operator's ability to adjust resource output can impact the ability of the operator to keep the system in balance. NERC Reliability Standard BAL-001-2 (Real Power Balancing Control Performance) addresses this issue.

Voltage must be controlled to protect system reliability and move power where it is needed in both normal operations and following a disturbance. Voltage issues tend to be local in nature, such as in sub-areas of the transmission and distribution systems. Reactive power is needed to keep electricity flowing and maintain necessary voltage levels. Several NERC Reliability Standards address voltage control.

Restated, replacing BAL-002-WECC-3 with NERC BAL-002-3 frees dispatchable resources to address FERC-identified reliability gaps created by variable generation, and may bolster vital public interests.

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[29] "335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social, and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard. " (Emphasis added.) Order 693, P35.

[30] "Essential Reliability Services (ERS) are the elemental 'reliability building blocks' from resources (generation and demand) necessary to maintain Bulk Power System (BPS) reliability." NERC ERS Task Force – Scope – 2014.

Because adequate levels of reserves are established in NERC BAL-002-3, and supported by BAL-003-2, BAL-002-WECC-3, Requirements R1 through R4 are not needed.

Replacing BAL-002-WECC-3 With NERC BAL-002-3 Provides Sufficient Reserves at a Continent-Wide Level

In the earliest stages of the Western Interconnection's strides to establish adequate Contingency Reserves, the applicable entity's reserves were established by BAL-STD-002-0, Operating Reserves, at 5% of hydro generation and 7% thermal generation (50% spinning and 50% non-spinning).[31] These thresholds were not technically supported; they were the result of contractual negotiations. Today, such a standard would likely not be approved by FERC as violative of the principles established in FERC Order 672. (See foot note 2.)

As BAL-STD-0-2 was replaced with later iterations of that standard, the result was today's BAL-002-WECC-3, in which the Responsible Entity's reserves are set at:

R1.1.1 "The greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;[32] (or)
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation."

Bullet one of BAL-002-WECC-3 describes the Most Severe Single Contingency, or MSSC.

The MSSC ensures that all entities can recover Area Control Error (ACE) within 15 minutes. The MSSC serves as the upper Contingency Reserve threshold for all interconnections, except the Western Interconnection. Within the Western Interconnection, the levels of reserve set by BAL-002-WECC-3 can exceed that of the rest of the continent that is protected by FERC-approved BAL-002-3. As a result, the Western Interconnection carries an excess of reserve that exacerbates concerns raised by FERC in Order 901 wherein FERC addresses the need for continent-wide standards to backstop the operational performance of variable generation. Comparing NERC BAL-002-3 with BAL-002-WECC-3 illustrates this outcome.

NERC BAL-002-3 states that the BA and the RSG are not subject to compliance with BAL-002-3, R1 for multiple events that exceed the MSSC. NERC BAL-002-3 requires the applicable entity to deploy Contingency Reserve *up to its MSSC*; however, it does not require Contingency Reserve deployment *beyond MSSC.*

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[31] See Attachment - Transition from 5-7 to 3-3, as described in 2005 by Merrill Schultz; see also Attachment - History of WECC Reserve 5-7 Spin Merrill Schultz, March 3, 2005; see also BAL-STD-002-0, Operating Reserves.
[32] Also known as the Most Severe Single Contingency (MSSC).

By contrast, BAL-002-WECC-3 requires the applicable entity to maintain a level of Contingency Reserves *exceeding that required under NERC BAL-002-3*, as approved by FERC. Specifically, BAL-002-WECC-3, Requirement R1 requires the applicable entity to carry reserves that equal or exceed the entity's MSSC—beyond that required by BAL-002-3 that adequately serves the balance of the continent. Among other things, this means these valuable dispatchable resources in excess of the MSSC cannot be used to meet FERC's goal of backstopping variable resources as identified in FERC Order 901.

While the application of BAL-002-3 could free resources to enhance reliability, the application of BAL-002-WECC-3 can inhibit reliability when resources are withheld that could otherwise serve load and backstop variable resources.

For example:

Using historical data from January 2020 - May 2024, comparison of the hourly Contingency Reserve Requirement (calculated using 3% generation and 3% load) to the Most Severe Single Contingency (MSSC), the results identified there was more than 5,000 MW of capacity available during the summertime peak hours and between 2,000-2,500 MW during the remaining hours of the year. See figure below.

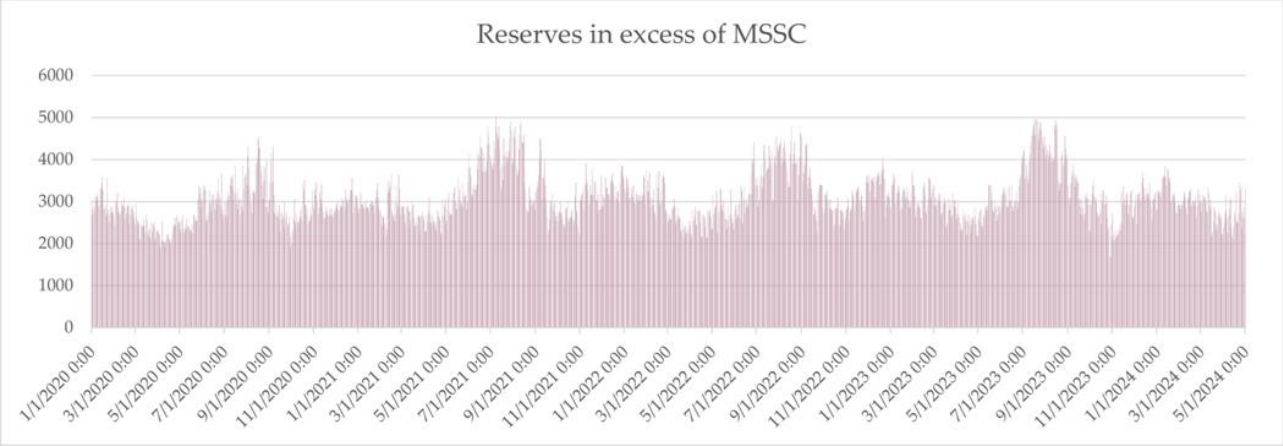


Figure 1: Reserves in excess of MSSC

The Shortened Execution Time of BAL-002-WECC-3 Inhibits Reliability Due to Market Rules in the Western Interconnection

BAL-002-WECC-3, Requirements R3 and R4 require the applicable entity to restore Contingency Reserve within 60 minutes of the initiating event. By contrast, BAL-002-3 requires the applicable entity to achieve the same task in 105 minutes. As a result, BAL-002-WECC-3 requires the performance of the same task 45 minutes earlier than its continent-wide counterpart. This shortened period inhibits reliability in that it forces the applicable entities into transactions agreed upon during an arbitrarily shortened time window. Like BAL-002-3, Requirement R1., there is no technical support suggesting

that rushing this transaction enhances reliability—yet it remains in force 28 years after its inception, still lacking any technical support.

Further, the restoration of reserves in a 60-minute timeframe is restrictive on the entity's ability to secure additional resources within the established business practices in the region. The NERC Standard of up to 105 minutes (90 minutes after the 15 minutes Contingency Recovery Period) after the event has less commercial impact and is acceptable from both a commercial standpoint as well as an operational standpoint.

The WECC requirement of 60 minutes from start of a DCS event restricts the deficient entity from rescheduling resources to replace those that were lost during the event. Western market practices require schedules to be submitted and approved well in advance to ensure reliability, and once the schedule windows close, it is difficult to make last-minute changes. Before markets, when transactions were bilateral, a recovery of generation resources was more flexible, and could be more quickly executed.

The NERC BAL-002-3 Contingency Reserve Restoration Period of up to 105 minutes allows applicable entities to use normal market scheduling practices to replace lost generation. FERC's approval of NERC BAL-002-3 shows its belief that the NERC standard of 105 minutes (90 plus 15) is adequate and does not degrade reliability.

In attempting to meet the 60-minute restoration requirement, the applicable entity has two options.

First, the BA must carry significantly more Contingency Reserve than is required to maintain an adequate level of reliability, or second, be prepared to enter an Energy Emergency Alert 3 which allows the BA to deploy Contingency Reserves to serve load. By definition, entering into an Energy Emergency Alert is an indication of reduced reliability. Given normal scheduling practices, a 90-minute restoration time allows a Responsible Entity to restore Contingency Reserve using normal established market scheduling practices.

In addition, many entities own BES equipment in more than one interconnection. Having a single standard enhances these entities' ability to stay in compliance with the standard using consistent business practices across the interconnections.

Reserve Thresholds do Not Reflect Resource Mix

Due to the changing resource mix and the proliferation of renewable generation, battery storage, and retirements of conventional synchronous generation, resource adequacy has become a serious concern. The BAL-002-WECC standard unnecessarily ties up significant generation which is dispatchable, frequency responsive and fast ramping. Generation that could be used to meet ramps, follow variable resources, or simply meet expected loads, is committed to contingency reserve capacity that is not available to serve load. For example, Western Power Pool's Northwest Power Pool Reserve Sharing Group Northwest-Montana zone typically has a 1,200 MW MSSC, yet routinely has over 3,000 MW of

reserves being held under the 3/3 requirement. That available capacity, usually in excess 1,800 MW, could be used to meet other reliability related services obligations. The existing 3/3 contingency reserve requirement results in the construction of at least 1800 MW of excess generation in the Northwest-Montana zone. The ability to use this generation capacity exceeding the MSSC will also allow entities to efficiently operate their facilities. Idled excess capacity will be reduced and productive generation increased.

Under NERC standard NERC BAL-002-3, the Eastern, Texas and Quebec Interconnections operate without the additional reserve requirement (3% load and 3% generation), and they are allowed to restore their reserves within 90 minutes. The changing market structure in the Western Interconnection has made it difficult to fully restore the required reserves within 60 minutes due to market scheduling timelines. This can lead to implementation of emergency procedures, typically Energy Emergency Alert 3 conditions, due to an energy shortfall precipitated by the 60-minute recovery period. When the Western markets were mostly bilateral, the 60-minute recovery was consistent with energy scheduling protocols. Market integration has altered energy scheduling protocols making it very difficult to modify schedules within 60 minutes of a generation contingency. For these reasons BAL-002-WECC-3 has become obsolete, while not enhancing reliability.

Reserves are unused or unloaded generation that are in a state of readiness in case there is sudden loss of loaded generation. When reserves are held above the MSSC, as they are in the Western Interconnection, excess capacity must be built that has no other reliability benefit. Every energy customer in the West absorbs this excess cost. Retirement of BAL-002-WECC-3 reallocates these excess resources to the benefit of the interconnection in the form of dispatchable, responsive, and available resources to reliably integrate future variable resources, such as wind, solar, and other renewable resources.

Vital Public Interests will be Enhanced[33] [34]

Market Timing Issues

The emergence of organized markets in WECC, since the inception of BAL-002-WECC-1 has brought a new dynamic in the timing and means by which the reserves are procured. The number of participants in the California ISO Energy Imbalance Market (AKA: Western Energy Imbalance Market, or WEIM)

[33] "Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social, and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard." FERC Order No. 672 at P 335.

[34] "The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently." FERC Order No. 672 at P 328.

has grown significantly in the past several years. CAISO EIM market rules require a participating BA to balance its resources and loads 75 minutes before the next operating hour (T-75). Failure to do this can result in financial penalties to the participating BA. This rule has had the effect of discouraging any bilateral energy trading after T-75 and does not align well with a 60-minute reserve recovery time limit. No bilateral trading for replacement energy reserve is possible for the next operational hour because participating WEIM BAs cannot participate in trades within T-75.

This leaves the contingent BA in a resource short position when the 60-minute contingency restoration time expires. At this point, the contingent BA must activate emergency operating procedures up to asking the Reliability Coordinator to declare an EEA3, including load shedding to balance the contingent BA. By extending the contingency restoration time to 105 minutes (15-minute recovery plus 90-minute restoration), the contingent BA has at least 30 minutes to arrange replacement energy in a bilateral manner from other BAs or schedule their own resource in the WEIM. The additional contingency reserve recovery time allows the contingent BA to make orderly and planned adjustments and continue to serve firm load without the implementation of emergency operating procedures, up to and including shedding firm load.

FERC and the industry have determined that 90 minutes from the end of the recovery period (up to 15 minutes) is sufficient to maintain an adequate level of reliability. The shorter restoration period in the WECC creates artificial reliability issues as the applicable entity tries to rebalance supply and demand in an arbitrarily shorter period than that required in the NERC BAL-002-3.

To give a clear understanding of the impact of either option, the following example is provided.

Assume the NWPP RSG's MSSC is approximately 1,200 MW. Under BAL-002-WECC-3, the NWPP RSG would normally carry approximately 2,200-4,000 MW of Contingency Reserves depending on the time of year. Assuming the MSSC occurs, the NWPP RSG would activate 1,200 MW of its reserves and restore the ACE to the pre-event level. Members now have approximately 60 minutes to restore 1,200 MW of reserves while still carrying more than 1,000–2,800 MW, which is greater than the MSSC, assuming it was not reduced with the loss of the 1,180 MW event. See figure below.

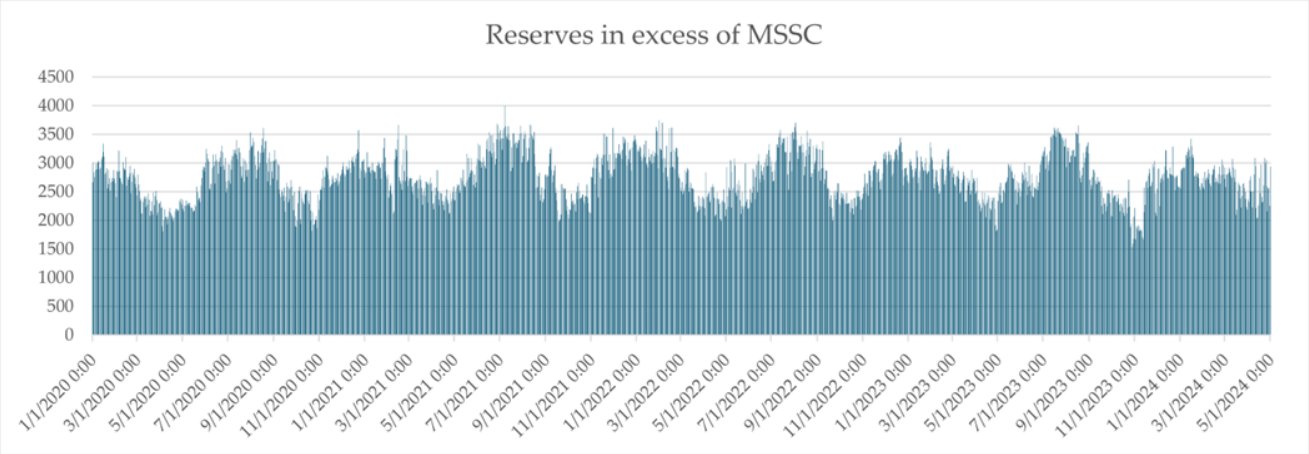


Figure 2: Reserves in excess of MSSC; January 1, 2020, through May 1, 2024

As discussed earlier, due to market rules related to the WEIM in which most entities are taking part, new resources cannot be added to an entity's reserves for the next hour (minimum time to add a resource under the WEIM (75 minutes), or other emerging markets. If a resource is not already in the WEIM, it cannot count toward the reserves needed. So, an entity must have already been carrying reserves greater than required under the WECC standard, or it must reduce load to balance its resources and loads including reserves. (It can be argued that by reducing loads, you are putting the interconnection at greater risk because you have removed one available resource, the load, from being an option for the next event.) To avoid the declaration of an EEA, the NWPP would need to carry an additional 1,000 MW above the required reserves or declare an EEA any time the reserves need to be restored within 60 minutes of the event.

When entities withhold extra reserves to avoid the EEA, this paradigm keeps 2,500 to 4,000 MW from serving load due to the WECC current standard, which has no technical merit, as compared to the NERC Standard. These additional resources could be used to help integrate more inverter-based resources and serve loads more efficiently if it were available for load service.

Entering an Energy Emergency Alert indicates reduced reliability. Given normal scheduling practices, which require bilateral schedules to be completed and approved 75 minutes before the hour, a 60-minute restoration time does not allow adequate time for a Responsible Entity to restore Contingency Reserve in less than 60 minutes from the initiating event, potentially resulting in an Energy Emergency Alert situation.

Capacity Could be Better Used than Simply Holding Reserve

FERC and the industry have determined that the amount of Contingency Reserve needed to maintain an adequate level of reliability is the amount of Contingency Reserve needed to replace the MSSC resource. Holding Contingency Reserve more than MSSC precludes using operating reserve for other purposes, particularly load and resource balancing in real-time. As the grid transitions from

conventional synchronous generation to more variable renewable resources, increasing capacity will be needed to manage the variability and faster ramping requirement of these resources. Allocating reserves in excess of that needed to maintain an adequate level of reliability, or MSSC, ultimately detracts from reliability.

Conclusion

Retirement of BAL-002-WECC-3 Contingency Reserve would reduce required reserves in WECC without diminishing the ability to meet the deployment requirement. Freeing up reserves from the Contingency Reserve requirement would increase the resources available to manage variable resources and accommodate increased renewable resource integration.

The existing BAL-002-WECC-3 Contingency Reserve sets a BA's or RSG's Contingency Reserve requirement to the greater of the MSSC or 3% of the applicable entity's generation and 3% of its load. This 3/3 requirement exceeds MSSC for most responsible entities.

By contrast, NERC Standard BAL-002-3 Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event, Requirement R1.3.2 states that the BA/RSG is not subject to compliance with Requirement R1 for multiple events that exceed the MSSC. NERC BAL-002-3 requires the applicable entity to deploy Contingency Reserve up to the MSSC but does not require Contingency Reserve deployment beyond the MSSC.

In BAL-002-3, FERC and the industry have determined that the amount of Contingency Reserve needed to maintain an adequate level of reliability is the amount of Contingency Reserve needed to replace the MSSC resource.

Holding Contingency Reserve more than MSSC precludes using operating reserve for other purposes, particularly load and resource balancing in real time. As the grid transitions from conventional synchronous generation to more variable renewable resources, increasing capacity will be needed to manage the variability and faster ramping requirement of these resources. Allocating reserve in excess of that needed to maintain an adequate level of reliability, or MSSC, ultimately detracts from reliability.

BAL-002-WECC-3 requires an applicable entity to restore Contingency Reserve within 60 minutes of the initiating event (as opposed to up to 105 minutes in BAL-002-3), or 45 minutes sooner than required by BAL-002-3. With respect to impacts to the time to restore Contingency Reserve, FERC and the industry have determined that 90 minutes from the end of the recovery period (up to 15 minutes) is sufficient to maintain an adequate level of reliability. By contrast, the 60-minute requirement within BAL-002-WECC-3 creates potential reliability issues as an applicable entity tries to rebalance in an arbitrarily shorter period than that required in the NERC BAL-002-3. In attempting to meet the 60-minute restoration requirement, an applicable entity has two options. First, the BA must carry significantly more Contingency Reserve than is required to maintain an adequate level of reliability, or second, be prepared to enter an Energy Emergency Alert 3 and deploy Contingency Reserve to serve load. Given normal scheduling practices, a 90-minute restoration time allows an applicable entity to restore Contingency Reserve without employing emergency procedures.

Retirement of BAL-002-WECC-3 will enhance the reliable operation of the Western Interconnection by allowing resources that are presently used for overprotecting above the MSSC to be available to meet

the immediate balancing needs of the Interconnection. This will free those resources to be used as needed in a rapidly changing system to maintain overall reliability.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-84:
WECC Risk Factor Criteria

WECC Risk Factor Criteria for Inherent Risk Assessment Effective March 22, 2021				
	Criteria for Assessment			
Risk Factor	**N/A**	**Low Risk**	**Medium Risk**	**High Risk**
CIP - Impact Rating Criteria	Entity has no BES Cyber Systems (BCS)	Entity has one or more low impact BCS(s)	Entity has one or more medium impact BCS(s)	Entity has one or more high impact BCS(s)
ICCP Connectivity	Entity has no BES Cyber Systems (BCS)	Entity has low impact BCS(s) without ICCP connections or external routable connectivity	Entity has low impact BCS(s) with at least one ICCP connection - or - Entity has low impact BCS(s) with external routable connectivity (LERC) - or - Entity has medium impact BCSs	Entity has medium impact BCS(s) with at least one ICCP connection - or - Entity has high impact BCS(s)
Load	Entity does not have any system load	Entity's system load is less than 300 MW	Entity's system load is between 300 - 2,000 MW	Entity's system load is greater than 2,000 MW
Transmission Portfolio	Entity does not own, operate, coordinate, plan, design, or monitor the status of transmission facilities	Entity has transmission facilities less than 200kV	Entity has transmission facilities between 200 - 300 kV - or - Entity has over 1,000 miles of transmission lines 100 kV or greater	Entity has transmission facilities greater than 300 kV - or - Entity has over 4,000 miles of transmission lines 200 kV or greater
Critical Transmission	Entity does not own, operate, coordinate, plan, design, or monitor the status of transmission facilities	Entity's system is not critical to adjacent entities as it is not being used as a flow through system for power flow	Entity's system is critical to adjacent entities as it is being used as a flow through system for power flow	Entity's system includes elements (owned or operated) of an IROL / Flowgate / Major Transmission Path (WECC) / Generic Transmission Limit (Texas RE) / Cranking Path
Voltage Control	Entity does not own or operate any voltage control equipment	----------	Entity owns and/or operates reactive resources to provide voltage control	Entity owns and/or operates reactive resources other than generators to provide voltage control
Largest Generator Facility	Entity does not own any generation facilities	Entity's largest single generation facility is less than 500 MVA	Entity's largest single generation facility is between 500 - 1,000 MVA	Entity's largest single generation facility is greater than 1,000 MVA

Total Generation Capacity	Entity does not own or operate any generation facilities	Entity's total generation nameplate capacity is less than 1,000 MVA	Entity's total generation nameplate capacity is between 1,000 - 5,000 MVA	Entity's total generation nameplate capacity is greater than 5,000 MVA
Variable Generation	Entity does not meet any of the identified criteria	Less than 10% of the entity's BA Area total generation nameplate MVA is comprised of non-dispatchable generation	10% - 25% of the entity's BA Area total generation nameplate MVA is comprised of non-dispatchable generation	Over 25% of the entity's BA Area total generation nameplate MVA is comprised of non-dispatchable generation
Balancing Authority (BA) Coordination	Entity does not meet any of the identified criteria	Entity's BA Area has less than 5,000 MW of generation capacity	Entity's BA Area has between 5,000 - 10,000 MW of generation capacity	Entity's BA Area has greater than 10,000 MW of generation capacity - or - Entity's BA Area has greater than 5,000 MW of generation capacity and its Generation to Peak Load ratio is more than 1.2
Planned Facilities	Entity does not meet any of the identified criteria	Entity is planning on or currently building transmission facilities less than 200 kV in the next three years - or - Entity is planning on or currently building generation facilities that are less than 500 MVA in the next three years	Entity is planning on or currently building transmission facilities between 200 - 300 kV in the next three years - or - Entity is planning on or currently building generation facilities that are between 500 and 1,000 MVA in the next three years	Entity is planning on or currently building transmission facilities greater than 300 kV in the next three years - or - Entity is planning on or currently building generation facilities greater than 1,000 MVA in the next three years
RAS/SPS	Entity does not own, operate, coordinate, plan, design, or monitor the status of a RAS/SPS	----------	Entity owns or designed a RAS/SPS that is not needed to meet TPL requirements - or - Entity owns or operates equipment that is part of a RAS/SPS that is not needed to meet TPL requirements	Entity owns or designed a RAS/SPS that is needed to meet TPL requirements - or - Entity owns or operates equipment that is part of a RAS/SPS that is needed to meet TPL requirements

Workforce Capability	Entity does not meet any of the identified criteria	Less than 25% of the entity's System Operators have less than 5 years of System Operator experience	Between 25 - 50% of the entity's System Operators have less than 5 years of System Operator experience	Greater than 50% of the entity's System Operators have less than 5 years of System Operator experience
System Restoration	Entity has no responsibilities during system restoration	Entity has regional or company system restoration responsibilities limited to load restoration	Entity has Blackstart Resource(s) - or - Entity provides switching or other logistics based on the direction from a different entity responsible for the restoration plan	Entity is an RC - or - Entity is responsible for independent actions coordinated with an RC
UFLS Equipment	Entity does not own or operate UFLS equipment	Entity is responsible for 0% up to 0.3% of the entire regionally identified UFLS program	Entity is responsible for 0.3% to 1.3% of the entire regionally identified UFLS program	Entity is responsible for more than 1.3% of the entire regionally identified UFLS program
UFLS Development and Coordination	Entity is not responsible for developing or coordinating a UFLS program	Entity is responsible for developing and/or coordinating a UFLS program for less than 500 MW of load	Entity is responsible for developing and/or coordinating a UFLS program for 500 MW to 900 MW of load	Entity is responsible for developing and/or coordinating a UFLS program for 900 MW of load
UVLS	Entity does not have any UVLS responsibilities	The Registered Entity owns or operates UVLS that is less than 10% of its peak load	The Registered Entity owns or operates UVLS that is greater than or equal to 10%, but less than 25%, of its peak load	The Registered Entity owns or operates UVLS that is greater than or equal to 25% of its peak load

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-85:
WECC 2024 Western Assessment of Resource Adequacy Appendix



WECC

Western Assessment of Resource Adequacy Appendix

January 24, 2025

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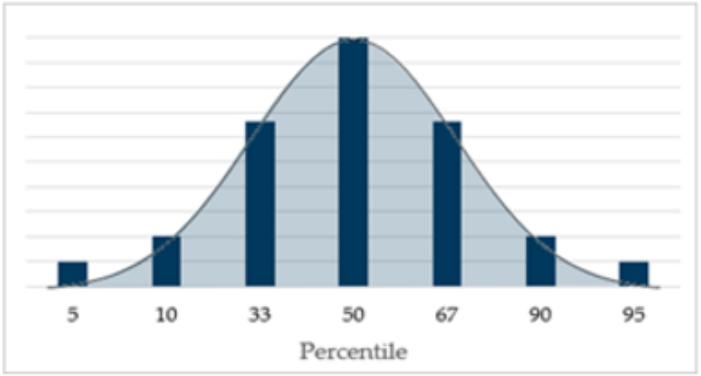
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Appendix A: Modeling Methodology

To determine the demand at risk hours (DARH) in the Western Assessment of Resource Adequacy (Western Assessment), WECC uses the Multiple Area Variable Resource Integration Convolution model (MAVRIC). MAVRIC is WECC's internally developed modeling tool that performs energy-based probabilistic assessments by applying the convolution method. In addition to applying the convolution method, a subset of assumptions within the model are also derived via a Monte-Carlo Markov-Chain method (see Appendix B). For a primer on Monte Carlo simulations and convolution methods, please see NERC's Probabilistic Adequacy and Measures Report.

MAVRIC examines the probability that demand and resource availability will intersect at expected energy values given their probability distribution curves. Figure 1 is an example of a probability curve. The curve shows the probability of potential outcomes based on an expected value. For example, if an expected value falls at the 50th percentile, this value has a 1-in-2 chance of occurring. MAVRIC evaluates the probability curves of demand and resource availability together (Figure 2). The overlapping area of the demand and resource availability curves represent the potential for unserved load, or DARHs. The more the two curves overlap, the greater the potential for demand at risk. The goal is to keep the two curves far enough apart that overlap is kept below a certain threshold. For the Western Assessment, WECC has set this threshold to the one-day-in-ten-year (ODITY) level, meaning 99.98% of the demand for each hour is covered by available resources. Put another way, the area of overlap for the availability and demand curves is equal to no more than 0.02% for any given hour.



Probability	Percentile	Likelihood of Occurrence
1-in-20	5th	5%
1-in-10	10th	10%
1-in-3	33rd	33%
1-in-2	50th	50% (expected)
1-in-3	67th	33%
1-in-10	90th	10%
1-in-20	95th	5%

Figure 1: A conceptual normal probability curve with percentiles and likelihood of occurrence

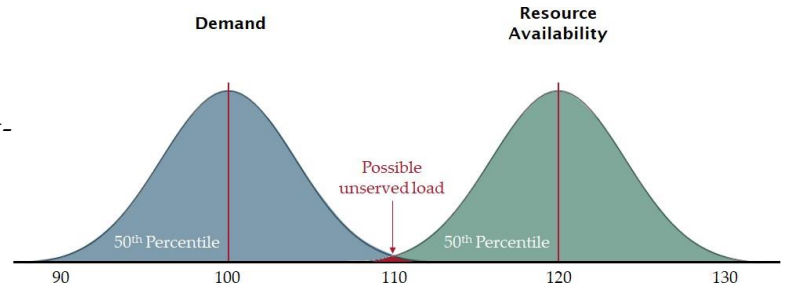


Figure 2: Evaluation of the supply side and demand probability curves for overlap which represents demand at risk

The potential for DARHs can increase or decrease when the demand or availability curves shift, expand, or contract. A shift in the position of a demand curve closer to the availability curve happens when demand uniformly increases without a corresponding increase in resource availability. When rare events occur more frequently, the demand probability curve changes shape and expands. When one or both curves change shape in this way, the overlap can increase, making it more likely that demand will exceed resource availability, as shown in Figure 3. For example, heat waves like those that occurred in the West in 2020 and 2021 were once rare events. The August 2020 Heat Wave was a 1-in-30 event. But, when evaluated considering climate change, it becomes a 1-in-20 event, widening the demand curve.

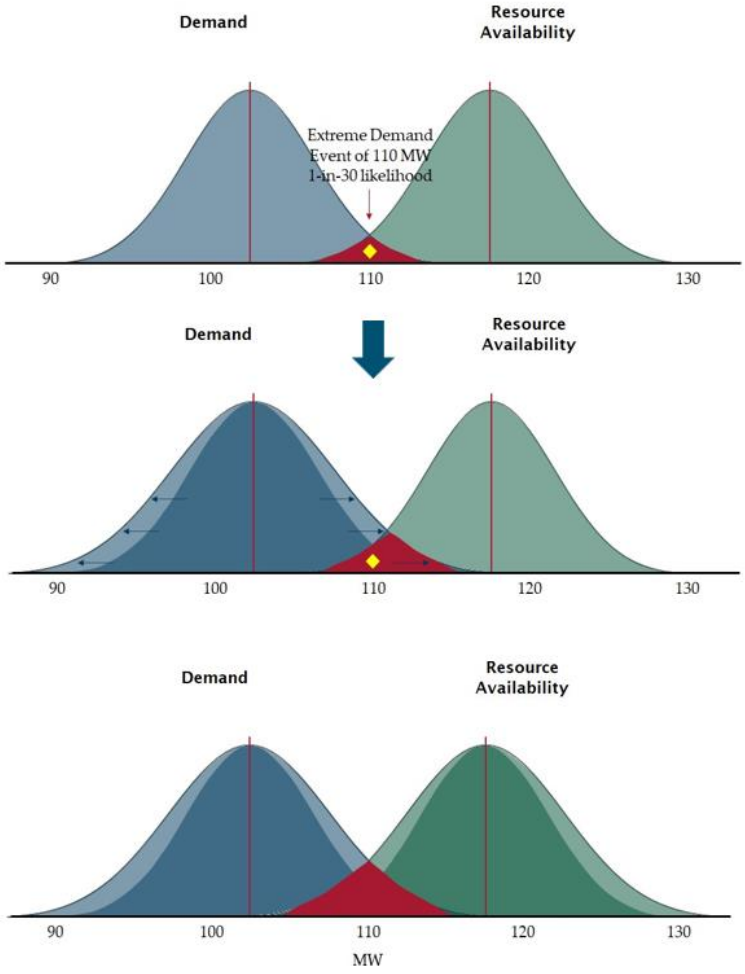


Figure 3: Demand and resource availability curves with increasing overlap due to increased frequency of extreme weather events

As additional variable energy resources (VER) are added to a portfolio, the resource availability curve expands like the demand curve expands when extreme events become more frequent. The variability in output of wind, solar, and hydro resources widens the potential range of expected values. Conversely, a decrease in unplanned outage frequency, or mean time to return from outages, would move the tails of the resource availability curve away from the demand curve. If resource availability decreases, the resource availability curve will shift closer to the demand curve, increasing overlap.

Calculating the Planning Reserve Margin

Assessing DARHs allows for the creation of planning reserve margins (PRM). Figure 4 shows a system with a 1-in-2 chance that demand is 100 MW and resource availability is 120 MW. A 20-MW—or 20%—PRM is needed to maintain 99.98% resource adequacy. This is based on the shapes of the demand and resource availability curves. If the availability curve shifts to the left, and only 115 MW of resources are available, the reserve margin has decreased to 15 MW. This amount of reserve margin will no longer maintain the ODITY threshold. Figure 5 shows the increased DARHs if the PRM does not increase to accommodate the change in distribution shape. To accommodate the change in distribution shape and maintain 99.98% resource adequacy, the PRM must increase. If the PRM is increased to 22 MW, the system returns to being 99.98% resource adequate, maintaining the ODITY threshold (Figure 6). Actual distributions for each subregion are in Appendix D.

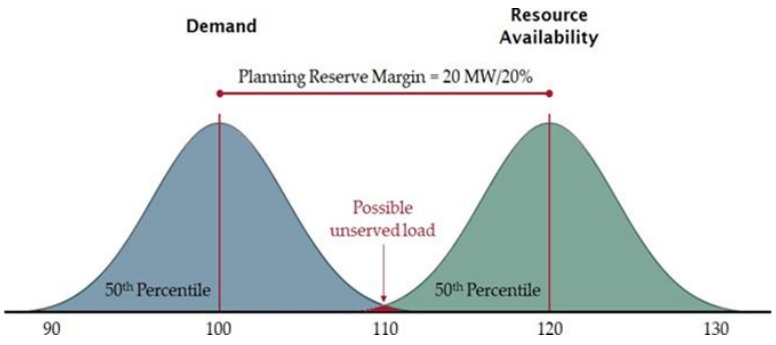


Figure 4: Conceptual system with 99.98% resource adequacy at a PRM of 20 MW

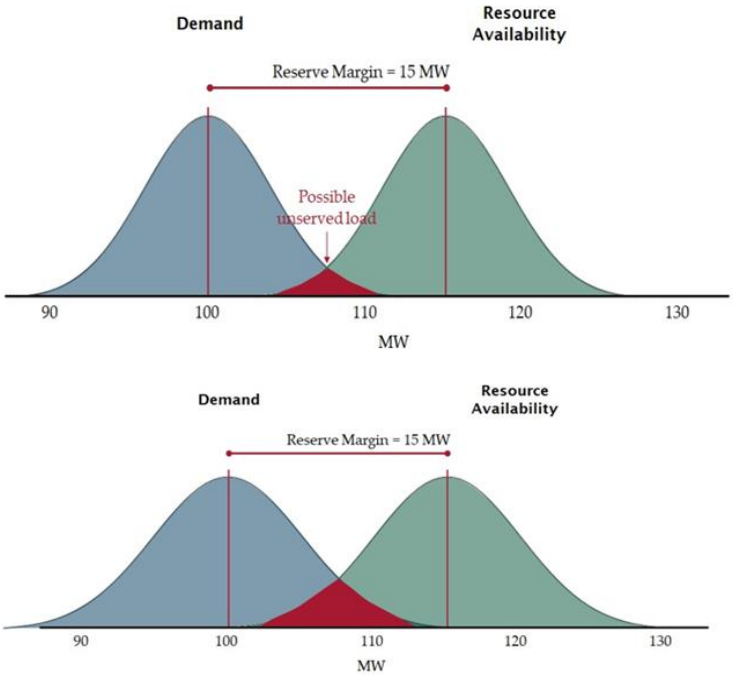


Figure 5: Demonstrates the increased demand at risk if the distributions expand or shift

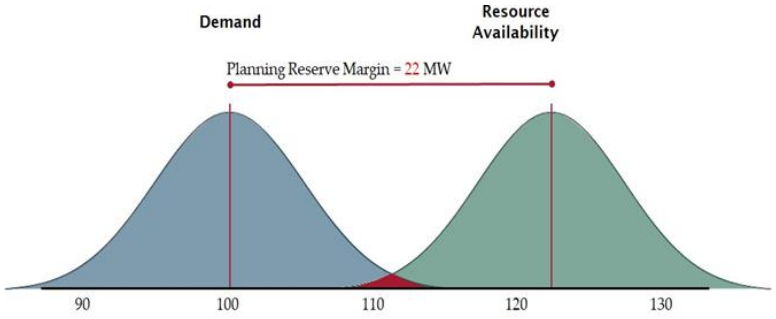


Figure 6: Shows the increased PRM required to maintain 99.98% resource adequacy with the wider distributions

Appendix B: MAVRIC Inputs, Assumptions, & Processes

The Western Interconnection has many transmission connections between demand and supply points, with energy transfers playing a significant role in reliable operations. On top of this, the Western Interconnection is geographically large and contains both winter-peaking and summer-peaking areas. To add to the complexity, there is a large amount of hydro capacity that experiences seasonal variability, and rapid adoption of solar and wind resources, which can vary hourly in output. WECC developed MAVRIC to handle these intricacies. MAVRIC can study all hours of the year, it can factor in dynamic imports from neighboring areas, and account for varying generation patterns dependent on geographical location and resource type. MAVRIC calculates resource adequacy through loss-of-load probabilities (LOLP). It calculates LOLPs on each of the stand-alone Balancing Authorities (BA) without transfers, then balances the system cohesively with transfers to a probabilistic LOLP (see Appendix A). This section will discuss the inputs, assumptions, and processes within MAVRIC required to perform this LOLP calculation. Figure 7 provides an overview of the MAVRIC process.

In step one of Figure 7, hourly historical data for demand and energy output from hydro, solar, wind, and battery energy storage system (BESS) resources are collected in WECC's annual Loads and Resources (L&R) Data Request. To develop hourly probability distributions for demand, hourly demand from previous years must be aligned. The first Sundays of each historical year are aligned so that weekends and weekdays are consistent. Each hour is then compared against a rolling seven-week average for the same hour of the same weekday. This establishes the difference between the historical hour and the average. MAVRIC uses each of these percentages to calculate a percentile probability for a given hour based on the variability of three

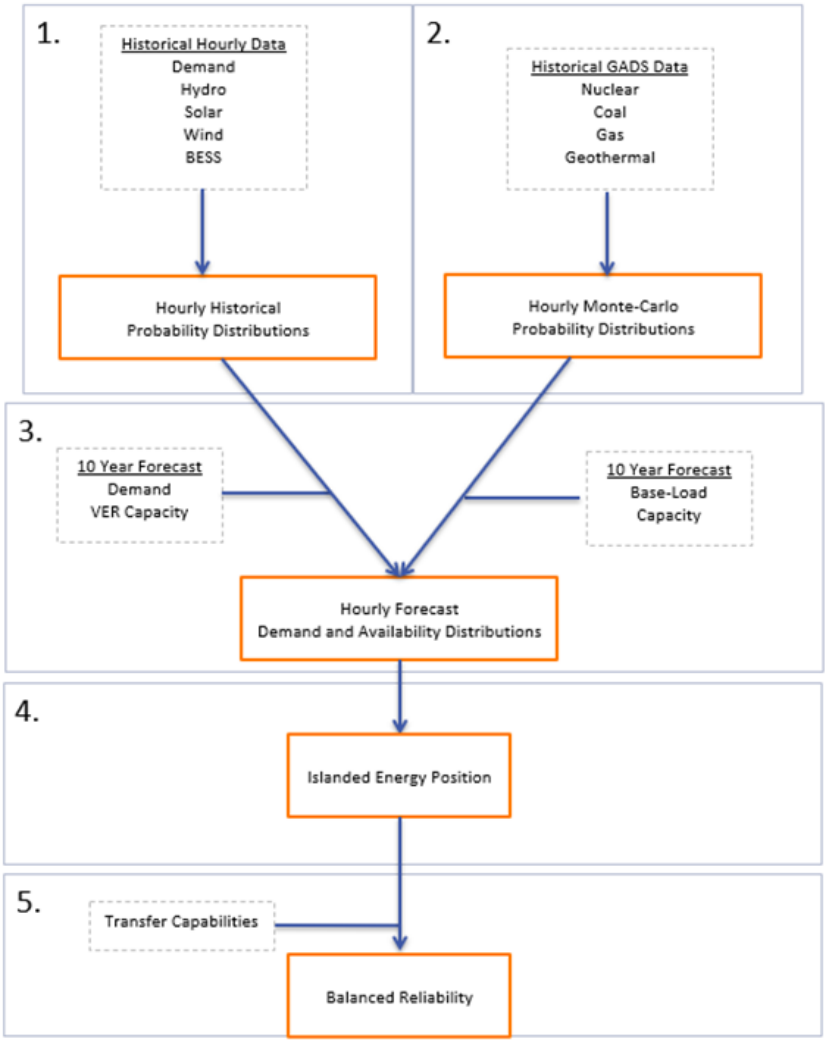


Figure 7: MAVRIC inputs and processes

weeks before and three weeks after the given hour for each historical year. The output of this step is a series of hourly percentile profiles with different probabilities of occurring. Figure 8 represents a demand probability distribution for a single hour. The peak is the expected deterministic forecast and is set at 100%. The profiles to the right of the peak are greater than 100% and those to the left are lower than 100%.

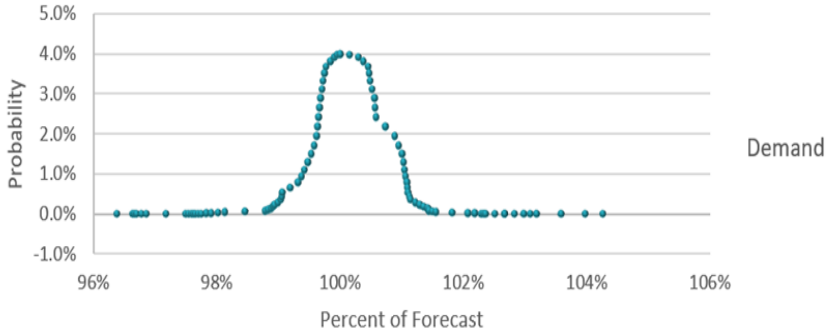


Figure 8: Example of a single hour's demand profile

The availability probability distributions for the VERs, which includes hydro, wind, and solar resources, is derived in a similar manner to that of the demand calculations but with two notable differences. The primary difference is the period used in calculating the VER availability distributions. For VERs, the day of the week does not influence variability, as weather is always variable. Therefore, the need to use data from the same day of the week is not necessary. This allows the VER distributions to be condensed to a rolling seven-day window using the same hour for each of the seven days. The second difference is that the historical generation data is compared against the nameplate capacity to determine the historical capacity factor for that hour, which is then used in the percentile probability calculation. Using nameplate in the denominator allows for the incorporation of unit outages due to non-fuel-related issues. The output of this process is a series of hourly percentile profiles with different probabilities of occurring. A random hour profile for each of the VER types is shown in Figure 9. Wind and hydro run-of-river units are positively skewed, whereas solar and hydro storage units are negatively skewed, meaning their distributions "lean" to the left and right, respectively. The highest point of the distribution indicates the most frequently anticipated capacity factor from the resource for a given hour. For instance, the hour represented in Figure 9 for wind tends to perform at the lower end of the capacity factor spectrum, whereas solar frequently performs at capacity factors above 90%. Hybrid resources such as solar with BESS or wind with BESS, are treated as VERs. MAVRIC does not account for the BESS properties of these resources.

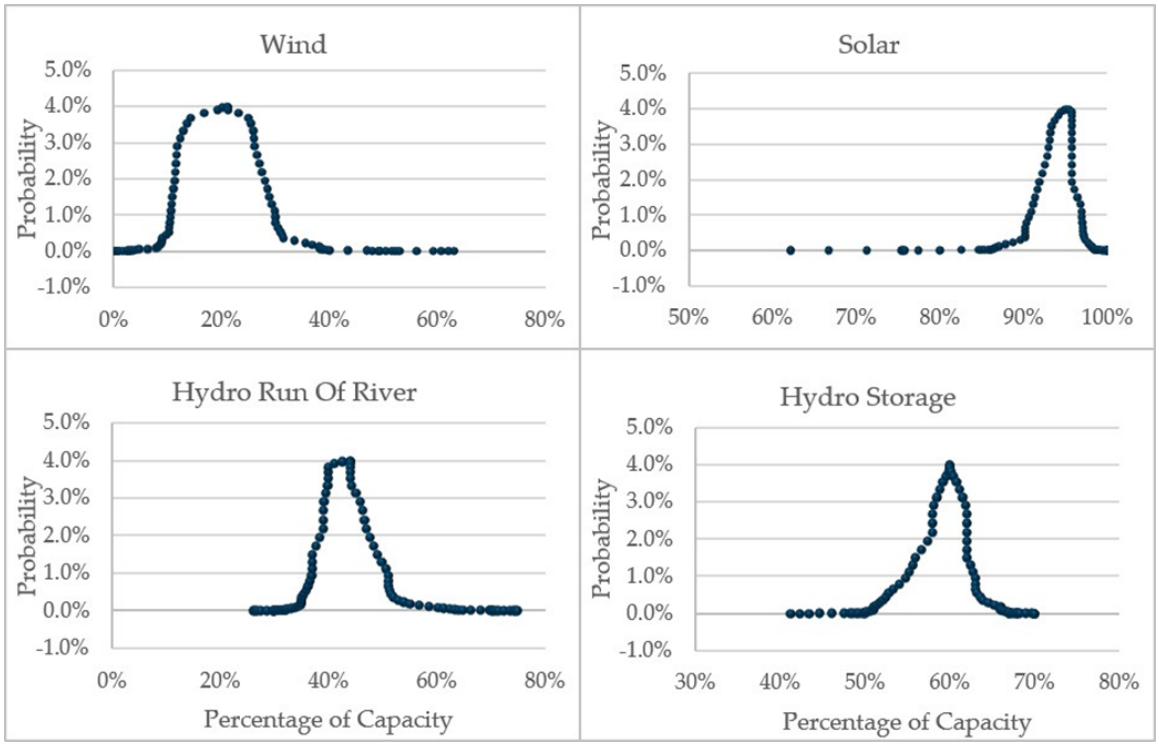


Figure 9: Examples of hourly profiles for each of the VER resource types

Hydro facilities with storage capability are highly correlated with demand. The ability to store the fuel leads to different operating characteristics between weekdays and weekends. Therefore, the availability distributions for hydro facilities with storage are calculated in the same manner as the demand distribution.

For the purposes of baseload resources, MAVRIC uses a Monte-Carlo Markov-Chain method (Step 2 in Figure 7). The distributions of nuclear, coal-fired, gas-fired, biofuel and geothermal resources, are determined by using the historical rate of unexpected failure and the time to return to service from NERC's Generation Availability Data System (GADS). The annual frequency of unexpected outages and recovery time from these outages is used to calculate the availability probability distributions for baseload resources. Based on this data, a random value is calculated for the first hour of the year for each of the units within a BA. If that random value falls below the frequency calculation to be available, the model will force the unit offline. Conversely, if the random value does not fall below the availability frequency calculation, the unit is deemed as available. Available resources are capable for their maximum winter or summer capacity rating, depending on the season. Once the status of each resource is determined, the next hour is then processed. If the resource was determined unavailable in the previous hour, the model will keep the resource unavailable until the average duration of the historical unplanned outages is reached. If the unit was determined as available the previous hour, the random variable for the next hour is checked against the forced outage frequency calculation and the process repeats. Through this random sampling method, MAVRIC performs 1,000 iterations for each resource for each hour. After 1,000 iterations, the data points of availability for each hour are used to

generate availability probability distributions. Figure 10 demonstrates a baseload availability distribution. It is consistent with the VER distributions, in that a series of expected values for capacity factors are produced for each hour. BESS resources are treated in the same manner as baseload generators. Their full capacity is available to be discharged when the resource is not in outage. MAVRIC does not account for the charging behavior of batteries.

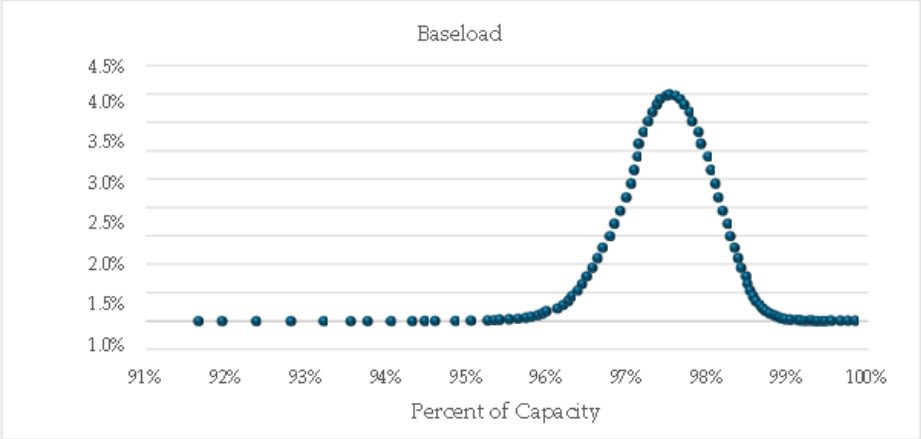


Figure 10: Example hourly probability distribution for thermal resources

In Step 3 of Figure 7, MAVRIC combines the 10-year demand forecast and resource availability to represent the hourly forecast demand and availability distributions. The 50th percentile of the demand distributions is set equal to 100% (as displayed in Figure 8), with the low and high side variability represented by the percentiles to the left and right, respectively. The hourly demand forecast in megawatts is multiplied by each of the percentiles of the probability distribution, creating a distribution of hourly megawatt forecasts. For availability, each of the probability distributions represent capacity factors. Therefore, by taking an expected capacity of each of the different types of resources and multiplying it by each of the hourly profiles, a distribution of hourly megawatt forecasts is derived.

Step 4 represents the comparison of the hourly demand distributions with the hourly availability distributions. For each hour, the distributions are compared to one another to determine the amount of overlap in the upper tail of the demand distribution with the lower tail of the availability distribution. The amount of overlap represents the LOLP. If the probability for a given hour is greater than a selected threshold (such as the ODITY threshold discussed in Appendix A), then that hour is a DARH.

If DARHs are identified in in Step 4, MAVRIC analyzes potential transfers to mitigate them. This is Step 5 in Figure 7. MAVRIC undergoes a step-by-step balancing logic in which excess energy, which is energy above an area's PRM, can be used to satisfy another area's resource adequacy shortfall. This depends on neighboring areas having excess energy and available transfer capability to allow the excess energy to flow. MAVRIC only allows for first and second order transfers to occur. Transfer capabilities are a deterministic input into MAVRIC, and they vary based on the direction of flow (see Appendix C). MAVRIC considers first-order transfers (external assistance from an immediate neighbor) and second-order transfers (external assistance from a neighboring entity's immediate neighbors). After balancing all areas in the system for a given hour, MAVRIC then moves to the next hour and balances the system as needed. The result is an analysis of the Western Interconnection that

reflects the ability of all defined areas or subregions to maintain a PRM equal to, or less than, the ODITY threshold.

Appendix C: MAVRIC Topology

Transfer capabilities are a deterministic input into MAVRIC, and they vary based on the direction of flow and season. MAVRIC topology uses a zonal approach, considering the transfer capability between regions but not accounting for nodal congestion. The transfer capabilities within MAVRIC are provided by BAs and Transmission Operators (TO) and resemble expectations during system peaking conditions. The transmission topology in MAVRIC is shown in Figures 11 and 12 for the summer and winter seasons, respectively.

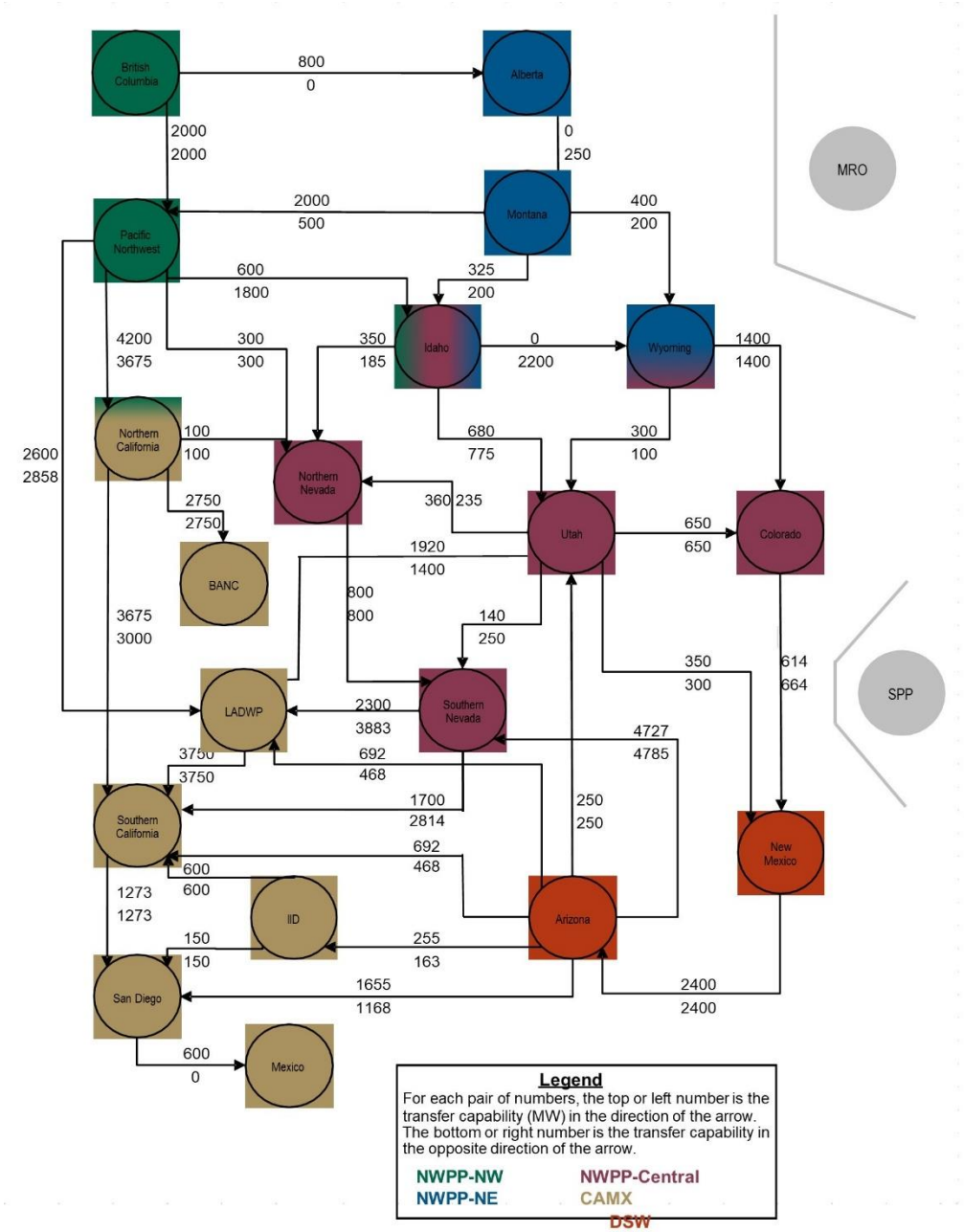


Figure 11: Summer topology in MAVRIC

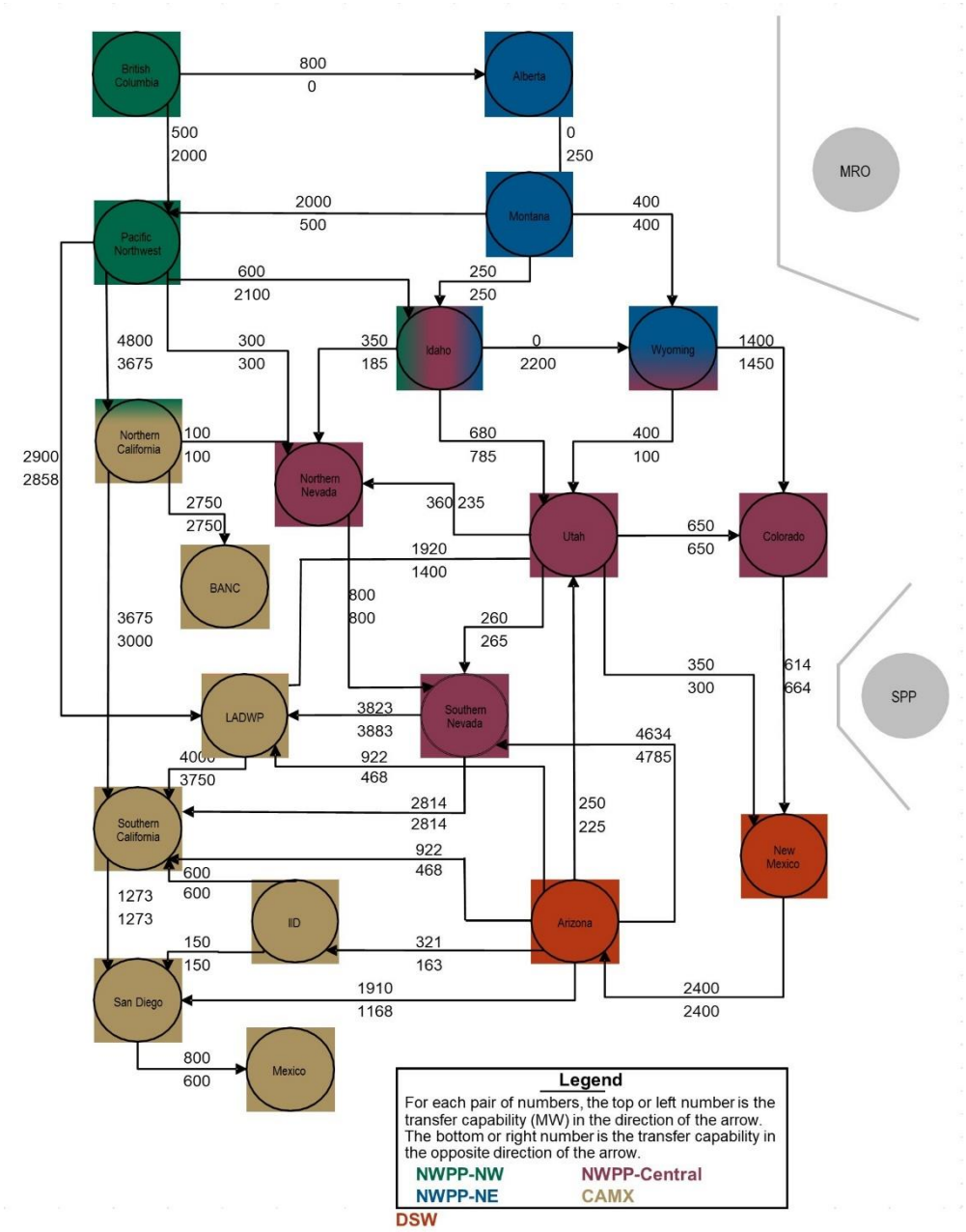


Figure 12: Winter topology in MAVRIC

Appendix D: Regional Portfolios, Variability, & Volatility

Figures 13 through 17 show each subregion's resource portfolio on a capacity basis, demand and supply probability distributions, and demand and supply volatility curves in the 2028 assessment year. The 2028 assessment year was selected for this section to balance current data trends and resource plans without extending so far into the future that the data becomes mostly speculative. As discussed in Appendix A, many factors influence the shape of the demand and availability curves. Increasing the frequency of extreme weather events in a subregion will result in the demand curve developing a positive skew. General forecast growth moves the center of the demand curve closer to the availability curve. Conversely, adding VERs to a subregion's portfolio will widen the availability curve, but also move the center of the availability curve away from the demand curve due to the increase in capacity. Adding thermal and BESS resources will shift the center of the availability curve away from the demand curve. A decrease in forced outage rate will tighten the availability curve. Volatility represents the percent deviation from the 50/50 case that the demand has in the 95th percentile and the availability has in the 5th percentile. Put another way, volatility shows the potential down-side availability risk and high-side demand risk. Availability volatility correlates with a portfolio's share and type of VERs, the capacity factor distributions of those VERs, and forced outage rates. Volatility of demand will be greater in subregions prone to extreme or prolonged weather events. The overlap of the availability and demand distributions represents DARHs. This appendix adds to the insights provided in the subregional documentation for the DARHs calculated in the Scenario Analysis portion of the Western Assessment. The charts below do not account for transfers that may mitigate DARHs.

California & Mexico (CAMX)

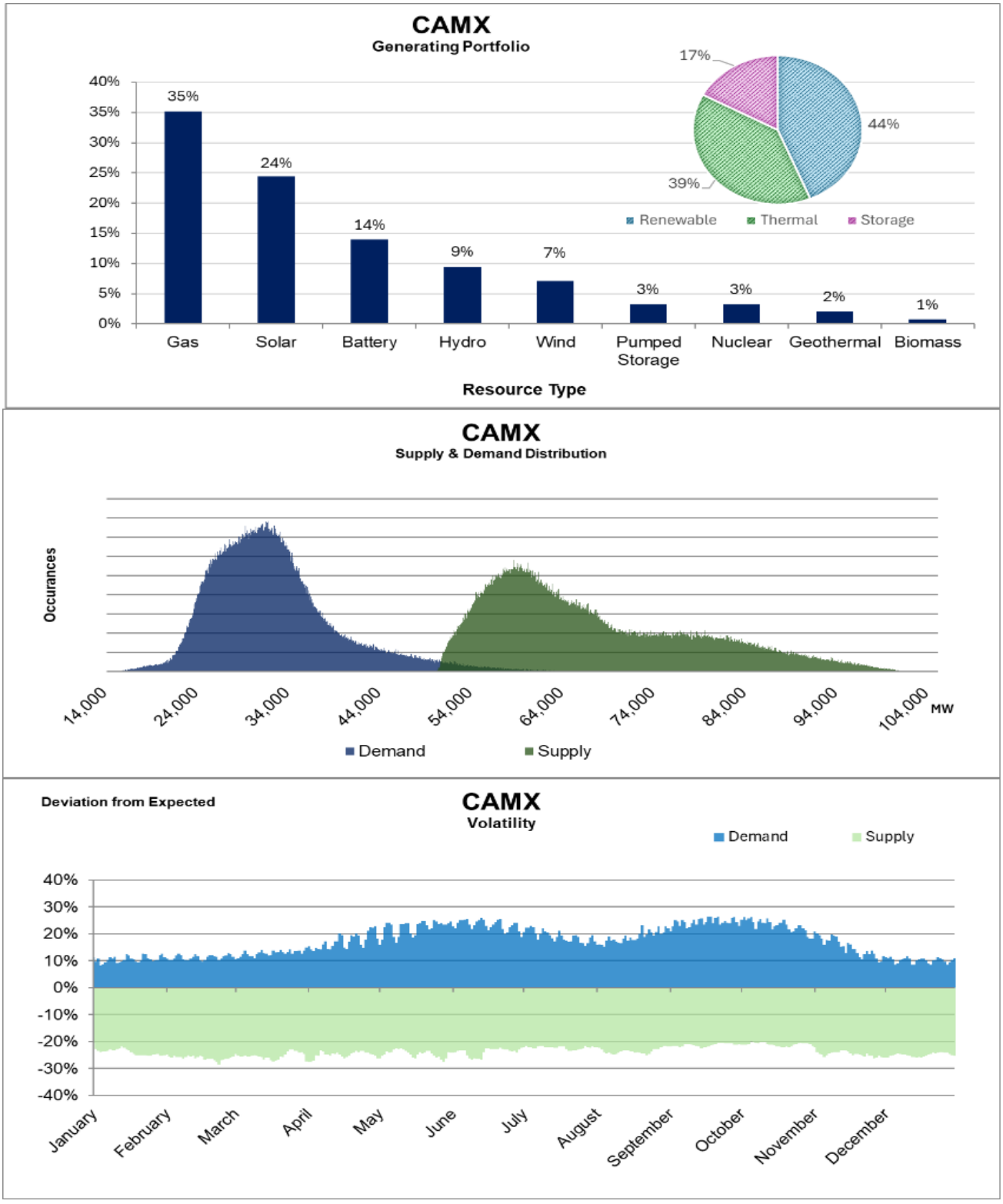
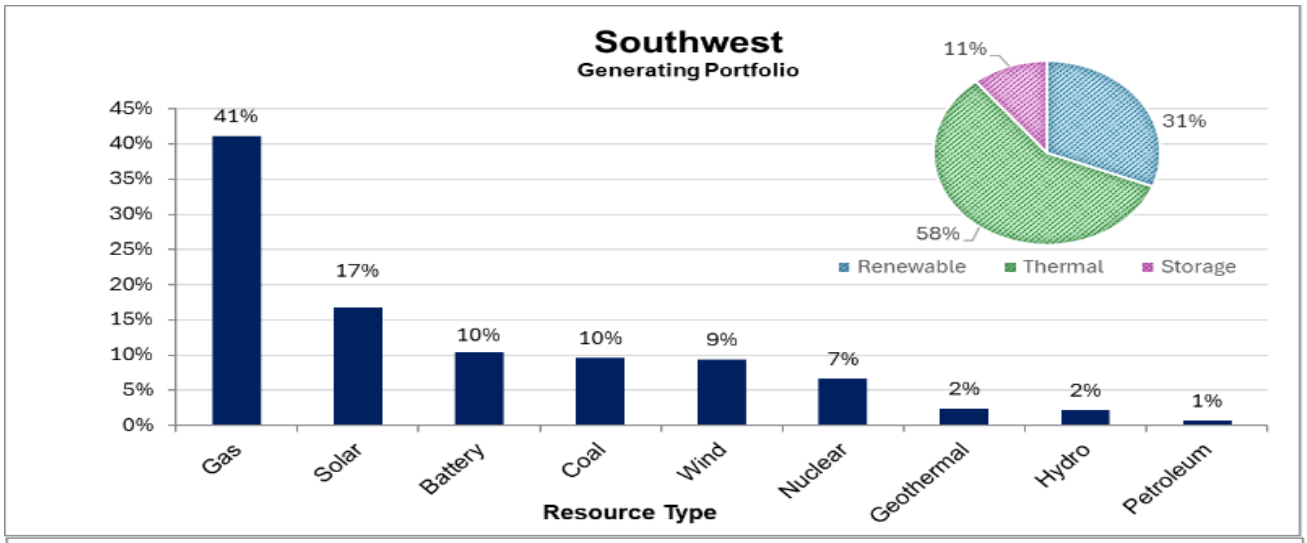
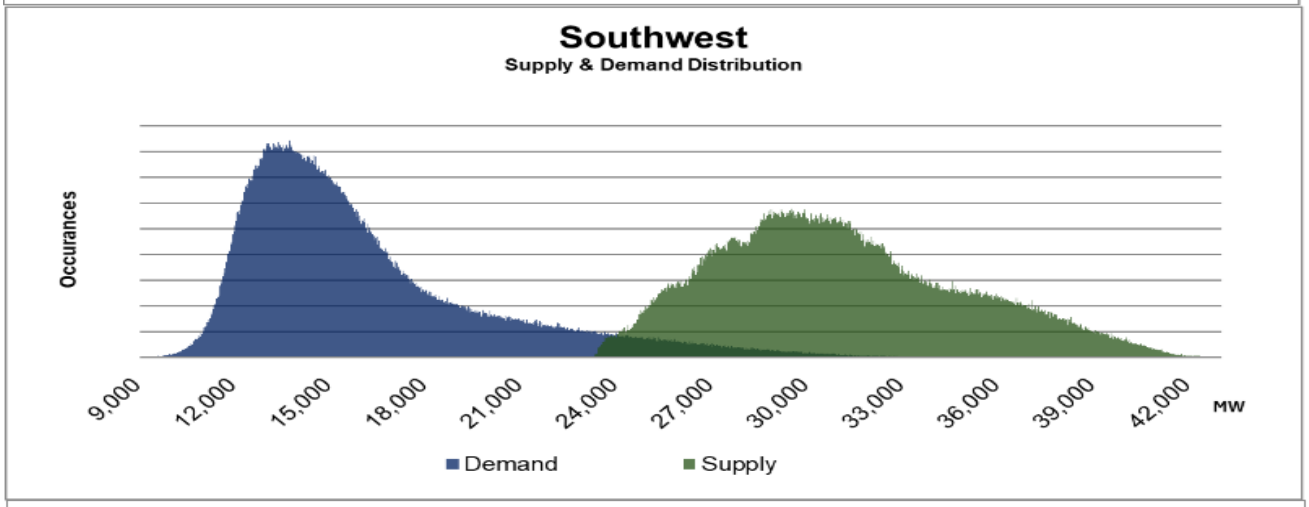


Figure 13: CAMX resource portfolio and variability

For 2028, CAMX shows little overlap of the demand and supply distributions. This indicates that CAMX should be able to meet demand under all but the most extreme circumstances coupled with resource underperformance. In 2028, the CAMX portfolio is forecast to be 39% thermal resources, 17% BESS resources, and the remainder attributed to VERs. A large share of thermal and BESS resources helps maintain certainty in resource output while minimizing volatility on the supply side. CAMX has significant solar contribution in its portfolio, which typically presents at higher capacity factors than other VERs when available. CAMX shows less supply-side volatility than other subregions and a long tail at the high end of its supply curve due to the high percentage of thermal, BESS, and solar contributions. CAMX is a summer-peaking subregion and has experienced prolonged heat wave events over the past four years. Two of these events resulted in new hourly peak loads for the Western Interconnection. This amplifies the positive skew of the demand curve as well as the demand volatility in the early summer through early fall months.

Desert Southwest (DSW)





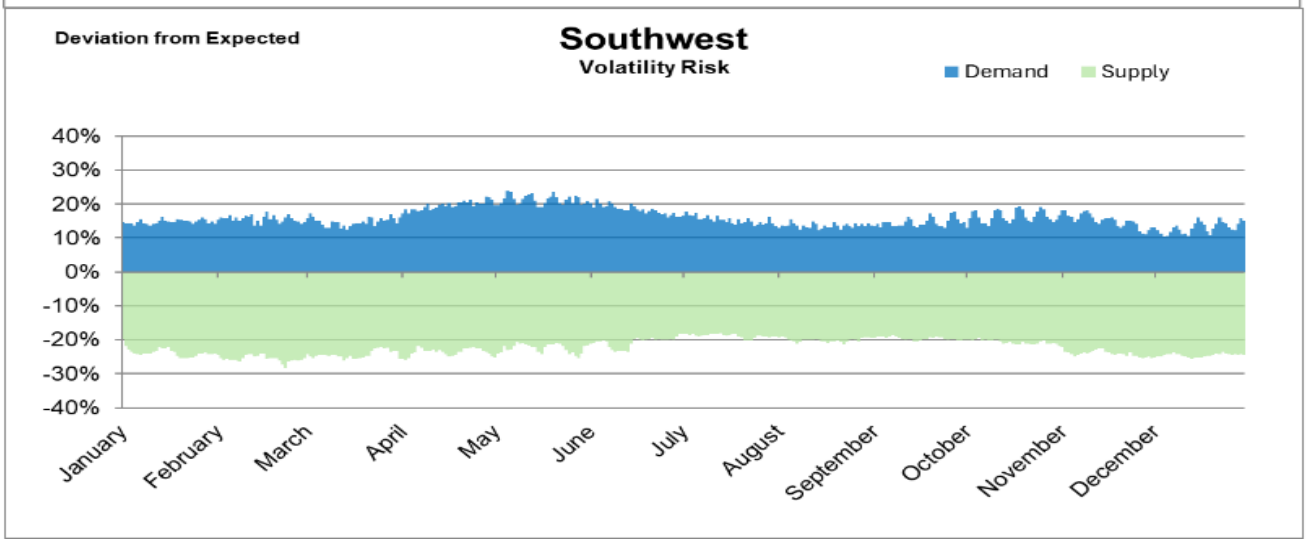


Figure 14: DSW resource portfolio and variability

In 2028, thermal resources are anticipated to comprise 58% of generating capability in the DSW, followed by VERs at 31%, and the remaining being supplied by BESS resources. The DSW is forecast to have the highest share of thermal sites of all subregions, with 41% of its portfolio being natural gas. The DSW is a summer-peaking subregion and has experienced prolonged heat wave events over the past four years. Natural gas resources can be derated in high temperatures which can lower expected contribution during heat wave events. Despite this, the large share of thermal and BESS resources gives the DSW lower volatility on the supply side than other subregions. The DSW also has a large share of solar resources, which are projected to make up 17% of its portfolio. Solar tends to generate at the high end of the capacity factor distribution when available, resulting in less supply side volatility than other VERs. Recent extreme weather events have resulted in the positive skew of the demand distribution and high volatility of demand in the early summer through early fall months.

Northwest-Central (NW-Central)

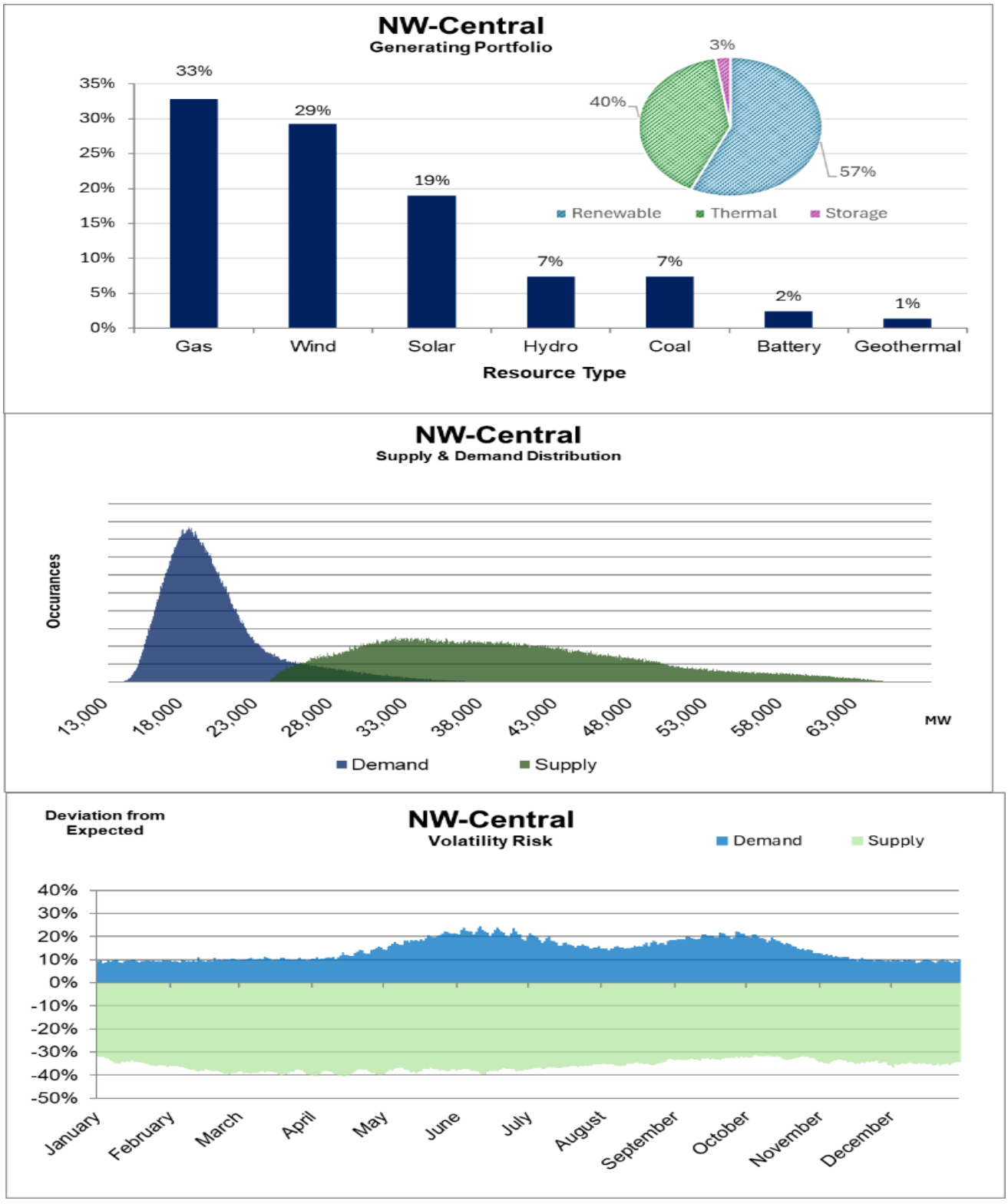


Figure 15: NW-Central resource portfolio and variability

The NW-Central portfolio is forecast to be 29% wind resources in 2028, with solar resources making up just under 20%. The substantial share of wind in this subregion's portfolio results in a wide availability curve due to its high uncertainty in output. The significant wind resources in this subregion also result in supply side volatility that is higher than the other subregions. The spring and winter months carry the greatest supply-side volatility. The large solar contribution results in the extended tail of the availability distribution due to solar resources typically generating at higher capacity factors. The NW-Central subregion is summer peaking and displays the greatest potential for demand volatility in the early summer through early fall months.

Northwest-Northeast (NW-NE)

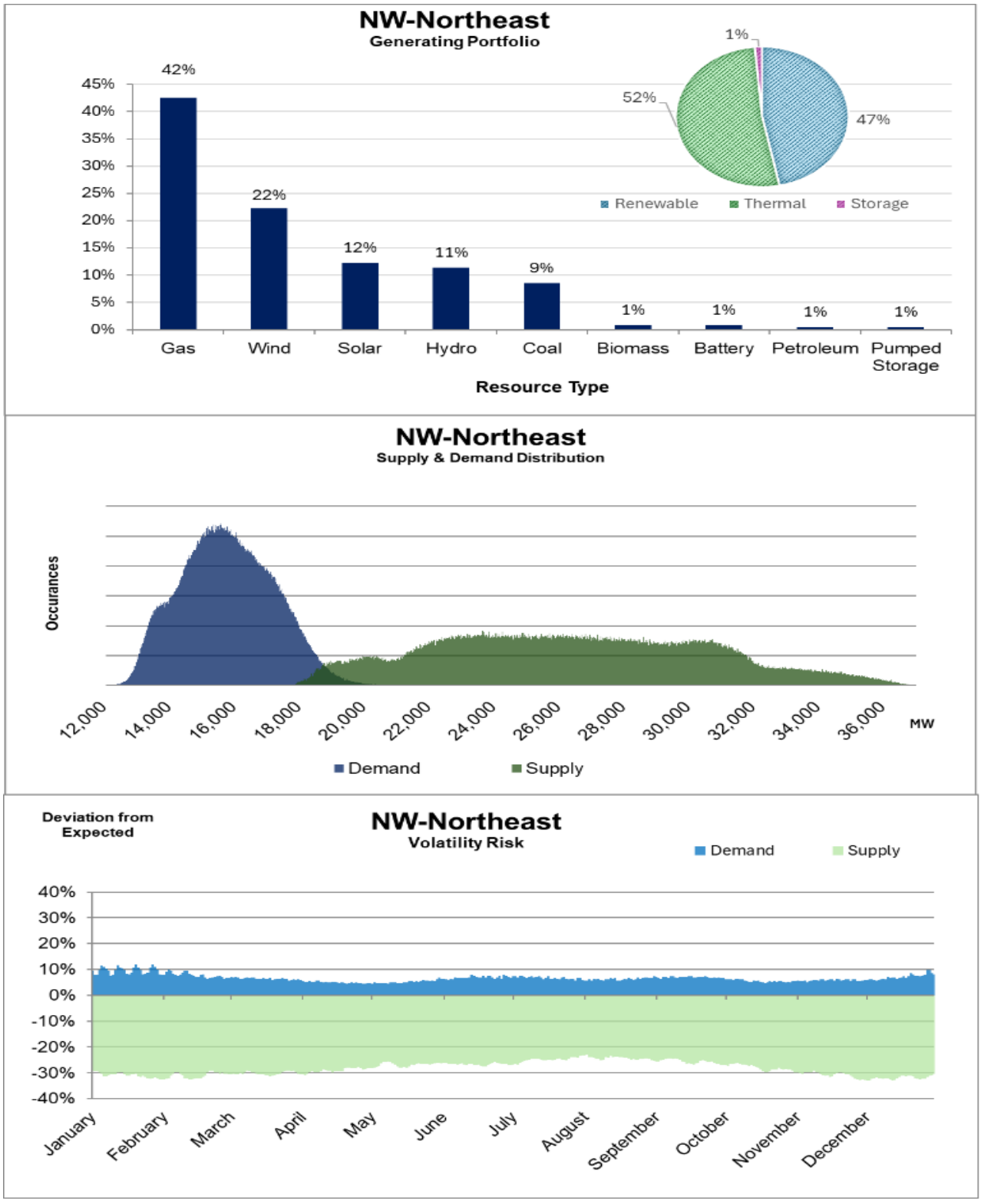
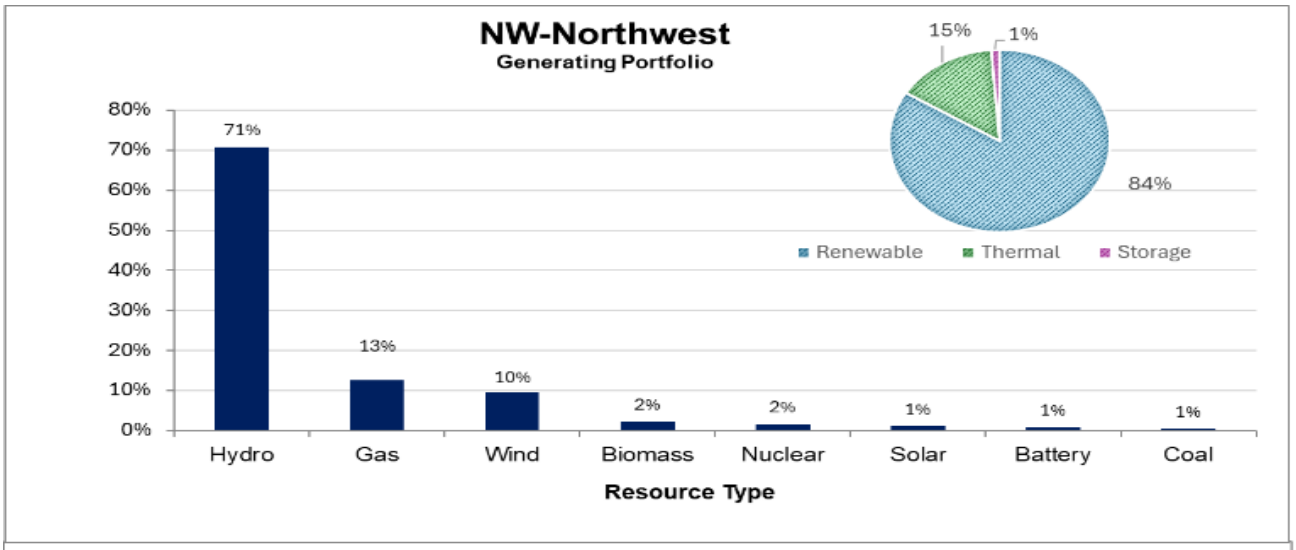
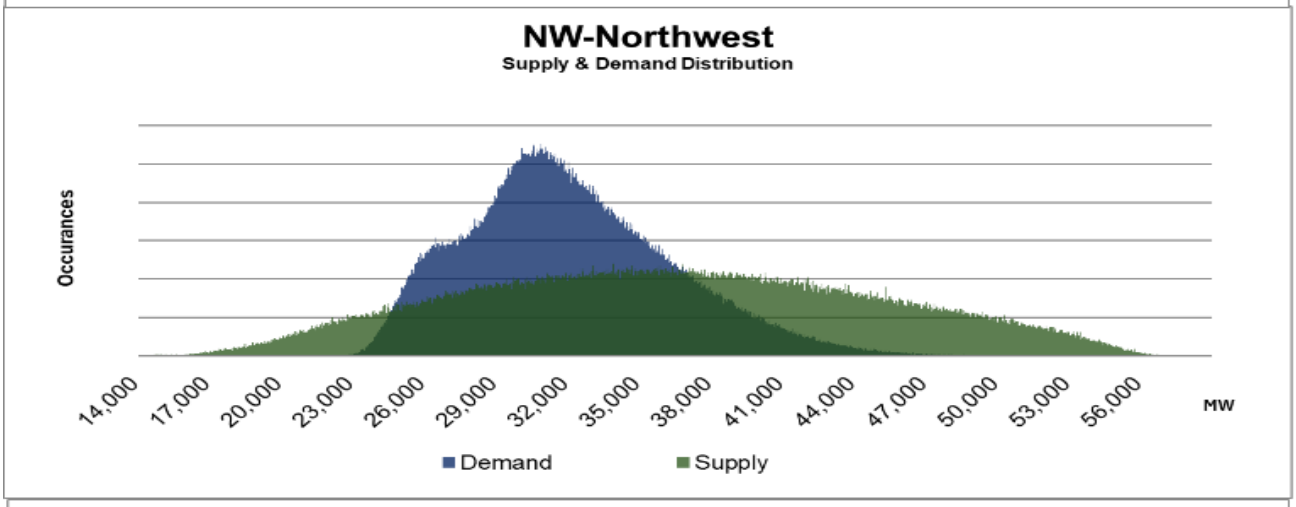


Figure 16: NW-Northeast resource portfolio and variability

The NW-NE is anticipated to have a substantial share of wind that will make up approximately 22% of its generating portfolio in 2028. This results in a wide availability curve due to the high variability of wind resource output. However, the NW-NE also is expected to have a large natural gas contribution, making up 42% of its generating portfolio. The significant share of natural gas in this subregion's portfolio helps shift the NW-NE availability curve away from the demand curve and reduces supply-side volatility in comparison to other regions in the Northwest. The NW-NE can be summer peaking or winter peaking, and generally does not experience extreme heat events to the same degree as the DSW or CAMX subregions. Demand-side volatility is greatest in the winter due to winter storm risk. The NW-NE displays the least demand-side volatility of all the subregions.

Northwest-Northwest (NW-NW)





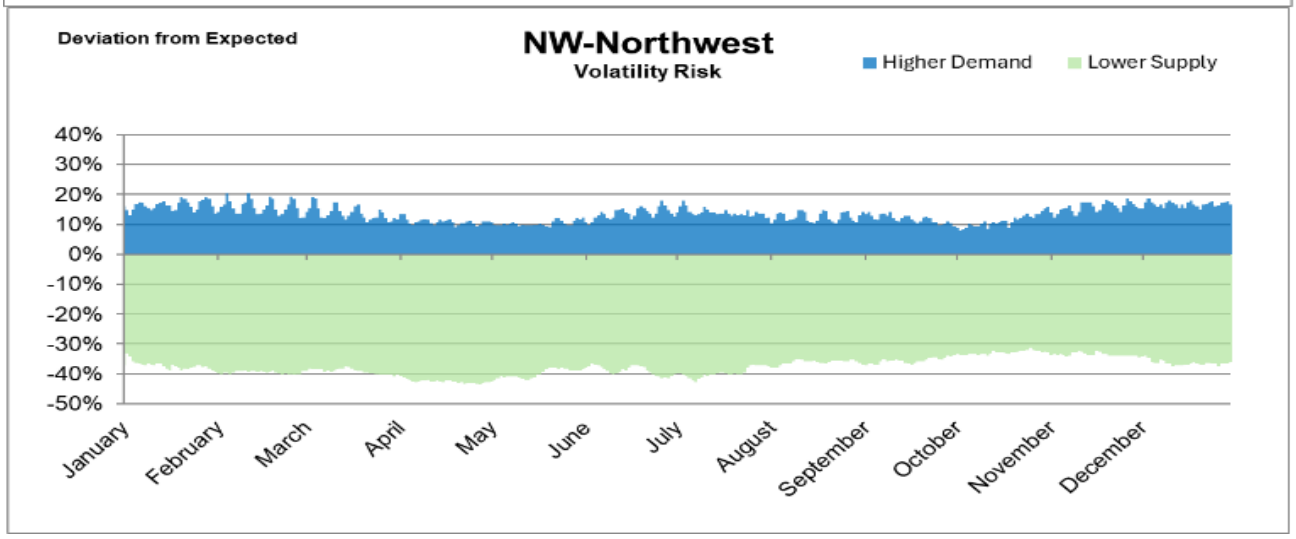


Figure 17: NW-Northwest resource portfolio and variability

The NW-NW portfolio is unique, with over 70% of its generating portfolio projected to be hydro resources in 2028, and over 84% of its portfolio being made up of VERs. The large share of hydro resources gives this subregion an extremely wide availability curve due to historic variability in output. In addition, 10% of the NW-NW generating portfolio is projected to be wind, which further widens the availability distribution. In 2028, the NW-NW subregion shows the greatest overlap of the demand and supply curves, indicating that the potential demand at risk is highest for this subregion. The NW-NW is a winter-peaking subregion, and correspondingly shows increased demand volatility during the winter months due to potential winter storms and cold weather events.

Appendix E: Demand Forecasts

The demand forecasts for each subregion are derived from WECC's Annual L&R Data Request. In this data request, each BA in the Western Interconnection provides demand forecasts, which are combined into subregions. The methodology and sources of demand for each BA's forecasts differ; however, frequently cited load types and factors that BAs account for are:

- Behind-the-meter solar adoption
- Calendar-driven events (i.e., holidays)
- Data centers
- Employment rates
- Historic peak demand
- Income of population
- Increasing efficiency of appliances
- Irrigation
- Local, state, and federal incentives and policies
- Population
- Residential building electrification
- Residential, commercial, and industrial electric sales
- Transportation electrification
- Weather and climate trends

Figures 18 and 19 show the annual and peak hour demand forecasts by subregion for this year's Western Assessment and the 2023 Western Assessment. All subregions are projected to experience growth in total annual demand and peak demand from 2025 through 2034. All times shown in Apprendix E are Pacific Prevailing Time.

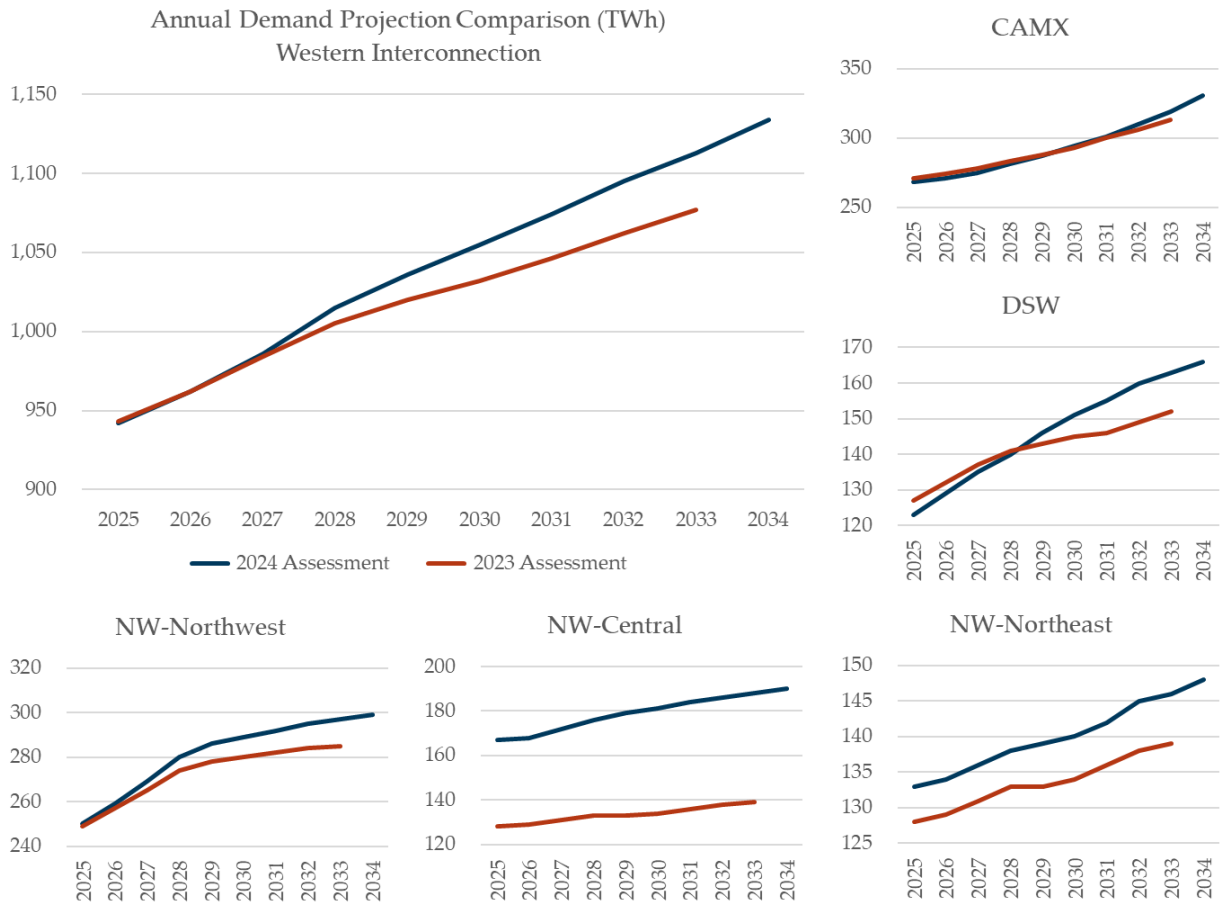


Figure 18: Annual demand forecasts in TWh for the Western Interconnection.

As denoted in the Load Growth section of the Western Assessment, the Western Interconnection is anticipated to grow in annual demand by 20.4% from 942 TWh to 1,134 TWh over the next decade. The greatest rate of growth is seen in the DSW subregion, which forecasts growth from 123 TWh in 2025 to 166 TWh in 2034, an increase of 35%. The majority of this growth has been cited as large industrial and commercial load additions such as data centers. The second-greatest forecast growth is seen in CAMX, which is projected to increase from 268 TWh of annual demand to 331 TWh of annual demand by 2034, a 23.5% increase. This is driven by transportation and building electrification. The NW-NW subregion is forecast to have an annual demand growth rate of 19.6%, increasing from 250 TWh in 2025 to 299 TWh in 2034. This demand is primarily expected to be added in the Pacific Northwest, and is largely correlated with data center additions. Electrification of transportation, buildings, and emerging industries such as hydrogen production account for demand growth in the Canadian portion of the NW-NW subregion. The NW-Central subregion shows annual demand growth of 13.8% from 167 TWh in 2025 to 190 TWh in 2034. Demand growth in this region is driven by data center additions and building and transportation electrification. The subregion showing the lowest growth rate over the next decade is the NW-NE, going from 133 TWh in 2025 to 148 TWh in 2034, an increase of 11.3%. Demand

growth in this region is attributed to industrial sources such as gas and oil processing and pulp and paper mill operations, as well as incoming data centers.

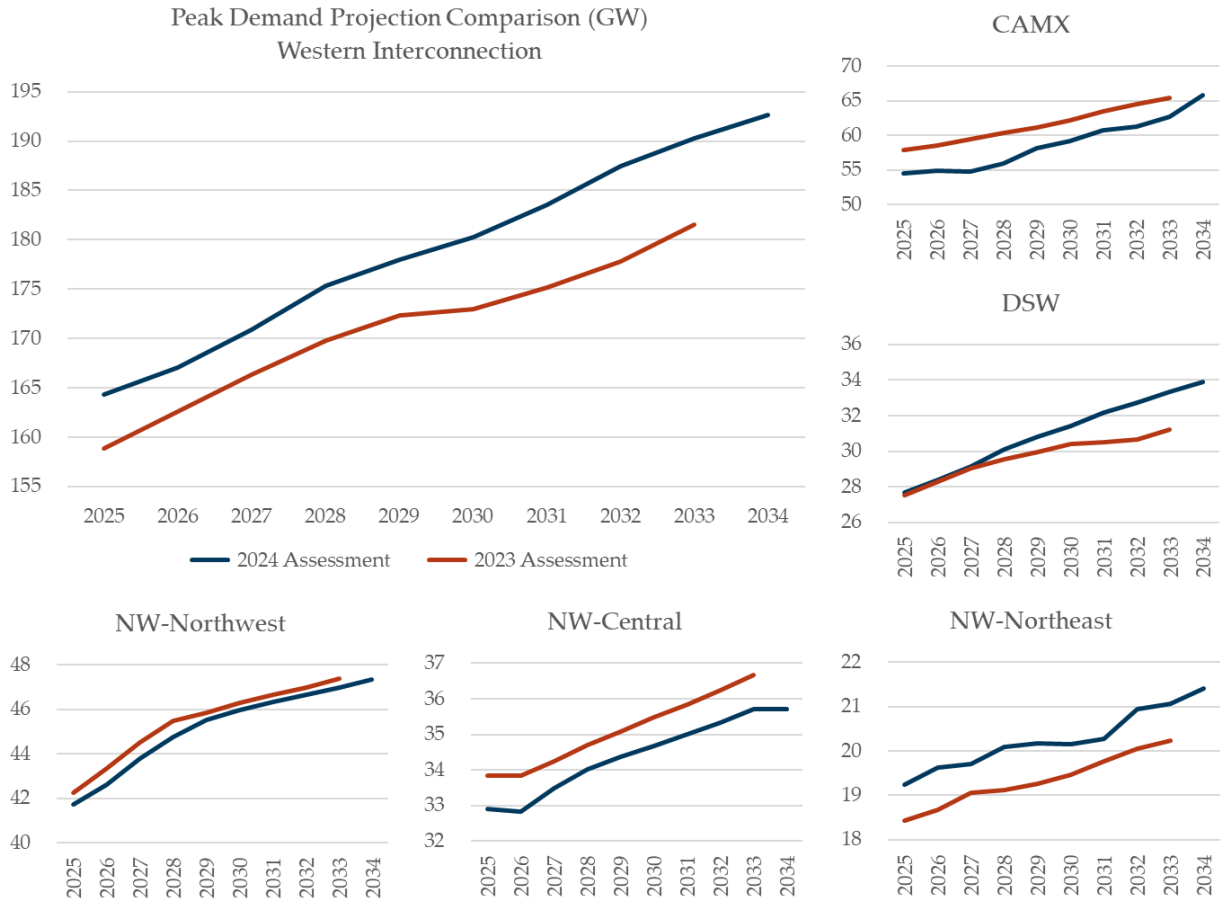


Figure 19: Peak hour demand forecasts in GW for the Western Interconnection.

Peak demand trends closely mimic those observed for annual demand. The DSW subregion leads peak demand growth with an increase of 22.5% over the next 10 years, from 28 GW to 34 GW. CAMX is projecting a peak demand increase of 20.7%, from 55 GW in 2025 to 66 GW in 2034. Both the DSW and CAMX subregions are summer peaking and show peak hours at the same time, hour ending 17:00. However, the month of peak occurrence is different between the two. The DSW peak hour is projected to occur in the mid to late July timeframe, whereas CAMX's peak hour is projected to occur in August or early September. The NW-NW peak hour projection in 2025 is 42 GW and is forecast to increase to 47 GW by 2034, a 13.5% increase. The NW-NW differs from the DSW and CAMX as it is a winter-peaking subregion, with the peak hour projected to occur at hour ending 9:00 in January. The NW-NE shows the second-lowest increase in peak demand growth at 11.3%, forecasting 19 GW as the peak in 2025 and 21 GW in 2034. The NW-NE subregion is dual peaking, meaning a peak hour may occur in either the summer or winter. Summer peak hours are projected to occur in July at hour ending 15:00 or 16:00, and winter peak hours are anticipated to occur in January at hour ending 9:00. The NW-Central shows the

smallest percentage increase in peak demand growth, 8.5%, with a projection of 33 GW in 2025 and 36 GW in 2034. This subregion is summer peaking, and is forecast to have peak demand hours in July at hour ending 17:00. From a Western Interconnection perspective, the peak demand is anticipated to grow by 17.2% over the next decade, from 164 GW to 193 GW. The coincident forecast peak for the interconnection is anticipated to occur in August at hour ending 17:00.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-86:
WECC Reliability Assessment Webpage

LOGIN

Reliability Assessments

WECC's work identifies potential reliability risks to the Bulk Power System stemming from changes in loads and resources over the next 10 years. Through initiatives like the Western Assessment of Resource Adequacy, WECC provides analysis and information on resource adequacy to stakeholders and decision makers. WECC's work supports resource adequacy work at an ERO level by providing information on the West to assessments such as NERC's Long-Term Reliability Assessment (LTRA), Summer Assessment, Winter Assessment, and Probabilistic Assessment.

Request Outreach Event

- Western Assessment
- Western Assessment Comment Form
- Resources
- NERC Assessments
- WECC Studies
- Archive

Reliability Assessments

- Interregional Transfer Capability Study

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-87:
TransAlta Form EIA-860

2024 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

Utility ID	Utility Name	Plant Code	Plant Name	State	County	Generator ID	Technology	Prime Mover	Unit Code	Ownership	Duct Burners	Can Bypass Heat Recovery Steam Generator?
19099	TransAlta Centralia Gen LLC	3845	Transalta Centralia Generation	WA	Lewis	2	Conventional Steam Coal	ST		S	X	X

RTO/ISO LMP Node Designation	RTO/ISO Location Designation for Reporting Wholesale Sales Data to FERC	Nameplate Capacity (MW)	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Minimum Load (MW)	Uprate or Derate Completed During Year	Month Uprate or Derate Completed	Year Uprate or Derate Completed	Status	Synchronized to Transmission Grid	Operating Month
		729.9	0.940	670.0	670.0	250.0	N			OP	X	7

Operating Year	Planned Retirement Month	Planned Retirement Year	Associated with Combined Heat and Power System	Sector Name	Sector	Topping or Bottoming	Energy Source 1	Energy Source 2	Energy Source 3	Energy Source 4	Energy Source 5	Energy Source 6
1973	12	2025	N	IPP Non-CHP	2	X	SUB					

Startup Source 1	Startup Source 2	Startup Source 3	Startup Source 4	Solid Fuel Gasification System?	Carbon Capture Technology?	Turbines or Hydrokinetic Buoys	Time from Cold Shutdown to Full Load	Fluidized Bed Technology?	Pulverized Coal Technology?	Stoker Technology?	Other Combustion Technology?	Subcritical Technology?
DFO				N	N		OVER		Y			Y

Supercritical Technology?	Ultrasupercritical Technology?	Planned Net Summer Capacity Uprate (MW)	Planned Net Winter Capacity Uprate (MW)	Planned Uprate Month	Planned Uprate Year	Planned Net Summer Capacity Derate (MW)	Planned Net Winter Capacity Derate (MW)	Planned Derate Month	Planned Derate Year	Planned New Prime Mover	Planned Energy Source 1	Planned New Nameplate Capacity (MW)

Planned Repower Month	Planned Repower Year	Other Planned Modifications?	Other Modifications Month	Other Modifications Year	Multiple Fuels?	Cofire Fuels?	Switch Between Oil and Natural Gas?
					N	N	N

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-88:
Wash. Commerce Util. Res. Planning Report (Compiled 2022 & 2024)

Washington State Electric Utility Resource Planning

Washington State Department of Commerce

2022 Report

ENERGY

April 2024

Report to the Legislature

Director Mike Fong

v3.4

Acknowledgments

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Executive summary

Chapter 19.280 RCW requires electric utilities develop resource plans to assess their specific future load and resource requirements. The Department of Commerce is tasked with collecting and analyzing the utility resource plans and creating a summary report for the Legislature.[1]

The 2022 Utility Resource Plan Report summarizes the findings of Washington state load and resource information for a 10-year planning cycle – with most utilities using 2021 as the base year.[2] Key findings of the 2022 Utility Resource Plan report are:

- Utilities plan to reduce their use of coal-fired electricity generation serving Washington retail customers and net use of short-term contracts in the forecast periods, and to increase their use of natural gas-fired generation, wind power, other renewables, and Bonneville Power Administration resources. Hydropower will remain the dominant source of electric for Washington utilities over the 10-year forecast period.

- There was no significant variation in the electricity needed to serve the state from 2008 through 2022. Statewide aggregate load growth forecasts by utilities for the next five and 10 years has trended down with each successive Commerce Utility Resource Plan report.

- The statewide aggregate load growth in electricity demand for 2026 and 2031 is expected to be moderate, and most of this growth will be offset through energy conservation programs operated by utilities. With the majority of load growth met by energy conservation programs, new renewable resources primarily serve to replace retiring coal-fired generation and thermal natural gas generation. However, several utilities (Chelan, Douglas and Grant PUDs) are forecasting high load growth rates over the next 10 years due to growth in data centers, computing demand, and cryptocurrency mining.

Most utilities plan to meet load requirements in the lowest-cost, least-risk way by renewing Bonneville Power Administration contracts (for slice or block products or shifting to a load following product), maximizing energy conservation measures, and implementing new demand response measures. While several consumer-owned utilities plan to remove natural gas from their resource portfolios in their five-year forecast, all the investor-owned utilities plan to maintain relatively steady amounts of natural gas in their resource portfolio.

Regional resource planning studies have found the Northwest has adequate resources to meet current demand for electricity and does not face significant risk of outages in the short term, but there needs to be a concerted effort to bolster the electric grid to serve the dual objectives of reducing fossil-fired generation and increasing electric loads for transportation, buildings, and industry.

The Clean Energy Transformation Act (CETA), Washington's 100% clean electricity law, includes requirements for utilities to establish specific standards for resource adequacy and incorporate those standards into their planning and compliance. As utilities reduce reliance on coal-fired and gas-fired power plants and add variable renewable energy such as wind and solar, new approaches and resources will be required to maintain resource

[1] Section 19.280.060, Department's duties—Report to the legislature. (2022, June 29). Retrieved from Revised Code of Washington: https://app.leg.wa.gov/RCW/default.aspx?cite=19.280.060. This report was completed prior to the close of the 2024 legislative session. Any amendments to this statute will be taken into consideration in future reports.

[2] Completed reporting of utility plans under Washington's 100% clean electricity law (RCW 19.405) and proposed legislation to amend this report led Commerce to delay the release of the 2022 report.

adequacy to ensure reliable service to customers. It is equally important to incorporate risks associated with fossil generating resources, including fuel supply risk and weather-driven forced outage risks.

While resource adequacy is an obligation of each electric utility serving end use customers in the state, it also is a shared responsibility of the overall electric power system and the entities that operate, plan, regulate, design, and fund the generation, transmission, and delivery of that system.

At the state level, Commerce and the Utilities and Transportation Commission hold an annual resource adequacy meeting in accordance with RCW 19.280.065.[3] A summary of that meeting is available on Commerce's Resource Adequacy webpage.

Legislative mandate

This report is required biennially per RCW 19.280.060, which states:

> The department shall review the plans of consumer-owned utilities and investor-owned utilities, and data available from other state, regional, and national sources, and prepare an electronic report to the legislature aggregating the data and assessing the overall adequacy of Washington's electricity supply. The report shall include a statewide summary of utility load forecasts, load/resource balance, and utility plans for the development of thermal generation, renewable resources, conservation and efficiency resources, and an examination of assessment methods used by utilities to address overgeneration events. The commission shall provide the department with data summarizing the plans of investor-owned utilities for use in the department's statewide summary. The department shall submit any reports it receives of existing and potential combined heat and power facilities as reported by utilities to the Washington State University extension energy program for analysis. The department may submit its report within the biennial report required under RCW 43.21F.045.

[3] Section 19.280.065, Department and commission meeting—Summary to the governor and legislature. (2022, June 29). Retrieved from Revised Code of Washington: https://app.leg.wa.gov/RCW/default.aspx?cite=19.280.065

Introduction

Background

Washington consumers and businesses depend on electricity service from more than 60 electric utilities operating in this state. These utilities vary greatly in size, geographic scope, history and governance, but each is responsible for ensuring an adequate supply of an essential resource.

Washington law requires each utility plan for the future by examining the projected amounts of electricity that will be required by customers in the coming decade and identifying the power resources that will be used to meet those demands.[4] Each utility must prepare a report every two years and submit it to Commerce. Commerce reviews the utility reports and submits a summary to the Legislature. This is the eighth report since the Legislature enacted the resource planning law in 2006.

Depending on their size and power sources, utilities submit either a resource plan (RP) or an integrated resource plan (IRP). The RP is a short-form report of load[5] and resources and may be submitted only if the utility has fewer than 25,000 customers and is a full requirements customer"[6] of Bonneville Power Administration. The IRP is a more detailed plan and must incorporate a number of specific requirements identified in statute.

Purpose

Utilities develop resource plans to assess their future load and resource situations. This report aggregates the individual reports to provide an assessment at the statewide level of whether utilities are planning for adequate supplies, and what resources are expected to meet any growth in electric power demand.

This report summarizes the electricity loads and resources reported by Washington utilities in their 2022 reports to Commerce. It compares them to estimated summaries of previous years. Resources proposed to meet load are categorized by generating fuel type and source type (such as contract or market). An imbalance of loads and resources may indicate either a resource surplus or deficit.

The information collected for this report is limited to the identification of loads and resources and their associated aggregate quantities. It does not attempt to evaluate specific goals or outcomes for resource acquisition strategies used by utilities.

This report provides information on utilities' energy efficiency and renewable energy resources. It does not analyze issues related to the energy efficiency and renewable energy requirement of, or compliance with, the Energy Independence Act (Chapter 19.285 RCW) or the Clean Energy Transformation Act (Chapter 19.405 RCW).

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[4] Chapter 19.280, Electric Utility Resource Plans. (2022, June 29). Retrieved from Revised Code of Washington: https://app.leg.wa.gov/RCW/default.aspx?cite=19.280

[5] As used in the statute and this report, "load" means the amount of electric energy demanded by a utility's customers during a defined period.

[6] "Full requirements customer" as defined in Section 19.280.020(7) means an electric utility that relies on the Bonneville Power Administration for all power needed to supply its total load requirement other than that served by nondispatchable generating resources totaling no more than six megawatts or renewable resources.

Utility reporting

The utility resource planning statutes (Chapter 19.280 RCW) require that each utility prepare a resource plan (RP) and submit it to Commerce by Sept. 1 of each even-numbered year. Commerce received reports from 63 utilities. The individual reports are presented in Appendix A.

Electric utilities in Washington vary significantly in size and the scope of operations. This is reflected in the way utilities approach resource planning and forecasting. Larger utilities typically use multiple sources of electricity supply to meet their customers' requirements and engage in sophisticated assessments of risks and benefits in evaluating alternative sources of new energy. Many smaller utilities rely on the Bonneville Power Administration, which undertakes the complex planning and forecasting exercise that leads to a resource plan.

The resource planning statute reflects this difference in approaches. It requires that larger utilities prepare and submit IRPs, which are the product of a thorough assessment of future needs and alternatives for meeting those needs through both demand-side and supply-side resources. Smaller utilities are allowed to prepare and submit a simplified assessment of loads and resources.

Interpretation of base year, five-year and 10-year data

The resource plan summary submitted to Commerce includes load and resource information for three points in a 10-year planning cycle. These points are the base year, five-year and 10-year plans. In 2022, most utilities used 2021 as the base year, and the five-year and 10-year points are 2026 and 2031, respectively. However, utilities vary in their planning cycles, and some utilities use an earlier or later set of years in their reporting; the base year ranges from 2020 to 2022. For purposes of the statewide summary, Commerce aggregates all base-year data into a single value (2021) and does likewise for the five-year (2026) data and 10-year data (2031).

Interpretation of conservation and load data

An important principle of integrated resource planning is that all resources should be evaluated on a consistent basis. This includes different generating resources, such as wind and natural gas, as well as energy conservation measures and demand response resources. With energy conservation measures and demand response being analyzed and compared to supply-side options, utilities are able to determine whether customers are better served by increasing energy efficiency, demand reduction, or energy supply. Consequently, energy conservation measures are sometimes portrayed as a reduction in the utility's load and sometimes portrayed as resources available to meet load. This can lead to confusion in interpreting utility plans.

Here is how this potential confusion is resolved:

> Utilities report a base year load amount that reflects whatever conservation has occurred in the past. For the five-year and 10-year values, utilities are directed to report the load that they would expect to serve in the absence of any additional conservation savings. The report separately lists the conservation resources that the utility expects to acquire during the five-year and 10-year periods.
>
> For example, Avista reports that its load in 2022 (base year) was 680 average megawatts (aMW).[7] This figure represents the actual load of its customers in the base year. It reflects many years of conservation programs at Avista and would be significantly higher without those historical conservation achievements. For the five-year interval (2027), Avista forecasts a load of 692 aMW and conservation savings of 33 aMW.

[7] aMW, or average megawatt, is an amount of electric energy equal to one megawatt-hour per hour for an entire year, or 8,760 megawatt-hours.

The first number represents the load that Avista would expect if it achieved no conservation savings after the base year. Without additional conservation, its load would increase by 12 aMW, but with future conservation the forecast load with conservation decreases by 21 aMW for an adjusted total load of 659 aMW at the end of the five-year interval.

In summary, the amounts reported as load for the five-year and 10-year intervals are based on an assumption of no new conservation. The actual loads at these future time points are likely to be lower by the amount of energy conservation identified by each utility.

Results

The 2022 resource plans submitted to Commerce are summarized in Table 1-5 and Figures 1 and 3.

Table 1 presents utility report information in units of average-Megawatts (aMW) on statewide annual utility load and resources, including imports and exports, for the base year (2021), and the five and 10-year forecasts. The right two columns in the table illustrate the difference between the base year and the five and 10-year forecasts.

Table 1 also presents the composition of electric generation resources for the base year, and the five and 10-year forecasts.

Figure 1 presents the composition of electric generation resources for the five-year and 10-year forecasts.

Table 1 and Figure 1 show that utilities plan to continue relying mostly on Bonneville Power Administration (BPA), hydroelectric generation and thermal natural gas plants to meet electricity demand. The BPA resource is a blended resource and is typically 85% hydropower, 11% nuclear, and 4% unspecified market purchases. Figure 1 reveals that hydropower will remain the largest source of electricity for Washington utilities. While several consumer-owned utilities plan to remove natural gas from their resource portfolios in their five-year forecast, all the investor-owned utilities plan to maintain relatively steady amounts of natural gas in their resource portfolio.

Table 1: Washington's Projected Requirements and Resources - Annual Energy aMW

	Base Year	5-year forecast	10-year forecast	5-year change	10-year change
Requirements					
Loads	10,202	10,818	11,363	616	1,161
Exports	226	217	190	(9)	(36)
Energy Conservation Measures	-	(405)	(816)	(405)	(816)
Demand Response	0	(23)	(33)	(23)	(33)
Total Net Requirements	**10,428**	**10,607**	**10,704**	**179**	**276**
Resources					
Total BPA	4,360	4,492	4,669	132	309
Hydro	2,681	3,316	3,553	635	872

	Base Year	5-year forecast	10-year forecast	5-year change	10-year change
Thermal Natural Gas	2,692	2,563	2,433	(129)	(259)
Wind	638	1,070	1,026	432	388
Other Renewables	142	342	538	200	395
Net Short-Term Contracts	214	78	114	(136)	(100)
Net Long-Term Contracts	1,080	197	103	(883)	(977)
Other	37	44	77	7	40
Thermal Coal	726	156	67	(570)	(658)
Imports	89	56	51	(33)	(38)
Distributed Generation	5	11	18	6	13
Cogeneration	15	15	15	0	0
Undecided	-	1	13	1	13
Market Purchase	2			(2)	(2)
Total Resources	**12,680**	**12,341**	**12,676**	**(339)**	**(4)**
Load Resource Balance	**2,252**	**1,735**	**1,972**	**(517)**	**(280)**

Of note is that coal resources listed after 2025 are entirely attributable to PacifiCorp's integrated resource plan. PacifiCorp pro-rated its total system resources to Washington based on the ratio of Washington's energy usage to PacifiCorp's total system energy usage. In the company's April 13, 2023, submission, Washington is seeing a share of coal resources because PacifiCorp does not have a Washington-specific load and resource balance and therefore all resources (regardless of type) were pro-rated. This methodology notwithstanding, Washington will no longer receive either the costs or benefits from PacifiCorp's coal resources after 2025, in accordance with Washington Clean Energy Transformation Act (CETA) requirements and Washington Utilities and Transportation Commission (WUTC) orders.

Figure 1: Forecast Available Resources

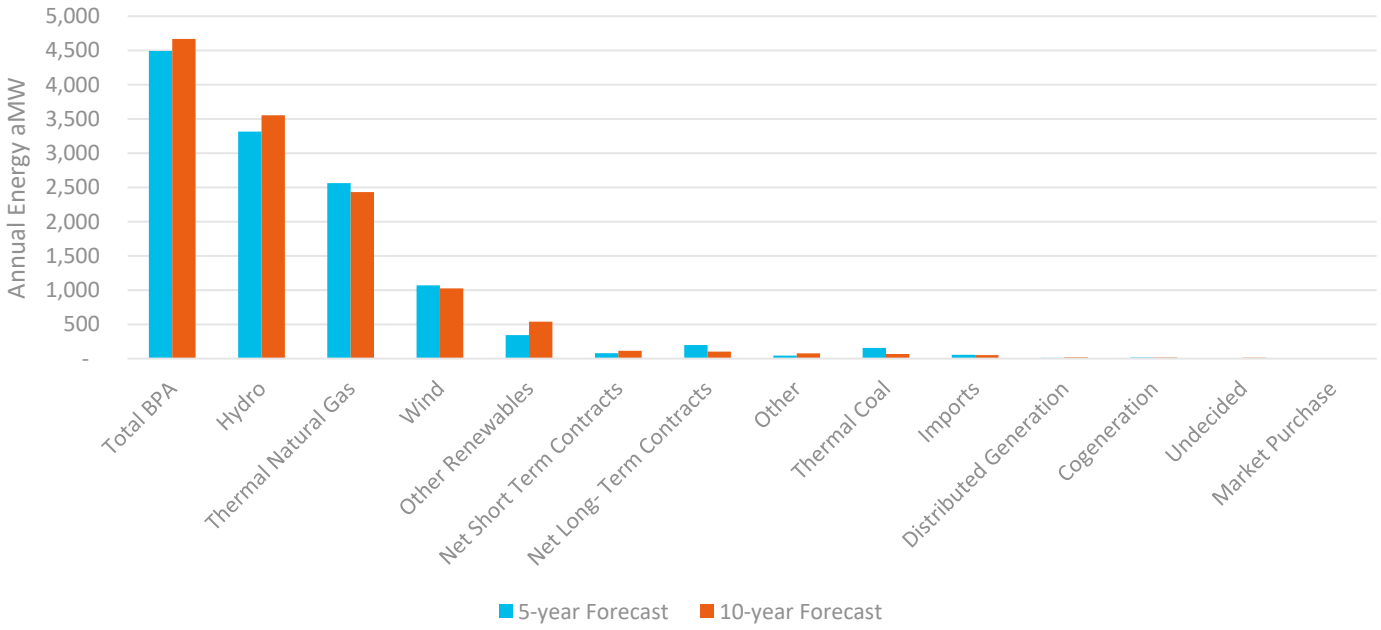


Table 2 presents in average-megawatts the differences between the 2022 and 2020 resource reports on statewide annual utility load and resources and the five and 10-year forecasts.

Table 2 shows a diminished contribution from coal-fired electricity generation in the forecast period, and an increased reliance on natural gas-fired generation, wind power, other renewables, and BPA resources.

The shift in electric generation resources shows progress towards meeting the requirements of the Clean Energy Transformation Act (CETA). CETA prohibits utilities from using coal generation after 2025.[8] It requires all retail sales of electricity to Washington be greenhouse gas neutral by 2030[9] and 100% non-emitting by 2045.[10]

Table 2: Difference between 2022 and 2020 Requirements and Resources - Annual Energy aMW

	Base Year	5-year Forecast	10-year Forecast
Requirements			
Loads	(105)	43	(9)
Exports	(107)	(40)	(1)
Energy Conservation Measures	-	88	(2)
Demand Response	-	(13)	(23)
Total Net Requirements	**(213)**	**78**	**(35)**
Resources			
Total BPA	(57)	212	265
Hydro	(379)	127	193
Thermal Natural Gas	606	675	690
Wind	119	395	448
Other Renewables	61	188	257
Net Short-Term Contracts	(32)	(243)	(221)
Net Long-Term Contracts	553	(302)	8
Other	42	49	71
Thermal Coal	(252)	(527)	(402)
Imports	(76)	2	(6)
Distributed Generation	2	4	5
Cogeneration	2	(0)	11
Undecided	-	(10)	(14)

[8] Section 19.405.030(1), Coal-fired resources-Depreciation schedule-Penalties. (2022, June 29). Retrieved from Revised Code of Washington: https://app.leg.wa.gov/RCW/default.aspx?cite=19.405.030
[9] Section 19.405.040(1), Greenhouse gas neutrality-Responsibilities for electric utilities-Energy transformation project criteria-Penalties. (2022, June 29). Retrieved from Revised Code of Washington: https://app.leg.wa.gov/RCW/default.aspx?cite=19.405.040
[10] Section 19.405.050(1), Clean energy implementation-Hydroelectric facilities-Special contracts. (2022, June 29). Retrieved from Revised Code of Washington: https://app.leg.wa.gov/RCW/default.aspx?cite=19.405.050

	Base Year	5-year Forecast	10-year Forecast
Market Purchase	(10)	(34)	(43)
Total Resources	**580**	**535**	**1,262**
Load Resource Balance	**792**	**459**	**1,297**

Most Washington utilities experience their annual peak load during the winter months. Table 3 presents utilities' aggregated report information for their highest estimated one-hour load during the winter season,[11] including imports and exports, for the base year (2021), and the five and 10-year forecasts. Because electricity demand tends to be higher during the winter season compared to other seasons, utilities rely more extensively on dispatchable thermal resources and short-term contracts to meet load during the winter season. Demand response is also an important resource during the winter, as this reduces the need for utilities to operate gas turbines or make market purchases during periods of very high demand. Utilities forecast reduced use of long-term contracts, coal, and BPA resources to meet summer peak and winter peak requirements in the five-year and 10-year forecasts.

Table 3: Washington Projected Requirements and Resources - Winter Capacity MW

	Base Year	5-year forecast	10-year forecast	5-year change	10-year change
Requirements					
Loads	12,721	13,623	14,640	902	1,919
Exports	263	188	162	(75)	(102)
Energy Conservation Measures		(524)	(1,006)	(524)	(1,006)
Demand Response		(202)	(387)	(202)	(387)
Total Net Requirements	**12,985**	**13,086**	**13,409**	**102**	**425**
Resources					
Hydro	3,225	4,595	5,146	1,370	1,920
Total BPA	3,762	3,506	3,650	(256)	(112)
Wind	233	310	323	77	90
Other Renewables	68	130	179	61	111
Thermal Natural Gas	3,175	2,849	3,258	(326)	83
Cogeneration	15	16	16	0	0
Thermal Coal	935	342	263	(593)	(672)
Other	20	112	244	92	224
Undecided	-	-	-	-	-
Imports	309	323	305	13	(5)
Distributed Generation	1	2	3	1	2
Net Short-Term Contracts	1,836	1,816	1,892	(20)	56

[11] Table 1 expressed in energy units of aMW, Table 3 in capacity units of MW.

	Base Year	5-year forecast	10-year forecast	5-year change	10-year change
Net Long-Term Contracts	1,396	114	70	(1,282)	(1,326)
Market Purchase				-	-
Total Resources	**14,976**	**14,114**	**15,349**	**(862)**	**372**
Load Resource Balance	**1,991**	**1,028**	**1,939**	**(964)**	**(52)**

Table 4 presents a time series of Commerce Utility Resource Plans. The information in the table presents aggregated annual utility loads (base year, five-year and 10-year) for the 2008 through 2022 Commerce reports. The forecast loads do not include the energy conservation measure (ECM) forecast by utilities. Figure 2 presents the information in Table 4 in a graphical format. Table 5 and Figure 3 present the aggregated annual utility loads (base-year, five-year and 10-year) and include energy conservation measures and demand response forecasts by utilities.

Table 4 and Table 5 and Figure 2 and Figure 3 show load growth forecasts by utilities for the five and 10-year out points have been trending down with each successive report. By comparing Figure 2 and Figure 3 it is evident that utility conservation programs significantly reduce aggregate load growth.

Table 4: Utility Report Time Series — Base Year and Forecast Loads Without Energy Conservation Measures

Utility Report Year	Base Year	Base Year, aMW	5-year Est.	5-year Est. aMW	10-year Est.	10-year Est. aMW
2008	2007	10,008	2012	11,304	2017	12,270
2010	2009	10,606	2014	11,737	2019	12,717
2012	2011	10,265	2016	11,264	2021	12,126
2014	2013	10,166	2018	11,502	2023	12,380
2016	2015	10,099	2020	10,875	2025	11,576
2018	2017	10,231	2022	10,816	2027	11,356
2020	2019	10,307	2024	10,775	2029	11,372
2022	2021	10,202	2026	10,818	2031	11,363

Figure 2: Utility Report Time Series — Base Year and Forecast Loads Without Energy Conservation Measures

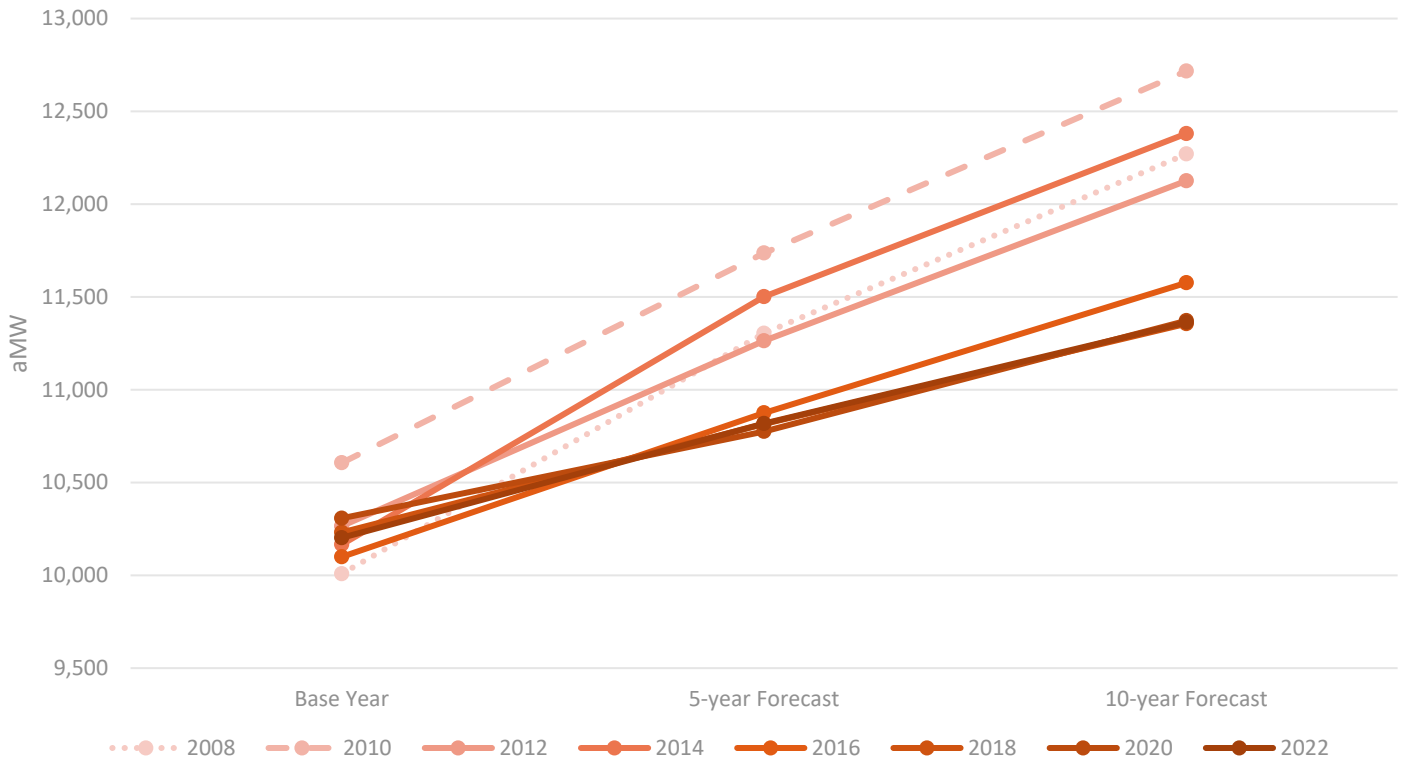


Table 5: Utility Report Time Series — Base Year and Forecast Loads with ECM and Demand Response

Utility Report Year	Base Year	Base Year, aMW	5-year Est.	5-year Est. aMW	10-year Est.	10-year Est. aMW
2008	2007	10,008	2012	10,890	2017	11,524
2010	2009	10,555	2014	11,145	2019	11,691
2012	2011	10,265	2016	10,692	2021	11,107
2014	2013	10,166	2018	11,017	2023	11,423
2016	2015	10,099	2020	10,347	2025	10,629
2018	2017	10,231	2022	10,345	2027	10,582
2020	2019	10,307	2024	10,272	2029	10,548
2022	2021	10,202	2026	10,389	2031	10,514

Figure 3: Utility Report Time Series — Base Year and Forecast Loads with ECM and Demand Response

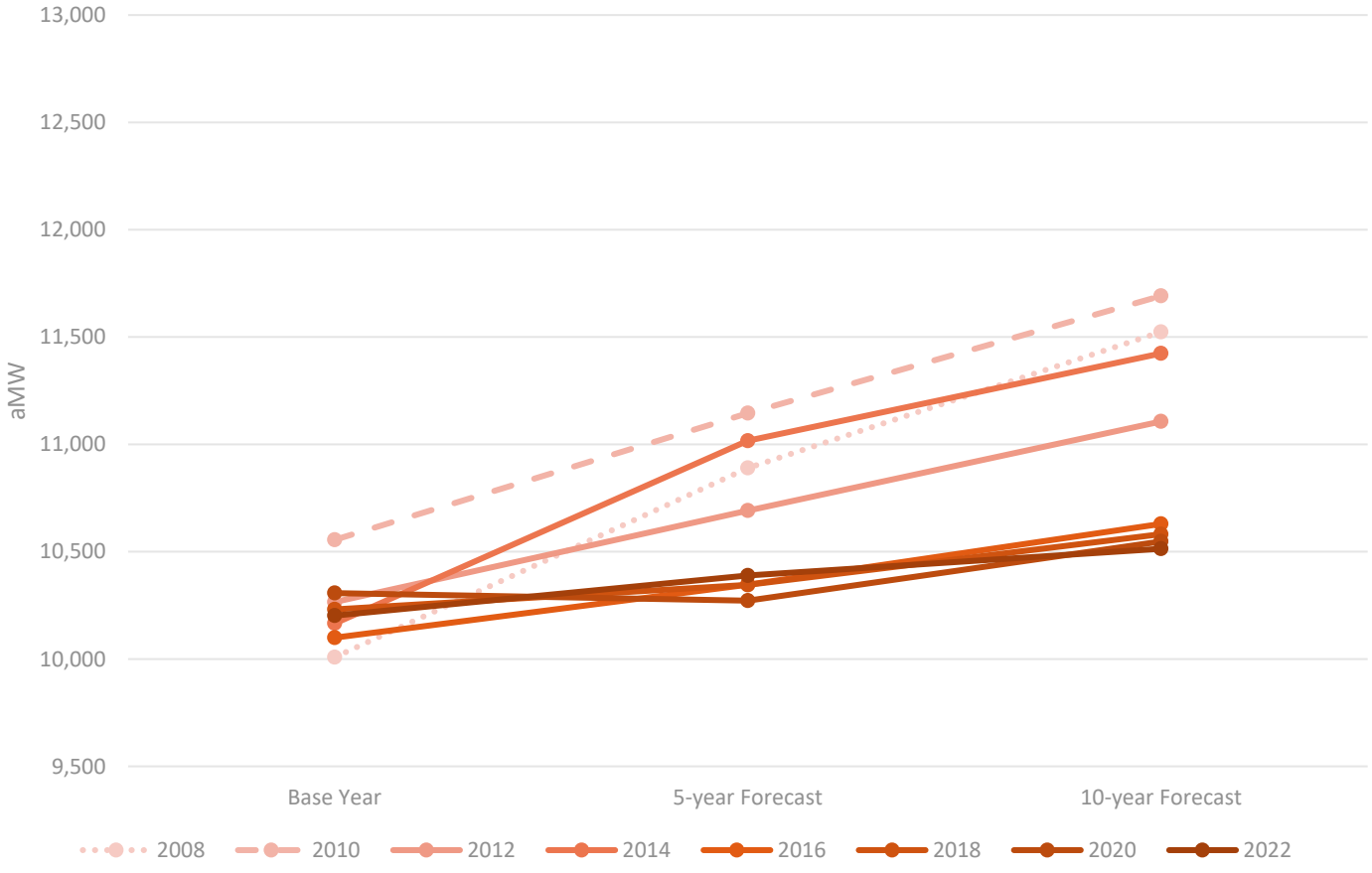


Table 6 presents the individual utility growth forecasts and the percent of load growth anticipated to be met by energy conservation measures. For example, Benton County PUD No 1 estimates a load growth of 14.2 aMW or 6.52% by 2031. Benton County PUD No 1 estimates 11.72 aMW of energy conservation measures by 2031, and 82.52% of that load growth will be met by energy conservation measures (11.72 aMW/14.2 aMW=82.52%). Several utilities (Chelan, Douglas, and Grant PUDs) are forecasting very high load growth rates over the next 10 years due to the growth of data centers, computing demand, and cryptocurrency mining. Chelan County PUD forecasts the average base case annual growth rate for High Density Loads, Cryptocurrency Loads, and Large Loads combined to be 31.88% for their 2023-2032 planning period. In comparison, Chelan County PUD expects its base case residential average annual growth rate to be 1.44% and its base case commercial sector average annual growth rate to be 1.97% during the same planning period.[12] As a result of data center proliferation and the growth of computing demand, especially artificial intelligence, Douglas PUD will experience significant increases in new data loads in the next several years as well. By 2029, new data load will increase from 22% of 2024 load to 58% of 2029 energy load.[13] For Grant County PUD, over the past the decade, industrial class load growth has made up an ever-increasing portion of their total retail load, and data centers have grown to dominate load growth in that sector.[14]

Table 6: Individual Utility Load Forecasts With and Without Conservation

Utility Name	Load Growth with No Conservation		% of Load Growth Met by Conservation	
	5-year Change %	10-year Change %	5-year Conservation	10-year Conservation
Alder Mutual Light Co, Inc	-2.91%	-2.91%	-5.12%	-5.12%
Asotin County PUD No 1	-0.22%	2.27%	0.00%	0.00%
Avista Corp	1.76%	2.65%	275.00%	372.22%
Benton County PUD No 1	2.21%	6.52%	108.46%	82.52%
Benton Rural Electric Assn	-9.18%	-8.28%	-9.40%	-10.43%
Big Bend Electric Coop, Inc	-4.62%	-2.39%	-10.24%	-19.81%
Blaine City Public Works	0.49%	1.14%	#N/A	#N/A
Centralia City Light	2.64%	2.65%	#N/A	#N/A
Chelan County PUD No 1	16.38%	22.25%	16.69%	31.12%
Chewelah Electric Dept	2.94%	2.96%	8.33%	8.29%
City of Cheney Light Dept	15.93%	22.63%	#N/A	#N/A
City of Coulee Dam Light Dept	4.84%	7.27%	14.76%	9.82%
City of McCleary Public Utility	3.85%	7.20%	2.11%	1.13%
City of Milton Electric Division	-0.27%	-0.07%	-44.63%	-178.78%
City of Sumas Electric Services	4.77%	2.28%	2.34%	4.88%
Clallam County PUD No 1	0.31%	0.32%	257.00%	251.45%
Clark County PUD No 1	4.65%	18.40%	#N/A	#N/A
Columbia Rural Elec Assn, Inc	2.80%	5.78%	#N/A	#N/A

[12] Chelan County PUD. (2023, p. 15-16). Integrated Resource Plan Progress Report. Retrieved from https://www.chelanpud.org/docs/default-source/default-document-library/irp-2023-book.pdf
[13] Douglas PUD. (2024, p. 14, 21-23). Integrated Resource Plan. Retrieved from https://douglaspud.org/wp-content/uploads/2024/02/2024-Draft-IRP.pdf
[14] Grant County PUD. (2022, p.25). Integrated Resource Plan. Retrieved from https://www.grantpud.org/templates/galaxy/images/Exhibit_A_2022_Integrated_Resource_Plan.pdf

Utility Name	Load Growth with No Conservation		% of Load Growth Met by Conservation	
	5-year Change %	10-year Change %	5-year Conservation	10-year Conservation
Consolidated Irrigation District No 19	-29.94%	-29.94%	#N/A	#N/A
Cowlitz County PUD No 1	13.04%	20.26%	#N/A	#N/A
Douglas County PUD No 1	21.07%	36.99%	6.66%	8.53%
Eatonville Power & Light Dept	0.73%	1.39%	58.19%	30.61%
Ellensburg Energy Services Dept	1.20%	2.74%	3.49%	1.53%
Elmhurst Mutual Power & Light Co	1.65%	3.66%	33.86%	15.26%
Ferry County PUD No 1	-9.17%	-8.26%	-2.75%	-3.05%
Franklin County PUD No 1	29.74%	33.72%	#N/A	#N/A
Grant County PUD No 2	28.53%	44.52%	4.53%	6.47%
Grays Harbor County PUD No 1	-2.27%	-3.79%	-22.00%	-18.00%
Inland Power & Light Company	10.41%	21.90%	2.72%	2.93%
Jefferson County PUD No 1	2.49%	4.11%	23.00%	13.94%
Kalispel Tribal Utilities	20.05%	27.45%	0.00%	0.00%
Kittitas County PUD No 1	2.99%	8.03%	19.96%	7.43%
Klickitat County PUD No 1	4.77%	11.31%	#N/A	#N/A
Lakeview Light & Power	1.21%	2.23%	65.56%	35.63%
Lewis County PUD No 1	4.49%	7.69%	52.04%	96.94%
Mason County PUD No 1	-2.16%	-0.28%	-6.06%	-47.36%
Mason County PUD No 3	9.77%	16.92%	15.20%	24.96%
Modern Electric Water Company	0.74%	2.93%	157.74%	39.88%
Nespelem Valley Elec Coop, Inc	-0.07%	0.66%	-252.67%	27.55%
Ohop Mutual Light Company, Inc	-0.59%	-0.59%	-3.15%	-3.15%
Okanogan County Elec Coop, Inc	3.95%	16.38%	#N/A	#N/A
Okanogan County PUD No 1	1.05%	3.60%	0.00%	0.00%
Orcas Power & Light Coop	0.67%	4.08%	25.57%	4.18%
Pacific County PUD No 2	7.18%	10.22%	38.46%	24.32%
PacifiCorp	3.46%	9.07%	206.79%	139.63%
Parkland Light & Water Company	-0.09%	0.93%	-320.63%	29.33%
Pend Oreille County PUD No 1	3.75%	11.77%	#N/A	#N/A
Peninsula Light Company	-5.20%	-4.78%	-13.26%	-28.82%
Port Angeles City Light	-1.36%	-1.36%	-7.12%	-7.12%
Port of Seattle	6.66%	6.66%	15.93%	15.93%
Puget Sound Energy, Inc	5.88%	12.80%	144.90%	130.31%
Richland Energy Services	0.77%	1.77%	388.37%	504.04%
Seattle City Light	0.47%	2.99%	960.00%	265.63%
Skamania County PUD No 1	-4.08%	-2.15%	-0.88%	-1.68%
Snohomish County PUD No 1	1.87%	5.16%	183.80%	189.06%

Utility Name	Load Growth with No Conservation		% of Load Growth Met by Conservation	
	5-year Change %	10-year Change %	5-year Conservation	10-year Conservation
Steilacoom Public Works	-0.12%	2.30%	-10.97%	5.62%
Tacoma Power	1.51%	-3.70%	150.62%	-129.65%
Tanner Electric Coop	0.42%	3.19%	18.37%	2.44%
Town of Ruston Utility Dept	1.85%	-3.70%	#N/A	#N/A
Vera Irrigation District #15	-3.23%	-0.78%	-3.36%	-13.84%
Wahkiakum County PUD No 1	-1.96%	-0.50%	-1.89%	-7.46%
Whatcom County PUD No 1	14.43%	13.19%	0.00%	0.00%

The current round of utility resource plans indicates a continued reliance on energy conservation measures as the primary resource for balancing electricity supply and demand. The statewide aggregate growth in electricity demand is expected to be moderate with an average load growth of 3.15% over the five-year forecast and 6.16% over the 10-year forecast without conservation. The load growth projections may be conservative for 2022 because some of the utility resource plan results do not fully account for the impacts of climate change or new policies passed after 2021. Several utilities (Avista, Benton PUD, Seattle City Light, PacifiCorp and Puget Sound Energy) project that their energy conservation programs will result in more electricity savings than their projected amount of load growth. These utilities expect to experience negative growth in observed electric loads. With the majority of load growth met by energy conservation programs, new renewable resources primarily serve to replace retiring coal-fired generation and thermal natural gas generation.

Overgeneration

In 2013, the Legislature amended the resource planning statute to address concerns about the potential for "overgeneration" events.[15] The legislation required that utilities consider this potential in their planning "if applicable to the utility's resource portfolio," and required that Commerce include in this report an assessment of utility approaches to overgeneration.

The statute defines an overgeneration event as:

> *An event within an operating period of a balancing authority when the electricity supply, including generation from intermittent renewable resources, exceeds the demand for electricity for that utility's energy delivery obligations and when there is a negatively priced regional market.*

Overgeneration is also referred to as oversupply, and the consequence is generation curtailment. It might occur when high river flows and high wind volumes coincide. It might also occur when the hours of solar generation misaligns with peak electricity demand. The capacity of the hydroelectric system to store extra river flow is limited, and even the option of spilling water over the dams is restricted by fish mortality concerns. In these circumstances, the regional power system may have more electric generation from hydroelectric, wind, and solar resources than what is required to meet regional loads and export opportunities.

[15] Section 19.280.060, Department's duties—Report to the legislature. (2022, June 29). Retrieved from Revised Code of Washington: https://app.leg.wa.gov/RCW/default.aspx?cite=19.280.060

Since 2013, the Bonneville Power Administration has adopted an Oversupply Management Protocol, providing tools for the operators of the hydroelectric system and transmission grid to manage oversupply situations.[16] The implementation of this protocol has generally shifted the overgeneration issue from a planning concern to an operational concern.

In many cases, utilities did not find it necessary in their 2020-2022 resource plans to address overgeneration, or generation curtailment, as an issue separate from the more general assessment of generating resource alternatives.

Resource adequacy

Most utilities plan to meet load requirements in the lowest-cost, least-risk way by renewing BPA contracts (for slice or block products or shifting to a load following product), maximizing energy conservation measures, and implementing new demand response programs. Many consumer-owned utilities already have 80% or more renewable electric generation, and they plan to comply with CETA requirements between 2030 and 2045 using renewable energy credits.[17] With increased demand for renewables, some utilities, such as Clark PUD and Seattle City Light, have requested 100% clean block products from BPA. Some utilities, such as Centralia City Light, would like BPA to find a way to eliminate unspecified power purchases; otherwise, they would have to purchase renewable energy credits to cover the unspecified purchases by BPA to comply with CETA.[18]

Other strategies utilities reported considering include:

- Developing the Western Resource Adequacy Program
- Investigating dispatchable, renewable and non-emitting resources such as batteries, hydrogen, geothermal, and small modular nuclear reactors
- Diversifying the geographic location of their renewable resources
- Utilities reported transmission constraints as a key constraint to accessing cheap renewable resources.

There has been significant progress in the development of a Resource Adequacy Program; however, significant work remains in developing the Western Resource Adequacy Program. Grant PUD explains: "[T]he Western Resource Adequacy Program (WRAP), aims to set regional standards for planning methods and metrics, provide load and resource diversity savings, and establish a robust procurement process... There are many challenges that will need to be overcome for establishing a Resource Adequacy program unique to the Northwest, including the lack of an organized market administrator, the large number of consumer-owned utilities, the significant amount of hydropower resources and the size and role of Bonneville Power Administration (BPA). In addition, questions remain on how WRAP might coexist with energy imbalance and day-ahead markets."[19]

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[16] Oversupply. (n.d.). Retrieved from Bonneville Power Administration: https://www.bpa.gov/energy-and-services/transmission/oversupply

[17] Section 19.405.040(1) states that it is the policy of the state that all retail sales be greenhouse gas neutral by January 1, 2030, and that through December 31, 2044, an electric utilities may satisfy up to 20% of its compliance obligation using an alternative compliance option, such as unbundled renewable energy credits.

[18] Centralia City Light. (2022, p.34). 2022 Electric Utility Resource Plan Update. Retrieved from https://cityofcentralia.com/DocumentCenter/View/1938/2022-Electric-Utility-Resource-Plan-PDF?bidId=

[19] Grant Public Utility District. (2022, p.32). Integrated Resource Plan. Retrieved from https://www.grantpud.org/templates/galaxy/images/Exhibit_A_2022_Integrated_Resource_Plan.pdf

Regional resource forecasts

PNUCC 2022 Northwest Regional Forecast

The Pacific Northwest Utilities Conference Committee (PNUCC) is an electric utility association that compiles information on expected loads and resources of electric utilities in the Pacific Northwest. It includes the loads and resources of Washington utilities along with those of utilities in Oregon, Idaho and Montana.[20] Washington state is the largest state in the Northwest Regional Planning Area which is the area defined by the Pacific Northwest Electric Power Planning and Conservation Act.

The 2022 Northwest Regional Forecast (through 2032) highlighted three key themes:

- A significant transition from thermal generation to clean energy resources is underway in the Pacific Northwest and the rest of the Western Interconnection, with coal plant retirements and increasing adoption of variable clean energy resources. The transition in the Pacific Northwest in large part due to Washington's Clean Energy Transformation Act and Oregon's Renewable Porfolio Standard.[21]
- A variety of new policies that promote electrification such as Washington's Climate Commitment Act, Washington State's new building code standards, and Oregon's Climate Change Executive Order 20-40 are contributing to the challenges of electricity demand forecasting. The shift to a more variable clean power supply coinciding with growth in electricity demand due to electrification results in a growing need to address resource adequacy issues and increasing winter and summer peak deficits.
- Continued robust energy efficiency acquisition efforts and new demand response efforts by Northwest utilities.

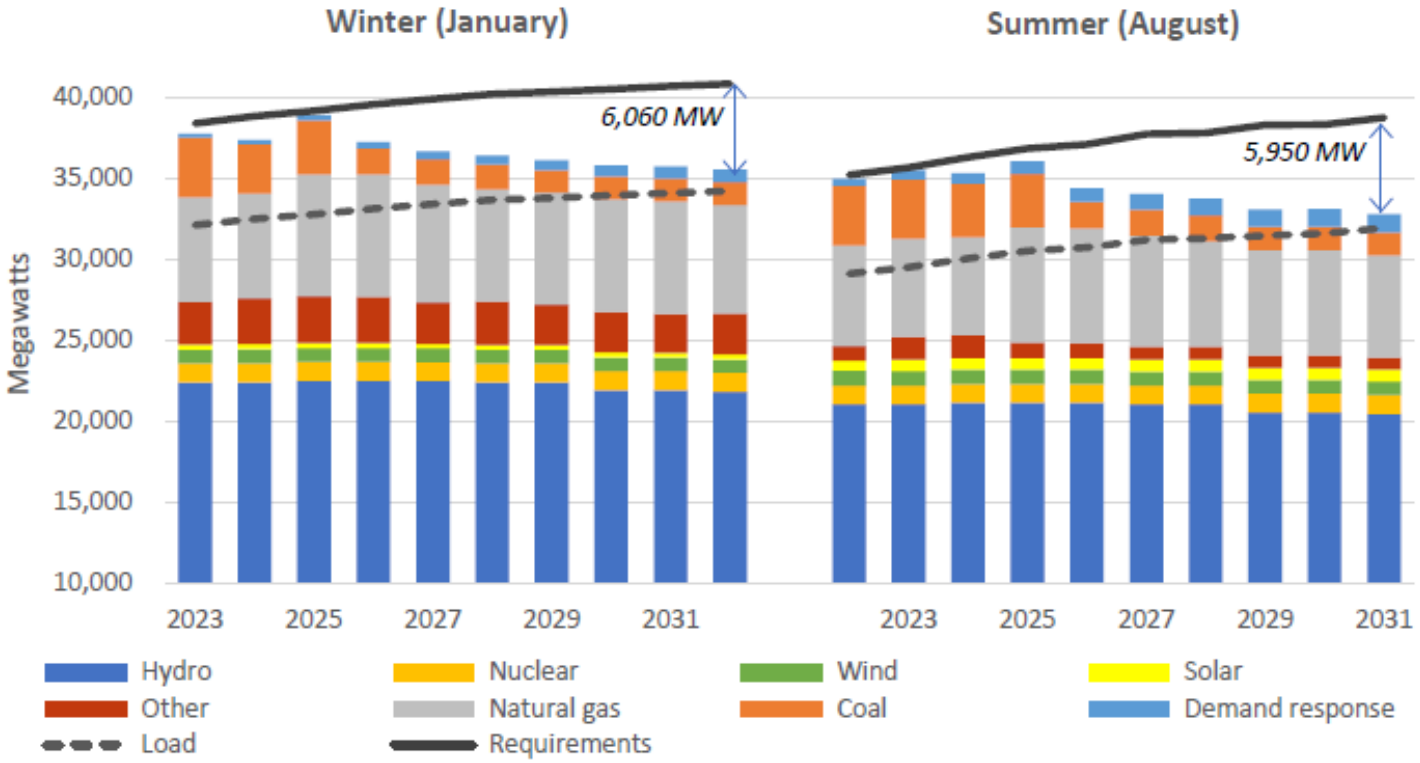
The report concluded that more regional utilities are expecting modest growth in retail loads through the forecast period compared to the previous year. Load growth is largely coming from new industrial loads that include server farms and a growing population in eastern Washington, Idaho, and western Montana. The load growth is diminished due to energy efficiency programs, as well as energy codes and standards. However, estimates of load growth may be conservative because many utilities are only just beginning to examine the implications of electrification and climate change in their load forecasts. In PNUCC's request for data, utilities representing just over 25% of load indicated that they factored in climate change, and utilities making up 30% of regional load are directly accounting for some electrification.[22] The inclusion of electrification in load forecasts will increase load estimates, and the inclusion of climate change impacts will increase summer load estimates while decreasing winter supply estimates.

PNUCC highlights winter-peaking requirements as a continuing concern. Additionally, as shown in

[20] Pacific Northwest Utilities Conference Committee. (2022). Northwest Regional Forecast of Power Loads and Resources 2022 through 2032. Retrieved from https://www.pnucc.org/wp-content/uploads/2022-PNUCC-Northwest-Regional-Forecast-final.pdf
[21] Idaho and Montana do not have any renewable portfolio standards. Montana's renewable portfolio standard of fifteen percent renewable energy by 2015 was repealed in 2021. Source: State Renewable Portfolio Standards and Goals. (2021). Retrieved from National Conference of State Legislatures: https://www.ncsl.org/energy/state-renewable-portfolio-standards-and-goals
[22] (Pacific Northwest Utilities Conference Committee, 2022, p. 6)

Figure 4, the summer peak deficit is widening to nearly match the expected winter peak deficit in the future. The region's projected peak demand is projected to exceed utilities' firm resources in every year of the planning period. The supply of winter peaking and summer peaking resources does not include out-of-region imports, the capacity of independent power projects within the Northwest or hydroelectric system capacity in excess of critical water conditions.

Figure 4: Northwest Utilities Peak Capacity Load/Resource



Source: Pacific Northwest Utilities Conference Committee

The compiled results from PNUCC indicate that the Northwest utilities collectively expect to have surplus energy resources for the 2022-23 operating years on an annual energy basis. The regional forecast shows an energy deficit starting in 2023-2024 (19 aMW) and continuing to grow through the end of the 10-year planning period (3,790 aMW). Much of the deficit is the result of the retirement of coal plants. Just over 2,100 MW of coal have already retired in the Northwest, with more to come. And by 2025, two coal plants[23] (almost 1,100 MW) will be converted to natural gas-fired generation.[24]

According to PNUCC, Northwest utilities made capacity additions of 58 MW in 2019 and are committed to adding nearly 1,647 MW of capacity from 2020 through 2025 -- primarily wind, solar, battery projects with one natural gas plant. PNUCC identifies a larger amount of planned resources in the region. Planned resources through 2032 are estimated at 9,447 MW of capacity and include 3,385 MW of wind, 2,130 MW of standalone solar, 2,541 MW of solar capacity with battery storage, as well as over 2,000 MW of dispatchable resources, such as natural gas and storage (for peak demand). However, they are not included in the forecast because they have less certainty from a financial or regulatory standpoint.

[23] PacifiCorp is converting Jim Bridger 1 and 2 in Wyoming to natural gas in order to keep operating them while complying with federal regional haze requirements. Source: NewsData. (2023, August 25). PacifiCorp Coal Units Set for Conversion to Natural Gas This Fall. Retrieved from https://www.newsdata.com/clearing_up/supply_and_demand/pacificorp-coal-units-set-for-conversion-to-natural-gas-this-fall/article_9802600e-435f-11ee-9dba-a3fe639f5da2.html

[24] (Pacific Northwest Utilities Conference Committee, 2022, p. 4)

Pacific Northwest Power Supply Adequacy Assessment for 2027

The Northwest Power and Conservation Council , which is the region's premier power planning body, evaluated the adequacy of the Northwest electric power supply in 2023 and concluded that the 2027 regional power supply would be adequate if the region's utilities add the resources identified in the Council's most recent regional power plan. Power supply would not be adequate if the region relied solely on existing resources, existing reserve levels, and no new energy efficiency measures.

Traditionally, resource adequacy was assessed through the loss of load probability metric which is limited to 5%. However, this metric fails to indicate the shortfall magnitude, duration, or frequency. To better assess customer risk, the Council examined additional metrics and proposed standards for each one. These metrics are loss of load events (LOLEV), duration value at risk (VaR Duration), and peak (VaR Peak) and energy value at risk (VaR Energy).[25] If demand growth remains consistent with the plan's baseline forecast, then the power supply would be adequate with resources and reserves identified in the 2021 Power Plan's resource strategy.

However, if future electricity market supplies are significantly limited, if new policy commitments to electrification accelerate demand growth, or if major coal resources are retired earlier than expected without replacement, then additional resources and reserves will be required to maintain system adequacy. More work needs to be done to understand how the average load increase in the regional load forecast compare to the actual expected load growth driven by new policies implemented since the adoption of the 2021 Power Plan. Given the passage of recent electrification policies and recent global instability, the current resource strategy may be inadequate to ensure resource adequacy and reliability in 2027 based on the estimates of resource adequacy metrics.

This assessment also found that the 2021 Power Plan resource strategy is effective at eliminating nearly all summer shortfalls, when resource needs peak in the rest of the Western Interconnection (outside of the Pacific Northwest region).[26] Implementing the strategy does not eliminate winter shortfall events, but it does mitigate them by reducing shortfall event magnitude and shortening event duration to only a few hours during the morning and evening ramps.[27] New clean energy policies will result in market supply and demand dynamic changes because the hours of renewable generation will not always coincide with the hourly pattern of greatest energy need. Under the limited markets and high Western Electricity Coordinating Council (WECC) interconnection demand scenarios, summer market imports decrease in the morning and summer evening imports are eliminated. Under the limited markets and high WECC demand scenarios, the winter morning ramp period has increased imports. Transmission limitations within the Western grid may have a larger influence on market dynamics, as it may not be adequate to meet the import needs of California and Canada under certain scenarios.

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[25] Northwest Power and Conservation Council. (2023, p.4). Pacific Northwest Power Supply Adequacy Assessment for 2027. Retrieved from https://www.nwcouncil.org/reports/2023-1/

[26] (Northwest Power and Conservation Council, 2023, p. 5). The Northwest Power Plan applies to the Pacific Northwest states (Washington, Oregon, Idaho, and Montana). The interconnected Western power grid encompasses 14 states, two Canadian provinces, and a portion of Mexico.

[27] (Northwest Power and Conservation Council, 2023, p. 29)

2022 Western Assessment of Resource Adequacy[28]

The WECC is a regional entity with authority delegated under the Federal Power Act to ensure a reliable and secure bulk power system in the Western Interconnection. As the only independent, interconnection-wide organization in the West, WECC creates and enforces reliability standards.

The Western Assessment of Resource Adequacy provides assessments for the Western Interconnection and five subregions. Washington is part of the Northwest Power Pool subregion. Over the next decade, entities will retire nearly 26 GW of resources, mostly coal and natural gas, while building close to 80 GW of new generation and energy storage resources, three-quarters of which will be solar, wind, and battery storage. The resource mix in 2032 will be very different and highly variable. This is because solar and wind resources have constantly changing energy outputs and limited dispatchability. Additionally, it is uncertain how electrification, energy efficiency, and new technologies will affect demand over the next decade. The assessment shows some near-term reduction in resource adequacy risk, but WECC foresees an increasing risk over the next 10 years. Not only is resource adequacy risk growing, but it is spreading throughout beyond the peak load seasons.

WECC uses two measures of resource adequacy: demand-at-risk indicator and planning reserve margin indicator. The demand-at risk indicator (DRI) is the number of hours in a year when demand is at risk. Planning reserve margin indicator (PRMI) is a measure of variability on the system. WECC presents major findings and recommendations to manage resource adequacy risks:

- **The increase in PRMI indicates that entities may need to plan for more reserves or take other actions to account for the increased variability.** Mitigation actions could include adding dispatchable resources; increasing demand management measures; participating in subregional cooperative efforts; supporting the research and development of new technology; and improving coordination of transmission planning and operation.
- **New challenges like supply chain disruption, skilled workforce shortages, and siting issues may impede or delay the build-out of new resources.** WECC recommends resource plans should include contingency plans to manage the risk of impediments to building planned resources. State commissions and regulatory bodies should continue to scrutinize integrated resource plans to ensure that utilities are planning for the increased risks.
- **All subregions rely on imports to help be resource adequate; however, the risk of wide-spread variability could create situations where the imports that entities depend on are not available.** WECC recommends that the Western Interconnection evaluate resource and transmission adequacy in a coordinated fashion through comprehensive wide-area system planning.
- **Uncertainty about future impacts to demand of electrification, energy efficiency, new technology, and other factors creates difficulties for load forecasting.** WECC recommends that some entities will need to evaluate and adapt their resource planning approaches to account for increased future uncertainty.

[28] Western Electricity Coordinating Council. (2022). Western Assessment of Resource Adequacy. Retrieved from https://www.wecc.org/Reliability/2022%20Western%20Assessment%20of%20Resource%20Adequacy.pdf

Appendix A: Utility Cover Sheets

Washington Electric Utility Loads and Resources Estimates reported to the Department of Commerce in 2022

Avista Utilities

Washington State Utility Integrated Resource Plan Year 2022									
Prepared by: Mike Hermanson									
		Base Year			**5 Year Estimate**			**10 Year Estimate**	
Estimate Year		**2022**			**2027**			**2032**	
Period	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**
Units	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**
Loads	1,086.00	1,019.00	680.00	1,135.00	1,037.00	692.00	1,186.00	1,056.00	698.00
Exports	36.00	5.00	19.00	0.00	0.00	0.00	0.00	0.00	0.00
Resources:									
Future Conservation/Efficiency				34.00	38.00	33.00	70.00	75.00	67.00
Demand Response				23.00	23.00		26.00	25.00	
Cogeneration									
Hydro	773.00	748.00	371.00	720.00	696.00	351.00	711.00	639.00	344.00
Wind	8.00	8.00	60.00	75.00	75.00	151.00	103.00	106.00	196.00
Other Renewables	31.00	37.00	31.00	31.00	37.00	31.00	31.00	37.00	31.00
Thermal - Natural Gas	576.00	478.00	425.00	483.00	403.00	370.00	483.00	403.00	370.00
Thermal - Coal	222.00	222.00	222.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Long Term Contracts	26.00	22.00	25.00	26.00	22.00	25.00	26.00	22.00	25.00
Net Short Term Contracts									
BPA									
Other									
Imports									
Distributed Generation									
Undecided									
Total Resources	**1,636.00**	**1,515.00**	**1,134.00**	**1,392.00**	**1,294.00**	**961.00**	**1,450.00**	**1,307.00**	**1,033.00**
Load Resource Balance	**514.00**	**491.00**	**435.00**	**257.00**	**257.00**	**269.00**	**264.00**	**251.00**	**335.00**

Date of Board/Commission Approval: N/A

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Loads are 1 in 2 expected values and do not include any consideration of planning margin. Reported loads and resources represent the Washington share of Avista's system. Resources include new resource selection in 2027 of 100 MW of NG CT new facilities and upgrades, 67 MW of wind, and 23 MW of DR. New Resources in addition to those selected in 2027 include 3 additional MW of DR, 44 MW of hydro, and an additional 28 MW of wind. These resource selections provide a resource balance commensurate with Avista planning parameters.

PUD No. 1 of Chelan County

Washington State Utility Integrated Resource Plan Year 2022									
Prepared by: Becky Keating									
		Base Year			**5 Year Estimate**			**10 Year Estimate**	
Estimate Year		**2020**			**2025**			**2030**	
Period	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**
Units	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**
Loads	446.00	243.00	204.50	522.93	274.73	238.00	547.16	289.01	250.00
Exports									
Resources:									
Future Conservation/Efficiency				11.93	6.73	5.59	30.16	17.01	14.16
Demand Response									
Cogeneration									
Hydro	419.00	220.00	189.00	770.00	386.00	338.00	1,227.00	603.00	532.00
Wind	0.37	0.33	2.58	1.38	0.76	2.25	1.38	0.76	2.25
Other Renewables									
Thermal - Natural Gas									
Thermal - Coal									
Net Long Term Contracts									
Net Short Term Contracts									
BPA									
Other									
Imports									
Distributed Generation									
Undecided									
Total Resources	**419.37**	**220.33**	**191.58**	**783.31**	**393.49**	**345.84**	**1,258.54**	**620.77**	**548.41**
Load Resource Balance	**-26.63**	**-22.67**	**-12.92**	**260.38**	**118.76**	**107.84**	**711.38**	**331.76**	**298.41**

Date of Board/Commission Approval: December 21

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Appendix B in Chelan PUD's IRP includes this cover sheet with supplemental information on loads and resources.

Clark Public Utilities

Washington State Utility Integrated Resource Plan Year 2022

Prepared by: Steve Andersen

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		**2021**			**2026**			**2031**	
Period	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**
Units	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**
Loads	967.96	1,016.20	553.68	1,024.00		579.41	1,331.00		655.58
Exports									
Resources:									
Future Conservation/Efficiency									
Demand Response									
Cogeneration									
Hydro	5.00	5.00	1.75	80.00		51.74	80.00		51.74
Wind	6.00	0.00	16.31	9.00		18.13	9.00		18.00
Other Renewables									
Thermal - Natural Gas	255.40	203.80	221.80	265.00		227.16	265.00		102.00
Thermal - Coal									
Net Long Term Contracts									
Net Short Term Contracts	200.56	473.40	72.00						
BPA	506.00	340.00	323.74	554.00		363.96	762.00		500.48
Other				4.00		4.18	5.00		4.72
Imports									
Distributed Generation									
Undecided									
Total Resources	**972.96**	**1,022.20**	**635.59**	**912.00**	**0.00**	**665.17**	**1,121.00**	**0.00**	**676.94**
Load Resource Balance	**5.00**	**6.00**	**81.91**	**-112.00**	**0.00**	**85.76**	**-210.00**	**0.00**	**21.36**

Date of Board/Commission Approval: August 22

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Line 10: Historic 2021 actual winter and summer peak demands and annual energy. Projected 2026 and 2031 winter peak demands and annual energy. A summer peak demand forecast is not included in the IRP update. Line 16: Hydro includes the Packwood Hydroelectric Project (CPU receives an 18% share of project generation) and a future Power Purchase Agreement
Line 17: Wind is the Combine Hills II Wind Project (CPU receives 100% of project generation)
Line 19: Natural Gas is the River Road Generating Plant
Line 21: Net Short Term Contracts includes all historic market purchases
Line 24: Other is future market balancing purchases

Cowlitz PUD

Washington State Utility Integrated Resource Plan Year 2022

Prepared by: TEA

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		**2021**			**2026**			**2031**	
Period	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**
Units	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**
Loads	725.03	608.54	515.24	893.34	780.77	582.41	977.36	846.58	619.63
Exports									
Resources:									
Future Conservation/Efficiency									
Demand Response									
Cogeneration									
Hydro	76.20	78.50	24.49	79.00	79.00	15.80	79.00	79.00	15.80
Wind	0.82	1.04	40.01	0.00	0.00	34.71	0.00	0.00	0.00
Other Renewables									
Thermal - Natural Gas									
Thermal - Coal									
Net Long Term Contracts									
Net Short Term Contracts				212.68	173.87		340.84	193.81	61.89
BPA	776.00	614.00	455.06	601.66	527.90	541.70	557.52	573.77	541.94
Other									
Imports									
Distributed Generation									
Undecided									
Total Resources	**853.02**	**693.54**	**519.56**	**893.34**	**780.77**	**592.21**	**977.36**	**846.58**	**619.63**
Load Resource Balance	**127.99**	**85.00**	**4.32**	**0.00**	**0.00**	**9.80**	**0.00**	**0.00**	**0.00**

Date of Board/Commission Approval: August 22

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Line 10: Base year seasonal peak loads are not weather adjusted. Actual summer peak occurred: 8/11/21 HE 19 Actual winter peak occurred: 12/27/21 HE 18; Annual average load is weather normalized
Line 13: Loads were forecasted using regression methodology that captured conservation effects and trends, therefore conservation is not captured as a separate line item
Line 16: Hydro resources include Swift No. 2, Wanapum, and Priest Rapids, Winter and Summer values represent actual average peak generation and the Annual value reflects the yearly average
Line 17: Wind resources include White Creek Wind, Nine Canyon Wind, and Harvest Wind--Peak MW represent wind actuals on winter and summer load peaks
Line 22 (Net Short Term Contracts): Future energy and capacity beyond the District portfolio will continue to be supplemented with market purchases on a short-term basis.
Line 23: Winter and Summer values for 2021 represent the maximum peak slice + block BPA power and the Annual value is based on actual average slice + block, for 2026 and 2031 critical water assumptions were used for the federal system, the deficits resulting from the critical water assumptions are captured in the Net Short Term Contracts (line 22) and would be purchased from the market.

Public Utility District No. 1 of Douglas County

Washington State Utility Integrated Resource Plan Year 2020 2022

Prepared by: Jeff Johnson

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		**2021**			**2026**			**2031**	
Period	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**
Units	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**
Loads	239.00	179.00	142.56	289.40	209.20	172.60	319.50	226.50	195.30
Exports									
Resources:									
Future Conservation/Efficiency				2.00	2.00	2.00	4.50	4.50	4.50
Demand Response				5.00	5.00	1.00	10.00	10.00	2.00
Cogeneration									
Hydro	355.50	227.30	181.50	444.00	339.00	268.00	452.00	434.00	323.00
Wind	10.00	10.00	2.29	10.00	10.00	2.95	10.00	10.00	2.95
Other Renewables									
Thermal - Natural Gas									
Thermal - Coal									
Net Long Term Contracts	47.00	47.00	47.00						
Net Short Term Contracts									
BPA									
Other									
Imports									
Distributed Generation									
Undecided									
Total Resources	**412.50**	**284.30**	**230.79**	**461.00**	**356.00**	**273.95**	**476.50**	**458.50**	**332.45**
Load Resource Balance	**173.50**	**105.30**	**88.23**	**171.60**	**146.80**	**101.35**	**157.00**	**232.00**	**137.15**

Date of Board/Commission Approval: September 22

Public Utility District No. 2 of Grant County

Washington State Utility Integrated Resource Plan Year 2022

Prepared by: Lisa Stites

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		**2021**			**2026**			**2031**	
Period	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**
Units	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**
Loads	833.57	929.18	639.33	1,008.99	1,146.55	821.73	1,134.57	1,289.25	923.95
Exports									
Resources:									
Future Conservation/Efficiency				8.14	8.40	8.27	17.91	18.91	18.41
Demand Response									
Cogeneration									
Hydro	114.46	124.00	117.74	1,089.19	1,011.29	628.70	1,142.00	1,059.18	638.90
Wind	0.93	1.56	3.52	8.74	12.85	50.10	7.80	10.47	46.82
Other Renewables				62.95	82.30	93.85	114.40	149.41	210.57
Thermal - Natural Gas				198.00	198.00	11.51	270.00	270.00	5.91
Thermal - Coal									
Net Long Term Contracts	702.73	788.18	401.59						
Net Short Term Contracts			110.57			23.90			-2.06
BPA	15.44	15.44	5.90	15.44	15.44	5.40	15.44	15.44	5.40
Other									
Imports									
Distributed Generation									
Undecided									
Total Resources	**833.57**	**929.18**	**639.33**	**1,382.46**	**1,328.28**	**821.73**	**1,567.55**	**1,523.41**	**923.96**
Load Resource Balance	**0.00**	**0.00**	**0.00**	**373.47**	**181.73**	**0.00**	**432.98**	**234.16**	**0.00**

Date of Board/Commission Approval: August 22

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Line 10: Base year load is actual load for 2021
Line 18: Our other renewables includes both stand-alone solar PV and solar PV+battery hybrids

Lewis County PUD 1

Washington State Utility Integrated Resource Plan Year 2022

Prepared by: Luke Canfield

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		**2021**			**2026**			**2031**	
Period	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**
Units	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**
Loads	213.08	148.36	114.63	239.34	154.40	119.78	239.34	158.35	123.45
Exports									
Resources:									
Future Conservation/Efficiency				4.30	2.60	2.68	14.40	9.50	8.55
Demand Response									
Cogeneration									
Hydro	5.12	4.52	1.19	5.12	4.52	1.19	5.12	4.52	1.19
Wind	1.80	1.40	1.60	1.80	1.40	1.60	1.80	1.40	1.60
Other Renewables									
Thermal - Natural Gas									
Thermal - Coal									
Net Long Term Contracts									
Net Short Term Contracts									
BPA	142.00	111.40	114.60	151.22	118.88	120.89	156.63	117.75	126.04
Other									
Imports									
Distributed Generation									
Undecided									
Total Resources	**148.92**	**117.32**	**117.39**	**162.44**	**127.40**	**126.36**	**177.95**	**133.17**	**137.38**
Load Resource Balance	**-64.16**	**-31.04**	**2.76**	**-76.90**	**-27.00**	**6.58**	**-61.39**	**-25.18**	**13.93**

Date of Board/Commission Approval: September 22

Grays Harbor PUD

Washington State Utility Integrated Resource Plan Year 2022

Prepared by: Shailesh Shere

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		**2021**			**2026**			**2031**	
Period	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**
Units	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**
Loads	235.00	143.00	132.00	224.00	138.00	129.00	219.00	136.00	127.00
Exports									
Resources:									
Future Conservation/Efficiency						0.66			0.90
Demand Response									
Cogeneration	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00
Hydro									
Wind	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
Other Renewables									
Thermal - Natural Gas	45.00	45.00	45.00						
Thermal - Coal									
Net Long Term Contracts									
Net Short Term Contracts									
BPA	170.00	129.00	135.70	170.00	129.00	135.00	170.00	129.00	135.00
Other									
Imports									
Distributed Generation									
Undecided									
Total Resources	**236.00**	**195.00**	**201.70**	**191.00**	**150.00**	**156.66**	**191.00**	**150.00**	**156.90**
Load Resource Balance	**1.00**	**52.00**	**69.70**	**-33.00**	**12.00**	**27.66**	**-28.00**	**14.00**	**29.90**

Date of Board/Commission Approval: September 6

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Line 13: Annual data from 2021 Conservation Potential Assessment.
Lines 15 and 17: Assumption Resource Power Contract's will be extended.
Line 23: Assumption we will purchase similar product to the current Slice/Regional Dialogue contract. Current contract expires 9/30/2028.

Washington State Utility Integrated Resource Plan Year 2022

Prepared by: Brian Osborn

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		2022			2027			2032	
Period	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**
Units	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**
Loads	699.25	716.34	528.18	767.83	802.04	546.43	803.37	822.11	576.08
Exports	33.23	35.17	6.33	26.60	29.78	3.19	26.63	27.87	3.15
Resources:									
Future Conservation/Efficiency				30.96	74.95	37.74	47.94	120.30	66.88
Demand Response				50.20	61.53	10.75	28.92	27.94	11.32
Cogeneration									
Hydro	91.97	78.57	45.97	73.08	63.83	34.11	70.45	63.12	33.54
Wind	25.31	31.44	103.14	48.75	69.02	166.77	49.99	51.50	177.20
Other Renewables	8.26	31.94	46.61	6.39	48.50	99.45	5.63	11.31	178.56
Thermal - Natural Gas	218.67	192.50	102.65	213.81	187.26	98.54	190.33	172.98	98.88
Thermal - Coal	405.91	372.08	256.54	341.72	318.50	155.81	262.73	256.08	67.31
Net Long Term Contracts	0.00	0.00	6.98	0.00	0.00	0.10	0.00	0.00	0.10
Net Short Term Contracts	49.61	114.11	23.08	0.00	0.00	28.46	0.00	0.00	35.98
BPA									
Other	19.98	26.41	-1.40	108.16	108.68	2.71	238.77	234.65	35.35
Imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distributed Generation	0.21	5.57	2.46	0.71	7.45	3.54	1.25	14.58	6.83
Undecided									
Total Resources	**819.93**	**852.63**	**586.04**	**873.76**	**939.73**	**637.98**	**896.01**	**952.44**	**711.95**
Load Resource Balance	**87.44**	**101.11**	**51.53**	**79.33**	**107.92**	**88.35**	**66.01**	**102.46**	**132.72**

Date of Board/Commission Approval:

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Information is based on the 2021 Update Integrated Resource Plan filed with the Washington Utilities and Transportation Commission on March 31, 2022.
The Load Resource Balance in Capacity primarily reflects the 13% Planning Reserve Margin not included in Loads.

Puget Sound Energy

Washington State Utility Integrated Resource Plan Year 2022

Prepared by: Chris Schaefer

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		**2022**			**2027**			**2032**	
Period	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**
Units	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**
Loads	4,687.00	3,515.00	2,500.00	4,949.00	3,848.00	2,647.00	5,269.00	4,220.00	2,820.00
Exports	24.00	324.00	59.00	0.00	300.00	47.00	0.00	300.00	47.00
Resources:									
Future Conservation/Efficiency				383.00	188.00	213.00	693.00	335.00	417.00
Demand Response				89.00	89.00		198.00	198.00	
Cogeneration									
Hydro	743.00	774.00	514.00	762.00	808.00	505.00	757.00	801.00	504.00
Wind	118.00	118.00	295.00	113.00	113.00	485.00	129.00	129.00	475.00
Other Renewables	28.00	28.00	52.00	28.00	28.00	52.00	27.00	27.00	52.00
Thermal - Natural Gas	2,050.00	1,689.00	1,856.00	1,689.00	2,050.00	1,856.00	2,050.00	1,689.00	1,856.00
Thermal - Coal	307.00	307.00	247.00						
Net Long Term Contracts	612.00	612.00	534.00	63.00	63.00	107.00	44.00	44.00	45.00
Net Short Term Contracts	1,518.00	1,487.00		1,479.00	1,433.00		1,479.00	1,435.00	0.00
BPA									
Other									
Imports	303.00	303.00	50.00	303.00	303.00	50.00	303.00	303.00	50.00
Distributed Generation									
Undecided									
Total Resources	**5,679.00**	**5,318.00**	**3,548.00**	**4,909.00**	**5,075.00**	**3,268.00**	**5,680.00**	**4,961.00**	**3,399.00**
Load Resource Balance	**968.00**	**1,479.00**	**989.00**	**-40.00**	**927.00**	**574.00**	**411.00**	**441.00**	**532.00**

Date of Board/Commission Approval:

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Line 18: PSE's Other Renewables are Solar and Biomass. PSE's Integrated Resource Plan ("IRP") includes the least cost combination of conservation and supply-side resources to meet requirements per WAC 480-100-620. This information is also available in PSE's 2021 IRP, Appendix B, page 30, filed with the Washington Utilities and Transportation Commission ("WUTC") Docket UE-200304, filed April 20, 2021.

City of Richland

Washington State Utility Integrated Resource Plan Year 2022

Prepared by: Sandi Edgemon

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		2021			2026			2031	
Period	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**
Units	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**
Loads	189.78	211.82	111.84	194.40	193.80	112.70	199.10	198.50	113.82
Exports									
Resources:									
Future Conservation/Efficiency				3.34	3.34	3.34	9.98	9.98	9.98
Demand Response				0.00	0.00	0.00	0.00	0.00	0.00
Cogeneration									
Hydro									
Wind									
Other Renewables	0.79	1.05	0.70	0.75	1.00	0.67	0.71	0.95	0.63
Thermal - Natural Gas									
Thermal - Coal									
Net Long Term Contracts	8.00	8.00	8.00	0.00	0.00	0	0.00	0.00	0
Net Short Term Contracts									
BPA	180.99	202.77	103.63	190.31	189.46	108.69	188.41	187.57	103.21
Other									
Imports									
Distributed Generation									
Undecided									
Total Resources	**189.78**	**211.82**	**112.33**	**194.40**	**193.80**	**112.70**	**199.10**	**198.50**	**113.82**
Load Resource Balance	**0.00**	**0.00**	**0.49**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Date of Board/Commission Approval: August 20

Seattle City Light (SCL)

Washington State Utility Integrated Resource Plan Year 2022

Prepared by: Paul Nissley

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		**2021**			**2026**			**2031**	
Period	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**
Units	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**
Loads			1,072.00			1,077.00			1,104.00
Exports			25.00						
Resources:									
Future Conservation/Efficiency						48.00			85.00
Demand Response				20.00	14.00		89.00	53.00	
Cogeneration									
Hydro			719.00			742.00			733.00
Wind			41.00			95.00			95.00
Other Renewables			12.00			64.00			64.00
Thermal - Natural Gas									
Thermal - Coal									
Net Long Term Contracts									
Net Short Term Contracts									
BPA			470.00			418.00			416.00
Other			37.00			37.00			37.00
Imports			31.00						
Distributed Generation						3.00			4.00
Undecided									
Total Resources	**0.00**	**0.00**	**1,310.00**	**20.00**	**14.00**	**1,407.00**	**89.00**	**53.00**	**1,434.00**
Load Resource Balance	**0.00**	**0.00**	**213.00**	**20.00**	**14.00**	**330.00**	**89.00**	**53.00**	**330.00**

Date of Board/Commission Approval: August 22

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Line 10: this row's 1072 aMW base year load is weather adjusted** (includes 3aMW OwnUse & 5.5% line loss). 2026 and 2031 load estimates don't include conservation. Line 11: this row's Exports include Lucky Peak contract, but no contract in place after 2025. Line 16: This row represents City Light's hydro resources and long-term hydro contracts. For purposes of 2026 & 2031 estimates, a hypothetical median hydro year was created based on individual median months from historical period 1999 to 2020.
Line 17: this row's Stateline wind contract expires in 2021; 95 aMW new Gorge wind resources planned in 2026.
Line 18:this row's Other renewables include landfill gas and sewage treatment plant digester gas (~13aMW in 2026 & 2031) and 51 aMW planned SE OR and/or WA utility solar by 2026.
Line 24: this row's Other includes SCL long term PPAs with BC Hydro classified as unspecified power. Line 25: this row's Imports include Lucky Peak exchange energy. Line 26: this row's estimated incremental distributed solar generation in Seattle associated w/ customer programs.**Annual estimates of weather normalized system load are computed by summing together the weather normalized monthly system loads. The monthly system load model is fit using 5 years of daily observed system load and temperature data. Additional effects like day of the week, holidays, annual level shifts, and a trigonometric seasonal component are also included to capture non-weather drivers. This isn't an exhaustive list of explanatory variables that could drive day-to-day changes in load, but it is sufficient to get an accurate estimate of the non-linear relationship between load and temperature which is the crux of the weather normalization process. To model the non-linear link between system load and temperature a Multivariate Adaptive Regression Spline (MARS) model is used to estimate a piece wise linear function. The MARS model selects break points in temperature to estimate the system response to changes in temperature

Public Utility District #1 of Snohomish County

Washington State Utility Integrated Resource Plan Year 2022

Prepared by: Landon Snyder

		Base Year			5 Year Estimate			10 Year Estimate	
Estimate Year		**2021**			**2026**			**2031**	
Period	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**
Units	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**	**(MW)**	**(MW)**	**(MWa)**
Loads	946.89	663.73	784.42	948.90	685.07	799.11	977.19	710.02	824.93
Exports	170.16	158.59	116.51	161.74	212.78	166.86	135.25	167.03	140.19
Resources:									
Future Conservation/Efficiency				28.77	25.58	27.00	81.22	73.43	76.59
Demand Response				4.54	0.00	1.74	25.18	0.00	9.82
Cogeneration	2.29	1.63	2.06	2.78	1.87	2.34	2.78	1.87	2.34
Hydro	99.87	34.64	59.31	89.45	40.09	62.22	94.00	37.52	63.52
Wind	48.72	67.97	56.48	28.06	54.22	41.30	0.00	0.00	0.00
Other Renewables	0.03	0.14	0.09	0.45	1.48	0.98	0.45	1.48	0.98
Thermal - Natural Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Thermal - Coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Long Term Contracts	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Short Term Contracts	25.00	0.00	8.33	50.00	0.00	16.67	0.00	0.00	0.00
BPA	940.35	714.36	772.56	905.21	768.34	810.03	906.77	753.48	806.41
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distributed Generation	0.79	3.58	2.10	1.38	6.27	3.69	2.04	9.27	5.46
Undecided	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Resources	**1,117.05**	**822.32**	**900.93**	**1,110.64**	**897.85**	**965.97**	**1,112.44**	**877.05**	**965.12**
Load Resource Balance	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Date of Board/Commission Approval: December 22

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

1. Not in the categories listed, so not in the table, Snohomish has identified a storage need of up to 70MW by 2031.
2. Snohomish plans to add 5MW of local, utility-scale solar by 2031. (Line 18)
3. Snohomish plans to offer Smart Rate programs to customers in conjunction with AMI meter rollout in the early 2020's, in order to achieve over 25MW of peak demand reduction by 2031. (Line 14)
4. Snohomish currently plans to let existing wind contracts expire at the end of their term without renewal (line 17)
5. Snohomish plans to add winter capacity via short-term contract from 2022-2026 (line 22)

Alder Mutual Light Co.

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	0.67	0.65	0.65
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response			
BPA Tier 1 (include BPA PF)	0.55	0.55	0.55
BPA Tier 2	0.13	0.10	0.10
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**0.67**	**0.65**	**0.65**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Asotin County PUD No 1

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	0.63	0.58	0.58
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response			
BPA Tier 1 (include BPA PF)	0.57	0.57	0.57
BPA Tier 2	0.05	0.01	0.01
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**0.63**	**0.58**	**0.58**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Benton Rural Electric Association

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	71.37	64.82	65.46
Resources:			
Future Conservation/Efficiency		0.62	0.62
Demand Response			
BPA Tier 1 (include BPA PF)	59.34	59.66	59.66
BPA Tier 2	12.03	4.54	5.19
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**71.37**	**64.82**	**65.46**
Load Resource Balance	**0.00**	**0.00**	**0.00**

City of Centralia

Washington State Utility Resource Plan Year 2022

Prepared by: David Hayes

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2027**	**2032**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	31.57	32.41	32.41
Resources:			
Future Conservation/Efficiency			
Demand Response			
BPA Tier 1 (include BPA PF)	23.98	24.37	24.37
BPA Tier 2	0.48	0.92	0.93
Non BPA:			
Co-generation			
Hydro (critical water)	7.11	7.11	7.11
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**31.57**	**32.41**	**32.41**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Date of Board/Commission Approval: August 22

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

SEE 2022 ELECTRIC UTILITY RESOURCE PLAN UPDATE

City of Cheney

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	15.82	18.34	19.40
Resources:			
Future Conservation/Efficiency			
Demand Response			
BPA Tier 1 (include BPA PF)	14.82	18.34	19.40
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)	1.00	0.00	0.00
Other			
Distributed Generation			
Undecided			
Total Resources	**15.82**	**18.34**	**19.40**
Load Resource Balance	**0.00**	**0.00**	**0.00**

City of Chewelah

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	2.45	2.52	2.52
Resources:			
Future Conservation/Efficiency		0.01	0.01
Demand Response			
BPA Tier 1 (include BPA PF)	2.45	2.51	2.51
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**2.45**	**2.52**	**2.52**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Clallam County PUD No. 1

Washington State Utility Resource Plan Year 2022

Prepared by: Tyler King

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2020**	**2025**	**2030**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	77.23	77.47	77.48
Resources:			
Future Conservation/Efficiency		0.62	0.62
Demand Response			
BPA Tier 1 (include BPA PF)	75.62	76.03	76.03
BPA Tier 2	0.94	0.15	0.16
Non BPA:			
Co-generation			
Hydro (critical water)	0.67	0.67	0.67
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**77.23**	**77.47**	**77.48**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Date of Board/Commission Approval: August 22

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Data is reported using the Federal fiscal year (October through September). The base year is 2020 actual load. The 2025 and 2028 load forecasts are based on 2020 weather normalized actual load applied to BPA using a flat growth rate, including mandated conservation from the Energy Independence Act. The non-federal hydro resource "Line 17" is Clallam's share of the Packwood Lake project owned by Energy Northwest. We have current contracts for RECs to meet the 15% Washington State Renewable Energy Portfolio Standard through 2028. The PUD is planning a Demand Response pilot project within 5 years load shifting 0.10 aMW. The 10 year projected demand response is contingent on an estimated BPA demand rate, with the pilot project saving 0.80 aMW.

Columbia REA

Washington State Utility Resource Plan Year 2022

Prepared by: Jim Cooper

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year			
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	42.54	43.73	45.00
Resources:			
Future Conservation/Efficiency			
Demand Response			
BPA Tier 1 (include BPA PF)	37.85	37.57	43.93
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)	1.07	1.07	1.07
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)	3.62	5.09	0.00
Other			
Distributed Generation			
Undecided			
Total Resources	**42.54**	**43.73**	**45.00**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Date of Board/Commission Approval: October 23

Consolidated Irrigation District

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	0.31	0.22	0.22
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response			
BPA Tier 1 (include BPA PF)	0.23	0.22	0.22
BPA Tier 2	0.08		
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**0.31**	**0.22**	**0.22**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Town of Coulee Dam

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	1.96	2.05	2.10
Resources:			
Future Conservation/Efficiency		0.01	0.01
Demand Response			
BPA Tier 1 (include BPA PF)	1.96	2.02	2.02
BPA Tier 2		0.02	0.07
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**1.96**	**2.05**	**2.10**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Date of Board/Commission Approval:

Town of Eatonville

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	3.29	3.31	3.33
Resources:			
Future Conservation/Efficiency		0.01	0.01
Demand Response			
BPA Tier 1 (include BPA PF)	3.29	3.30	3.32
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**3.29**	**3.31**	**3.33**
Load Resource Balance	**0.00**	**0.00**	**0.00**

City of Ellensburg

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	23.89	24.18	24.55
Resources:			
Future Conservation/Efficiency		0.01	0.01
Demand Response			
BPA Tier 1 (include BPA PF)	23.89	23.98	23.98
BPA Tier 2		0.19	0.55
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**23.89**	**24.18**	**24.55**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Elmhurst Mutual Power & Light Company

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	32.62	33.16	33.81
Resources:			
Future Conservation/Efficiency		0.18	0.18
Demand Response			
BPA Tier 1 (include BPA PF)	32.24	32.24	32.24
BPA Tier 2	0.38	0.74	1.39
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**32.62**	**33.16**	**33.81**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Ferry County PUD No 1

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	9.12	8.28	8.37
Resources:			
Future Conservation/Efficiency		0.02	0.02
Demand Response			
BPA Tier 1 (include BPA PF)	9.12	8.26	8.34
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**9.12**	**8.28**	**8.37**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Jefferson County PUD No 1

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	45.20	46.33	47.06
Resources:			
Future Conservation/Efficiency		0.26	0.26
Demand Response			
BPA Tier 1 (include BPA PF)	45.17	45.17	45.17
BPA Tier 2	0.03	0.90	1.63
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**45.20**	**46.33**	**47.06**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Inland Power & Light

Washington State Utility Resource Plan Year 2022

Prepared by: Brian Hess

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	127.53	140.80	155.46
Resources:			
Future Conservation/Efficiency		0.36	0.82
Demand Response			
BPA Tier 1 (include BPA PF)	104.89	104.89	120.70
BPA Tier 2	12.37	35.55	33.94
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)	10.27	0.00	0.00
Other			
Distributed Generation			
Undecided			
Total Resources	**127.53**	**140.80**	**155.46**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Starting in 2025, Inland Power & Light will supply all needed resources from BPA and transition away from any market purchases in order to better comply with CETA obligations.

Kalispel Indian Community of the Kalispel Reservation

Washington State Utility Resource Plan Year 2002

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	3.44	4.13	4.38
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response			
BPA Tier 1 (include BPA PF)	3.44	4.07	4.07
BPA Tier 2		0.06	0.31
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**3.44**	**4.13**	**4.38**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Kittitas County PUD No. 1

Washington State Utility Resource Plan Year 2022

Prepared by: EES Consulting

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	13.75	14.15	14.84
Resources:			
Future Conservation/Efficiency		0.08	0.08
Demand Response			
BPA Tier 1 (include BPA PF)	9.70	9.70	9.70
BPA Tier 2	2.74	2.79	3.20
Non BPA:			
Co-generation			
Hydro (critical water)	0.98	0.98	0.98
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation	0.33	0.60	0.88
Undecided			
Total Resources	**13.75**	**14.15**	**14.84**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Date of Board/Commission Approval: November 22

Public Utility District No. 1 of Klickitat County

Washington State Utility Resource Plan Year 2022

Prepared by: Mike DeMott-Director of Finance and Power Management

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	60.32	63.20	67.14
Resources:			
Future Conservation/Efficiency			
Demand Response			
BPA Tier 1 (include BPA PF)	36.28	37.20	45.00
BPA Tier 2	10.74	21.60	17.74
Non BPA:			
Co-generation			
Hydro (critical water)	4.80	4.40	4.40
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)	8.50	0.00	0.00
Other			
Distributed Generation			
Undecided			
Total Resources	**60.32**	**63.20**	**67.14**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Lakeview Light & Power

Washington State Utility Resource Plan Year 2022

Prepared by: PBA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	29.99	30.35	30.66
Resources:			
Future Conservation/Efficiency		0.24	0.24
Demand Response			
BPA Tier 1 (include BPA PF)	29.99	30.12	30.42
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**29.99**	**30.35**	**30.66**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Mason County PUD No. 1

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	10.69	10.45	10.66
Resources:			
Future Conservation/Efficiency		0.01	0.01
Demand Response			
BPA Tier 1 (include BPA PF)	8.85	8.99	8.99
BPA Tier 2	1.30	0.91	1.11
Non BPA:			
Co-generation			
Hydro (critical water)	0.54	0.54	0.54
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**10.69**	**10.45**	**10.66**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Mason PUD 3

Washington State Utility Resource Plan Year 2022

Prepared by: Michele Patterson

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	80.76	88.65	94.42
Resources:			
Future Conservation/Efficiency		1.20	3.41
Demand Response		0.00	0.00
BPA Tier 1 (include BPA PF)	77.79	79.93	79.93
BPA Tier 2	0.00	5.04	0.00
Non BPA:			
Co-generation	0.00	0.00	0.00
Hydro (critical water)	0.97	0.66	0.66
Wind	1.97	1.80	0.00
Other Renewables	0.00	0.00	0.00
Thermal-Natural Gas	0.00	0.00	0.00
Thermal-Coal	0.00	0.00	0.00
Market Purchase (non BPA)	0.00	0.00	0.00
Other	0.00	0.00	0.00
Distributed Generation	0.02	0.02	0.02
Undecided	0.00	0.00	10.40
Total Resources	**80.76**	**88.65**	**94.42**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Date of Board/Commission Approval: August 22

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Based on federal fiscal year to align with BPA.
Line 5: actuals used for base year load; forecast not weather adjusted.
Line 20: distributed generation source is solar.
Line 21: decision to be made at a later date once 2028 BPA contract terms better understood.

City of McCleary

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	3.70	3.84	3.97
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response			
BPA Tier 1 (include BPA PF)	3.70	3.72	3.72
BPA Tier 2		0.12	0.25
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**3.70**	**3.84**	**3.97**
Load Resource Balance	**0.00**	**0.00**	**0.00**

City of Milton

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	6.63	6.62	6.63
Resources:			
Future Conservation/Efficiency		0.01	0.01
Demand Response			
BPA Tier 1 (include BPA PF)	6.63	6.61	6.62
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**6.63**	**6.62**	**6.63**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Modern Electric Water Company

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	26.88	27.08	27.67
Resources:			
Future Conservation/Efficiency		0.31	0.31
Demand Response			
BPA Tier 1 (include BPA PF)	26.29	26.29	26.29
BPA Tier 2	0.59	0.48	1.07
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**26.88**	**27.08**	**27.67**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Nespelem Valley Electric Cooperative Inc.

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	8.20	8.20	8.26
Resources:			
Future Conservation/Efficiency		0.02	0.02
Demand Response			
BPA Tier 1 (include BPA PF)	5.88	5.88	5.88
BPA Tier 2	2.32	2.30	2.36
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**8.20**	**8.20**	**8.26**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Okanogan County Electric Cooperative

Washington State Utility Resource Plan Year 2022

Prepared by: Jeff Kugel

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2022**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	8.85	9.20	10.30
Resources:			
Future Conservation/Efficiency			
Demand Response			
BPA Tier 1 (include BPA PF)	8.10	8.00	8.00
BPA Tier 2	0.56		
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)	0.19		
Other			
Distributed Generation			
Undecided		1.20	2.30
Total Resources	**8.85**	**9.20**	**10.30**
Load Resource Balance	**0.00**	**0.00**	**0.00**

PUD No. 1 of Okanogan County

Washington State Utility Resource Plan Year 2022

Prepared by: Ron Gadeberg

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	75.04	75.83	77.74
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response		0.00	0.00
BPA Tier 1 (include BPA PF)	45.00	45.00	45.00
BPA Tier 2	0.00	0.00	0.00
Non BPA:			
Co-generation	0.00	0.00	0.00
Hydro (critical water)	0.00	0.00	0.00
Wind	0.00	0.00	0.00
Other Renewables	0.00	0.00	0.00
Thermal-Natural Gas	0.00	0.00	0.00
Thermal-Coal	0.00	0.00	0.00
Market Purchase (non BPA)	30.04	30.83	32.74
Other	0.00	0.00	0.00
Distributed Generation	0.00	0.00	0.00
Undecided	0.00	0.00	0.00
Total Resources	**75.04**	**75.83**	**77.74**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Date of Board/Commission Approval: June 23

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Loads: Used Actual 2021 Loads at POD (Point of Delivery). Used Actual 2021 Resources at POD. Forecasted Load based on BPA approved load forecast. Forecasted Resources: BPA based on Block Slice Contract. Future load growth met via PGE Load following product.

Ohop Mutual Light Company

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	10.73	10.67	10.67
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response			
BPA Tier 1 (include BPA PF)	10.16	10.16	10.16
BPA Tier 2	0.57	0.51	0.51
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**10.73**	**10.67**	**10.67**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Orcas Power and Light Cooperative

Washington State Utility Resource Plan Year 2022

Prepared by: RHS

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year			
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	26.47	26.64	27.55
Resources:			
Future Conservation/Efficiency		0.05	0.05
Demand Response		0.00	0.00
BPA Tier 1 (include BPA PF)	26.39	26.01	26.40
BPA Tier 2	0.00	0.00	0.00
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation	0.08	0.59	1.10
Undecided			
Total Resources	**26.47**	**26.64**	**27.55**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

No plans demand response at this point 2.) 5/10 year projections on load comes from BPA 3.)Distributed generation is solely solar

Pacific PUD #2

Washington State Utility Resource Plan Year 2022

Prepared by:

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	36.20	38.80	39.90
Resources:			
Future Conservation/Efficiency		1.00	0.90
Demand Response			
BPA Tier 1 (include BPA PF)	35.60	36.87	39.00
BPA Tier 2		0.93	
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)	2.00		
Other			
Distributed Generation			
Undecided			
Total Resources	**37.60**	**38.80**	**39.90**
Load Resource Balance	**1.40**	**0.00**	**0.00**

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

BPA has not set contract high water marks for new contract just yet.

Parkland Light & Water Company

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	13.49	13.48	13.62
Resources:			
Future Conservation/Efficiency		0.04	0.04
Demand Response			
BPA Tier 1 (include BPA PF)	13.49	13.45	13.58
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**13.49**	**13.48**	**13.62**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Pend Oreille PUD

Washington State Utility Resource Plan Year 2022

Prepared by: April Owen

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	34.40	35.69	38.45
Resources:			
Future Conservation/Efficiency			
Demand Response			
BPA Tier 1 (include BPA PF)	29.20	0.00	0.00
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)	94.90	94.90	94.90
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation	0.01	0.01	0.01
Undecided			
Total Resources	**124.11**	**94.91**	**94.91**
Load Resource Balance	**89.71**	**59.22**	**56.46**

Date of Board/Commission Approval: September 22

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

Line 17: Pend Oreille PUD is anticipating it will sell approximately 54.00 of the 94.90 MWa reported Hydro as a wholesale product beginning in 2026.
Line 24: We have a limited amount of distributed generation, mostly in the form of solar. We are not expecting a material amount of growth in this area. Pend Oreille PUD currently sells its length as a wholesale product. Loads reported are the District's base load and do not include cryptomining consumption of approximately 90 MWa.

City of Port Angeles

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	47.41	46.76	46.76
Resources:			
Future Conservation/Efficiency		0.05	0.05
Demand Response			
BPA Tier 1 (include BPA PF)	47.41	46.71	46.71
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**47.41**	**46.76**	**46.76**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Port of Seattle

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	15.83	16.89	16.89
Resources:			
Future Conservation/Efficiency		0.17	0.17
Demand Response			
BPA Tier 1 (include BPA PF)	15.83	16.72	16.72
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**15.83**	**16.89**	**16.89**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Town of Ruston

Washington State Utility Resource Plan Year 2022

Prepared by: Rick Applegate

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	1.08	1.10	1.04
Resources:			
Future Conservation/Efficiency			
Demand Response			
BPA Tier 1 (include BPA PF)	0.79	0.80	0.74
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)	0.69	0.41	0.40
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**1.47**	**1.21**	**1.14**
Load Resource Balance	**0.39**	**0.11**	**0.10**

Notes: Explain resource choices other than conservation / use of renewable energy credits in planning/ distributed generation sources

The Town of Ruston is a full requirements customer of Tacoma Power. As a result, the Resource Plan has been derived from the Tacoma Power IRP, scaled to load values for the Town of Ruston. The assumed load for Ruston is as follows: 2021 uses actual load for the calendar year; 2026 and 2031 reflect the same load growth percentage rates as forecast in the Tacoma Power IRP for the same periods.

Skamania County PUD No 1

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	16.68	16.00	16.32
Resources:			
Future Conservation/Efficiency		0.01	0.01
Demand Response			
BPA Tier 1 (include BPA PF)	15.91	15.91	15.91
BPA Tier 2	0.77	0.09	0.41
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**16.68**	**16.00**	**16.32**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Town of Steilacoom

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	4.65	4.64	4.75
Resources:			
Future Conservation/Efficiency		0.00	0.01
Demand Response			
BPA Tier 1 (include BPA PF)	4.65	4.64	4.75
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**4.65**	**4.64**	**4.75**
Load Resource Balance	**0.01**	**0.00**	**0.00**

City of Sumas

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	3.59	3.76	3.67
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response			
BPA Tier 1 (include BPA PF)	3.59	3.64	3.64
BPA Tier 2		0.11	0.03
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**3.59**	**3.76**	**3.67**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Tanner Electric Cooperative

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	11.57	11.62	11.94
Resources:			
Future Conservation/Efficiency		0.01	0.01
Demand Response			
BPA Tier 1 (include BPA PF)	11.03	11.03	11.03
BPA Tier 2	0.54	0.58	0.90
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**11.57**	**11.62**	**11.94**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Vera Water and Power

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	27.67	26.781	27.457
Resources:			
Future Conservation/Efficiency		0.03	0.03
Demand Response			
BPA Tier 1 (include BPA PF)	25.91	26.751	27.157
BPA Tier 2	0.77	0.00	0.27
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other*	1.00		
Distributed Generation			
Undecided			
Total Resources	**27.67**	**26.78**	**27.46**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Wahkiakum County PUD No 1

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	5.39	5.29	5.37
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response			
BPA Tier 1 (include BPA PF)	5.01	5.01	5.01
BPA Tier 2	0.39	0.28	0.36
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**5.39**	**5.29**	**5.37**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Whatcom County PUD No 1

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	26.45	30.27	29.94
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response			
BPA Tier 1 (include BPA PF)	26.45	26.83	26.83
BPA Tier 2		3.44	3.11
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**26.45**	**30.27**	**29.94**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Yakama Power

Washington State Utility Resource Plan Year 2022

Prepared by: BPA

	Base Year	5 Yr. Est.	10 Yr Est.
Estimate Year	**2021**	**2026**	**2031**
Period	**Annual**	**Annual**	**Annual**
Units	**(MWa)**	**(MWa)**	**(MWa)**
Loads	17.66	18.59	18.80
Resources:			
Future Conservation/Efficiency		0.00	0.00
Demand Response			
BPA Tier 1 (include BPA PF)	17.66	18.59	18.80
BPA Tier 2			
Non BPA:			
Co-generation			
Hydro (critical water)			
Wind			
Other Renewables			
Thermal-Natural Gas			
Thermal-Coal			
Market Purchase (non BPA)			
Other			
Distributed Generation			
Undecided			
Total Resources	**17.66**	**18.59**	**18.80**
Load Resource Balance	**0.00**	**0.00**	**0.00**

Appendix B: Washington Utility Customer Count, Revenue, Sales, and Average Price[29]

2021 Utility Data

	Customers (Count)	Revenue (Thousand Dollars)	Retail Sales (Megawatthours)	Average Price (Cents/kWh)
Cooperatives				
Inland Power & Light Company	42,755	$62,455	977,541	6¢
Peninsula Light Company	34,707	$60,505	602,240	10¢
Elmhurst Mutual Power & Light Co	15,741	$19,527	287,017	7¢
Orcas Power & Light Coop	15,569	$32,011	219,743	15¢
Benton Rural Electric Assn	15,309	$42,519	592,182	7¢
Modern Electric Water Company	10,420	$14,926	224,121	7¢
Lakeview Light & Power	10,311	$23,531	252,098	9¢
Big Bend Electric Coop, Inc	9,686	$39,958	582,631	7¢
Columbia Rural Elec Assn, Inc	5,999	$33,350	381,765	9¢
Tanner Electric Coop	5,186	$12,316	95,867	13¢
Parkland Light & Water Company	4,603	$8,799	113,343	8¢
Ohop Mutual Light Company, Inc	4,591	$7,542	90,949	8¢
Okanogan County Elec Coop, Inc	3,952	$6,356	65,828	10¢
Nespelem Valley Elec Coop, Inc	1,536	$5,311	64,234	8¢
Clearwater Power Company	1,030	$2,305	22,054	10¢
Alder Mutual Light Co, Inc	315	$405	5,019	8¢
Kootenai Electric Cooperative	97	$245	2,807	9¢
Northern Lights, Inc	15	$15	117	13¢
Investor Owned				
Puget Sound Energy Inc	1,196,851	$2,367,219	23,282,858	10¢
Avista Corp	263,559	$568,172	5,730,590	10¢
PacifiCorp	134,816	$339,381	4,198,960	8¢
Municipal				
City of Seattle - (WA)	485,155	$952,665	8,922,444	11¢
City of Tacoma - (WA)	184,103	$380,881	4,642,537	8¢
City of Richland - (WA)	26,485	$74,590	950,951	8¢
City of Port Angeles - (WA)	11,864	$24,942	374,660	7¢
City of Centralia - (WA)	10,550	$26,480	266,777	10¢

[29] Energy Information Administration. (2023, October 5). Annual Electric Power Information Report. Retrieved from https://www.eia.gov/electricity/data/eia861/

	Customers (Count)	Revenue (Thousand Dollars)	Retail Sales (Megawatthours)	Average Price (Cents/kWh)
City of Ellensburg - (WA)	10,345	$18,148	206,175	9¢
City of Cheney - (WA)	5,879	$8,325	134,942	6¢
City of Blaine - (WA)	3,612	$6,853	81,074	8¢
City of Milton - (WA)	3,541	$4,989	55,790	9¢
Town of Steilacoom	2,990	$4,069	38,973	10¢
City of Chewelah	1,341	$2,001	21,433	9¢
Town of Eatonville - (WA)	1,278	$2,210	27,312	8¢
City of McCleary - (WA)	1,227	$2,892	32,390	9¢
City of Sumas - (WA)	1,050	$2,300	30,431	8¢
City of Coulee Dam - (WA)	605	$1,169	16,749	7¢
Town of Ruston - (WA)	575	$1,160	9,330	12¢
Public Utility Districts				
PUD No 1 of Asotin County	3	$18	302	6¢
PUD 1 of Snohomish County	367,096	$623,345	6,587,977	9¢
PUD No 1 of Clark County - (WA)	224,988	$381,092	4,675,496	8¢
PUD No 1 of Benton County	56,072	$130,786	1,807,315	7¢
PUD No 2 of Grant County	53,213	$231,937	5,382,366	4¢
PUD No 1 of Cowlitz County	52,217	$261,272	4,509,075	6¢
PUD No 1 of Chelan County	48,576	$80,373	1,984,267	4¢
PUD No 1 of Grays Harbor County	43,620	$107,549	1,164,781	9¢
PUD No 3 of Mason County	35,082	$71,024	675,366	11¢
PUD No 1 of Lewis County	33,873	$79,825	948,798	8¢
PUD No 1 of Clallam County	33,397	$68,656	651,819	11¢
PUD No 1 of Franklin County	28,824	$85,833	1,104,954	8¢
PUD No 1 of Okanogan County	21,663	$49,357	616,510	8¢
PUD No 1 of Jefferson County	20,440	$38,776	377,797	10¢
PUD No 2 of Pacific County	18,071	$25,814	309,414	8¢
PUD No 1 of Douglas County	16,779	$38,958	1,222,085	3¢
PUD No 1 of Klickitat County	13,696	$36,090	442,246	8¢
Vera Irrigation District #15	12,920	$19,233	234,126	8¢
PUD No 1 of Pend Oreille County	9,648	$20,298	275,483	7¢
PUD No 1 of Skamania Co	6,470	$14,079	127,678	11¢
PUD No 1 of Mason County	5,505	$9,711	81,779	12¢
PUD No 1 of Kittitas County	4,888	$11,687	110,501	11¢
PUD No 1 of Ferry County	3,700	$7,179	72,939	10¢
PUD No 1 of Wahkiakum County	2,685	$4,422	43,860	10¢
PUD No 1 of Whatcom County	1	$11,479	223,343	5¢

Appendix C: Glossary of Terms

Average Annual Energy: one megawatt is equal to one million watts. One million watts delivered continuously 24 hours a day for a year (8,760 hours) is called an average megawatt. The maximum amount of power a generating plant is capable of producing over the course of an average year is called its generating capability or average annual energy, expressed in average megawatts.

Cogeneration: the sequential production of electricity and useful thermal energy from a common fuel source.

Demand Response: the voluntary and temporary reduction in consumers' use of electricity when the power system is stressed. It includes voluntary demand response, demand response with paid incentives, time-of-use, and demand voltage reduction programs.

Distributed Generation: an eligible renewable resource where the facility or any integrated cluster of generating units has a generating capacity of not more than five megawatts.

Duration Value at Risk (VaR Duration): longest shortfall event for the 97.5th worst simulation year. VaR Duration sets a limit for shortfall duration during rare (once per 40 year) events. To calculate this metric, the duration of the longest shortfall event for each simulation year is recorded (or zero if there is no shortfall). The Duration VaR97.5 is the 97.5th highest duration from that record. Choosing the 97.5th percentile limits the risk of an excessively long shortfall event to no more than once per 40 years.

Energy Conservation Measures: any reduction in electric power consumption resulting from increases in the efficiency of energy use, production, or distribution.

Energy Value at Risk (VaR Energy): total annual shortfall energy for the 97.5th worst simulation year. VaR Energy set limits for the big energy shortfalls during rare (once per 40 year) events.

Loss of Load Probability (LOLP): traditionally, a power supply is deemed to be adequate when its annual Loss of Load Probability (LOLP) is 5% or less; that is, when the likelihood of having one or more shortfalls during an operating year is less than or equal to 5%. A 5% LOLP means that the simulated operation of the power supply yields only one year out of 20 with shortfalls.

Loss of Load Events (LOLEV): the expected number of shortfall events per year. A shortfall event is a set of contiguous hours of unserved demand. LOLEV is equal to the total number of shortfall events divided by the total number of simulation years.

Net short-term contracts/Market Purchases: refers to limited duration wholesale power purchase not to exceed one month, made by an electric utility for delivery to Washington retail electric customers for which the source of the power is not known at the time of entry into the transaction to procure the electricity.

Loads: electric loads include retail sales + line losses + utility needs. The base year includes existing conservation or demand reduction as a part of base year load. All projected electric loads (non-base year) are estimated before reductions from energy conservation measure programs or demand response program estimates. Additional future conservation and demand response are treated as resources to meet future load.

Peak Energy: highest estimated one-hour load for summer and winter, normalized for weather.

Peak Value at Risk (VaR Peak): highest single-hour shortfall for the 97.5th worst simulation year. VaR Peak set limits for occurrences of big energy shortfalls during rare (once per 40 year) events.

Resource Adequacy: the ability of the electricity system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components.

Renewable Resources: RCW 19.280, Electricity Utility Resource Plans, defines "renewable resources" as "electricity generation facilities fueled by: (a) Water; (b) wind; c) solar energy, (d) geothermal energy, (e) landfill gas, (f) biomass energy utilizing animal waste, solid organic fuels from wood, forest or field residues or dedicated energy crops that do not include wood pieces that have been treated with chemical preservatives such as creosote, pentachlorophenol, or copper-chrome-arsenic; (g) by-products of pulping or wood manufacturing processes, including but not limited to bark, wood chips, sawdust, and lignin in spent pulping liquors; (h) ocean thermal, wave or tidal power; and (i) gas from sewage treatment facilities."

Western Electricity Coordinating Council (WECC): WECC promotes bulk power system reliability and security in the Western Interconnection. WECC is the regional entity responsible for compliance monitoring and enforcement and oversees reliability planning and assessments. In addition, WECC provides an environment for the development of reliability standards and the coordination of the operating and planning activities of its members.

Western Interconnection: the geographic area containing the synchronously operated electric grid in the western part of North America, which includes parts of Montana, Nebraska, New Mexico, South Dakota, Texas, Wyoming and Mexico and all of Arizona, California, Colorado, Idaho, Nevada, Oregon, Utah, Washington and the Canadian provinces of British Columbia and Alberta.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-89:
Washington Agencies Resource Adequacy Meeting Summaries (Compiled)

November 19, 2025

The Honorable Bob Ferguson
Governor of Washington
Office of the Governor
PO Box 40913
Olympia WA 98504-0913

The Honorable Sarah Bannister
Secretary of the Senate
312 Legislative Building
PO Box 40482
Olympia WA 98504-0482

The Honorable Bernard Dean
Chief Clerk of the House of Representatives
338 Legislative Building
PO Box 40482
Olympia WA 98504-0482

Re: Summary of the 2025 Long-term Resource Adequacy Meeting

Dear Governor Ferguson, Secretary Bannister, and Chief Clerk Dean,

We submit this attached summary of the 2025 long-term resource adequacy meeting held Sept. 22, 2025, as required by statute. This year, in response to public feedback to expand our schedule under RCW 19.280.065, we hosted three meetings: one each for summer readiness, long-term resource adequacy, and winter preparedness. The meeting agendas, recordings of each meeting, and presentation materials are available on the Department of Commerce webpage and the Utilities and Transportation Commission webpage.

Reliability assessments presented at the September 22 meeting indicated that the Northwest's electric grid meets national resource adequacy criteria over the near and medium terms under a broad range of operating conditions. As a region assessed as "normal risk," the Northwest has a low likelihood of electricity supply shortfall.

However, "normal risk" is not the same as "no risk." Although areas categorized as normal risk are expected to have sufficient resources for plausible extreme conditions, they are not immune to the effects of high-impact, low frequency weather events that affect demand and generation

simultaneously. Presentations also indicated that normal conditions are shifting with the impacts of climate change, large new electricity uses like data centers and building and vehicle electrification. If significant new electricity usage materializes and more extreme weather continues, the grid could face reliability challenges. Presentations emphasized that no electric system is 100% resource adequate, and there is no resource that provides perfect capacity. We also underscore that it is important to incorporate risks associated with fossil generating resources, including fuel supply risk and weather-driven forced outages.

With this uncertainty, it is clear that utilities and policy makers must increase efforts to make customer energy demand more flexible, reduce delays in siting and interconnecting new clean energy projects, expand regional transmission capacity, and improve transparency and accuracy of load forecasts and planned resource additions. There is also a need to consider potential changes to the mix of generating resources with greater focus on the capacity and fuel requirements of the power system during critical periods, such as days of extreme cold combined with low hydroelectric and wind generation.

Lack of Clarity Surrounding New Load Growth
There is limited visibility into whether large customer (including data center) interconnection requests are duplicative or speculative, and utility-submitted data on planned resource additions are less predictable than in recent history.

Discussions at the meeting underscored that, under some forecasts presented, if the region did not add new generation capacity by 2030, it would have a resource gap equivalent to the current electricity requirements of the State of Oregon, approximately 9 gigawatts. Existing utility integrated resource plans (IRPs) show this gap closing. In addition, collaborative utility efforts, such as the Northwest Energy Efficiency Association's End-Use Load Flexibility project,[1] show progress on reducing peak electricity demand through grid-connected consumer products and dynamic services.

New Resource Challenges
We should be cautious of the assumptions behind the finding of adequacy. Bringing new resources online continues to be difficult due to:

- Changes in federal policy and corresponding increased costs,
- Lack of in-state and regional transmission capacity, and
- Permitting and interconnection challenges.

Voluntary Resource Adequacy Program Struggles
Shortly after our meeting, six utilities announced they would not join the Western Resource Adequacy Program (WRAP). This is an industry-led, voluntary regional resource adequacy program to help utilities share resources during scarcity. PacifiCorp, which serves approximately 141,000 customers in Washington, opted out of the program, while Avista and Puget Sound

[1] End-Use Load Flexibility - Northwest Energy Efficiency Alliance (NEEA).

Energy remain in. Reduced WRAP participation means that there will be fewer resources to share, and therefore the benefits of the program potentially diminish for Washington utilities and customers. Some utilities that have opted out of WRAP are now in talks to potentially create their own regional program. We continue to monitor this dynamic and encourage continued development and participation in regional resource adequacy initiatives.

Meanwhile, climate change is making extreme weather more frequent, posing the gravest threat to grid reliability. The experts who gathered at this meeting continue to stress that the increased severity and frequency of extreme weather events from climate change pose the greatest threat to resource adequacy.

We look forward to continuing to partner with you on this work.

Sincerely,





Brian J. Rybarik
Chair
WA Utilities and Transportation Commission

Jennifer Grove
Assistant Director, Energy Division
Washington Department of Commerce

Enclosure (1)
cc:

2025 Long-Term Resource Adequacy Meeting Summary

Introduction

On September 22, 2025, the Washington Utilities and Transportation Commission (UTC) and the Washington Department of Commerce (Commerce) convened a public meeting to review the adequacy of energy resources to serve the state's electricity needs and receive an update from regional experts and Washington utilities on the long-term resource adequacy of the electric grid. We convened this meeting and submit this summary in response to public feedback to expand our annual resource adequacy meeting under RCW 19.280.065 to three meetings: one meeting in the spring focused on summer readiness, one meeting in late summer to discuss long-term resource adequacy, and another in late fall to focus on winter preparedness.
RCW 19.280.065(1) says:

> At least once every twelve months, the department and the commission shall jointly convene a meeting of representatives of the investor-owned utilities and consumer-owned utilities, regional planning organizations, transmission operators, and other stakeholders to discuss the current, short-term, and long-term adequacy of energy resources to serve the state's electric needs, and address specific steps the utilities can take to coordinate planning in light of the significant changes to the Northwest's power system including, but not limited to, technological developments, retirements of legacy baseload power generation resources, and changes in laws and regulations affecting power supply options. The department and commission shall provide a summary of these meetings, including any specific action items, to the governor and legislature within sixty days of the meeting.

Maintaining an adequate supply of electricity is a core obligation of the utilities that provide electric service to Washington residents and businesses. State policy reinforces this obligation as Washington transforms its electric power system and economy, reducing and eventually eliminating emissions from fossil fuel combustion for electricity generation.[2]

The state's 100% clean electricity law, the Clean Energy Transformation Act,[3] includes requirements for utilities to establish specific standards for resource adequacy and incorporate those standards into their planning and compliance.[4] As utilities reduce reliance on fossil fuels and add renewable resources such as wind and solar, new approaches and resources will be required to maintain resource adequacy.

While resource adequacy is an obligation of each electric utility serving end-use customers in the state, it also is a shared responsibility of the overall electric power system and the entities that operate, plan, regulate, design, and fund that system.

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[2] Washington 2021 State Energy Strategy, page 119-120. https://commerce.wa.gov/energystrategy

[3] Chapter 19.405 RCW.

[4] RCW 19.280.030. This resource planning statute was amended by the CETA legislation to add explicit resource adequacy provisions.

The following summarizes the presentations and discussion at the September 2025 meeting.

Resource Adequacy 101—Energy Systems Integration Group
Energy Systems Integration Group (ESIG) is a non-profit organization and a leading source of expertise for energy systems around the world. ESIG described resource adequacy as "the ability of the electric system to supply firm demand at all times (up to some criteria)." This definition highlights two important aspects of resource adequacy.

- Resource adequacy refers to the ability to generate and move power over transmission lines to where it is needed; it does not include local distribution line disruptions.
- It is measured against criteria, such as a One-day-in-ten-years loss-of-load event, which determines an acceptable amount of risk of resource shortfall.

In other words, resource adequacy is the likelihood we will have enough power and transmission to meet electricity demand based on defined criteria. Changes in resource adequacy criteria may impact whether an electric system is deemed adequate. The industry is increasingly moving to multi-metric criteria to examine the adequacy of the electric system and the capacity contributions of individual resources to account for shifting resource adequacy risks, such as potential weather-related and fuel supply outages.

Key takeaways from the presentation were that no electric system is 100% resource adequate, and there is no resource that provides perfect capacity. Meeting resource adequacy will require utilities to develop diverse resource portfolios and secure transmission capacity necessary to meet multi-metric criteria. Utilities should continue to evaluate the adequacy of their resource portfolios as the region adds new loads. ESIG observed a system that was 100% adequate would be cost prohibitive.

ESIG offered a number of ways to improve resource adequacy while lowering system costs, including energy efficiency and demand response, expansion of regional transmission and energy markets, and adoption of a binding regional resource adequacy program, such as the WRAP, that would allow utilities to coordinate their diverse resources to avoid shortfalls.

Reliability Assessments — North American Electric Reliability Corporation and Western Electric Coordinating Council
The North American Electric Reliability Corporation (NERC) is the Electric Reliability Organization for North America. Its mission is to assure the effective reduction of risks to the reliability and security of the grid. It is subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. The Western Electricity Coordinating Council (WECC) is one of six regional entities under NERC that has authority delegated under the Federal Power Act to ensure a reliable and secure bulk power system throughout the Western Interconnection. WECC has the responsibility to create, monitor, and enforce reliability standards and promote activities, such as regional resource adequacy assessments, of the bulk power system in the Western Interconnection.

NERC presented its 2024 Long-Term Reliability Assessment (LTRA), as its 2025 LTRA was not yet complete at the time of the meeting. The LTRA found that unlike some parts of the United

States, which have an elevated risk of resource inadequacy, the Western Interconnection has a normal level of risk as of the 2024 assessment.

Study results show WECC is in the top one-third of all assessment areas for demand growth. Demand growth is being driven primarily by data centers, but also industrial onshoring and electrification of transportation and buildings. Meanwhile, resource projections reflect slower rates of additional resources being interconnected to the grid due to project delays and cancellations.

Data presented by WECC shows the Northwest adding 14 GW in new generation between 2026 and 2035. Nearly all these resource additions are intermittent power sources, and almost half of the generation comes from wind. Meanwhile, nearly 345 MW of generation over the same time period is planned to be retired, roughly 85% of which are clean resources. In the Northwest subregion, annual demand is expected to grow 24% between 2026 and 2035 with peak demand expected to increase by 20.6%.

The information that goes into the LTRA is aggregated from data provided by balancing authorities that collect and aggregate resource plans of utilities (not all utilities are balancing authorities). WECC explained they have been working more closely with balancing authorities and utilities to standardize and ensure the integrity of reporting to WECC.

Northwest Utilities Resource Adequacy Study — Energy and Environmental Economics, Inc.
Energy and Environmental Economics, Inc. (E3) is a nationally recognized consultant specializing in decarbonization and the clean energy transition, including climate policy analysis, integrated system planning, and asset valuation and strategy. E3 was retained by Pacific Northwest utilities and generation owners to evaluate resource adequacy in the Pacific Northwest today and in the future. The industry hired E3 to do a similar study prior to adoption of Washington's 100% clean electricity law, the Clean Energy Transformation Act (CETA), in 2019. The findings are similar.

The preliminary results of the 2025 study suggest the planned resource additions in utility IRPs are likely sufficient to meet the region's resource adequacy needs, but that meeting the pace of growth anticipated in utility IRPs will require annual resource additions equal to four to five times historic levels. The study finds the region experiencing significant headwinds due to permitting and interconnection delays, changes in federal policy, and higher costs. Without any new resource additions, the region would have a gap in resources beginning in 2026 and growing to 9 gigawatts by 2030, which is approximately the load of the state of Oregon. Data centers and the electrification of buildings and transportation are the principal contributors to load growth.

The study finds the most constraining reliability conditions are extended cold weather events in the winter during very low water years. The preliminary results suggest utilities will need to deploy some natural gas resources under the 2030 carbon neutral standard of CETA to meet demand during these extreme and infrequent conditions. The second phase of the study, expected by the end of this year, will evaluate resource options for meeting near-term and long-term resource adequacy and clean energy needs.

Update on Data Center Working Group under Governor's EO 25-05 — UTC and Commerce

UTC and Commerce provided an update on the Data Center Workgroup convened by the Department of Revenue and Governor's Office, in response to the Governor's Executive Order 25-05. Representatives from the UTC and Commerce provided a summary of each agency's priorities, which include:

- **Accurate load forecasting:** Speculation and duplicative load forecasts make it hard to forecast regional resource needs.
- **Conformance with state energy and climate laws:** Data center loads should comply with state clean energy and climate laws.
- **Load flexibility:** Data centers should exercise available load flexibility to help the electric grid during peak periods.
- **Leveraging tech investments in transmission and generation:** The state should work with hyperscalers who have immense experience deploying transmission and clean energy technologies and the funding needed to deploy them to the benefit of data centers and the overall electric grid.
- **Adequate resources to maintain reliability:** Utilities should not feel obligated to serve large loads if serving these loads threatens the resource adequacy and reliability of the electric grid.
- **Impacts on hydropower resources and fish populations:** Data center operations should not affect the operation of the hydropower system or fish populations.
- **Rate impacts:** Existing ratepayers should be insulated and protected against potential rate impacts of adding data centers to the electric grid.
- **Clean energy for economic development:** The development of data centers should support the growth of clean energy jobs.

Demand-side Resource Opportunities — Northwest Energy Efficiency Alliance and Tacoma Power

Northwest Energy Efficiency Alliance (NEEA) is an alliance of utilities and partners that pools resources and shares risks to transform the market for energy efficiency to the benefit of all consumers in the Northwest.

Recently NEEA announced that 10 regional utilities are funding an End-Use Load Flexibility initiative, exploring ways that grid-connected consumer products and dynamic services can fill regional winter-time power constraints within the next five years.

NEEA forecasts the project will deliver a 1-to-3-gigawatt resource to the region within the next four years, reducing the region's peak load by 10%. NEEA is developing its strategic and business plans for the 2026-2029 period, which include testing and refining projects and scaling and adapting utility load-flex programs by codifying best practices and providing tools to support market awareness.

Tacoma Power shared the potential for demand flexibility in its service territory and the technical and economic challenges of being an early adopter of demand response. The utility shared that

industrial partners were often eager to participate in demand response programs. Residential customers have varied responses and often require intentional outreach before participating.

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July 30, 2025

The Honorable Bob Ferguson, Governor of Washington
The Honorable Sarah Bannister, Secretary of the Senate
The Honorable Bernard Dean, Chief Clerk of the House

Re: Summary of the 2025 Summer Readiness Resource Adequacy Meeting

Dear Governor Ferguson and Members of the State Legislature:

It is our pleasure to provide the attached summary of a meeting held by the Department of Commerce and the Utilities and Transportation Commission on June 5, 2025, concerning resource adequacy, specifically focused on utility preparations to meet summer conditions, or summer readiness. We convened this meeting and submit this summary in response to public feedback to expand our annual resource adequacy meeting under RCW 19.280.065 to three meetings per year: one focused on summer readiness, another on long-term resource adequacy, and the third on winter preparedness. The meeting agenda, a recording of the meeting, and presentation materials from the first meeting are available on the Department of Commerce webpage and the Utilities and Transportation Commission webpage.

The expert assessments on resource adequacy presented at the summer readiness meeting conclude the Northwest has adequate resources to meet expected demand for electricity this summer and does not face a significant risk of outages under normal weather conditions. However, low snowpack and warmer and drier weather this summer pose an increased likelihood of wildfires and heat waves, especially in certain parts of the state. The Bonneville Power Administration (BPA) and Washington utilities reported they have the resources to meet customer and business demand and that short-term weather-related events are unlikely to impact the electric power system. That said, long duration heat waves and catastrophic wildfires across the West increase the risk of resource inadequacy and could severely strain the electric power system.

BPA and Washington utilities are taking steps to harden their systems against weather-related threats. The risk of the federal government no longer providing National Oceanic Atmospheric Administration (NOAA) weather data threatens the ability of weather experts and Washington utilities to identify weather-related threats to the electric power system.

The meeting included an update on the development of the Western Resource Adequacy Program (WRAP)—a utility-initiated effort to hold participating utilities accountable for maintaining reliable service while maximizing reliability benefits and cost savings of their

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diverse resources and loads. While acknowledging the challenges of implementing this program, we remain concerned that the industry is not moving fast enough to align itself with the contractual requirements of the program, and that some utilities have not committed to participating in the program. Nonetheless, we appreciate the commitment to WRAP implementation expressed by many utilities and the revised transition plan shared after our 2024 resource adequacy meeting.

Expert assessments of resource adequacy presented at this meeting highlight the need for the state and region to hasten efforts to increase transmission capacity and secure resources and strategies to meet medium-to-long-term load growth. These projects have long timelines and need to begin construction soon to be serviceable in the medium-to-long term. On the demand-side, a few utilities have started leveraging small demand response and virtual power plant programs to reduce peak demand on the power system. If scaled, these programs represent an immense opportunity to reduce peak demand. We look forward to taking a deeper dive into medium-and-long-term resource adequacy issues and policy opportunities at our next resource adequacy meeting, scheduled for Sept. 22, 2025.

This meeting's presentations highlight that the greatest near-term threat to resource adequacy is weather-related events, which continue to grow more severe and wide spread. We remain committed to monitoring resource adequacy and appreciate the continued engagement of the utility industry and consumer and environmental advocates, as our state continues to pursue resource adequacy while combatting climate change in an affordable and equitable manner.

Sincerely,

Brian Rybrik
Chair
WA Utilities and Transportation Commission

Signed by:
Jennifer Grove
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Jennifer Grove
Assistant Director, Energy Division
WA Department of Commerce

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2025 Summer Readiness Resource Adequacy Meeting Summary

Introduction

On June 5, 2025, the Washington Utilities and Transportation Commission (UTC) and the Washington Department of Commerce (Commerce) convened a public meeting to review the adequacy of energy resources to serve the state's electricity needs and receive an update from regional experts and Washington utilities on their readiness for the summer of 2025.
We convened this meeting and submit this summary in response to public feedback to expand our annual resource adequacy meeting under RCW 19.280.065 to three annual meetings: one meeting in the spring focused on summer readiness, one meeting in late summer to discuss long-term resource adequacy, and another to be schedule in late fall to focus on winter preparedness.
RCW 19.280.065(1) requires:

> At least once every twelve months, the department and the commission shall jointly convene a meeting of representatives of the investor-owned utilities and consumer-owned utilities, regional planning organizations, transmission operators, and other stakeholders to discuss the current, short-term, and long-term adequacy of energy resources to serve the state's electric needs, and address specific steps the utilities can take to coordinate planning in light of the significant changes to the Northwest's power system including, but not limited to, technological developments, retirements of legacy baseload power generation resources, and changes in laws and regulations affecting power supply options. The department and commission shall provide a summary of these meetings, including any specific action items, to the governor and legislature within sixty days of the meeting.

Maintaining an adequate supply of electricity is a core obligation of the utilities that provide electric service to the residents and businesses of Washington. State policy reinforces this obligation as Washington transforms its electric power system and economy, reducing and eventually eliminating emissions from fossil fuel combustion for electricity generation.[1]

The state's 100% clean electricity law, the Clean Energy Transformation Act,[2] includes requirements for utilities to establish specific standards for resource adequacy and incorporate those standards into their planning and compliance.[3] As utilities reduce reliance on coal-fired and gas-fired power plants and add renewable resources such as wind and solar, new approaches and resources will be required to maintain resource adequacy. It is equally important to incorporate risks associated with fossil generating resources, including fuel supply risk and weather-driven forced outage risk.

While resource adequacy is an obligation of each electric utility serving end use customers in the state, it also is a shared responsibility of the overall electric power system and the entities that operate, plan, regulate, design, and fund that system.

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[1] Washington 2021 State Energy Strategy, page 119-120. https://commerce.wa.gov/energystrategy
[2] Chapter 19.405 RCW.
[3] RCW 19.280.030. This resource planning statute was amended by the CETA legislation to add explicit resource adequacy provisions.

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The following summarizes the presentations and discussion at the June 2025 meeting.

Summer Assessment—Western Electricity Coordinating Council (WECC)
The Western Electricity Coordinating Council (WECC) is a regional entity with authority delegated under the Federal Power Act to ensure a reliable and secure bulk power system throughout the Western Interconnection. WECC has the responsibility to create, monitor, and enforce reliability standards and promote activities, such as regional resource adequacy assessments, of the bulk power system in the Western Interconnection.

WECC presented findings from the 2025 North American Electric Reliability Corporation (NERC) Summer Reliability Assessment, and the WECC 2025 State of the Interconnection and 2025 Western Assessment of Resource Adequacy reports.

The assessments show the region has adequate resources in the short-term with weather-related events being the greatest threat to resource adequacy in the near term. The assessments show an unprecedented growth in regional resource demand in the medium to long term driven by large industrial loads, including data centers. The region needs to redouble efforts now to increase transmission capacity and generation resources to meet load growth and maintain resource adequacy over the medium-to-long term.

WECC shared that its assessments are informed by individual utility resource plans. These plans may in the aggregate overstate future resource needs, because large industrial loads, such as data centers, are counted multiple times if they submit interconnection requests across multiple utility service territories, which is common across the rapidly expanding data center industry. On the other hand, utility-submitted data currently lacks enough granularity to understand the status of projected new generation resources in utility IRPs. Improved transparency and consistency in utility reporting in response to these emerging industrial and resource adequacy trends is key to improving the precision of future WECC assessments.

Western Resource Adequacy Program — Western Power Pool
The Western Power Pool shared an update on the Western Resource Adequacy Program (WRAP). The program aims to transition individual utility resource adequacy approaches to a single resource adequacy standard and program to make it easier for utilities to share energy in times of need. A uniform resource adequacy standard will increase transparency into regional needs and help the region utilize diverse resources and loads to reduce overall capacity needs among participating utilities.

WRAP remains in a non-binding phase. During this phase, utilities submit data and view their resource obligations, which helps identify whether they have enough contracted capacity to comply with program requirements. This past year, the program added an option to allow participants with resource needs to “raise their hand” to enlist the help of other members with excess resources. There is no obligation to offer help and no penalties for non-compliance with program requirements during the non-binding phase.

Summer Readiness — Bonneville Power Administration
The Bonneville Power Administration (BPA) is obligated under the Pacific Northwest Electric Power Planning and Conservation Act to assure the adequate supply of power to its load-following customers. Those obligations are satisfied through 20-year contracts due to be updated in 2028. Utilities that elect slice or block contracts retain responsibility for their own resource adequacy.

BPA reported that it has adequate contracted resources to meet WRAP requirements and plans to join the binding phase of the program at program launch in the winter of 2027-2028. BPA anticipates reduced stream flow with this past winter's snowpack concentrated in areas of its system with less generation but expects minimal risks to its system given current hydraulic forecasts. BPA shared that its power system is well positioned to respond to short-term weather events, but longer-term weather events could put stress on its system.

Current conditions and Summer Outlook — Washington State Climate Office
The Washington State Climate Office (WASCO) housed at the University of Washington monitors and forecasts climate trends, provides training and capacity building, houses data and information resources on Washington's current and past climate, and conducts applied research on the climate and its impacts to Washington residents.

WASCO reported that this past winter was drier than normal with low precipitation leaving little snowpack for multiple years in a row. Snow sites are melting two-to-four weeks faster than usual, compounding precipitation deficits and the risk of wildfires this summer. An emergency drought declaration has already been issued for Yakima County and drought advisories have been issued for seven other counties. Weather forecasts indicate a higher likelihood that this summer will be warmer and drier than normal conditions expected, leaving our state at an elevated risk of wildfires and more frequent, longer-duration heat waves through September.

Summer Readiness — Puget Sound Energy
Puget Sound Energy (PSE) reported that the utility is participating in WRAP and plans to enter the binding phase of the program in the Winter of 2027-2028. PSE reported the utility has enough resources to meet peak summer demand and plans in place to coordinate with transmission providers to deliver power to customers during heat events. The utility holds daily coordination calls on system conditions between real-time power merchants and PSE's load office operations and has backup fuel (diesel) in place for natural gas fired generation if needed.

PSE provided information about the impact of its nascent demand response and virtual power plant programs in reducing load to maintain resource adequacy. PSE intends to build on the success of its demand response and virtual programs going forward.

Summer Readiness: System Operations Overview — Avista
Avista expects to meet resource adequacy this summer. Avista has broadened its transmission portfolio with BPA and added new transmission capacity on its own lines. The utility sees wildfires as the largest risk to resource adequacy this summer. In partnership with the Department of Natural Resources and local fire responders, Avista has newly installed cameras across its service territory to detect smoke and send alerts to Avista and local fire responders. In

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addition, Avista is adding weather stations to help the utility better understand and manage risks to its system.

Wildfire and Summer Readiness — PacifiCorp
PacifiCorp acknowledged higher than expected wildfire risk in its service territory in Yakima County. The utility reported that across its multi-state service territory it is investing $2 billion to improve its situational awareness, harden its electric grid, and improve operations to respond to weather-related threats and outages. This includes new protocols to improve communications with customers. In addition, the utility reported it is investing 75 GW in natural gas resources across its multi-state footprint.

PacifiCorp shared that its newly energized Gateway South transmission project from Wyoming to Salt Lake City has loosened up congestion on its transmission system and allowed additional wind resources onto its system. The utility reported it has resources to meet the resource adequacy needs of Washington customers and businesses, but extreme heat with little decrease in nightly temperatures across the Pacific Northwest, Desert Southwest and California would cause extremely high loads and strain its system.

Summer Readiness — Public Generating Pool
The Public Generating Pool (PGP) is composed of eight publicly owned electric utilities in Washington and one electric utility in Oregon. The Washington utilities in PGP include Seattle City Light, Snohomish County Public Utility District (PUD), Tacoma Power, Clark County PUD, Chelan County PUD, Grant County PUD, Lewis County PUD, and Cowlitz County PUD. These utilities operate non-federal assets and purchase 35% of their power from BPA.
PGP reported its member utilities are seeing near average hydro levels and did not have anything to flag for the summer of 2025. PGP is concerned that the region will grow more dependent on imported power and laments the lack of a regional summer preparedness dashboard, which is common in parts of the county with regional transmission organizations.

Public Comment
Christina Wyatt of Big Bend Electric Cooperative shared that as a Bonneville Customer in multiple balancing authorities Big Bend does not have any real time operational signals and there is a lack of fiber to implement demand response programs. She said that 50% of Big Bend's customers are irrigation customers and a demand response program would require them to shutoff power, which would impact food security.

Lauren McCloy of the Northwest Energy Coalition (NWEC) shared her observations from the meeting. She highlighted how the presentations stressed the importance of transmission to resource adequacy and demand response. NWEC views demand response as a low-cost way to meet the capacity needs of the region and encourages the region to continue to investigate how to best integrate demand response on the grid and pilot projects to develop and scale demand response programs. NWEC advocated for everyone to continue to encourage the federal government to keep data on water levels in the public realm.

Blake Scherer of Benton PUD commented that "the continued implementation of CETA is in itself a risk to utility resource adequacy and affordability, especially penalizing dispatchable

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natural gas resources and promoting the overbuild of non-dispatchable, transmission-dependent, land-intensive wind and solar resources." He said CETA legislation allows CETA to suspend implementation of the law or exempt a utility from paying penalties if Commerce finds RCW 19.405.080 demonstrates adverse system reliability impacts due to CETA[4]. The first report said it was too early to tell if CETA was impacting system reliability. The next report is due in July of 2028.

Nicolas Garcia of the Washington Public Utility District Association (WPUDA) stressed that resource adequacy has a real economic impact to households. Resource adequacy challenges can lead to high costs being passed onto customers, especially low-income customers.

[4] We include this statement to reflect public comments provided at the workshop but note that this comment does not accurately state the provisions of law related to temporary suspension of the clean electricity standards. CETA provides a temporary exemption provision in RCW 19.405.090(3) and (5) and provides that the governing body of a consumer-owned utility may authorize a temporary exemption based on factors specified in the statute, without reference to the assessment made by Commerce under RCW 19.405.080.

December 31, 2025

The Honorable Bob Ferguson, Governor of Washington
The Honorable Sarah Bannister, Secretary of the Senate
The Honorable Bernard Dean, Chief Clerk of the House

Re: Summary of the 2025 Winter Preparedness Resource Adequacy Meeting

Dear Governor Ferguson and Members of the State Legislature,

Please find the attached summary of the 2025 winter preparedness resource adequacy meeting held November 4, 2025. This year, in response to public feedback, we expanded our annual resource adequacy meeting under RCW 19.280.065 to three gatherings: one each for summer readiness, long-term resource adequacy, and winter preparedness. The meeting agenda, recording, and presentation materials are available on the Department of Commerce webpage and the Utilities and Transportation Commission webpage.

Winter reliability assessments, presented by regional resource adequacy experts, the North American Electric Reliability Corporation and Western Electricity Coordinating Council, indicate the Northwest's electric grid meets national resource adequacy criteria under normal conditions this winter. Extreme weather poses an elevated risk of short-duration outages absent additional measures, such as utilities following their emergency policies and procedures or firing up their backup generators. The Bonneville Power Administration and Washington utilities do not forecast outages this winter.

At the November 4 meeting, the Bonneville Power Administration and utilities shared the steps they are taking in preparation for the season. This includes daily monitoring of weather conditions, regular calls with reliability coordinators and fuel suppliers, maintenance of the system, and updates to their operations and emergency planning procedures. Utilities reported they have maximized hydro and natural gas storage ahead of winter and ensured facilities are operating properly. Some, such as Seattle City Light and Puget Sound Energy, noted voluntary customer curtailment programs intended to help offset electricity demand if needed.

The meeting highlighted the need for coordination between the natural gas system and the electric system to ensure a reliable energy supply throughout winter. The Northwest Gas Association and Pacific Northwest Utilities Conference Committee discussed collaboration between the electric and gas industries to prepare for winter, as well as broader efforts to bring utility leaders, regulators, state policymakers, power producers, and other stakeholders together, for the purposes of better cross-sector planning and operations. This ensures discussion around

the increased interdependence of gas and electric systems as the region continues its transition to clean energy and state-level climate goals. We appreciate seeing natural gas and electric utilities working together to ensure affordable, reliable, and equitable services for Washington customers.

Preparing for this winter
Washington has already seen some extreme weather as the winter season begins. Utilities can take near-term steps to preserve reliable service in case of extreme weather. These include:

- Ensuring customers' backup generators are in service and ready to be deployed,
- Ensuring the industry's emergency and curtailment plans and procedures are in place, and
- Coordinated planning and response between electric and natural gas systems.

Preparing for future winters
While this meeting focused on readiness for winter 2025-2026, there is a clear need for concerted action to prepare for future winters. Washington law provides utilities with flexibility to use gas-fired generating facilities and, if needed, to expand gas-fired capacity to meet winter peaks. In the meantime, Washington must do more to streamline siting and permitting, add in-state and out-of-state transmission capacity, proactively pursue transmission enhancements and expansions and demand flexibility, and improve resource forecasting for large new loads, such as data centers and advanced manufacturing facilities.

Our energy system is deeply interconnected, and every aspect is vulnerable to extreme weather events fueled by climate change. We remain committed to working with our natural gas and electric utility partners to further our joint efforts to maximize the reliability and affordability of our state's energy system as we decarbonize our economy.

Sincerely,

Brian J. Rybarik
Chair
WA Utilities and Transportation Commission

Jennifer Grove
Assistant Director, Energy Division
WA Department of Commerce

Attachment (1)

2025 Winter Preparedness Adequacy Meeting Summary

Introduction

On November 4, 2025, the Washington Utilities and Transportation Commission (UTC) and the Washington Department of Commerce (Commerce) convened a public meeting to review the adequacy of energy resources to serve the state's electricity and natural gas needs.

We convened this meeting and submit this summary in response to public feedback to expand our annual resource adequacy meeting under RCW 19.280.065 to three annual meetings: one meeting in the spring focused on summer readiness, one meeting in late summer to discuss long-term resource adequacy, and another in late fall to focus on winter preparedness.

RCW 19.280.065(1) says:

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Maintaining an adequate supply is a core obligation of the utilities that provide energy service to the residents and businesses of Washington. State policy reinforces this obligation as Washington transforms its electric power system and economy, reducing and eventually eliminating emissions from fossil fuel combustion for electricity generation.[1]

The state's 100% clean electricity law, the Clean Energy Transformation Act,[2] includes requirements for utilities to establish specific standards for resource adequacy and incorporate those standards into their planning and compliance.[3] As utilities reduce reliance on coal-fired and gas-fired power plants and add renewable resources such as wind and solar, new approaches and resources will be required to maintain resource adequacy. Utilities must also incorporate equally-important risks associated with fossil generating resources, including fuel supply risk and weather-driven forced outage risk.

While resource adequacy is an obligation of each electric utility serving end-use customers in the state, it also is a shared responsibility of the overall energy system and the entities that operate, plan, regulate, design, and fund that system.

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[1] Washington 2021 State Energy Strategy, page 119-120. https://commerce.wa.gov/energystrategy

[2] Chapter 19.405 RCW.

[3] RCW 19.280.030. This resource planning statute was amended by the CETA legislation to add explicit resource adequacy provisions.

Northwest Gas Association (NWGA)—Gas-Electric Integration and Regional Winter Readiness

NWGA represents the Pacific Northwest gas industry, which includes regional natural gas distribution companies and pipeline operators. Natural gas is used for space and water heating, and process heat for industrial applications. In addition, natural gas is used to generate electricity and, in some cases, provides feedstock for other products.

Natural gas and electric systems operate differently. Electrons move instantly and operate at a frequency and not at a speed. The legacy electric grid had no inherent way to store electricity. Meanwhile, natural gas molecules move at about 25 miles an hour, and the natural gas pipeline serves as inherent storage with the packing and drafting of gas molecules. When the electric system experiences systemwide outages, the system can be restored in segments, with power returning when each segment is energized. By comparison, when the gas system experiences a system outage, the system requires door-to-door service to turn off service, and then again for restoration when gas is flowing again.

Today the Pacific Northwest natural gas pipeline system delivers 33 percent more gas than 25 years ago. The majority of the gas, 75 percent, is weather-dependent, used in the winter and summer months. During winter peaks, gas supplies can supply over 75 percent of the total energy customers use in Oregon and Washington. To ensure the gas system can meet this demand, natural gas utilities and suppliers conduct long-term plans that consider pipeline constraints, contract terms, policies, and local distribution, consumption, and generation analyzed in tandem to determine contract needs.

Many natural gas utilities and suppliers participate in mutual assistance agreements, such as the Northwest Mutual Assistance Agreement (NWMAA), to maintain the natural gas system. NWMAA is a voluntary collaboration among entities that control natural gas assets in the Northwest, primarily focused on enhancing reliability during emergencies, such as by providing neighbors with gas. Many utilities have daily communication between gas suppliers and system operators, conduct simulated emergency scenario simulations, and have some level of generation that can switch to secondary fuel, such as fuel oil. Lastly, members of Reliability Coordinator (RC) West, the California Independent System Operator's electricity reliability coordinator in the western US, convene ahead of winter to prepare for regional cold weather events.

Winter Reliability and Electric-Gas Coordination—North American Electric Reliability Corporation (NERC) and Western Electricity Coordination Council (WECC)

NERC is the Electric Reliability Organization for North America, with a mission to assure the effective reduction of risks to reliability and security of the grid. NERC is subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. WECC is one of six regional entities under NERC that has authority delegated under the Federal Power Act to ensure a reliable and secure bulk power system throughout the Western Interconnection. WECC has the responsibility to create, monitor, and enforce reliability standards and promote activities, such as regional resource adequacy assessments, of the bulk power system in the Western Interconnection.

WECC's Winter Reliability Assessment finds long duration cold snaps are the primary concern for grid reliability in the Northwest, British Columbia, and Alberta. Low temperatures can lead to elevated demand, reduced output from renewable and fossil generation facilities, gas delivery constraints, and unplanned transmission and generation outages. The Pacific Northwest is one of a handful regions that face an elevated risk[4] of operating reserves or energy shortfalls in instances of a regionwide cold snap, in which case the region would need to take additional steps, such as running back-up generators or importing power from other regions, to maintain services.

Utilities in the WECC flagged survey responses to NERC that there should be an increased emphasis on regional gas-electric coordination, stressing the need to continue regional tabletop exercises between gas and electric operators to simulate emergency scenarios and improve readiness. Utilities in the West also reported updating pipeline operation logic and expedited emergency protocols, as well as deployment of limited duration battery energy storage systems to increase capacity on the grid.

Winter Preparedness—PacifiCorp

PacifiCorp is an investor-owned electric utility. It serves 141,000 customers in Washington, and a total of 2.1 million customers across Washington, Oregon, Idaho, California, Utah, and Wyoming.

PacifiCorp's Pacific Northwest service territory is winter-peaking, and its southwest is summer-peaking. Based on National Oceanic and Atmospheric Administration (NOAA) weather forecasts from September 2025, the utility anticipates average temperatures in most of the Northwest in October through December, below average temperatures in most of the Northwest in January through March, and above average temperatures in the Southwest portions of WECC throughout winter. PacifiCorp plans to take advantage of its transmission system and regional generation and load diversity to move energy across its Northwest and Southwest territories to meet its Northwest load this winter.

PacifiCorp's operational planning for winter readiness includes securing and maintaining firm gas transportation and power transmission contracts for its electric generation fleet, improved operational coordination between the generation fleet and the natural gas system, extensive winter scenario modeling, and leveraging storage, flexible resources, and regional markets.

Bonneville Power Administration (BPA)

BPA is obligated under the Pacific Northwest Electric Power Planning and Conservation Act to assure the adequate supply of power to its load-following customers. Those obligations are satisfied through 20-year contracts due to be updated in 2028. Utilities that elect slice or block contracts retain responsibility for their own resource adequacy.

BPA is not forecasting any unusual system outages during this winter and has regular capability to meet load during short-term cold snaps. Long-duration cold snaps would introduce more

[4] Elevated risk is an indication of insufficient operating reserves or energy shortfalls in above-normal peak-day demand or outages.

uncertainty and risk to the reliability of BPA's system. Fish passage constraints are currently uncertain and could impact BPA's ability to respond to extreme weather events in March, but BPA observed that extreme weather events in March are rare.

Seattle City Light (SCL)

SCL delivers electricity to approximately 513,500 customers in Seattle and a handful of surrounding communities. SCL expects this winter to be wetter and cooler with healthier snowpacks; however, these weather patterns could make polar vortex events more likely in mid-to-late winter as the polar jet stream weakens. SCL shared it has outage and water management procedures, and has maximized capacity of its system and conserved its hydro storage for use in peak winter events. The utility practices proactive forward hedging when necessary to ensure resource availability and closely monitors weather forecasts.

SCL also has implemented a new large industrial curtailment program, in which large industrial customers can receive incentives to curtail their load during key events. The events in this program are scheduled a day ahead for a 24-hour period, and there are no limits on the number of times the utility can call for industrial customers to curtail. Incentives for participating are based on the day-ahead market value of electricity.

NW Natural Gas (NWN)

NWN plans for all resources to be available at their maximum output. The utility shared that regional natural gas prices are still highly volatile, and cold weather can lead to infrastructure constraints and higher prices. While national natural gas production reached record highs in 2025, NW Natural Gas noted new liquified natural gas (LNG) export facilities are coming online, driving higher demand. Meanwhile, natural gas use for electric power generation remains high.

Cascade Natural Gas (Cascade)

Cascade shared that at 100 percent demand on its system it can meet approximately 53 percent of peak day needs with its storage resources. Total storage capacity accounts for approximately 14.75 percent of winter demand, and winter demand is approximately 68 percent of its annual demand. It has eight natural gas generation plants behind its system, highlighting the importance of gas and electric coordination efforts.

Avista

Avista reported it has prepared for the winter through diversifying their electric and gas portfolio, grid maintenance, regular winter prep calls with natural gas suppliers, increasing planning reserve margins, internal planning, refueling storage facilities, and participation in mutual assistance check-ins.

Avista participated in a NWGA and Pacific Northwest Utilities Conference Committee (PNUCC) symposium created to discuss gas-electric coordination issues, including a tabletop exercise to practice coordination during key events. The utility highlighted that sustained regional cold

fronts, bulk electric or gas system issues, or regional transfer constraints could lead to high prices for customers.

Avista is continuing to explore multiple winter strategies. These include requesting customers to conserve, diversifying energy supply, conducting full system integrated resource planning, evaluating back up fuel supplies, exploring the need for regional infrastructure, continuing to evolve gas and electric coordination, and participating in regional resource adequacy initiatives and electricity markets.

Puget Sound Energy

Puget Sound Energy serves over 1.2 million electric customers and nearly 900,000 natural gas customers primarily in Western Washington. Winter readiness and energy emergency operations contingency plans span both its gas system and electric system.

On its gas system, PSE has a comprehensive cold weather action plan based on peak morning forecasts. The plan includes its LNG peak shaving plant, compressed natural gas injection sites, bypassing operations at key locations, and interruptible customer curtailment. Gas projects target specific inventories prior to winter peak season and PSE validates power plant readiness through vaporization test runs. Gas emergency contingency plans include participation in the NWMAA, curtailable interruptible loads, requests for customer conservation, and curtailment of firm sales customers through system isolation.

Winter readiness on PSE's electric system begins with resources and capacity contracts established to meet winter planning targets. The utility holds weekly collaborative meetings with PSE meteorologists to ensure early awareness of weather. The Cold Weather Action Plan ensures preparedness for high energy usage days, and electric system and transmission studies ensure reliability. Early and ongoing conservation efforts further reduce peak needs. Electric emergency contingency plans include energy supply monitoring alerts, planning reserve margins, contingency reserve obligations, emergency operations and energy agency plans.

Key **Findings** from Gas-Electric Integration Literature Review and Regional Symposium—NWGA and PNUCC

PNUCC is a not-for-profit trade association of consumer-owned and investor-owned electric utilities and other power industry partners that share a common interest in the efficacy and reliability of the Northwest power system. PNUCC and NWGA shared their gas-electric coordination initiative, which aims to underscore and strengthen collaboration in maintaining a reliable, affordable, and resilient energy future between the electric and gas sectors.

The initiative began with a literature review of regional energy studies, which underscored the need for better coordination between gas and electric systems. To this end, PNUCC, NWGA, Western Power Pool, and the Public Generating Pool convened a symposium of utility leaders, regulators, state policymakers, power producers, and other key stakeholders to discuss key opportunities and challenges. Key themes from the symposium include a need to (1) establish

cross-sector coordination forums to align planning and share data; (2) jointly plan for load growth and peak mitigation, particularly around hybrid systems; (3) integrate models and metrics to stress-test system resilience; and (4) align regulatory frameworks to support long-term, co-optimized planning.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-90:
E3 Resource Adequacy Phase 1 Presentation

Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results

Washington Utilities and Transportation Commission
Washington Department of Commerce

Resource Adequacy Meeting, RCW 19.280.065, Docket UE-210096

September 22, 2025

Lacey, Washington



Arne Olson, Sr. Partner
Aaron Burdick, Director
Charles Li, Sr. Managing Consultant
Bill Wheatle, Managing Consultant
Pedro de Vasconcellos Oporto, Sr. Consultant
Hugh Somerset, Sr. Consultant

Energy+Environmental Economics

Overview of Phase 1

E3 was retained by regional utilities and generation owners to evaluate the state of resource adequacy in the Pacific Northwest today and into the future. Key findings of Phase 1:

1. **Accelerated load growth and continued retirements create a resource gap beginning in 2026 and growing to *9 GW by 2030***
   - 9 GW is approximately the load of the state of Oregon
2. **Preferred resources such as wind, solar and batteries make only *small contributions* to meeting resource adequacy needs**
3. ***Timely development of all resources is extremely challenging* due to permitting and interconnection delays, federal policy headwinds, and cost pressures**

STUDY SPONSORS

- Puget Sound Energy
- Public Generating Pool
  - Chelan Public Utility District
  - Clark Public Utility District
  - Cowlitz Public Utility District
  - Eugene Water & Electric Board
  - Grant Public Utility District
  - Lewis Public Utility District
  - Seattle City Light
  - Snohomish Public Utility District
  - Tacoma Power
- Avista Corporation
- Benton Public Utility District
- Douglas Public Utility District
- Emerald People's Utility District
- Franklin Public Utility District
- Idaho Power
- Klickitat Public Utility District
- Mason Public Utility District No. 3
- Northwest & Intermountain Power Producers Coalition
- NorthWestern Energy
- Okanogan Public Utility District
- Pacific Public Utility District
- Portland General Electric

Who is E3?

Our Practice Areas

+ **E3 is the largest consulting firm focused on the clean energy transition in North America**
+ **E3 is a recognized thought leader on decarbonization and clean energy transition topics**
+ **E3 has three major practice areas covering energy systems from bulk grid to behind the meter**

Climate Pathways / Policy Analysis

- Climate and energy policy analysis
- Long-term energy & climate scenarios
- Electrification and low-carbon fuels
- Future of gas

Asset Valuation & Strategy

- Asset valuation and due diligence
- Strategic advisory
- Energy market price forecasting
- Market design
- Transmission planning

Integrated System Planning

- Integrated resource planning for electric systems: reliability and resource mix
- Planning for utility and state RPS + GHG targets
- Utility planning and procurement decisions

Economy-wide energy systems ← Bulk grid power systems → Grid edge & behind-the-meter



E3 has extensive experience planning for deeply-decarbonized power systems for a wide range of clients

+ State agencies

- **California:** E3 provides technical support and advisory services to the CPUC in administration of the state's IRP program, to CARB in implementation of AB32 "cap-and-trade" program, and to the CEC on a variety of research topics including compliance with SB100
- **New York State Climate Act Scoping Plan:** E3 supports NYSERDA with technical analysis of pathways to achieve economy-wide carbon neutrality by 2050 including 100x40 in the power sector
- **Illinois:** E3 supports the Illinois Power Authority and Commerce Commission on a variety of topics including resource adequacy, procurement, and renewable energy transmission studies
- **Massachusetts Department of Energy Resources:** Evaluating the benefits of long-duration energy storage and other topics

+ Utilities

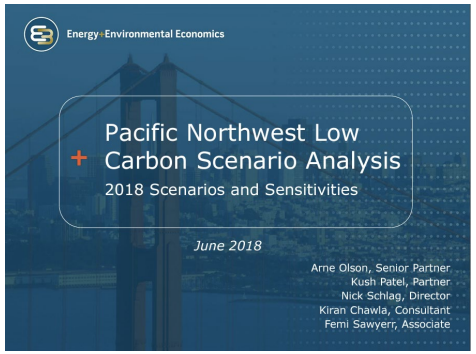
- **E3 has provided IRP support to dozens of utilities** including Puget Sound Energy, Eugene Water and Electric Board, Sacramento Municipal Utilities District, Arizona Public Service, Salt River Project, NV Energy, Public Service Company of New Mexico, El Paso Electric, Xcel Energy, Black Hills Energy, Hawaiian Electric Company, Omaha Public Power District, Florida Power & Light, Tampa Electric Company, Nova Scotia Power, New Brunswick Power, and others

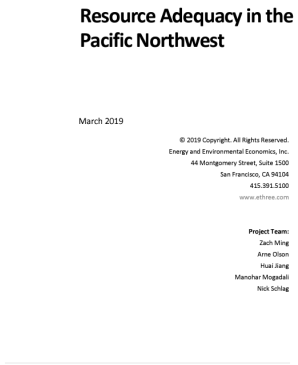
+ Non-profits

- E3 has advised **environmental advocacy organizations** including the Natural Resources Defense Council, Environmental Defense Fund, The Nature Conservancy, Clean Air Task Force, EarthJustice, World Resources Institute, Climate Solutions, and others

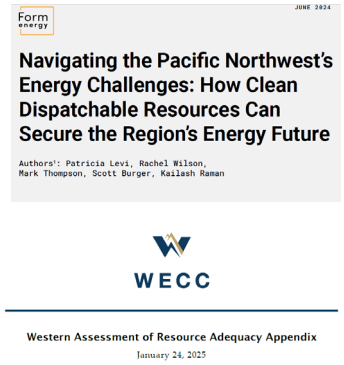
Resource Adequacy and the Energy Transition: Project Background

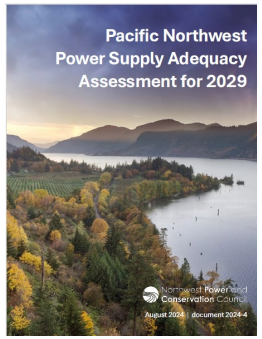
Prior E3 Studies in the Pacific Northwest

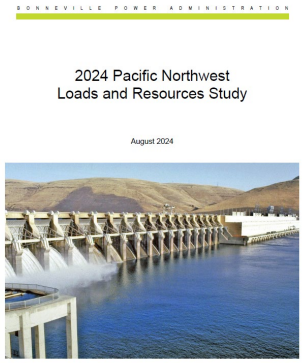


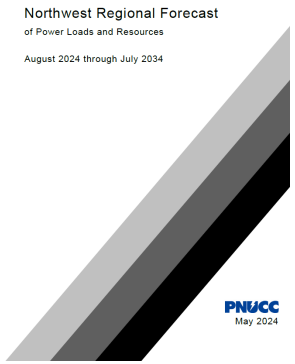


Recent PNW Regional Studies and Forecasts









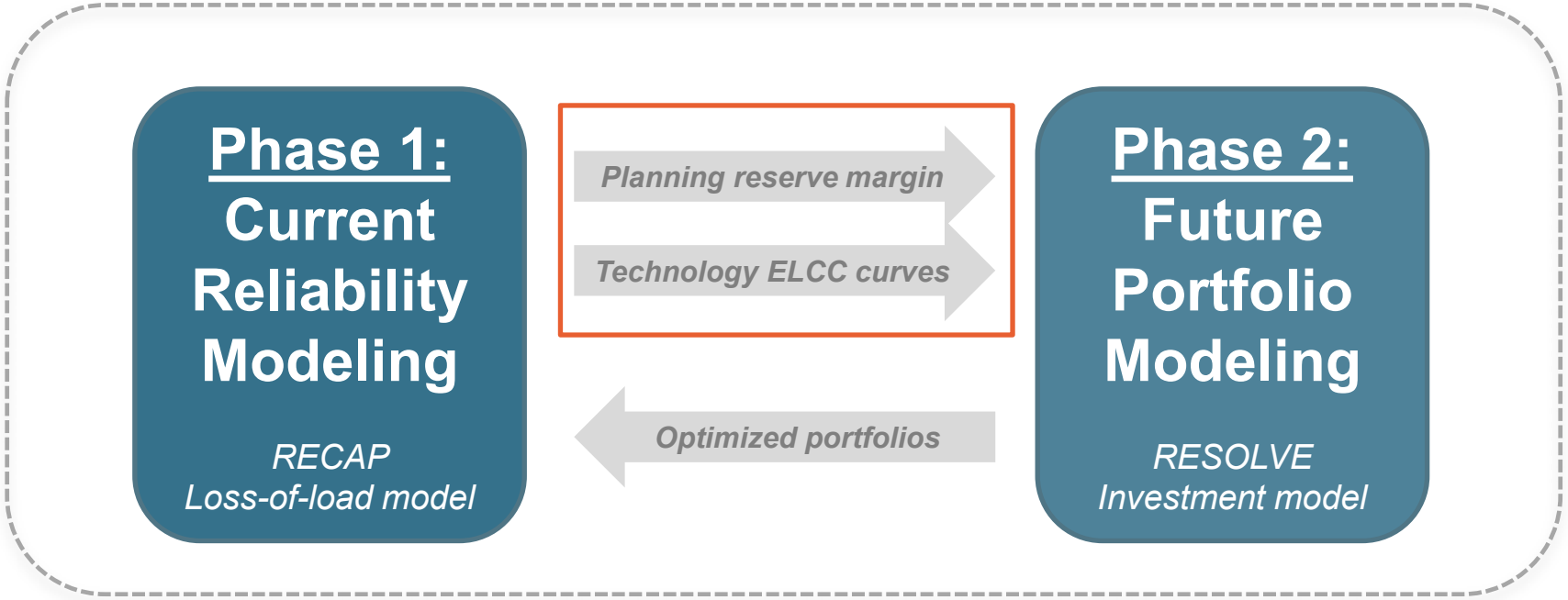
+ **Prior E3 studies found that the Pacific Northwest faces *immediate and growing* resource adequacy challenges**

+ **Much has happened over the past six years that might change the regional resource adequacy picture**

+ **Current study objectives:**
  - Evaluate current load-resource balance
  - Examine the role of various technologies including flexible loads and firm generation for ensuring reliability
  - Identify potential barriers that may prevent the region from meeting its goals in the future

Study uses a two-phased modeling approach

+ **The modeling approach pairs detailed loss-of-load-probability modeling with capacity expansion modeling to provide a robust perspective on system reliability and cost under aggressive clean energy targets**

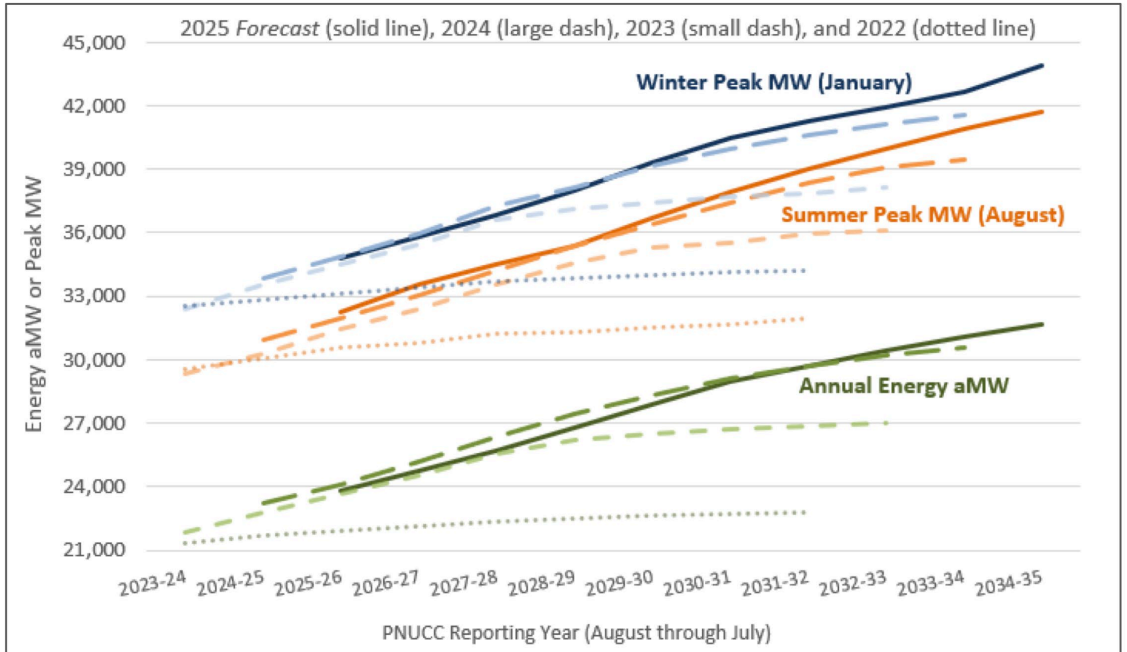


Key Study Topics:

1. Near-term resource adequacy picture
2. Barriers to new resource development
3. How to maintain long-term resource adequacy on a transitioning grid
4. Potential role for DSM and emerging "clean firm" resources
5. Stranding risk for near-term capacity resources

Regional load forecasts continue to increase due to AC adoption, electric vehicles, and data centers

PNUCC 2025 Northwest Regional Forecast
Energy aMW or Peak MW Forecast



Growth Rates

Energy	10 year
2025 *Forecast*	3.2%
2024 *Forecast*	3.1%
2023 *Forecast*	2.4%
2022 *Forecast*	0.9%

Summer Peak	10 year
2025 *Forecast*	2.9%
2024 *Forecast*	2.7%
2023 *Forecast*	2.3%
2022 *Forecast*	1.0%

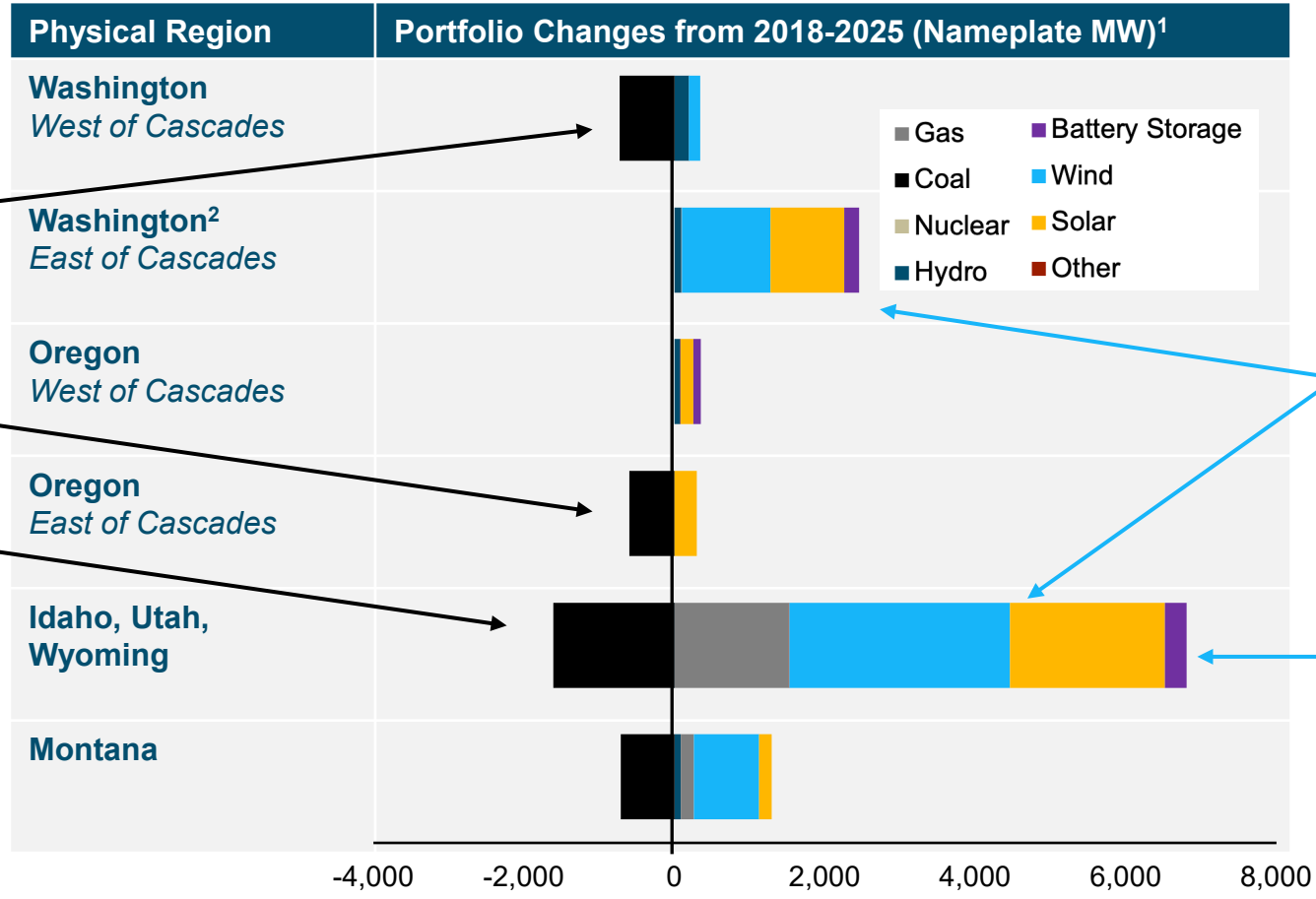
Winter Peak	10 year
2025 *Forecast*	2.6%
2024 *Forecast*	2.3%
2023 *Forecast*	1.8%
2022 *Forecast*	0.7%

+ Load growth acceleration is attributable to multiple distinct drivers, despite impact of energy efficiency

Driver	Near-term Impact
Economywide **energy efficiency**	Small load reductions in both seasons
Higher-than-expected **air conditioning adoption** after recent heat waves	Small-medium peak load growth in the summer
Policy-driven **electric vehicle adoption**	Medium peak load growth in both seasons
Population growth and new building construction	Medium peak load growth in both seasons
Anticipated **data center** interconnection	Large average and peak load growth in both seasons

New resource additions have been slow, and located primarily outside of Washington and Oregon

Coal retirements are reducing the quantity of firm capacity available in the region



Almost all new resources have been wind and solar

New resources are mostly being built in Wyoming and Utah

1. Based on WECC 2034 ADS and recent retirements)

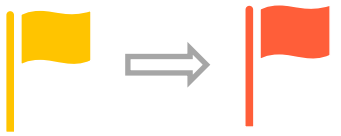
The Greater Northwest faces a supply deficit in 2026 which grows to 8,700 MW by 2030

+ **Load growth and retirements mean the region faces a power supply shortfall in 2026**
  - The region currently relies on imports to maintain reliability
+ **Nearly 9,000 MW of new capacity is needed by 2030**
+ **Projects currently in active development account for only 3,000 MW of new capacity**
  - 850 MW are coal-to-gas conversions
  - 260 MW are hydro upgrades

Greater Northwest
Total Resource Need and Effective Capacity Contribution from Planned Resources (MW)

** Total Resource Need includes peak load + planning reserve margin as well as obligation to serve the Columbia River Treaty Regime*

The Greater Northwest faces a supply deficit in 2026 which grows to 8,700 MW by 2030



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Greater Northwest
Total Resource Need and Effective Capacity Contribution from Planned Resources (MW)

System Needs (MW)	2025	2026	2027	2028	2029	2030
Total Resource Need*	49,245	50,737	52,499	54,184	55,879	57,195
Existing Portfolio w/ Retirements	46,716	45,666	45,395	45,388	45,098	44,757
Firm Imports	3,750	3,750	3,750	3,750	3,750	3,750
Reliability Position Surplus (+) / Shortfall (-)	**+1,221**	**-1,321**	**-3,354**	**-5,046**	**-7,031**	**-8,689**
ELCC from "In-Development" Firm Resources	-	296	407	580	770	1,114
ELCC from "In-Development" Wind, Solar and Battery projects	-	645	1,015	1,316	1,508	1,934

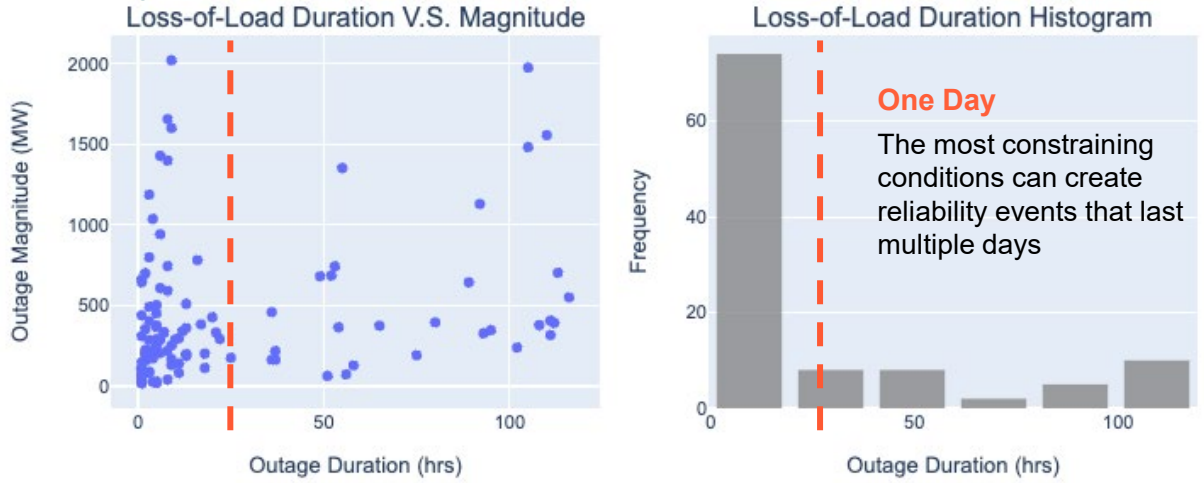
** Total Resource Need includes peak load + planning reserve margin as well as obligation to serve the Columbia River Treaty Regime*

The most constraining reliability conditions are extended wintertime cold weather events during very low water years

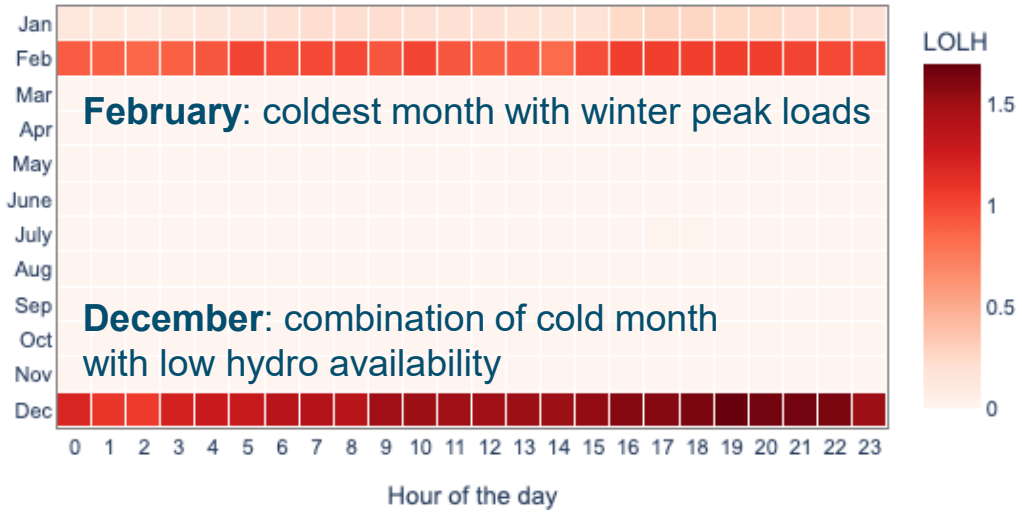
- **Most loss-of-load events occurring during the coldest winter months**
- **Many events exceed 50 hours in duration with some exceeding 100 hours due to energy shortfalls in dry years**

Greater Northwest, tuned to 1-day-in-10-year standard

Distribution of Loss-of-Load Events across over 2,500 years of simulated load, hydro, and renewable conditions



Average Loss-of-Load Hours (LOLH) by Month x Hour*



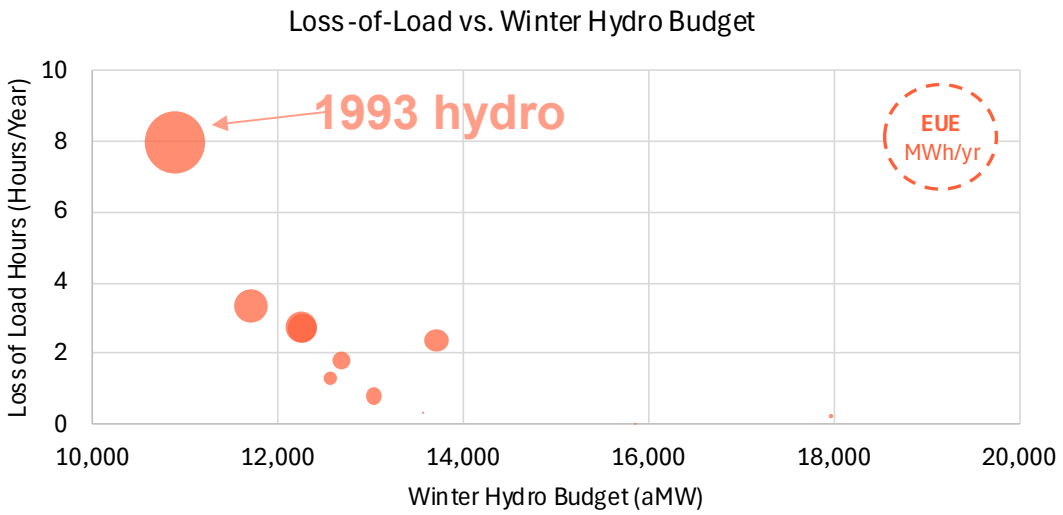
* Metrics + heatmap shown without firm imports

Addressing these events requires resources that can deliver energy over long periods of time

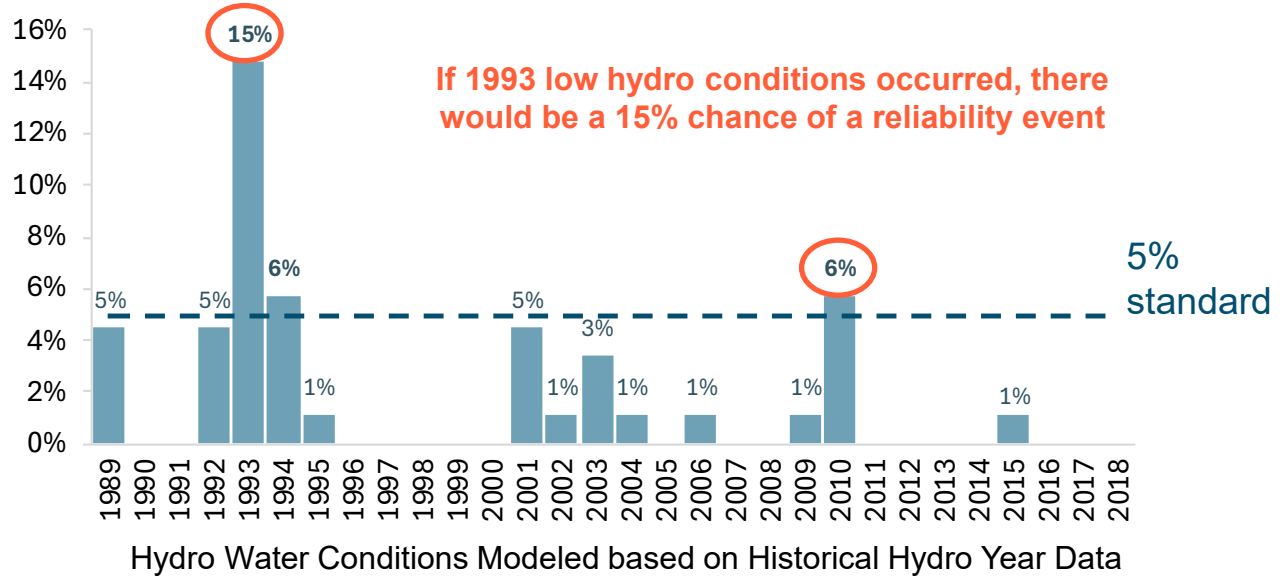
Energy shortfalls that occur during low hydro years contribute significantly to resource adequacy events

+ Loss of load events are concentrated during the lowest hydro years (1989, 1990, 1992, 1993, 1994, 2001, 2010)
+ January 2024 conditions were consistent with the very low hydro years simulated here

2025 Average Loss-of-Load Hours (LOLH) and Expected Unserved Energy (EUE) by Hydro Year



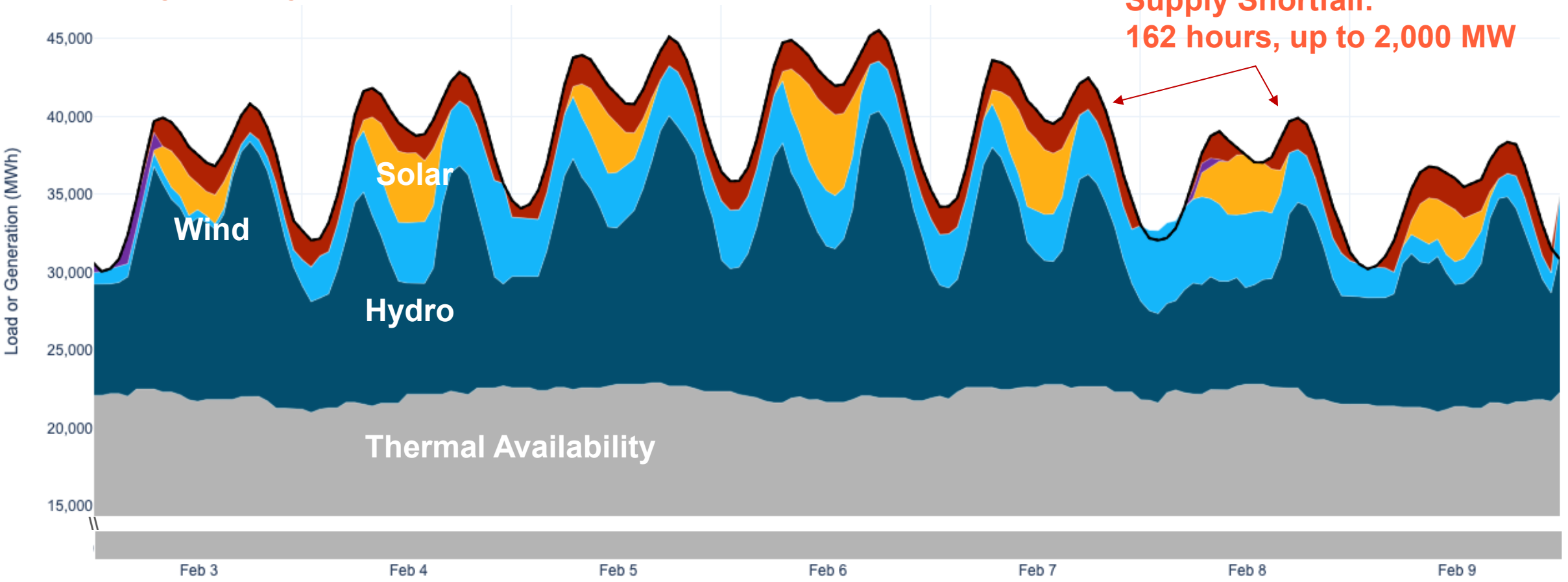
2025 Loss-of-Load Probability (LOLP) by Hydro Year



Resource availability example: February 2014 load conditions combined with 1993 hydro conditions

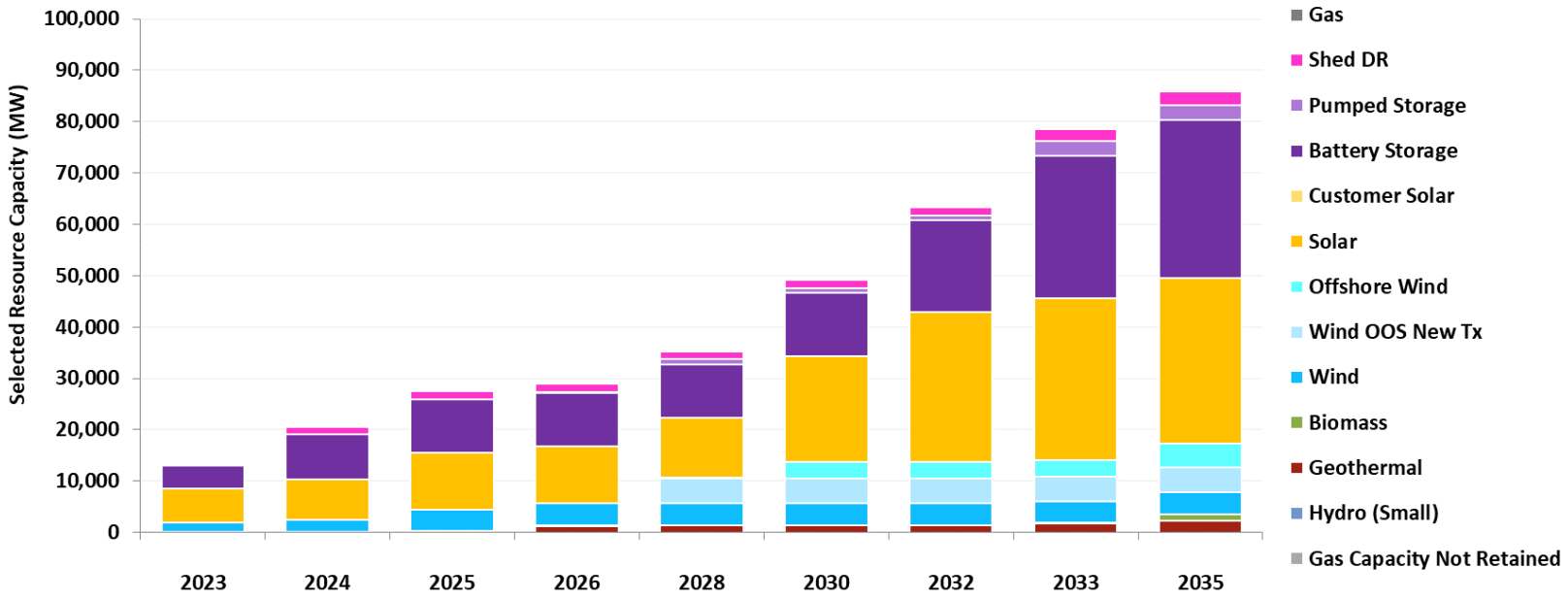
Greater Northwest 2025, RECAP simulated energy-limited event

February 1993 Hydro Conditions

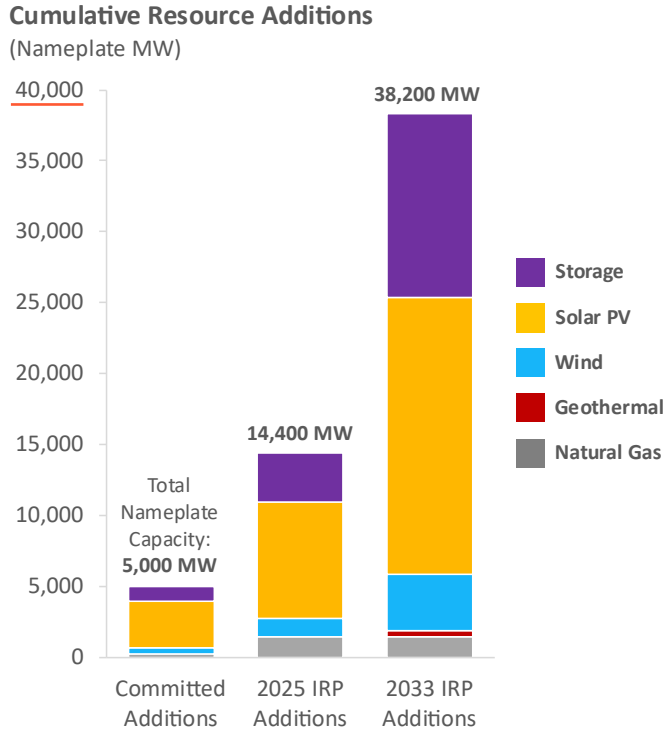


Regional comparison: solar and batteries provide high capacity value in summer-peaking regions like the Southwest

California is planning to build 50 GW of solar and storage resources by 2035 and 100 GW by 2040 (on top of 50 GW installed in 2025)

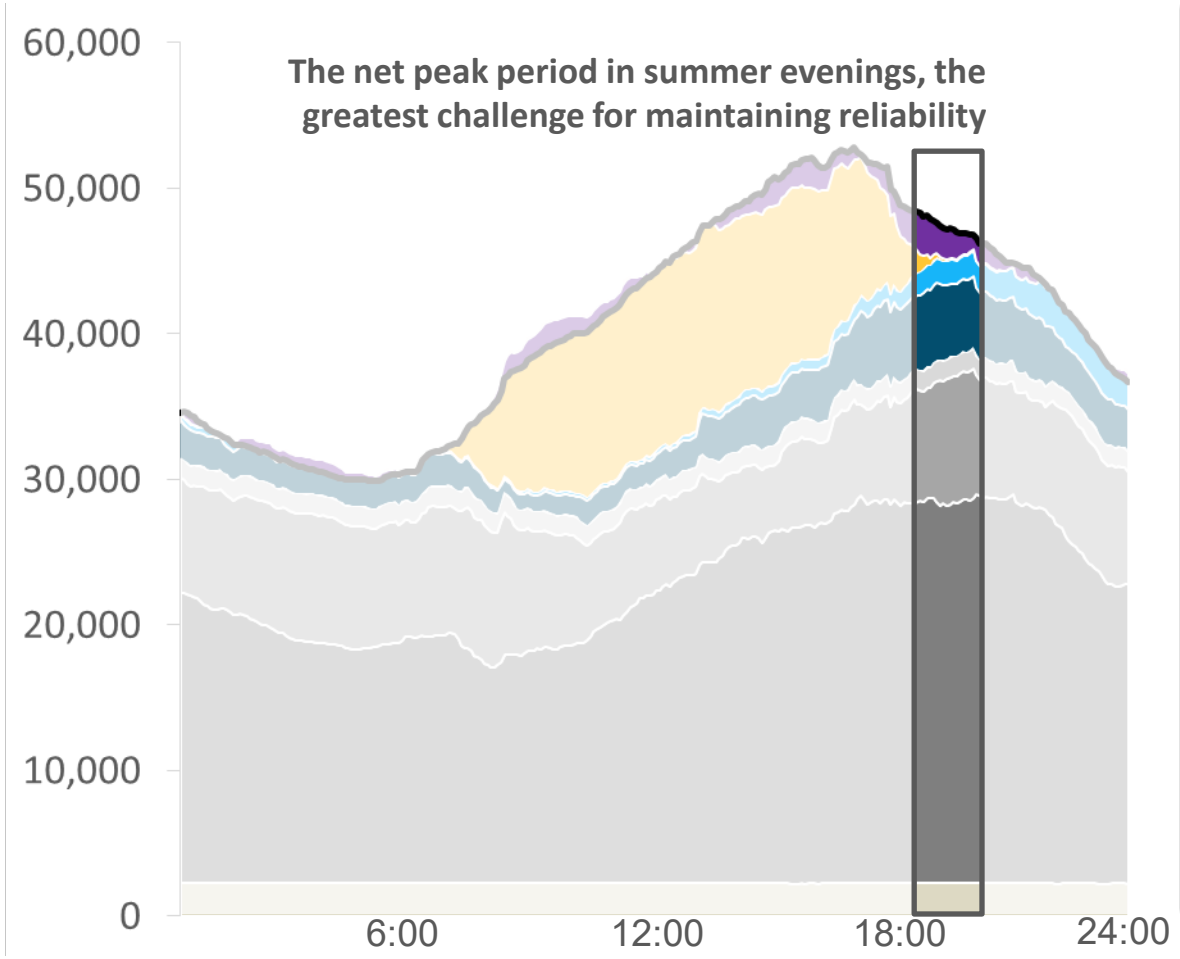


Desert Southwest is planning to build 30 GW of solar and storage resources through 2033

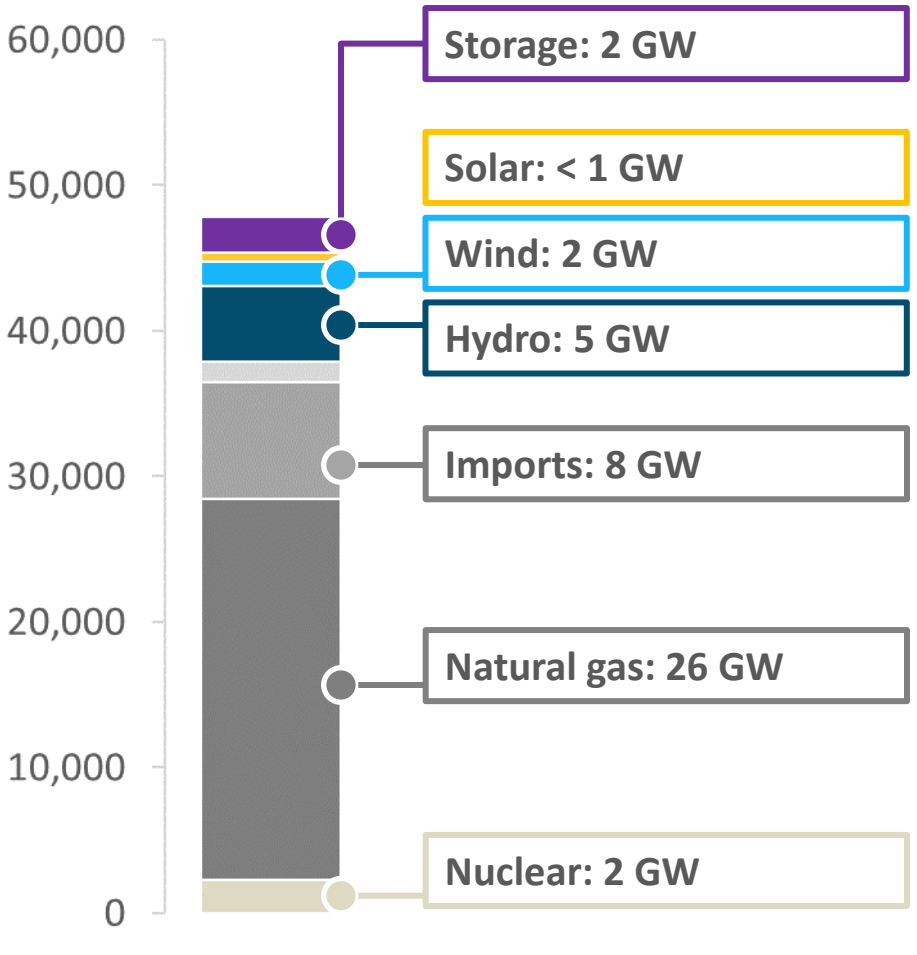


Regional comparison: California's most recent near reliability event was during a historic heatwave in September 2022

CAISO System Operations on September 6, 2022
(MW)

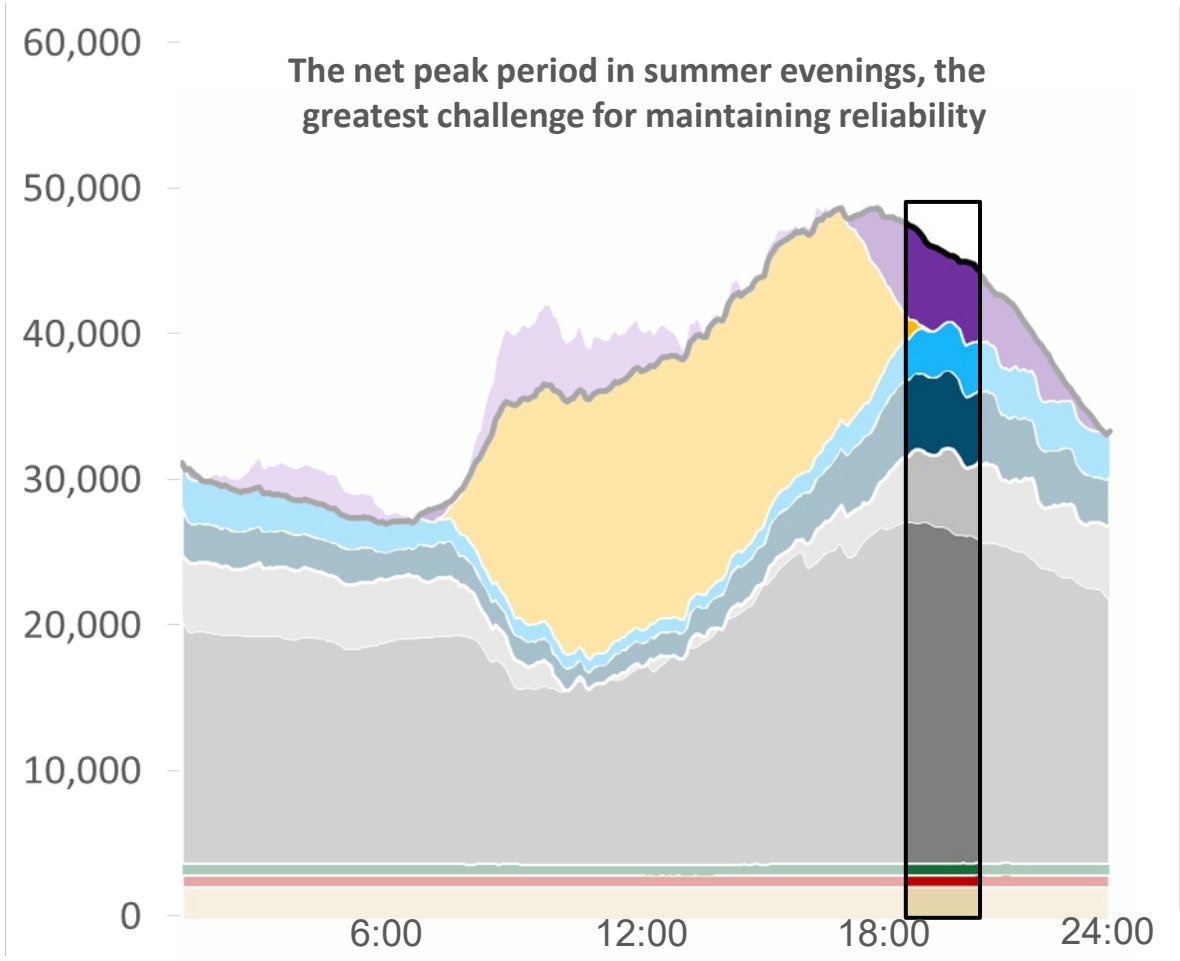


Generation During Hour of Highest Net Load
(MW)

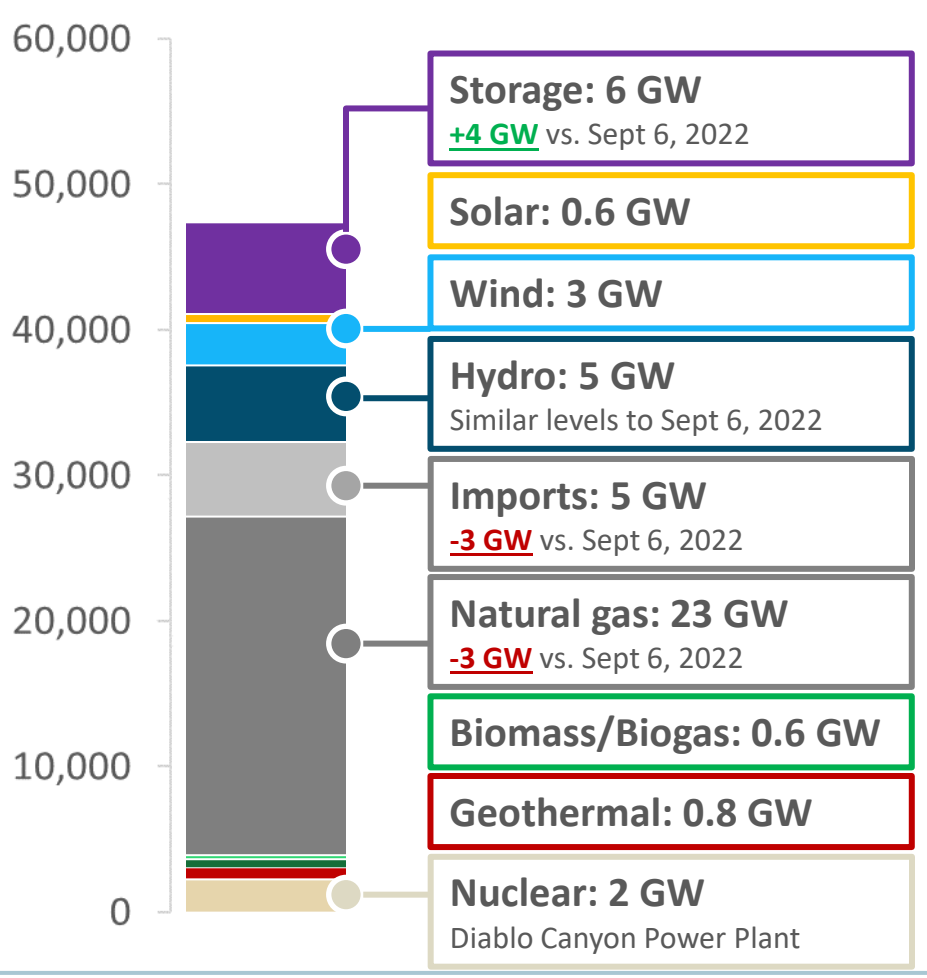


Regional comparison: Significant additions of batteries helped make the next September heatwave in 2024 a non-event

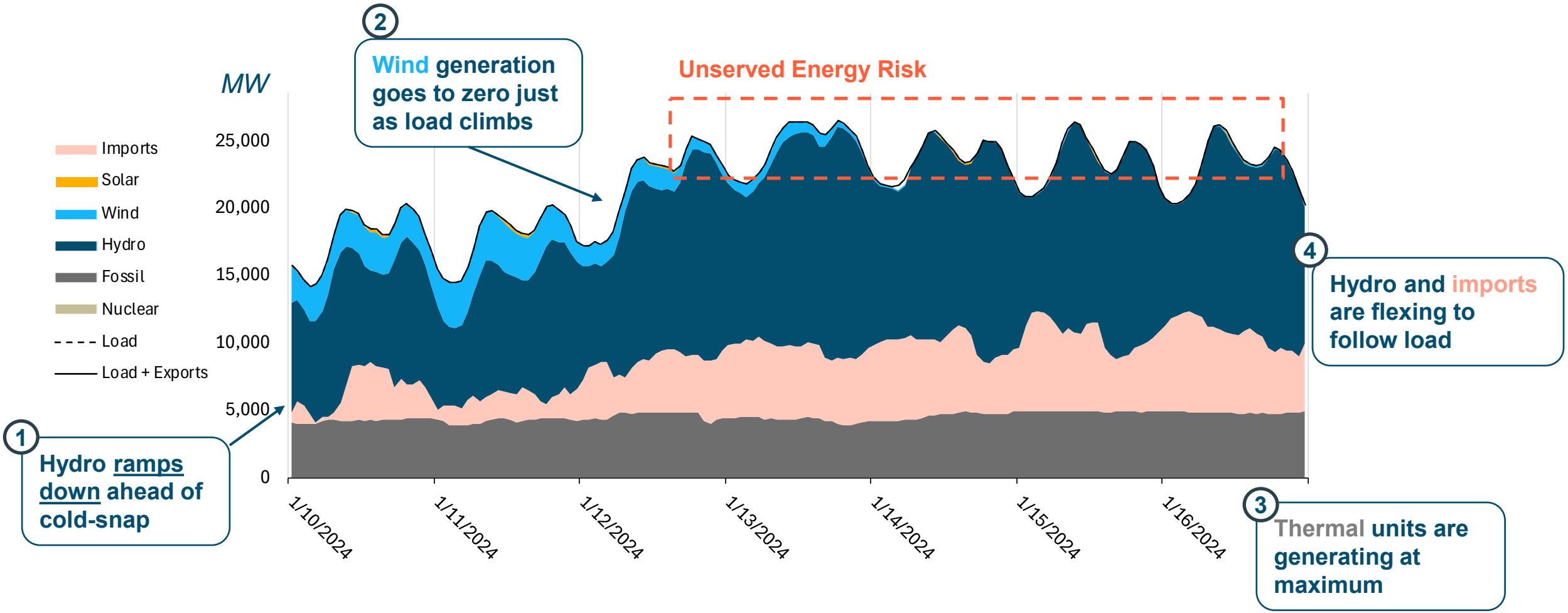
CAISO System Operations on September 5, 2024
(MW)



Generation During Hour of Highest Net Load
(MW)



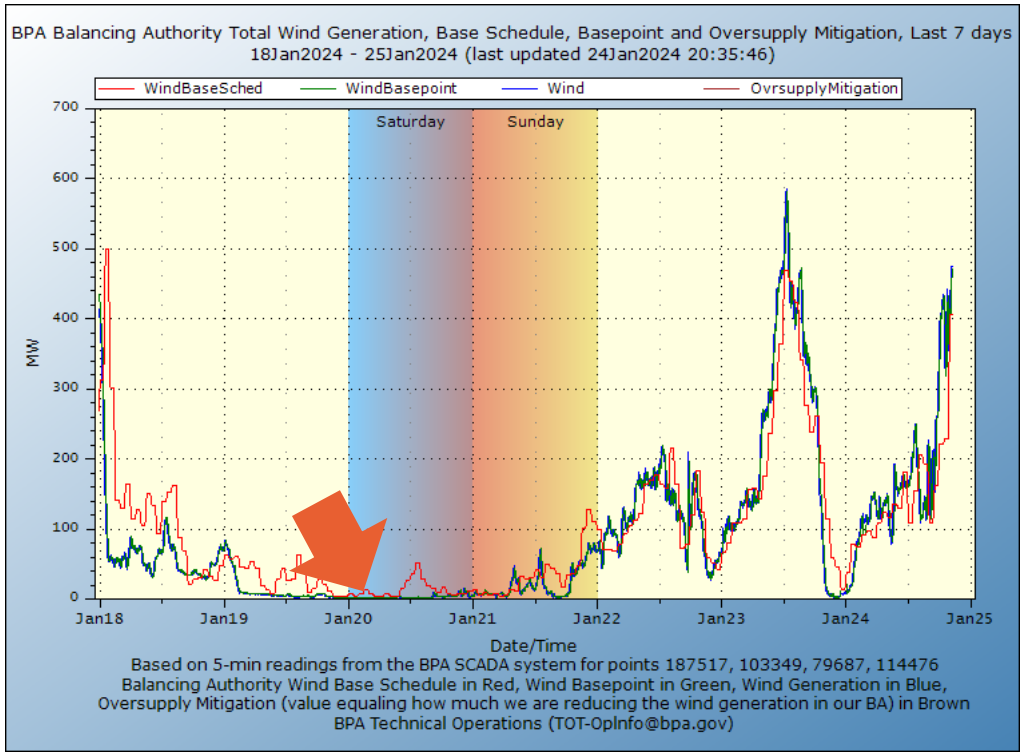
Regional comparison: The Northwest's most recent near reliability event was the multi-day January 2024 cold snap



Source: EIA, BPA

Northwest wind produced at very low levels during most of the January 2024 cold weather event

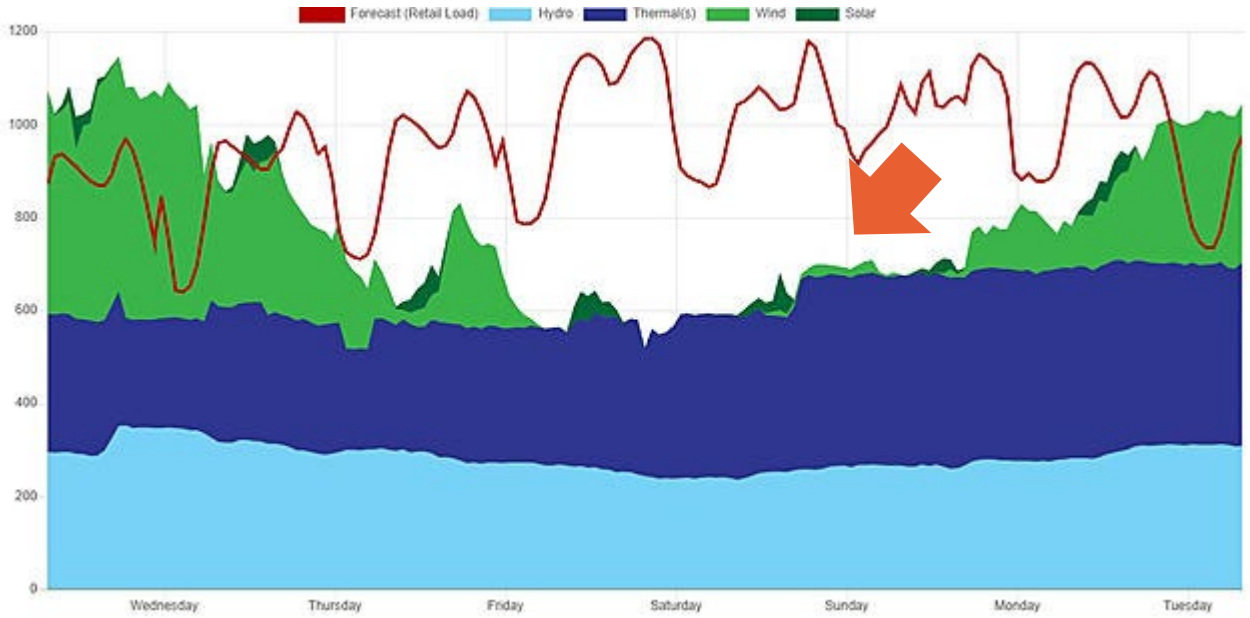
BPA: Almost no wind production on January 15-17 and 19-21



Average Jan 13: **567 MW**

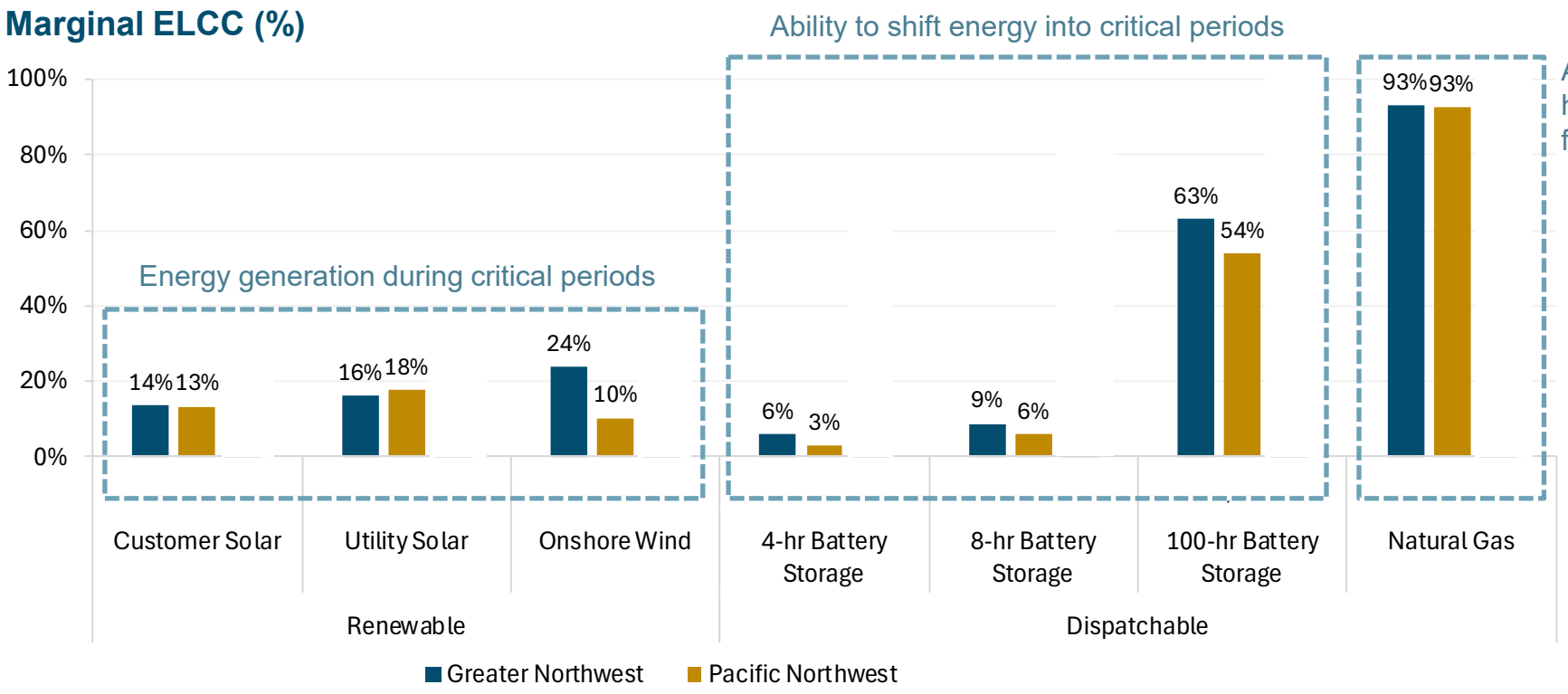
Average Jan 15 5:00 AM – Jan 17 10:00 AM: **8 MW**

NorthWestern Energy: Almost no wind production on January 12-14



Low temperature records set on January 13 in Portland (12 degrees) and Seattle (16 degrees)

Resource reliability value depends on ability to supply energy during multi-day cold snaps under low hydro conditions



These annual marginal ELCC values represent the ability of a marginal resource addition to reduce region-wide reliability risk relative to a firm, always available generator. For these 2025 values, ELCCs are primarily a function of output during the wintertime multi-day energy-constrained events that define risk for the Greater NW and the PNW subregion.

+ **Solar and wind have low capacity factor during reliability events → 10-24% of nameplate**
+ **Short-duration energy storage cannot charge during most energy-constrained events → 3-9%**
+ **Natural gas plants with firm fuel can run when needed → 93%**

Energy storage and flexible loads can be valuable if matched to the duration of the reliability event

+ Short-duration storage and demand response solutions do not have high reliability value
+ Multi-day response is valuable but more difficult to source

	Duration (hours)	# of Calls per year	2030 Marginal ELCC
Energy Storage	4		6%
	8		9%
	100		**63%**
Load-shed Demand Response	6	12	18%
	12	10	30%
	24	8	44%
	48	6	**54%**
	72	4	**57%**
	120	2	**61%**

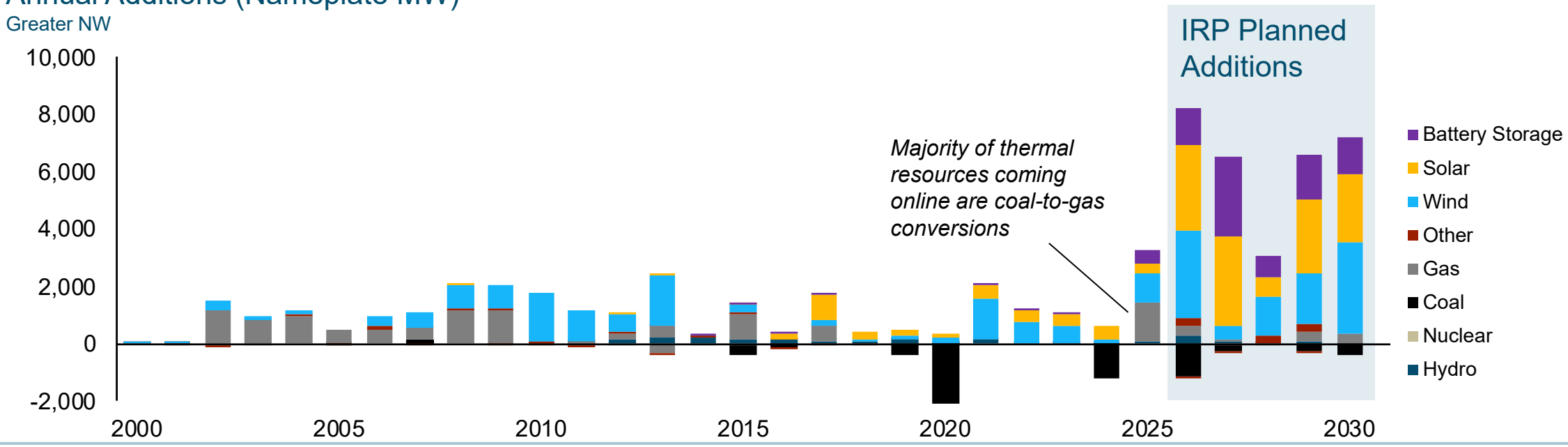
The rate of new resource additions required to meet resource adequacy needs in the next five years is unprecedented

- Meeting the pace of growth anticipated in utility IRPs would require annual resource additions equal to 4-5x historical levels
- Project development is currently experiencing significant headwinds due to changes in federal policy and higher costs

Retirements and New Installed Capacity Additions by Year

Annual Additions (Nameplate MW)

Greater NW



Utility + developers identified transmission, accreditation uncertainty, and new firm capacity barriers as key challenges

Key challenge	Findings from stakeholder interviews	Potential Solutions
1. Transmission access faces physical and institutional constraints	• Separate procurement and transmission planning processes leading to chicken-and-egg challenges • Lack of firm transmission rights for new resources • Difficult terrain and siting challenges	• **Improve regional transmission planning and interconnection processes**
2. Uncertain capacity accreditation metrics	• **WRAP is voluntary** and has not yet become binding • **Accreditation metrics are uncertain**	• **Strengthen the WRAP program with fundamentals-based capacity accreditation**
3. Barriers to building new RA capacity	• Utilities are likely to be challenged by the **sheer volume** of new resources in their IRPs • Existing clean resources make limited contributions to resource adequacy and **"clean firm" options are not yet commercially available** • Natural gas is the only viable near-term firm capacity option, yet siting new gas plants is extremely challenging and may create **stranded asset risks**	• **New firm resources may be needed** if they do not set the region back on long-term carbon reduction goals • **"Clean firm" resources may need policy support to** speed commercialization

Key findings of Phase 1:

1. **Accelerated load growth and continued retirements create a resource gap beginning in 2026 and growing to *9 GW by 2030***
   - 9 GW is approximately the load of the state of Oregon
2. **Preferred resources such as wind, solar and batteries make only *small contributions* to meeting resource adequacy needs**
3. ***Timely development of all resources is extremely challenging* due to permitting and interconnection delays, federal policy headwinds, and cost pressures**

Phase 2 will evaluate resource options for meeting near-term and long-term resource adequacy and clean energy needs

	Scenario	RA contributions	Additional considerations
Mature	Solar	Low and declining ELCCs	Variable energy resource
	Onshore wind	Declining ELCCs	Variable energy resource
	Natural gas	Firm	Carbon emitting, requires pipeline infrastructure
	Biomass/biodiesel	Firm	Uncertain fuel availability and cost
	Short-duration storage (4-8 hr li-ion)	Declining ELCCs	ELCC saturation impacted by hydro fleet interactions
	Long duration storage (10-12 hr pumped hydro)	Declining ELCCs	ELCC saturation impacted by hydro fleet interactions
	Geothermal	Limited potential	High cost per kWh and limited PacNW sites
	Energy efficiency	Limited potential vs. cost	Can reduce new load but cannot serve existing load
	Demand response	Declining ELCCs	Duration and use limited
Emerging	Floating offshore wind	Declining ELCCs	High enabling infrastructure costs + long timelines
	Natural gas to H2 retrofits	Firm	High enabling infrastructure costs + long timelines
	New dual fuel gas + H2-ready plants	Firm	High enabling infrastructure costs
	New H2-only plants	Firm	High enabling infrastructure costs + long timelines
	Gas w/ 90-100% carbon capture and storage	Firm	High enabling infrastructure costs + long timelines
	Nuclear small modular reactors	Firm	Uncertain costs + long timelines
	Enhanced geothermal	Firm	Uncertain costs and potential
	Multi-day storage (100 hr)	Slower declining ELCCs	Uncertain costs, high round-trip energy losses
	Direct air capture	n/a	Can offset emitting gas that serves RA needs

Note: emerging technologies face cost uncertainty, unclear commercialization timelines, and/or high enabling infrastructure needs

Thank you!

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Energy+Environmental Economics

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-91:
NERC Winter Assessments 2022-24 (Compiled)

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2022–2023 Winter Reliability Assessment

November 2022



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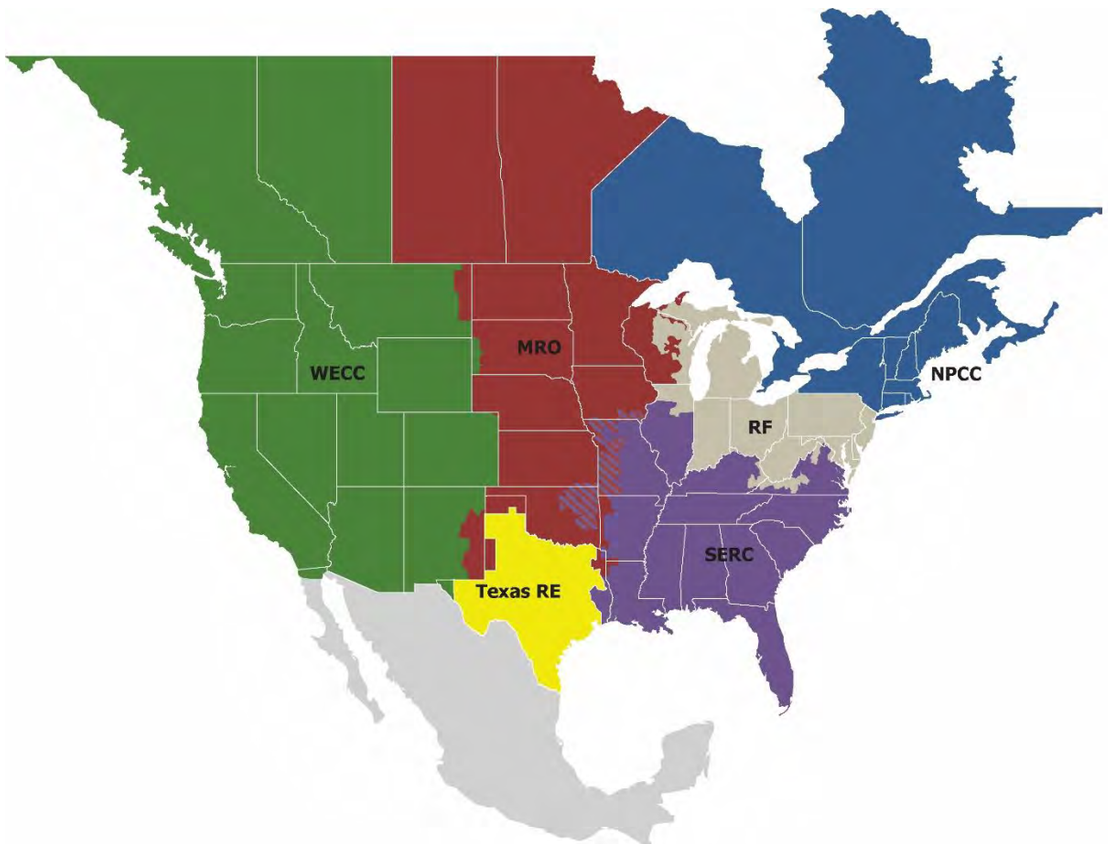
Preface

The vision for the Electric Reliability Organization Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

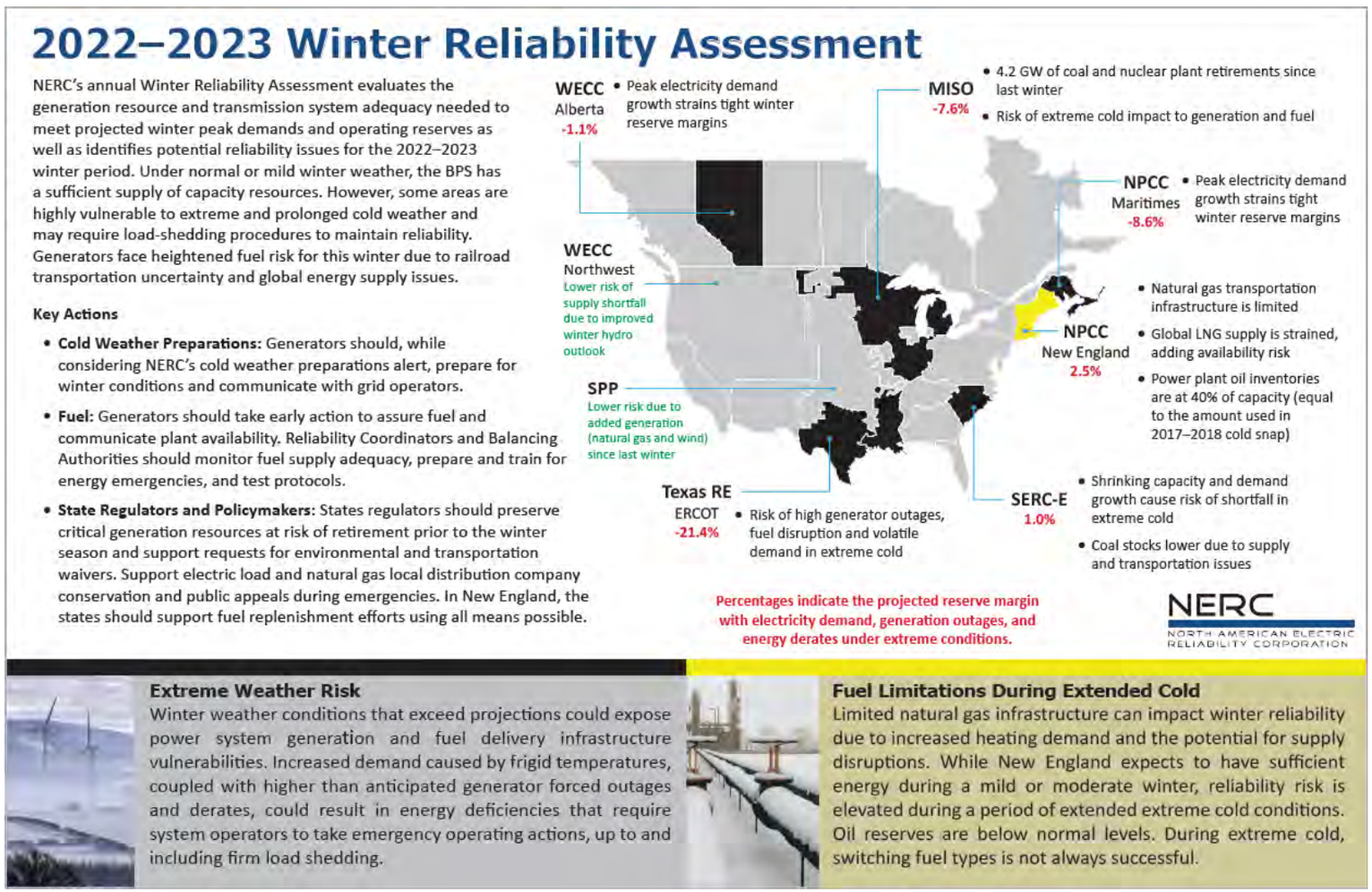
The North American BPS is made up of six Regional Entity boundaries as shown in the map below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another. Refer to the **Data Concepts and Assumptions** section for more information. A map and list of the assessment areas can be found in the **Regional Assessments Dashboards** section.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC's *2022–2023 Winter Reliability Assessment* (*WRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the *WRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might impact the BPS. The reliability assessment process is a coordinated reliability evaluation between the Reliability Assessment Subcommittee (RAS), the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects NERC's independent assessment and is intended to inform industry leaders, planners, operators, policy makers, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming winter period. Below is a summary of this *WRA*.



Key Findings

This *WRA* covers the upcoming three-month (December–February) winter period. This assessment provides an evaluation of generation resource and transmission system adequacy necessary to meet projected winter peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional topics of concern. The following findings are NERC and the Regional Entities' (the ERO Enterprise's) independent evaluation of electricity generation and transmission capacity and potential operational concerns that may need to be addressed for the upcoming winter:

A large portion of the North American BPS is at risk of insufficient electricity supplies during peak winter conditions (Figure 1). Higher peak-demand projections, inadequate generator weatherization, fuel supply risks, and natural gas infrastructure are contributing to risks seen in the following areas:

- **Texas RE-ERCOT:** The risk of a significant number of generator forced outages in extreme and prolonged cold temperatures continues to threaten reliability where generators and fuel supply infrastructure are not designed or retrofitted for such conditions. Furthermore, a U.S. Environmental Protection Agency (EPA) decision regarding compliance with hazardous coal ash disposal regulations is expected before the end of 2022 that could impact the availability of two coal-fired generation units (combined total of 1,477 MW) in the last weeks of winter. These units could be important resources during extreme conditions, and an EPA decision can provide flexibility in scheduling outages for plant improvements. Demand volatility in Texas from extreme cold temperatures also contributes to energy shortfall risks.
- **Midcontinent ISO (MISO):** Since the 2021/2022 winter, reserve margins in MISO have fallen by over 5%. Nuclear and coal-fired generation retirements total over 4.2 GW since the prior winter. Declining reserves are the result of few resource additions. An extreme cold-weather event that extends deep into MISO's area could lead to high generator outages from inadequate weatherization in southern units and unavailability of fuel for natural-gas-fired generators.
- **SERC-East:** Like Texas RE-ERCOT and the southern parts of MISO, extreme cold could result in high generator outages and demand volatility. A rare cold weather event in the South could result in an energy emergency in this area.
- **WECC-Alberta and NPCC-Maritimes:** Peak electricity demand is projected to grow in both of these winter-peaking systems. In Maritimes, this could strain capacity for normal winter peak conditions. Alberta has sufficient capacity for normal winter peak demand; however, extreme conditions that cause high generator forced outages are likely to cause energy emergencies.
- **NPCC-New England:** The capacity of the natural gas transportation infrastructure could be constrained when cold temperatures cause peak demand for both electricity generation and consumer space-heating needs. Potential constraints on the fuel delivery systems and limited inventory of liquid fuels may exacerbate the risks for fuel-based generator outages and output reductions that result in energy emergencies during extreme weather.



Figure 1: Winter Reliability Risk Area Summary

- **Generator Owners (GO) face additional fuel and supply risk.** Reliable operation of the thermal generating fleet is critical to winter reliability, and assured fuel supplies is an ongoing winter reliability concern. Current domestic and global affairs warrant even greater attention to generator fuel supplies, including natural gas, fuel oil, and coal for the upcoming winter. Inventories of coal and fuel oil in most areas are lower than usual due to a summer of high electricity demand and high natural gas prices that made other fuels more economically advantageous for electricity generation. Low fuel storage levels coupled with a range of potential fuel resupply challenges are creating additional risks for winter regional BPS reliability. Careful attention should be paid to periodic fuel surveys that provide early indication of fuel supply risks.

- **Steps have been taken since 2021's Winter Storm Uri to improve generator performance during extreme cold weather events.** The three areas hardest hit by the 2021 Winter Storm Uri[1]—Texas RE-ERCOT, SPP, and MISO—have implemented several improvements based on their operating experience. Texas weatherization standards for both generators and natural gas facilities designated as critical infrastructure aim to improve generator availability during extreme weather this winter. In SPP and MISO, where Winter Storm Uri impacts were less severe, a focus on operational coordination and situational awareness is intended to help operators ensure that sufficient resources are available for extreme conditions. While the risk of energy emergencies for the upcoming winter has not been eliminated, improvements—due to lessons learned from Winter Storm Uri—are expected to reduce the likelihood and lessen the severity of a future Winter Storm Uri scale event.
- **NERC's 2022 Level 2 Alert, *Cold Weather Preparations for Extreme Weather Events.*** In September 2022, the ERO issued a Level 2 NERC alert to Reliability Coordinators (RC), Balancing Authorities (BA), Transmission Operators (TOP), and GOs.[2] The alert includes recommendations as well as a series of questions to help evaluate the Bulk Electric System's winter readiness. The responses indicate the importance of grid operators being prepared to implement their operating plans to manage potential supply shortfalls in extreme weather.
- **Inadequate supply of distribution transformers could slow restoration efforts following winter storms.** The electricity industry is facing a shortage of distribution transformers as a result of production not keeping pace with demand. A survey by the American Public Power Association revealed that many utilities have low levels of emergency stocks that are used for responding to natural disasters and catastrophic events.[3] Severe winter storms often include high winds, icing, and precipitation that damage distribution power lines and transformers. Asset sharing programs used by utilities provide visibility and voluntary equipment sharing to maximize resources; however, electricity customers may experience delayed restoration of power following storms as crews must work to obtain new equipment.

Recommendations

To reduce the risks of energy shortfalls on the BPS this winter, NERC recommends the following:

- BAs and RCs should work with GOs to ensure fuel supplies are adequate for normal and extreme conditions prior to winter. Fill storage capacity, prepare fuel delivery systems, and coordinate with fuel providers to secure needed fuel as applicable. While short-term solutions are limited, firm supply arrangements should be pursued when feasible. Long-term solutions are needed to secure energy and maintain fuel assurance to support reliability and resilience. In addition, GOs should routinely and periodically keep BAs and RCs informed on fuel levels and readiness.
- RCs and BAs should implement fuel surveys early to monitor the adequacy of fuel supplies. They should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions.
- State and province policy makers have the authority and jurisdiction to implement actions that preserve critical generation resources. State and provincial regulators should consider energy risks for the upcoming winter season and take steps to delay imminent generation retirements if essential to reliability. Additionally, state regulators can assist grid operators in advance of and during extreme cold weather by supporting requested environmental and transportation waivers as well as public appeals for electric load and natural gas conservation.
- Grid operators, GOs, and Generator Operators (GOP) should implement the mitigations identified in the NERC Level 2 alert*, Cold Weather Preparations for Extreme Weather Events–II*, and they should take recommended weatherization steps prior to winter.

[1] The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report | Federal Energy Regulatory Commission

[2] https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20R-2022-09-12-01%20Cold%20Weather%20Events%20II.pdf

[3] https://www.publicpower.org/periodical/article/appa-survey-members-shows-distribution-transformer-production-not-meeting-demand

Risk Highlights

Additional Generator Fuel and Supply Risk

Reliable operation of the thermal generating fleet is critical to winter operations, and assured fuel supplies is an ongoing winter reliability concern. The current state of domestic and global affairs warrants even greater attention on generator fuel supplies, including natural gas, fuel oil, and coal. Low fuel storage levels coupled with a range of potential fuel resupply challenges are creating additional risks for winter regional BPS reliability.

Generator Fuel Supplies

Owners of coal, fuel oil, and dual-fueled generators in North America typically replenish stored fuels following the peak summer season in preparation for winter. Energy suppliers also increase inventories of natural gas, coal, and distillate fuels in preparation for high-demand winter periods. Several fuel supply challenges have emerged in the lead-up to the 2022–2023 winter that are being monitored by grid operators and GOs, including potential rail strikes, constrained and delayed rail deliveries, reduced stored natural gas and fuel oil inventories, and uncertainty from global markets in New England potentially impacting liquefied natural gas (LNG) deliveries. The following are two areas of concern:

Coal Inventories

Grid operators in the U.S. Southeast, MISO, and PJM are monitoring coal inventories (fuel and consumables) as GOs face limited stocks and resupply uncertainty. Across the United States, resupply by rail has been hampered throughout 2022 as staffing shortages and other issues have affected the rail industry. Some GOs in the Midwest and Southeast are experiencing delivery issues for coal and certain emissions-control chemicals. A small number of units currently have low coal inventory. Inventories in some areas are lower than typical following a summer of high electricity demand and high natural gas prices that made coal more economically advantageous. A milder fall in the Central and Eastern parts of North America has helped some coal stocks rebound. Monitoring performed by PJM, where coal-fired generation can be expected to contribute over 25% of peak demand needs, indicates that pre-winter coal supplies in November now exceed 85% of the levels reached at their peak in the prior winter (**Figure 2**).

Based on coal stock data from the Energy Information Administration,[4] fuel inventories have reached 96 days of bituminous supply and 81 days subbituminous across the coal generation fleet on average (**Figure 3**). Some plants reported as low as 15 days of supply during the past summer.

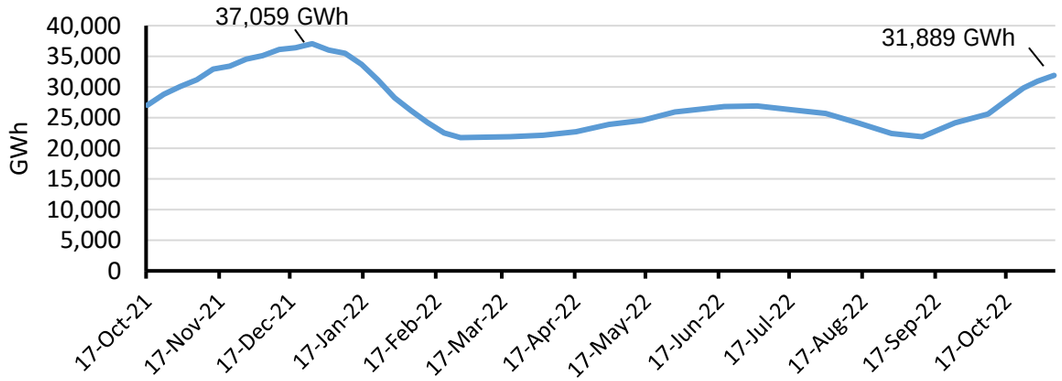


Figure 2: PJM Bi-weekly Fuel Inventory for October 10, 2022[5]

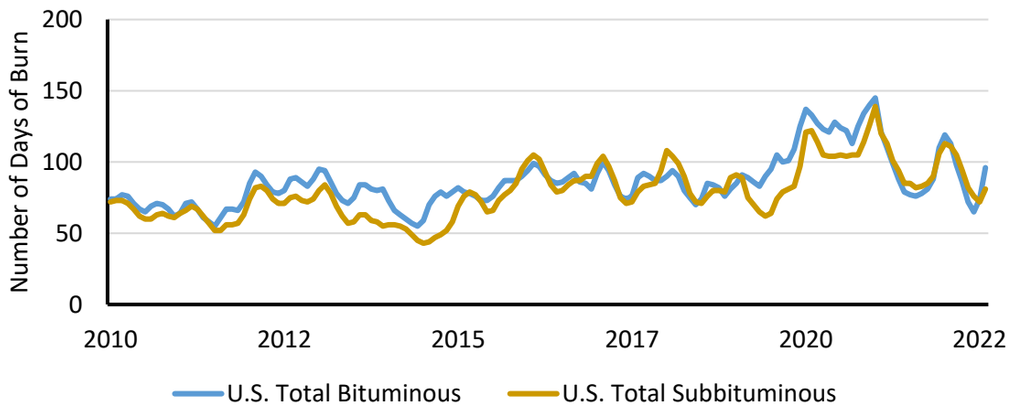


Figure 3: Days of Burn by Non-lignite Coal, January 2010–August 2022

[4] EIA Electric Power Sector Coal Stocks: Electricity Monthly Update - U.S. Energy Information Administration (EIA)

[5] Displays the fuel inventory in GWh calculated by PJM based on data provided through PJM's Fuel Inventory and Supply Data Request. Information is available on PJM's Operating Committee page: https://www.pjm.com/committees-and-groups/committees/oc

Shipping availability by rail this winter is uncertain, reinforcing the need to monitor generator coal stockpiles and act early to reach peak winter levels. RCs in affected areas are continuing to mitigate the coal supply issues by working with their BAs to limit run time of low-inventory plants, using economics, de-rating units, reducing loading at night, and monitoring coal supply.

LNG and Fuel Oil Availability

Low fuel availability elevates winter reliability risk. LNG is critical to meeting energy needs in New England during cold weather, and the continuing disturbance to global energy markets creates supply uncertainty. LNG terminals in New England help alleviate pipeline constraints by providing access points for LNG shipped in tankers to be vaporized and injected into pipelines that serve many natural-gas-fired generators.

As a global energy commodity, LNG is experiencing record high demand that is straining supplies and transportation as well as increasing the risk of disruption. Fuel oil stores are also an important generator fuel in New England as well as in neighboring New York and the Maritimes Provinces of Canada.

Fuel oil is used as either a primary fuel or as a backup to natural gas. Replenishment of on-site generator fuel oil stores since last winter is lagging, and levels remain below historical norms. In New England, the Independent System Operator (ISO) survey of generators in October indicates that on-site stored fuel oil used for electricity generation is just over 92 million gallons, or 40% of available storage capacity (**Figure 4**). Most oil-fired generating capacity (70%) in New England uses lighter distillate fuel oil (DFO). The remaining 30% of the oil-fired fleet capacity uses residual fuel oil (RFO). The current level of combined fuel oil in storage is far lower than the 54% peak level of the prior winter. It is also close to being insufficient for the kind of extreme winter events that could occur in the area. For instance, during a 13-day cold snap over the 2017–2018 winter, over 80 million gallons of fuel oil was used for electricity generation in the New England area. [6]

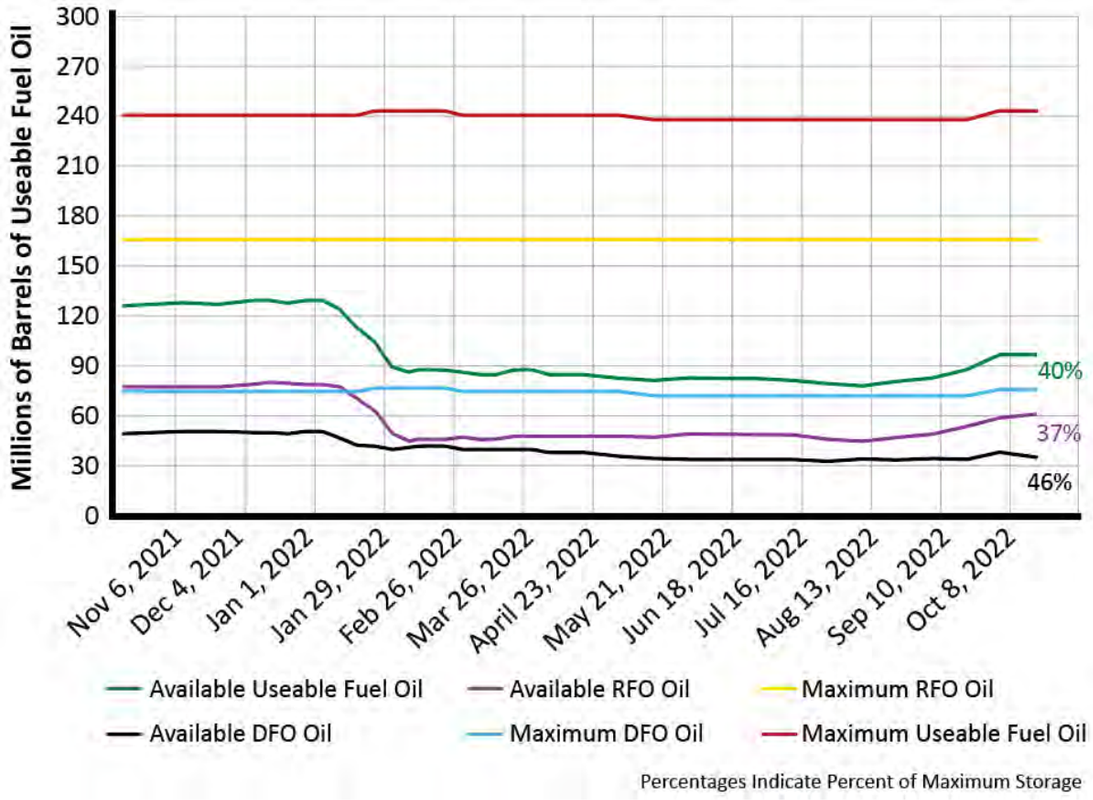


Figure 4: ISO New England 21-day Energy Assessment, Total Usable New England Fuel Oil Inventory Through October 8, 2022[7]

Assessment of Stored Fuel Risk

No specific issues have been identified that would prevent reaching the necessary fuel levels. However, weather, staffing, and general issues affecting transportation have the potential to either directly impact fuel delivery to generator storage sites or affect fuel production through disrupted chemical shipments. Careful attention to ISO's pre-winter and periodic fuel surveys is needed to provide early indication of fuel supply risks. Tools like ISO-New England's (ISO-NE) 21-day energy assessments can reduce these risks to operations.

[6] ISO-NE *Winter 2017/2018 Recap: Historic cold snap reinforces findings in Operational Fuel-Security Analysis*: https://isonewswire.com/2018/04/25/winter-2017-2018-recap-historic-cold-snap-reinforces-findings-in-operational-fuel-security-analysis/

[7] https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/21-Day-Energy-Assessment-Forecast-and-Report-Results

Seasonal Risk Scenario Margins

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margins and seasonal risk scenario chart in each dashboard provide potential winter peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below the seasonal risk scenario charts; see the **Data Concepts and Assumptions** for more information about these chart.

The seasonal risk scenario charts can be expressed in terms of reserve margins. In **Table 1**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario. The typical outages reserve margin is comprised of anticipated resources, less the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the anticipated reserve margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

Table 1: Seasonal Risk Scenario Margins

Assessment Area	Anticipated Reserve Margin	Typical Outages	Extreme Conditions
MISO	43.1%	14.0%	-7.6%
MRO-Manitoba	18.1%	16.2%	9.2%
MRO-SaskPower	28.7%	22.0%	12.6%
NPCC-Maritimes	17.5%	11.3%	-8.6%
NPCC-New England	72.0%	54.7%	2.5%
NPCC-New York	83.2%	58.9%	23.9%
NPCC-Ontario	24.3%	24.3%	9.5%
NPCC-Quebec	12.7%	12.7%	2.3%
PJM	45.9%	33.2%	16.0%
SERC-C	25.1%	18.4%	2.7%
SERC-E	23.9%	17.3%	1.0%
SERC-FP	36.7%	33.2%	0.0%
SERC-SE	31.7%	22.8%	8.4%
SPP	70.0%	44.5%	9.3%
TRE-ERCOT	36.4%	20.4%	-21.4%
WECC-AB	20.8%	18.3%	-1.1%
WECC-BC	16.2%	16.1%	6.4%
WECC-CAMX	49.7%	41.7%	18.6%
WECC-WPP	33.8%	31.3%	10.1%
WECC-SRSG	93.5%	84.7%	55.7%

Reliability Enhancements in Storm-Affected Assessment Areas

Industry, regulators, and the ERO Enterprise have taken significant actions to improve winter readiness following the devastating effects of the February 2021 Winter Storm Uri cold weather event. The first cold weather Reliability Standards, adopted by the NERC Board in June 2021, advance BPS reliability by requiring generators to implement plans for cold weather preparedness as well as to provide cold weather operating parameters to their RCs, TOPs, and BAs for use in operating plans. Though these requirements take effect in the United States in April 2023, just after the upcoming winter season, some reliability benefits of the new requirements may be realized sooner through cold weather planning and preparations that improve generator performance and operator coordination. Across industry, the recommendations of the FERC-NERC-Regional Entity staff report—*The February 2021 Cold Weather Outages in Texas and South Central United States.*—are shaping direction at ISO/RTOs, in technical committees and industry forums, and among industry planners and operators.

The three hardest-hit areas by the 2021 Winter Storm Uri—Texas RE-ERCOT, SPP, and MISO—have implemented several improvements based on their operating experience. Texas weatherization standards, applicable to generators and natural gas facilities designated as critical infrastructure, aim to improve generator availability during extreme weather this winter. In SPP and MISO, where Winter Storm Uri impacts were less severe, a focus on operational coordination and situational awareness should help operators prepare to have sufficient resources for extreme conditions.

Texas RE-ERCOT, SPP, and MISO continue to be at-risk for energy emergencies during the upcoming winter based on their expected resources, normal and extreme demand, and historical generator outage information. However, the enhancements described in the following Texas RE-ERCOT, SPP, and MISO sub-sections are expected to reduce the likelihood of emergencies and lessen the severity that an extreme winter cold weather event on the scale of Winter Storm Uri could cause.

Texas RE-ERCOT

Since February 2021, Texas regulators, ERCOT, and GOs have implemented winter preparedness programs and other reforms aimed at improving generator performance in extreme winter weather. These actions are expected to reduce generator outages in extreme conditions to reduce the likelihood of energy emergencies as well as to mitigate impacts to firm load should an energy emergency occur:

- Regulations in Texas require generator and transmission owners to winterize equipment and facilities. ERCOT conducts weather preparedness inspections of generation and transmission as well as tracks exceptions to requirements until completed.
- In August 2022 the Railroad Commission of Texas (RRC), which regulates the Texas fuel oil and natural gas industry, approved its Final Rule[8] on weather emergency preparedness standards for designated "critical [natural] gas facilities" in the state's new Electricity Supply Chain Map.[9] TRRC inspectors will begin inspecting facilities to determine compliance beginning December 1, 2022, based on submitted compliance attestations. Inspections will focus on infrastructure that produces, stores, processes, and/or transports large volumes of natural gas, and this TRRC effort will be prioritized by facility size.
- ERCOT procured over 2,900 MW of firm fuel supply resources for the upcoming winter. Under the new market product, the procured natural-gas-fired generators must have back-up fuel that would support operations for 48 hours in the event that natural gas supply is interrupted.
- ERCOT has reviewed load-shedding plans with area TOPs and conducts periodic training exercises. Additionally, they coordinate with TOPs to prepare enhanced manual load-shedding and rotating outage plans designed to minimize disruption to firm load.

SPP

SPP is implementing a set of actions—policy changes and assessments approved by the SPP Board of Directors—to address issues related to fuel assurance, resource planning and availability, emergency response, communications, and other critical areas. For the upcoming winter, these actions will improve generator preparedness and operator response:

- SPP held the Winter Preparedness Workshop to help inform members of forecasted conditions for the upcoming season and review SPP's seasonal preparedness steps outlined in its operating procedures.
- RC and BA staff have implemented a high risk scenario alerting system for managing risk periods. This system will identify and alert staff on potential upcoming records, such as load, wind, and wind penetration, to allow time for extra studies to be executed and analyzed as well as to be addressed by the SPP response team.

SPP established an Improved Resource Availability Task Force, which will take primary responsibility for addressing recommendations related to fuel assurance and resource planning as well as

[8] https://www.rrc.texas.gov/media/c5hdc4ga/rule-3-66.pdf
[9] https://www.puc.texas.gov/agency/resources/reports/mapping/2021_Mapping_Agency_Report.pdf

availability that is identified in SPP's *Comprehensive Review of SPP's Response to the February 2021 Winter Storm* report.[10]

MISO

MISO has implemented actions to provide situational awareness and early coordination for reducing risks from extreme winter weather:

- MISO continues to survey GOs and GOPs about unit preparedness and winter fuel sufficiency.
- Processes are in place for coordination with neighboring RCs and BAs on needs for firm or non-firm transfers to address extreme system conditions. Pre-season transfer studies for normal and extreme scenarios are underway.

For future years, MISO's new resource adequacy construct (filed with FERC for approval) is expected to deliver additional winter resource capacity by using a winter reserve margin and resource capacity accreditations that account for winter peak conditions.

MISO Neighboring Area Studies

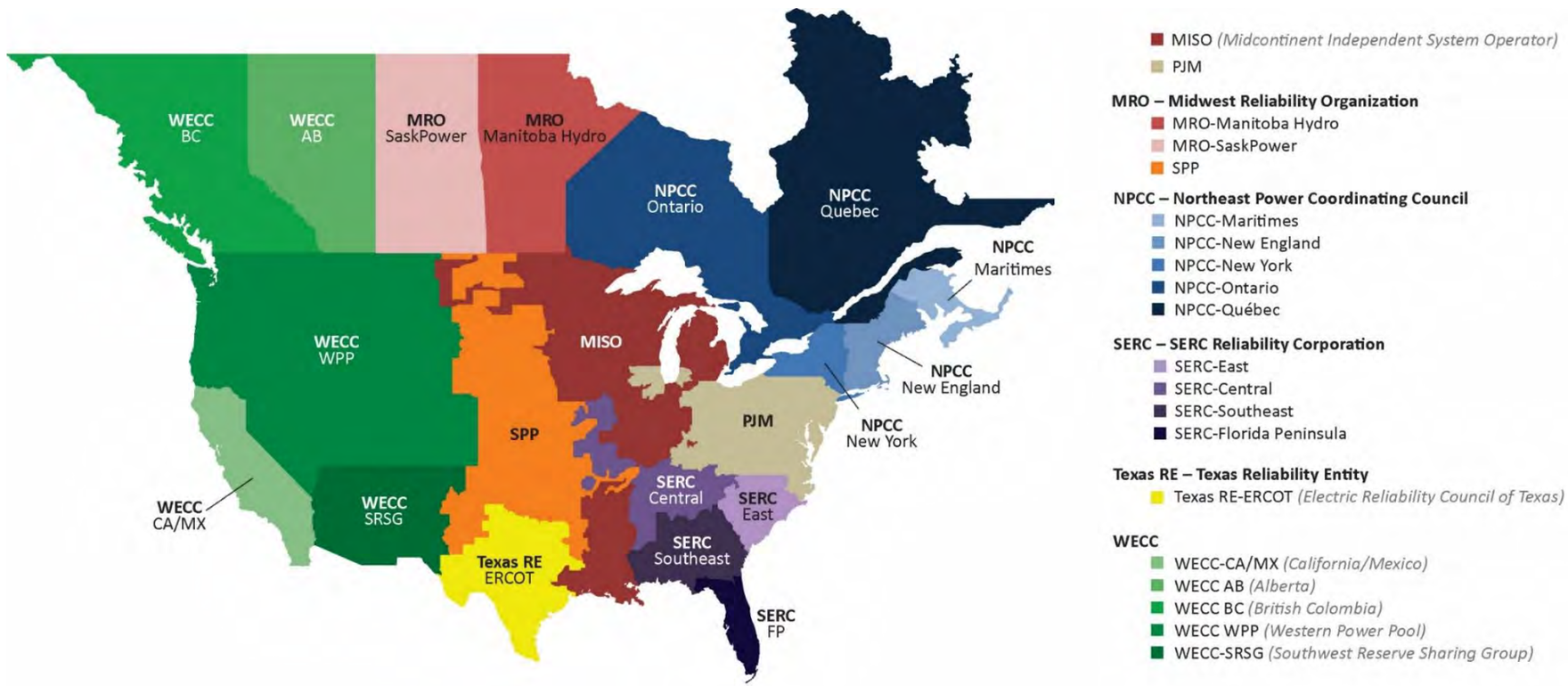
During Winter Storm URI, other areas in the Eastern Interconnection experienced localized transmission emergencies resulting from the large transfers flowing across the transmission system from generators in PJM to the affected areas in MISO and SPP. Accordingly, the *FERC-NERC-Regional Entity staff Joint Report* recommended planners and operators study large power transfers during stressed conditions. Transfer studies have been conducted in SERC to help prepare for the upcoming winter. During extreme cold temperatures, there is the potential for significant transfers through the area as excess power is shipped to meet power demands in affected areas outside of SERC.

A SERC technical working group performed a 2022–2023 winter reliability study to determine the adequacy and reliability of the SERC transmission system using a 2022–2023 winter peak power flow model, which included 12 GW power transfer from PJM to MISO. The study also simulated the impacts of higher load demands due to colder than normal temperatures in each SERC sub-area by increasing generation throughout them all while simultaneously increasing load in a particular sub-area. SERC concluded that the transmission system was adequate for normal and extreme conditions and that localized transmission constraints, when observed, could be mitigated through system reconfiguration.

[10] https://www.spp.org/markets-operations/current-grid-conditions/2021-winter-storm-review/

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-Peak Reserve Margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level established for the area to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the **Demand and Resource Tables**), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme winter peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the WRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios.



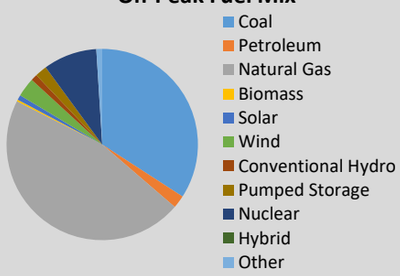


MISO

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency.

MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authority and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

On-Peak Fuel Mix



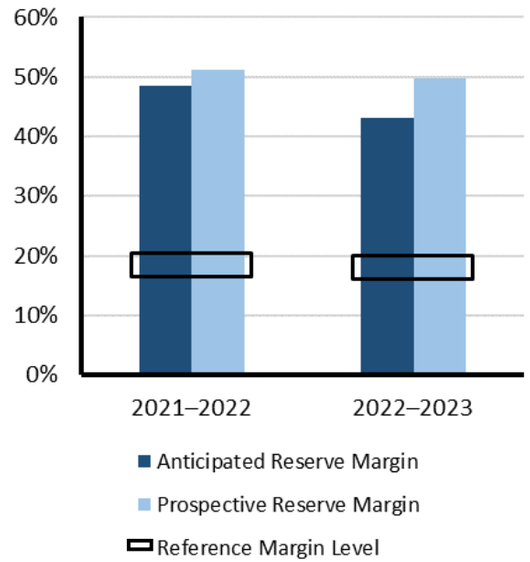
Highlights

- Since 2021–2022 winter, reserve margins in MISO have fallen by over 5%. Nuclear and coal-fired generation retirements total over 4.2 GW since the prior winter. Declining reserves are the result of few resource additions. Since last winter, more demand response (2,250 MW) and new wind generation (500 MW on-peak/3,200 MW nameplate) was added.
- MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency. In addition, MISO is acknowledging that resource adequacy risk is not limited to the summer system peak season, MISO is filing changes to the resource adequacy construct to implement a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons.
- Though risk has been identified for this upcoming winter season in a high generation outage and high winter load scenario, MISO expects to maintain reliability through the use of measures that include load modifying resources (LMR) (MISO's demand response), non-firm transfers into the system, energy only interconnection service resources not receiving capacity credit, and/or internal transfers that exceed the sub-area import/export constraint between the MISO North/Central and South areas. MISO continues to coordinate extensively with neighboring RCs and BAs to improve situational awareness and vet needs for firm or non-firm transfers to address extreme system conditions.

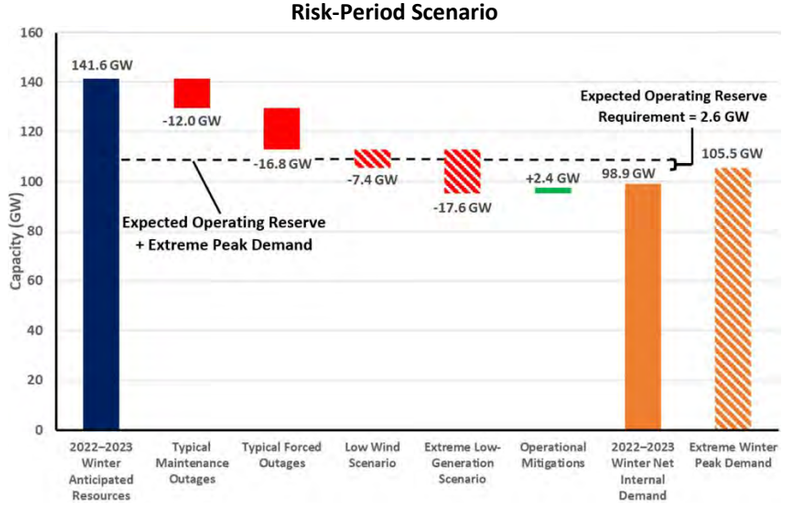
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and energy emergency alerts (EEAs). Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year winter average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Low Wind Scenario: Below average wind contributions

Extreme Low-Generation: Maximum historical generation outages

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme operating conditions

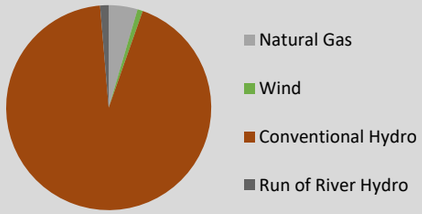


MRO-Manitoba Hydro

Manitoba Hydro is a provincial crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 601,000 electric customers in Manitoba and provides approximately 291,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba which is 251,000 square miles.

Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator and Balancing Authority. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

On-Peak Fuel Mix



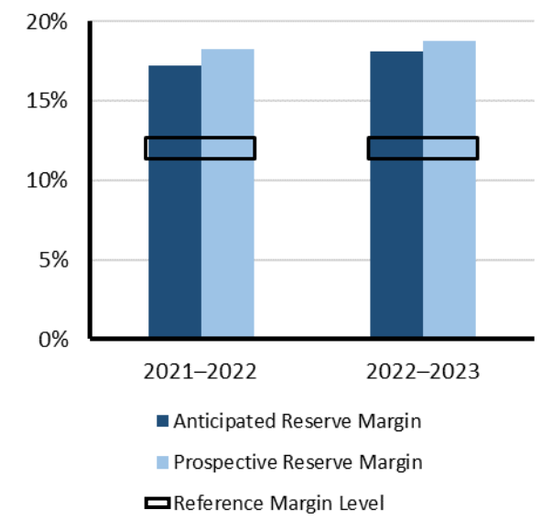
Highlights

- The Anticipated Reserve Margin for the 2022–2023 winter exceeds the 12% Reference Margin Level.
- There are no emerging reliability/resource adequacy issues anticipated for the upcoming winter season.
- All seven units at the Keeyask Hydroelectric Generating Station (630 MW net addition) are anticipated to be in commercial operation for the 2022–2023 winter.

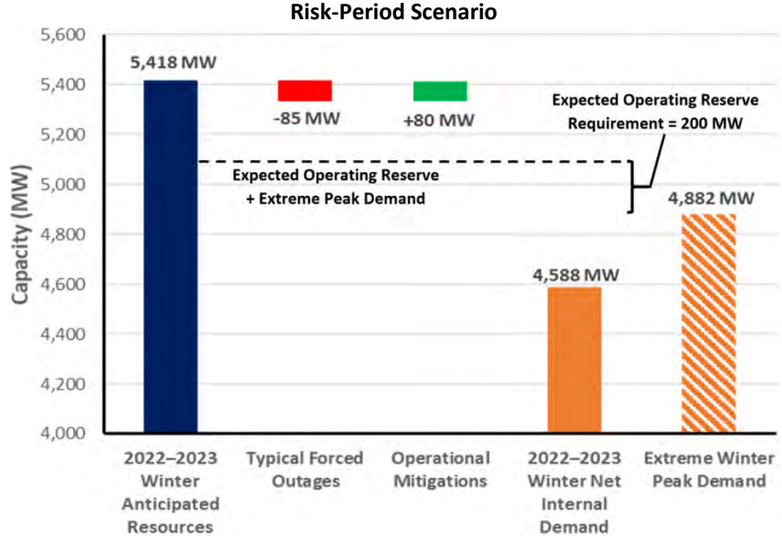
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand scales additional load experienced during all-time peak actual versus forecasted load (January 2019)

Forced Outages: Accounts for average forced outages

Operational Mitigations: Recall 80 MW of additional curtailable load



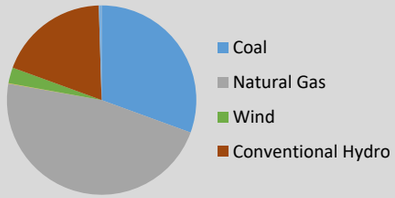
MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and approximately 1.1 million customers. Peak demand is experienced in the winter.

The Saskatchewan Power Corporation (SaskPower) is the Planning Coordinator and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province.

SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System and its interconnections.

On-Peak Fuel Mix



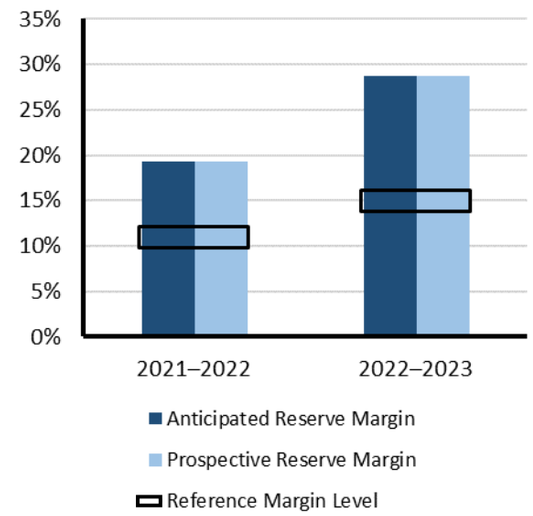
Highlights

- SaskPower experiences peak load in winter because of extreme cold weather. Reserve margins have increased since the 2021–2022 winter with the addition of new wind generators and increased firm capacity imports from Manitoba.
- SaskPower conducts an annual winter joint operating study with Manitoba Hydro with inputs from Basin Electric Power Cooperative (North Dakota) and prepares operating guidelines for any identified issues.
- The risk of operating reserve shortage or EEA during peak load times exists if large generation forced outage occurs during peak load times combined with transmission tie-line maintenance work or generation maintenance work scheduled during winter months.
- In case of extreme winter conditions combined with large generation forced outages, SaskPower would use available demand response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions.

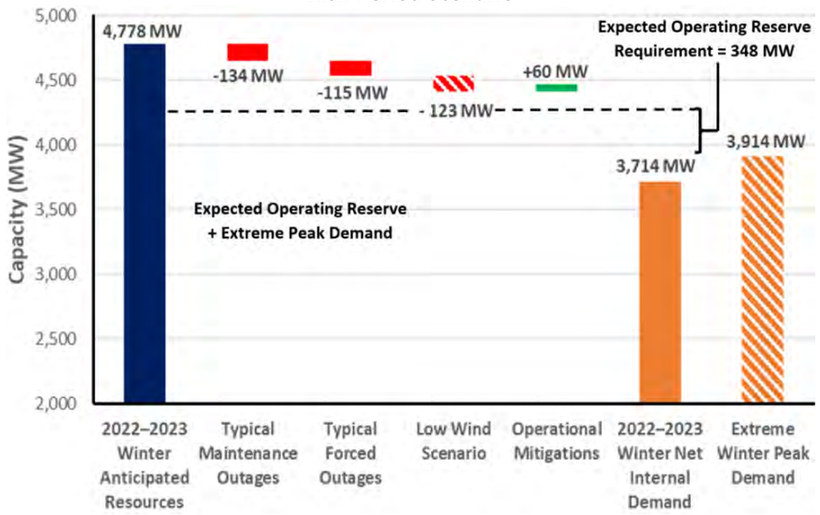
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Maintenance Outages: Average of planned maintenance outages for the winter months, December–February, over the past three years

Forced Outages: Estimated using SaskPower forced outage model

Low Wind Scenario: Estimated using SaskPower forced outage model

Operational Mitigations: Estimated average value based on short term transfer capability from neighboring utilities for the upcoming 2022–2023 winter



NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two Balancing Authorities. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

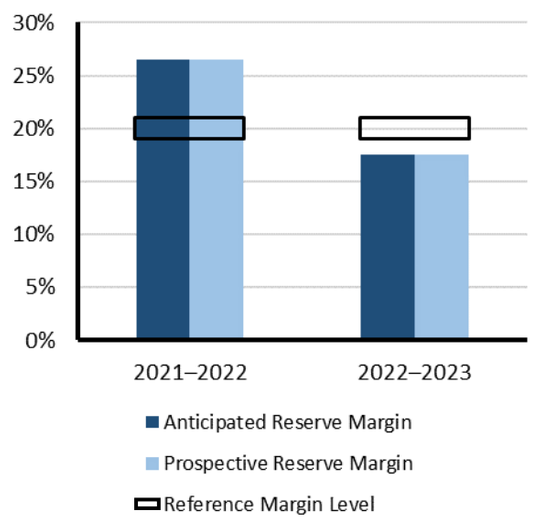
Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event was to occur, there are emergency operations and planning procedures in place.
- The Maritimes area is a winter-peaking system. All of the area's declared firm capacity is expected to be operational for the winter operating period.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil on-site to enable sustained operation in the event of natural gas supply interruptions.
- The results (preliminary) of NPCC's probabilistic assessment indicate that established operating procedures are sufficient to maintain a balance between electricity supply and demand.[11] Only the low likelihood reduced resource case, highest peak load scenario, resulted in an estimated cumulative loss of load expectation (LOLE) risk of ~0.2 days/period with associated loss of load hours (LOLH) (<1 hours/period) and expected unsupplied energy (EUE) (3.4 MWh) over the winter period. The Maritimes area's low likelihood resource case assumed that wind capacity was de-rated by half (1,100 to 550 MW) for every hour in the winter period, coupled with an assumed 50% reduction in natural-gas-fired generation and reduced transfer capabilities.

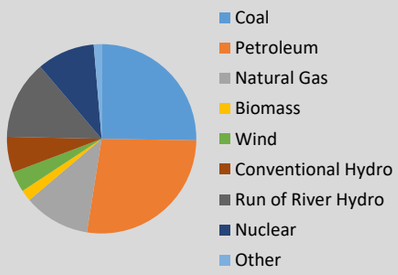
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. As noted above, the risk of load shedding is low.

On-Peak Reserve Margins



On-Peak Fuel Mix



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (above 90/10) extreme demand forecast.

Outages: Based on historical operating experience

Extreme Derates: A low likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions.

[11] Final NPCC Assessment Results will be published at the NPCC Seasonal Assessments page: https://www.npcc.org/library/reports/seasonal-assessment

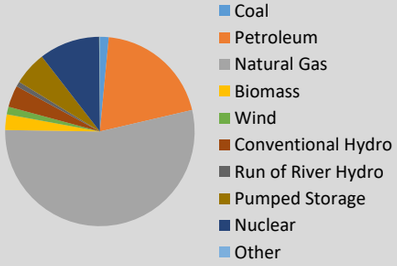


NPCC-New England

NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

On-Peak Fuel Mix



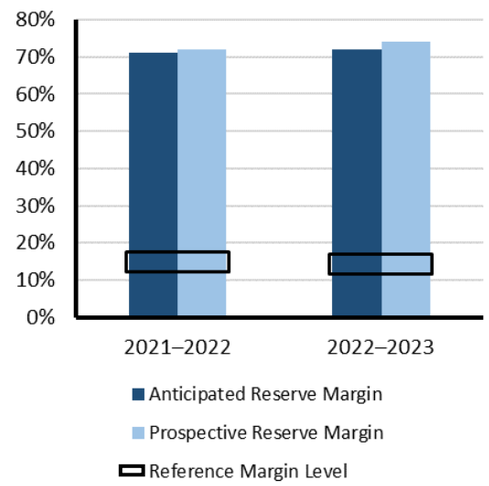
Highlights

- ISO-NE expects to meet its regional resource adequacy requirements this 2022–2023 winter operating period for a mild or moderate winter similar to 2021–2022 or 2017–2018. A standing concern is whether there will be sufficient energy available to satisfy electricity demand during an extended cold spell given the existing resource mix, fuel delivery infrastructure, and expected fuel arrangements without considerable effort to replenish stored fuels (i.e., fuel oil and LNG).
- ISO-NE expects to have sufficient capacity resources to meet the 2022–2023 90/10 winter peak demand forecast of 20,695 MW for the weeks beginning January 8, January 15, and January 22, 2023.
- ISO-NE evaluates an above 90/10 scenario that captures the area's coldest day in the last 25 years while using both our current and future load models. The above 90/10 winter peak demand forecast is 21,238 MW for the three previously identified peak weeks. ISO-NE currently has sufficient resources to meet this demand; however, if a cold snap were to occur, the area may have to rely on its external ties and emergency procedures to operate reliably.[12]

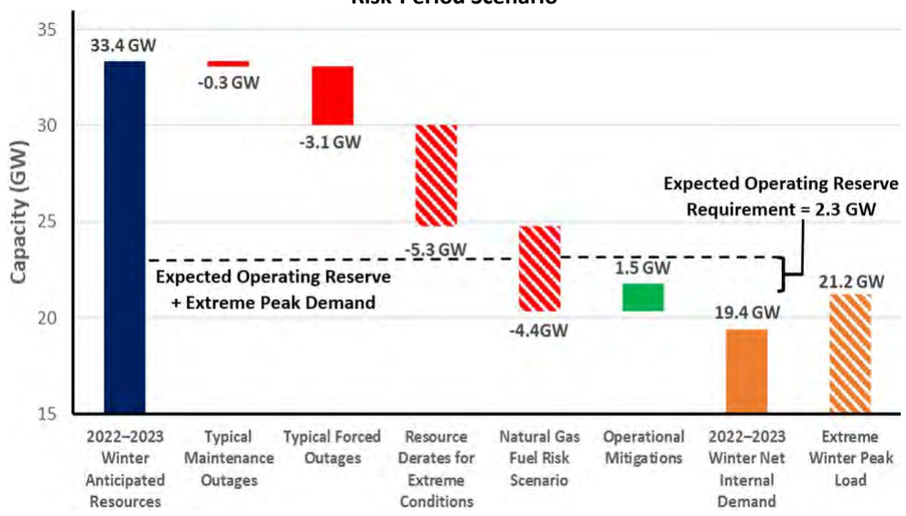
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and demand forecast for coldest day from the last 25 years

Maintenance and Forced Outages: Based on weekly averages

Extreme Derates and Natural Gas Scenario: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply and cold weather related outages reported by generators

Operational Mitigations: Based on ISO-NE operating procedures

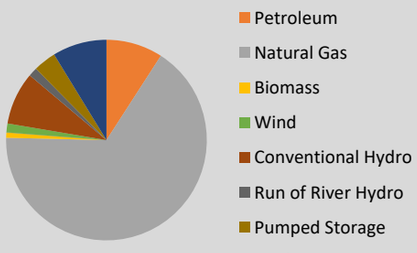
[12] Final NPCC Assessment Results will be published at the NPCC Seasonal Assessments page: https://www.npcc.org/library/reports/seasonal-assessment



NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The NYISO is the only Balancing Authority within the state of New York. The BPS encompasses over 11,000 miles of transmission lines, 760 power generation units, and serves 20.2 million customers. The established Reference Margin Level is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load serving entities to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2022–2023 IRM at 19.6%.

On-Peak Fuel Mix



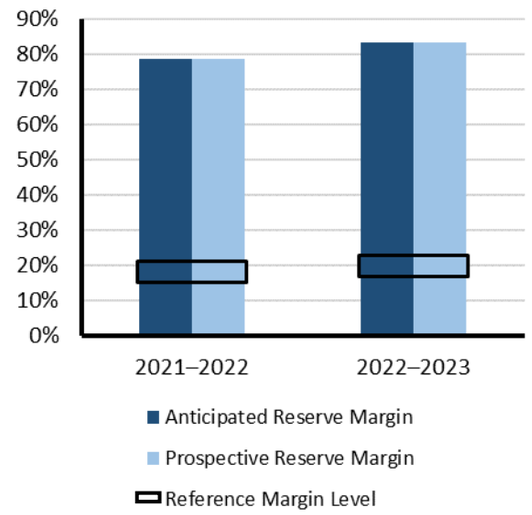
Highlights

- New York is a summer peaking area and no emerging reliability issues are anticipated during the 2022–2023 winter assessment period. Surplus capacity margins above the NYISO's operating reserve requirements are projected.
- The results (preliminary) of NPCC's probabilistic assessment for the area indicate that emergency operating procedures to maintain a balance between electricity supply and demand are not anticipated for the upcoming winter. No cumulative LOLE, LOLH, or EUE risks were found for the winter period for all modeled scenarios.[13]

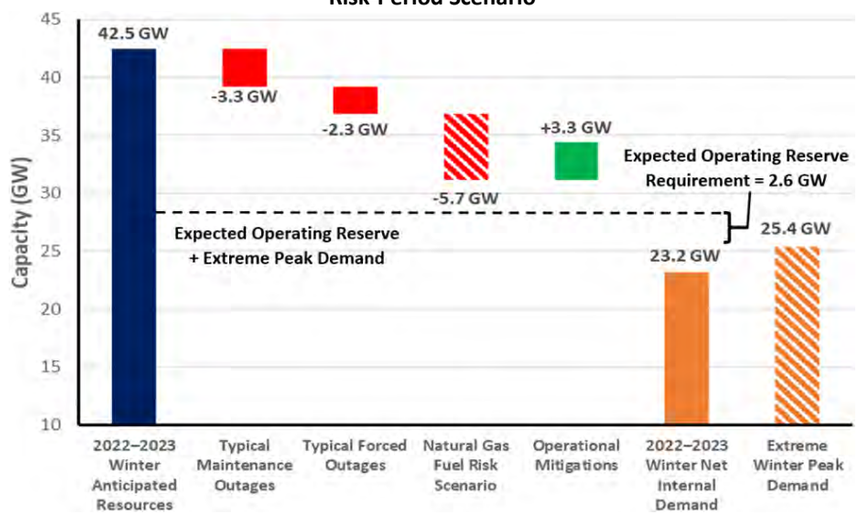
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (99/1) demand forecast with demand response adjustments

Maintenance Outages: Based on planned scheduled maintenance

Forced Outages: Based on historical 5-year averages

Natural Gas Fuel Scenario: Potential natural gas generation at risk if non-firm supply is unavailable in a period of extended cold weather

Operational Mitigations: Based on NYISO operating procedures

[13] Final NPCC Assessment Results will be published at the NPCC Seasonal Assessments page: https://www.npcc.org/library/reports/seasonal-assessment



NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the Balancing Authority for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 14 million.

Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

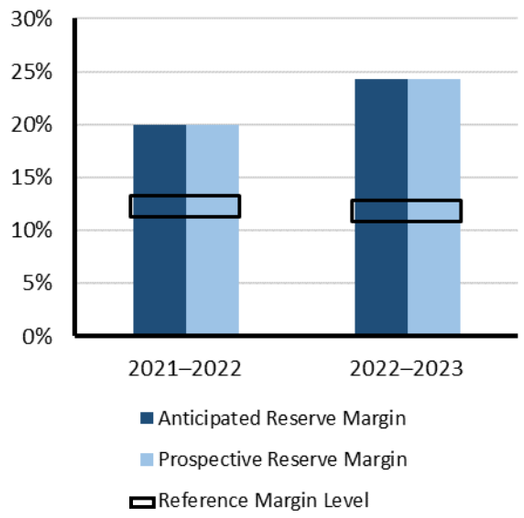
Highlights

- IESO anticipates that it will maintain reliability on its system through the 2022–2023 winter
- In spite of Ontario's ongoing nuclear refurbishment program, the IESO expects to have comfortable reserve margins throughout the winter season
- The results (preliminary) of NPCC's probabilistic assessment for the area indicate that emergency operating procedures to maintain a balance between electricity supply and demand are not anticipated for the upcoming winter. No cumulative LOLE, LOLH or EUE risks were found for the winter period for all modeled scenarios.[14]

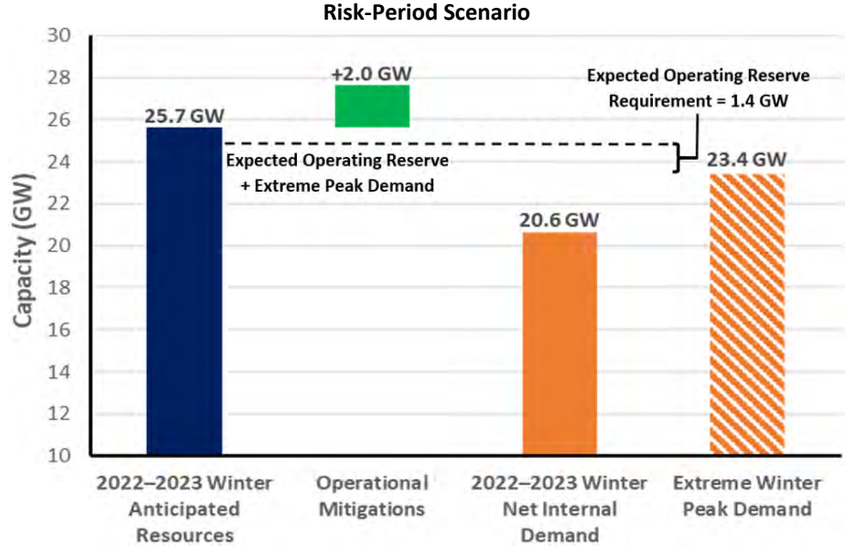
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



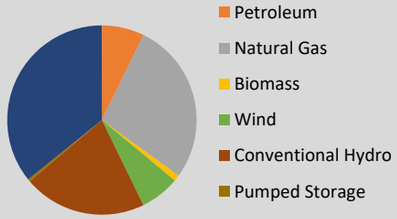
Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 Forecast) and highest weather-adjusted daily demand from 31 years of winter demand history

Operational Mitigations: Imports anticipated from neighbors during emergencies

On-Peak Fuel Mix



[14] Final NPCC Assessment Results will be published at the NPCC Seasonal Assessments page: https://www.npcc.org/library/reports/seasonal-assessment

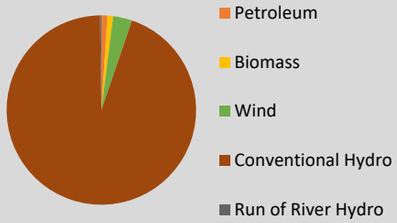


NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million.

Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes; consisting of either HVDC ties, radial generation, or load to and from neighboring systems.

On-Peak Fuel Mix



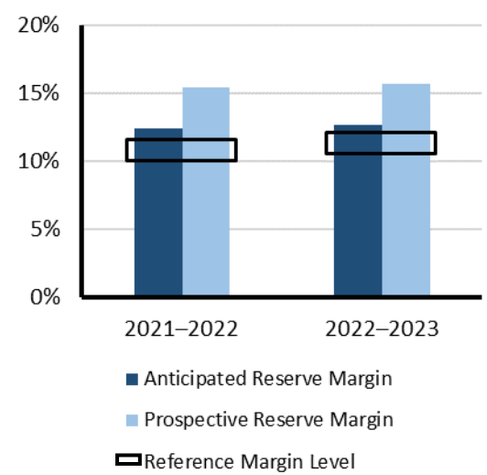
Highlights

- Québec is expecting to maintain system resource adequacy this winter.
- The Québec area is a winter-peaking system with predominately hydroelectric generation resources. Adequate capacity margins above its reference reserve requirements are projected for the 2022–2023 winter assessment period.
- No changes have been made to the assessment area's winter preparedness programs since the previous winter season.
- The results (preliminary) of NPCC's probabilistic assessment for the area indicate that emergency operating procedures to maintain a balance between electricity supply and demand are not anticipated for the upcoming winter. No cumulative LOLE, LOLH, or EUE risks were found for the winter period for all modeled scenarios.[15]

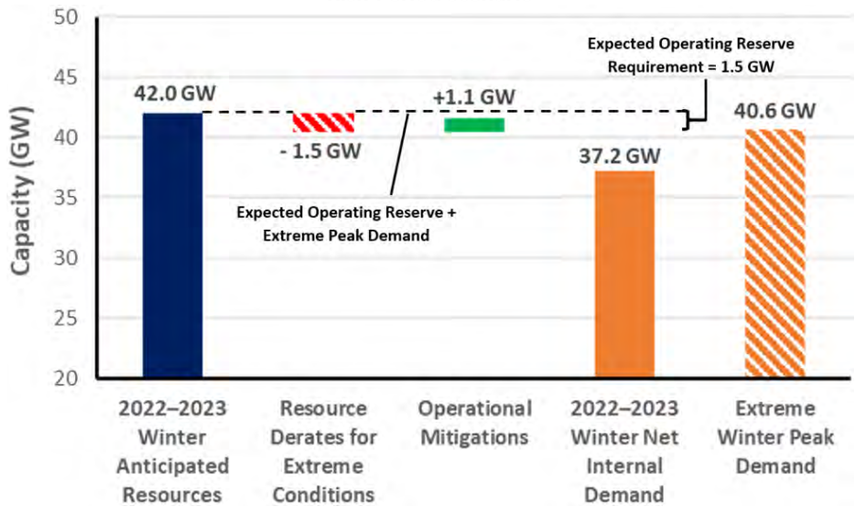
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Québec plans to use short-term capacity purchases in order to meet capacity requirements when needed. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. As noted above, risk of load shedding is low.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand represents two standard deviations higher than the mean demand forecast

Extreme Derates: Rare scenario of 1,500 MW in unplanned outages

Operational Mitigations: Imports anticipated from neighbors during emergencies

[15] Final NPCC Assessment Results will be published at the NPCC Seasonal Assessments page: https://www.npcc.org/library/reports/seasonal-assessment

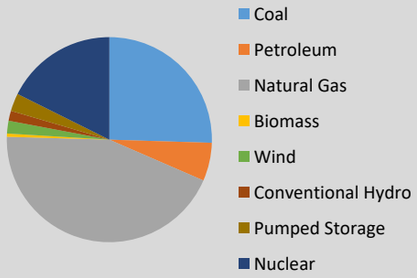


PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles.

PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator.

On-Peak Fuel Mix



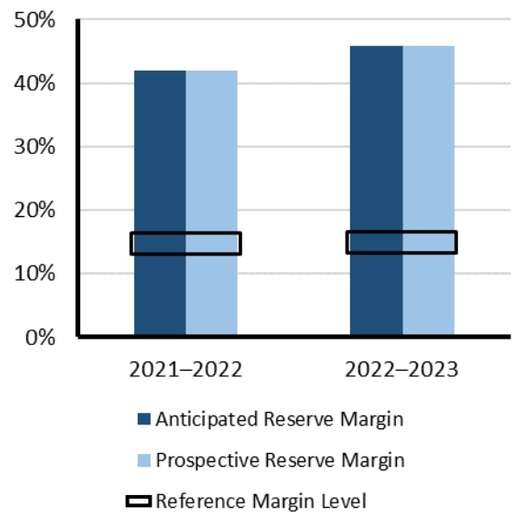
Highlights

- PJM expects no resource problems over the entire 2022–2023 winter peak season because installed capacity is almost three times the reserve requirement.
- No other reliability concerns are expected.

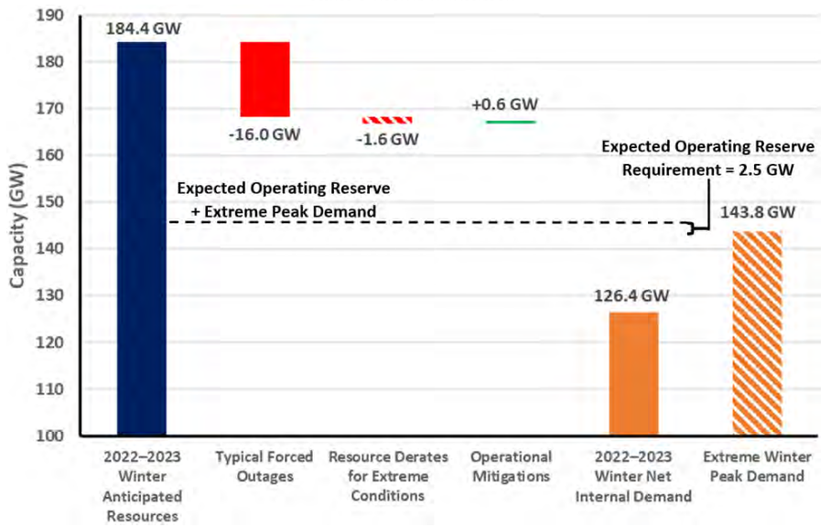
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 0.6 GW based on operational/emergency procedures



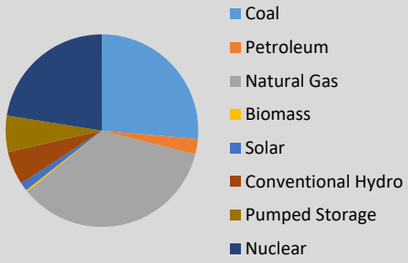
SERC-East

SERC-East is a winter-peaking assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



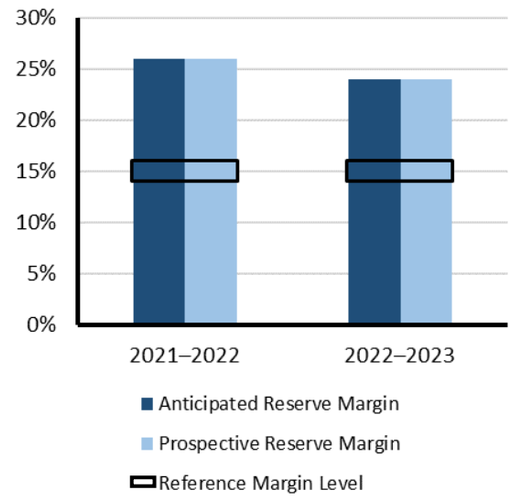
Highlights

- SERC-East has not identified any emerging or potential reliability issues for the upcoming winter season.
- Currently, there are issues with fuel supply and transportation in the SERC-East assessment area. Transportation providers and coal suppliers continue to struggle with post pandemic personnel shortages, volume increases, and inflationary cost increases. SERC-East does not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- SERC-East has extensive weatherization processes that include procedures specific to freezing events. SERC-East is prepared to respond to unexpected day-to-day events and coordinate with neighboring entities to promote overall system reliability.

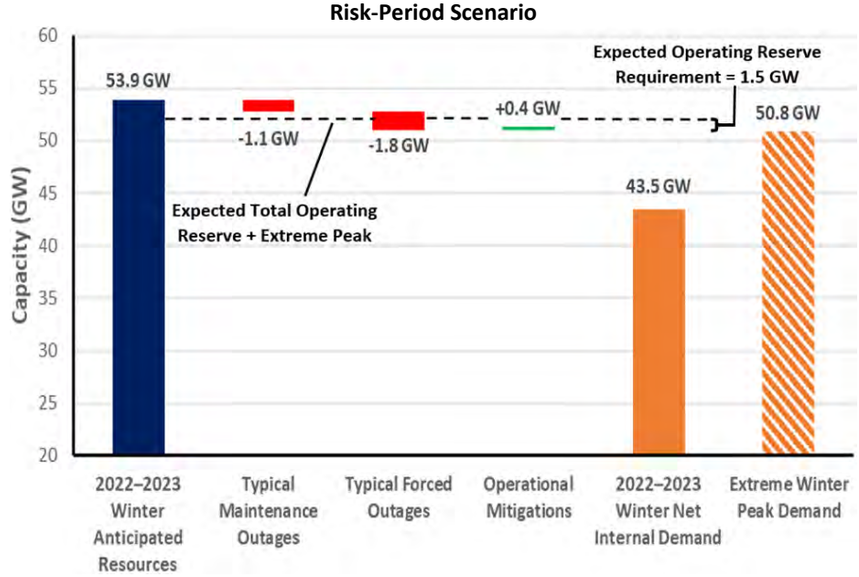
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need for non-firm transfers, operating mitigations and EEAs. Risk of load shedding is low.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation

Operational Mitigations: A total of 0.4 GW based on operational/emergency procedures



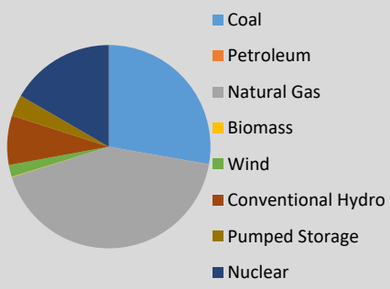
SERC-Central

SERC-Central is a winter-peaking assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

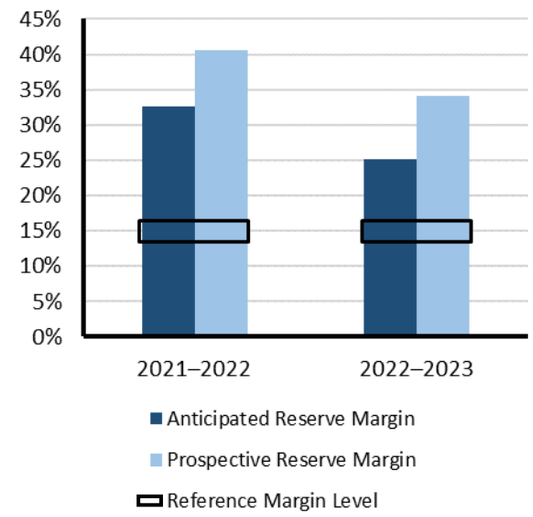
On-Peak Fuel Mix



Highlights

- SERC-Central has not identified any emerging or potential reliability issues for the upcoming winter season.
- SERC-Central does not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- SERC-Central has extensive weatherization processes that include procedures specific to freezing events and is prepared to respond to unexpected day-to day-events and coordinate with neighboring entities to promote overall system reliability.

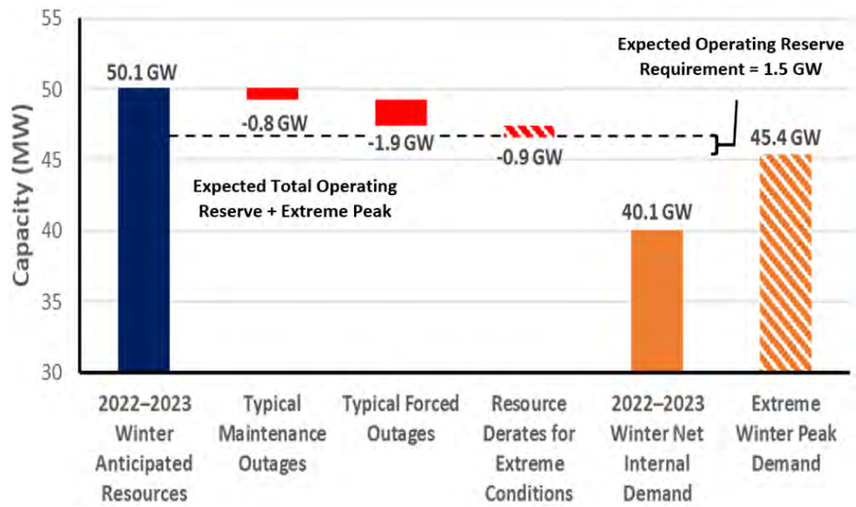
On-Peak Reserve Margins



Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions



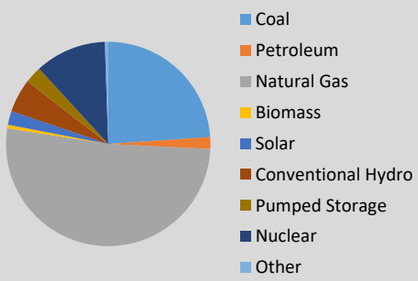
SERC-Southeast

SERC-Southeast is a winter-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



Highlights

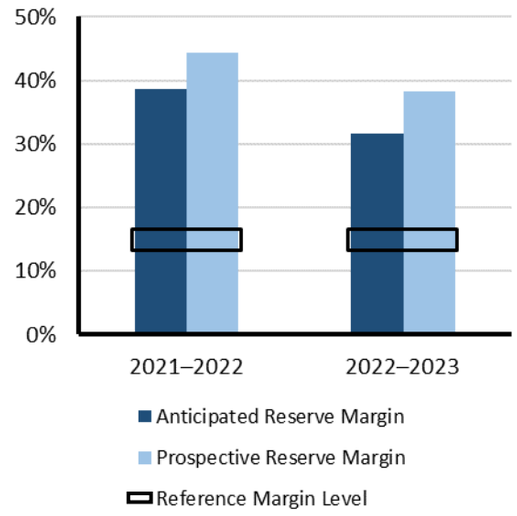
Aside from fuel availability concerns shared across the industry, SERC-Southeast have not identified any additional or emerging potential reliability related risks.

SERC-Southeast has extensive weatherization processes that include procedures specific to freezing events and is prepared to respond to unexpected day-to-day events and coordinate with neighboring entities to promote overall system reliability.

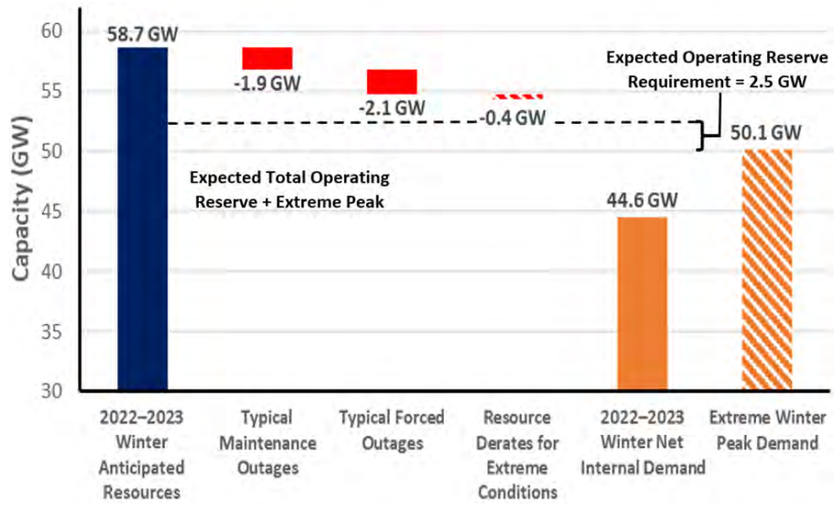
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions



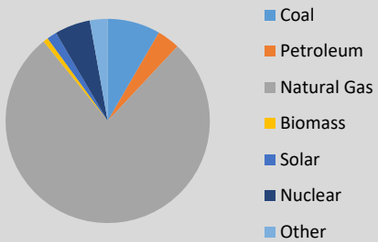
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC.

SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million.

The SERC Regional Entity includes 36 Balancing Authorities, 28 Planning Authorities, and 6 Reliability Coordinators.

On-Peak Fuel Mix



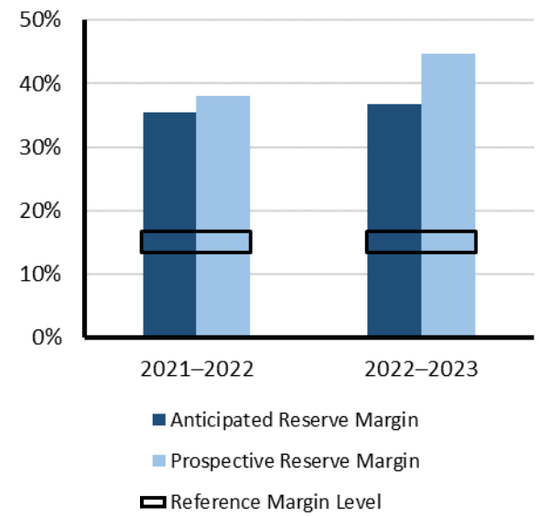
Highlights

- SERC-Florida Peninsula have not identified any emerging or potential reliability issues for the upcoming winter season.
- SERC-Florida Peninsula do not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- SERC-Florida Peninsula have extensive weatherization processes that include developing procedures specific to freezing events.

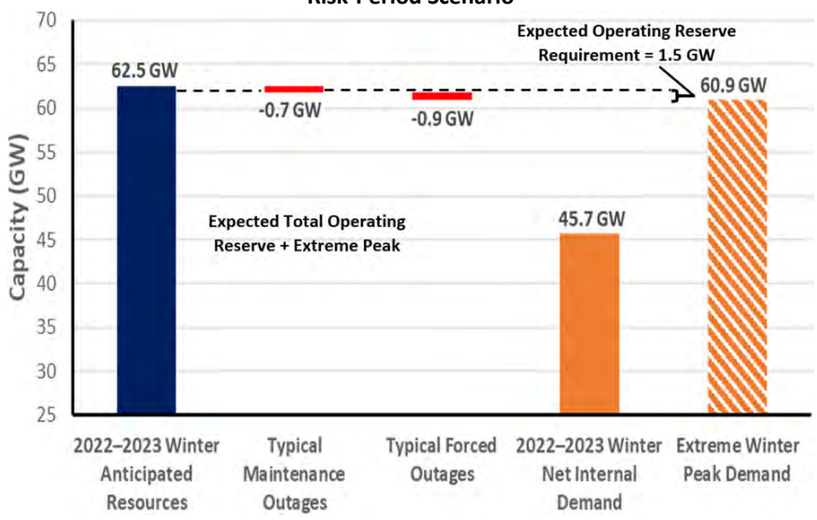
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (95/5) demand forecast

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation

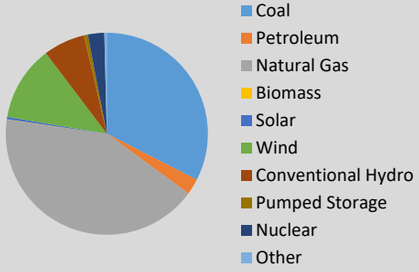


SPP

Southwest Power Pool (SPP) Planning Coordinator footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming.

The SPP long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

On-Peak Fuel Mix



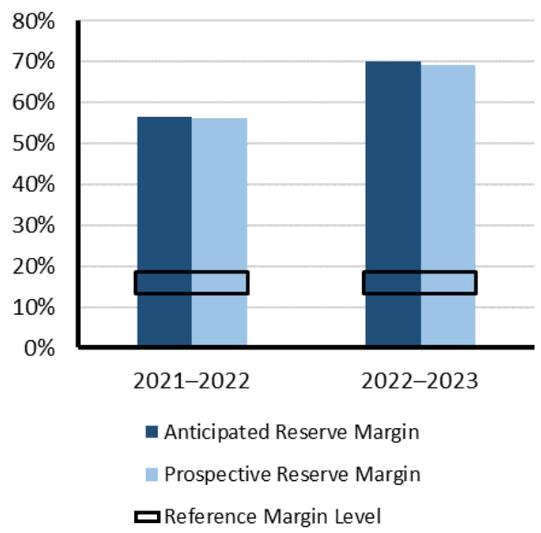
Highlights

- SPP's planning reserves are adequate for the upcoming winter season. Since the 2021–2022 winter, SPP has added 3,700 MW of natural-gas-fired generation.
- SPP does not anticipate any emerging reliability issues impacting the area for the 2022–2023 winter season but realizes that interruptions to fuel supply could create unique operation challenges.
- SPP continues to work with neighboring areas to address potential electric deliverability issues associated with extreme weather events. Efforts focus on enhancing communications and operator preparedness.
- In an effort to minimize the need for conservative operations, EEAs, and the responses to mid-range forecast error uncertainty in wind forecasts, SPP created some new mitigation processes to deal with high impact areas of concern. SPP has developed operational mitigation teams, processes, and procedures that have been put in place to maintain real time reliability needs.
- SPP created the Improved Resource Availability Task Force , which will take primary responsibility for addressing Tier 1 recommendations related to fuel assurance and resource planning and availability identified in the ***Comprehensive Review of SPP's Response to the February 2021 Winter Storm*** report.
- SPP hosts its winter preparedness workshop in October 2022.

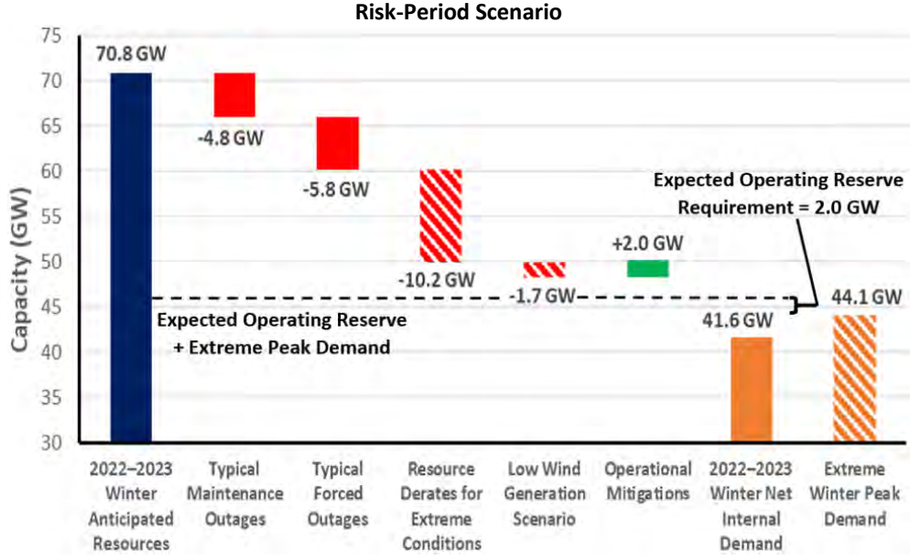
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance and Forced Outages: A capacity derate for maintenance outages, forced outages, and performance in extreme weather based on historical data

Extreme Derates: A capacity derate for generator performance in extreme weather based on historical data

Low Wind Scenario: 1.7 GW of wind potentially off-line when temperatures fall below their cold weather performance packages

Operational Mitigations: A total of 2 GW based on operational/emergency procedures (External Assistance)

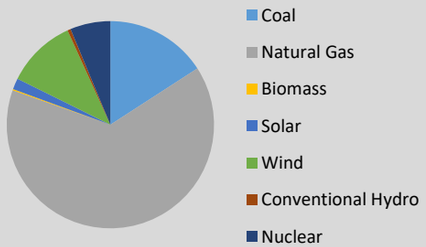


Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature.

ERCOT is summer-peaking. It covers approximately 200,000 square miles, connects over 46,500 miles of transmission lines, has over 710 generation units, and serves more than 25 million people. Lubbock Power & Light joined the ERCOT grid on June 1, 2021. Texas Regional Entity is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT.

On-Peak Fuel Mix



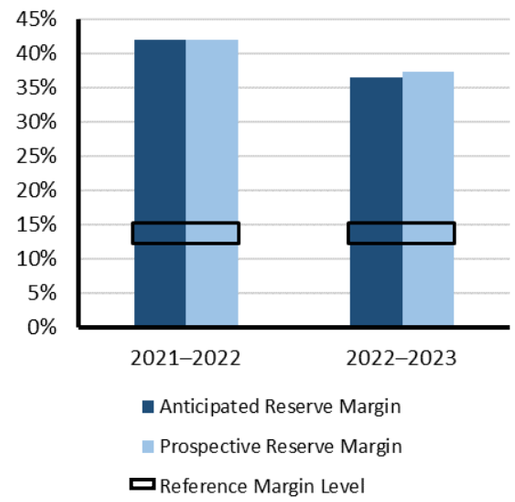
Highlights

- With an Anticipated Reserve Margin of 36.4%, capacity reserves are sufficient to meet forecasted peak demand to cover the types of weather events regularly experienced.
- Probabilistic risk assessment for the upcoming winter season confirms a low probability of energy emergency events occurring during the expected peak load hour (hour-ending 8:00 a.m.) and other higher-risk hours. The assessment accounts for the risk of another weather event like Winter Storm Uri as well as the impacts of winter preparedness standards implemented by the Public Utility Commission of Texas and the TRRC, which regulates the Texas fuel oil and natural gas industries.
- ERCOT conducted 324 weather preparedness inspections during 2021, covering 302 generation sites and 22 transmission service providers. These inspections focused on whether each reporting entity performed the weatherization activities described in their winter weather readiness reports required by the PUCT. ERCOT has been working with the PUCT on development of Phase II of the preparedness standards, which addresses both winter and summer preparedness compliance.
- The U.S. EPA is proposing a "conditional acceptance" of CPS Energy's plan to address two ponds at the coal-fired Calaveras Spruce station that are not in compliance with EPA regulations for coal combustion residuals. If the generation units at the site (J.K. Spruce 1 and 2: 1,477 MW) are found to be needed for grid reliability, then the EPA would allow ERCOT and CPS Energy to plan the outages to best minimize reliability issues during the outage period. If the EPA denies the conditional acceptance, then the Spruce units would cease operations 135 days after the EPA denial decision is made.

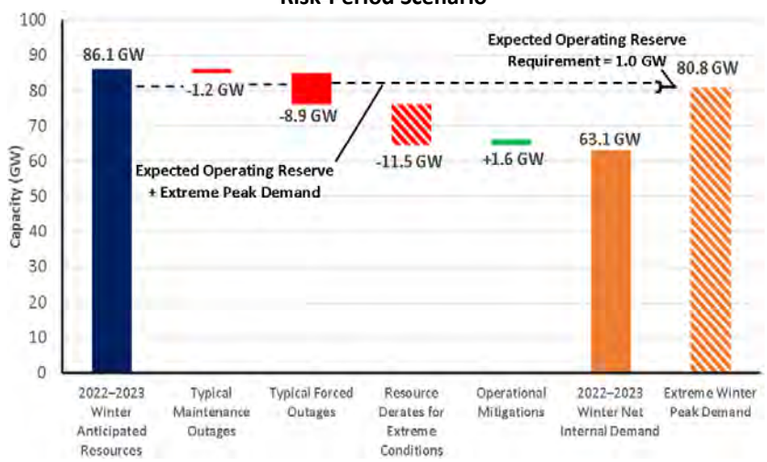
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs, including load shedding that may be needed under extreme peak demand and outage scenarios studied.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme winter peak demand based on 2020–2021 winter storm Uri peak demand

Maintenance and Forced Outages: Based on the historical averages of maintenance or forced outages respectively for December through February weekdays, hours ending 7:00–10:00 a.m. local time for the last three (2019/2020, 2020/2021, and 2021/2022) winter seasons (Winter Storm Uri-related forced outages between February 15–18, 2021, were excluded from this calculation.)

Extreme Derates: Accounts for reduced thermal, wind, and solar PV capacity contributions due to performance in extreme conditions. Uses averages from Winter Storm URI with adjustments to account for implemented weatherization improvements.

Operational Mitigations: Additional capacity from switchable generation, additional imports, and voltage reduction



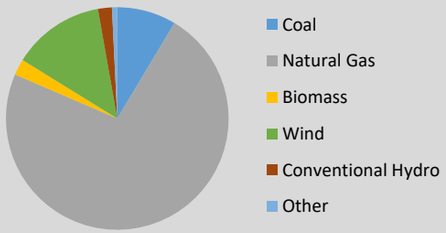
WECC-AB

WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



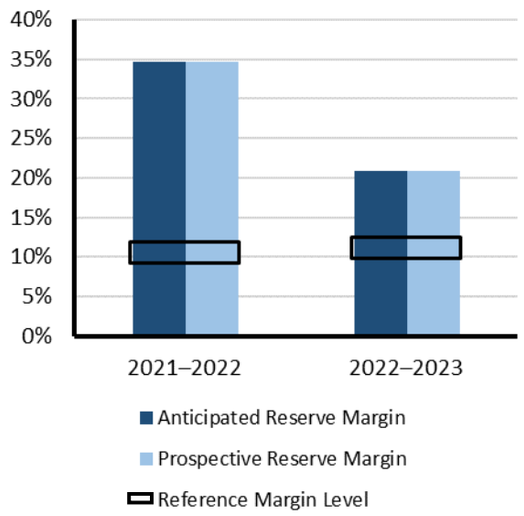
Highlights

- Alberta is a winter peaking area. Winter temperatures are forecast to be below normal. Alberta's operating reserve margins are met before imports in all scenarios except the Low Wind, which leaves a gap of 0.1 GW, and the extreme combined scenario, which leaves a gap of 0.6 GW under extreme peak demand conditions. Both are anticipated to be able to be covered through imports.
- The drop in on-peak reserve margins between last winter and the upcoming winter is a reflection of a slight demand increase of 330 MW combined with roughly 1,500 MW less Tier 1 resources than in the last plan.

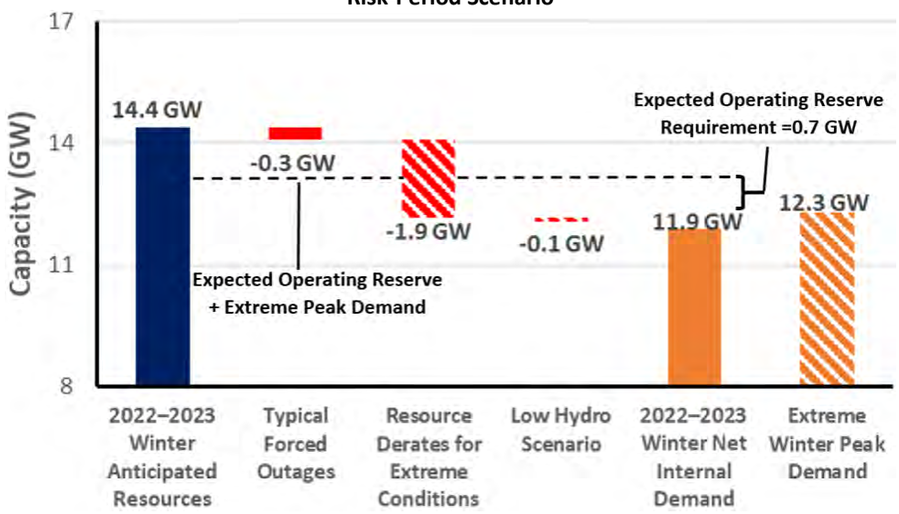
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Risk of load shedding is low due to the expected availability of transfers from neighboring areas.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro output due to drought conditions



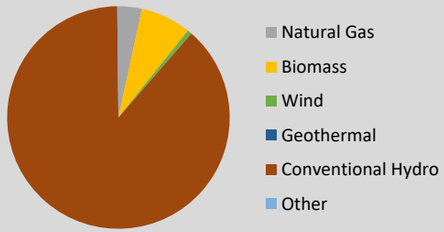
WECC-BC

WECC-BC (British Columbia) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



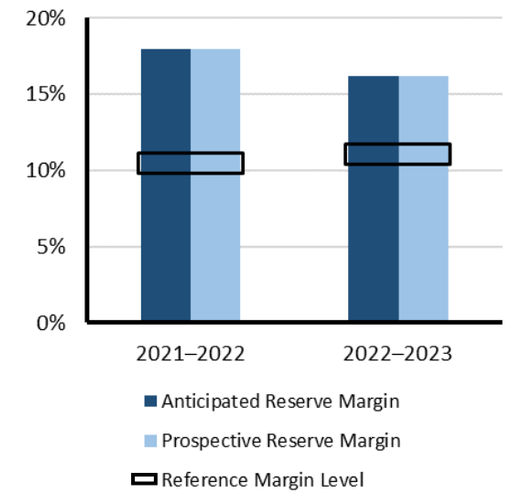
Highlight

- British Columbia is winter peaking with below normal temperatures forecast. In British Columbia before imports, operating reserve margins are not met by at least 0.4 GW in the occurrence of an extreme peak demand. However, the net internal demand is met before imports in all winter resource availability scenarios except under Low Hydro, which leaves an approximate gap of 1 GW, and Extreme Combined, which leaves a gap of 1.1 GW. Both of these are expected to be able to be covered through imports.

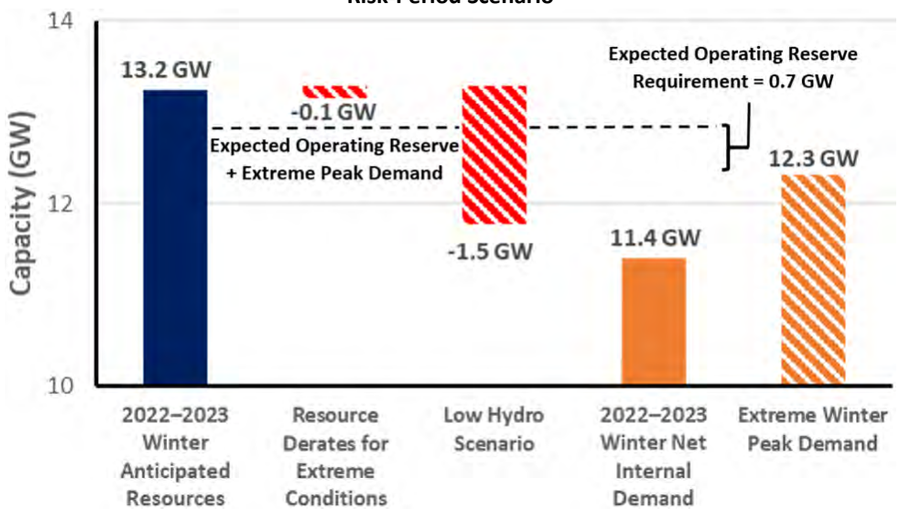
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions combined with an unlikely low-hydro scenario could result in the need to employ operating mitigations (e.g., demand response, transfers, short-term load interruption) and EEAs.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro output due to drought conditions



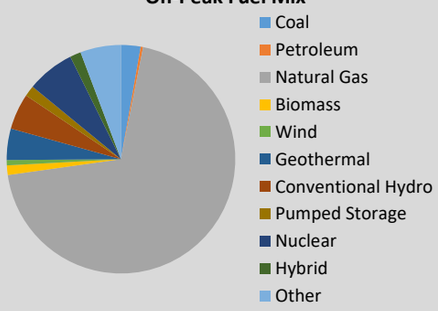
WECC-CA/MX

WECC-CA/MX (California/Mexico) is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorizes, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

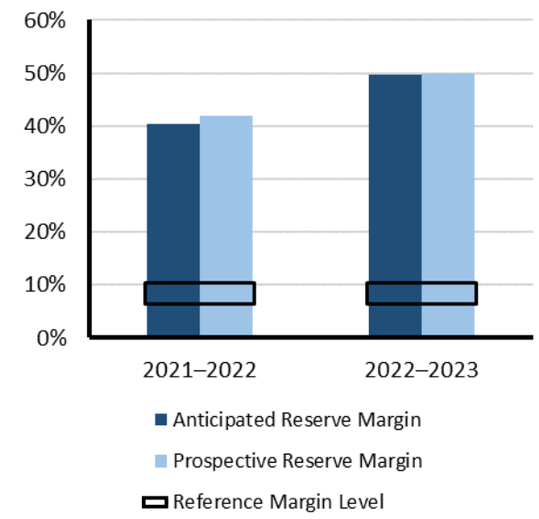
On-Peak Fuel Mix



Highlight

- CA/MX is a summer-peaking area. Above average temperatures are forecasted for the upcoming winter. Operating reserve margins are met before imports in all winter resource availability scenarios.

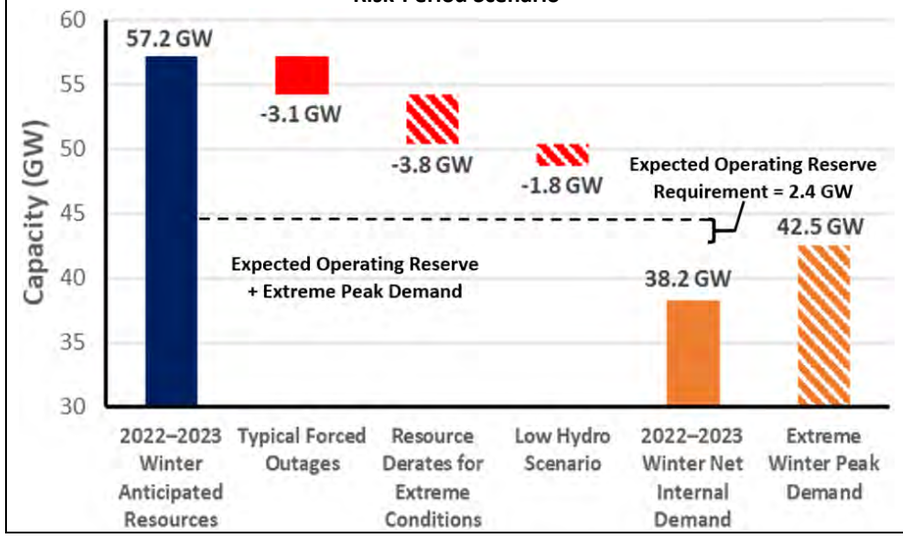
On-Peak Reserve Margins



Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historic data and manufacturer data for temperature performance and outages

Low Hydro Scenario: Reduced hydro output due to drought conditions



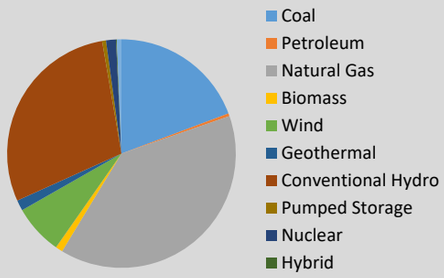
WECC-WPP

WECC-WPP (Western Power Pool) is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



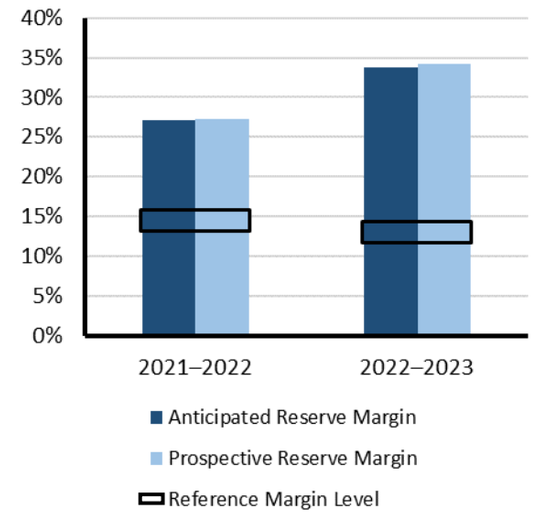
Highlight

- WPP has historically been a mixed season peaking area but is moving towards summer peaking. Operating reserve margins are met at the expected peak demand hour under all but the Extreme Combined scenario, where 1.6 GW of imports would be needed to meet operating reserve margins at an extreme peak demand.

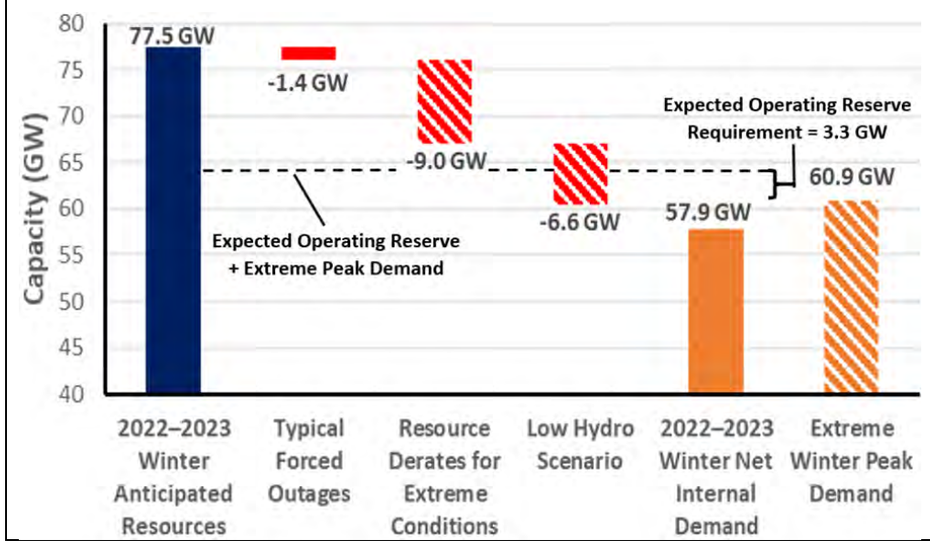
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal and extreme peak-demand scenarios. Low hydro output is unlikely, but could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. The risk of load shedding is low due to the expected availability of transfers from neighboring areas.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro output due to drought conditions



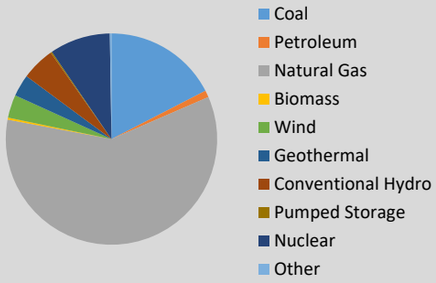
WECC-SRSG

WECC-SRSG (Southwest Reserve Sharing Group) is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas.

WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity.

WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 Western United States in between.

On-Peak Fuel Mix



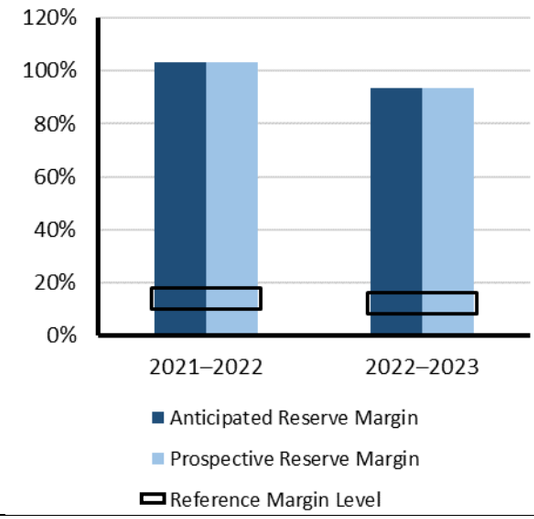
Highlight

- The summer peaking SRSG is expecting above average temperatures this winter. It is anticipated to be resource adequate under all winter extreme availability and demand scenarios. The higher margins compared to the summer season are due to a demand peak of 14 GW in the winter versus a peak of 26 GW in the summer.

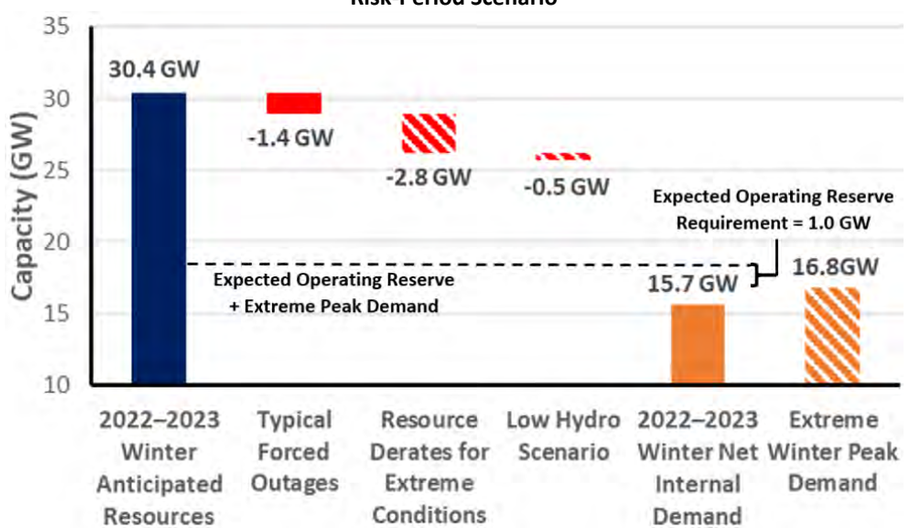
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Reserve Margins



Risk-Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro output due to drought conditions

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• The reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electricity system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electricity system to withstand sudden disturbances such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• *2022 Long-Term Reliability Assessment* data has been used for most of this 2022–2023 assessment period augmented by updated load and capacity data.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[16] or total internal demand for the summer and winter of each year.[17]
• Total internal demand projections are based on normal weather (50/50 distribution[18]) and are provided on a coincident[19] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

[16] *Glossary of Terms* used in NERC Reliability Standards

[17] The summer season represents June–September and the winter season represents December–February.

[18] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[19] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the winter season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

Prospective Resources: Includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources (from the resource adequacy data table), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand from the resource adequacy data table and the extreme winter peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced, not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Further, the effects from extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme winter peak demand.

Resource Adequacy

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[20] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. Other than in NPCC-Maritimes, all assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for the 2022–2023 winter as shown in **Figure 5**. The Canadian winter-peaking systems of NPCC-Maritimes and NPCC-Québec have reserve margins that are near Reference Margin Levels but are unlikely to experience high outage rates from their winterized generators. The potential limited availability of locally stored fuel supplies could result in additional generator outages due to depleted fuel inventories. Variable energy resources, such as wind and solar, often contribute significantly less of their installed capability at the period of peak demand in winter. Winter peaks in many areas occur in early morning hours or other times of darkness, resulting in little or no electrical resource output. Consequently the capacity contribution of variable energy resources to an area's anticipated resources may be a fraction of installed capability in winter.

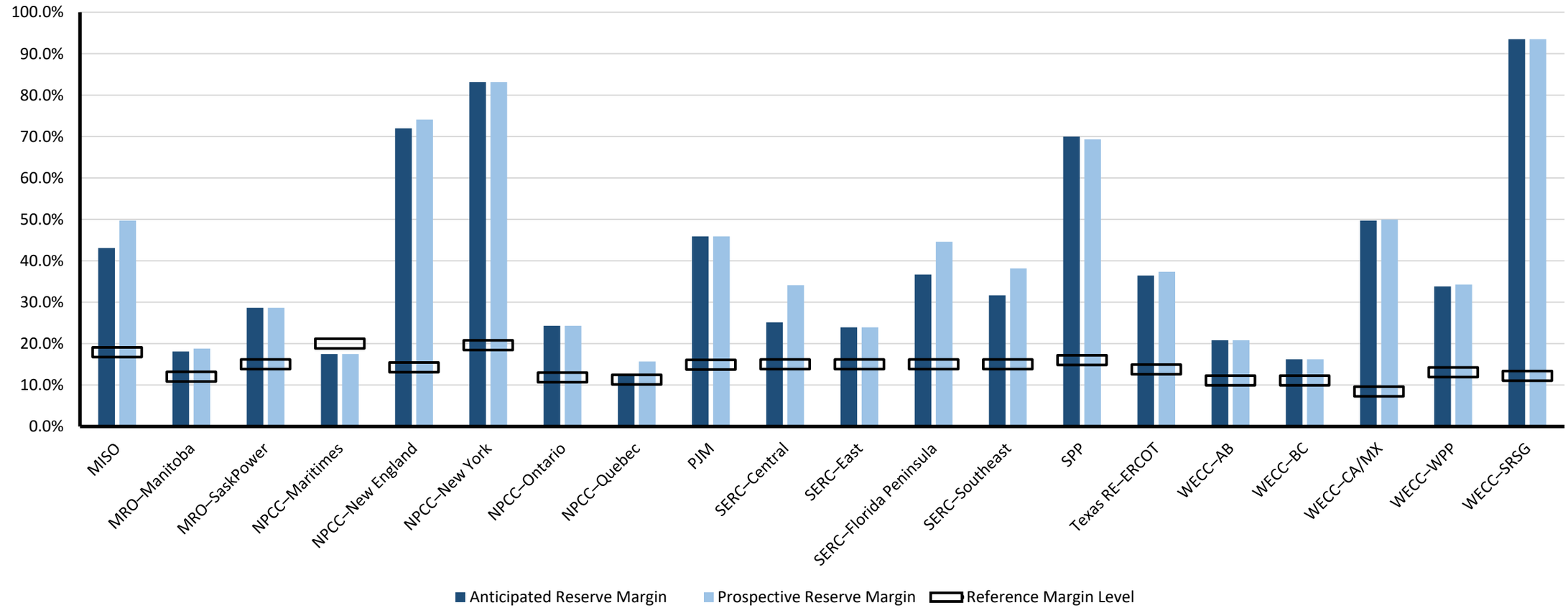


Figure 5: Winter 2022–2023 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[20] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and Reference Margin Levels.

Changes from Year-to-Year

Figure 6 provides the relative change in the forecast Anticipated Reserve Margins from the 2021–2022 winter to the 2022–2023 winter. Note that the Reference Margin Level is unchanged for areas that don't have a 2021–2022 Reference Margin Level shown. A significant decline can indicate potential operational issues that emerge between reporting years. MISO, NPCC-Maritimes, SERC-Central, SERC-Southeast, Texas RE-ERCOT, and WECC-AB have noticeable reductions in anticipated resources between the 2021–2022 winter and the 2022–2023 winter. All areas except NPCC-Maritimes remain above their Reference Margin Levels for 2022–2023 winter. The lower Anticipated Reserve Margins for MISO, SERC-Central, SERC-Southeast, Texas RE-ERCOT, and WECC-AB do not result in reliability concerns on peak for this upcoming winter. The Canadian winter peaking systems of NPCC-Maritimes and NPCC-Québec have reserve margins that are near Reference Margin Levels but are unlikely to experience high outage rates from their winterized generators. Additional details are provided in the **Data Concepts and Assumptions** section.

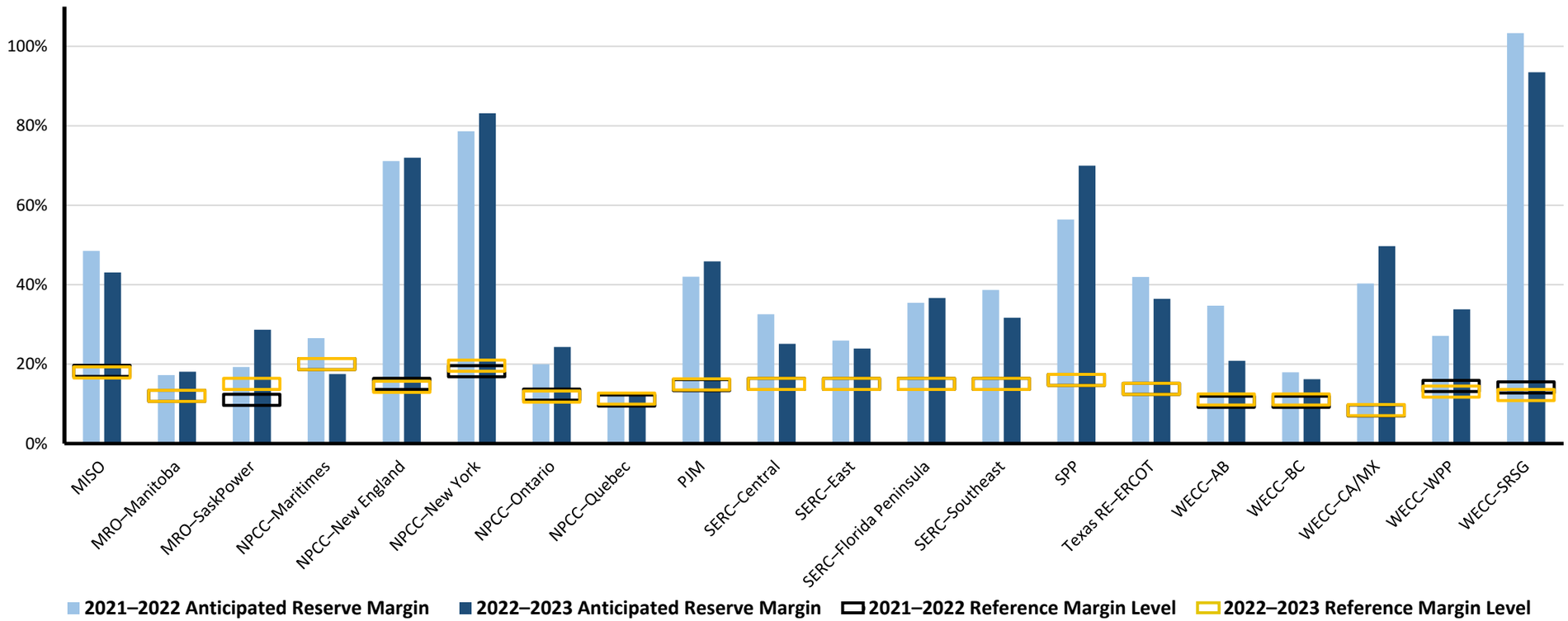


Figure 6: Winter 2021–2022 and Winter 2022–2023 Anticipated Reserve Margins Year-to-Year Change

Internal Demand

Winter peak demand forecasts in many assessment areas are increasing (see **Figure 7)**. The aggregate of winter peak demand forecasts for all areas in the North American BPS has increased by 4,381 MW (0.6%) since the 2021–2022 winter. Since the 2019–2020 winter projections (made prior to the COVID-19 pandemic), the aggregate of demand forecasts for all of North America has increased by 2,766 MW, a 0.4% increase.

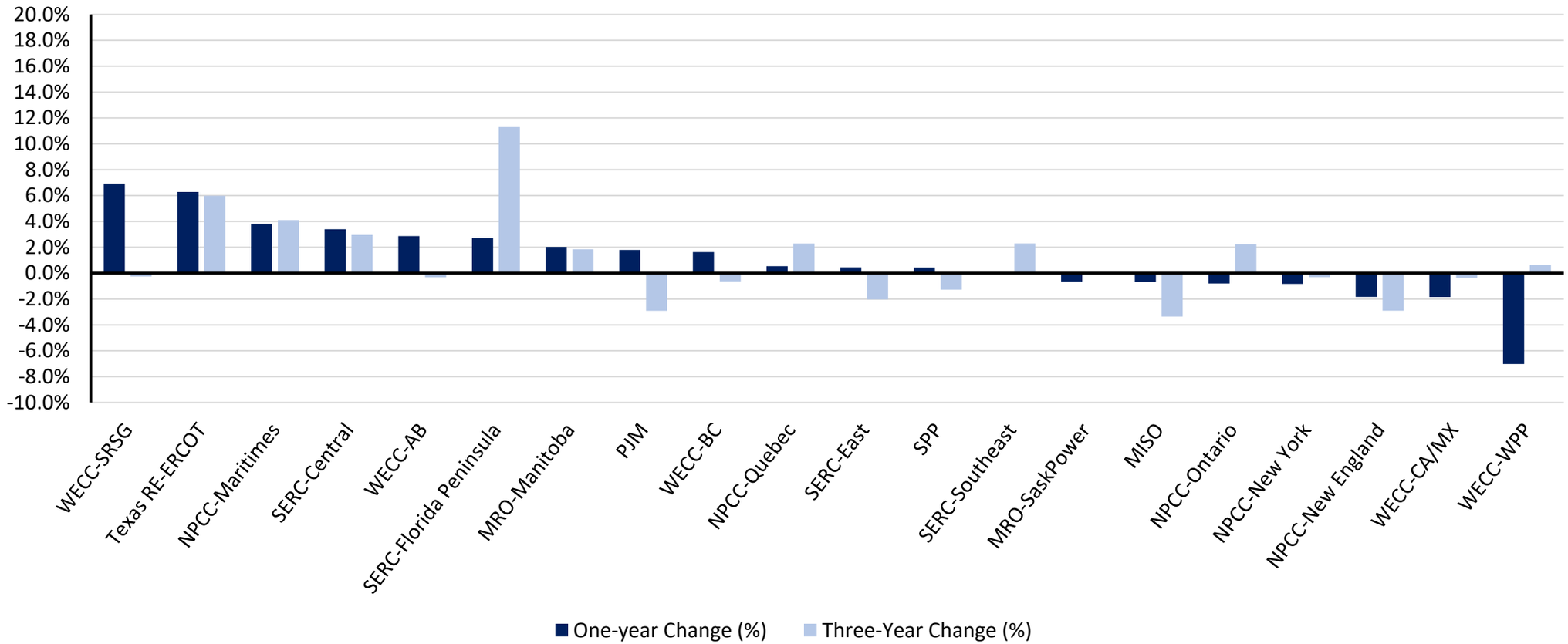


Figure 7: Change in Net Internal Demand: 2022–2023 Winter Forecast Compared To Prior Year Winter Forecasts

Demand and Resource Tables

Peak demand and supply capacity data for each assessment area are provided below (in alphabetical order).

MISO Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	100,812	102,611	1.8%
Demand Response: Available	3,480	3,672	5.5%
Net Internal Demand	97,332	98,939	1.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	138,535	137,926	-0.4%
Tier 1 Planned Capacity	3,738	0	-100.0%
Net Firm Capacity Transfers	2,283	1,352	-40.8%
Anticipated Resources	144,556	141,565	-2.1%
Existing-Other Capacity	0	669	-
Prospective Resources	147,182	148,125	0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	48.5%	43.1%	-5.4
Prospective Reserve Margin	51.2%	49.7%	-1.5
Reference Margin Level	18.3%	17.9%	-0.4

MRO-SaskPower Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,798	3,781	-0.4%
Demand Response: Available	60	67	11.7%
Net Internal Demand	3,738	3,714	-0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,321	4,488	3.9%
Tier 1 Planned Capacity	13	0	-100.0%
Net Firm Capacity Transfers	125	290	132.0%
Anticipated Resources	4,459	4,778	7.2%
Existing-Other Capacity	0	0	-
Prospective Resources	4,459	4,778	7.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.3%	28.7%	9.4
Prospective Reserve Margin	19.3%	28.7%	9.4
Reference Margin Level	11.0%	15.0%	4.0

MRO-Manitoba Hydro Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	4,497	4,588	2.0%
Demand Response: Available	0	0	-
Net Internal Demand	4,497	4,588	2.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,438	5,705	4.9%
Tier 1 Planned Capacity	279	279	0.1%
Net Firm Capacity Transfers	-446	-566	26.9%
Anticipated Resources	5,271	5,418	2.8%
Existing-Other Capacity	46	33	-29.4%
Prospective Resources	5,318	5,451	2.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	17.2%	18.1%	0.9
Prospective Reserve Margin	18.3%	18.8%	0.5
Reference Margin Level	12.0%	12.0%	0.0

NPCC-Maritimes Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	5,616	5,784	3.0%
Demand Response: Available	317	282	-11.0%
Net Internal Demand	5,299	5,502	3.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	6,584	6,461	-1.9%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	121	4	-96.7%
Anticipated Resources	6,705	6,465	-3.6%
Existing-Other Capacity	0	0	-
Prospective Resources	6,705	6,465	-3.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.5%	17.5%	-9.0
Prospective Reserve Margin	26.5%	17.5%	-9.0
Reference Margin Level	20.0%	20.0%	0.0%

NPCC-New England Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,349	20,009	-1.7%
Demand Response: Available	587	610	4.0%
Net Internal Demand	19,762	19,399	-1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	32,668	32,129	-1.6%
Tier 1 Planned Capacity	14	162	1057.0%
Net Firm Capacity Transfers	1,134	1,070	-5.6%
Anticipated Resources	33,816	33,361	-1.3%
Existing-Other Capacity	184	142	-23.0%
Prospective Resources	34,000	33,769	-0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	71.1%	72.0%	0.9
Prospective Reserve Margin	72.0%	74.1%	2.1
Reference Margin Level	15.0%	14.3%	-0.7

NPCC-Ontario Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,940	21,255	1.5%
Demand Response: Available	132	614	364.1%
Net Internal Demand	20,808	20,641	-0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	25,403	26,051	2.6%
Tier 1 Planned Capacity	63	112	77.0%
Net Firm Capacity Transfers	-500	-500	0.0%
Anticipated Resources	24,966	25,662	2.8%
Existing-Other Capacity	0	0	-
Prospective Resources	24,966	25,662	2.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.0%	24.3%	4.3
Prospective Reserve Margin	20.0%	24.3%	4.3
Reference Margin Level	12.3%	11.8%	-0.5

NPCC-New York Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	24,025	23,893	-0.5%
Demand Response: Available	631	695	10.1%
Net Internal Demand	23,394	23,198	-0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,239	40,393	0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,547	2,097	35.6%
Anticipated Resources	41,786	42,490	1.7%
Existing-Other Capacity	0	0	-
Prospective Resources	41,786	42,490	1.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	78.6%	83.2%	4.6
Prospective Reserve Margin	78.6%	83.2%	4.6
Reference Margin Level	18.2%	19.6%	1.4

NPCC-Québec Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	39,386	39,699	0.8%
Demand Response: Available	2,368	2,759	16.5%
Net Internal Demand	37,017	37,217	0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	42,072	42,113	0.1%
Tier 1 Planned Capacity	27	255	838.2%
Net Firm Capacity Transfers	-499	-417	-16.4%
Anticipated Resources	41,600	41,951	0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	42,700	43,051	0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.4%	12.7%	0.3%
Prospective Reserve Margin	15.4%	15.7%	0.3%
Reference Margin Level	10.8%	11.3%	0.5%

PJM Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	132,632	132,980	0.3%
Demand Response: Available	8,466	6,583	-22.2%
Net Internal Demand	124,166	126,397	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	179,247	185,102	3.3%
Tier 1 Planned Capacity	19	0	-100.0%
Net Firm Capacity Transfers	-2,937	-726	-75.3%
Anticipated Resources	176,329	184,376	4.6%
Existing-Other Capacity	0	0	-
Prospective Resources	176,329	184,376	4.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.0%	45.9%	-3.9
Prospective Reserve Margin	42.0%	45.9%	-3.9
Reference Margin Level	14.7%	14.9%	-0.2

SERC-East Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	44,175	44,648	1.1%
Demand Response: Available	903	1,180	30.7%
Net Internal Demand	43,272	43,468	0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	53,933	53,287	-1.2%
Tier 1 Planned Capacity	0	75	-
Net Firm Capacity Transfers	562	513	-8.7%
Anticipated Resources	54,495	53,875	-1.1%
Existing-Other Capacity	0	3	-
Prospective Resources	54,495	53,877	-1.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.9%	23.9%	-2.0
Prospective Reserve Margin	25.9%	23.9%	-2.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Central Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	40,320	41,745	3.5%
Demand Response: Available	1,564	1,671	6.8%
Net Internal Demand	38,756	40,074	3.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,271	51,008	-0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	99	-868	-
Anticipated Resources	51,370	50,140	-2.4%
Existing-Other Capacity	3,135	3,601	14.9%
Prospective Resources	54,505	53,741	-1.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	32.5%	25.1%	-7.4
Prospective Reserve Margin	40.6%	34.1%	-6.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,074	48,582	5.4%
Demand Response: Available	1,571	2,870	82.7%
Net Internal Demand	44,503	45,712	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	57,694	61,987	7.4%
Tier 1 Planned Capacity	1,169	237	-79.7%
Net Firm Capacity Transfers	1,414	250	-82.3%
Anticipated Resources	60,277	62,474	3.6%
Existing-Other Capacity	1,147	3,618	215.5%
Prospective Resources	61,424	66,092	7.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	35.4%	36.7%	1.3
Prospective Reserve Margin	38.0%	44.6%	6.6
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,232	46,513	0.6%
Demand Response: Available	1,682	1,954	16.2%
Net Internal Demand	44,550	44,559	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	61,899	60,097	-2.9%
Tier 1 Planned Capacity	1,102	1,102	0.0%
Net Firm Capacity Transfers	-1,218	-2,524	107.2%
Anticipated Resources	61,782	58,674	-5.0%
Existing-Other Capacity	2,516	2,895	15.1%
Prospective Resources	64,298	61,569	-4.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	38.7%	31.7%	-7.0
Prospective Reserve Margin	44.3%	38.2%	-6.1
Reference Margin Level	15.0%	15.0%	0.0

SPP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	41,669	41,650	0.0%
Demand Response: Available	211	13	-93.7%
Net Internal Demand	41,458	41,637	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	65,197	71,131	9.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-348	-359	3.3%
Anticipated Resources	64,850	70,772	9.1%
Existing-Other Capacity	0	0	-
Prospective Resources	64,820	70,496	8.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	56.4%	70.0%	13.6%
Prospective Reserve Margin	56.4%	69.3%	13.0%
Reference Margin Level	16.0%	16.0%	0.0

Texas RE-ERCOT Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	62,001	66,436	7.2%
Demand Response: Available	2,598	3,302	27.1%
Net Internal Demand	59,403	63,134	6.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	81,443	85,478	5.0%
Tier 1 Planned Capacity	2,665	644	-75.8%
Net Firm Capacity Transfers	210	20	-90.5%
Anticipated Resources	84,318	86,142	2.2%
Existing-Other Capacity	0	0	-
Prospective Resources	84,382	86,710	2.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	41.9%	36.4%	-5.5
Prospective Reserve Margin	42.1%	37.3%	-4.8
Reference Margin Level	13.75%	13.75%	0.0

WECC-AB Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,569	11,901	2.9%
Demand Response: Available	0	0	-
Net Internal Demand	11,569	11,901	2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	12,842	13,144	2.3%
Tier 1 Planned Capacity	2,743	1,234	-55.0%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	15,585	14,378	-7.7%
Existing-Other Capacity	0	0	-
Prospective Resources	15,585	14,378	-7.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	34.7%	20.8%	-13.9
Prospective Reserve Margin	34.7%	20.8%	-13.9
Reference Margin Level	10.5%	11.1%	0.6

WECC-BC Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,213	11,395	1.6%
Demand Response: Available	0	0	-
Net Internal Demand	11,213	11,395	1.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,077	13,223	1.1%
Tier 1 Planned Capacity	146	20	-86.4%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	13,223	13,243	0.1%
Existing-Other Capacity	0	0	-
Prospective Resources	13,223	13,243	0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	17.9%	16.2%	-1.7
Prospective Reserve Margin	17.9%	16.2%	-1.7
Reference Margin Level	10.5%	11.1%	0.6

WECC-CA/MX Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	39,779	38,978	-2.0%
Demand Response: Available	829	749	-9.7%
Net Internal Demand	38,950	38,230	-1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,996	55,287	6.3%
Tier 1 Planned Capacity	2,205	1,943	-11.9%
Net Firm Capacity Transfers	449	0	-100.0%
Anticipated Resources	54,650	57,231	4.7%
Existing-Other Capacity	0	0	-
Prospective Resources	55,312	57,326	3.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	40.3%	49.7%	9.4
Prospective Reserve Margin	42.0%	50.0%	8.0
Reference Margin Level	8.3%	8.4%	0.1

WECC-SRSG Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	14,910	16,004	7.3%
Demand Response: Available	241	318	32.3%
Net Internal Demand	14,669	15,686	6.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	29,446	29,799	1.2%
Tier 1 Planned Capacity	381	553	45.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	29,827	30,352	1.8%
Existing-Other Capacity	0	0	-
Prospective Resources	29,836	30,352	1.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	103.3%	93.5%	-9.8
Prospective Reserve Margin	103.4%	93.5%	-9.9
Reference Margin Level	14.1%	12.2%	-1.9

WECC-WPP Resource Adequacy Data			
Demand, Resource, and Reserve Margins	**2021–2022 WRA**	**2022–2023 WRA**	**2021–2022 vs. 2022–2023 WRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	62,822	58,605	-6.7%
Demand Response: Available	551	707	28.4%
Net Internal Demand	62,271	57,898	-7.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	74,865	76,477	2.2%
Tier 1 Planned Capacity	424	988	133.1%
Net Firm Capacity Transfers	3,877	0	-100.0%
Anticipated Resources	79,166	77,465	-2.1%
Existing-Other Capacity	0	0	-
Prospective Resources	79,205	77,730	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.1%	33.8%	6.7
Prospective Reserve Margin	27.2%	34.3%	7.1
Reference Margin Level	14.5%	13.1%	-1.4

Errata

November 2022

- The Extreme Conditions reserve margin for SERC-FP in Table 1 was corrected (page 8)
- The Scenario Description language in Texas RE-ERCOT's dashboard was corrected (page 26)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2023–2024 Winter Reliability Assessment

November 2023



WRA Infographic | WRA Video

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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entity as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC's *2023–2024 Winter Reliability Assessment (WRA)* identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the *WRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS.

This reliability assessment process is a coordinated evaluation between the Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas.

This report reflects an independent assessment by the ERO Enterprise (i.e., NERC and the six Regional Entities) and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming winter period.

Key Findings

This *WRA* covers the upcoming three-month (December–February) winter period. This assessment provides an evaluation of the generation resource and transmission system adequacy necessary to meet projected winter peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional risks. The following findings are the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as the potential operational concerns that may need to be addressed for the upcoming winter:

1. **A large portion of the North American BPS is at risk of insufficient electricity supplies during peak winter conditions** (Figure 1). Prolonged, wide-area cold snaps threaten the reliable performance of BPS generation and the availability of fuel supplies for natural-gas-fired generation. As observed in recent winter reliability events, over 20% of generating capacity has been forced off-line when freezing temperatures extend over parts of North America that are not typically exposed to such conditions. When electricity supplies become constrained, BPS system operators can face a simultaneous sharp increase in demand as electric heating systems consume more power in cold temperatures. These areas (see **Figure 1)** are at greatest risk for electricity supply shortfalls this winter:

   - **Midcontinent ISO (MISO):** New wind and natural-gas-fired generation and the extension of some older fossil-fired plants have increased available resources this winter by over 9 GW from 2022. Recently, MISO implemented a seasonal resource adequacy construct that more effectively values risks and resource contributions that vary by time of year. Like prior years, an extreme cold-weather event that extends into MISO's southern areas can cause high generator outages from inadequate weatherization or insufficient natural gas fuel supplies.

   - **MRO-SaskPower:** Reserve margins have fallen this winter by eight percentage points when compared to the previous winter due to increased peak demand projections, the retirement of a natural-gas-fired unit (95 MW), and planned generator maintenance. High numbers of forced generator outages or wind turbine cold temperature cutouts can lead to operating reserves shortfalls at peak winter demand levels.

   - **NPCC-Maritimes:** Peak demand growth has been offset by additional resource capacity and import agreements for the upcoming winter, causing reserve margins to rise by over two percentage points compared to 2022. Demand levels at the forecasted peak can still strain the area's firm supplies and lead to operating mitigations or energy emergencies.

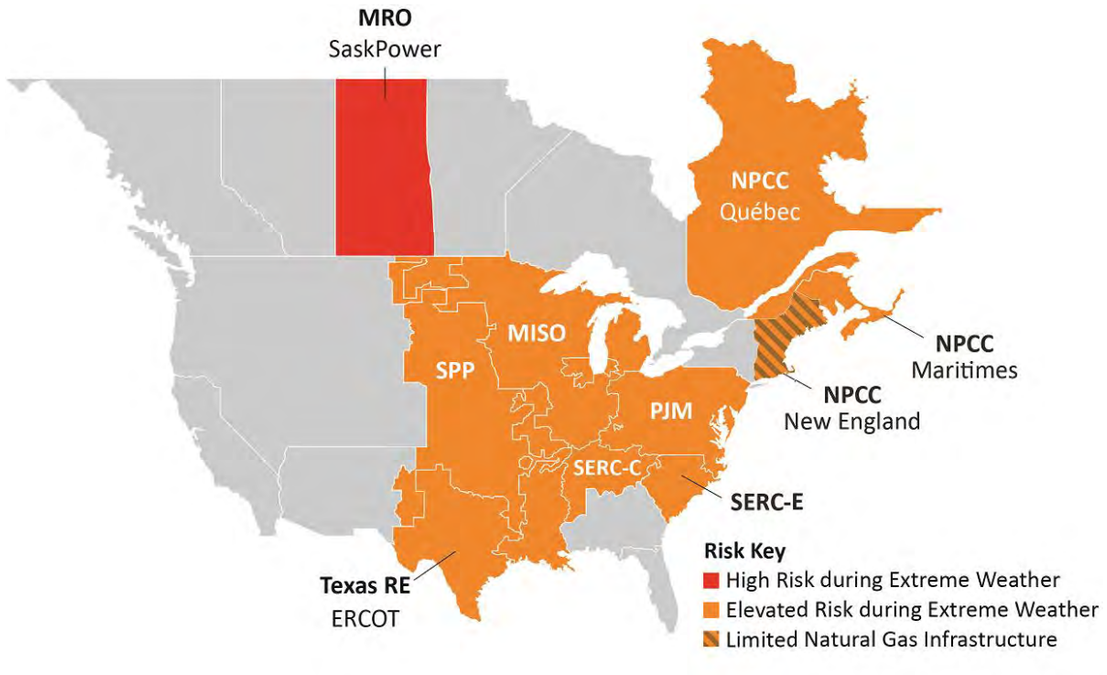


Figure 1: Winter Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

- **NPCC-New England:** The capacity of natural gas transportation infrastructure could be constrained when cold temperatures cause peak demand for both electricity generation and consumer space-heating needs. Potential constraints on the fuel delivery systems and the limited inventory of liquid fuels may exacerbate the risks for fuel-based generator outages and output reductions that result in energy emergencies during extreme weather. ISO-New England (ISO-NE) introduced the Inventoried Energy Program this year as an interim measure to address energy security concerns. The program provides compensation for generators that maintain inventoried energy for their assets during extreme cold periods. The program is also planned for 2024–2025 winter while ISO-NE develops more comprehensive energy security measures for regulatory approval.

- **NPCC-Québec:** An increase in forecasted peak demand and additional firm export commitments have resulted in lower reserve margins for the upcoming winter. Despite having reliable performance from hydroelectric generation in winter, non-firm imports may be needed to meet operating reserve requirements if demand levels exceed the forecasted peak.
- **PJM, SERC-East, and SERC-Central:** A severe cold weather event that extends to the Southern United States can lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Forecasted peak demand has risen while resources have changed little in these areas since Winter Storm Elliot caused energy emergencies across the area in 2022. PJM and SERC have adequate resources for normal winter conditions; however, their generators are vulnerable to derates and outages in extreme conditions.
- **Southwest Power Pool (SPP):** The Anticipated Reserve Margin (ARM) of 38.8% is over 30 percentage points lower than last winter; this is driven by higher forecasted peak demand and less resource capacity. While the reserve margin is adequate for normal forecasted peak demand and expected generator outages, higher demand levels and outages that have occurred during extreme cold weather result in shortfalls that can trigger energy emergencies. The vast wind resources in the area can alleviate firm capacity shortages under the right conditions; however, energy risks emerge during periods of low wind or forecast uncertainty and high electricity demand.
- **Texas RE-ERCOT:** Like other assessment areas in the Southern United States, the risk of a significant number of generator forced outages in extreme and prolonged cold temperatures continues to threaten reliability where generators and fuel supply infrastructure are not designed or retrofitted for such conditions. The risk of reserve shortage is greater than last winter due primarily to robust load growth that is not being met by corresponding growth in dispatchable resources. ERCOT is taking steps to procure additional capacity ahead of winter that can reduce the likelihood of energy emergencies. Additionally, ERCOT implemented a new firm fuel supply service in its market that is expected to partially offset the lost generation capacity that can occur when natural gas supplies are limited. Electricity demand in Texas rises sharply as extreme cold temperatures add to winter operating challenges and energy shortfall risks.

2. **Generator fuel supplies remain at risk during extreme, long-duration cold weather events.** Fuel assurance is vitally important to meeting winter electricity demand across North America. Natural-gas-fired generator availability and output can be threatened when natural gas supplies are insufficient or when the flow of fuel cannot be maintained. During Winter Storm Elliott, natural gas production rapidly declined with the onset of extreme cold temperatures, contributing to wide-area electricity and natural gas shortages.

   Currently, natural gas production, transportation, storage, and a significant portion of the BPS link together to form a single interconnected energy delivery system that extends from the natural gas wellhead to end-use electricity and natural gas customers. The operation of this interconnected energy system can be disrupted when natural gas fuel supplies are not available for electricity generation as well as when electricity is not available to operate electricity-driven compressors and other critical infrastructure components in the natural gas supply chain. Recent extreme cold weather events have shown that energy delivery disruptions can have devasting consequences for electric and natural gas consumers in impacted areas.

   Winter Storm Elliott demonstrated the wide-area consequences for BPS reliability that can result from reduced natural gas production during periods of extreme cold weather. In addition to wellhead impacts on production, natural-gas-fired generating units that lacked firm supply or transportation contracts to meet their winter peak electrical output faced challenging and often insurmountable fuel procurement issues when natural gas supply and available pipeline capacity became scarce. During Winter Storm Elliott, natural-gas-related fuel outages occurred alongside generator outages, derates, and failures to start that resulted from freezing issues and mechanical/electrical issues that are closely correlated with falling temperatures.

   The joint *FERC-NERC-Regional* Entity *Joint Inquiry into Winter Storm Elliott* made the following recommendations related to adequate fuel supply assurance and other matters:[1]

   - Establishing reliability rules for natural gas infrastructure
   - Improving communication and business practices between industries
   - Assessing Balancing Authority (BA) reliability commitment processes for addressing potential capacity shortages during forecasted cold weather events

   To enhance situational awareness across impacted interconnected energy delivery systems, the FERC-NERC report also included a more immediate recommendation that BPS operators and natural gas industry controllers convene to establish control room to control room operational communications protocols that can be invoked when extreme cold weather approaches and that these protocols remain in place over the duration of the event.

[1] FERC Winter Storm Elliott Report

Coal is also an important fuel for electricity generation in winter. Generator owners report fewer coal supply issues compared to last winter. Normal rail transportation services are available and coal stocks are at a high level compared to historical averages. Some coal fired generation that relies on barge shipments in inland waterways could be impacted by drought restrictions that limit barge loading.

3. **Load forecasting in winter is growing in complexity. Underestimating demand is a risk to reliability in extreme cold temperatures.** Extreme cold temperatures and irregular weather patterns characterized by strong cold fronts, wind, and precipitation can cause demand for electricity to deviate significantly from historical forecasts. Electrification of the heating sector is increasing temperature-sensitive load components while increasing levels of variable-output solar photovoltaic (PV) distributed energy resources (DER) add to the load forecast uncertainty. Underestimating electricity demand prior to the arrival of cold temperatures can lead to ineffective operations planning and insufficient resources being scheduled. Generator performance and fuel issues are more likely to occur when generators are called upon with short notice; this can expose BAs to potential resource shortfalls. Load serving entities and BAs should apply lessons from prior winter operating experience to operational load forecasts and pay particular attention to the risk of demand underestimation ahead of extreme winter conditions.

4. **Curtailment of electricity transfers to areas in need during periods of high regional demand is a growing reliability concern.** During energy emergencies and periods of transmission system congestion, Reliability Coordinators (RC) and BAs may curtail transfers for various reasons with established procedures and protocols. While the curtailments alleviate an issue in one part of the system, curtailments can contribute to supply shortages or affect local transmission system operations in another area. During Winter Storm Elliott, firm exports were curtailed from PJM during a period of widespread energy emergencies in the U.S. Eastern Interconnection. For winter 2023–2024, several areas identified as having capacity or energy risks are relying on imports of electricity supplies. These areas include MRO-SaskPower, NPCC-Maritimes, NPCC-New England, SERC-Central, and SERC-East. A wide-area cold snap that severely affects regional demand or generator availability presents an added concern in areas that are dependent on imports for managing high electricity demand.

5. **New cold weather Reliability Standards in place at the start of the 2023–2024 winter are aimed at improving coordination between Generator Owners/Operators and BPS Operators.** New cold weather Reliability Standards adopted by the NERC Board of Trustees (Board) in June 2021 went into effect in the United States earlier this year. Generator Owners (GO) and Generator Operators (GOP) are required to implement plans for cold weather preparedness and provide cold weather operating parameters to their RCs, Transmission Operators (TOP), and BAs for use in operating plans. Additional Reliability Standard requirements have been developed by NERC and industry to address further recommendations of the *FERC-NERC-Regional Entity staff report—The February 2021 Cold Weather Outages in Texas and Southcentral United States.* The NERC Board adopted these requirements in October 2023 and directed NERC to file them with regulatory authorities for approval and industry implementation.

6. **Industry responses to NERC's Level 3 Alert - Cold Weather Preparations for Extreme Weather Events–III indicate that generator winter preparations are on a positive trend, but freezing temperatures remain a concern for some generators.** In May, NERC issued a Level 3 essential actions alert to BAs, TOPs, and GOs. The alert highlighted actions to increase readiness and enhance plans to reduce risk for the upcoming winter and beyond. Additionally, recipients of the alert were required to respond to questions that support NERC's review of progress toward mitigating winter reliability risks. The responses indicate GOs have determined cold weather temperature limits for their generators and taken steps to assess and prepare critical components to operate at these temperatures. Many GOs, however, noted that generator unit and auxiliary component mechanical failures from past cold weather events remain a concern for the upcoming winter. Problem areas include improper heat tracing, frozen instrumentation and control equipment, generator circuit breaker tripping in low temperatures or low air pressures, and wind turbine blade icing.

Recommendations

To reduce the risks of energy shortfalls on the BPS this winter, NERC recommends the following:

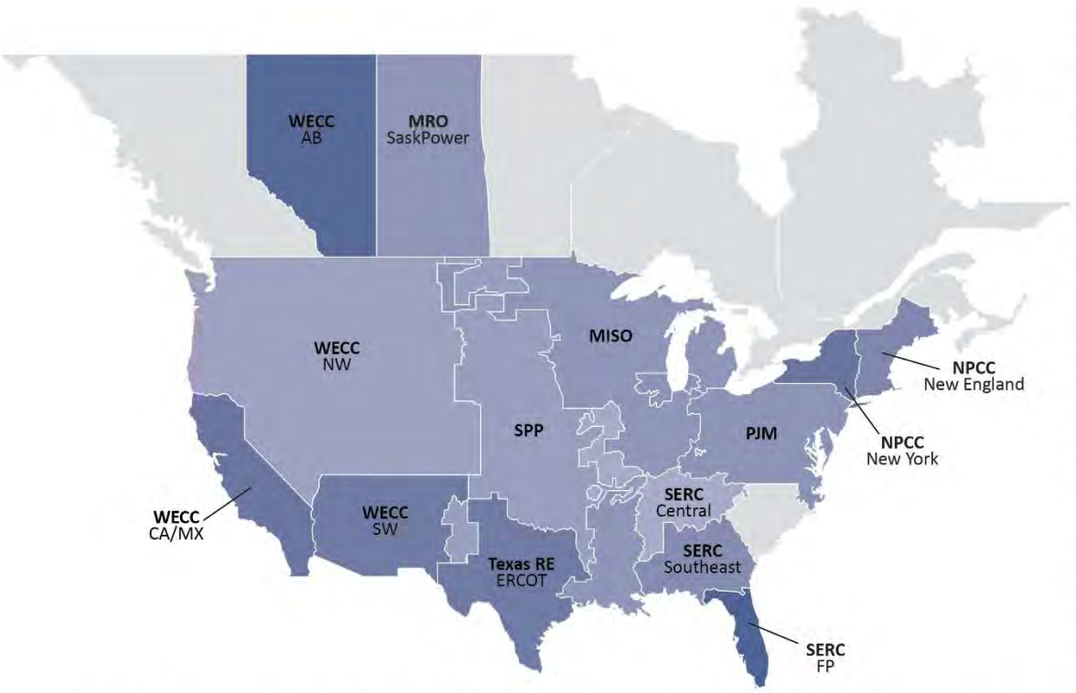
- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially high generator outages and extreme demand levels. Operators should be trained and familiar with manual load shedding plans prior to winter and review procedures in advance of severe winter weather.
- TOPs, BAs, and GOs should implement the essential actions identified in the NERC Level 3 alert, Cold Weather Preparations for Extreme Weather Events–III, and should take recommended weatherization steps prior to winter.
- BAs should be cognizant of the potential for short-term load forecasts to underestimate load in extreme cold weather events and be prepared to take early action to implement protocols and procedures for managing potential reserve deficiencies.
- RCs and BAs should implement generator fuel surveys to monitor the adequacy of fuel supplies. They should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions.
- State and provincial regulators can assist grid owners and operators in advance of and during extreme cold weather by supporting requested environmental and transportation waivers as well as public appeals for electricity and natural gas conservation.

Risk Highlights

Over the past 11 years, five cold weather events have jeopardized Bulk Electric System (BES) reliability by triggering unplanned cold weather-related generation outages. To maintain BES reliability during Winter Storm Uri in February 2021 and Winter Storm Elliott in December 2022, BES operators were required to shed firm load. During both winter storms, numerous electrical and mechanical issues rendered significant portions of the impacted areas' thermal generation fleet unavailable while natural gas supply and transportation issues prevented numerous otherwise available natural-gas-fired generators from supplying much needed electrical energy. Moreover, a significant portion of generating units failed to perform at temperatures above their own documented minimum operating temperatures.

Generator Fuel Supply Risk

As noted in past winter reliability assessments, the performance of the thermal generating fleet is critical to winter operations. The electric and natural gas industries continue to work through the recommendations contained in the *FERC-NERC-Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South-Central United States.*[2] The final report on Winter Storm Elliott—the 2022 storm that contributed to power outages for millions of electricity customers in the Eastern half of the United States—recommends completion of cold weather reliability standard revisions stemming from 2021's Winter Storm Uri and improvements to reliability for the U.S. natural gas infrastructure.[3] What has become clear is that the natural-gas-electric system has now become fully interconnected, each requiring the other to remain reliable (i.e., impacts on one system can impact the other). These considerations should drive higher levels of coordination to ensure sustained reliable operation of this interconnected system.



All other assessment areas have less than 35% natural gas fired generation contribution to winter resource mix.

	Natural-Gas-Fired Generation	
	Peak Winter Capacity	Contribution to Total Winter Resource Mix
MISO	67.5 GW	46%
MRO-SaskPower	2.1 GW	46%
NPCC-New England	17.3 GW	54%
NPCC-New York	24.5 GW	66%
PJM	84.9 GW	47%
SERC-Central	22.7 GW	44%
SERC-Florida Peninsula	50.6 GW	79%
SERC-Southeast	31.5 GW	51%
SPP	27.4 GW	41%
Texas RE-ERCOT	54.2 GW	62%
WECC-AB	11.4 GW	75%
WECC-CA/MX	39.9 GW	65%
WECC-NW	31.0 GW	39%
WECC-SW	18.2 GW	62%

Figure 2: Natural-Gas-Fired Generation Capacity Contributions to 2023–2024 Winter Generation Mix

Natural Gas Supply to Generators

Natural-gas-fired generation is vitally important to meeting winter electricity demand across much of North America (**Figure 2**). Furthermore, the natural gas industry relies on electricity to power some of its critical components. For instance, some compressors run on electricity while others are fueled by natural gas. This means that the natural gas industry depends on the delivery of electricity to run as intended, and as stated in many other places, the electric industry depends on the delivery of natural gas. This can exacerbate the scale of impacts when either industry is threatened.

[2] The February 2021 Cold Weather Outages in Texas and the South-Central United States | FERC, NERC and Regional Entity Staff Report | Federal Energy Regulatory Commission

[3] FERC Winter Storm Elliott Report

Generator availability and output can be threatened when natural gas supplies are insufficient or when natural gas infrastructure is unable to maintain the flow of fuel. The BES's ability to deliver electricity was put at risk by past natural gas production declines during periods of extreme cold weather. As Winter Storm Elliott demonstrated, this is the case even in areas of North America where cold weather is common. Wide-area extreme cold events increase the likelihood of natural gas production declines and result in increased demand for natural gas by local distribution company (LDC) customers and natural-gas-fired electric generators. Wide-area events can also concurrently render multiple grid BA areas energy deficient and thus preclude an impacted BA from importing the electricity it requires to meet BA load even when transmission to support such transfers is available. Longer duration events increase the risk that the imbalances resulting from declining natural gas production and increased natural gas demand approach unsustainable levels. For areas that are pipeline constrained, high natural gas demand during extreme cold weather presents risks for generators that lack firm natural gas transportation arrangements.

Coal Transportation

While many factors that contributed to uncertain rail shipment of coal to electric generators prior to the 2022–2023 winter assessment have subsided, other transport issues could emerge for this winter. Drought conditions that impact the Missouri River and other major navigable waterways could restrict coal availability and cause units to run at a derated level to conserve coal inventory. Low water levels can also affect generators that rely on once-through cooling processes and limit the generator's capacity output.

Extreme Cold Temperatures and Demand Forecasting

Accurate load forecasting is essential for reliable operations. BAs and load-serving entities frequently update the load forecasts that serve as key inputs for long-range resource planning, seasonal outage coordination, and operational plans from day-ahead to real-time. Cold weather patterns and the temperature-correlated behavior of some end-use loads present some of the most challenging issues and complex load forecasting, adding to winter reliability risk.

Most assessment areas can experience a wide range of winter peak demand from one year to the next, largely depending upon the severity of winter conditions. Load forecasts for normal winter peak (referred to as 50/50 peak demand or net internal demand elsewhere in this report) reflect the highest expected system load for an average winter. A higher level of demand used throughout this report is the load forecast for extreme 90/10 peak demand, which generally represents the highest 10% of the winter peak demand forecast distribution.[4] Actual winter peak demand in each area is expected to be below this level most (but not all) years. **Figure 3** shows these two demand levels for assessment areas where the extreme peak demand forecast is 9% or greater than the normal peak demand forecast. Year-to-year differences in winter weather conditions are key drivers of the large variation in normal and extreme demand forecasts, but changing load characteristics also contribute in many areas. ARMs, which measure resource levels above the normal 50/50 peak demand, have limited ability to identify resource adequacy risk when peak demand is highly variable from year to year.

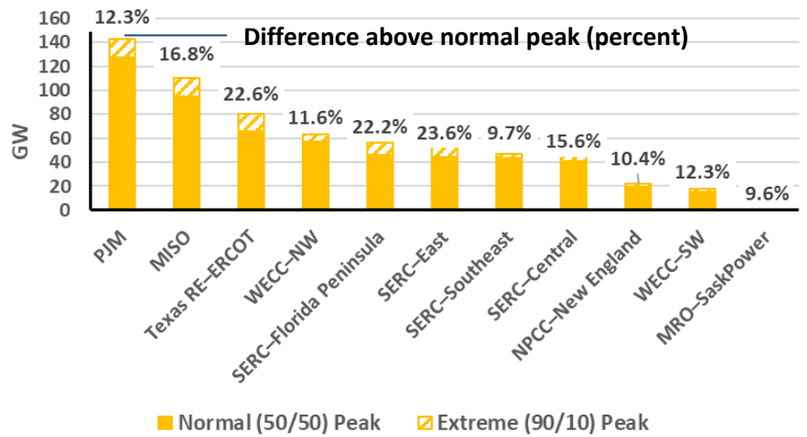


Figure 3: Normal and Extreme Peak Demand Forecasts for 2023–2024 Winter

The growing complexity in load forecasting and increasing load forecast uncertainty adds to winter reliability risks. Extreme cold temperatures and unfamiliar weather patterns characterized by strong cold fronts, wind, and precipitation can cause demand for electricity to deviate significantly from historical forecasts. Electrification of the heating sector is increasing temperature-sensitive load components while increasing levels of variable-output solar PV DERs add to load forecast uncertainty. Underestimating electricity demand prior to the arrival of cold temperatures can lead to ineffective operations planning and insufficient resources being scheduled. Generator performance and fuel issues are more likely to occur when generators are called upon with short notice, exposing BAs to potential resource shortfalls. Load serving entities and BAs should apply lessons from prior winter operating experience to operational load forecasts and pay particular attention to the risk of demand underestimation ahead of extreme cold temperatures.

[4] Anticipated Reserve Margins (ARM) are calculated from this demand level. NERC assesses winter reliability risk using this extreme 90/10 peak demand level (see the risk scenario summary for each assessment area in the **Regional Assessments Dashboards** section).

Seasonal Risk Scenario Margins

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margins and seasonal risk scenario chart in each dashboard provide potential winter peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized below the seasonal risk scenario charts; see the **Data Concepts and Assumptions** section for more information about these charts.

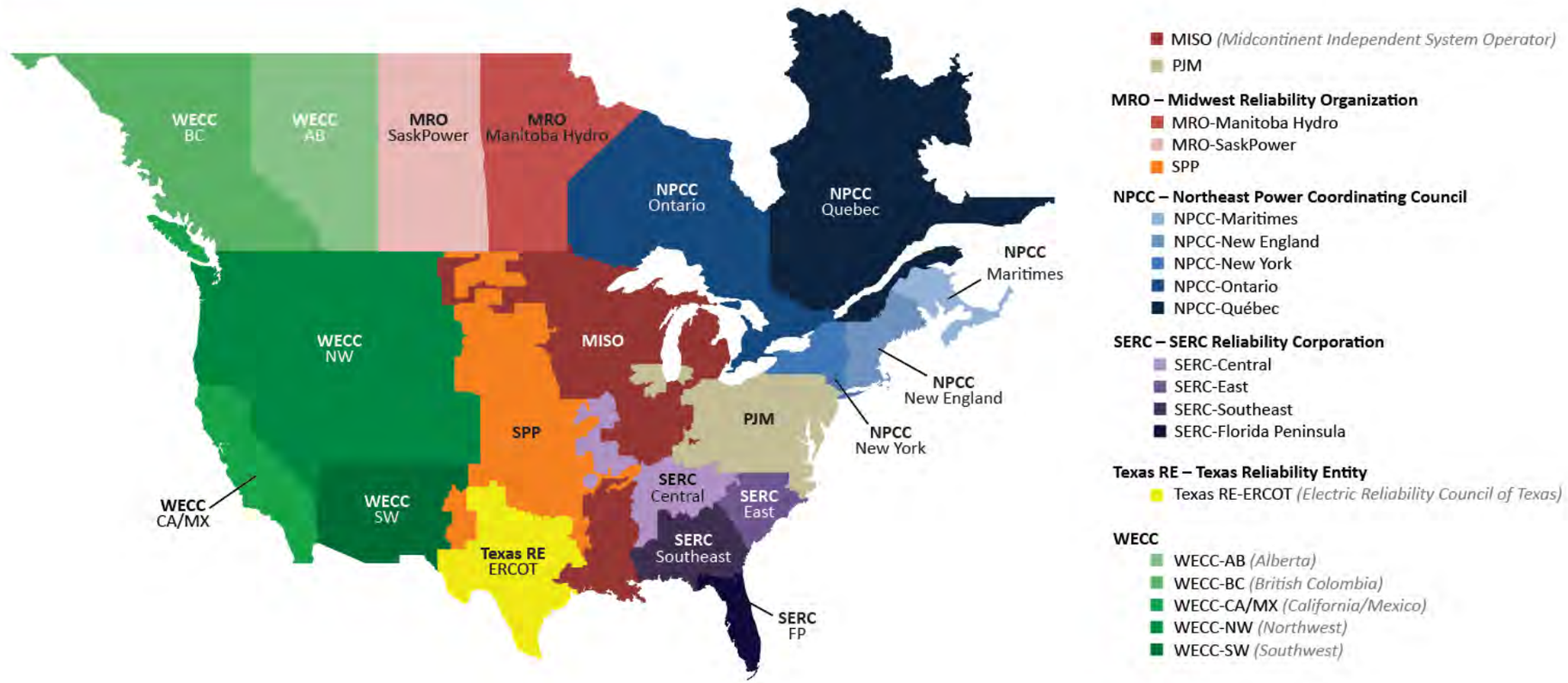
The seasonal risk scenario charts can be expressed in terms of reserve margins. In **Table 1**, each assessment area's ARM is shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario. The typical outages reserve margin is comprised of anticipated resources less the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the ARM, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

Table 1: Seasonal Risk Scenario Margins

Assessment Area	Anticipated Reserve Margin	Typical Outages	Extreme Conditions
MISO	55.8%	26.5%	-5.9%
MRO-Manitoba	15.3%	13.2%	6.6%
MRO-SaskPower	20.6%	6.9%	7.7%
NPCC-Maritimes	19.7%	13.5%	-0.5%
NPCC-New England	67.2%	47.3%	6.3%
NPCC-New York	76.3%	49.9%	12.4%
NPCC-Ontario	28.2%	28.2%	20.3%
NPCC-Quebec	10.5%	6.5%	-2.2%
PJM	39.8%	26.4%	4.2%
SERC-C	30.1%	22.6%	5.2%
SERC-E	24.4%	19.6%	9.3%
SERC-FP	41.0%	37.8%	12.7%
SERC-SE	41.6%	35.7%	13.7%
SPP	38.8%	14.5%	-14.1%
TRE-ERCOT	41.2%	27.3%	-6.6%
WECC-AB	27.1%	24.3%	5.5%
WECC-BC	15.1%	15.0%	-8.6%
WECC-CA/MX	65.3%	57.4%	32.2%
WECC-NW	43.5%	37.5%	-4.1%
WECC-SW	90.4%	85.1%	43.4%

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-Peak Reserve Margin bar charts show the ARM compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the **Demand and Resource Tables**), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme winter peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the WRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods vary by assessment area and provide further insights into the risk conditions forecasted for this upcoming winter period.





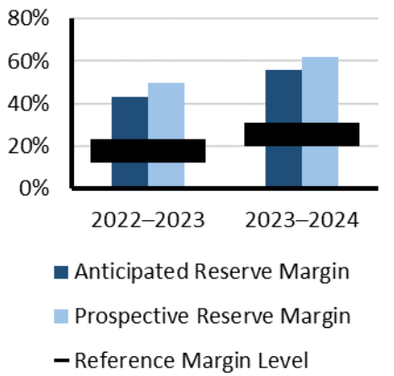
MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 39 local BAs and over 500 market participants, serving approximately 45 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Highlights

- Though some risk has been identified for this upcoming winter season in a high generation outage and high winter load scenario, reliability is expected to be maintained by the use of any number of measures, including load modifying resources, non-firm energy transfers into the system, energy-only resources that do not have a must-offer requirement for the winter but may still offer into the energy markets, or internal transfers that exceed the sub-regional import/export constraint between MISO North/Central and MISO South. MISO continues to coordinate extensively with neighboring RCs and BAs to improve situational awareness and vet any needs for firm or non-firm transfers to address extreme system conditions.
- The extreme cold weather of last winter is a reminder of just how critical resource adequacy and proper planning are for all seasons of the year, not just for a systems summer peak. Acknowledging this, MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency. In addition, MISO has filed and implemented a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons. As a result, MISO has raised Reference Margin Levels for the 2023–2024 winter season. The 2023–2024 Planning Resource Auction conducted in April 2023 was the first implemented under the seasonal construct.

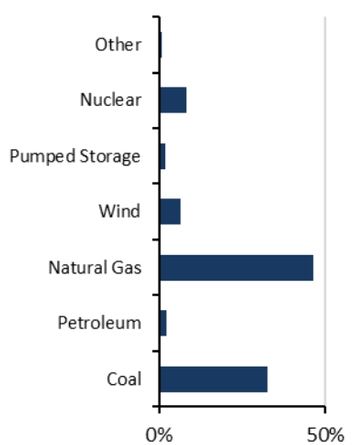
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and energy emergency alerts (EEA). Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year winter average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Low Wind Scenario: Below average wind contributions

Extreme Low-Generation: Maximum historical generation outages

Operational Mitigations: A total of 2.6 GW capacity resources available during extreme operating conditions



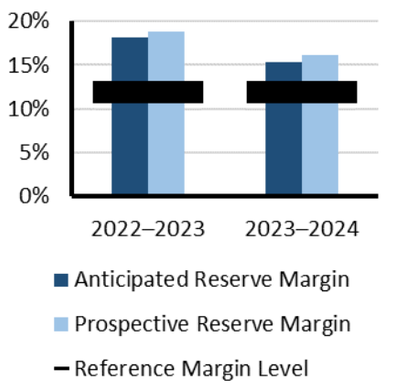
MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown Corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas Manitoba Hydro provides electricity to approximately 608,500 electricity customers in Manitoba and provides approximately 293,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba, which is 251,000 square miles Manitoba Hydro is winter-peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the RC for Manitoba Hydro.

Highlights

- The ARM for winter 2023–2024 exceeds the 12% Reference Margin Level.
- No emerging reliability issues are anticipated for the upcoming winter season that are pertinent to Manitoba Hydro.
- Manitoba Hydro continues to monitor a number of issues, including extreme weather events like drought, decarbonization-driven changes to supply and demand, and asset health.
- All seven units at the Keeyask hydro station (630 MW net addition) are anticipated to be in commercial operation for winter 2023–2024.

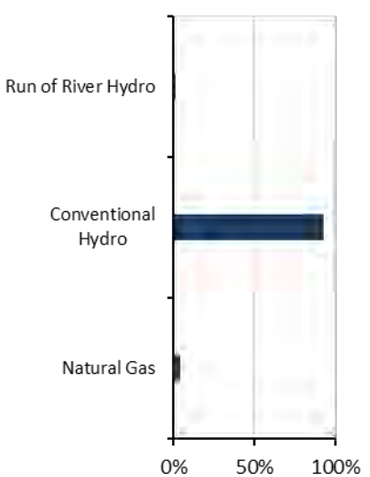
On-Peak Reserve Margin



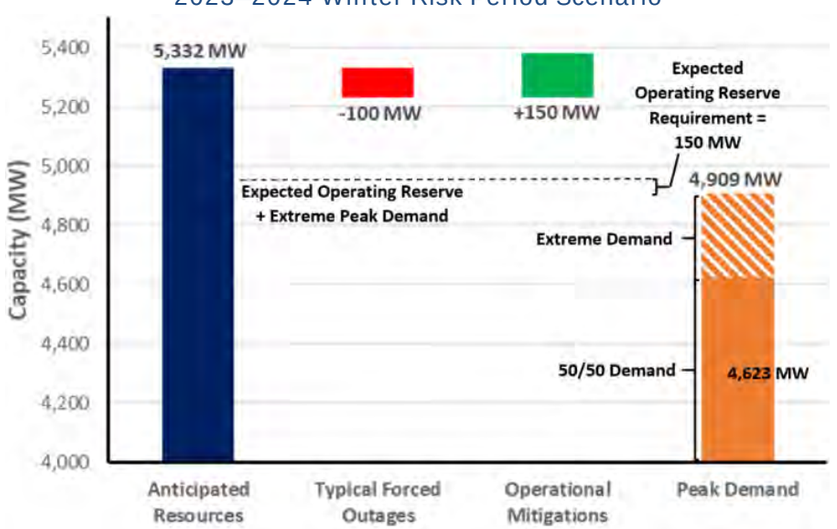
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand scales additional load experienced during all-time peak actual versus forecasted load (January 2019)

Forced Outages: Accounts for average forced outages

Operational Mitigations: Emergency Operating Procedures



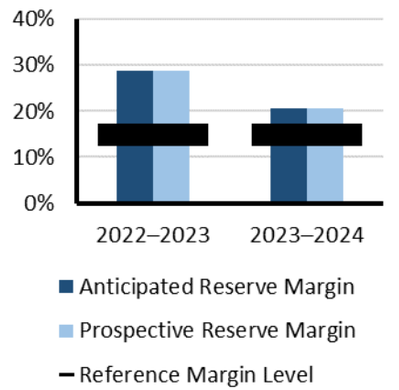
MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.2 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.

Highlights

- Saskatchewan experiences peak load in winter because of extreme cold weather. Reserve margins have fallen this winter by about 8% when compared to the previous winter due to increased peak demand projections, the retirement of a natural gas unit (95 MW), and an increase of planned maintenance.
- The risk of operating reserve shortage or EEA during peak load times exists if a large generation forced outage occurs during peak load times combined with transmission tie-line maintenance work or generation maintenance work scheduled during winter months.
- In case of extreme winter conditions combined with large generation forced outages, SaskPower would utilize available demand response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions.

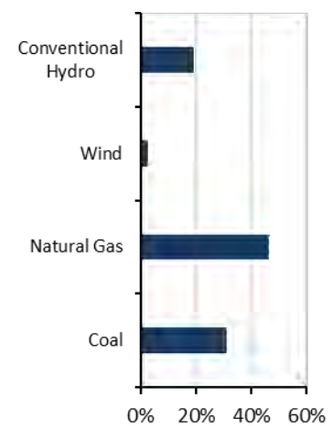
On-Peak Reserve Margin



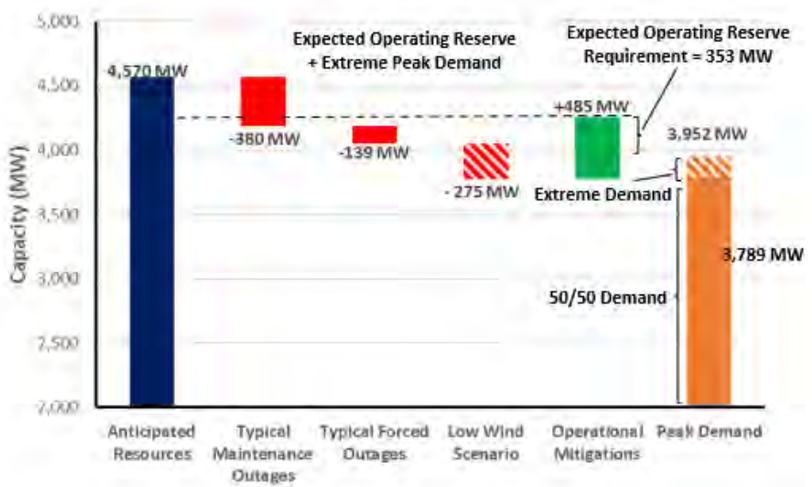
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. The risk of load shedding is low.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on potential system peak load increased by average forecast error of previous five years

Maintenance Outages: Average of planned maintenance outages for the winter months, December–February, over the past three years

Forced Outages: Estimated using SaskPower forced outage model

Low Wind Scenario: Estimated using SaskPower forced outage model

Operational Mitigations: Estimated average value based on short term transfer capability from neighboring utilities (150 MW) and reserved generating units (135 MW) for the upcoming 2023–2024 winter. This also includes 200 MW in demand-side resources and non-firm loads that require 15 minutes to 2 hours of advanced notification.



NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

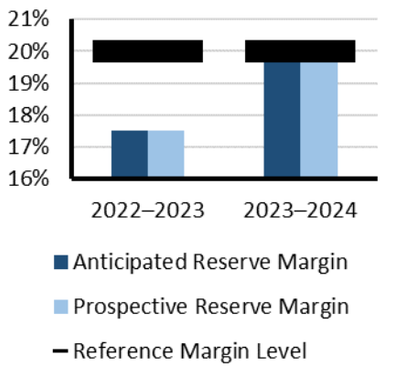
Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event was to occur, there are emergency operations and planning procedures in place. All of the area's declared firm capacity is expected to be operational for the winter operating period.
- The Maritimes area is a winter-peaking system.
- As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil on-site to enable sustained operation in the event of natural gas supply interruptions.

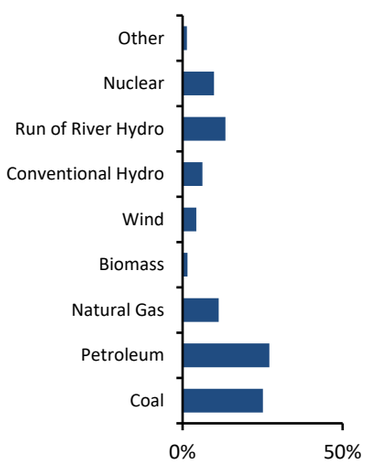
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. NPCC probabilistic analysis indicates that the risk of load shedding is low. See **Probabilistic Assessment** section.

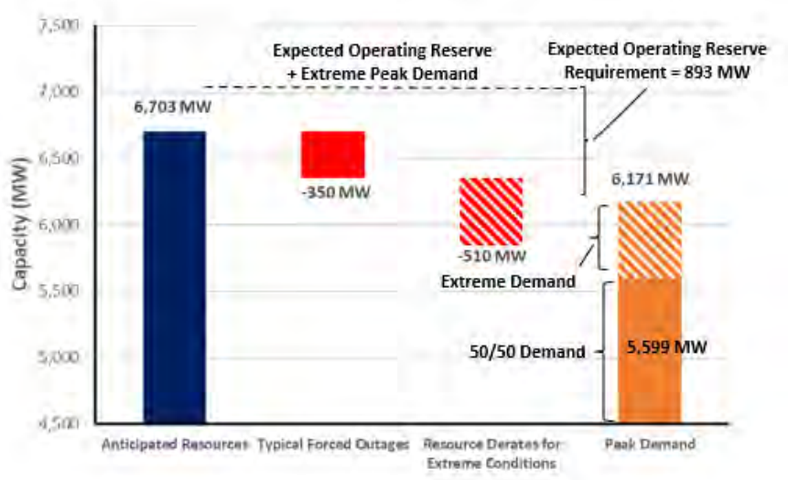
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 20 years of historical data

Forced Outages: Based on historical operating experience

Extreme Derates: A low likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions



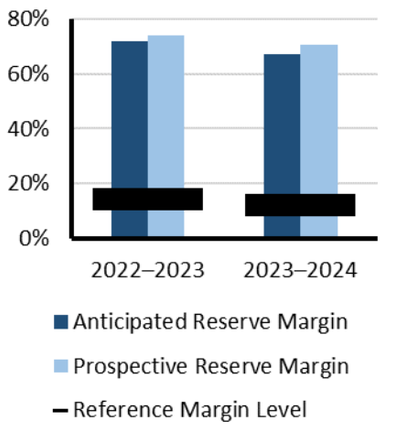
NPCC-New England

NPCC-New England is an assessment area that is served by ISO-NE, and it consists of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS. The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- ISO-NE expects to meet its regional resource adequacy requirements this 2023–2024 winter operating period for a mild or moderate winter similar to 2021–2022 or 2017–2018. A standing concern is whether there will be sufficient energy available to satisfy electricity demand during an extended cold period given the existing resource mix, fuel delivery infrastructure, and expected fuel arrangements without considerable effort to replenish stored fuels (i.e., fuel oil and liquified natural gas).
- ISO-NE is offering an interim program to compensate certain resources that provide fuel security. The Inventoried Energy Program is a voluntary, interim program designed to provide incremental compensation for participants that maintain inventoried energy for their assets during extreme cold periods when winter energy security is most stressed.
- ISO-NE expects to have sufficient capacity resources to meet the 2023–2024 90/10 winter peak demand forecast of 21,032 MW for the weeks beginning January 7, January 14, and January 21, 2024.
- ISO-NE evaluates an above 90/10 scenario, which captures the area's coldest day in the last 25 years while using both their current and future load models. The above 90/10 winter peak demand forecast is 21,746 MW for the three previously identified peak weeks. ISO-NE currently has sufficient resources to meet this demand however if a cold snap were to occur the area may have to rely on its external ties and emergency procedures to operate reliably.

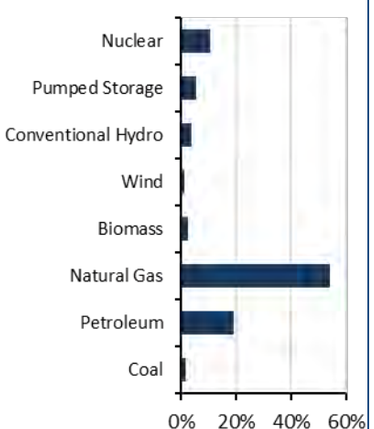
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area prolonged cold weather events. See **Probabilistic Assessment** section.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast for coldest day from the last 25 years

Maintenance and Forced Outages: Based on weekly averages

Extreme Derates and Natural Gas Scenario: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply and cold weather-related outages reported by generators

Operational Mitigations: Based on ISO-NE operating procedures



NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS encompasses over 11,000 miles of transmission lines, 760 power generation units, and serves 20.2 million customers. For this WRA, the established Reference Margin Level is 15%; wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. New York State Reliability Council approved the 2023–2024 IRM at 20.0%.

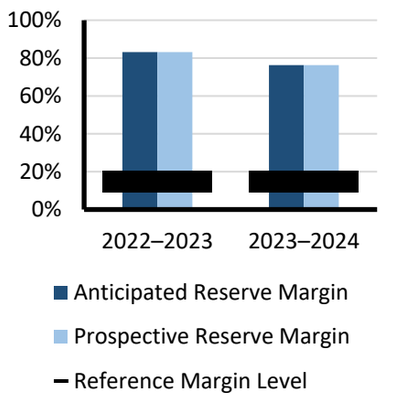
Highlights

- New York is a summer-peaking area, and no emerging reliability issues are anticipated during the 2023–2024 winter assessment period. Surplus capacity margins above the NYISO's operating reserve requirements are projected.

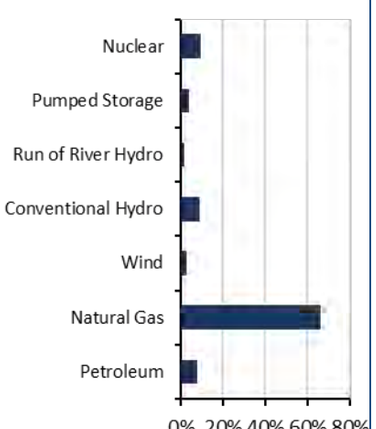
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

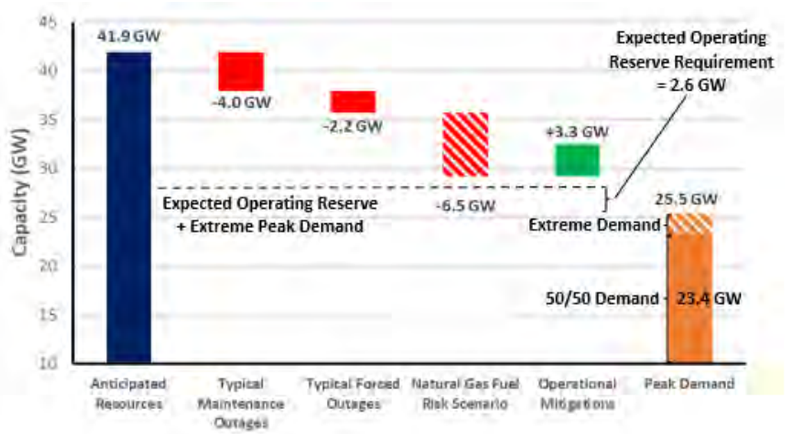
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Based on planned scheduled maintenance

Forced Outages: Five-year average of all outages that were not planned

Natural Gas Fuel Scenario: Potential natural gas generation at risk if non-firm supply is unavailable in a period of extended cold weather

Operational Mitigations: Based on NYISO operating procedures



NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 15 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

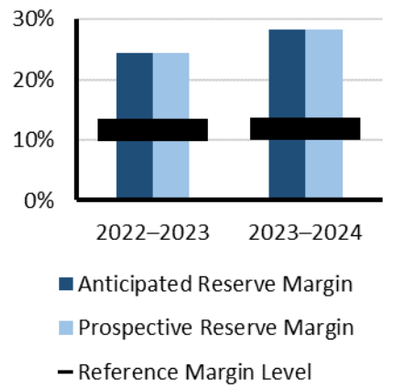
Highlights

- IESO anticipates that it will maintain reliability on its system through the winter of 2023–2024.
- Reference margins are forecast to remain at adequate levels in both normal and extreme weather scenarios.
- Ontario regularly experiences extreme cold weather; its generation fleet, transmission system, and fuel delivery infrastructure are well prepared for and adapted to such conditions.
- Unit 3 at the Darlington Nuclear Generating Station was reconnected to the provincial grid following refurbishment in July 2023, nearly six months ahead of schedule. Bruce Nuclear Generating Station's Unit 6 was returned to service following a successful refurbishment that began in January 2020.
- The IESO's December 2022 Annual Capacity Auction secured 1,160 MW of capacity for winter 2023–2024.

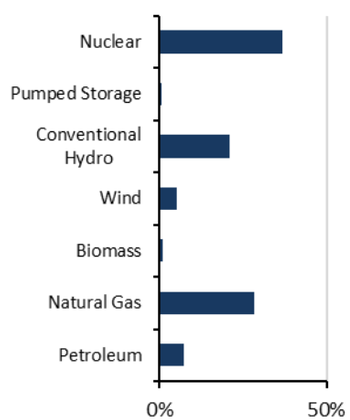
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

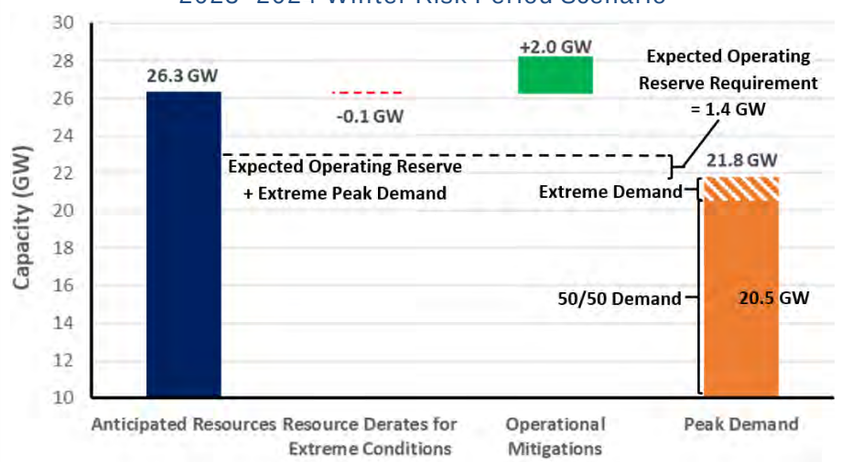
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 Forecast) and highest weather-adjusted daily demand from 31 years of winter demand history

Extreme Derates: Generation unavailability in an extreme event using temperature derates

Operational Mitigations: Imports anticipated from neighbors during emergencies



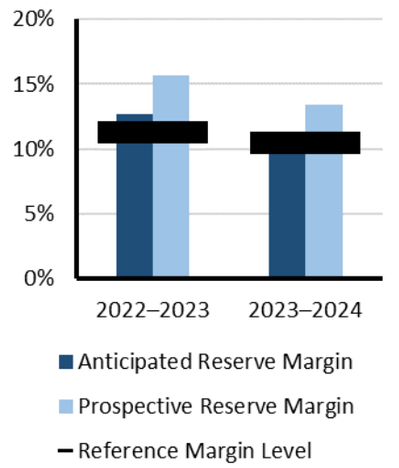
NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America, and it has ties to Ontario, New York, New England, and the Maritimes that consist of either high voltage direct current ties, radial generation, or load to and from neighboring systems.

Highlights

- Québec predicts that it will maintain system resource adequacy this winter.
- Forecasted demand increase and additional firm export commitments have resulted in shrinking reserve margins.
- The Québec area is a winter-peaking system with predominately hydroelectric generation resources. Adequate capacity margins above its reference reserve requirements are projected for the 2023–2024 winter assessment period.
- No changes have been made to the assessment area's winter preparedness programs.

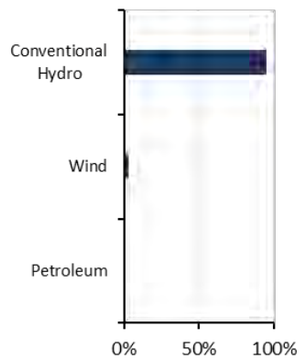
On-Peak Reserve Margin



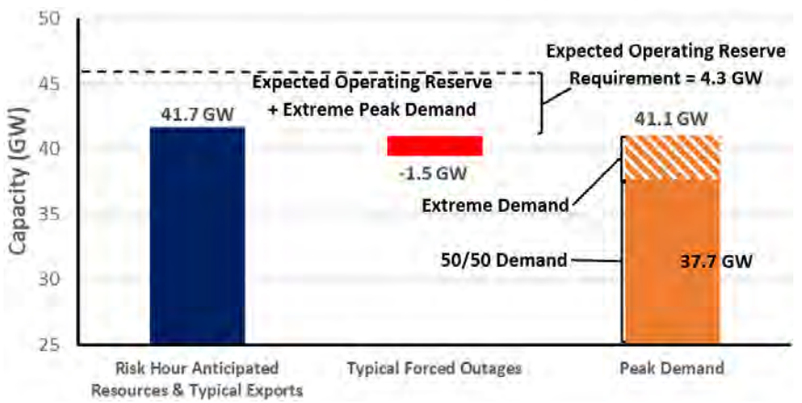
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. NPCC probabilistic analysis indicates that the risk of load shedding is low. See the **Probabilistic Assessment** section.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 8:00 a.m.

Demand Scenarios: Net internal demand (50/50) and (95/5) demand forecast

Forced Outages: Rare scenario of 1,500 MW in unplanned outages



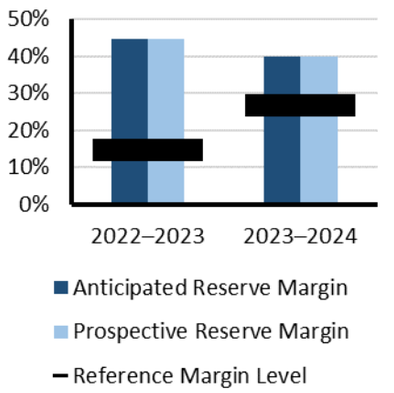
PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.

Highlights

- Installed capacity is significantly higher (13 percentage points) than PJM's Reserve Requirements. PJM does not expect to encounter resource problems for anticipated conditions over the 2023–2024 winter Peak season.
- A severe cold weather event that extends to the South can lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Forecasted peak demand has risen while resources have decreased since 2022 when Winter Storm Elliot caused energy emergencies in PJM and surrounding areas.

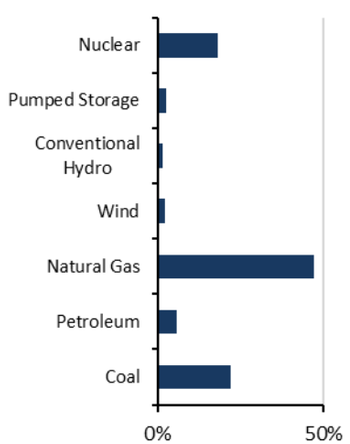
On-Peak Reserve Margin



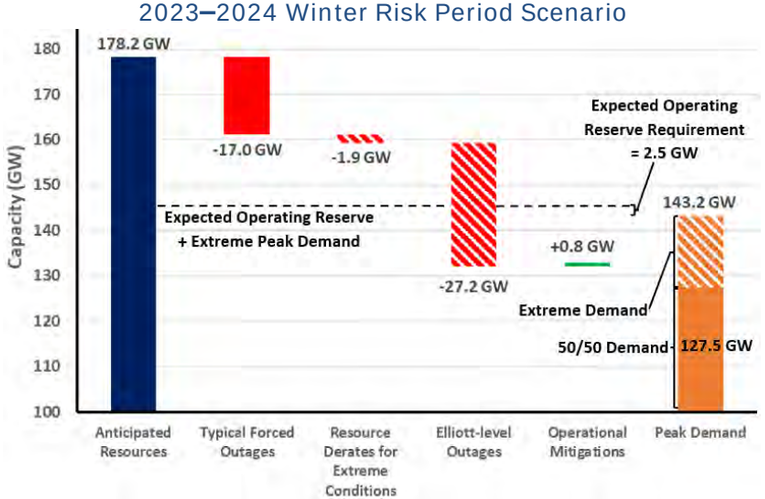
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed normal and extreme scenarios. Generator outages on a level of those experienced during Winter Storm Elliot would lead to energy emergencies.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Elliott-level Outages: Additional forced outages equal to the total MW capacity on outage due to freezing and fuel issues during winter storm Elliott in 2022.

Operational Mitigations: A total of 0.8 GW based on operational/emergency procedures

* See PJM Report *Winter Storm Elliott Event Analysis and Recommendations Report*, July 17, 2023, available here.



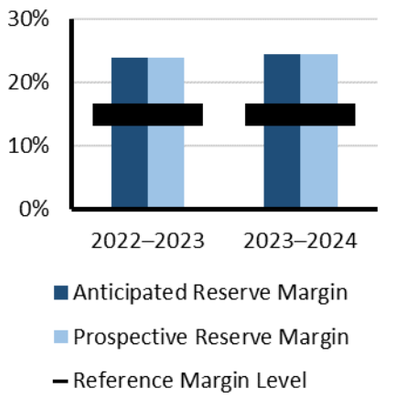
SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six Regional Entities across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC) approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

Highlights

- Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC East assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- The entities do not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- Many entities have extensive weatherization processes that include developed procedures specific to freezing events. The entities are prepared to respond to unanticipated operational events and coordinate with neighboring entities to promote overall system reliability.

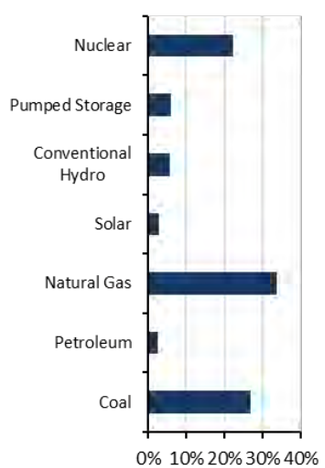
On-Peak Reserve Margin



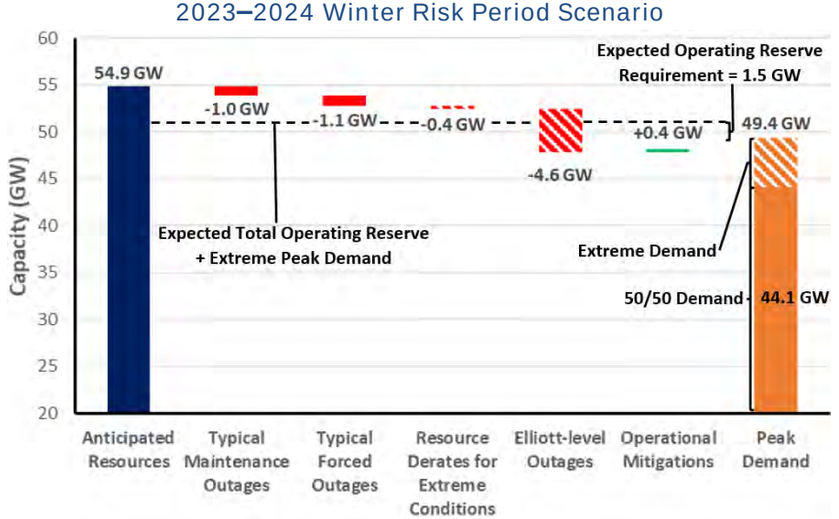
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. A severe cold weather event extending to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation

Extreme Derates: Maximum historical generation outages (excluding 2022-2023)

Elliott-level Outages: Additional forced outages that, when added to the typical outage scenario, equal the total MW capacity on outage due to freezing and fuel issues during Winter Storm Elliott in 2022

Operational Mitigations: A total of 0.4 GW based on operational/emergency procedures



SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six Regional Entities across North America that is responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity area covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

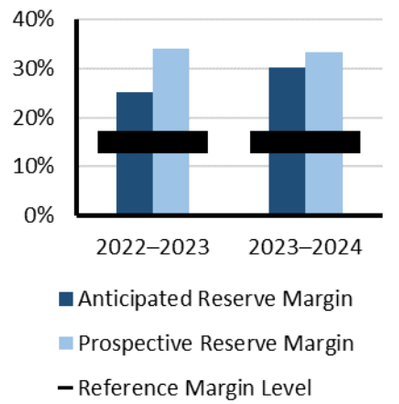
Highlights

- Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC-Central assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- While short-term issues (e.g., forced outages, colder than normal temperatures, or supply issues) around neighboring systems or natural gas pipelines are possibilities, the SERC-Central assessment area expects to maintain real-time operating reserves at all times. Therefore, SERC-Central does not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- SERC-Central has extensive weatherization processes that include developed procedures specific to freezing events. SERC-Central is prepared to respond to unanticipated operational events and coordinate with neighboring entities to promote overall system reliability.

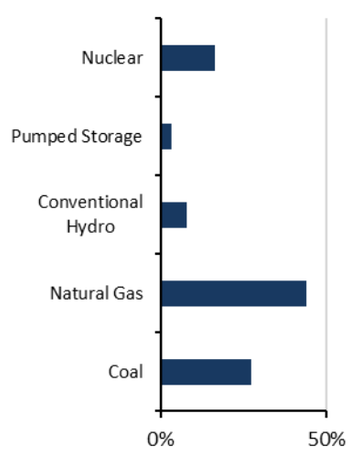
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. A severe cold weather event that extends to the South could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

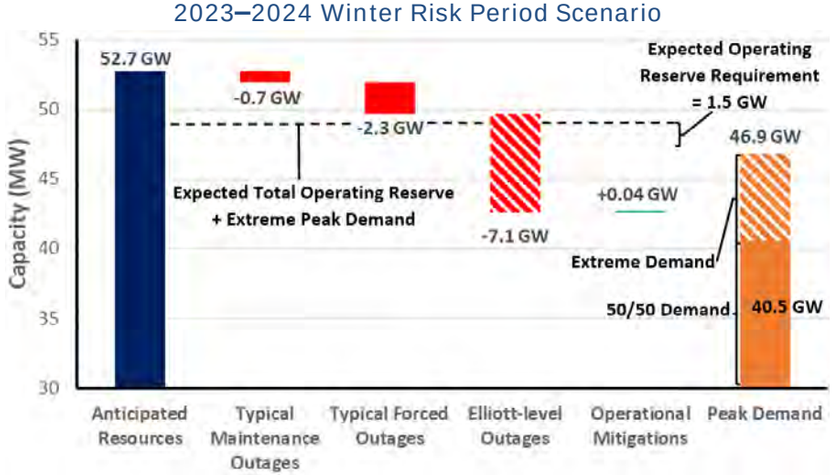
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Includes any weighted average forced outage rates on-peak that are not factored into the anticipated resources calculation

Elliott-level Outages: Additional forced outages that, when added to the typical outage scenario, equal the total MW capacity on outage due to freezing and fuel issues during Winter Storm Elliott in 2022

Operational Mitigations: A total of 0.04 GW based on operational/emergency procedures



SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six Regional Entities across North America that is responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

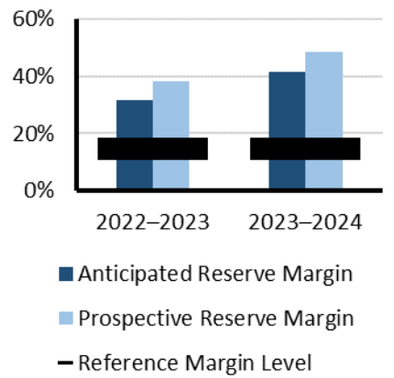
Highlights

- Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC-Southeast assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- The entities do not anticipate any significant reliability issues because of fuel supply, inventory, or transportation.
- Many entities have extensive weatherization processes that include developed procedures specific to freezing events. The entities are prepared to respond to unexpected, day-to-day events and coordinate with neighboring entities to promote overall system reliability.

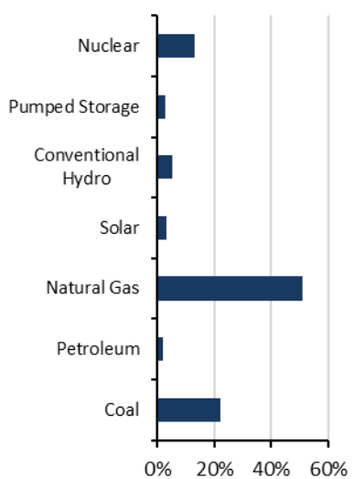
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

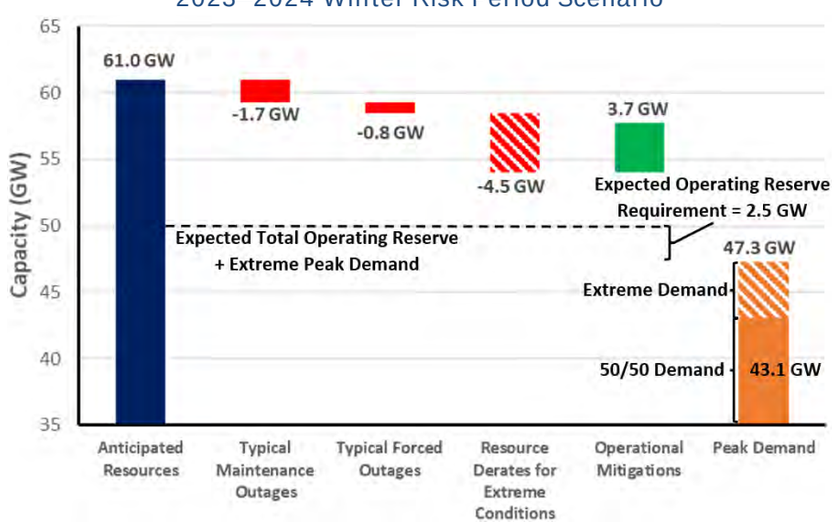
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 3.7 GW based on operational/emergency procedures



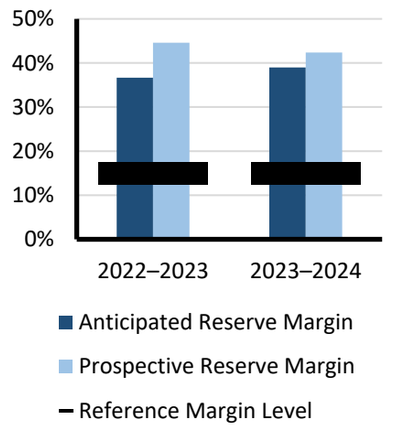
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six Regional Entities across North America that is responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity area covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

Highlights

- Based on the projected non-coincident net peak demand forecast as well as existing and planned generation resources, the ARM for the SERC Florida-Peninsula assessment area is projected to exceed the 15% NERC Reference Reserve Margin.
- Although the entities do not currently anticipate reliability impacts in the upcoming winter season, some entities have expressed concerns about the difficulty of scheduling and receiving coal deliveries on a consistent basis, which would affect unit availability.
- The entities have performed a summary review of their winterization plans as well as the coordination of generation and transmission outages through the Florida Reliability Coordinating Council (FRCC) Operations PC and RC functions.

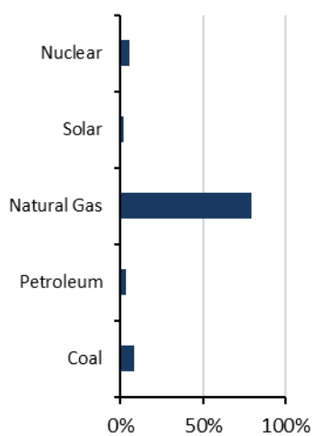
On-Peak Reserve Margin



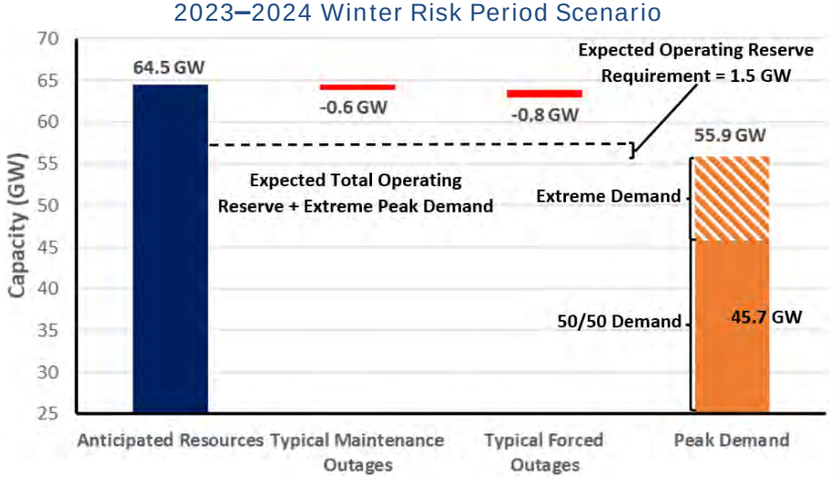
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Data collected through a survey of members for outages during December through February

Forced Outages: Weighted average forced outage rates on-peak are factored into the anticipated resources calculation



SPP

SPP PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and serves a population of more than 18 million.

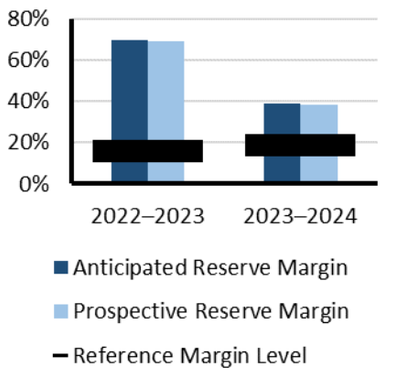
Highlights

- SPP anticipates that planning reserves are adequate for the upcoming winter season. Reserve margins have fallen this winter because of increased peak demand projections and declining anticipated resources.
- SPP does not anticipate any emerging reliability issues impacting the area for the 2023–2024 winter season but realizes that interruptions to fuel supply could create unique operation challenges.
- SPP continues to work with neighboring areas to address potential electricity deliverability issues associated with extreme weather events. Efforts are aimed at enhancing communications and operator preparedness.
- To minimize conservative operations, EEAs, and the response to mid-range forecast error uncertainty in wind forecasts, SPP created some new mitigation processes to deal with high-impact areas of concern. SPP has developed operational mitigation teams, processes, and procedures that have been put in place to maintain real-time reliability needs.
- SPP created a Resource and Energy Adequacy Leadership Team that is addressing numerous resource adequacy initiatives that are addressing an expected unserved energy (EUE) standard, fuel assurance, winter requirements, winter PRM, outage policies, demand response, accreditation, and other areas of impact.
- SPP hosted its winter preparedness workshop in October 2023.

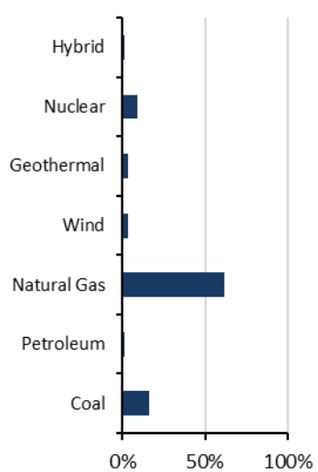
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

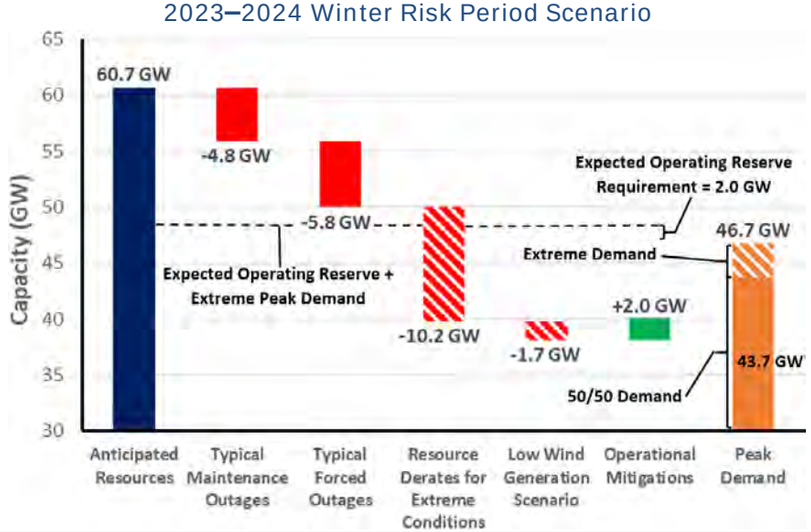
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast using historical data

Maintenance and Forced Outages: A capacity derate for maintenance outages, forced outages, and performance in extreme weather based on historical data

Extreme Derates: A capacity derate for generator performance in extreme weather based on historical data

Low Wind Scenario: 1.7 GW of wind potentially off-line when temperatures fall below their cold weather performance packages

Operational Mitigations: A total of 2 GW based on operational/emergency procedures (External Assistance)



Texas RE-ERCOT

ERCOT is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking and covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas power grid.

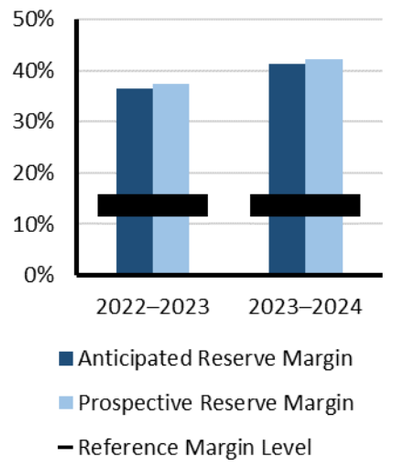
Highlights

- For the upcoming winter season, Texas RE-ERCOT will face reserve shortage risks during high net load hours. In winter, solar generation is not available to serve peak demand, making the system dependent on wind generation and dispatchable resource availability to serve load.
- Reserve scarcity risks are greater than last winter due primarily to robust load growth along with insufficient new dispatchable resources to serve the higher net peak loads.
- The area has also experienced a large increase in thermal units planned to be indefinitely mothballed to operate under a summer-only availability schedule; a loss of 1,283 MW of winter-rated capacity is expected.
- The risk of reserve shortages leading to EEA declarations has increased from “low” to “elevated” for hour-ending 8:00 a.m. based on ERCOT’s probabilistic risk assessment. ERCOT is investigating the option to procure additional capacity to reduce this reserve shortage risk on a competitive basis.
- ERCOT does not expect any significant fuel supply issues for the winter. However, fuel-related outages during Winter Storm Elliott (December 22–25, 2023) indicated that natural gas-fired generators that normally experience fuel restrictions during cold weather are expected to continue to face such restrictions. ERCOT’s new Firm Fuel Supply Service was deployed during this storm and is expected to partially offset the lost generation capacity due to these natural gas restrictions.
- ERCOT has observed increasing transmission congestion from South Texas to South-Central Texas (including the San Antonio area) that will limit transfers during the winter. A transmission project that includes a new 345 kV double circuit transmission line was recommended with an expected in-service date of June 2027 to address this congestion.

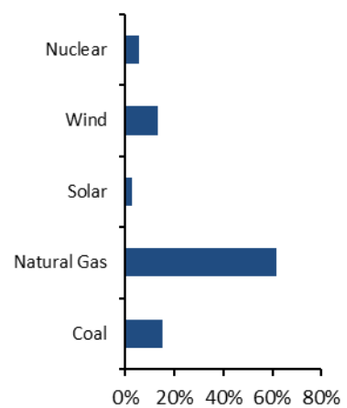
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

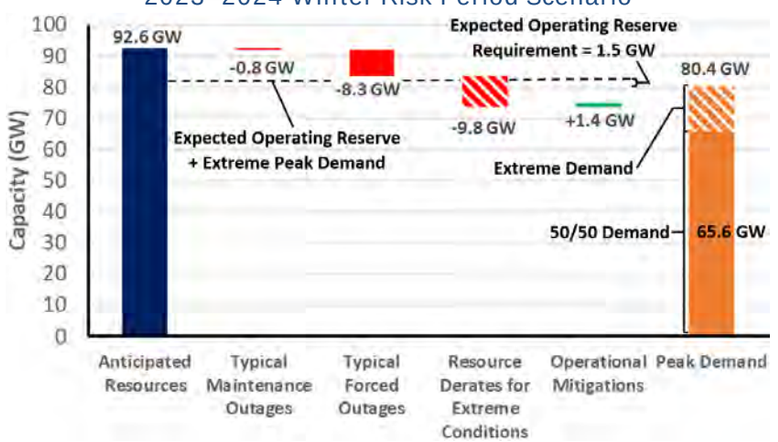
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme winter peak demand based on 2020–2021 Winter Storm Uri peak demand

Maintenance Outages: Based on historical winter data and consideration of ERCOT’s allowed maximum system daily planned outage capacity

Forced Outages: Based on the historical averages of maintenance or forced outages respectively for December through February weekdays, hours ending 7:00–10:00 a.m. local time for the last three (2020/2021, 2021/2022, and 2022/2023) winter seasons (Winter Storm Uri-related forced outages between February 15–18, 2021, were excluded from this calculation.)

Extreme Derates: Accounts for reduced thermal, wind, and solar PV capacity contributions due to performance in extreme conditions (uses averages from Winter Storm URI with adjustments to account for implemented weatherization improvements)

Operational Mitigations: Additional potential capacity from switchable generation and imports



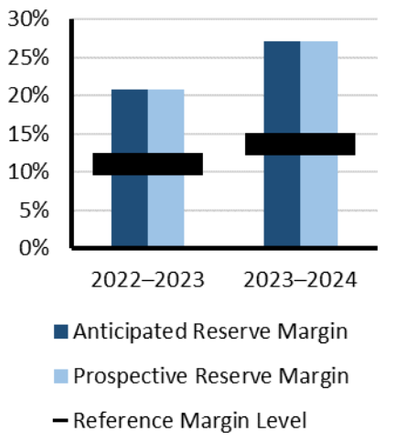
WECC-Alberta

WECC-Alberta is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western U.S. states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

Highlights

- WECC-Alberta shows some risk highlighted by the risk period scenario; however, the area is expected to be able to be covered through imports if not islanded.
- WECC- Alberta's operating reserve margins are met before imports in all scenarios except the Low Wind Scenario, which leaves a gap of 0.5 GW, and the Extreme Combined Scenario, which leaves a gap of 1.0 GW under extreme peak demand conditions. Both of these scenarios are anticipated to be able to be covered through imports. WECC-Alberta is a winter-peaking area and did see a few EEA-3s last season due to a combination of extreme demand peaks from cold temperatures, low wind, and the loss of a baseload unit.

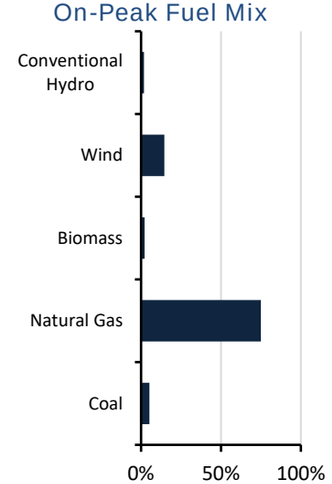
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output



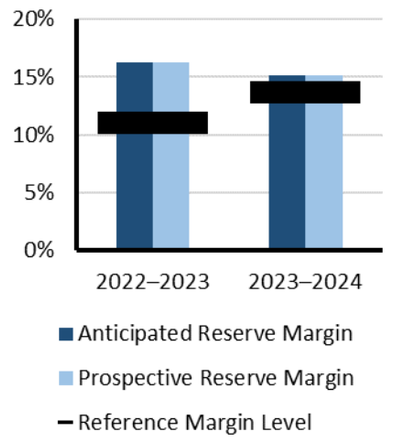
WECC-British Columbia

WECC-British Columbia is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western US states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

Highlights

- WECC-British Columbia has adequate resources for anticipated winter conditions. If peak demand exceeds normal forecasts or hydroelectric generation is lower than normal, non-firm imports may be needed to meet required operating reserves.
- WECC-British Columbia could require a range of import levels for extreme demand or low-resource scenarios. For expected demand, the area falls short of its operating reserve requirements if hydro output is abnormally low (low likelihood scenario). During the Extreme Peak Demand Scenario (90th percentile), operating reserve margins fall short by 0.6 GW with anticipated resources and could increase for more extreme outages or low-hydro scenarios. Sufficient imports from neighbors in the Western Interconnection are expected to be available, provided that BC does not become electrically islanded.

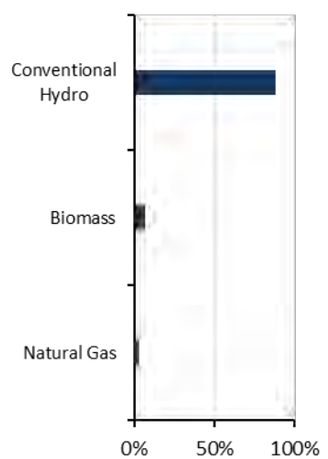
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output



WECC-California/Mexico

WECC-Californica/Mexico is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western US states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

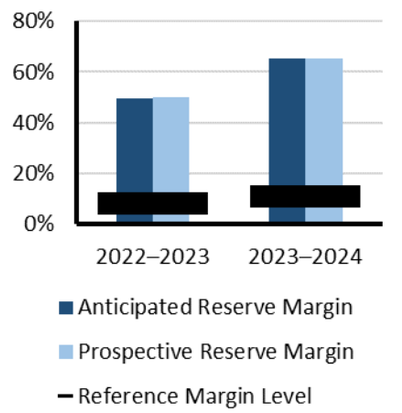
Highlights

- WECC-Californica/Mexico shows adequate energy availability under both expected and extreme scenarios.

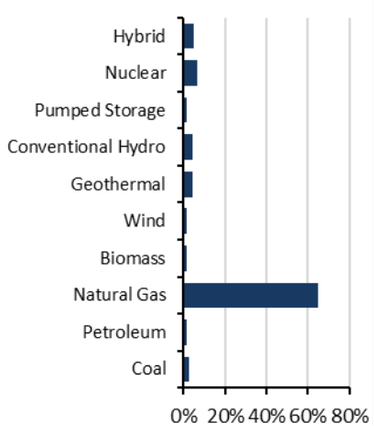
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

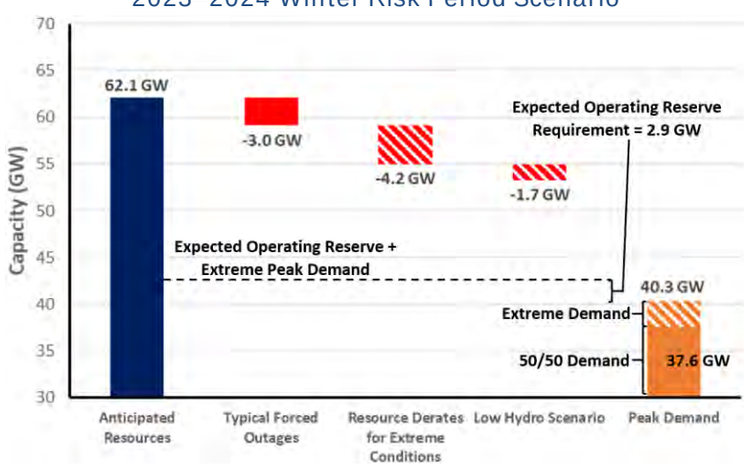
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output



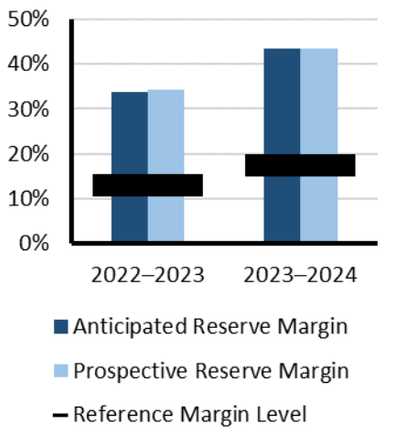
WECC-Northwest

WECC-Northwest is a summer-peaking assessment area in the WECC Regional Entity that includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western US states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

Highlights

- WECC-Northwest shows some risk highlighted by the risk period scenario; however, the area is expected to be able to be covered through imports.
- WECC-Northwest has historically been a mixed-season peaking area. Operating reserve margins are met at the expected peak demand hour under all but the Extreme Combined Scenario, where 5.3 GW of imports would be needed to meet operating reserve margins at an expected peak demand (50th percentile) and 10 GW for an extreme peak load level (90th percentile). Depending on the situation in neighboring areas, imports are expected to be available to fill the gap.

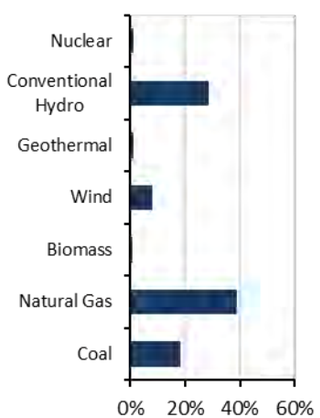
On-Peak Reserve Margin



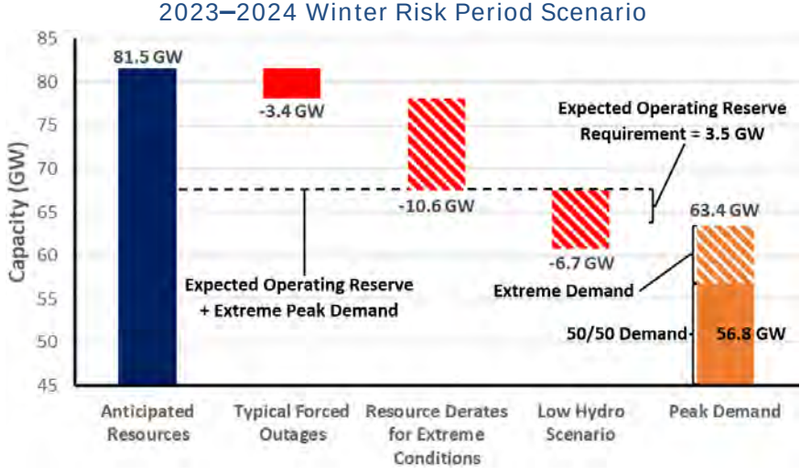
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output



WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the WECC Regional Entity that includes Arizona, New Mexico, and part of California and Texas. WECC is responsible for coordinating and promoting BES reliability across the entire Western Interconnection. WECC is geographically the largest and most diverse Regional Entity serving an area of nearly 1.8 million square miles and more than 82 million customers. The WECC Regional Entity area includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of 14 western US states in between. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES.

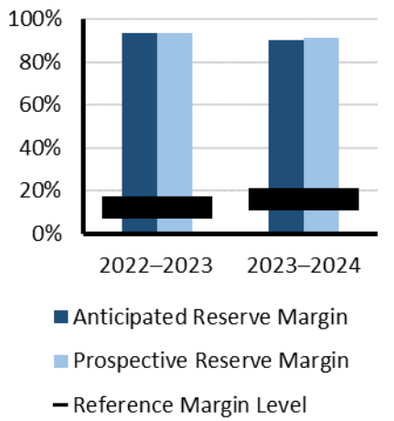
Highlights

- WECC-Southwest shows adequate energy availability under both expected and extreme scenarios.

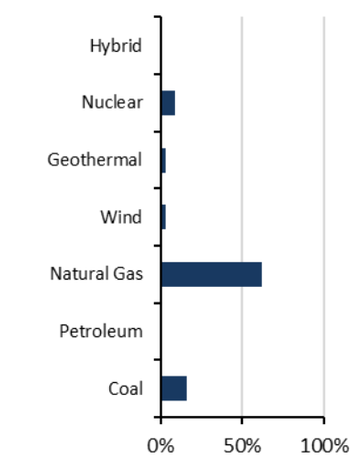
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

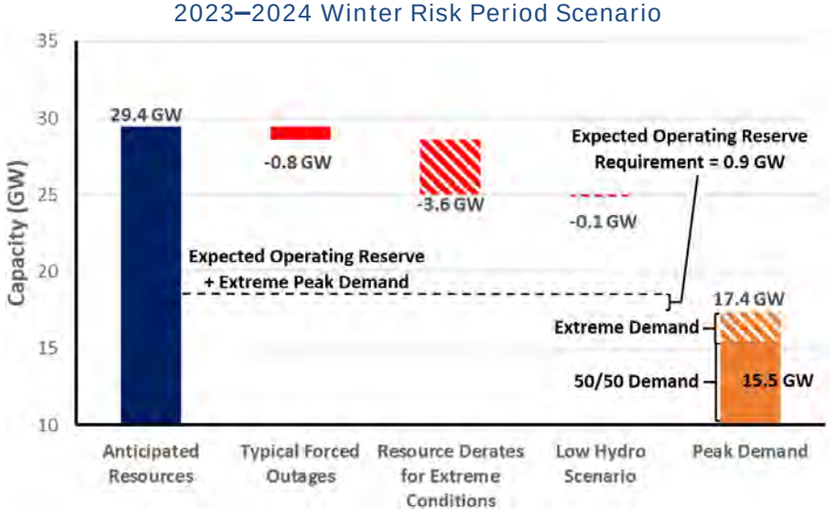
On-Peak Reserve Margin



On-Peak Fuel Mix



2023–2024 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Calculated using (90/10) scenario

Extreme Derates: Resources derates based on (90/10) scenario

Low Hydro Scenario: Estimated derate for lower hydro output

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• The reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electricity system to supply the aggregate electric power and energy requirements of consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electricity system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• *2023 Long-Term Reliability Assessment* data has been used for most of this 2023–2024 assessment period augmented by updated load and capacity data provided by Regional Entities and assessment areas.
• A positive net transfer capability would indicate a net-importing assessment area, a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[5] or total internal demand for the summer and winter of each year.[6]
• Total internal demand projections are based on normal weather (50/50 distribution[7]) and are provided on a coincident[8] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (e.g., wind, solar) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

[5] *Glossary of Terms* used in NERC Reliability Standards

[6] The summer season represents June–September and the winter season represents December–February.

[7] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[8] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the winter season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

Prospective Resources: This includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources (from the resource adequacy data table), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand from the resource adequacy data table and the extreme winter peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced, not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme winter peak demand.

Resource Adequacy

The ARM, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[9] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. NPCC-Maritimes marginally does not meet their RML for the upcoming winter. Other than NPCC-Maritimes, all assessment areas have sufficient ARMs to meet or exceed their Reference Margin Level for the 2023 winter as shown in **Figure 4**.

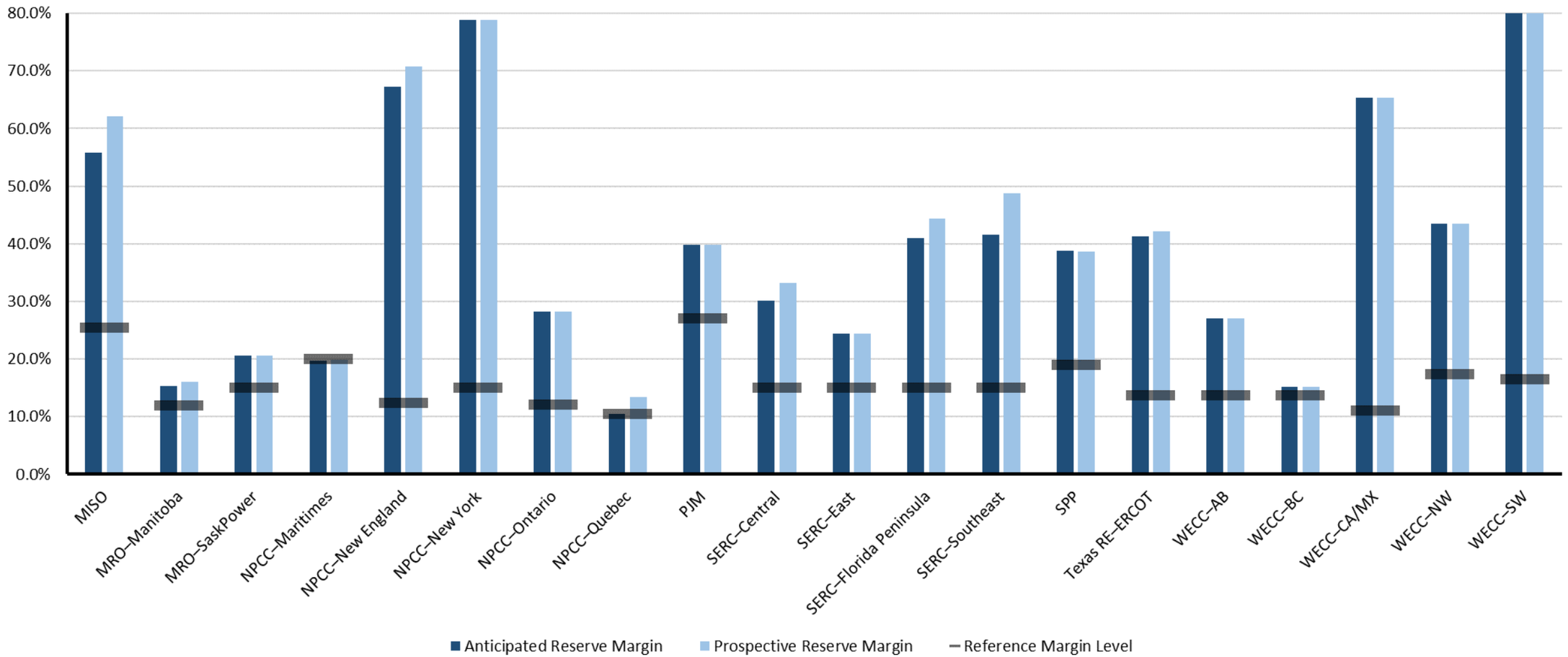


Figure 4: Winter 2023–2024 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[9] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and Reference Margin Levels.

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast Anticipated Reserve Margins (ARM) from the 2022–2023 winter to the 2023–2024 winter. Note that the Reference Margin Level is unchanged for areas that don't have a 2022–2023 Reference Margin Level shown. A significant decline can indicate potential operational issues that emerge between reporting years. MRO-Manitoba, MRO-SaskPower, NPCC-Québec, and WECC-BC have noticeable reductions in anticipated resources between the 2022–2023 winter and the 2023–2024 winter. All areas except NPCC-Maritimes remain above their Reference Margin Levels for 2023–2024 winter. NPCC-Québec is marginally above its Reference Margin Level. The lower ARMs for MRO-Manitoba, MRO-SaskPower, NPCC-Québec, and WECC-BC do not result in reliability concerns during expected conditions for this upcoming winter. The Canadian winter-peaking systems of MRO-Manitoba, MRO-SaskPower, NPCC-Maritimes and NPCC-Québec have reserve margins that are near Reference Margin Levels but are unlikely to experience high outage rates from their winterized generators. Additional details are provided in the **Data Concepts and Assumptions** section.

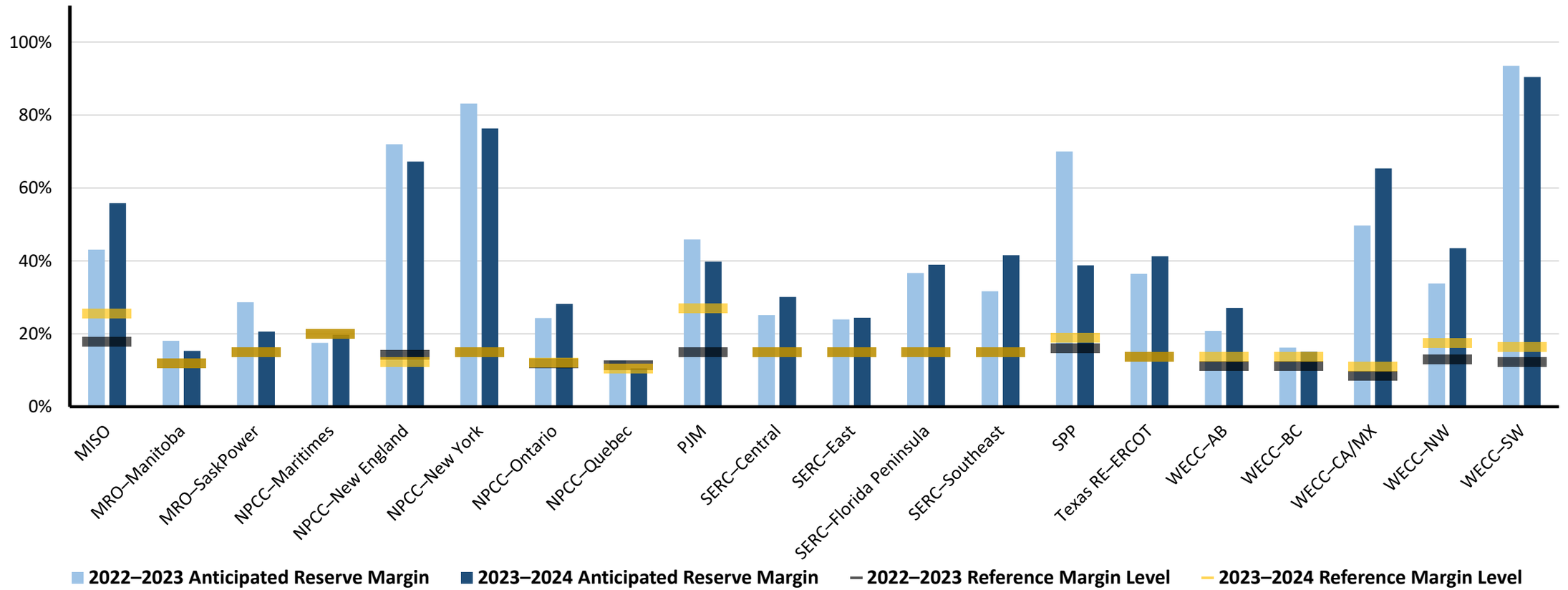


Figure 5: Winter 2022–2023 and Winter 2023–2024 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted Net Internal Demand for each assessment area are shown in **Figure 6**.[10] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections. Most assessment areas are showing increasing demand for the upcoming winter compared with the last WRA.

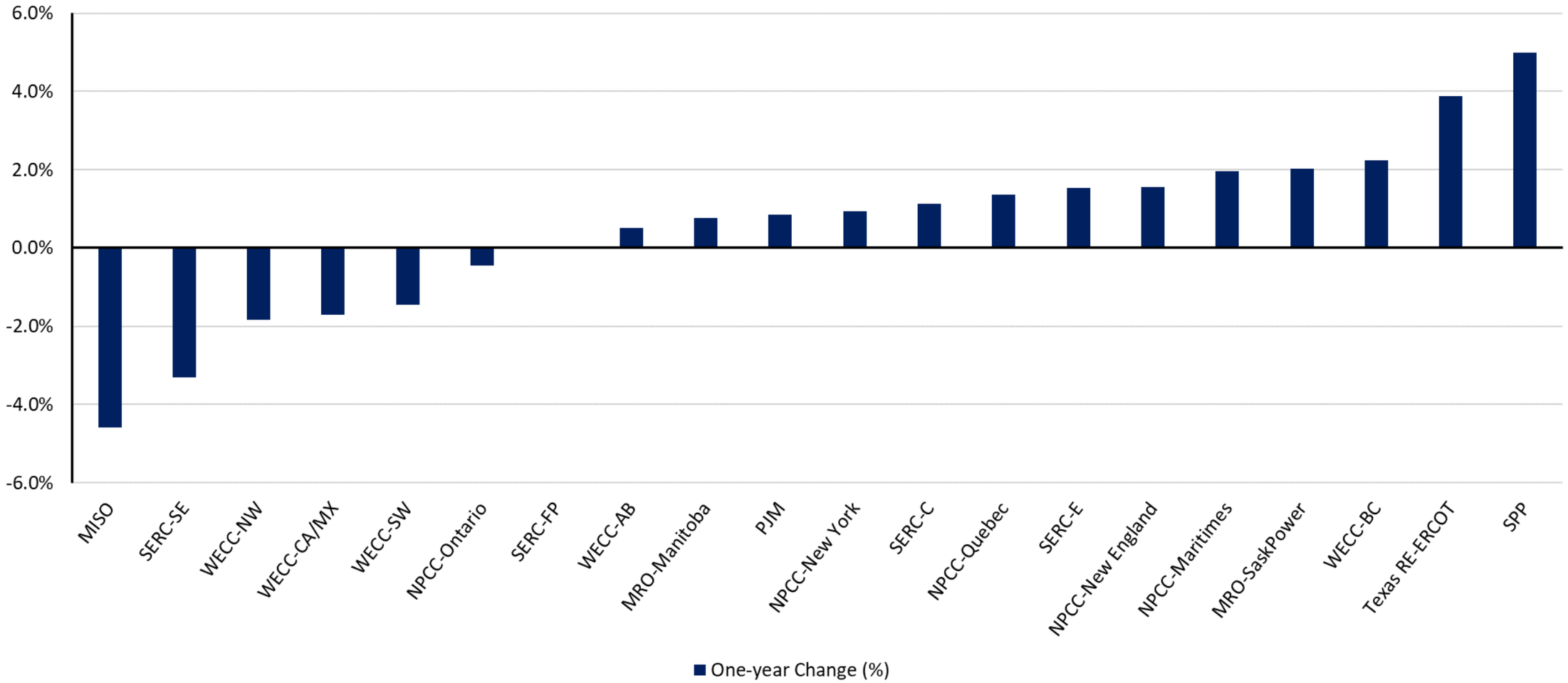


Figure 6: Change in Net Internal Demand—Winter 2022–2023 Forecast Compared to Winter 2023–2024 Forecast

[10] Changes in modeling and methods may also contribute to year-to-year changes in forecasted net internal demand projections.

Demand and Resource Tables

Peak demand and supply capacity data (i.e., resource adequacy data) for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	102,611	102,075	0.5%
Demand Response: Available	3,672	7,681	109.2%
Net Internal Demand	98,939	94,394	-4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	137,926	146,976	6.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,352	121	91.1%
Anticipated Resources	141,565	147,097	3.9%
Existing-Other Capacity	669	2,614	290.8%
Prospective Resources	148,125	153,003	3.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	43.1%	55.8%	12.7
Prospective Reserve Margin	49.7%	62.1%	12.4
Reference Margin Level	17.9%	25.5%	7.6

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	4,588	4,623	0.8%
Demand Response: Available	0	0	-
Net Internal Demand	4,588	4,623	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,705	5,864	2.8%
Tier 1 Planned Capacity	279	90	-67.8%
Net Firm Capacity Transfers	-566	-622	9.9%
Anticipated Resources	5,418	5,332	-1.6%
Existing-Other Capacity	33	36	9.5%
Prospective Resources	5,451	5,368	-1.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.1%	15.3%	-2.8
Prospective Reserve Margin	18.8%	16.1%	-2.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,781	3,839	1.5%
Demand Response: Available	67	50	-25.4%
Net Internal Demand	3,714	3,789	2.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,488	4,320	-3.8%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	250	-13.8%
Anticipated Resources	4,778	4,570	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	4,778	4,570	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.7%	20.6%	-8.1
Prospective Reserve Margin	28.7%	20.6%	-8.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	5,784	5,863	1.4%
Demand Response: Available	282	264	-6.4
Net Internal Demand	5,502	5,599	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	6,461	6,622	2.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	4	81	1925.0%
Anticipated Resources	6,465	6,703	3.7%
Existing-Other Capacity	0	0	-
Prospective Resources	6,465	6,703	3.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	17.5%	19.7%	2.2
Prospective Reserve Margin	17.5%	19.7%	2.2
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,009	20,269	1.3%
Demand Response: Available	610	570	-6.6%
Net Internal Demand	19,399	19,699	1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	32,129	31,795	-1.0%
Tier 1 Planned Capacity	162	187	15.2%
Net Firm Capacity Transfers	1,070	958	-10.5%
Anticipated Resources	33,361	32,940	-1.3%
Existing-Other Capacity	142	201	42.1%
Prospective Resources	33,769	33,641	-0.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	72.0%	67.2%	-4.8
Prospective Reserve Margin	74.1%	70.8%	-3.3
Reference Margin Level	14.3%	12.3%	-2.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	23,893	24,220	1.4%
Demand Response: Available	695	803	15.5%
Net Internal Demand	23,198	23,417	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,393	39,697	-1.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,097	1,589	-24.2%
Anticipated Resources	42,490	41,285	-2.8%
Existing-Other Capacity	0	0	-
Prospective Resources	42,490	41,285	--2.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	83.2%	76.3%	-6.9
Prospective Reserve Margin	83.2%	76.3%	-6.9
Reference Margin Level	15.0%	15.0%	-4.6

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,255	21,402	0.7%
Demand Response: Available	614	853	39.0%
Net Internal Demand	20,641	20,549	-0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,051	26,301	1.0%
Tier 1 Planned Capacity	112	24	-78.6%
Net Firm Capacity Transfers	-500	17	-103.4%
Anticipated Resources	25,662	26,342	2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	25,662	26,342	2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	28.2%	3.9
Prospective Reserve Margin	24.3%	28.2%	3.9
Reference Margin Level	11.8%	12.0%	0.2

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	39,699	40,642	2.4%
Demand Response: Available	2,759	2,914	5.6%
Net Internal Demand	37,217	37,728	1.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	42,113	42,423	0.7%
Tier 1 Planned Capacity	255	0	-100.0%
Net Firm Capacity Transfers	-417	-726	74.1%
Anticipated Resources	41,951	41,697	-0.6%
Existing-Other Capacity	0	0	-
Prospective Resources	43,051	42,797	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.7%	10.5%	-2.2
Prospective Reserve Margin	15.7%	13.4%	-2.3
Reference Margin Level	11.3%	10.5%	-0.8

PJM			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	132,980	132,667	-0.2%
Demand Response: Available	6,583	5,189	-21.2%
Net Internal Demand	126,397	127,478	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	185,102	179,060	-3.3%
Tier 1 Planned Capacity	0	0	0%
Net Firm Capacity Transfers	-726	-872	20.1%
Anticipated Resources	184,376	178,188	-3.4%
Existing-Other Capacity	0	0	-
Prospective Resources	184,376	178,188	-3.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	45.9%	39.8%	-6.1
Prospective Reserve Margin	45.9%	39.8%	-6.1
Reference Margin Level	14.9%	27.0%	12.1

SERC-East			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	44,648	45,044	0.9%
Demand Response: Available	1,180	912	-22.7%
Net Internal Demand	43,468	44,132	1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	53,287	54,229	1.8%
Tier 1 Planned Capacity	75	55	-26.6%
Net Firm Capacity Transfers	513	624	21.6%
Anticipated Resources	53,875	54,908	1.9%
Existing-Other Capacity	3	3	0.0%
Prospective Resources	53,877	54,910	1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.9%	24.4%	0.5
Prospective Reserve Margin	23.9%	24.4%	0.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Central			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	41,745	42,282	1.3%
Demand Response: Available	1,671	1,753	4.9%
Net Internal Demand	40,074	40,529	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,008	50,196	-1.6%
Tier 1 Planned Capacity	0	1,386	-
Net Firm Capacity Transfers	-868	1,145	-231.9%
Anticipated Resources	50,140	52,727	5.2%
Existing-Other Capacity	3,601	1,255	-65.1%
Prospective Resources	53,741	54,002	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.1%	30.1%	5.0
Prospective Reserve Margin	34.1%	33.2%	-0.9
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,582	48,470	-0.2%
Demand Response: Available	2,870	2,753	-4.1%
Net Internal Demand	45,712	45,717	0.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	61,987	62,679	0.8%
Tier 1 Planned Capacity	237	344	522.2%
Net Firm Capacity Transfers	250	509	103.6%
Anticipated Resources	62,474	63,531	3.2%
Existing-Other Capacity	3,618	1,563	-56.8%
Prospective Resources	66,092	65,094	-0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.7%	39.0%	4.3
Prospective Reserve Margin	44.6%	42.4%	-0.2
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,513	45,101	-3.0%
Demand Response: Available	1,954	2,018	3.3%
Net Internal Demand	44,559	43,083	-3.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	60,097	60,640	-0.8%
Tier 1 Planned Capacity	1,102	1,165	105.6%
Net Firm Capacity Transfers	-2,524	-815	-67.7%
Anticipated Resources	58,674	60,990	3.9%
Existing-Other Capacity	2,895	3,090	6.8%
Prospective Resources	61,569	64,081	4.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.7%	41.6%	9.9
Prospective Reserve Margin	38.2%	48.7%	10.5
Reference Margin Level	15.0%	15.0%	0.0

SPP			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	41,650	43,996	5.6%
Demand Response: Available	13	278	2006.1%
Net Internal Demand	41,637	43,718	5.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	71,131	61,173	-14.0%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-359	-498	-38.4%
Anticipated Resources	70,772	60,676	-14.3%
Existing-Other Capacity	0	0	-
Prospective Resources	70,496	60,630	-14.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	70.0%	38.8%	-31.2
Prospective Reserve Margin	69.3%	38.7%	-30.6
Reference Margin Level	16.0%	19.0%	3.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	66,436	70,451	6.0%
Demand Response: Available	3,302	4,868	47.4%
Net Internal Demand	63,134	65,583	3.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	85,478	92,387	8.1%
Tier 1 Planned Capacity	644	228	-64.6%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	86,142	92,635	7.5%
Existing-Other Capacity	0	0	-
Prospective Resources	86,710	93,203	7.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.4%	41.2%	4.8
Prospective Reserve Margin	37.3%	42.1%	4.8
Reference Margin Level	13.75%	13.75%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,901	11,961	0.5%
Demand Response: Available	0	0	-
Net Internal Demand	11,901	11,961	0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,144	13,694	4.2%
Tier 1 Planned Capacity	1,234	1511	22.5%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	14,378	15,205	5.8%
Existing-Other Capacity	0	0	-
Prospective Resources	14,378	15,205	5.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.8%	27.1%	6.3
Prospective Reserve Margin	20.8%	27.1%	6.3
Reference Margin Level	11.1%	13.7%	2.6

WECC-BC			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,395	11,651	2.2%
Demand Response: Available	0	0	-
Net Internal Demand	11,395	11,651	2.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,223	13,166	-0.4%
Tier 1 Planned Capacity	20	134	574.4%
Net Firm Capacity Transfers	0	110	-
Anticipated Resources	13,243	13,410	1.3%
Existing-Other Capacity	0	0	-
Prospective Resources	13,243	13,410	1.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	16.2%	15.1%	-1.1
Prospective Reserve Margin	16.2%	15.1%	-1.1
Reference Margin Level	11.1%	13.7%	2.6

WECC-CA/MX			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	38,978	38,328	-1.7%
Demand Response: Available	749	755	0.9%
Net Internal Demand	38,230	37,573	-1.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	55,287	56,405	2.0%
Tier 1 Planned Capacity	1,943	5400	177.9%
Net Firm Capacity Transfers	0	315	-
Anticipated Resources	57,231	62,120	8.5%
Existing-Other Capacity	0	0	-
Prospective Resources	57,326	62,136	8.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	49.7%	65.3%	15.6
Prospective Reserve Margin	50.0%	65.4%	15.4
Reference Margin Level	8.4%	11.0%	2.6

WECC-NW			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	58,605	57,408	-2.0%
Demand Response: Available	707	578	-18.3%
Net Internal Demand	57,898	56,829	-1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	76,477	77,389	1.2%
Tier 1 Planned Capacity	988	2188	121.4%
Net Firm Capacity Transfers	0	1,964	-
Anticipated Resources	77,465	81,541	5.3%
Existing-Other Capacity	0	0	-
Prospective Resources	77,730	81,558	4.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	33.8%	43.5%	9.7
Prospective Reserve Margin	34.3%	43.5%	9.2
Reference Margin Level	13.1%	17.4%	4.3

WECC-SW			
Demand, Resource, and Reserve Margins	**2022–2023 WRA**	**2023–2024 WRA**	**2022–2023 vs. 2023–2024**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	16,004	15,743	-1.6%
Demand Response: Available	318	285	-10.6%
Net Internal Demand	15,686	15,458	-1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	29,799	28,306	-5.0%
Tier 1 Planned Capacity	553	1129	104.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	30,352	29,435	-3.0%
Existing-Other Capacity	0	0	-
Prospective Resources	30,352	29,587	-2.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	93.5%	90.4%	-3.1
Prospective Reserve Margin	93.5%	91.4%	-2.1
Reference Margin Level	12.2%	16.4%	4.2

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. In many areas, winter demand peaks in the early morning hours or other times of darkness, resulting in little or no electrical resource output from solar PV resources. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS.

BPS Variable Energy Resources by Assessment Area									
	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind (MW)	Expected Wind (MW)	Expected Share of Nameplate (%)	Nameplate Solar PV (MW)	Expected Solar (MW)	Expected Share of Nameplate (%)	Nameplate Hydro (MW)	Expected Hydro (MW)	Expected Share of Nameplate (%)
MISO	26,082	9,683	37%	2,559	130	5%	4,884	4,688	96%
MRO-Manitoba Hydro	259	52	20%	0	0	0%	6,220	5,548	89%
MRO-SaskPower	615	124	20%	0	0	0%	851	797	94%
NPCC-Maritimes	1,207	261	22%	42	0	0%	1,312	1,180	90%
NPCC-New England	1,463	397	27%	107	1	1%	3,565	2,472	69%
NPCC-New York	2,720	870	32%	154	13	9%	6,731	5,067	75%
NPCC-Ontario	4,943	1,433	29%	0	0	0%	8,985	5,185	58%
NPCC-Québec	3,820	1,375	36%	-	10	-	40,307	32,974	82%
PJM	11,992	3,695	31%	0	0	0%	3,027	3,027	100%
SERC-Central	28	8	28%	774	230	30%	4,967	3,315	67%
SERC-East	0	0	0%	6,245	1,483	24%	3,064	3,013	98%
SERC-Florida Peninsula	0	0	0%	3,499	1,264	36%	-	-	0%
SERC-Southeast	0	0	0%	5,234	1,889	36%	3,288	3,288	100%
SPP	33,120	6,856	21%	351	118	34%	5,465	4,996	91%
Texas RE-ERCOT	37,974	11,910	31%	16,403	2,547	16%	563	477	85%
WECC-AB	4,931	2,221	45%	0	0	0%	894	416	47%
WECC-BC	747	111	15%	0	0	0%	16,519	10,124	61%
WECC-CA/MX	9,443	848	9%	0	0	0%	13,957	4,606	33%
WECC-SW	3,121	994	32%	2,494	103	4%	1,202	844	70%
WECC-NW	20,697	6,319	31%	0	0	0%	41,860	22,752	54%
EASTERN INTERCONNECTION	120,404	35,318	29%	26,673	7,676	29%	52,316	42,578	81%
QUÉBEC INTERCONNECTION	3,820	1,375	36%	-	10	-	40,307	32,974	82%
TEXAS INTERCONNECTION	37,974	11,910	31%	16,403	2,547	16%	563	477	85%
WECC INTERCONNECTION	38,940	10,494	27%	2,494	103	4%	74,432	38,742	52%
INTERCONNECTION TOTAL:	**201,137**	**59,098**	**29%**	**45,579**	**10,337**	**23%**	**167,618**	**114,771**	**68%**

Probabilistic Assessment

Regional Entities and assessment areas provided a resource adequacy risk assessment that was probability-based for the winter season. Results are summarized in the table below.[11] The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include loss of load expectation (LOLE), loss of load hours (LOLH), EUE, and the probabilities of EEA occurrence.

Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
MRO-Manitoba	Verification of NERC 2022 Probabilistic Assessment (2022 ProbA)	The annual probabilistic statistics for model year 2024 for the 2022 Probabilistic Assessment (ProbA) show: • Base Case: 29 MWh per year of EUE • Risk Scenario (10th percentile water flow conditions): 477 MWh per year of EUE An expected unserved energy in the 29 to 477 MWh range is a reasonable estimate for the winter 2023–2024 based on the 2022 NERC ProbA Base Case for the year 2024 given comparable loads and resources, and that water flow conditions are, as of late summer 2023, below average but still above the 10th percentile.
MRO-SaskPower	Probability-based capacity adequacy assessment	Results indicate that the expected number of hours with operating reserve deficiency for the 2023–2024 winter season is 0.31 hours. The estimated probability of having generation forced outages of 350 MW or greater in the winter season is 11.2%. A Risk of supply shortfall exists when generation forced outages at this level coincide with periods of high demand.
NPCC	NPCC conducted an all-hour probabilistic reliability assessment that consisted of a base case and severe case examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring. Preliminary results are included in this table. NPCC will publish final probabilistic assessment results in December. [12]	The assessment forecasts that the NPCC Regional Entity will have an adequate supply of electricity this winter and a low risk of disconnecting load. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Results of the probabilistic analysis by assessment area are below. The assessment evaluates the probabilistic indices of LOLE, LOLH and EUE.
NPCC-Maritimes		NPCC's assessment preliminary results indicate that operating procedures are sufficient to maintain a balance between electricity supply and demand, if needed. Only the low likelihood reduced resource case, highest peak load scenario resulted in an estimated cumulative LOLE risk of ~0.1 days/period, with associated LOLH (<1 hour/period) and EUE (10.6 MWh) over the November–March winter period. The Maritimes area low likelihood resource case assumed that wind capacity would be de-rated by half (1,200 to 600 MW) for every hour in December through February to simulate icing conditions and a 50% natural gas capacity curtailment (610 to 305 MW) to simulate a reduction in gas supply for December through February (dual fuel units assumed reverting to oil) and reduced transfer capabilities.

[11] A probabilistic assessment for the 2023-2024 winter is not available for SPP at the time of publication. SPP's 2023 Loss of Load Expectation (LOLE) Study incorporates modeling assumptions based on recent winter events. SPP expects to complete the study prior to the end of 2023. For more information see the study scope document here: **2023 LOLE Scope**

[12] Based on October 2023 revised results. The final NPCC 2023–2024 Winter Reliability Assessment be available in December 2023.

Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-New England		NPCC's assessment preliminary results indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the November–March winter period, for all the scenarios modeled. The New England Area low likelihood resource case assumed 500 MW of additional maintenance outages, ~4,817 MW of gas-fired generation unavailable due to fuel supply constraints, and 50% reduced import capabilities of external ties (i.e., 1,850 MW total). The NPCC Probabilistic Assessment did not evaluate a prolonged, extreme cold weather event that threatens to exhaust stored liquid fuels.
NPCC-New York		NPCC's assessment preliminary results indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the November–March winter period for all the scenarios modeled.
NPCC-Ontario		NPCC's assessment preliminary results indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the November–March winter period for all the scenarios modeled.
NPCC-Québec		NPCC's assessment preliminary results indicate that operating procedures are sufficient to maintain a balance between electricity supply and demand, if needed. Only the low likelihood reduced resource case, highest peak load scenario resulted in an estimated cumulative LOLE risk of ~0.1 days/period, with associated LOLH (<1 hour/period) and EUE (92.7 MWh) over the November–March winter period. The Québec Area low likelihood resource case assumed: 1,000 MW of generation reductions.
PJM	Based on 2022 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves. PJM forecasts a 40% installed reserve margin, well above the target of 27%. The RRS analyzed a wide range of load scenarios (low, regular and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages and ambient derations. The RRS report was also influenced by the extreme weather experienced in December of 2022. NERC assesses an elevated risk of energy shortfall for the upcoming winter due to the potential for a weather event on the scale of Winter Storm Elliott to cause similar generation outages from fuel and winterization issues.
SERC	Verification of NERC 2022 ProbA Results	The 2022 Base Case results indicated adequate resources for the SERC Regional Entity. The base case did not include high-outage conditions similar to those experienced during Winter Storm Elliott.
Texas RE-ERCOT	ERCOT Probabilistic Reserve Risk Model	There is a 11.6% probability that ERCOT will declare an EEA1 during the highest-risk hour ending at 8:00 am. The Probabilistic Reserve Risk Model, which performs Monte Carlo simulations, determines the probability that capacity available for operating reserves for a seasonal peak load day is at or below the various EEA risk thresholds.
WECC	The 2022 Western Assessment of Resource Adequacy provides the most recent probability-based resource adequacy risk assessment for Summer 2023 across WECC's areas.	The Western Interconnection is experiencing heightened reliability risks heading into Summer 2023 due to increased supply-side shortages and fuel constraints along with ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events. The installation of new resources for the summer and the availability of the imports, especially during wide-area heat events, affects resource adequacy for the U.S. assessment areas. The reliability and resource adequacy of the Western Interconnection depends on the ability to move power throughout the footprint.
WECC-AB		Alberta is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile. When wind output is below average, imports are likely to be needed to meet operating reserves for normal and above-normal peak demand.

Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-BC		BC is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile. When hydroelectric generation output is below average, imports are likely to be needed to meet operating reserves for normal and above-normal peak demand.
WECC-CA/MX		WECC-CA/MX is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile.
WECC-NW		WECC-NW is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile. In a scenario involving high thermal generation outages, low wind output, and low hydroelectric generation output, imports are likely to be needed to meet operating reserves for normal and above-normal peak demand.
WECC-SW		WECC-SW is expected to have sufficient resource availability to meet demand and cover reserves under a winter peak defined at the 90th percentile.

Errata

December 2023

- Updated On-Peak Reserve Margin graphics for NPCC-New York (page 18) and SERC-Florida Peninsula (page 25)
- Updated fuel mix chart for WECC-Alberta (Page 28)
- Updated Figure 5 to reflect NPCC-New York 2022-2023 Reference Margin Level and SERC-Florida Peninsula reserve margins (page 36)
- Updated capacity numbers provided by SERC-East, SERC-Florida Peninsula, and SERC-Southeast (pages 40–41)
- Revised percentage change numbers for SPP (page 41)
- Added footnote to reference SPP's probabilistic study (page 44)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-92:
WECC 2024 Western Assessment of Resource Adequacy Demand at Risk Analysis

WECC
Electric Reliability and Security for the West

Demand at Risk by Subregion

WECC's annual Western Assessment of Resource Adequacy (Western Assessment) examines resource-adequacy-related risks concerning the reliability of the Western Interconnection over the next 10 years. Through an energy-based probabilistic approach, WECC looks at the risks throughout the interconnection and five subregions (See Figure 1). This work is meant to help stakeholders target specific areas and topics for deeper evaluation and mitigation.

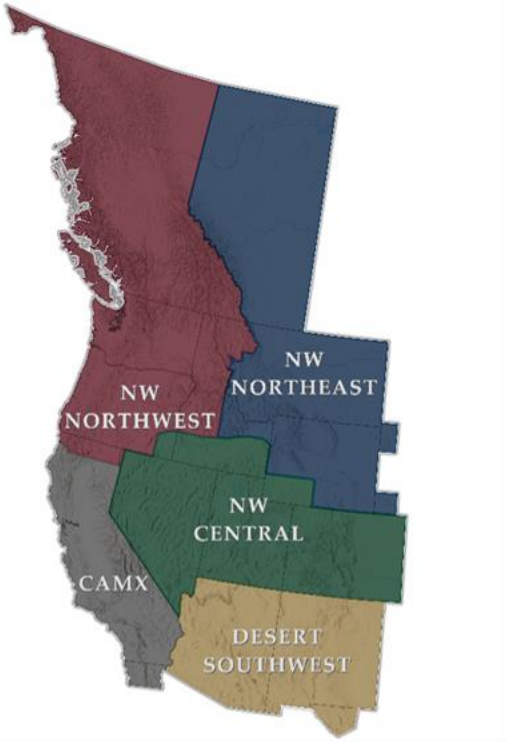


Figure 1: Map of the Western Interconnection with subregions

In the 2024 Western Assessment, WECC studied four resource addition scenarios. In the first scenario (All Additions), all planned resource additions come online in the year scheduled over the next 10 years. The remaining scenarios examine the effects on reliability if only 95%, 85%, and 55% of planned resource additions come online on schedule. This document provides noteworthy demand-at-risk takeaways within the subregions studied.

All Additions

There was demand at risk in one subregion, NW-Northwest, in the scenario in which all planned resource additions were made. A total of 89 demand-at-risk hours appeared in this scenario, with all but four of those hours occurring in the winter (See Figure 2). Most of the risk occurred in 2029 and later years, peaking at 26 hours in 2034.

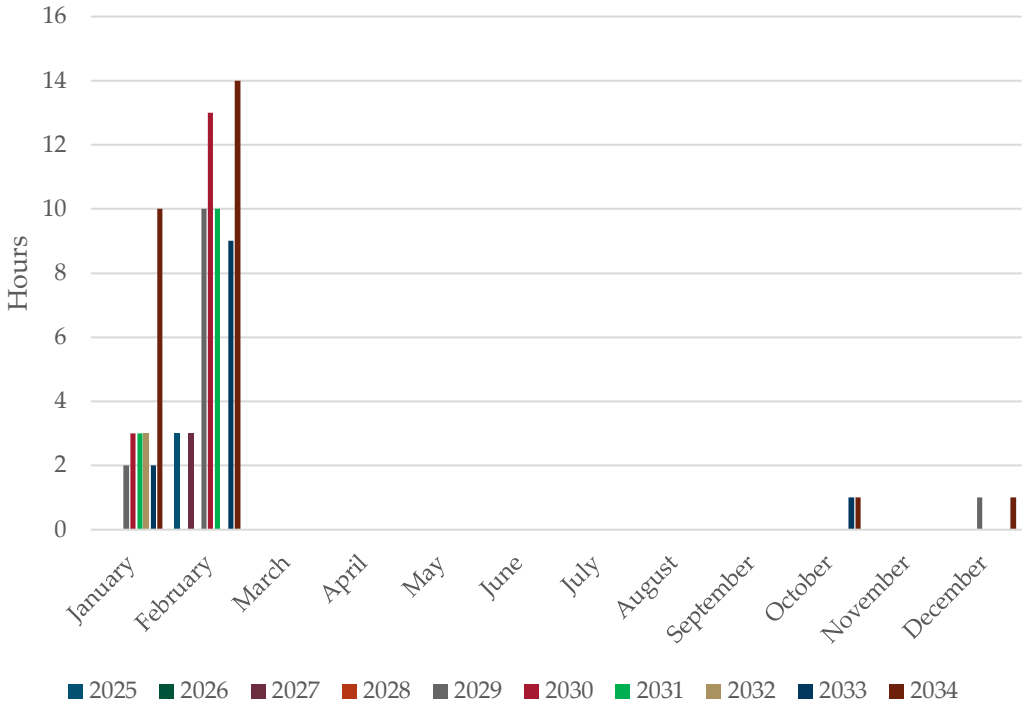


Figure 2: Demand-at-risk hours in the NW-Northwest subregion in the All-Additions scenario

95% Scenario

Demand at risk appeared in two subregions in this scenario: NW-Northwest and NW-Northeast. As in the 100% scenario, most of the demand at risk occurred in the winter months in the NW-Northwest (See Figure 3). In the NW-Northeast, all but four of the demand-at-risk hours occurred in August, beginning with one hour in 2027 and increasing to 51 hours in 2034 (See Figure 4).

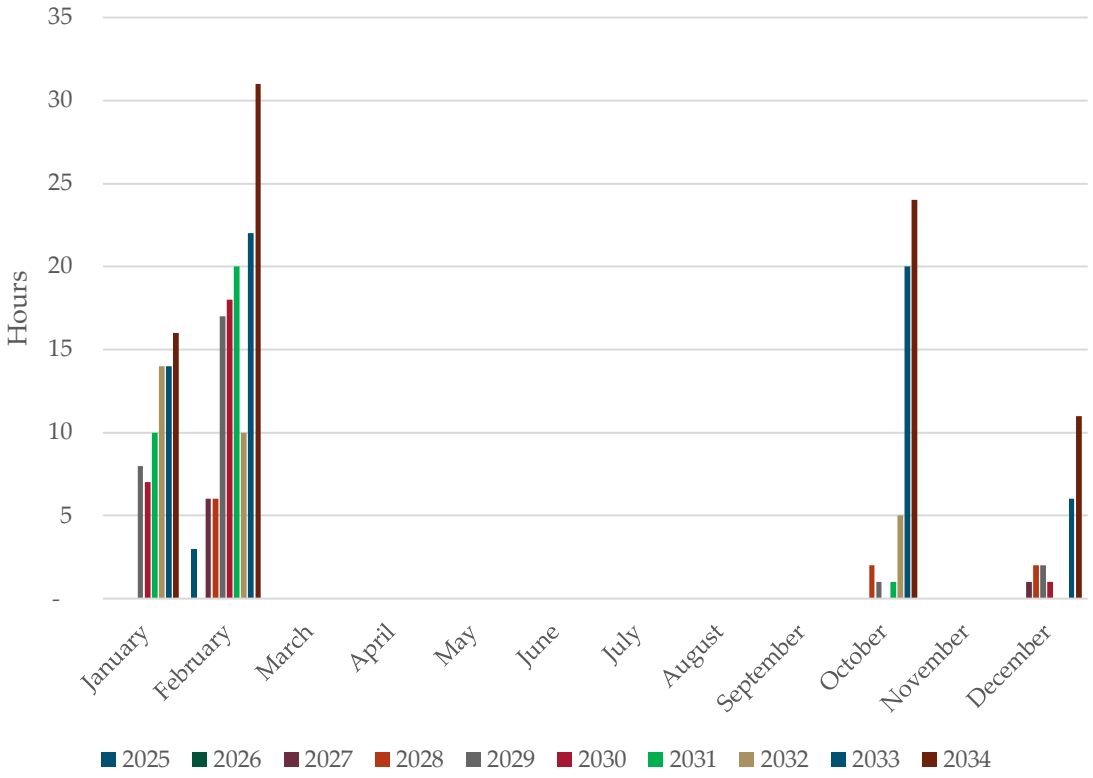


Figure 3: Demand-at-risk hours in the NW-Northwest subregion in the 95% scenario

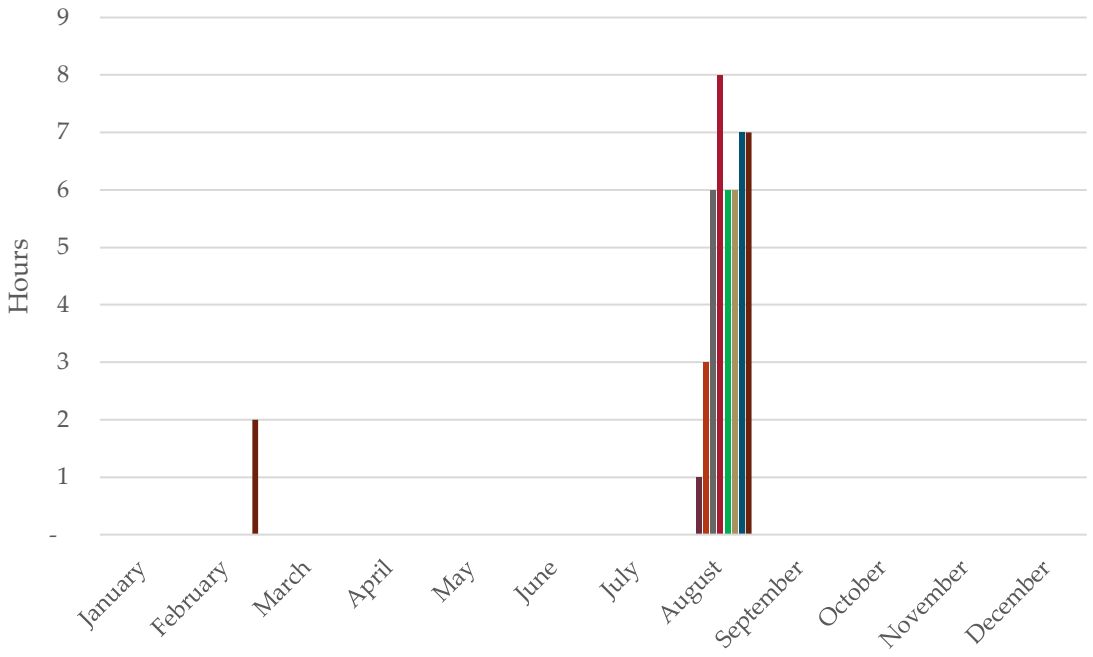


Figure 4: Demand-at-risk hours in the NW-Northeast subregion in the 95% scenario

85% Scenario

Demand at risk occurred in three subregions in this scenario: NW-Northwest, NW-Northeast, and NW-Central. Only one hour of demand at risk appeared in the NW-Northeast subregion (See Figure 6), in August 2034, while 94 hours appeared the NW-Central (See Figure 7), all between June and September and with almost half of that in 2034. In the NW-Northwest, 311 demand-at-risk hours appeared in this scenario, most of that in the winter (See Figure 5).

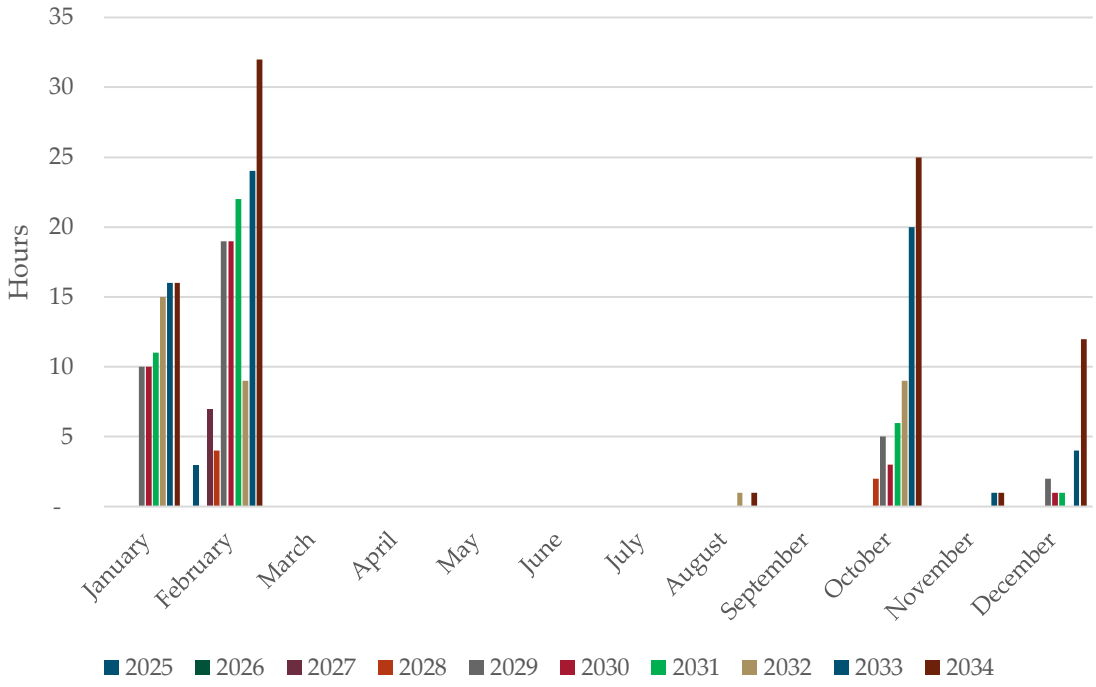


Figure 5: Demand-at-risk hours in the NW-Northwest subregion in the 85% scenario

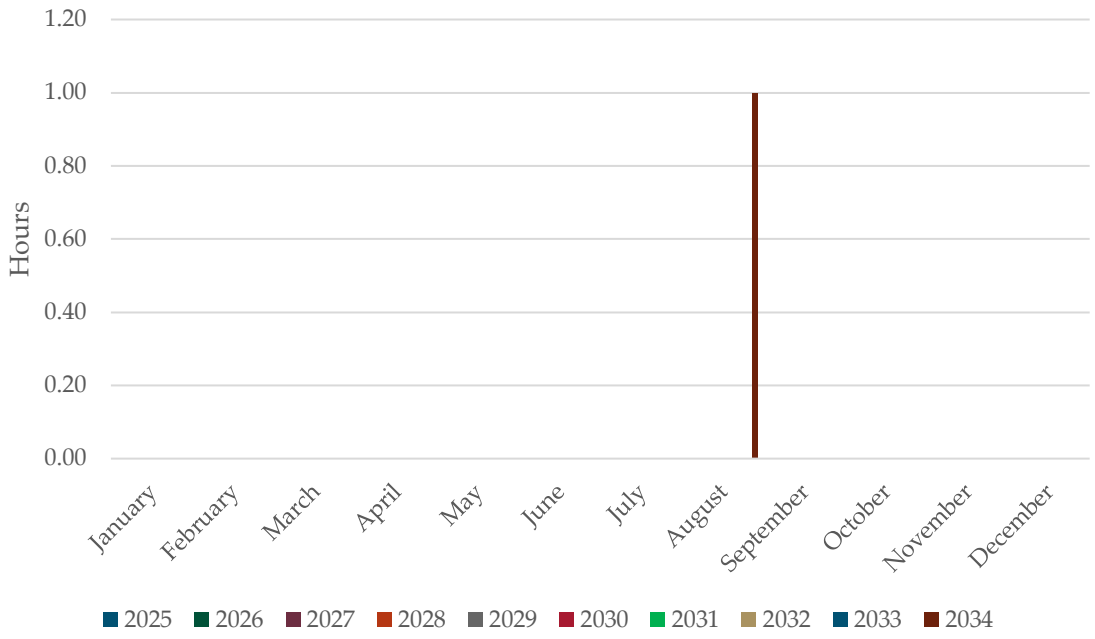


Figure 6: Demand-at-risk hours in the NW-Northeast subregion in the 85% scenario

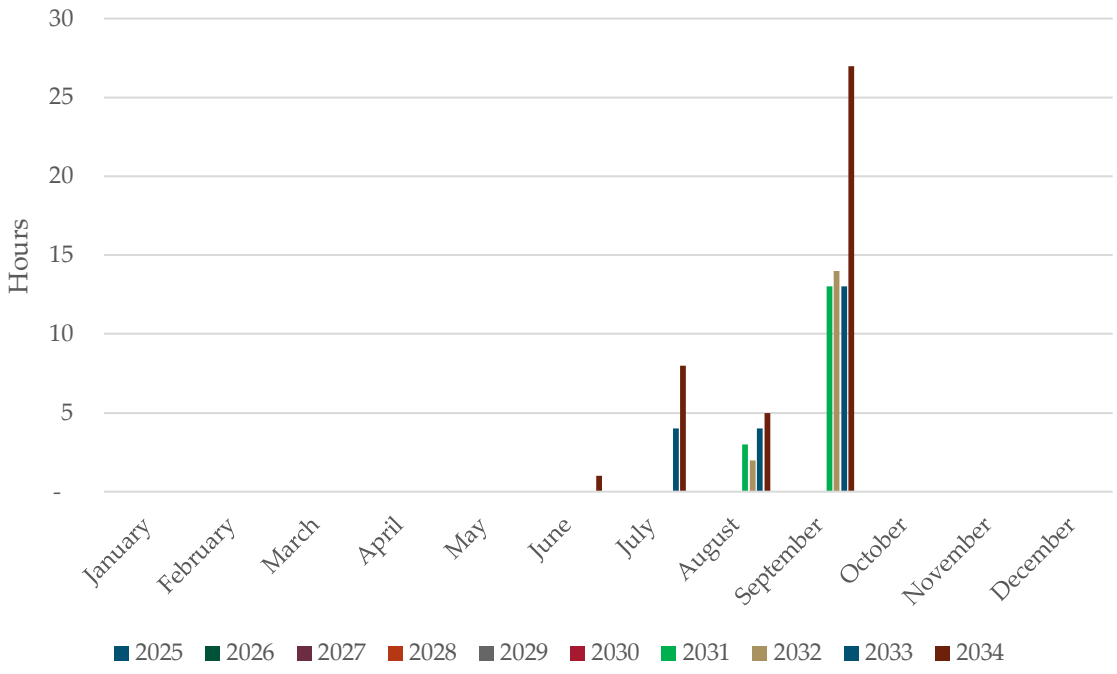


Figure 7: Demand-at-risk hours in the NW-Central subregion in the 85% scenario

55% Scenario

Demand at risk increased to four of the interconnection's five subregions in this scenario. Again, the most demand at risk occurred in the NW-Northwest in this scenario (See Figure 9), beginning in 2025 with eight hours and increasing to almost 800 hours in 2034. Most of the demand at risk in the other subregions occurred in the summer (See Figure 8, 10, and 11).

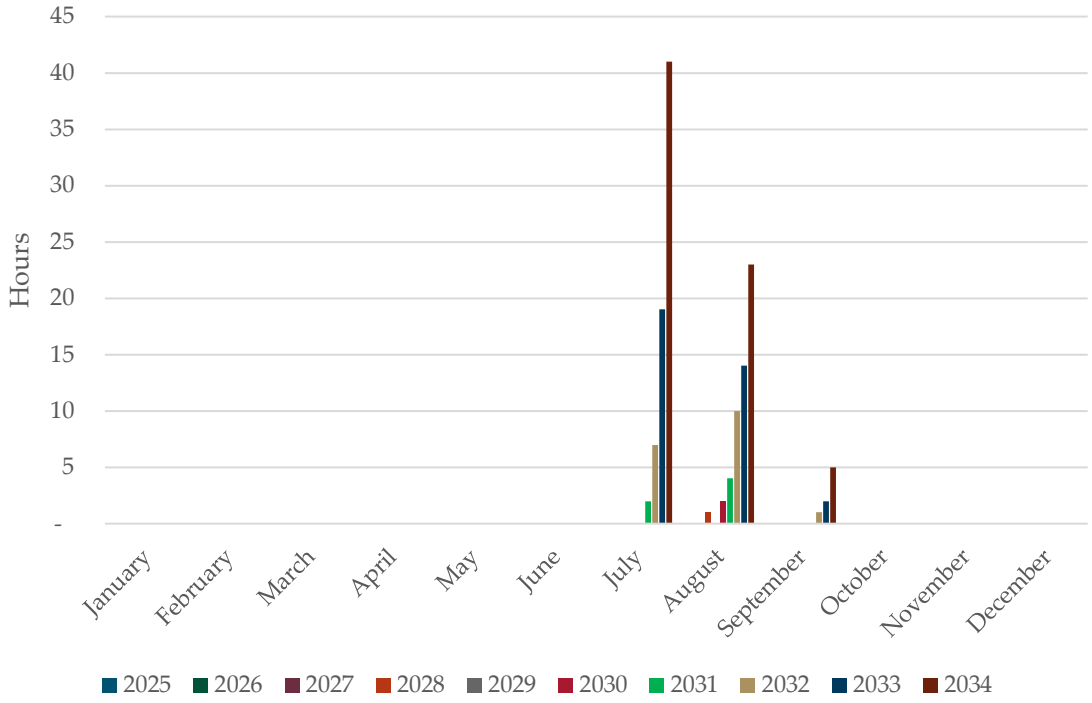


Figure 8: Demand-at-risk hours in the Desert Southwest subregion in the 55% scenario

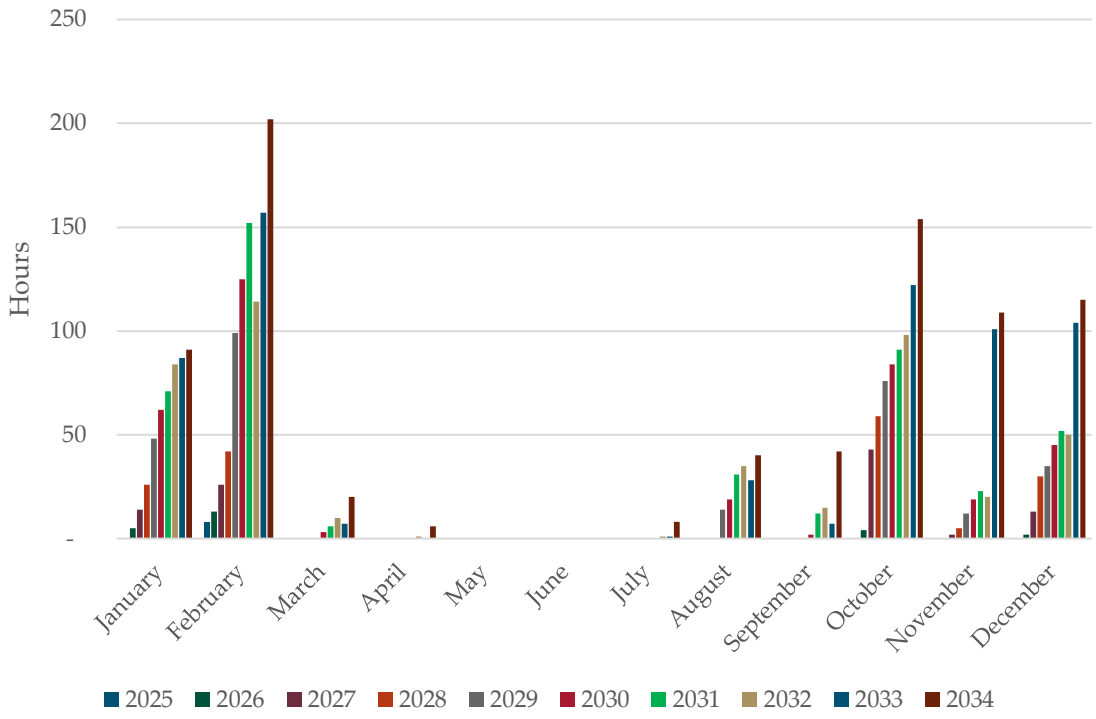


Figure 9: Demand-at-risk hours in the NW-Northwest subregion in the 55% scenario

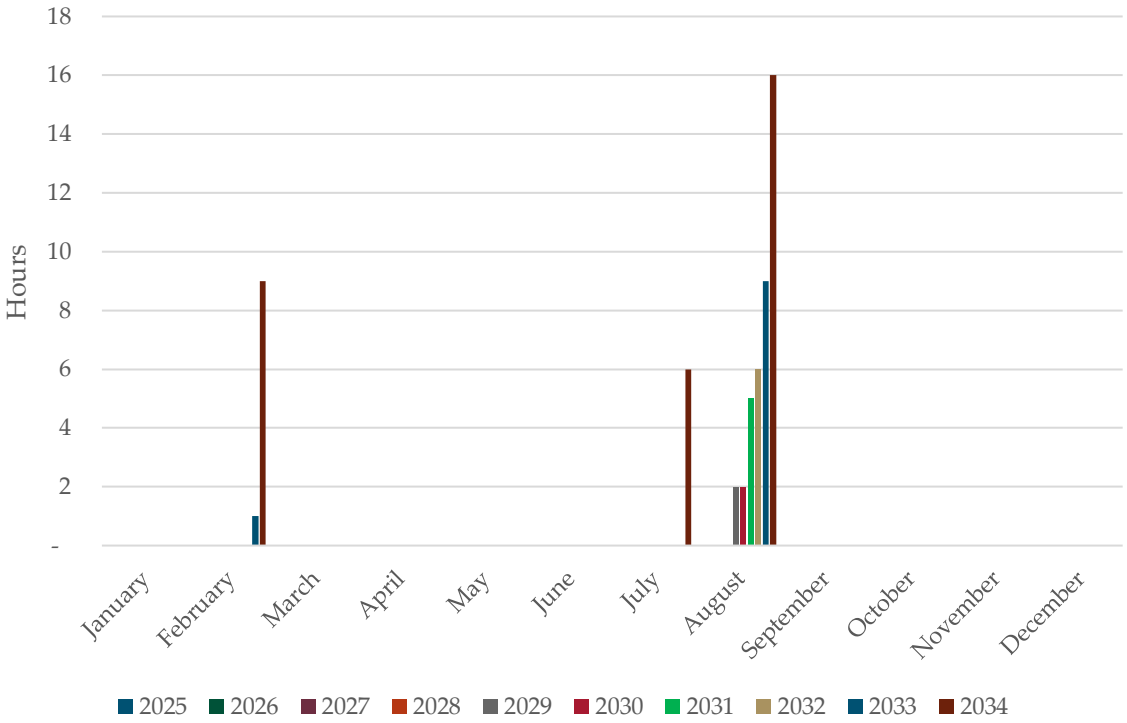


Figure 10: Demand-at-risk hours in the NW-Northeast subregion in the 55% scenario

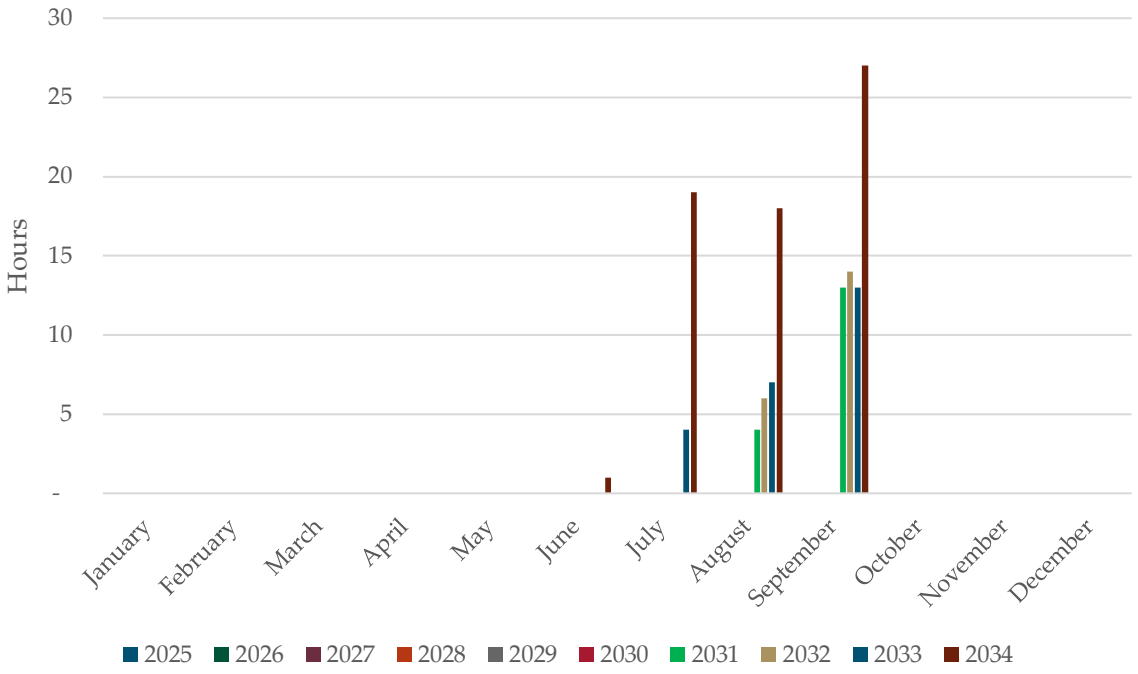


Figure 11: Demand-at-risk hours in the NW-Central subregion in the 55% scenario

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-93:
Bonneville Day-Ahead Market Policy

Bonneville Power Administration

Day-Ahead Market Policy

May 9, 2025

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1. Executive Summary

The Bonneville Power Administration's Day-Ahead Market Policy (Policy) contains the policy direction of the Administrator of the Bonneville Power Administration based on the extensive stakeholder process analyzing Bonneville's potential day-ahead market participation in the California Independent System Operator's (CAISO) Extended Day-Ahead Market (EDAM) or the Southwest Power Pool's (SPP) Markets+. Bonneville conducted its stakeholder process from July 2023 through May 2025. During this time, Bonneville was, and continues to be, an active participant in both CAISO and SPP's stakeholder processes. The purpose of the Day-Ahead Market Policy is to transparently inform stakeholders about the scope of subsequent actions towards market participation.

On March 6, 2025, Bonneville issued its Day-Ahead Market Draft Policy, which proposed Bonneville should participate in a day-ahead market and pursue participation in Markets+ due to its superior market design, independent governance structure, and inclusive stakeholder process. This was followed by a 30-day formal comment period, which resulted in 1,614 comments. This Policy provides background information, addresses issues raised during the comment period and memorializes Bonneville's final direction and provides initial guidance on next steps.

After careful consideration of public input on Bonneville's evaluation principles and key considerations, governance and stakeholder processes, resource adequacy and resource sufficiency, price formation and market power mitigation, transmission and congestion rent and greenhouse gas accounting, Bonneville will adopt the recommendations in the draft policy and pursue participation in a day-ahead market and specifically pursue participation in Markets+.

Bonneville will now shift its focus to joining Markets+ by initiating a formal process to implement Markets+ participation. Bonneville will address customers' and stakeholders' impacts in future proceedings such as its rate case and tariff terms and conditions proceedings, and if Bonneville ultimately joins the market as a participant, it will address impacts in these forums as well as transmission business practice updates and a Provider of Choice power sales contract day-ahead market amendment process. Bonneville will leverage the lessons learned from its Western Energy Imbalance Market (WEIM) decision process, ultimately making a decision to go-live after reevaluating it through the implementation process, including any changes to the structure of Markets+ or underlying facts since the earlier phase of Markets+ final policy.

2. Introduction

In July 2023, Bonneville began to engage the region in a public process to evaluate its potential participation in a day-ahead market. As one of the largest wholesale power and transmission providers in the Western Interconnection, Bonneville's decision regarding day-ahead market participation will play a critical role in the energy and capacity market landscape for the region.

2.1. Description of the Bonneville System

Bonneville is a federal power marketing administration under the United States (U.S.) Department of Energy, is self-funding, and covers its costs by selling its products and services. Bonneville makes power sales and provides transmission service within its statutorily defined service territory in the Pacific Northwest,[1] including Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah, and Wyoming. Bonneville markets about 32% of the wholesale electric power generated in the Pacific Northwest[2] from 31 federal hydroelectric dams, one non-federal nuclear plant, and several smaller non-federal generating resources.[3] See Figure 1 for a visual of hydroelectric resources. Bonneville also operates and maintains more than 15,000 circuit miles of high-voltage transmission in its service territory, which is used to deliver power to its customers and transmit power for third-party transmission customers.

Figure 1 | Transmission System and Federal Dams



Bonneville's statutory mission is threefold: (1) to provide an adequate, efficient, economical, and reliable power supply to its firm power customers in the Pacific Northwest; (2) to provide a transmission system that is adequate to the task of integrating and transmitting power from federal and non-federal resources, providing service to Bonneville's customers, providing interregional interconnections, and maintaining electrical reliability and stability; and (3) to mitigate the impacts on fish and wildlife from the federally owned hydroelectric projects from which Bonneville markets power.

[1] In this Policy, the "Pacific Northwest" or "region" has the meaning set forth in the Northwest Power Act, 16 U.S.C. § 839a(14).
[2] Bonneville Power Administration, BPA Facts (Sept. 2024), *available at* https://www.bpa.gov/about/newsroom/fact-sheets.
[3] *Id.*; *see also* Bonneville Power Administration, 2024 Pacific Northwest Loads and Resources Study (Aug. 2024) ("The White Book"), *available at* https://www.bpa.gov/-/media/Aep/power/white-book/2024-white-book.pdf.

2.2. Development of Day-Ahead Markets in the West

As background, the Bulk Electric System in the U.S. is managed in six different regions.[4] The Western Interconnection is the largest region encompassing 38 Balancing Authority Areas (BAAs)[5] that are individually responsible for ensuring the reliable operation of the electric grid.[6] The regulatory Regional Entity approved by the Federal Energy Regulatory Commission (FERC) for the Western Interconnection is the Western Electricity Coordinating Council (WECC). The North American Electric Reliability Corporation (NERC) delegated some of its authority to create, monitor, and enforce reliability standards to WECC through a Delegation Agreement.[7] WECC promotes bulk power system reliability and security.

Historically, entities within the Western Interconnection have managed and balanced electricity supply and demand through bilateral transactions across forward contracts of varying duration, day-ahead transactions, and real-time transactions. The CAISO BAA is an exception in its role as an Independent System Operator (ISO).[8] Outside of the Western Interconnection, most regions have transitioned from a bilateral framework into ISOs or Regional Transmission Organizations (RTOs).[9] RTOs and ISOs manage about 60% of the U.S. electric power supply[10] and expand market activities through the consolidation of many BAAs into one BAA. They each maintain a single Open Access Transmission Tariff with standardized terms and conditions for transmission service and centralized transmission planning.

One component of RTOs and ISOs is the inclusion of a centrally organized market. A centrally organized market is administered by a market operator, which is a clearinghouse for bids and offers from market participants. Market participants continue to transact bilaterally on a forward time horizon but allow the market to dispatch generation and serve load across the day-ahead and real-time time horizons.[11] All centralized markets use Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) accompanied by a nodal network model with Locational Marginal Pricing

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[4] For more information, see Federal Energy Regulatory Commission (FERC), Electric Power Markets, *available at* https://www.ferc.gov/electric-power-markets.

[5] A BAA is defined as "The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area." North American Electric Reliability Corp., Glossary of Terms used in NERC Reliability Standards at 5 (Jan. 7, 2025), *available at* https://www.nerc.com/pa/stand/glossary%20of%20terms/glossary_of_terms.pdf. In turn, a Balancing Authority is defined as "The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time." *Id.*

[6] BAAs are responsible for meeting North American Electric Reliability Corporation (NERC) reliability compliance standards (*see NERC*, *available at* https://www.nerc.com) and Western Electricity Coordinating Council (WECC) reliability compliance standards (*see* WECC, *available at* https://www.wecc.org).

[7] WECC, About WECC, *available at* https://www.wecc.org/about/about-wecc.

[8] FERC Order No. 888, 75 FERC ¶ 61,080, promoted the concept of ISO formation based on an earlier "power pool" concept. Several groups of transmission owners then formed ISOs, some from existing power pools Along with facilitating open access to transmission, ISOs operate the transmission system independently, and foster competition for electricity generation among wholesale market participants.

[9] In Order No. 2000, 89 FERC ¶ 61,285, FERC encouraged utilities to join regional transmission organizations (RTOs), which, like an ISO, would operate the transmission systems and develop innovative procedures to manage transmission equitably.

[10] U.S. Energy Information Administration, *About 60% of U.S. Electric Power Supply is Managed by RTOs* (Apr. 4, 2011), *available at* https://www.eia.gov/todayinenergy/detail.php?id=790#:~:text=Source:%20ISO/RTO%20Council,power%20marketers%20and%20energy%20traders.

[11] An RTO is an entity that is independent from all generation and power marketing interests and has exclusive responsibility for grid operations, short-term reliability, and transmission service within the region. Enerdynamics, Energy Knowledge Database, FERC Order 2000, *available at* https://energyknowledgebase.com/topics/ferc-order-2000.asp.

(LMP)[12] to create an "economic dispatch."[13] Section 1234 of the Energy Policy Act of 2005 defines "economic dispatch" as "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[14]

CAISO operated an organized day-ahead and real-time market solely within its BAA footprint comprising most of California until 2014. In 2014, CAISO expanded its real-time market by offering the Western Energy Imbalance Market (WEIM) as an option for other BAAs in the Western Interconnection to join.[15] Voluntarily on an hourly basis, participants offer resources for within-hour dispatch by the market to manage the difference in energy for load and resources between what was scheduled ahead of time and what materializes in real-time. The market operator uses SCED to meet the within-hour real-time energy imbalances with the most cost-effective generation offered to the market. Unit commitment is generally performed by the market participants, not by CAISO in this real-time market. WEIM balances fluctuations in supply and demand by dispatching lower cost resources and it manages congestion on transmission lines to maintain grid reliability and to support integrating new resources.[16]

WEIM now includes 21 BAA participants operating the majority of the Western Interconnection.[17] CAISO's overarching market governance is entrusted to the CAISO Board of Governors. The Board has delegated certain authority for the WEIM to the Western Energy Markets (WEM) Governing Body, subject to the Board's oversight, in a model referred to as Joint Authority.[18] The CAISO Board of Governors is appointed by the Governor of California with the consent of the California State Senate.

In 2021, SPP launched a second imbalance market offering in the Western Interconnection, the Western Energy Imbalance Service market (WEIS). The WEIS has 16 participants. SPP's independent board of directors provides ultimate oversight of the administration of the WEIS market. In its role as the market operator, SPP performs analysis to ensure each balancing authority (BA) and market participant in each BA's boundaries have enough generation in their operating plan to satisfy the load and obligations for that

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[12] *See* SPP Markets+ Tariff, Attach. A § 3.2, *available at* https://www.spp.org/Documents/71376/Markets%20Plus%20Tariff%20amended%2020240405_filed%20version%202.pdf ("The LMP at a Pnode is the cost of delivering an incremental MW of Energy at that specific Pnode, while satisfying all operational constraints where such cost will include applicable Demand Curve prices if the incremental MW of Energy would result in a corresponding increase in shortage conditions. The LMP at any Pnode is the sum of three components: the marginal costs of Energy (the MEC), the marginal cost of losses (the MLC), and the marginal cost of congestion (the MCC)"). LMPs are the commonly accepted means for settling resources and loads in all centrally organized markets in the U.S. For more thorough details on the history and development of LMPs and the various considerations of how they are used within organized markets, see Harvey Scott & William Hogan, *Locational Marginal Prices and Electricity Markets* (2022), *available at* https://whogan.scholars.harvard.edu/sites/g/files/omnuum4216/files/whogan/files/locational_marginal_prices_and_electricity_markets_hogan_and_harvey_paper_101722.pdf.

[13] *See* FERC, Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations: A Report to Congress Regarding the Recommendations of Regional Joint Boards for the Study of Economic Dispatch Pursuant to Section 223 of the Federal Power Act as Added by Section 1298 of the Energy Policy Act of 2005 (July 31, 2006), *available at* https://www.ferc.gov/sites/default/files/2020-05/final-cong-rpt.pdf.

[14] 42 U.S.C. § 16432.

[15] *See* CAISO, Western Energy Imbalance Market (WEIM) (2025), *available at* https://www.westerneim.com/Pages/About/default.aspx.

[16] *See* CAISO, How the Markets Work (2025), *available at* https://www.westerneim.com/Pages/About/HowItWorks.aspx.

[17] *See* CAISO, Western Energy Imbalance Market (WEIM) (2025). *available at* https://www.westerneim.com/Pages/About/default.aspx.

[18] *See* CAISO, Governance (2025), *available at* https://www.westerneim.com/Pages/Governance/default.aspx.

market participant and BA.[19] The WEIS accommodates a diverse set of resource types. This helps ensure the market operates as efficiently as possible and can take advantage of the capabilities of different resources.[20] As of 2022, WEIS balanced the demand for real-time energy and the power produced by more than 150 generating units in its multi-state footprint.[21]

Both CAISO and SPP have developed proposals to develop day-ahead markets that would manage a significant increase in the volume of transactions. CAISO began development of EDAM in 2019,[22] and SPP began development of Markets+ in 2022.[23,24] A day-ahead market is designed to optimize a participant's loads, resources, and transmission within the market footprint using a security constrained unit commitment and economic dispatch on a day-ahead basis with hourly granularity coupled with the underlying real-time market. In the real-time WEIM and WEIS markets, participants can submit voluntary bids for the next hour in sub-hourly (15-minute or five-minute) increments. In contrast, in a day-ahead market, participants can bid generation capacity and load for every hour in the day-ahead timeframe, which is then optimized by the unit commitments and economic dispatch accounting for constraints, including transmission availability and congestion. A day-ahead market continues to include a real-time market component, including voluntary submissions of any remaining real-time energy, much like the existing WEIM and WEIS.

Notably, CAISO and SPP employed different stakeholder participation models to develop the EDAM and Markets+ proposals. CAISO designed and authored the EDAM market offering, and Bonneville participated in stakeholder meetings, reviewed proposals, and provided written comments. CAISO ultimately determined which stakeholder suggestions to address and incorporate into the final EDAM design. Certain key issues that Bonneville raised were not fully addressed. In contrast, while SPP developed the initial conceptual framework for Markets+, stakeholder workgroups developed the Markets+ design elements to reflect the operational characteristics of the Western Interconnection. Bonneville participated in the committees, work groups, and task forces that developed Markets+ tariff language and business protocols. The collaborative design framework of Markets+ better addressed the many issues raised by Bonneville and other stakeholders.

2.3. Why is Bonneville Considering Joining a Day-Ahead Market?

Bonneville joined CAISO's WEIM in May 2022, eight years after its inception, after the market had grown into a large footprint and matured in its design elements. With FERC approval of two day-ahead market offerings, Bonneville expects day-ahead markets to gain a foothold, particularly with some states requiring utilities to transition to organized markets.[25] Based on its experience as a later entrant to the WEIM, Bonneville believes that early day-ahead market involvement will better meet its customer and stakeholder

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[19] *See* SPP, A Proposal for the Southwest Power Pool Western Energy Imbalance Service (WEIS) (2019)*, available at* https://www.spp.org/documents/60104/a%20proposal%20for%20spp's%20western%20energy%20imbalance%20service%20market.pdf.

[20] *See* SPP, Western Energy Imbalance Service Market (2025), *available at* https://www.spp.org/western-services/weis/.

[21] SPP, Annual Report 2022 at 4, *available at* https://spp.org/documents/70194/2022%20annual%20report%20-%209.26.23.pdf.

[22] *See* CAISO, Initiative: Extended day-ahead market, *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market.

[23] *See* SPP, Markets+, *available at* https://www.spp.org/western-services/marketsplus/.

[24] SPP is also developing RTO West in the Western Interconnection, with the corresponding tariff approved by FERC on March 20th, 2025. See *Southwest Power Pool, Inc., 190 FERC ¶61,169 (2025)*. RTO West is a separate offering from Markets+ and is not co-optimized with the Markets+ footprint.

[25] FERC Office of Public Participation, Western Energy Markets Explainer (Jan. 2025), *available at* https://www.ferc.gov/OPP/western-markets-explainer.

objectives because the first years of a market greatly influence development and maturation of the market design. The following are some categories of benefits that are associated with day-ahead market participation.

Continued Access to Trading Partners via a Liquid Market

Bonneville has observed a strong interest in day-ahead market development across the West, and many entities have already indicated their intent to pursue participation in the coming years. Today, Bonneville transacts bilaterally to ensure it meets its load service and operational obligations and to maximize the value of net-secondary revenue to keep rates low for customers. As entities joined the WEIM, Bonneville and others outside of the WEIM noticed reductions in the liquidity of the hourly bilateral market. Similarly, Bonneville expects that organized day-ahead market growth may result in reduced liquidity in both the day-ahead and real-time bilateral markets.[26] The expected result is fewer options for bilateral purchases of power or fewer counterparties to sell to, which could result in operational impacts and increased financial hurdles associated with these transactions. Participation in a day-ahead market will allow Bonneville continued access to a range of trading partners, without increasing hurdles and barriers to transact, so it can continue to carry out its objectives in the day-ahead and real-time horizons.

Optimization

An organized day-ahead market brings together a variety of resources and loads and enables an optimization to dispatch those resources to serve loads at the least cost. Both buyers and sellers can achieve economic benefit. Dispatched resources are compensated at their bid or higher for the energy they offered to supply. Resources that are not dispatched are given a concrete price signal to either conserve their resource for future periods of higher demand or offer a more competitive bid if they wish to be awarded. Loads can economically bid in day-ahead to indicate a price at which they are willing to purchase energy, and all loads are ultimately served in real-time through the least-cost economic dispatch. The optimization allows for a broader and more transparent exchange of pricing information. Compared to the bilaterial world of today, where there are numerous information asymmetries, a market optimization can provide participants, including Bonneville, with access to a more transparent picture of regional operations and tradeoffs, which aids both financial transactions and operational awareness.

In addition, joining a day-ahead market will give Bonneville better access to resources and loads across a broader footprint compared to bilateral markets. This allows for more flexible resources to respond to the needs of loads across that footprint. For resources with significant ramping capabilities, such as Bonneville's hydro resources, the more granular awards and dispatches of an organized market benefit both customers and the region more broadly.

Reliability

As a BA and a Transmission Operator (TOP), Bonneville is tasked with operating the electric grid in a reliable manner. Bonneville may utilize participation in an organized day-ahead market to reliably operate the grid. The market operator has a much wider view of transactional activity and grid operation compared to that of each individual BAA. Prior to real-time, the day-ahead market operator can forecast load needs and transmission constraints (i.e., areas on the transmission grid that may end up operating at their maximum transfer capacity based on expected system conditions), and award resources in a manner that honors those constraints in the day-ahead and real-time horizons. The market operator can also redispatch generation to reliably and most economically serve load (e.g., by supplying energy from a different resource

[26] *See* WECC, Reliability Implications of Expanding the EIM to Include Day-Ahead Market Services: A Qualitative Assessment (Sept. 2020), *available at* https://www.westernenergyboard.org/wp-content/uploads/WECC-report-reliability-implications-of-expanding-EIM-to-include-day-ahead-market-services.pdf.

that relieves a transmission constraint).[27] This ability of the market operator may reduce the likelihood and magnitude of transmission curtailments by Transmission Service Providers (TSP)/TOP.

Energy Resources

Bonneville has pledged to respond to customers' requests for integration of energy resources through the Evolving Grid initiative.[28] According to WECC's 2024 State of the Interconnection report, entities in the Western Interconnection plan to build close to 172 gigawatts (GW) of resources in the next 10 years. Addressing the changing resource mix and load shapes will be more successful through improved operation and coordination among many BAAs. An organized day-ahead market offers broader access to a larger portfolio of resources, which will enhance reliability because the market operator may dispatch resources within the broader market footprint.[29]

Timeliness

While many commenters have called for a delay in Bonneville's day-ahead market policy decision, for reasons including for additional time to comment, to allow EDAM governance to continue to develop, to conduct government-to-government consultation, and to conduct further economic analysis, Bonneville must declare a policy direction now. Strategically, Bonneville's timeline allows better coordination with other Bonneville efforts such as Provider of Choice, allows Bonneville an "early seat at the table" for participation in Markets+, places Bonneville on a similar timeline to other entities in the West who are joining day-ahead markets, and maintains two viable market options. In addition, it is necessary for Bonneville to provide clear expectations to its customers, sovereigns, and stakeholders now to mitigate uncertainty and to collaborate on next steps.

2.4. Day-Ahead Market Framework

A day-ahead market is a centrally organized financial and physical electricity market where participants submit hourly resource offers and bids for load. The market optimization combines all offers and bids to determine the least cost energy dispatch to serve load while recognizing physical system constraints. If the market optimization determines the offers and bids to be economical, the participant receives a financially binding award. The resource offers can be updated with the market operator to reflect operational changes, with the ultimate real-time dispatches of resources serving all load economically given physical system conditions. Market participants ultimately receive settlements from the market operator for all resources and loads cleared through the market.

The market operator uses a SCUC and SCED[30] accompanied by a nodal network model with locational marginal pricing to create an optimized dispatch plan.[31] "Unit commitment" determines the optimal

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[27] *See* Mareldi Ahumada-Paras, Michael Mastrandrea, and Michael Wara, Stanford Climate and Energy Policy Program, *Grid Regionalization in the West: Reliability Benefits from Increased Cooperation in Electricity Markets and Operations* (Aug. 2024), *available at* https://woodsinstitute.stanford.edu/system/files/publications/Woods_Grid_Regionalization_White_Paper_v05_WEB.pdf.

[28] *See* Declaring a National Energy Emergency, Exec. Order No. 14156, 90 Fed. Reg. 8433, 8434 (Jan. 20, 2025).

[29] *See* WECC, Reliability Implications of Expanding the EIM to Include Day-Ahead Market Services: A Qualitative Assessment (Sept. 2020) at 3, *available at* https://www.westernenergyboard.org/wp-content/uploads/WECC-report-reliability-implications-of-expanding-EIM-to-include-day-ahead-market-services.pdf.

[30] As a reminder, SCUC stands for security-constrained unit commitment and SCED stands for security-constrained economic dispatch.

[31] *See* FERC, Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations: A Report to Congress Regarding the Recommendations of Regional Joint Boards for the Study of Economic Dispatch Pursuant to Section 223 of the Federal Power Act as Added by Section 1298 of the Energy Policy Act of 2005, *available at* https://www.ferc.gov/sites/default/files/2020-05/final-cong-rpt.pdf.

combination of resources to bring online from those that are available for some or all of the operating day.[32] "Economic dispatch" determines the optimal output of all committed resources relative to bid-in or expected load and other resource output forecasts to minimize total cost to serve load.[33] To ensure that the unit commitment and economic dispatch are feasible, the optimization is "security-constrained," which means that the optimization must adhere to certain limits (known as "constraints") such as flow across transmission elements and maximum ramp rate of generators. For instance, if increasing the output of a generator that is otherwise economic to serve load would cause flow on a transmission element to exceed its limit, the optimization will instead increase the output of the next least-cost resource that does not cause the flow on that element to exceed its limit.

To incorporate these constraints into the optimization, the market operator has a full nodal network model showing the locations and relevant characteristics of all transmission elements and generation resources of a certain size as well as approximations to represent load across the area. The market operator receives updated constraint information in day-ahead and real-time data submittals from market participants and reliability entities. Transmission Operators and BAs update constraint information on the elements or system areas that have new or existing limitations. Resource Owners/Operators submit hourly offer information about the minimum and maximum amount of generation they are willing to sell and the associated price between those output levels, as well as resource limitations (e.g., ramp rate, minimum or maximum run time when committed, etc.).

For day-ahead optimization, the SCUC and SCED solve simultaneously across all 24 hours of the next operating day. For real-time optimization, the SCED solves for a set number of sub-hourly intervals for the applicable operating hour. In between the day-ahead optimization and the real-time optimization, the market operator runs additional SCUCs.[34] These intra-day SCUCs are used to ensure enough generation is online and available to serve expected load as input information changes, such as load forecast increases or an unexpected outage on a previously committed generation resource.

Finally, the market produces financial settlements for all energy traded and load ultimately served. Settlements are for all location-nodes for day-ahead and real-time resources generated and load demand, as well as other associated payments or charges. All centrally organized markets in the U.S. settle based on LMPs, which generally represent the incremental cost to serve another megawatt (MW) of load at a given location. LMPs are composed of the following pricing components: energy, losses, and congestion. In a day-ahead market framework, the award from the day-ahead solution is settled at the day-ahead LMP and is used as the financial reference point for settlement of energy in the real-time solution.

3. Public Process

In July 2023, Bonneville started its public process to evaluate day-ahead market participation including hosting 11 public workshops (see below for a list of workshops and their respective topics) to share and discuss potential benefits and risks. A high priority for Bonneville is ensuring that customers and stakeholders understand the day-ahead market proposals and have multiple opportunities to provide substantive feedback on the decision. Bonneville has accepted public comments and concerns and posted all the written comments on its day-ahead market process website.[35] Stakeholder comments have provided valuable information about concerns and issues and have had a direct impact on the decision process. Bonneville appreciates the robust engagement and the feedback it has received.

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[32] CAISO, Technical Bulleting 2009-06-05, Market Optimization Details § 2 (Nov. 19, 2009), *available at* https://www.caiso.com/Documents/TechnicalBulletin-MarketOptimizationDetails.pdf.
[33] *Id.* § 3.
[34] Referred to as "Reliability Unit Commitment" in Markets+ and "Residual Unit Commitment" in EDAM.
[35] Bonneville Power Administration, Day-Ahead Market, *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.

Additionally, Bonneville coordinated with customers in the Provider of Choice public process to design power products that will be compatible with a day-ahead market for October 1, 2028 through September 30, 2044 contract period.[36]

Topics covered in the public workshops include:

No.	Meeting Date	Topics
1	July 14, 2023	• Why are we exploring day-ahead market participation? • Overview of public engagement for establishing a Bonneville policy direction on potential day-ahead market participation • Discussion on drafting Bonneville day-ahead market evaluation principles • Overview of day-ahead markets
2	September 11, 2023	• Update on day-ahead market development & update on developing GHG accounting in a day-ahead market • Bonneville will continue to supply electric power to customers in a day-ahead market • Draft day-ahead market evaluation principles • Review of comments received • Section 5(b) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act)[37] (Section 5(b))/day-ahead market compatibility • Tabletop scenario work with the Public Power Council
3	October 23, 2023	• Energy and Environmental Economics (E3) overview of Western Market Exploratory Group (WMEG) cost/benefit study • Initial takeaways from WMEG Result • Considerations for Bonneville's day-ahead market business case analysis
4	November 29, 2023	• Discussion of Section 5(b) obligations/day-ahead market compatibility • Review of Bonneville's policy direction public process • Considerations for Bonneville's day-ahead market business case • GHG Update and consideration of GHG business case
5	February 1, 2024	• Update on Bonneville's decision process and timeline for CY 2024 • Review of Bonneville's day-ahead market evaluation and decision criteria • Update on Bonneville's day-ahead market public comment tracking • Responses to public comments at this workshop
5.5	May 3, 2024	• Tabletop scenario refresh (from workshop 2) • Workshop 6 scenarios
6	May 8, 2024	• Review of Bonneville's Staff Recommendation on Day-Ahead Market Participation; update on decision process and timeline for CY 2024 • Baseline process and scenario discussions

[36] *See* Bonneville Power Administration, Provider of Choice (Post-2028), *available at* https://www.bpa.gov/energy-and-services/power/provider-of-choice.
[37] 16 U.S.C. § 839c(b).

7	June 3, 2024	• Review of Bonneville's comments on Pathways April 10 proposal and legal analysis • High-level congestion rent scenario • Congestion rent design • Congestion revenue scenario with congestion rights
8	July 18, 2024	• Update on the Pathways initiative • Day-ahead market from the transmission perspective
9	November 4, 2024	• Timeline update and key dates for CY 2025 • Update on Markets+ FERC filing and EDAM engagement • Transmission update • Bonneville's continued decision process • Evaluation of market governance developments • Bonneville's supplemental production-cost analysis/result interpretation
10	January 29 & 30, 2025	• Review of Bonneville's day-ahead market decision process • E3 Case Result – Hydro Operational Limitations Scenario • Expected transmission revenue impact • Day-ahead market participation & implementation fees • Day-ahead market seams, reliability and operational impacts
11	March 19, 2025	• Opportunity to ask clarifying questions of the draft policy

Based on stakeholder feedback, Bonneville also considered potential day-ahead market participation through the lenses of firmness of power supply and certainty of delivery. This Policy addresses firmness of power supply in section 6.2, focusing on ensuring adequate supply through resource planning. Certainty of delivery is addressed in section 6.7, which describes how a day-ahead market paradigm would build upon existing constructs. Section 5.2.5 on GHG accounting addresses how market designs can provide for transparent accounting of environmental attributes.

4. Day-Ahead Market Evaluation Process

Bonneville has been evaluating potential day-ahead market participation based on eight evaluation principles. This section provides further detail for each evaluation principle.

4.1. Discussion of Evaluation Principles

While potential benefits, like those listed in section 2.3, are an important part of Bonneville's evaluation, there are additional considerations for Bonneville to weigh in its evaluation. In its decision process, Bonneville is assessing the business case for day-ahead market participation based on both quantitative and qualitative evaluation components. Bonneville assessed day-ahead market participation based on the following evaluation principles. These principles were shared with stakeholders in public workshops and include revisions based on stakeholder feedback:

- Statutes – Bonneville meets its statutory, regulatory, and contractual obligations.
- Reliability – Bonneville maintains efficient, economical, and reliable delivery of power and transmission service to its customers.
- Reliability – Market design includes resource sufficiency and/or resource adequacy frameworks that ensure reliability.
- Business – Bonneville's participation is supported by a sound business rationale.

- Strategy – Bonneville's participation is consistent with Bonneville's 2024-2028 Strategic Plan.
- Governance – The market has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders. Decision-making and stakeholder engagement occur in a transparent and inclusive manner.
- Customers – Bonneville's evaluation of day-ahead market participation includes transparent consideration of the commercial and operational impacts on its products and services.
- GHG – Bonneville will evaluate how participation will impact GHG emissions attributed to the federal system and its regional firm power customers' ability to comply with applicable state carbon programs. Participation must maintain the value of the low-carbon nature of the federal system to the extent possible.

The sections below highlight how a day-ahead market meets our evaluation principles.

4.1.1. Statutes – Bonneville meets its statutory, regulatory, and contractual obligations.

Bonneville has not identified any legal barriers to day-ahead market participation. See Appendix A for a discussion of Bonneville's statutory authority to participate in Markets+.

4.1.2. Reliability – Bonneville maintains efficient, economical and reliable delivery of power and transmission service to its customers.

Maintaining the reliability of the power and transmission systems for all of Bonneville's customers is one of the most important aspects of Bonneville's various roles. Indeed, reliability is foundational to accomplishing many of the other principles, objectives, and goals upon which Bonneville focuses.

Day-ahead markets and market operators do not assume any of the reliability roles of a utility. Bonneville will retain its reliability roles, such as Transmission Planner, BA, and TOP, and remain responsible for compliance with applicable NERC reliability standards. Further, Bonneville and its federal generating partners maintain full control of federal resources, including authority to manage output and make energy available to the market. Thus, Bonneville will continue to serve its direct role in operation of the federal power and transmission systems and maintaining system reliability.

As described in Section 2.3, participating in a day-ahead market will provide Bonneville opportunities to support or improve reliability due to system optimization and geographic diversity benefits. As Bonneville moves into a day-ahead market implementation phase, Bonneville will continue to assess any potential reliability concerns, identify and design necessary mitigations, and work with the market operators to ensure the markets are able to support those mitigations where necessary.

4.1.3. Reliability - Market design includes resource sufficiency and/or resource adequacy frameworks that ensure reliability.

Bonneville believes that it is important for a day-ahead market to address long-term Resource Adequacy (RA) as well as short-term resource sufficiency. Resource sufficiency generally refers to resources' availability to produce power (energy and capacity) to serve the expected load in the short term (e.g., moving into the next week, day or hour). RA generally refers to long-term planning and acquisition of resources, if needed, to serve the expected peak or critical load in a season or upcoming year. RA aims to have enough "steel in the ground" (resources built and accessible) to serve a forecasted peak load, while resource sufficiency considers the current operational landscape (e.g., outages or derates, up-to-date variable generation and load forecasts, etc.). The two concepts work in concert to minimize scarcity, emergency, or loss-of-load events.

In a day-ahead market, market participants continue to be responsible for their own RA and sufficiency, and thus they are obligated to bring a resource portfolio (including power purchases) able to meet their

expected load to the market; the market is then able to optimize the dispatch of resources, along with any independently-offered resources, creating a more efficient and economical load service plan reflecting the current system landscape. Market design frameworks try to ensure that market participants are held accountable for this responsibility to receive the shared benefits of an integrated market through penalties or limitations on market access.

Both day-ahead market options include an evaluation for resource sufficiency. EDAM has a set of resource sufficiency evaluation tests and Markets+ has a must-offer obligation, both of which compare an entity's day-ahead load and uncertainty requirements to its available resources to ensure they have sufficient resources to meet their loads or are held accountable. However, as explained further in section 5.2.2, Bonneville prefers the design in Markets+, primarily because it also includes a long-term RA requirement. Markets+ includes a standardized RA requirement, requiring all load responsible entities (LREs)[38] to participate in the Western Resource Adequacy Program (WRAP) administered by the Western Power Pool. While the CAISO BAA has its own RA framework, this framework is not extended to other entities outside of CAISO's BAA in general, and the EDAM design does not include a requirement for entities to participate in any RA program. Bonneville believes that Markets+ requiring participation in WRAP, a standardized RA framework, will better meet this principle.

4.1.4. Business - Bonneville's participation is supported by a sound business rationale.

With the emergence of day-ahead market offerings by both CAISO and SPP, most entities in the Western Interconnection are evaluating participation in an organized day-ahead market. While economic value is an important factor, a decision about day-ahead market participation encompasses many considerations beyond just economic value.

Production Cost Modeling (PCM) provides an initial analysis of various simulations. Bonneville joined WMEG and contracted with E3 to explore the economic possibilities. In Section 5.1 Bonneville describes the benefits and limitations of the PCM studies. However, for the evaluation of a day-ahead market, a sound business rationale must encompass factors beyond the short-term economic results. The long-term industry trends must also be considered. These trends could include more entities joining day-ahead markets, new variable energy resources integrating into the system which causes power purchase changes, and the potential development of an RTO. Joining a day-ahead market allows Bonneville to continue to align with the majority of the industry on the business of power markets.

4.1.5. Strategy - Bonneville's participation is consistent with Bonneville's Strategic Plan.

The "Evolving Grid" sets the agency's path for the Pacific Northwest, including the use of Bonneville's transmission system. Through the evolution, Bonneville will maximize the value of the federal hydropower and transmission systems. As the needs of its customers evolve, so must the products and services it offers. Bonneville must address customer demand for more renewable generation and amplifying RA concerns brought about by a changing resource mix. An objective in meeting this goal is fostering market evolution to enhance the delivery of cost-effective, reliable power and transmission service while modernizing business systems and processes. The flexible and reliable power of the Federal Columbia River Power System (FCRPS), coupled with the expansive high-voltage transmission grid, is the bedrock Bonneville will build on to meet these future needs.

4.1.6. Governance – The market has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders. Decision-making and stakeholder engagement occurs in a transparent and inclusive manner.

Bonneville performed a rigorous assessment of day-ahead market offerings from a governance perspective because insufficient independence and limitations on stakeholder engagement pose risks to creating a fair

[38] A Load Responsible Entity (LRE) is an entity directly responsible for ensuring an electrical load is served.

and equitable market that brings equitable value to all participants. Risks arise from market governance that retains authority for a single state, entity, or customer class.

At the highest level, the decision-making body for the market must be free of disproportionate obligation to the policies of a single state, entity, or customer class to ensure that market design is on an equal footing for all participants, including Bonneville. In CAISO markets, Bonneville has observed disadvantages for market participants outside of California during market design development and in times of outlier events.[39] The staffing and process for decision development and stakeholder engagement should equitably weigh the policies or priorities of all states, entities, and customer classes. Bonneville finds that the governance structure for Markets+ meets that standard.

As it engaged in the stakeholder processes for the development of both markets, Bonneville strongly advocated for the inclusion of sound independent governance principles in market design. Bonneville believes its efforts have positively impacted the governance structures of both EDAM and Markets+.

4.1.7. Customers - Bonneville's evaluation of day-ahead market participation includes transparent consideration of the commercial and operational impacts on its products and services.

Bonneville has conscientiously considered the needs of its large customer base as it evaluated joining a day-ahead market, including public customer/stakeholder workshops[40] exploring how a decision to participate in day-ahead markets may impact different customer types and how its various power and transmission products and services may work in a day-ahead market. Bonneville also collaborated with customers to design a long-term power sales contract[41] that includes provisions to adapt to potential day-ahead markets to ensure the flexibility to meet a changing landscape. Further, in the public processes for EDAM and Markets+ development, Bonneville advocated for policies and designs to unlock additional value from the federal hydropower and transmission systems that benefit Bonneville and its customers.

Bonneville expects to continue holding day-ahead market public workshops. It will also work through various day-ahead market specifics in its rate cases and tariff terms and conditions proceedings, contract negotiations, business practice change forums, etc., as appropriate. Throughout these various processes, Bonneville will continue to comprehensively address the impacts of day-ahead market participation on the products and services it offers to customers.

4.1.8. GHG - Bonneville will evaluate how participation will impact GHG emissions attributed to the federal system and our regional firm power customers' ability to comply with applicable state carbon programs. Participation must maintain the value of the low-carbon nature of the federal system to the extent possible.

Bonneville is not subject to any state GHG programs in the region. However, Bonneville customers have repeatedly expressed the importance of the low-carbon attributes of their power purchases from Bonneville.[42] Bonneville markets power from the federal hydropower system, Columbia Generating station,

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[39] Examples include wheel through priorities in August 2020 and greenhouse gas allocation market design.

[40] Bonneville Power Administration, Day-Ahead Market, *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.

[41] Bonneville Power Administration, Provider of Choice (Post-2028), *available at* https://www.bpa.gov/energy-and-services/power/provider-of-choice.

[42] Examples of customer comments related to GHG emissions can be found in Bonneville's Final Energy Imbalance Market Close-Out Letter § 5.2.3 (Sept. 2021), *available at* https://www.bpa.gov/-/media/Aep/projects/energy-imbalance-market/final-eim-close-out-letter.pdf (full comments available at https://publiccomments.bpa.gov/CommentList.aspx?ID=421); Bonneville's Provider of Choice Policy Record of Decision § 8 (Mar. 2024), *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/2024-rod/rod-20240321-bonneville-power-administration-provider-of-choice.pdf (full comments available

and other resource acquisitions and market purchases. Today, market purchases are the only resources in the federal system to which state programs attribute emissions. These purchases are an important component of Bonneville's power supply and have historically comprised 3 to 10% of the FCRPS.

Organized markets change GHG accounting dynamics because, absent a GHG accounting design, the market does not specify which resources are dispatched to meet a particular load. For example, when Bonneville joined the EIM in May 2022, the volume of unspecified purchases included in Bonneville's federal system fuel mix slightly increased. This was due to increased transfers of energy to meet load imbalance between Bonneville's BAA and other BAAs, which states accounted for at an unspecified emission factor. Currently, WEIM only employs a GHG accounting mechanism to support implementation of California's cap-and-trade program.

Both EDAM and Markets+ developed mechanisms to support the implementation of carbon pricing programs generally including California's program and Washington's cap-and-invest program. Over 60% of Bonneville's long-term power sales are to customers in Washington and are subject to the state's cap-and-invest program as well as the state's Clean Energy Transformation Act. Bonneville also has customers in Oregon that are subject to Oregon's GHG reporting requirements. Bonneville has participated in day-ahead market GHG accounting conversations mindful of impacts to customers in those states with the goal of ensuring customers can continue to claim low-carbon attributes associated with power purchases from Bonneville. As discussed in section 5.2.5, Bonneville believes the Markets+ design better reflects environmental attributes related to its firm power sales to its customers.

5. Day-Ahead Market Participation Evaluation

Bonneville has spent over two years evaluating whether to join a day-ahead market, and if so, which of the two available day-ahead markets options Bonneville should join. With the principles described in Section 4 in mind, Bonneville has considered quantitative analyses, market design elements, footprint, and other relevant information in its evaluation. On the whole, Bonneville finds that joining a day-ahead market will result in benefits to its customers.

Bonneville contracted with E3 to analyze economic costs and benefits using PCM. The initial PCM results depicted a wide range of economic benefits for day-ahead market participation. Bonneville's assessment is that the forecasted benefits justify participation in either EDAM or Markets+. Subsequent sections of this document further discuss the initial PCM results as well as supplemental analysis Bonneville contracted for with E3.[43] These results should not be viewed with the expectation of achieving specific forecasted revenues. The PCM results are forecasts that can be influenced by other factors that may alter the projected outcome. For example, modifications to market design items such as Congestion Rent, Scarcity Pricing, or LMP computation can impact benefits. PCM models also do not account for qualitative elements such as differences in market governance structure that can also produce quantitative impacts.

Overall, the PCM results showed:

- Participation in the EDAM market produces the highest net cost benefit in the cases studied.
- Markets+ offers the lowest cost to serve load but also forecasts reduced generation revenue.

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at https://publiccomments.bpa.gov/CommentList.aspx?ID=480); and in customer comments received to-date in Bonneville's Day-Ahead Market process (comments available at https://www.bpa.gov/learn-and-participate/projects/day-ahead-market).

[43] Energy and Environmental Economics, WMEG Cost Benefit Study (CBS), BPA Day-Ahead Market Participation Workshop presentation (Oct. 23, 2023), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/e3-wmeg-benefits-study.pdf; Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation (Nov. 4, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/E3Presentation-bpa-stakeholder-meetingnov4-2024.pdf.

- Although the net cost looks favorable, remaining a WEIM-only participant carries significant risk not easily reflected in the quantitative case result.

As mentioned in section 4, one of the eight evaluation principles is governance. Bonneville is specifically looking for a market that has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders. Bonneville's evaluation considers the relevant factors associated with governance structures under both Markets+ and EDAM to identify the best governance structure available for Bonneville's decision regarding day-ahead market participation. RA and resource sufficiency are included in the reliability evaluation principle in market design. RA aims to have enough physical resources (both transmission and generation) to serve a forecasted peak load well into the future (often years or multiple months), while resource sufficiency considers the current operational landscape (outages or derates, up-to-date variable generation and load forecasts, etc.).

Price formation and market power mitigation ensures that market rules provide appropriate price signals, which compensate resources at prices that reflect both the value of the services that resources provide to the market and the operational conditions under which the resource is awarded. EDAM and Markets+ are broadly similar in the way they model constraints and manage transmission, with some key differences, particularly regarding allocation of congestion rents, which are described in section 5.2.4. The market design for GHG accounting—how resources and their associated emissions are assigned to market participants—is critical to ensuring Bonneville's customers can continue to claim the low-carbon attributes of their federal system power purchases for applicable state programs or for their own utility purposes.

This section discusses the economic and market design benefits associated with Bonneville's Policy direction to participate in Markets+ with emphasis on governance, RA and resource sufficiency, price formation and market power mitigation, transmission and congestion rent, and GHG.

5.1. Economic Costs/Benefits Analyses

As part of its day-ahead market evaluation, Bonneville assessed costs and benefits using PCM. PCM is an industry-standard approach for analyzing costs and revenues associated with energy trading and load service. PCM is explained below in section 5.1.1.1.

Many entities in the Western Interconnection, including Bonneville, employ PCM in their evaluations of day-ahead markets, in integrated resource planning, and when assessing long-term transmission expansion costs. Bonneville also included consideration of the economic impact to its Power and Transmission business lines, reflecting both the PCM results and additional considerations. Further, Bonneville has considered the implementation costs (both internal to the agency and those paid to the market operator) as well as on-going participation fees associated with the day-ahead market options. These analyses and considerations are discussed in this section.

5.1.1. Production Cost Modeling

Bonneville was part of two separate cost-benefit analyses using PCM as part of its day-ahead market evaluation. Bonneville joined the WMEG in the summer of 2022. WMEG is a group of 25[44] BAAs within WECC that came together to examine participation in day-ahead market offerings. WMEG hired E3 to provide PCM analysis for each respective BAA across varying market footprints and varying years (2026,

[44] The 25 WMEG members represented are AEPCO, APS, Avista, Balancing Authority of Northern California (BANC), Black Hills Energy, Bonneville, Chelan County PUD, El Paso Electric (EPE), Grant County PUD, Idaho Power Company, Los Angeles Department of Water & Power (LADWP), NV Energy, PacifiCorp, Public Service of new Mexico (PNM), Platte River power Authority, Public Service of Colorado (PSCO), Puget Sound Energy (PSE), Salt River Project (SRP), Tacoma Power, Tucson Electric Power (TEP), Tri-State Generation and Transmission Authority (TSGT), and Western Area Power Administration (WAPA), which was modeled in 5 separate areas (SNR, CRCM, LAP, WALC/DSW, and WAUW). The rest of the WECC was represented as non-WMEG.

2030, 2035). Following the WMEG analysis, Bonneville contracted directly with E3 in 2024 for supplemental analysis using the WMEG data set to test additional market footprints and sensitivities of a number of other variables. This section discusses both sets of PCM analyses.

5.1.1.1. What is Production Cost Modeling?

PCM is an industry standard simulation software tool that attempts to model a day-ahead market by producing a least-cost dispatch to serve load based on a set of static input data. PCM incorporates SCUC and SCED, which are the processes the day-ahead market uses to optimize participants' loads, resources, and transmission.[45] The analysis produces hourly generation dispatches and associated electricity production costs to serve load based on numerous operational inputs. Such inputs include loads, generation resources, weather, fuel, and transmission connectivity/constraints.

There are many underlying assumptions that must be made to model such a complex system. In particular, the study results are highly dependent on the composition of the market footprint (i.e., which load, generation, and transmission are included in the market optimization). Identifying a market footprint requires assumptions about which market a utility may choose to join. The footprint composition brings together the resources that will be optimized to serve load at the least cost and is constrained by the transmission connectivity that is utilized by the market to deliver all the footprint resources to load. Adjusting the market participants, and therefore changing the footprint, can offer additional load to be served, additional generators to serve load, and new transmission connectivity that expands the possible solutions of the market optimization. Therefore, the composition of the market is an important and influential component in PCM.

PCM must also assume the cost associated with transmission within a market (usually assumed to be zero) and transmission and other incremental "friction" between markets (sometimes called the "hurdle rate"). Hurdle rates represent the "friction" between markets, which could come in the form of actual costs associated with sales across markets, or as a representative cost representing the inefficiency of two separate optimizations (one for each footprint) as opposed to a single optimization. This could show up as price divergence between markets such that the price in one market must be high enough to incentivize exporting from the other market. Much like the footprint composition, the adjustment (i.e., reduction and variation) in the hurdle rate also proved to be a notable operational model input.

PCM is a powerful tool that relies on a range of assumptions to produce modeling results that provide direction and magnitudes of market participation outcomes. PCM comes with both strengths and limitations. It produces simulations that optimize dispatch of resources to meet demand at the lowest possible cost, facilitate long-term planning and investment decisions, inform policy making and potential regulatory impacts, and provide insight for market dynamics and analysis to help understand price trends and identify opportunities for cost savings. The limitations of PCM are discussed further in the section below.

5.1.1.1.1. Production Cost Modeling Limitations

PCM is a useful industry-standard tool, however, it is accompanied by certain limitations. In PCM, a range of assumptions are required to produce effective modeling. While PCM results are useful in providing market participation outcomes, these results do not represent an exact expected outcome. Moreover, while PCM is a valuable industry standard method to simulate friction and hurdle rates, it is prudent to acknowledge that actual real-world values of friction and hurdle rates may differ from simulated results because of the inherent complexity, uncertainty, and variability associated with the assumptions and data quality in the model. For example, some entities view long-term firm transmission cost as a sunk cost and therefore do not include it in their price evaluation in their decision of whether they transact between

[45] For information on day-ahead market processes, see section 2.4 above.

markets. Further, there is not a single value that uniformly represents the risk that sellers are willing to take on, and thus a modeled hurdle rate can never perfectly represent reality.

In the supplemental analysis, E3 ran case studies to simulate scarcity events through the application of stressed conditions.[46] Specifically, E3 applied stressed conditions to the following market footprints 1) Business-as-usual, 2) West-wide market, 3) Alt Split 4A (current market declarations). In the results of these cases, net costs showed a minimal decline and prices in the model did not rise nearly as significantly as would be expected.

The minimal change in forecasted benefits in the PCM results stand in stark contrast to real-world outcomes from recent events such as the 2024 Martin Luther King, Jr. (MLK) holiday weekend winter storm. During that short period of time, the region faced significant competition for available resources to meet load accompanied by hourly prices exceeding the WECC soft-offer cap of $1,000 per megawatt-hour (MWh). There was also significant congestion on key transmission paths and congestion revenues within WECC exceeded $100 million dollars. The 2024 MLK weekend event represents an extreme outlier that a PCM cannot replicate. A typical scarcity outlier, experienced over a few days to a week, will likely see multi-hour, peak load block prices rise to triple digits. Frequently, evening hourly prices will rise above this into the mid-to-high hundreds, sometimes exceeding the WECC soft-offer cap, as loads are peaking and renewable resources are ramping down. The pricing levels reflected in the PCM captured neither the extreme event like a 2024 MLK, nor the more typical scarcity event of sustained elevated prices. The PCM pricing outputs simply do not reach the magnitude nor the daily sustained level of pricing that we would expect to see, even under the stressed load parameters. The minimal decline in net cost results for stressed conditions in the PCM study demonstrates that the financial impacts of a scarcity event are not captured in the modeling. Regardless of day-ahead markets, such events occur, and Bonneville simply acknowledges that these risks are not fully represented in the PCM study.

Additionally, PCM studies do not reflect various market design elements such as GHG pricing programs, market power mitigation, out-of-market actions, and market bid caps. Lastly, PCM results cannot account for market design changes and modifications to market rules influenced by the market's governance structure. Bonneville explores a number of these design elements in section 5.2.

5.1.1.2. WMEG Study

Bonneville participated in WMEG with 24 other BAAs in a joint exploration of day-ahead market participation. The WMEG group sought economic analysis results that would help forecast costs and benefits associated with day-ahead market participation for each BAA participating in the study. E3 used PCM to develop categorical results, discussed below in section 5.1.1.2.2, for each BAA. The categorical results were summed together to create a single "net cost" number, which was intended to indicate whether costs or benefits were likely for a given BAA's participation in a day-ahead market. The PCM studies were modeled across three different time horizons of 2026, 2030, and 2035. The 2026 scenarios depicted initial day-ahead market launch. The 2030 scenarios assumed maturation of the day-ahead market by layering on some BAA consolidation and an ancillary services market. The 2035 scenarios modeled a full RTO, which consisted of a single consolidated BAA (however, it did not include any estimates of transmission cost savings). Load, generation, and transmission were also augmented in future cases, reflecting anticipated growth in each category. Each participating BAA received only their respective results, though they were free to share their results on a wider basis. Bonneville publicly released its WMEG PCM results in the fall

[46] Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation at 4, 11 (Nov. 4, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/E3Presentation-bpa-stakeholder-meetingnov4-2024.pdf (Task 3: Low Water Year (+ Stressed Load)).

of 2023 in public workshop 3.[47]

5.1.1.3. WMEG Data Elements

Each WMEG member provided generation, transmission, and load data to E3 for use in the PCM to model market activity and calculate categorical costs and benefits. This data was retained by E3 following the completion of the initial WMEG study and used in the supplemental analysis that Bonneville requested.

5.1.1.3.1. WMEG Cost Benefit Categories

The PCM results consisted of eight distinct categories: load costs, generation costs, reserve costs, reserve revenue, generation revenue, wheeling revenue, congestion revenue, and GHG revenue. It is important to emphasize that the results are reported such that costs are represented as positive numbers and revenues are represented as negative numbers (as indicated by the positive or negative sign in the category list below). The eight categories were then added together to create a "net cost," which indicated whether the WMEG member should expect a cost or benefit. Again, a positive "net cost" indicated cost to the WMEG member because of day-ahead market participation, and a negative "net cost" indicated benefits to the WMEG member because of day-ahead market participation.

Net Variable Cost = Load Cost + Generation Cost + Reserve Cost – Reserve Revenue – Generation Revenue – Wheeling Revenue – Congestion Revenue – GHG Revenue

The following are the categories from the PCM results accompanied by their applicable sign:

PCM Results Categories (as defined in E3's Western Markets Exploratory Group: Western Day -Ahead Market Production Cost Impact Study)[48]

1. Load Costs (+)

Entities incur a cost to serve load based on (a) the hourly quantity of load (in MWh) that the entity is obligated to serve in each zone of the model times (b) the hourly zonal energy price

2. Generation Costs (+)

The model reports variable production costs for each generating unit as the sum of fuel costs, startup costs, and variable O&M cost for that resource. Generation Costs are attributed to each entity as (a) the total variable production cost of the unit times (b) the percentage share of that unit that is owned or contracted to the entity.

3. Reserve Costs (+)

In the Business-as-Usual (BAU) Case, E3 enforces ancillary service reserve requirements at the BAA level but does not settle these products at a market clearing price. For all the market cases, day ahead forecast error reserves are enforced at the level of a subregion within each market (e.g. the Northwest portion of Markets+), and each entity is assigned a Reserve Cost responsibility based on of (a) the hourly quantity of reserves that entity needs times (b) the hourly market price for reserves within that market sub-region.

4. Reserve Revenue (-)

Each entity is also awarded Reserve Revenue from the market based on (a) the quantity of reserves that are contributed by generators owned or contracted by the entity times (b) the hourly market price for reserves

[47] For results, see Bonneville Power Administration, Day-Ahead Market, *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market (*see* Workshops, Oct. 23, 2023, WMEG Materials).
[48] Energy and Environmental Economics, Western Markets Exploratory Group: Western Day Ahead Market Production Cost Impact Study at 9-11 (June 2023), *available at* http://www.oasis.oati.com/woa/docs/NEVP/NEVPdocs/3._E3_WMEG_Western_Day_Ahead_Market_Production_Cost_Impact_Study_-_Final.pdf.

within that market subregion. In the 2030 and 2035 CBA cases, Reserve Costs and Reserve Revenues are calculated separately for each reserve product (spinning reserves, non-spinning reserves, and regulating reserves, as well as day ahead forecast error reserves)

5. Generation Revenue (-)

Generation Revenue is first calculated for each resource based on (a) the hourly energy produced by the generator, times (b) the hourly price at the generator's zone. This Generation Revenue is then attributed to each entity based on the percentage share of each resource that is owned or contracted to the entity

6. Wheeling Revenue (-)

Wheeling revenue is revenue that transmission providers earn by selling transmission service. In the BAU Case, total Wheeling Revenue is calculated in the model for each entity based on the product of (a) the amount of energy exported over transmission lines connected to that entity, times (b) the OATT rate or market wheeling rate applicable that BAA or transmission entity, plus an additional $/MWh charge for bilateral day ahead market friction. In the RT stage of the BAU Case, wheeling is not charged for transactions between entities in the WEIM or WEIS market. In the DA markets cases, total wheeling revenue is first determined at a market-footprint level based on the (a) amount of energy flowing exported over transmission lines connected to each market footprint times (b) the load-weighted average of OATT rates of zones participating in that market, plus an additional $/MWh charge for transactional friction on seams between the markets. This total market wheeling revenue is then distributed among market participants based on each participant's percentage share of total load in the market (load-ratio share basis).

7. Congestion Revenue (-)

Price differentials between zones due to transmission constraints creates congestion between entities, resulting in loads paying higher prices than remote generators receive on the other side of congested interface. The value of this difference is assigned back to the entities in the BAU case and for lines within each market footprint. Congestion on the border of each market is allocated among all participants in that market on a load ratio share basis.

8. GHG Revenue[49] (-)

Revenue associated with any MW of generator output that was attributed as an import into a state with a pricing program (CA/WA). The way Bonneville elected to model its resources in the E3 studies resulted in minimal attribution of imports.

9. Net Cost (+) OR (-)

The difference between the Net Variable Costs for an entity in a market case compared to that entity's Net Variable Revenues.

5.1.1.3.2. Bonneville's Modified Calculation of Net Cost

As Bonneville examined the PCM results, it became evident that certain categories could be set aside, and a net cost could be recalculated with the remaining categories. Bonneville set aside generation cost, reserve cost, and reserve revenue because they were a static or negligible value, meaning there was zero or almost zero difference among scenarios. Further, after some conversation with E3 regarding wheeling revenue, Bonneville and E3 determined that the study approach did not attempt to capture existing transmission contracts. Instead, it assumed that all transactions outside of or between markets required incremental purchase of transmission and that all transactions within a market required no purchase of transmission. These assumptions do not approximate likely transmission purchase patterns for Bonneville customers and therefore do not appropriately reflect a likely outcome of market participation. Therefore, Bonneville

[49] The text of Result Category No. 8 has been modified from the E3 report for clarity.

removed the wheeling revenue category from the net cost computation when analyzing the PCM results.[50] Based on the negligible value category exclusions and wheeling revenue exclusion, the results discussed throughout the rest of this document focus on PCM results for load costs, generation revenue, congestion revenue, and GHG revenue, and a net cost summing those four categories (reported as "Net Cost without Wheeling" for clarity). Bonneville separately provides an analysis of the potential impact to transmission revenues in section 5.1.1.7.

Net Cost = Load Cost – Generation Revenue – GHG Revenue – Congestion Revenue

5.1.1.3.3. WMEG Footprints

Of the 38 BAAs in WECC, spanning from Canada to Mexico, 25 participated in the WMEG study. In all cases except for a "business as usual" (BAU) case, each BAA in WECC was designated to fall within one of two categories to comprise a day-ahead market footprint:

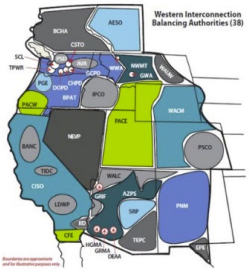
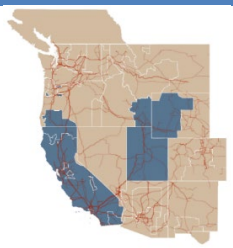
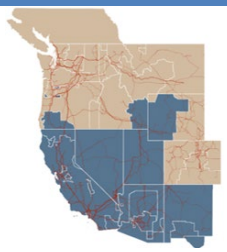
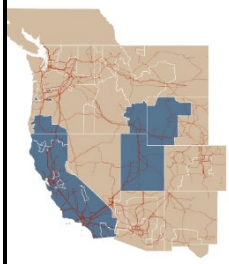
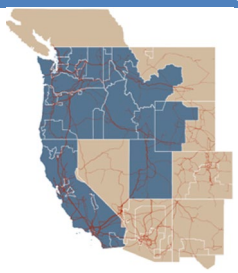
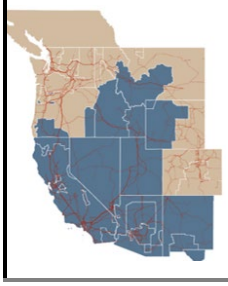
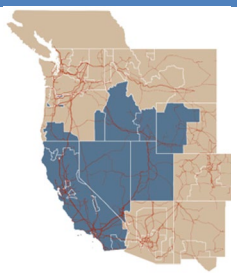
1) The BAA participates in EDAM,

2) The BAA participates in Markets+

During the initial 2023 PCM analysis, WMEG members designed a number of footprint scenarios representing the footprints that they determined were most plausible to test the impacts of different market footprints on the benefits. WMEG also included a BAU scenario to represent continued bilateral trading without any entities joining a day-ahead market. These footprints are shown in Table 1 on the next page.

[50] Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation at 20.

Table 1 | Footprints used in WMEG studies

Business-as-Usual	Main Split
 This footprint was intended to model the operational and trading world as it exists today. Bilateral trading (no centralized market) in day-ahead; EIM & EIS cover most of WECC in real-time stage	 PacifiCorp (PAC) + all of California (including Western Area Power Administration Sierra Nevada Region (WAPA SNR)) in EDAM; rest of WECC in Markets+
EDAM Bookend	**Alternative Split 1**
 All US WECC in EDAM; British Columbia Hydro only in Markets+	 PAC + California (excluding WAPA SNR) + SW (AZ + NM + NV) in EDAM; rest of WECC in Markets+
Markets+ Bookend	**Alternative Split 2**
 PAC, CAISO, Los Angeles Department of Water & Power. Turlock Irrigation District, Balancing Authority of Northern California (BANC) (not WAPA SNR) in EDAM; rest of WECC in Markets+ (including WAPA SNR)	 PAC + California (including WAPA SNR) + NW (WA, OR, ID, NWMT) in EDAM; rest of WECC in Markets+
Alternative Split 3	**Alternative Split 4**
 PAC + California (excluding WAPA SNR) + SW + ID + NWMT in EDAM; rest of WECC in Markets+	 PAC + California (excluding WAPA SNR) + ID + NV in EDAM; rest of WECC in Markets+ [Same as Markets+ Bookend, but NV & ID move to EDAM]

5.1.1.3.4. Bonneville's WMEG PCM 2023 Results

Table 2 shows a summary of Bonneville's results across the footprint scenarios. The top half of the table reflects the categorical results as absolute costs (positive numbers) or revenues (negative numbers). The bottom half calculates the delta result for each scenario relative to the BAU scenario. Again, a positive number represents an increased cost or a decreased revenue (and is accompanied by a red dot), and a negative number represents a decreased cost or an increased revenue (and is accompanied by a green dot).

The full set of Bonneville's initial WMEG results are available on Bonneville's website.[51]

Table 2 | Bonneville's WMEG Results (Fall 2023, units in millions of dollars)

	A	B	C	D	E	F	G	H	I	J
1	Footprint									
2		Cost/Benefit Category	BAU (2026)	EDAM Bookend (2026)	Main Split (2026)	Markets Bookend (2026)	Alt Split 1 (2026)	Alt Split 2 (2026)	Alt Split 3 (2026)	Alt Split 4 (2026)
3	Category Value	Load Costs	921	944	924	902	919	982	840	861
4		Gen Costs	131	131	131	131	131	131	131	131
5		Gen Revenues	-1341	-1490	-1370	-1329	-1360	-1515	-1152	-1220
6		Congestion Revenues	-50	-60	-53	-53	-48	-49	-51	-48
7		GhG Revenues	0	0	-1	-1	-1	0	-1	-1
8		**Net Costs w/o Wheel**	**-339**	**-475**	**-369**	**-349**	**-359**	**-451**	**-233**	**-277**
9	Δ Category vs. BAU	Δ Load Cost		23	3	-19	-2	61	-81	-60
10		Δ Gen Revenue		-149	-29	12	-19	-174	189	121
11		Δ Congestion Revenue		-10	-3	-3	2	1	-1	2
12		Δ GhG Revenue		0	-1	-1	-1	0	-1	-1
13		**Δ Net Cost w/o Wheel**		**-136**	**-30**	**-10**	**-19**	**-112**	**107**	**62**

Green = Benefit Greater than BAU **Red = Increased Cost from BAU**

Starting with the top half of the table, the PCM results forecast Bonneville to achieve net benefit in each of the eight cases in Table 2 (see row 8). Moving to the bottom half of the table, benefits greater than BAU are achieved in five out of seven footprints (all footprints except Alt Split 3 and Alt Split 4). Alt Splits 3 and 4 results forecast reduced benefits relative to BAU. While those footprints project significant cost savings in serving load,[52] the reduction in projected benefits relative to BAU is driven by generation revenues declining[53] more than the load costs decline. The generation revenue declines are driven by lower marginal prices observed in these footprints, as Bonneville is a net exporter in the generation data provided, resulting in the impact to revenue outweighing the savings to load.

Notably, Bonneville determined that the BAU scenario studied by E3 assumes all utilities forgo day-ahead market participation and cannot account for what entities will do in the long term. As discussed above in section 5.1.1.2.4, the BAU case fundamentally assumes continued use of bilateral trading activity as the primary tool for energy trading and limited organized market activity (i.e., real-time only). With many entities in WECC evaluating participation and declaring intent to join organized day-ahead markets, the bilateral world, as it is today, is not expected to persist. Bonneville included modeled costs and benefits relative to BAU to provide a sense of the magnitude, and the direction of the impact day-ahead market participation has relative to today. BAU does not represent a realistic future scenario.

5.1.1.4. Bonneville's Supplemental Cost/Benefit Analysis 2024

Bonneville engaged E3 to perform additional supplemental analysis to enhance its modeling and assumptions for its evaluation of potential day-ahead market participation. Following the release of the WMEG PCM results and review of stakeholder comments on Bonneville's WMEG results, Bonneville requested E3 to assess additional market footprints and identified scenarios or variables. For the supplemental tasks that used years 2030 and 2035, there were no market maturation pieces layered on the analysis. The new studies applied only load growth, modifications to generation resources (e.g., new builds and retirements), and additions to the transmission grid (e.g., new transmission lines) to the respective year-based cases. The additional PCM analyses are listed below. The full set of Bonneville's PCM results are

[51] Bonneville Power Administration, Day-Ahead Markets *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.

[52] Alt Split 3 Load Cost reduced by $81m as shown in cell I9; Alt Split 4 Load Cost reduced by $60m as shown in cell J9.

[53] Alt Split 3 Gen Rev declines by $189m as shown in cell I10; Alt Split 4 Gen Rev declines by $121m as shown in cell J10.

available on Bonneville's website.[54]

Note: During the development and execution of the supplemental analysis, Bonneville and E3 identified an issue regarding data underlying the "generation revenue" category. The generation values supplied by Bonneville to E3 were reflective of all generation, including generation applicable to the Slice product. Bonneville and E3 decided to apply a 15% reduction to generation revenue results in the supplemental analysis to ensure generation revenue more accurately reflected Bonneville's estimated share of generation. This reduction was discussed with all stakeholders during the public workshop on November 4, 2024.[55]

5.1.1.4.1. Supplemental Analysis Tasks

1) (Single West-wide Market) | Compute PCM cost benefit values for Bonneville for the EDAM Bookend Footprint for 2030 and 2035.
2) Lower Market to Market Hurdle Rates | Adjust the Market-to-Market hurdle rates by running three sensitivities that progressively reduce the hurdle rates.
3) Low Water Year (& Stressed Conditions) | Compute PCM cost benefit values for Bonneville for reduced hydro resources due to poor rain and snowpack. Model increased loads to mimic stressed conditions resulting from a multi-day heat and multi-day cold event.
4) Bonneville WEIM-Only | Compute PCM cost benefit values for Bonneville where Bonneville decides not to participate in a day-ahead market but remains a participant in CAISO WEIM. Neighboring and adjacent BAAs proceed with day-ahead market participation.
5) Additional Transmission Capacity | Compute PCM cost-benefit values for Bonneville where transmission connectivity between the Pacific Northwest and the Desert Southwest is increased.
6) Potential Capacity Value | Estimate the range of potential capacity benefits associated with day-ahead market participation.
7) Market Seam at California Border | Compute PCM cost benefit values for Bonneville where only entities lying within the state boundary of California participate in EDAM.
8) Alt Split 4A – Market Declarations | Compute PCM cost benefit values for Bonneville utilizing a two-market footprint that reflects the current market declarations and leanings.
9) Alt Split 2NV Pacific Northwest & Nevada join | Compute PCM cost benefit values for Bonneville where the Pacific Northwest, California, Nevada, and PAC BAAs are modeled as participants in EDAM while the Desert Southwest BAAs are modeled in Markest+.

Supplemental Analysis that was identified but unable to be modeled in PCM - No results were provided by E3

1) Market Interactions with WRAP | Understanding the potential difference in ability of either market's rules & practices to enable realization of RA benefits.
2) GHG Regulation | Understanding the impact that Markets+ vs. EDAM rules regarding GHG import treatment and pricing specific to the treatment of resources contracted to load in a GHG zone.

5.1.1.4.2. Supplemental Analysis Footprints

The supplemental analysis used several of the initial WMEG footprints in conjunction with the new footprints in Table 3. Each new footprint was added for a specific reason. Alt 2NV was designed to represent a more realistic scenario in which Bonneville is in EDAM while the Desert Southwest, which is unlikely to

[54] Bonneville Power Administration, Day-Ahead Markets *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.
[55] *Id.*

join EDAM, is in Markets+. Alt 4A was designed to reflect utilities' market declarations and publicly stated leanings available at the time of the analysis. The Non-California West-wide Market footprint was added to see what west-wide benefits could be realized without the complexities presented in attempting to address CAISO's governance. These three additional footprints were used in various combinations with some of the above tasks, but not all additional footprints were tested for every task above.

Table 3 | Updated footprints for additional E3 studies

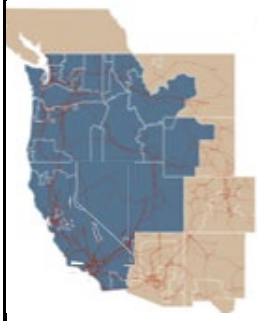
Alternative Split 2NV	Alternative Split 4A
 **EDAM:** California, PacifiCorp, NV Energy & all Pacific Northwest BAAs **Markets+:** BAAs located in the Desert Southwest and Rockies	 **EDAM**: California, PacifiCorp, NV Energy, Idaho Power, Portland General Electric, Seattle City Light **Markets+:** Rest of US WECC and British Columbia ***Reflects current day-ahead market declarations & leanings***
Non-CA Westwide Markets+	
 **EDAM:** California LSE's Only **Markets+:** Rest of US WECC and British Columbia	

Table 4 | Supplemental PCM Case Results[56]

- Section 1 of the table shares the raw case results by category for each of the supplemental analysis cases supplied by E3.
- Section 2 calculates the delta for each category of each case against anchor point BAU.
- Section 3 calculates the delta for each category of each case against anchor point Alt Split 4A.
- Positive numbers are costs and negative numbers are benefits.
- Red dots indicate a cost increase between the case and the anchor point.
- Green dots indicate a benefit increase between the case and the anchor point.

Table 4 | E3 Supplemental PCM results | Δ Supplemental case vs BAU | Δ Supplemental case vs Alt Split 4A

	Supplemental Analysis																						
	Cost/Benefit Category	BAU (2026)	T9 | Alt Split 4A (2026)	T2 | Alt Split 4A M2M (2026)	T2 | Alt Split 4A M2M2 (2026)	T2 | Alt Split 4A M2M3 (2026)	T2 | Main Split M2M (2026)	T2 | Main Split M2M2 (2026)	T2 | Main Split M2M3 (2026)	T3 | BAU Low Water (2026)	T3 | BAU Low Water & Stressed Loads (2026)	T3 | Alt Split 4A Low Hydro (2026)	T3 | Alt Split 4a Low Hydro & Stressed Loads (2026)	T3 | EDAM Bookend Low Water (2026)	T3 | EDAM Bookend Low Water & Stressed Loads (2026)	T4 | Alt Split 4A BPA EIM ONLY (2026)	T4 | Alt Split 4A BPA EIM ONLY Low Hydro Stress Load (2026)	T4 | EDAM Bookend BPA EIM ONLY Low Hydro Stress Load (2026)	T5 | Alt Split 4A Straw (2026)	T5 | Hypothetical New Additional TX (2026)	T10 | Non-CA WestWide M+ (2026)	T11 | Alt Split 2NV (2026)
E3 Supplemental PCM Results	Load Costs	921	739	818	874	910	961	981	983	1104	1132	957	1001	1043	1067	908	1109	1018	780	811	890	873
	Gen Costs	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131	131
	Gen Rev**	-1140	-835	-987	-1097	-1166	-1231	-1365	-1279	-1201	-1218	-1032	-1067	-1184	-1201	-1129	-1203	-1203	-1104	-977	-1182	-1156
	Congestion Rev	-50	-65	-59	-56	-57	-52	-54	-57	-30	-30	-39	-39	-39	-38	-69	-31	-31	-58	-88	-46	-44
	GhG Rev	0	0	0	0	0	-1	-1	-1	0	0	-1	-1	0	0	0	0	0	0	0	0	0
	Net Cost w/o Wheel	**-138**	**-30**	**-98**	**-148**	**-182**	**-192**	**-208**	**-222**	**4**	**15**	**16**	**26**	**-50**	**-42**	**-160**	**5**	**14**	**-61**	**-123**	**-207**	**-195**
Δ BAU vs Supplemental Case	Δ BAU | Load Cost		-182	-103	-47	-11	40	60	62	183	211	36	80	122	146	-13	188	97	-141	-110	-31	-48
	Δ BAU | Generation Rev		305	153	43	-26	-91	-125	-139	-61	-78	108	73	-45	-62	11	-63	36	226	163	-42	-15
	Δ BAU | Congestion Rev		-15	-9	-6	-7	-2	-4	-7	20	20	11	11	11	12	-19	19	19	-8	-38	4	6
	Δ BAU | GhG Rev		0	0	0	0	-1	-1	-1	0	0	-1	-1	0	0	0	0	0	0	0	0	0
	Δ BAU | Net Cost w/o Wheel		**108**	**41**	**-10**	**-44**	**-54**	**-69**	**-84**	**142**	**153**	**154**	**164**	**89**	**96**	**-22**	**143**	**152**	**78**	**15**	**-69**	**-57**
Δ Alt Splits 4A vs Supplemental	Δ Alt 4A | Load Costs	182		79	136	171	222	242	245	366	393	218	262	305	328	169	371	280	42	72	151	134
	Δ Alt 4A | Gen Rev	-305		-152	-262	-331	-397	-430	-445	-366	-384	-198	-232	-350	-367	-294	-369	-270	-79	-142	-347	-320
	Δ Alt 4A | Congestion Rev	15		6	9	8	13	11	8	35	35	26	26	26	27	-4	34	34	7	-23	19	21
	Δ Alt 4A | GhG Rev	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Δ Alt 4A | Net Cost w/o Wheel	**-108**		**-67**	**-118**	**-152**	**-161**	**-177**	**-192**	**35**	**45**	**47**	**56**	**-19**	**-12**	**-129**	**36**	**44**	**-30**	**-92**	**-177**	**-165**

Green = Benefit Greater than anchor point Red = Increased Cost than anchor point

**Generation Revenue has been reduced by 15% to reflect slice revenue reduction

Table 5 | Consolidated supplemental case results for Alt Split 4A, Alt Split 4A WEIM Only, Alt Split 2NV, Alt Split 4A M2M, Alt Split 4A M2M2, and Alt Split M2M3

[56] During the development and execution of the supplemental analysis, Bonneville and E3 identified an issue regarding the "Generation Revenue" category. The load values provided by Bonneville to E3 reflected the preference load that Bonneville serves. The Generation values supplied by Bonneville to E3 were reflective of all generation including generation applicable to the Slice product. Bonneville and E3 decided to apply a 15% reduction to Generation Revenue results in the supplemental analysis to ensure Generation Revenue reflected Bonneville's estimated share of generation. This reduction was discussed with all stakeholders the public workshop 9 on November 4, 2024.

	A	B	C	D	E	F	G
	BPA Day-Ahead Market →	Markets+	No DAM Market WEIM-Only	EDAM	Markets+	Markets+	Markets+
1		Alt Split 4A (2026)	Alt Split 4A BPA WEIM-Only (2026)	Alt Split 2NV (2026)	Alt Split 4A M2M (2026)	Alt Split 4A M2M2 (2026)	Alt Split 4A M2M3 (2026)
2	Cost/Benefit Category				Declining Hurdle Rates		
3	Load Costs	739	908	873	818	874	910
4	Gen Rev	-835	-1129	-1155	-987	-1097	-1166
5	Gen Costs	131	131	131	131	131	131
6	Congestion Rev	-65	-69	-44	-59	-56	-57
7	GhG Rev	0	0	0	0	0	0
8	**NC w/o Wheel**	**-30**	**-160**	**-196**	**-97**	**-148**	**-182**
9	Δ Alt 4A | Load Costs	--	169	134	79	136	171
10	Δ Alt 4a |Gen Rev	--	-294	-320	-152	-262	-331
11	Δ Alt 4A |Congestion Rev	--	-4	21	6	9	8
12	Δ Alt 4A | GhG Rev	--	0	0	0	0	0
13	**Δ Alt 4A |Net Cost w/o Wheel**	**--**	**-130**	**-166**	**-67**	**-118**	**-152**
14	**Δ Alt 4A M2M's vs Alt Split 4A WEIM-Only Net Cost w/o Wheel**	--	--	--	**63**	**12**	**-22**
15	**Δ Alt 4A M2M's vs Alt Split 2NV Net Cost w/o Wheel**	--	--	--	**99**	**48**	**14**

These PCM cases were the most stakeholder-cited cases in responses to the Draft Policy.

Supplemental Case Results[57]

On the next page, Bonneville discusses the results from the supplemental analyses. In each case, the figures show raw case results and do not reflect differences against any other study case, though the original BAU result is plotted for reference. Negative numbers represent forecasted benefit, and positive numbers represent forecasted costs.

Figure 2 | All Supplemental Case Results

Figure 2 plots each of the supplemental case results together on a single chart. 2026 case results are depicted with circles, 2030 case results are depicted with triangles, and 2035 case results are depicted as diamonds. Yellow and orange denote dry water years and dry water years accompanied by stressed loads. Purple shades denote modifications to hurdle rates in the model.

[57] Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation (Nov. 4, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/E3Presentation-bpa-stakeholder-meetingnov4-2024.pdf.

Figure 2 | E3 PCM results

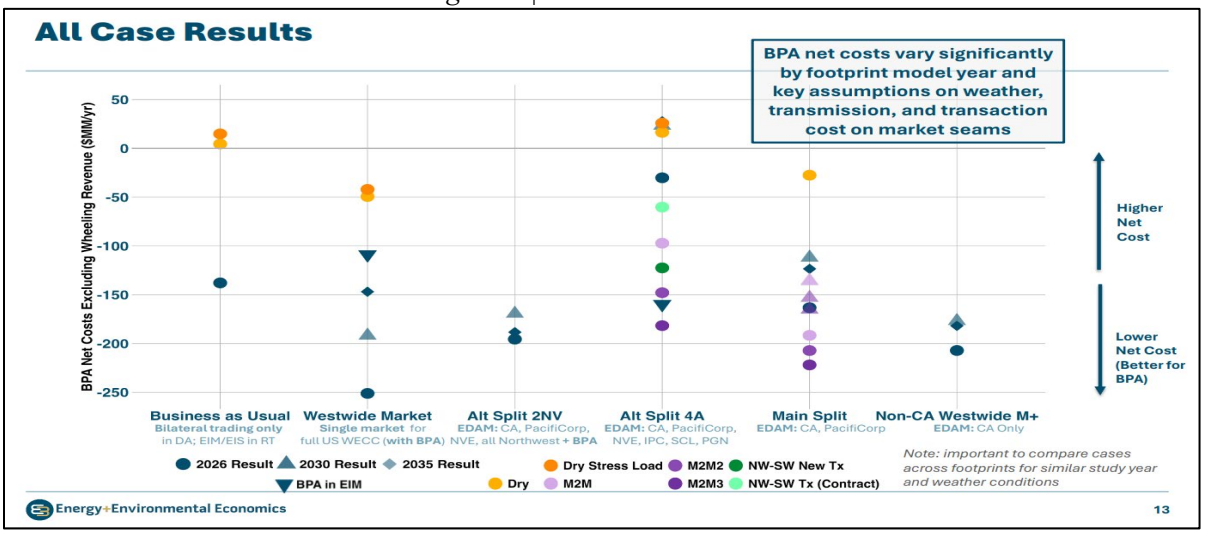


***Figure 2 Takeaway*:** Range of possible outcomes depending on various factors.

This graph shows the comparative impact of individual variables against each other. The graph illustrates an array of potential outcomes impacted by footprint composition, transmission connectivity, and other tested sensitivities. While Figure 2 plots all supplemental case results, not all case results are discussed in detail in the following sections. West-wide Market, Main Split, and Non-CA West-wide M+ are not feasible footprints due to market participation declarations already issued by BAAs.

Figure 3 | 2026 Base Footprint Results

Figure 3 plots 2026 supplemental case results including the new footprints as defined above plotted against some of the original WMEG footprints. We see that both the Alt Split 2NV case and the Non-California West-wide Market result in benefits above the BAU case, whereas Alt Split 4A results in benefits less than the BAU case.

Figure 3 | E3's 2026 Results

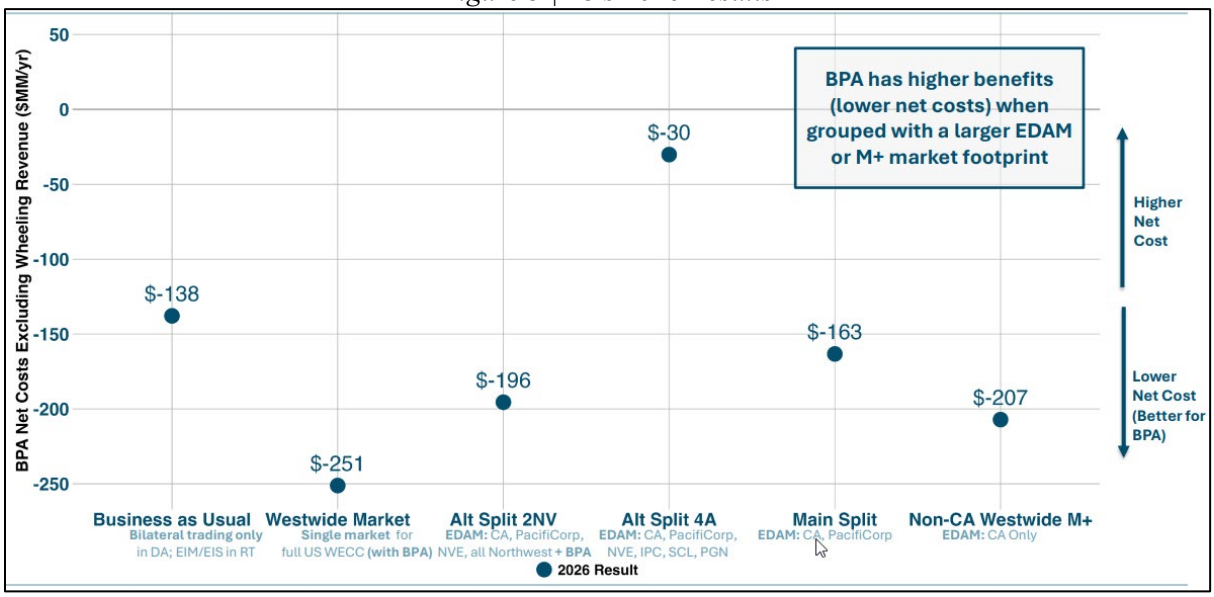


Table 6 | Alt Split 4A vs BAU

	N	O	R
1			
2	**Cost/Benefit Category**	**BAU (2026)**	**T9 | Alt Split 4A (2026)**
3	Load Costs	921	739
4	Gen Costs	131	131
5	Gen Rev	-1140	-835
6	Congestion Rev	-50	-65
7	GhG Rev	0	0
8	**Net Cost w/o Wheel**	**-138**	**-30**
9			
10	Δ BAU | Load Cost		-182
11	Δ BAU | Generation Rev		305
12	Δ BAU | Congestion Rev		-15
13	Δ BAU | GhG Rev		0
14	**Δ BAU | Δ Net Cost w/o Wheel**		**108**

Table 7 | Alt Split 2NV vs BAU

	N	O	AK
1			Supplemental
2	**Cost/Benefit Category**	**BAU (2026)**	**T11 | Alt Split 2NV (2026)**
3	Load Costs	921	873
4	Gen Costs	131	131
5	Gen Rev	-1140	-1155
6	Congestion Rev	-50	-44
7	GhG Rev	0	0
8	**Net Cost w/o Wheel**	**-138**	**-195**
9			
10	Δ BAU | Load Cost		-48
11	Δ BAU | Generation Rev		-15
12	Δ BAU | Congestion Rev		6
13	Δ BAU | GhG Rev		0
14	**Δ BAU | Δ Net Cost w/o Wheel**		**-57**

***Figure 3 Takeaway*: Footprint is a primary driver of results.**

As discussed previously, the PCM results are highly dependent on the market footprint. Because Bonneville is a net exporter in the generation input data provided, footprints with higher LMPs, particularly during times of surplus hydro, result in increases to generation revenue that outstrip the increases to load cost. We see this in the Alt Split 4A results, where load costs go down by $182 million (see cell R10), but generation revenues go down by more ($305 million, see cell R11). Alt Split 2NV seems to balance this impact. The results show a smaller decrease to load costs than Alt Split 4A ($48 million, see cell AK10), but an increase to generation revenue ($15 million, see cell AK11). This is likely due to the timing of price fluctuations.

It is not possible to predict with absolute certainty which footprint will ultimately materialize. As seen in Figure 2 and Table 2, the initial and supplemental PCM analyses resulted in a range of cost or benefit outcomes. Given that there are two day-ahead market options in the region, both with substantial support from various entities across the West, Bonneville determined that it is best to look at the results for footprints with multiple markets. Based upon the information and the modeled footprints available, Bonneville sees Alt Split 4A (see Table 6) as the most realistic footprint with Bonneville in Markets+ and Alt Split 2NV (see Table 7) as the most realistic footprint with Bonneville

in EDAM.

Alt Split 4A is a two-market scenario that divides participation between EDAM and Markets+. Geographically, Markets+ is divided into two regional areas. The first being the Pacific Northwest and the second being the Desert Southwest. EDAM participants are forecasted to lie between these two regional areas, creating a geographic division. The Net Cost without Wheeling Revenue forecast is an annual benefit of $30 million (as noted in Table 2 T9 – Alt Split 4A 2026), which is a decrease from the BAU case. The decline in benefit appears to be driven by a notable drop in Generation Revenue. Interestingly, this case also forecasts significant savings in Load Cost. Both the Generation Revenue decline and Load Cost savings are the product of lower locational marginal prices in Markets+ (relative to BAU). This footprint demonstrates the dichotomy between seeking the lowest cost to serve load and seeking to maximize value for surplus generation. Bonneville must weigh the challenges of seeking the greatest revenue value for surplus generation, while recognizing that customers may also benefit from the lowest costs to serve load.

Alt Split 2NV is a two-market scenario in which Bonneville, the Pacific Northwest, California, Nevada, and PacifiCorp's service territory are depicted as EDAM participants. Entities located in the Desert Southwest are modeled as Markets+ participants. This footprint creates geographical division, but, unlike in Alt Split 4A, each market maintains contiguous transmission connectivity. The Net Cost without Wheeling Revenue forecasts a benefit of nearly $200 million. When compared to BAU, Alt Split 2NV forecasts to be nearly $60 million better. Examining the categorical differences between cases shows that $48 million in Load Cost savings is driving the forecasted benefit.

Figure 4 | Base Footprint Results & WEIM-Only Results

Figure 4 plots 2026 supplemental case results and layers on the two WEIM-only scenarios that were modeled. In the WEIM-only cases, Bonneville remains outside day-ahead markets while continuing to be a WEIM participant, and the other entities in WECC participate in the day-ahead market in varying footprints. The WEIM-only option was evaluated for the West-wide Market footprint and Alt Split 4A footprint. (Note that Bonneville had not yet developed the Alt Split 2NV footprint for use in this task, so it was not modeled.) The arrows indicate the change in benefit to Bonneville of remaining a non-day-ahead market participant in the respective cases. Specifically, benefits for the West-wide market footprint decline from $251 million to $109 million. Conversely, Alt Split 4A sees an increase in benefit from $30 million to $160 million should Bonneville remain solely a WEIM participant. These are raw case results and do not reflect differences against any other study case.

Figure 4 | WEIM-only scenario

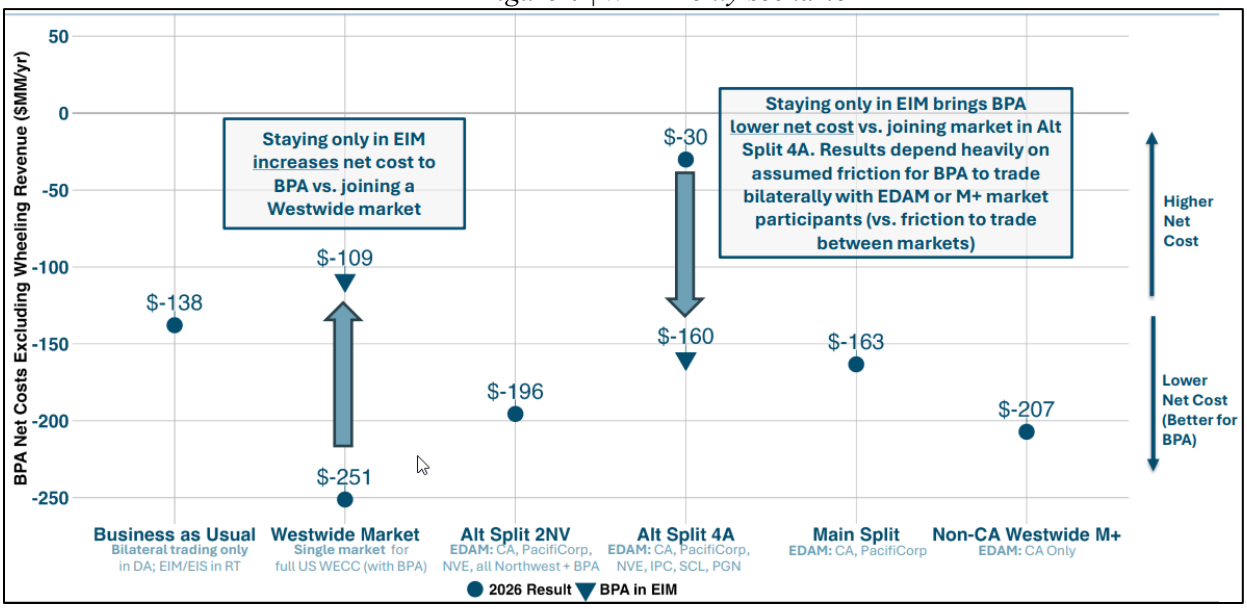


***Figure 4 Takeaway*: WEIM-only benefits appear positive but the analysis does not consider long-term viability questions.**

The results suggest Bonneville achieves benefit remaining outside of a day-ahead market, depending on the footprint. Compared to BAU, Bonneville would achieve benefits slightly greater than those in the current bilateral world if the Alt Split 4A footprint otherwise materializes. Comparing this WEIM-only case to that of Bonneville participating in Markets+ suggests that Bonneville achieves greater benefit by staying out of a day-ahead market. Alternatively, if the West-wide Market footprint materializes and Bonneville remains WEIM-only, Bonneville is modeled to see less benefit than being in EDAM and less benefit than BAU. However, these results cannot be viewed in a vacuum. Bonneville stresses that a significant limitation in these results is the assumption of a simple hurdle rate to access either market, which does not reflect the potential for decreased liquidity in the bilateral markets or increased friction to access either market as those markets grow. In addition, the reduction in access to trading partners may significantly degrade these results and make remaining a WEIM-only participant an unsustainable option in the long term.

Figure 5 | Base Footprint Results & Changing Hurdle Rates

Figure 5 plots 2026 supplemental case results testing multiple sensitivities of market-to-market (M2M) hurdle rates. The hurdle rates cases are noted in shades of purple (with lighter color representing a higher hurdle rate and darker color representing a lower hurdle rate) and were applied to Alt Split 4A and the Main Split footprints. The arrows indicate change in benefit for the respective cases. Both footprints demonstrate increased benefit as the hurdle rates are lowered. These are raw case results and do not reflect differences against any other study case.

As a reminder, hurdle rates are costs affiliated with transacting from one market to another. If no hurdle rate existed in the model, the market dispatch results would effectively be co-optimized results (like a single market footprint). This case study proposed to progressively lower the market-to-market hurdle rates with each new sensitivity. This was simulated through adjustment to transmission costs.

Table 8 | Hurdle Rate Descriptions & Value for M2M Cases

Hurdle Rates - Markets+ Footprint Exports						
WMEG	**Supplemental Analysis**					
	M2M		**M2M2**		**M2M3**	
Weighted Average OATT Rate of Market + Friction + Congestion Risk	**DA**	**Weighted Average OATT +$6 adder**	**DA**	**Weighted Average OATT + $3 adder**	**DA**	**50% of Weighted Average OATT + $3 adder**
	M2M DA = $10.50/MWh		**M2M2 DA = $7.50/MWh**		**M2M3 DA = $5.25/MWh**	
	RT	**Weighted Average OATT + $3 adder**	**RT**	**Weighted Average OATT + $3 adder**	**RT**	**50% of Weighted Average OATT + $3 adder**
$14.50 /MWh in DA & RT	**M2M RT = $7.50/MWh**		**M2M2 RT = $7.50/MWh**		**M2M3 DA = $5.25/MWh**	

**** Adder encompasses value for Friction & Congestion Risk***

Figure 5 | Hurdle Rate Sensitivities

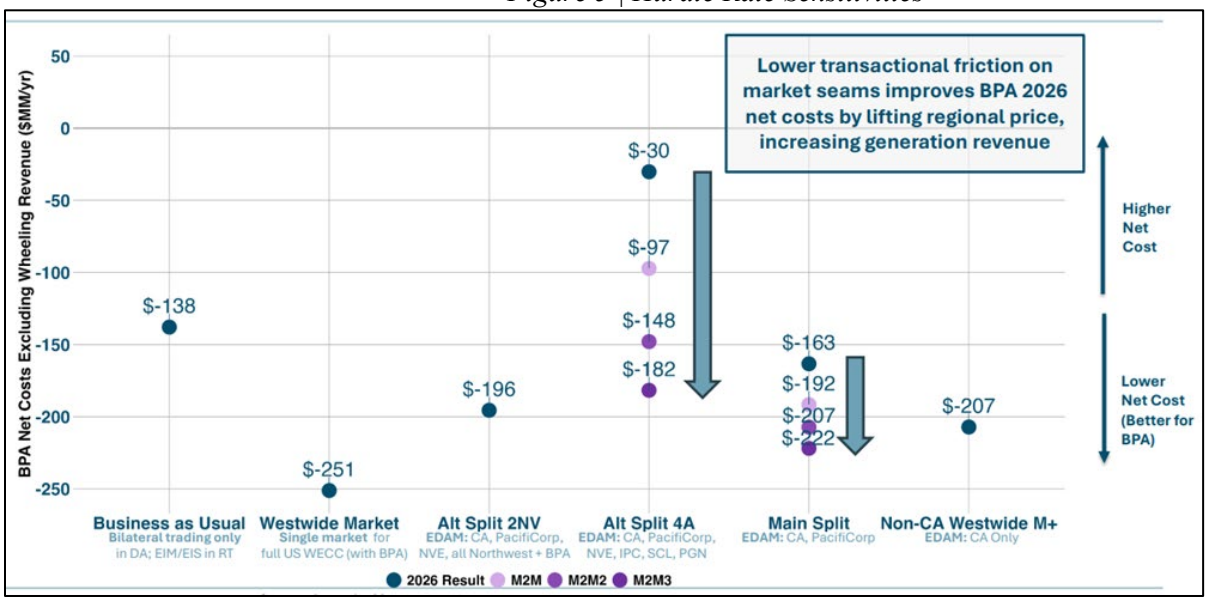


***Figure 5 Take-away*: Hurdle rates drive differences in footprint benefits; Bonneville can achieve benefits above BAU, including with the current expected Markets+ footprint.**

In both footprints tested, Bonneville's results improve with each reduction in the hurdle rate. For the Alt Split4A footprint, all three sensitivities forecast benefits for Bonneville. Two of the three cases forecast benefits greater than BAU. This suggests that Bonneville can achieve incremental net benefits in Markets+ in the Alt Split 4A footprint if it can still access EDAM with minimal friction, and that Bonneville would benefit from working to minimize that friction with both market operators. FERC recently noted that while seams are sure to materialize the market operators, BAAs, and stakeholders should coordinate to develop solutions that minimize friction at the seams. Bonneville concludes that lower hurdle rates are more likely than those initially modeled in the WMEG studies, providing better information that participating in Markets+ participation will result in benefits above business-as-usual.

Figure 6 | Base Footprint Results & Changing Timeline

Figure 6 plots 2026 supplemental case results and layers on future year scenarios which include augmentation of load, generation, and transmission (but do not include any changes to market design). Results for 2030 are plotted with triangles and results for 2035 are plotted with diamonds.

Figure 6: Cases over time 2026-2035

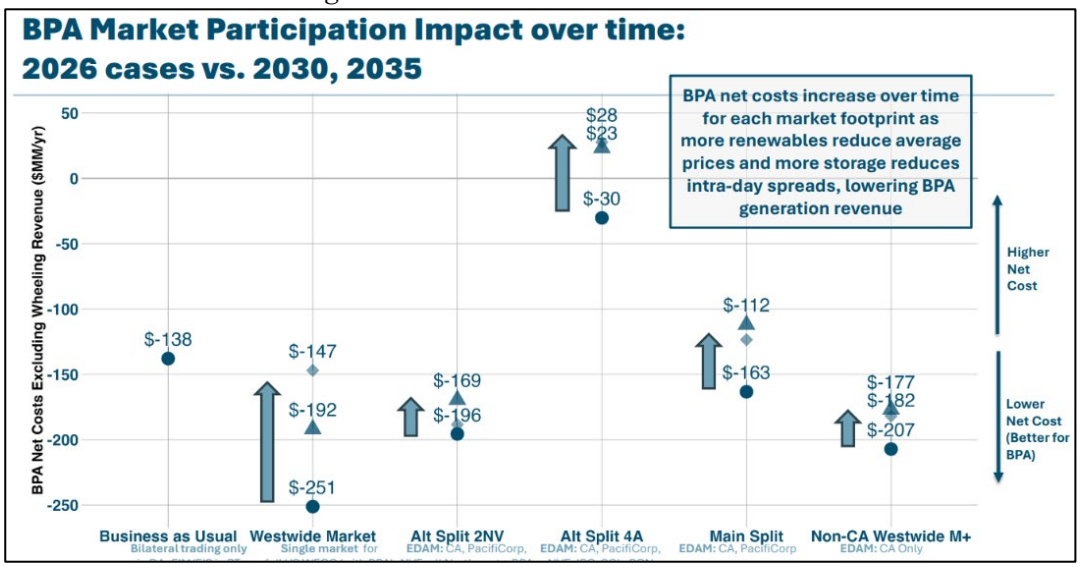


***Figure 6 Takeaway*: Changing regional resource mix may result in declining benefits over time.**

The supplemental PCM analysis also produced study case results for future years of 2030 and 2035. An interesting trend emerged when comparing the case study footprints from 2026 to 2035. In each footprint tested, forecasted Net Costs increase for Bonneville. As time progresses, benefits continue to decline. E3 identified this trend as the result of continued renewable resource participation and the expansion of storage resources. These resource additions result in reduced intra-day price spreads, limiting the value of shapeable hydro. Bonneville would see increased competition from those additional resources within the market and is unable to capture the same amount of Generation Revenue as depicted in early case results.

5.1.1.5. Concluding thoughts on PCM results

PCM results provide general direction (i.e., cost or benefit) and magnitude around market participation. The models offer an array of outcomes that are strongly impacted by the modelled footprint and hurdle rate.

Context for Magnitude of Benefits

To put these numbers in context, Bonneville's Fiscal Year 2026 Power Revenue Requirement is $3,451,708,000,[58] and provides the basis for recovering generation-related costs associated with the Federal Columbia River Power System (FCRPS), including the federal investment in hydro generation, fish and wildlife, conservation costs, non-federal power supply, and market purchases.[59] Bonneville's Fiscal Year 2026 Transmission Revenue Requirement is $1,626,696,000,[60] and provides the basis for rates to Federal Columbia River Transmission System (FCRTS) costs, including recovery of the federal investment in transmission and transmission-related assets, operations and

[58] Power Revenue Requirement Study Documentation - BP-26-E-BPA-02A Table 1A.
[59] Power Revenue Requirement Study - BP-26-E-BPA-02.
[60] Transmission Revenue Requirement Study Documentation - BP-26-E-BPA-09A TABLE 1-1.

maintenance and expenses associated with transmission and ancillary services.[61]

Bonneville's Power revenue uncertainty, largely driven by its power net secondary revenue uncertainty, has a standard deviation of approximately $250 million per year and a range of $2.2 billion.[62] This is not to diminish the significance of potential increased costs to Bonneville, but it is an important frame to place around the overarching strategic decision, the various other market design considerations, and the highlighted limitations of the PCM results. The general range of potential costs or benefits generated by Bonneville's PCM results of ~$150 million. This amounts to roughly +/- 3% of Bonneville's annual revenue requirement. This falls within Bonneville's range of Bonneville's net secondary revenue uncertainty.[63]

Participation in EDAM

Participation in EDAM produces the highest Net Cost benefit in the cases studied. However, examination of the sub-categories comprising the Net Cost illustrates that there are tradeoffs. Higher locational marginal prices drive up Generation Revenues in EDAM cases. The higher prices also result in greater cost to serve load. While Bonneville aims to maximize secondary revenue from surplus generation, it also aims to serve load at the lowest cost. Further, there is no guarantee Bonneville will continue to have significant surplus generation available to market, so the higher projected costs to serve load in EDAM may not always be offset by higher revenue associated with surplus.

Remaining a WEIM-only participant

Remaining a WEIM-only participant, which would require continued reliance on bilateral trading in all time-horizons prior to real-time, carries risks not easily reflected in the PCM. As discussed in section 2.3, staying outside a day-ahead market as other participants join presents risks to bilateral liquidity and introduces additional barriers to access trading partners.[64] Market participating entities are expected to focus on trading in their respective day-ahead markets and may be unwilling to or limited in the extent they can transact outside the market in the day-ahead time frame. Bonneville anticipates that convincing trading partners to trade bilaterally, instead of offering their resource to the market, may require a premium. This dynamic makes the longevity of remaining solely a WEIM participant unclear.

Participating in Markets+

Markets+ offers lower cost to serve load but also forecasts reduced Generation Revenue. Similar to participating in EDAM, there is tension created between the objectives of serving load at least cost and maximizing surplus revenue. The market hurdle rate sensitivity cases add further context, as they indicate that in the right conditions, Bonneville may achieve benefits greater than BAU.

Overall Takeaways

These PCM results provide good indicators of direction and magnitude regarding day-ahead market participation. However, these results should not be viewed with the expectation of achieving specific forecasted dollars. The PCM results are forecasts that can be influenced by other factors that may alter the projected outcome. For example, modifications to market design items such as Congestion Rent, Scarcity Pricing, or Locational Marginal Price

[61] Transmission Revenue Requirement Study - BP-26-E-BPA-09A. BP-26-E-BP-05A.
[62] BP-26-E-BP-05-CC01, Power and Transmission Risk Study, at 89 Table 1: Rev Sim Net Revenue Statistics for FY 2026 through FY 2028; *see also* Transmission Revenue Requirement Study Documentation, BP-26-E-BP-05A.
[63] Power and Transmission Risk Study, BP-26-E-BPA-05-CC01, at Table 1 (RevSim Net Revenue).
Power and Transmission Risk Study, BP-26-E-BP-05-CC01, at 89, Table 1 (Rev Sim Net Revenue Statistics for FY 2026 through FY 2028); *see also* Transmission Revenue Requirement Study Documentation, BP-26-E-BP-05A.
[64] *See* WECC, Reliability Implications of Expanding the EIM to Include Day-Ahead Market Services: A Qualitative Assessment, *available at* https://www.westernenergyboard.org/wp-content/uploads/WECC-report-reliability-implications-of-expanding-EIM-to-include-day-ahead-market-services.pdf.

computation can impact benefits. PCM models also do not account for qualitative elements such as differences in market governance structure, nor do they account for the way in which governance structure can impact market design, which impacts quantitative outcomes.

Bonneville views the PCM results as one component of a much larger decision framework for day-ahead market participation. While the PCM results are useful, they alone do not lead to a direct conclusion about which market participation decision Bonneville should make. These PCM results must be used in conjunction with the principles that Bonneville has proposed to inform a day-ahead market decision. The market design aspects discussed in section 5.2 provide important considerations for the broader potential benefits of Markets+ participation.

As explained earlier, one limitation of PCM is that it does not account for impacts to various types of power and transmission customers. The next section discusses Bonneville's proposed direction to continue assessing economic impacts.

5.1.1.6. Business Line Economic Impacts

Day-ahead market growth in the region is expected to impact Bonneville's costs, revenues, trading activity, and net secondary revenue volatility. While Bonneville's decision around day-ahead market participation will affect these impacts, changes are expected to occur regardless of whether Bonneville pursues day-ahead market participation. Bonneville is unable to forecast the financial impact around rates, products, and the volatility for any option prior to issuing its day-ahead market Policy.[65] This is because the specifics needed to conduct financial analysis, such as final market design, footprint, seams agreements, etc. are not yet known. Inventory and market price risk represent key drivers of overall financial risk to Bonneville, which exist in both bilateral and organized markets.

Most of the quantitative economic analysis on day-ahead market options were performed by E3 using PCM that produce a cost-benefit analysis. This analysis provides insight into the potential economic effect of different day-ahead market footprint options and a high-level evaluation of the overall economic effect on Bonneville. While informative, it does not provide the full range of inputs needed for Bonneville's finance models to show the full impact to setting and modeling rates nor the risk around those costs and revenues. Quantitative evaluation and modeling within both Power and Transmission Services also inform the range of financial impacts to both business lines, and to Bonneville as a whole. However, given what was modeled, Bonneville can understand some of the large drivers for costs and revenues.

5.1.1.7. Power Services

Joining a day-ahead market means that all resources and loads are served through the market clearing process. If customers or other utilities join a day-ahead market as their own market participant (Markets+) or Scheduling Coordinator (EDAM), they will bid and settle their own resources with the market and will have their load settled with the market operator directly. If a Bonneville customer is not a direct market participant, they will not be directly exposed to the day-ahead market settlements; instead, any financial impacts would be passed on through Bonneville rates.

In the context of what that means for cost-based rates, Bonneville will continue to conduct rate proceedings as described in Appendix A, and forecasted Net Secondary Revenue (NSR) will remain a meaningful component of calculating rates. The two main drivers of Bonneville's NSR forecasts in rates are Riverware modeling (forecasted hydro inventory) and Aurora modeling (forecasted energy prices). Aurora modeling results are frequently driven by price expectations for natural gas, and the fuel for frequent marginal resources in the modeling runs. These key drivers of NSR expectations will not be affected by Bonneville's decision to join a day-ahead market, as they will be subject to the same fundamentals regardless of day-ahead market participation. For example, the key drivers that influence prices, such as load demand, hydro inventory, and natural gas prices are fundamental conditions that will drive prices in bilateral markets as well as organized markets. Therefore, the forecasting of these drivers of NSR,

[65] See sections 5.1.1.6 and 5.1.1.7 below for a discussion of impacts to Power and Transmission customers.

which feed into rate proceedings, are not expected to change with a day-ahead market decision.

NSR represents a forecast of what Bonneville reasonably expects or targets for revenue outside of its long-term contract sales to preference customers (see section 6.7). In addition to continuing to provide long-term contracts, Bonneville expects that it will continue to conduct some level of bilateral forward transacting, however, frequency, volume, and terms may change with the evolution of markets within the region. Instead of bilateral trading in the day-ahead timeframe, Bonneville will see resources and loads cleared through the day-ahead market. As is the case today, actual NSR will deviate from rate case expectations, with the difference being reflected as an increase or decrease to Bonneville's financial reserves. Any financial impacts from day-ahead market participation will be a non-itemized portion of NSR to ensure consistency with the Bonneville objective of maximizing the value of its entire generation portfolio by optimizing across all market options.

The key area of difference introduced is that instead of bilateral transactions in the day-ahead timeframe, Bonneville will trade through the market, introducing financial settlements for resources and loads. In the same way that Bonneville must manage inventory and market price risk presented by regional fundamentals, Bonneville will continue to optimize the system through both commercial and operational actions, while minimizing risks. This will continue to be managed closely to minimize costs and maximize revenue for customers, as done today in the bilateral markets.

5.1.1.8. Transmission Services

The evolution of markets in the Pacific Northwest is ushering in day-ahead markets that will impact Bonneville as a BA and TSP. Just as the WEIM required Tariff, Rates, and Business Practice changes, the day-ahead market will require changes as well. This will affect both Network Integration Transmission Service (NITS) customers and Point-to-Point (PTP) transmission service customers. Bonneville needs to ensure that customers continue to receive reliable service. Bonneville's transmission customers rely on Bonneville for delivery of resources to load, whether in Bonneville's BAA or as a path to another BAA.

As Bonneville has seen two day-ahead markets developing, it has become reasonably certain that several of Bonneville's current transmission customers will be in BAAs that have joined a day-ahead market, even if Bonneville does not move to the same or any day-ahead market. Because Bonneville's transmission will be used in day-ahead, real time, and bilateral markets, Bonneville recognizes concerns about potential transmission cost shifts between these different markets. Bonneville will propose changes to its rates, tariff, and business practices to align cost impacts with cost-causation and ensure customers are informed to adjust their respective future business models as needed to account for the new market paradigm.

Both CAISO and SPP realize that day-ahead markets introduce a potential reduction of both short-term and long-term transmission revenues to participating TSPs.[66,67] This potential reduction results from the market design principle that all transmission of a participating TSP is available for the market to use, unless that transmission has been explicitly removed from the market's calculations. Because the market has access to all of the TSP's transmission, there is less incentive for entities to purchase transmission.

The E3 PCM analysis attempted to quantify the impact to transmission revenue, but Bonneville removed it from its PCM assessment.[68] Instead, Bonneville performed its own analysis on the potential impact that day-ahead market participation may have on its transmission revenue. Bonneville focused on PTP transmission because those customers mainly purchase PTP to wheel through Bonneville's BAA, while NITS customers mainly take service and remain in the Bonneville BAA. Bonneville assumed that sales of NITS transmission would remain the same.

[66] *Cal. Indep. Sys. Operator*, FERC Docket No. ER23-2686, Transmittal Letter at 22-23 (Aug. 23, 2023) ("CAISO EDAM Filing").
[67] *Sw. Power Pool*, FERC Docket No. ER24-1658, Transmittal Letter at 9-10 (Mar. 29, 2024).
[68] For more information on the removal of the "Wheeling Revenue" category from the PCM analysis, see section 5.1.1.2.3 above.

Bonneville estimated potential bookends for a potential decrease in transmission sales from $20 million to $200 million over time.[69] Fortunately, both Markets+ and EDAM have a mechanism to help the TSP recover some of the lost transmission revenues due to the day-ahead market; however, they are slightly different approaches.

Markets+ encourages transmission customers to retain and purchase long-term firm transmission rights through its congestion rent design that includes an allocation to transmission rights holders. This allocation allows a transmission customer to directly receive congestion rents if the customer holds firm PTP rights of monthly duration or longer or NITS rights (see section 5.2.4). The EDAM design does not provide the same direct allocation between OATT rights and congestion rents (see section 5.2.4), resulting in a less direct incentive for maintaining long-term transmission rights.

In addition to congestion rent, there are other incentives to maintain long-term firm transmission rights. These include transmission for load service, to meet the WRAP firm transmission requirement, and for interchange transactions importing, exporting, and wheeling through market footprints.

Furthermore, Bonneville has over 65 GW of long-term transmission service requests in its transmission queue, indicating significant demand that could mitigate potential losses of long-term firm sales. Although these customers can remove their requests, Bonneville has not experienced a reduction in its queue. If Bonneville did see a significant reduction of long-term revenues, Markets+ has a robust stakeholder process and governance model that would allow stakeholders to bring concerns up for review.

For the potential revenue loss associated with short-term transmission revenues, both the EDAM and Markets+ day-ahead market designs include a transmission revenue recovery mechanism allowing a participating TSP to recover the potential revenue loss resulting from releasing unsold available transfer capability (ATC) to the market. In Markets+, the Market Transmission Use (MTU) charge mitigates for short-term firm revenue losses, by allowing the TSP to recover the difference between its historical short-term revenue requirement and current short-term revenues.[70] The EDAM Access Charge provides a recovery mechanism for short-term revenue reductions, potential lost short-term revenues associated with future transmission capacity, and potential wheeling revenue shortfalls.[71] The MTU will be applied in the same manner for all TSPs in Markets+. The EDAM Access Charge, however, will be applied differently for CAISO than for other EDAM Entities because of differences in transmission service offerings.[72]

In summary, although participation in day-ahead markets may potentially reduce transmission revenues, both day-ahead market designs have mechanisms that help participating TSPs mitigate this impact. In addition, after entry into a day-ahead market, Bonneville will continue to monitor actual transmission revenue recovery and, if needed, advocate through the market stakeholder process for additional market design adjustments to mitigate any potential loss of transmission revenues.

5.1.2. Participation and Implementation Cost Estimates

Both EDAM and Markets+ have participation and implementation fees. Further, there would be implementation work associated with participation in either option. Cost estimates of each option are provided below. These are

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[69] *See* Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day-Ahead Market (DAM) Participation – Workshop 10 at 15 (Jan. 29-30, 2025), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2025/dam-workshop-10-presentation-20250129.pdf.

[70] SPP Markets+ Tariff, Attach. A § 7.11 (Market Transmission Use).

[71] CAISO EDAM Filing, Attach. A-2 (Clean Tariff) § 33.26.1 (EDAM Access Charges).

[72] For example, for potential wheeling revenue shortfalls "the EDAM transmission owner[] will be compensated for the transmission use that supports the excess wheeling at the EDAM transmission owner's non-firm hourly point-to-point transmission rate or the CAISO participating transmission owner will be compensated for excess wheeling through transmission use at the applicable wheeling access charge transmission rate." *Cal. Indep. Sys. Operator*, 187 FERC ¶ 61,154, at P 20 (2024).

based on Bonneville's BAA. Bonneville assessed implementation and participation costs from CAISO, SPP, and internal projections based upon the best available estimates in early 2025.

5.1.2.1. Market Operator Implementation Fee Estimates

EDAM Implementation Fees

CAISO's EDAM transmittal letter to FERC discusses implementation fees.[73] CAISO estimates the standard fee to be $1.2 million for each BAA that elects to join EDAM.[74] Fees can be larger due to the complexity and size of the joining entity, or if an entity seeks additional market simulation or parallel operations time.[75] CAISO projects typical implementation to take 18 months for each BAA. The timeline can be extended beyond 18 months to accommodate additional market simulation and parallel operations.

Bonneville is one of the largest transmission providers and BAAs in the Western Interconnection and expects a higher than standard implementation fee and a longer than average implementation timeline. If Bonneville were to elect to join EDAM, CAISO estimates the implementation fee to be between $2.5 million and $3 million, and the implementation time frame to be between eighteen and twenty-four months.[76]

Markets+ Implementation Fees

Based on Bonneville's proportional share among all likely funding participants, the estimated share of Phase 2 costs is approximately $26.8 million.[77] The implementation costs to join Markets+ are higher than those for EDAM because Markets+ will have its own software separate from SPP's other markets, whereas EDAM is an extension of the current CAISO day-ahead market, and WEIM and is implemented with the same software.

5.1.2.2. Ongoing Market Participation Fee Estimates

EDAM On-Going Fees

CAISO has annual operating fees to run the market. These fees cover the staff, tools, and applications needed for the market. These fees are collected through CAISO's Grid Management Charge (GMC). The GMC is charged to each EDAM transaction. Bonneville requested that CAISO provide a forecast of the annual GMC fees assuming that entities who have made declarations or provided market leanings are included in the EDAM footprint. CAISO projected that Bonneville could anticipate $29 million annually in GMC.

Markets+ On-Going Fees

Markets+ will also have an annual operating fee. This fee will cover staff, tools and applications needed to run and operate the market. The operating fee will be collected based upon the volume of transactions for each respective market participant. Bonneville contacted SPP to request a forecast of Bonneville's anticipated portion of these annual operating expenses. SPP estimated that Bonneville's expense could be between $13 and $15 million annually.

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[73] CAISO EDAM Filing, Transmittal Letter at 105-07.
[74] CAISO, Extended Day-Ahead Market Final Proposal at 126 (Dec. 7, 2022), *available at* https://stakeholdercenter.caiso.com/initiativedocuments/finalproposal-extendedday-aheadmarket.pdf.
[75] CAISO EDAM Filing, Transmittal Letter at 105.
[76] *See* Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day-Ahead Market (DAM) Participation - Workshop 10 presentation at 18-19 (Jan 29-30, 2025), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2025/dam-workshop-10-presentation-20250129.pdf.
[77] *Sw. Power Pool*, FERC Docket No. ER25-1372, SPP Markets+ Phase 2 Funding Agreement at 24 (Feb. 21, 2025).

Table 9 | Estimated Fees Paid to the Market Operator ($M)

Estimated Fees for Bonneville	**On-going Participation Fee (Paid to MO)***	**One-time Implementation Fee (Paid to MO)***
EDAM	~$29M /year	~$3M
Markets+	~$15M /year	~$26.8M
*BAA value/Bonneville share based on Load/Resource Activity		

Table 9 provides a summary of the on-going participation fees (based on footprints reflecting the current declarations and leanings) and the one-time implementation fees for EDAM and Markets+. While EDAM's implementation fee is quite low at $3 million, the recurring annual fee is double that of Markets+. The ongoing market participation fees above were provided by each respective market operator in early 2025. These are only preliminary estimates based on the information currently available. These estimates can be subject to change. The fees and cost allocations for each market may evolve as each market operator refines their annual market operating expense.

Bonneville has determined that the higher upfront Markets+ implementation fees are justified by the anticipated market benefits, including the superior design elements (discussed primarily in Section 5.2) and lower ongoing participation fees.

5.1.2.3. Internal Implementation Cost Estimates

Joining a day-ahead market would change the operations and systems for Bonneville across Power and Transmission Services. Bonneville performed an initial estimate of the costs to implement either day-ahead market. This assessment was separate from the E3 PCM cost-benefit analysis, which did not evaluate implementation costs. Any assignment of implementation costs to a particular business line will be done as part of an integrated program review process.

To develop the estimate for the implementation cost of joining a day-ahead market, Bonneville identified projects across the agency that would be required for implementation (e.g., metering, outage management, schedule submission, bid curve development, and settlements). The implementation cost of each project was then estimated based on the complexity in project execution. The cost estimate for each market is further broken into the non-labor and the labor components. The non-labor component reflects initial costs for software and hardware upgrades needed for supporting the technological or operational requirements for joining a day-ahead market, while the labor component reflects the incremental staffing costs. Non-labor costs are provided as a range to reflect the uncertainty around the ongoing EDAM and Markets+ design and development.

Bonneville's estimated implementation costs for EDAM and Markets+ are as follows in Table 10[78] :

Table 10 | Internal Implementation Costs ($M)

Market	**Non-Labor**	**Incremental Labor**	**Total Cost (Non-Labor + Incremental Labor)**
EDAM	$11.6M - $19.7M	$18.3M	$29.9M - $38M
Markets+	$26.8M - $47.3M	$26.9M	$53.7M - $74.2M

[78] CAISO's and SPP's one-time market implementation fees and annual operating fees are not included.

The estimated implementation cost for EDAM is about half of Markets+, as a large portion of Bonneville's existing infrastructure built for the WEIM could likely be used in EDAM. SPP has been developing Markets+ consistent with SPP's existing systems and processes, which are different than CAISO's and will require system modifications to enable Bonneville's market participation. Additionally, the higher estimate of the Markets+ implementation cost is also driven by an assumption that Bonneville may choose to switch Bonneville's Reliability Coordinator (RC) from CAISO RC West to SPP RC Services. While the RC change is included in the estimated costs for transparency, the change is not certain and would depend on future policy development.

5.2. Market Design Considerations

Bonneville has thoroughly evaluated various day-ahead market design elements and participated in the design development process for both EDAM and Markets+. While much of the design is similar between the two markets, there are several differences that Bonneville considers significant in its evaluation. These elements are discussed below.

5.2.1. Governance

Independent market governance continues to be paramount to Bonneville's Policy direction towards participation in Markets+. Bonneville defines its governance principle for market participation as "the market has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders" and that "decision-making and stakeholder engagement occurs in a transparent and inclusive manner."[79] Joining a day-ahead market would represent a significant change to how Bonneville operates. The electric industry is grappling with complex issues, and there will surely be additional difficult issues and circumstances in years to come. While Bonneville can never eliminate all risk, Bonneville believes a governance model tailored to support collaborative, unbiased decisions on current and future issues will mitigate risk inherent to the evolution of the industry. It is not possible to quantify a dollar value for the attributes of independent governance, but substantial value comes through in the decision process for market design and Bonneville's ability to influence that design. As noted, current examples include, but are not limited to congestion revenue, fast start pricing and GHG accounting.

Through its public discussion of market participation and consideration of market platforms, Bonneville has heard near-consensus agreement that independent governance is a core principle for regional market design.[80] Bonneville's evaluation considers the relevant factors associated with governance structures under both Markets+ and EDAM to identify the best governance structure available for Bonneville's decision regarding day-ahead market participation. While entities may disagree about what level of governance is sufficiently independent, Bonneville wants the decision-making body for a market to be free of disproportionate obligation to the policies of a single state, entity or customer type. Ideally, management and operations of the market would be independent of any single state or participating entity. In the near term, at the management level, the staffing and process for decision development and stakeholder engagement should equitably weigh the policies or priorities of all states, entities, and customer classes. Finally, the market's design and policies should be equitable in its consideration of the approaches established by all states with participating entities. The following discussion explains the evaluation under each of these factors.

Independence of the decision-making body

In its consideration of EDAM and Markets+, Bonneville evaluated the independence of their respective decision-

[79] Section 4.1.6 above.

[80] *See, e.g.*, Letter from Western State Utility Regulators to the Western Interstate Energy Board (July 14, 2023), *available at* https://www.westernenergyboard.org/wp-content/uploads/Letter-to-CREPC-WIEB-Regulators-Call-for-West-Wide-Market-Solution-7-14-23-1.pdf.

making bodies.

Today, governance for EDAM is entrusted to the CAISO Board of Governors. The Board has delegated certain authority to the Western Energy Markets (WEM) Governing Body, subject to the Board's oversight, in a model referred to as Joint Authority.[81] The CAISO Board of Governors is appointed by the Governor of California with the consent of the California State Senate. Board members oversee CAISO in both its role as the market operator and largest BAA in the market. Members of the WEM Governing Body are nominated from stakeholder sectors and approved by current members of the Governing Body. The Governing Body acts on recommendations developed under the CAISO stakeholder process, which is largely CAISO staff driven. CAISO utilizes working groups to develop the initial stages of policy initiatives then proposals are developed by staff with open comment opportunities for all stakeholders.

The Governor of California's selection of the CAISO Board of Governors risks undue influence of a single state over EDAM. In addition, California law establishing authority for the CAISO Board of Governors requires it to act in the interests of the people of California.[82] While these governance elements were reasonable for the original CAISO market that only operated within California, they are significant flaws in the governance of a regional market that includes participants in other states. These flaws require mitigation that is currently only proposed.

As addressed in Appendix B, a number of regional entities have acted in pursuit of this objective through Pathways,[83] which will be discussed in more detail. Pathways has continued development of proposals for a new entity with an independent governance structure that is capable of overseeing an expansive suite of West-wide wholesale electricity markets and related functions. In 2024, the CAISO Board of Governors and the WEM Governing Body jointly approved additional governance changes that were recommended from Step 1 of Pathways. These changes placed the sections of the CAISO Tariff for WEIM and EDAM under the primary authority of the independent WEM Governing Body. WEM Governing Body decisions will be reviewed by the CAISO Board of Governors on a consent agenda. If the Board disagrees with the Governing Body's decision or vice versa, CAISO will prepare and submit dual filings to FERC on behalf of each body. The CAISO Board of Governors may exercise sole authority for FERC filings in exigent circumstances. Critically, the day-to-day management of policy development and market operations remains with CAISO management who ultimately report to the CAISO Board of Governors. Additionally, the Board's considerations as a BA have the potential to influence its decisions as the market operator.

In contrast, Markets+ will be governed by the Markets+ Independent Panel (MIP).[84] MIP members must be independent of market participants. They are selected through a nomination process of the Markets+ Governance and Nomination Committee and confirmed by the Markets+ Executive Committee. One independent member of the SPP Board of Directors serves on the MIP. The SPP Board of Directors retains authority for specific financial oversight of Markets+. The independent board acts on recommendations developed through a transparent process involving all market participants and stakeholders. The participants and stakeholders collaborate in working groups that have proven effective to build consensus and, where consensus is elusive, to frame the different perspectives for the independent board's consideration in its decisions.

Markets+ decision-making will be under the authority of the MIP whose members, save one representative of the SPP Board, are selected by the Markets+ participants. Additionally, Markets+ is separate from the SPP RTO, so its only focus is on being a market operator. From this comparison, Bonneville finds that the independence of the

[81] *See* CAISO, Governance (2025), *available at* https://www.westerneim.com/Pages/Governance/default.aspx.
[82] Cal. Pub. Utils. Code § 345.5 (2025).
[83] *See* Western Interstate Energy Board, West-Wide Governance Pathways Initiative (2025), *available at* https://www.westernenergyboard.org/wwgpi/.
[84] SPP Markets+ Tariff, Attach. O (Markets+ Governance) § 4.2 (Markets+ Independent Panel). Pending initiation of operations as Markets+, this independent board role is exercised by the Interim Market Independent Panel (IMIP) of three members of the SPP Board. References to the ongoing role of the Markets+ independent governing board will be to the MIP.

Markets+ decision-making body is superior to that of the EDAM and is more likely to result in decisions that create a fair and equitable market that allows Bonneville to meet its load service, power marketing, and transmission obligations.

Decision development and stakeholder engagement

In Bonneville's experience, a market's structure for both stakeholder engagement and decision development are critical to ensuring fair and equitable decision outcomes. Bonneville places great weight on the supporting structure for market decision development through market operator staff and the roles of participants and stakeholders in policy development. This structure is critical to ensure that Bonneville's interests are heard and adequately addressed in the decision process. The difference is not theoretical; Bonneville has been an active participant in both EDAM and Markets+ stakeholder processes and has experienced the difference in terms of decision-making for agenda priorities, collaborative process, and consensus decisions.

Bonneville has observed that the Markets+ structure has a proven track record of effectiveness. Notably, the structure delivered the complete tariff design on an abbreviated schedule through 2023. The structure involved working groups and task forces of market participants and stakeholders who conducted their discussions in publicly noticed and accessible meetings. The structure uses "indicative voting" to document support and opposition from participating stakeholders individually and by sectors. The use of indicative voting promoted collaboration among participants and built confidence in the outcomes. A prime example of the success of the Markets+ governance structure is the development of a mechanism for GHG accounting that meets customer compliance obligations for multiple states and pricing approaches while not adversely affecting states without those obligations.

Bonneville proposed and obtained consideration of its statutory and contractual obligations through the Markets+ process. The working group processes are publicly accessible and consider perspectives from utilities, states, and independent organizations. Stakeholders themselves can set the agenda for issues to be considered by the Interim MIP (IMIP). SPP staff provide appropriate facilitation and technical support roles while respecting the decision-making roles of market participants. The Markets+ Executive Committee (MPEC) ultimately votes on decisions to be brought before the MIP, providing a final opportunity for input from the sectors. Decisions reflected negotiation and compromise, with the IMIP returning issues to the MPEC when insufficient consensus had been reached.

The Markets+ governance structure relies on the time and abilities of market participants and stakeholders to develop market design proposals and deliberate on recommendations. Bonneville acknowledges concerns about that level of commitment. From Bonneville's perspective, this time is well invested for the value of collaboration among participants, shared understanding of the issues and tradeoffs involved, and for durable outcomes. The experience to date has been demanding, to be certain. However, it has yielded unparalleled engagement in the complex challenge of establishing a market. As the market moves into implementation, the cadence of participant work should be more manageable and provide opportunities for entities to combine their efforts.

Bonneville has not experienced the same depth of balanced stakeholder consideration in the staff-driven CAISO engagement model. Bonneville acknowledges the knowledgeability of CAISO staff and CAISO's efforts to develop a more participatory stakeholder engagement process. Bonneville appreciates and respects the professionalism and expertise that CAISO staff routinely display in their stakeholder process. This process, however, could be enhanced through increased stakeholder leadership in policy and implementation development, evaluation, and decision processes. The CAISO governance model also continues to present challenges in resolving contentious regional issues. CAISO must navigate competing priorities for staff and management time on regional issues versus the demands for attention to its own BAA and participating transmission owners.

Bonneville concludes that the Markets+ decision development and stakeholder engagement process is the best approach to ensure a fair and equitable market across multiple states and fair consideration of Bonneville's objectives and obligations.

Reasonable harmonization of state policies

The influence of an individual state in market design can manifest in the obligation of the market to incorporate that state's regulatory or policy design as predetermined conditions. Bonneville, especially from its role as serving utility customers in seven states, seeks a governance model that fosters harmonizing differing state policies.

The structure of the Markets+ policy process supports treatment of different state policies on an equal basis. The policy development process invites market participants to bring their state compliance obligations to the market design and includes the active participation of state representatives. Bonneville observes that this structure has allowed consideration of different state policy designs to arrive at a high degree of consensus on designs that serve the goals of multiple states and the utilities that serve them.

By contrast, CAISO market design rests on a foundation of California state policies. In the design of a regional wholesale market, this approach carries forward to a choice that either California's policy design, for example in GHG accounting, must be accepted as the market standard, or that the market must develop and incorporate alternative designs for those participants outside California.

Bonneville determines that the equivalent consideration of state policies by the Markets+ governance design is superior to that of the EDAM. Currently, there are two FERC approved day-ahead market tariff options available to Bonneville but one—Markets+—is superior with respect to stakeholder engagement, decision-making, and overall market governance.

5.2.1.1. Impact of Pathways on Bonneville's -Day-Ahead Markets Decision

Bonneville has assessed the progress made by Pathways in evaluating its day-ahead market alternatives. Through the Pathways engagement, Bonneville has supported the option for creation of an independent entity with independent administration and operation. While Pathways has made progress in advancing the governance of the WEIM and EDAM, the initial structure proposed in the Step 2 final proposal does not meet Bonneville's standards for independent governance as discussed in detail in Appendix B. The proposed approach is also dependent on legislation successfully passing in California to enable the Regional Organization (RO) structure as proposed, and allowing expansion to greater independence as described in the Step 2 proposal. California Senate Bill540 seeks to enable the Pathways Step 2 recommendation. The legislation would authorize the CAISO and California investor-owned utilities to participate in voluntary energy markets governed by an independent regional organization. Proposed legislation responds to a delicate balance between the interests of parties outside of California, including Bonneville, that the independent regional organization be wholly separated from undue influence of California state government; and the interests of parties in California that the regional organization support California energy and environmental policies. To achieve this balance, the current legislation seeks to reassure California that there are adequate safeguards for respecting California policies through providing for rights of withdrawal as ordered by the California Public Utilities Commission (CPUC). The proposed legislation provides that the CPUC may order California IOUs to withdraw in response to market rules or operations that it deems "detrimental to California consumers or California procurement, environmental, reliability, or other public interest policies." While presented as a "savings" provisions representing current CPUC authority, this scope of authority is made explicit by the proposed legislation. In continuing legislative committee discussions, the bill author and legislators have discussed adding more "guardrails" to ensure market respect for a broad list of California policies and adding requirements for additional legislative review of the RO structure and functions. In emphasizing these authorities as a means of reassuring California policy leaders, it causes reasonable and substantial concern for entities outside of California. Entities outside of California, including Bonneville, will be in a difficult negotiating position within the regional organization governance structure when any proposed rule or business practices can be referred to the CPUC or Legislature for a determination that the proposal will be "detrimental" to a broad and general set of policies. The legislation does leave available improvements in the stakeholder process and market design process to make it more equitable for parties inside and outside of California. Nevertheless, Bonneville is concerned that the legislation as drafted may not meet Bonneville's governance requirement. At the time of this Policy direction, uncertainty remains regarding whether 5B 540 will ultimately be passed and, if so, in what form.

5.2.2. Resource Adequacy and Resource Sufficiency

As discussed in section 4.1.3, a primary aspect of reliability impacted by market design is resource sufficiency and by extension, RA. RA generally refers to long-term planning and procurement of resources to serve expected peak or critical load in a year or season. Resource sufficiency generally refers to procurement of enough resources to serve expected load in the short term (e.g., moving into the week/day/hour). In considering generation and transmission, RA aims to have enough physical resources (e.g., long term expected generation output, new generation or transmission construction) to serve a forecasted peak load well into the future (often many months or years), while resource sufficiency considers the current operational landscape (e.g., outages or derates, up-to-date variable generation and load forecasts, etc.). The two concepts work in concert and are both vital to minimizing scarcity, emergency, or loss-of-load events. The market operator does not take on the role of LRE in either day-ahead market option.[85] All day-ahead market participants are still responsible for their adequacy and sufficiency, and thus obligated to enter the day-ahead market timeframe with a resource portfolio (including power purchases) that can meet their expected load.

Markets+ contains both an RA and resource sufficiency requirement. As a prerequisite to joining Markets+, entities that are LREs must participate in WRAP.[86] WRAP is a regional RA program that increases transparency into the resources and transmission needed to reliably supply power to meet a participant's existing and future load demands. Participation in WRAP requires consistent planning from all participants (which is measured using common RA metrics applied consistently to all participants), to help prevent any entity from leaning on the power supplies of others. Current WRAP participants include most utilities within the Western Interconnection outside the state of California.[87] For long- and short-term planning, the WRAP Forward Showing program requires entities to demonstrate that they have the available generation capacity needed to meet its forecasted peak P50 obligations plus an established planning reserve margin, and 75% of the transmission (as firm transmission) needed to bring generation to load.[88] While Markets+ participation is not required to be a WRAP member, Markets+ is the only day-ahead market choice in the West that requires participants to be in a common RA program, in this case, WRAP.

WRAP feeds into Markets+ via the market's day-ahead and real-time Must Offer Obligations. The Must Offer Obligations require all entities to bring at least the amount of generation needed to meet their forecasted load. If an entity fails to meet its Must Offer Obligation, that entity is financially penalized to discourage failures in the future, but physical market transfers and the optimization of the market footprint are not impacted. This simplified approach is supported by the Markets+ common RA metrics provided by universal WRAP participation because market participants are not only checked for day ahead and real-time sufficiency, but are also assessed for RA much farther out than real time. The inclusion of WRAP and the potential charges for failure to be resource adequate disincentivizes utilities who do not have adequate resources from leaning on other market participants in order to serve load in a manner that is stronger than the EDAM design, which, as explained below, relies only on penalties in the operational timeframe.

The EDAM design does not propose a uniform RA metric nor require EDAM entities to participate in an RA program. EDAM does leverage a Resource Sufficiency Evaluation (RSE) to ensure its footprint is adequate heading into the day-ahead and real time operating periods. EDAM's design leverages the WEIM design which calls for the limiting of an entity's BAA-BAA market transfers for entities that ultimately fail the real time RSE unless entities elect to accept

[85] A Load Responsible Entity (LRE) is an entity directly responsible for ensuring an electrical load is served.
[86] SPP Markets+ Tariff, Attach. A § 5.1.1; *id.* Appendix 3 (Attestation Regarding RA and Participation in WRAP).
[87] Western Power Pool, WRAP Participant Map (last mod. Dec. 30, 2024), *available at* https://www.westernpowerpool.org/news/wrap-area-map.
[88] Western Power Pool, WRAP Tariff § 16.3 (FS Transmission Requirement), *available at* https://www.westernpowerpool.org/private-media/documents/WRAP_Tariff_Effective_1.27.25.pdf ("The FS Transmission Requirement must be met with NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service or network integration transmission service, from such Participant's Qualifying Resource(s) or from the delivery points for the resources identified for its Net Contract QCC or for its RA Transfer to such Participant's load.").

energy transfers through Assistance Energy Transfers, which include an associated penalty charge.[89]

The Markets+ Must Offer Obligation and the EDAM RSE serve a similar purpose, which is to evaluate whether each entity has procured enough resources to support its anticipated demand for the coming day, but the Markets+ integration of WRAP helps ensure equal and prudent planning and resource acquisition in the longer term. By leveraging the WRAP Forward Showing Program through its day-ahead and real-time Must Offer Obligations, Markets+ standardizes, simplifies, and solidifies each market participant's requirements to bring sufficient resources to the market to serve its loads. The more simplified resource sufficiency tests that Markets+ employs in the day-ahead and real-time also have the potential to provide benefits to Bonneville and other Markets+ participants. WRAP participation and the Markets+ Must Offer Obligations ensure sufficiency in a manner that sends strong financial signals that disincentivize future failure to bring sufficient capacity to the market and compensate those who make up any shortage, while still allowing all entities, and the market as a whole, to maintain a reliable, optimized footprint.[90]

While some California utilities are subject to RA requirements under the CPUC jurisdiction, these metrics may be different than those used in WRAP. Further, EDAM participants outside of California may be participants in WRAP, but they are not required by the EDAM market to participate in any RA program. EDAM's lack of common RA metrics makes it difficult to assess whether the footprint as a whole will be resource adequate in the planning horizon. While the EDAM RSEs are intended to prevent market participants from leaning on other market participants by failing to provide sufficient resources to meet their own loads absent market optimization, there are limited options in the day-ahead timeframe for addressing footprint wide sufficiency issues. A lack of a common RA program leaves the task of disincentivizing leaning solely to the EDAM RSE. Limiting transfers for entities that fail the real time RSE is suboptimal for all market participants, and the AET rate alone does not provide as robust an incentive for participants to maintain resource adequacy or resource sufficiency as the design of Markest+.[91] As long as EDAM entities find it more economical or convenient to pay the AET, they can lean on other EDAM entities as a substitute for effective long-term planning to meet their load obligations. The combination of both WRAP charges and the Must Offer Obligation makes such a determination less likely in Markets+.

As concerns continue to grow about RA in the Western Interconnection,[92] the Markets+ design is objectively superior to EDAM because it combines a common long-term RA metric with short-term resource sufficiency obligations, ensuring adequate supply, reliability, and fair compensation. Therefore, Bonneville views Markets+ as the superior day-ahead market choice for supporting regional RA.

5.2.3. Price Formation and Market Power Mitigation

Appropriate price formation ensures that market rules provide appropriate price signals, which compensate resources at prices that reflect both the value the resources provide to the market and the operational conditions that drive the need to procure certain energy or capacity products. Price formation should also ensure that resources respond appropriately and accurately to dispatch instructions from the market. Key aspects of price formation[93] issues can include: uplift payments (including bid cost recovery which can undermine actionable price signals), offer caps and offer mitigation usage, scarcity pricing, fast start pricing, and operator actions (and any associated impacts, or lack thereof, on pricing).

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[89] CAISO, Extended day-ahead market resource sufficiency evaluation discussion at 8 (Oct. 21, 2022), *available at* https://www.caiso.com/Documents/ExtendedDay-AheadMarketResourceSufficiencyEvaluation-Presentation-Oct21_2022.pdf. CAISO, WEIM Resource Sufficiency Evaluation Enhancements – Phase 2 (November 7, 2022), *available at* https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-ResourceSufficiencyEvaluationPhase2-Nov7_2022.pdf.

[90] SPP Markets+ Tariff, Attach. A §§ 5.1.1(C), 5.1.2(C).

[91] CAISO, Extended day-ahead market resource sufficiency evaluation discussion at 8.

[92] WECC, 2024 State of the Interconnection (Sept. 2024), *available at* https://feature.wecc.org/soti/index.html.

[93] For more information see FERC, Energy Price Formation (June 17, 2020), *available at* https://www.ferc.gov/industries-data/electric/electric-power-markets/energy-price-formation.

Related to price formation and necessary for a well-functioning electricity market, is the monitoring and mitigation of market power. The exercise of market power is when one or more entities reduce output below competitive levels so as to raise market-clearing prices.[94] Due to the nature of the deregulated electricity industry, with several large suppliers, who are regionally concentrated and loads with limited ability to exercise price sensitive demand, there is a possibility for the exercise of market power by certain entities. While organized markets are structured to encourage competitive and efficient outcomes through their formation, structural or behavioral issues may allow exercises of market power, which can be mitigated by design. Market power mitigation tests and rules, when effectively implemented, ensure that resources can bid their marginal costs, but are not able to exercise market power. Both market operators and market monitoring departments are committed to monitoring for and mitigating the exercise of market power, though they have different methodologies for assessing the market.

In EDAM, the Market Power Mitigation (MPM) assessment is an extension of the existing WEIM methodology, which looks to address structural market power in participating BAAs. BAA-level MPM uses a dynamic competitive path assessment to evaluate whether the available generation within the participating BAA can competitively meet its own demand without additional transfer imports. If the dynamic competitive path assessment conditions are deemed non-competitive, then all participating resources in the affected BAA are adjusted to the competitive locational marginal price or a lower value of their submitted bid or applicable Default Energy Bid (DEB).

Under the pivotal supplier assessment for MPM, large entities flowing on constrained paths are more likely to be considered a pivotal supplier and face price mitigation measures, by the nature of their structural location, leading to potential over-mitigation. Given the geographical structure of western BAAs, the mitigation assessment based on the pivotal supplier is determined on the participant's potential ability to exercise market power, rather than on the participant's observed behavior. Bonneville appreciates that CAISO is reviewing this aspect of the market design in its Price Formation Enhancements initiative.

In contrast, the Markets+ design leverages the conduct and impact framework for MPM which is used in other organized markets.[95] The conduct test evaluates whether a resource offer is significantly higher than the reference cost of energy, and the impact test determines whether that offer would significantly impact the market prices. If suppliers have been found to fail both conduct and impact tests, then mitigation measures can be applied. Under this framework, resource offers are actively assessed and a negative outcome to the market must occur in order to be considered an exercise of market power. Basing mitigation assessments on the perceived potential to exert market power, as EDAM does, particularly during times of scarcity, creates misaligned incentives and market signals which can prevent appropriate market outcomes. The Markets+ conduct and impact approach is more effective because it mitigates based on the exercise of observed market power, not the potential for market power, thus minimizing over mitigation.

In addition to the assessment for MPM, a key aspect of the market design is to ensure that the reference price calculation, the offer price used when a resource is mitigated, is appropriate. The methodology to determine the reference price for a mitigated offer curve will vary by resource type. For resources such as storage hydro, a key aspect is the opportunity costs associated with future generating periods. For storage hydro, the Markets+ and EDAM are very similar, as the Markets+ design was built upon the approach utilized in WEIM. Bonneville's internal opportunity cost estimation, a component of bid formulation, is dynamic and based on non-public information, making independent verification impossible, though both markets attempt to approximate Bonneville's

[94] For more information see Scott Harvey and William Hogan, Market Power and Withholding (Dec. 20, 2001), *available at* https://scholar.harvard.edu/files/whogan/files/market_power_withholding_harvey-hogan_12-20-01.pdf.

[95] *See* SPP Markets+ Tariff, Attach. B (Market Power Mitigation Plan) & Attach. C (Market Monitoring Plan); *see also* SPP Markets+ Protocols § 11 (Market Monitoring and Mitigation), *available at* https://www.spp.org/Documents/73199/MarketsPlus%20Protocols%20-%20Combined%20-%20MPEC%20Approved%20as%20of%2020250131.pdf.

cost for mitigation purposes. Imperfect cost verification (conduct verification) further reinforces the important role of an impact test to reduce inappropriate over-mitigation.

In EDAM, CAISO employs the DEB model for hydroelectric resources. The DEB uses a formula to estimate the opportunity cost of hydro, focused on three main pricing components: a gas-price floor, short-term energy prices, and a long-term geographic floor. This approach specifically tailors the DEB of a participating resource to its geographic location. Markets+ stakeholders worked with SPP's Market Monitoring Unit to develop the Seasonal Hydroelectric Offer Curve (SHOC) framework. The SHOC is very similar to the DEB but also accounts for a hydro project or aggregation of projects' seasonal storage horizon as part of the opportunity cost calculation.[96] Both designs do their best to account for the flexibility of the system, allowing participants to preserve the value of hydro for future months when appropriate for their resource(s), helping other market participants benefit from the flexible nature of these resources. Bonneville prefers the Markets+ SHOC approach because it distinguishes between hydro resources with and without significant storage availability.

CAISO has undertaken stakeholder initiatives, such as the Day-Ahead Market Enhancements (DAME) and Price Formation Enhancements, to review and address changes to products and prices within its market. During its DAME[97] effort, CAISO created the Imbalance Reserve Product, which recognized the need to procure additional flexible products that can be economically awarded to help provide additional capacity and reduce out-of-market actions by the market operator. The CAISO/EDAM footprint had a demonstrated need for this product due to the uncertainty swings in the load-resource balance caused by the variable renewable resource mix within the footprint and the need for dispatchable resources that are deliverable and can ramp between fifteen-minute intervals[98]. While Bonneville was initially very supportive of this product, the final product design changed significantly in the final stages of the stakeholder process, at which point Bonneville identified a number of significant areas of concern, as did other stakeholders[99]. While Markets+ does not include a comparable product, WRAP includes financial incentives to ensure equitable procurement of capacity to prevent leaning on the capacity of others, as well as compensation for holdback and energy deployment. Bonneville accepted the position that developing a similar product in Markets+ without a demonstrated need could impose additional and unnecessary costs to load service and agreed to move the topic to the Markets+ "parking lot" for consideration after go-live. Bonneville will monitor its participation in Markets+ and consider whether it feels a similar product would be necessary and/or beneficial to the Markets+ design. Bonneville is confident that the Markets+ stakeholder process will address any concerns that arise.

In the Price Formation Enhancements initiative,[100] scarcity pricing and fast-start pricing are critical elements because they can ensure resources are appropriately incentivized and compensated for the attributes they bring to a market dispatch, while reducing the need for out-of-market actions. In addition to ensuring accurate prices in the short term, price formation can help send better price signals for developing supply to meet future demand. Transparent and equitable price formation is an important step toward increasing market efficiency through increased competition, potentially ensuring supplier cost recovery while reducing the cost load pays.

CAISO has mechanisms for implementing a level of scarcity pricing when the system is low on reserves and

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[96] *See* SPP Markets+ Tariff, Attach. B (Market Power Mitigation Plan) & Attach. C (Market Monitoring Plan); *see also* Markets+ Protocols § 11.

[97] See the CAISO Day-Ahead Market Enhancements Initiative page for more details on these efforts and for Bonneville-submitted comments, *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements.

[98] *Id.*; *see also* CAISO, Day-Ahead Market Enhancements Stakeholder Technical Workshop presentation at 6 (June 20, 2019), *available for download at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements.

[99] *See* CAISO, Day-Ahead Markets Enhancements Initiative (comments submitted by Western Power Trading Forum, Vistra, The Energy Authority, and Powerex) *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements.

[100] *See id.*

network modeling needs to solve for tighter bid-supply conditions, but it does not currently have a design that includes compensation for fast-start pricing. Fast start pricing allows a generator's commitment costs, in addition to marginal fuel costs, to be considered in economic bid evaluation and directly captured in LMPs paid to all resources. CAISO is currently reviewing these topics as part of its Price Formation Enhancements initiative, in which Bonneville is actively engaged, although many stakeholders continue to oppose the adoption of fast start pricing. The absence of fast start pricing in CAISO reduces costs for California load by reducing fair and transparent compensation for generation in both California and throughout the West, including Bonneville's generation. In contrast, Markets+ incorporates fast-start as well as scarcity pricing into its day-ahead market design, which Bonneville believes helps to ensure accurate, fair compensation for all suppliers of flexible and reliable generation.

Bonneville's position on price formation and market power mitigation assessments has not changed from the April staff recommendation.[101] These are cornerstones of organized markets. Markets+ design elements ensure that resources can efficiently respond to market signals and be appropriately compensated, while avoiding over mitigation and ensuring transparent market pricing. Therefore, Markets+ design is more aligned with Bonneville's perspective regarding MPM and price formation, which can help improve outcomes for both resources and loads.

5.2.4. Congestion Modeling and Congestion Rent

Generally, the overall transmission design between EDAM and Markets+ is similar. Both day-ahead market frameworks rely upon transmission made available by market participants, TSPs, and transmission customers to facilitate the transfer of energy across the market footprint.[102] Market participants and participating TSPs in EDAM and Markets+ must make their transmission available for market use as a condition of participation, unless specifically opted out according to the respective market's rules. The CAISO EDAM Tariff allows participating entities to let transmission customers designate any of the transmission rights they hold as non-participating. The EDAM design intends for the EDAM Entity to make the ultimate decision to enable this market feature in its BAA.[103] The SPP Markets+ Tariff includes the opt-out of transmission from the market as part of the market design and has already established a communication process to opt-out transmission. In addition, both markets are designed to recognize market participants' existing transmission rights that can still be exercised in the day-ahead and real-time horizons. This is further explained in Section 6.8.

Physical Congestion Modeling

Ultimately, both EDAM and Markets+ will model constraints and manage transmission similarly. From a BAA perspective, each market will have to ensure that each participating and adjacent BAA can continue to calculate its

[101] Bonneville Power Administration, Staff Recommendation on Day-Ahead Market Participation (Apr. 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/02-day-ahead-market-attachment-1-staff-recommendation.pdf.

[102] SPP Markets+ Tariff, Attach. D (Markets+ Transmission) § 1.0 (General); CAISO EDAM Filing, Tariff Appendix B.33 (EDAM Transmission Service Provider Agreement (EDAMTSPA)).

[103] The CAISO EDAM tariff provides:

> **Transmission Not Available in the Day-Ahead Market**. If the CAISO is informed through the prospective EDAM Entity implementation process or by the EDAM Entity Scheduling Coordinator for the EDAM Transmission Service Provider that accommodation of incremental intra-day schedules in the Real-Time Market should be unavailable in the Day-Ahead Market according to the EDAM Transmission Service Provider tariff, the CAISO will accept a notification from the EDAM Entity Scheduling Coordinator associated with the EDAM Transmission Service Provider and will adjust Day-Ahead Market availability of the impacted transmission elements and the associated transmission service rights.

Cal. Indep. Sys. Operator Corp., FERC Docket No. ER23-2686, Transmittal Letter, Attach. A-2, Tariff § 33.18.3.3 (Aug. 23, 2023).

Net Scheduled Interchange (NSI), Net Actual Interchange, manage area control error (ACE)[104] in real-time, and perform After the Fact (ATF) energy accounting. Further, capacity or energy transfers from each BAA (EDAM and Markets+) must accurately account for Bonneville transmission rights that were used to facilitate the transfers. At times, these BAA-to-BAA rights and transfer accounting models in each market may end up being constrained and produce congestion revenue which will need to be allocated. Further, each market will also be able to model physical constraints (e.g., flowgates, paths, or lines). When the physical limit (or allocation of a physical limit) is reached in either the day-ahead or real-time, each market will attempt to honor the limit and potentially produce congestion revenue. Any congestion revenue would be allocated under the market tariff or under the participating BA's tariff in the case of EDAM, as described below.

Congestion Rent Allocation

Congestion rents[105] are payments to participants that occur within a market when the types of constraints described above become limiting (i.e., when congestion occurs). When congestion occurs at a constraint, the least-cost energy cannot be awarded to be delivered to all loads while respecting the constraint limits. The price to serve an incremental MW of load on either side of the constraint is different, resulting in different costs to serve demand in different locations.

To illustrate, a hypothetical generator clears at $25/MW and some portion of its output is serving load across a constraint. Due to congestion, it cannot send an incremental MW of energy across the congested element. Another resource offers $35/MW. The load will pay $35/MW rather than $25/MW because its incremental MWs are served by the other resource offering $35/MW. In this scenario, the market operator will have received more money than it distributed due to the congestion that caused price separation between LMPs.[106] The market operator must then allocate these congestion revenues in some manner to ensure that it remains revenue neutral. Methodologies for how a market allocates this congestion revenue vary, but generally the aim is to return it to the loads and to the transmission rights holders.

n most RTOs and ISOs, this allocation is effectuated by the conversion of physical OATT rights to Congestion Revenue Rights (CRRs) or similar path-specific financial rights, which can also be procured through auctions. However, neither Markets+ nor EDAM will rely on these financial instruments. Congestion rent is instead dictated by the respective market design and as applicable, the participating TSP OATT. The congestion rent designs and allocation methodologies for the proposed day-ahead markets are quite different.

EDAM breaks all congestion rents into two categories: congestion revenue and transfer revenue. In EDAM, congestion revenues are allocated to the BA where the binding constraint is modeled.[107] Transfer revenue is

[104] Area Control Error (ACE) is a real-time calculation performed by every BAA's Automatic Generation Control (AGC) system that indicates when something has changed and the BAA or interconnection is not balanced, such as: BAA load deviated from forecast, generator deviated from schedule, interchange deviated from schedule, or interconnection frequency deviated from schedule. ACE is measured in megawatts (MW).

[105] Congestion management includes all operational actions taken by grid/transmission operators to **proactively** and efficiently manage congestion, maintain the smooth flow of energy, and minimize the need to take operator actions in real-time. One aspect of congestion management is ensuring that a Market Operator honor the operational limits provided by TSPs and TOPs and that these operational limits are reflected in the market dispatch. Respecting these operational limits can result in price separation between loads, which results in congestion revenue or rent. Congestion revenue or rent is the money collected by the market operator due to the operational limitations that result in price separation between load and generation. Congestion rent is the term used in Markets+ and how we will refer to this topic generally. EDAM specifically differentiates between congestion revenue and transfer revenue as two components of the allocation of these congestion rents.

[106] To see a more detailed example of congestion, please see Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day Ahead Market (DAM) Participation - Workshop 7 presentation (June 3, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/dam-workshop-7-presentation-060324.pdf.

[107] *See* CAISO EDAM Filing, Tariff § 33.11.1.2 (Congestion Revenue).

collected when the net EDAM Transfer scheduling limit is reached in the day-ahead market, representing price separation between neighboring BAs in EDAM.[108] The transfer revenue is allocated equally between the two BAs, unless there is an alternative commercial arrangement.[109] An EDAM transfer rights holder that makes capacity available to CAISO is eligible to receive transfer revenue and congestion revenue settlements through the Scheduling Coordinator.[110] The allocation of congestion revenue and transfer revenue collected by the EDAM entity will be suballocated according to that EDAM BAA's OATT. The suballocation of congestion rents is thus subject to the individual rules of the transmission service provider's Tariff. This can present undue complexity for customers by producing a wide set of outcomes depending on the tariff or tariffs to which a customer is subject.

A fundamental challenge Bonneville sees with the EDAM approach to congestion rent is the allocation being based on BAs, rather than a footprint-wide allocation which focuses on rights attributable to key constraints. A transaction occurring inside of EDAM, even a scheduled delivery that exists entirely within one BA, could be exposed to congestion that occurs elsewhere within the EDAM footprint. Per the EDAM design, the revenues of this transaction would be solely distributed to the BA where the congestion is binding. Due to the nature of physical flows, this could be a frequent occurrence. Without the means to recover revenue from congestion that may have occurred in a neighboring BAA, entities are presented with the potential to be exposed to congestion charges without the means to adequately hedge or recover revenue from the costs incurred by load. When the congestion revenue occurs within the BAA, there is no guarantee that the BA's OATT will allocate congestion by constraint within their BAA, presenting additional risk that loads will be exposed to costs and unable to recover offsetting congestion revenue.

Issues with the EDAM design and concerns regarding parallel flows became apparent when PacifiCorp filed its Tariff revisions with FERC to enable its participation in EDAM.[111] Protesters raised concerns that the EDAM design did not allow for "a sufficient congestion hedge to transmission customers exercising their transmission rights."[112] In response to these protests, CAISO initiated an expedited stakeholder initiative to address these concerns. CAISO's proposal is "to allocate parallel flow congestion revenues to the EDAM balancing area where these revenues accrue associated with the exercise of long-term firm and monthly firm Point-to-Point and Network Integration Transmission Service rights based on submitted day-ahead balanced source and sink self-schedules."[113] While this proposed change presents a better hedge than the current design, Bonneville's concerns regarding the BAA sub-allocation design and the lack of direct hedging by constraint remain. In addition, proposed tariff revisions of entities pursuing participation in EDAM require self-scheduling in order to receive congestion rent.[114] Incentivizing self-scheduling significantly reduces economic participation in the market and limits optimization benefits.

Markets+ takes a very different approach to the allocation of congestion rents. It does not differentiate between congestion occurring within BAAs or between BAAs, but rather it evaluates allocations across the entire footprint, specifically the rights associated with individual constraints. The allocation of eligible rights by physical constraint across the entire footprint, rather than allocating by BAA, mitigates the concerns with the EDAM design highlighted above. In Markets+, congestion rents associated with physical constraints are allocated directly and proportionally to the transmission rights holders of firm and conditional firm PTP transmission service, network integration

[108] *See id.* § 33.11.1.1 (Energy Transfer Revenue). This language allows for either a 50/50 allocation or another pre-existing commercial arrangement.
[109] *See id.*
[110] *See id.* § 33.18.4 (CAISO Transmission at EDAM Interties).
[111] *PacifiCorp*, FERC Docket No. ER-25-951-000.
[112] *Draft Final Proposal: EDAM Congestion Revenue Allocation* at 3 (April 16, 2025) (available at: https://stakeholdercenter.caiso.com/InitiativeDocuments/Draft-Final-Proposal-EDAM-Congestion-Revenue-Allocation-April-16-2025.pdf.
[113] *Id.* (parentheticals omitted).
[114] *Portland Gen. Elec.*, FERC Docket No. ER-25-1868-000, Transmittal Letter at 17 (April 3, 2025); *PacifiCorp*, FERC Docket No. ER-25-951-000, Transmittal Letter at 18-19 (Jan. 16, 2025).

transmission service, and legacy transmission service of monthly or longer service increments whose rights are associated with that physical path, who have not opted these rights out of Markets+.[115]

Under the Markets+ design, PTP eligibility will be based on the eligible transmission service request (TSR), while NITS eligibility is tied to an allocation cap based on the customers' monthly peak load and the allocation across paths is based on the designated network resources offered to serve their loads.[116] However, if NITS customers use secondary NITS service, the Markets+ design does not include secondary service in the direct congestion rent allocation. In these cases, there may be congestion revenue, but SPP will not allocate it directly to the Market Participant. SPP will allocate any undistributed congestion revenue to the TSP, and the TSP will allocate those revenues according to its tariff.[117] In addition, the congestion revenue design will be monitored by the Markets+ stakeholders, with an emphasis on ensuring equity between customer types, and evaluated for potential changes in the future that may result in updates to the Markets+ design if appropriate[118]. If participants require an allocation between two binding BAAs to be enabled, similar to what is done for transfer revenue in EDAM, the Markets+ Tariff allows for an allocation between binding BAAs.[119]

Based on an assessment of these two approaches, Bonneville believes that the Markets+ constraint-level congestion rent design is more robust because it better recognizes the topology of the market footprint and directly aligns with how Bonneville models and manages transmission constraints. For this reason, along with the concerns regarding the EDAM design methodology for allocation of congestion revenue, Bonneville strongly supports the congestion revenue allocation methodology of Markets+.

5.2.5. Greenhouse Gas Accounting

Bonneville is not subject to any state GHG programs in the region. However, it is important to many of Bonneville's customers to maintain the low-carbon attributes of the federal system. The market design for GHG accounting—how resources and their associated emissions are assigned to market participants—is critical to ensuring Bonneville's customers can continue to claim the low-carbon attributes of the federal system to comply with various state-mandated GHG programs or for their own utility purposes. This is a particularly challenging area because the various state GHG-reduction programs have created a patchwork of inconsistent policy goals and economic drivers across the West that can be challenging for utilities to navigate in wholesale power markets. EDAM and Markets+ meet the GHG accounting needs of states and participants in two ways.

First, a dispatch-based solution has been developed that supports state carbon pricing programs like California's cap-and-trade program and Washington's cap-and-invest program. The dispatch-based solutions incorporate a price on carbon for generation located in the state subject to the state program and electricity imports to the state. The market optimization selects resources to be attributed to serving load in the state based on the most economically efficient outcome for the market, including the carbon price for the applicable state.

Second, out-of-market (i.e., non-dispatched based) tracking and reporting mechanisms are being developed to support the needs of states and participants generally. This accounting supports a participant's ability to claim their owned and contracted resources for GHG reporting purposes. Bonneville considered how a day-ahead market GHG accounting design will impact Bonneville's customers across the region. Bonneville believes that a market design must address GHG accounting in a way that works fairly and equitably for all participants and states and does not

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[115] *See* SPP Markets+ Tariff, Attach. A § 7.16 (Congestion Rent Eligible Transmission Service Reservation Verification).
[116] *Id.* § 7.16 (Congestion Rent Eligible Transmission Service Reservation Verification).
[117] *Id.* § 9.2.15 (Day-Ahead Excess Congestion Rent Allocation Distribution Amount).
[118] This monitoring plan was approved as part of the MCRTF protocols. SPP, Markets+ Monitoring Metrics Congestion Rent (Aug. 14, 2024), *available at*: https://www.spp.org/Documents/72193/Congestion%20Rent%20Monitoring%20Approach%20Clean.docx.
[119] SPP Markets+ Tariff, Attach. A § 7.16 (Coordinated Interchange Scheduling Limits). Similar to the EDAM design, this language allows for either a 50/50 allocation or another mutually agreed upon ratio.

prioritize a single state's policy.

Generally, day-ahead markets can improve GHG accounting by providing greater transparency and granularity of dispatch data, providing more specific emissions information associated with serving load inside the market footprint.[120] In recent years, markets have needed to develop solutions for addressing GHG accounting to support state program requirements and individual participant needs. Where state programs have enacted a price on GHG emissions, the market needs a way to determine what is least-cost for the entire market and simultaneously least-cost for meeting load in a state with the pricing program. In addition, the market needs a method for assigning dispatch of specific resources (and their associated emissions) to specific loads to support the GHG reporting needs and emission reduction goals for states and individual utilities.

GHG accounting and reporting for organized markets is an actively evolving area with markets developing solutions to meet state program GHG requirements and state programs updating rules to adapt to market design. There are still uncertainties about how organized market GHG accounting will work with state GHG reporting, and additional uncertainties as to how this transpires into the GHG reporting provided to states for purchases from the federal system. While Bonneville cannot provide explicit details on what GHG reporting will look like for Bonneville's customers with participation in a day-ahead market, significant progress has been made related to GHG market design and related state GHG reporting in recent years and there is sufficient information available to describe and assess generally how the market design will work. The GHG market designs are described below.

There is currently insufficient information to determine if joining a day-ahead market will increase or decrease emissions attributed to federal power purchases from Bonneville. There are a number of unknown factors that are material to overall emissions impacts, including what resources are participating in the market, the market's GHG tracking and reporting rules combined with state-specific GHG reporting requirements, and changes in market behaviors of participants (e.g., shifts from use of traditional bilateral markets to organized markets). Nevertheless, there is enough information available for Bonneville to determine that the Markets+ design is superior to the EDAM design as described below.

5.2.5.1. GHG Accounting for Carbon Pricing Programs

EDAM and Markets+ have developed solutions that dispatch and attribute least-cost resources (including GHG costs) to load in a carbon pricing state to support the needs of states with carbon pricing programs, like California and Washington. The market operators aim to meet the needs of states and utilities subject to the carbon pricing program without negatively impacting states and utilities without such a program. However, in many cases, challenging trade-offs are inevitable because the market must balance the differing policies of states with respect to GHG reduction.

Bonneville believes that Markets+ GHG accounting design for carbon pricing programs achieves a reasonable approach to a market design that supports states with carbon pricing programs while not unfairly impacting states and entities not subject to carbon pricing. Conversely, Bonneville finds that CAISO's design falls short. As explained below, Bonneville anticipates CAISO's current design could have adverse financial impacts to Bonneville's customers and jeopardize customers' abilities to continue to report the low-carbon attributes of their power purchases from the federal system. There are two fundamental differences in design features that lead Bonneville to this conclusion.

5.2.5.1.1. Markets+ "Type 1A" attribution ensures attribution of federal system power contracted to utilities in states with carbon pricing programs

For customers located in Washington and subject to the state's cap-and-invest program, Markets+ design is superior because it better supports customers' ability to claim the low-carbon attributes of the federal system. Markets+

[120] *See, e.g.*, CAISO, Average Emissions Rate Report, *available at* https://www.caiso.com/library/average-emissions-rate-reports.

design (for "Type 1A" attribution of power to a state) will result in greater assurance that power from the federal system will be attributed to Bonneville's Washington customers. Markets+ design allows participants to register resources as "Type 1A" if they have contracts with load in the GHG Pricing Zone.[121] This "Type 1A" treatment recognizes that utilities have entered into contractual arrangements to procure clean or low-carbon energy and honors those contractual agreements by attributing the resource (if it is economical within the market dispatch) to load in the state. This "Type 1A" treatment is a critical feature that will allow customers to identify federal resource amounts that are contracted to its customers in Washington[122] and the market design will ensure those resources are attributed to Washington load if dispatched.

The Markets+ design recognizes contractual commitments that meet certain qualifications as "Type 1A" resources. Type 1A resources are optimized in the same way as in-state resources, resulting in the inclusion of the appropriate GHG adder in the offer prices and attribution to load in the state with the GHG pricing program. Thus, the design ensures attribution of the low carbon attributes of the federal system to Washington loads that have contracted with Bonneville.

EDAM's design recognizes contractual commitments[123] but not in an equivalent manner to Markets+ Type 1A treatment. EDAM's design recognizes contractual commitments, but does not guarantee the federal system, if dispatched, will be attributed to Washington. The market will seek the most economic solution for the market, including the carbon pricing states (both California and Washington). The federal system could be dispatched and attributed to Washington or it could be dispatched and used to meet load in the rest of the market, when it is the most economical solution for the entire market footprint (this is more akin to Markets+ Type 1B).[124] Thus, EDAM's design, if extended to Washington, would not provide the same level of assurance that federal power would be attributed to Washington loads. Further, EDAM does not appear to support assured attribution, even for self-scheduled resources (although, if it did, self-scheduling would not be an efficient market design because it would not allow for an optimized dispatch when appropriate).

EDAM's market design, paired with the design of Washington's cap-and-invest program, could dispatch fossil fuel generation located inside Washington to help meet power balance of the market as a whole, and attribute the resulting GHG emissions to load across Washington, including that of Bonneville's preference customers. At the same time, less expensive federal power could also be dispatched by the market but not attributed to Bonneville's power customers in Washington. This could occur because in-state resources[125] always have the GHG adder[126] in their dispatch, so the market optimization will by default first deem all in-state resources to be serving load inside the carbon pricing state, to achieve a least-cost solution for the entire footprint of the market. This could happen even if the market also dispatches a cheaper out-of-state clean resource that is contracted to Washington load. While this is a good solution for economic efficiency when considered across the entire market footprint, it can create unintended consequences for Washington loads that have contracts with clean or low-carbon resources located outside of the state. This inability to ensure federal power is attributed to Washington prevents Bonneville's

[121] *See* SPP Markets+ Tariff, Attach. K §§ 2, 3.2.2.
[122] Currently, in Bonneville's BAA, only its customers in Washington will have load included in a GHG Pricing area.
[123] *See* CAISO, Extended Day-Ahead Market Final Proposal § 7(c) and (d) (Dec. 7, 2022), *available at* https://stakeholdercenter.caiso.com/initiativedocuments/finalproposal-extendedday-aheadmarket.pdf.
[124] Type 1B is energy from a resource with an agreement to supply load inside a GHG pricing zone. Type 1B energy is only attributed to the GHG pricing zone if it is the most economic solution for meeting power balance for the entire market. *See* SPP Markets+ Tariff § 1 (Definitions, Type 1B Energy) and Attach. K § 3.2.3.
[125] In-state resources are generally resources physically located in the state with the GHG pricing program (*e.g.*, Washington). However, pursuant to Washington's Climate Commitment Act, the federal system is considered to be external to the GHG Pricing Zone. *See* Wash. Rev. Code § 70A.65.010(42)(c).
[126] A GHG adder represents the monetary value of an individual resource's emission factor multiplied by the cost of compliance with the respective state program (e.g. cost of allowances). *See* CAISO EDAM Filing, Tariff § 29.32(a) (GHG Bid Adders); SPP Markets+ Tariff § 1 (Definitions, Specified GHG Adder).

Washington customers from claiming the low carbon attributes of the system and therefore equates to increased costs for Bonneville and its long-term firm power purchasers.

5.2.5.1.2. Markets+ Baseline "Threshold" Run recognizes Bonneville's load obligations in determining energy eligible for attribution, limiting the risk that energy contracted to other utilities will be attributed to states with GHG pricing programs

For customers located outside Washington, Markets+ design (the "threshold enhanced floating surplus" approach)[127] gives Bonneville the ability to manage how much energy from the federal system can and cannot be attributed to load in a state with carbon pricing (referred to as a GHG pricing area). Bonneville expects that the low-carbon nature of the federal system will often make it a least-cost option (including GHG cost), and, thus, result in attribution to load in California or Washington. Markets+ design includes market mechanisms that largely limit the amount of energy (aside from contracted amounts) that can be attributed to a GHG pricing area to circumstances when that energy is surplus to a market participant's total load obligations.

Markets+ design enables the resource owner to set a threshold reflective of the market participant's load obligations. Markets+ uses a baseline run that takes those obligations (the "threshold") into account by only making amounts dispatched over the threshold available for attribution to a GHG pricing area. The threshold run looks at the entire footprint of the market and is currently expected to run approximately every 15 minutes[128] and should yield results that are fairly aligned with the optimization and ultimate dispatch of the resource. In other words, the existing load obligations of the resource are a direct consideration of how much energy is eligible for and ultimately attributable to a GHG pricing area. This is a key feature of Markets+ design that would help ensure that Bonneville's customers can continue to claim the low-carbon attributes of their federal system power purchases for applicable state programs or for their own purposes.

While the newly adopted EDAM design will allow a participant to indicate how much energy they are willing to attribute to a GHG pricing area,[129] there is no in-market mechanism that aligns the participant's load obligations to the baseline run or optimization and resource dispatch. Rather, EDAM's baseline run (the "reference pass")[130] takes a broader look at resources across the market footprint to establish eligibility for attribution. As the CAISO explained in its EDAM filing, the EDAM counterfactual will "approximate how a balancing area outside the GHG regulation areas will meet its own load with its internal generation as well as supply from other balancing areas outside of the GHG regulation area. The goal of the GHG reference pass is to reflect how supply resources can optimally serve demand in the EDAM footprint without net imports into the GHG regulation areas and the associated cost of compliance with GHG regulation."[131] As a practical result of this, EDAM limits attribution of a resource to amounts that are determined to be surplus to the load needs of the entire market footprint rather than surplus to the participant's load obligation.[132]

Bonneville has two concerns with the EDAM design. First, this design incorrectly assumes that the best way to prevent leakage[133] is by assuming the load obligations of all market participants external to the GHG pricing area

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[127] *See* SPP Markets+ Tariff § 1 (Definitions, Surplus Threshold) and Attach. K §§ 3.4, 3.7.
[128] Email exchange between Bonneville and SPP (on file with author).
[129] *See* CAISO, Extended Day-Ahead Market Final Proposal § 7(b)(3)(a) (Dec. 7, 2022), *available at* https://stakeholdercenter.caiso.com/initiativedocuments/finalproposal-extendedday-aheadmarket.pdf.
[130] *See* CAISO EDAM Filing, Transmittal Letter at 163-69; CAISO, Extended Day-Ahead Market Final Proposal § 7(b)(3)(c).
[131] See CAISO EDAM Filing, Transmittal Letter at 163-69.
[132] The EDAM excludes committed capacity from the baseline run. In other words, committed capacity will always be eligible for attribution to the GHG pricing area that the load it is contracted to is in.
[133] "Leakage" as used in this context is a reduction in GHG emissions within one jurisdiction that is offset by an increase in GHG emissions in another jurisdiction. See, for example, the definition of leakage in the California Global Warming

must be met before a resource could have surplus energy available for attribution to the GHG pricing area. This unnecessarily limits attribution from a particular resource, which may not be fully obligated (or obligated at all), which can disadvantage not only the seller of clean and low-carbon energy but also the state with the pricing program because the remaining resources eligible for attribution tend to be higher cost. Rather, the more appropriate measure is whether an individual resource (or system of resources, in Bonneville's case) has surplus energy available above its particular load obligations. As discussed above, Bonneville believes the Markets+ design appropriately focuses on energy amounts surplus to an individual resource's load obligations.[134]

Bonneville notes that there is a related concern with CAISO's BAA net export constraint,[135] which limits attribution from resources in a BAA where that BAA is a net importer.[136] However, the BAA is also not the appropriate measure of whether an individual resource has surplus energy available to meet load in a GHG pricing area. While the Bonneville BAA as a whole may be a net importer, that does not identify whether individual non-federal resources or the federal system is surplus in relation to each resource's individual load obligations.

Second, under EDAM's design, the actual optimization could dispatch the resource at levels lower than those reflected in the reference pass, which could result in significant amounts of the federal system being attributed to California even though that power is contracted to Bonneville's customers in other states under long-term power sales contracts. While this can happen as well with Markets+'s design, the risk is minimized because, as discussed above, the threshold run is 1) based on all loads and resources in the market and 2) expected to be run every 15 minutes.

CAISO's existing market, the WEIM, demonstrates Bonneville's second concern. In the WEIM, there are often times when the amount of federal system WEIM dispatches that are attributed to California are greater than the amount that Bonneville's BAA is exporting to the WEIM. Specifically, when there is a non-zero GHG shadow price, meaning some carbon emitting resources are being attributed to California,[137] about 90% of Bonneville's WEIM power sales are being attributed to California. This occurs even though there may be a negative imbalance[138] in Bonneville's BAA (i.e., Bonneville BAA is importing from the WEIM) and customers have contracts with Bonneville for forward supply. A day-ahead market would subject a larger portion of the federal system to this effect. CAISO has taken recent steps to improve the GHG accounting design in EDAM by switching to a baseline

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Solutions Act of 2006 (Assembly Bill 32, or AB32), *codified as* Cal. Health and Safety Code Div. 25.5, §§ 38500-99.11. CAISO uses the term "secondary dispatch" to identify when leakage is occurring in its market design because a resource has been attributed to a jurisdiction (California) at levels below the resource's baseline.

[134] Bonneville notes that emissions leakage (also referred to as secondary dispatch in a markets context) is a state issue as opposed to a markets issue. Individual state programs may have differing views on whether leakage needs to be addressed and, if so, how stringently. CAISO's approach to minimize leakage is purportedly a California approach as the California Air Resource Board's cap-and-trade program was the only pricing program in effect with guidance on leakage at the time of EDAM development. Conversely, SPP's approach provides more state flexibility to determine parameters around the appropriate amount of leakage. This is because a resource owner's threshold can be informed by guidance from a state on what constitutes surplus energy that is eligible for attribution to the state.

[135] *See* CAISO EDAM Filing, Tariff § 29.32.1.

[136] The EDAM net export constraint does not apply when the BAA is located in a GHG pricing zone and does not limit committed capacity from being attributed to a GHG pricing zone.

[137] Bonneville uses its Asset Controlling Supplier emission factor to inform its GHG bid offer for California, resulting in a very low, but non-zero GHG emissions cost.

[138] The WEIM Transfer is an algebraic quantity (positive for export and negative for import) for the net energy exchange between a given BAA and the remaining BAAs in the WEIM Area. *See* CAISO Business Practice Manual for the Western EIM, Appendix A: Mathematical Formulation for WEIM Transfer § 16.2.1.1.1, *available at* https://bpmcm.caiso.com/BPM%20Document%20Library/Energy%20Imbalance%20Market/BPM_for_Energy%20Imbalance%20Market_V33_Clean.docx.

run[139] and adding the BAA next export constraint for EDAM. Bonneville expects that these updates will help reduce this effect but not minimize it as effectively as the Markets+ design. In the event this occurs in EDAM, it could undermine the ability for Bonneville's customers in other states, like Oregon, to claim energy from the federal system for GHG reporting purposes, despite the fact that they hold long-term contracts for federal system purchases.

5.2.5.2. GHG tracking and reporting for non-pricing programs and general needs of market participants

Both EDAM and Markets+ are also developing more broadly applicable GHG accounting solutions that could support meeting the requirements of states with non-pricing programs (e.g., emission reduction standards that do not explicitly place a price on carbon), as well as the GHG accounting needs of any individual market participant. Bonneville views these solutions as essential to its customers' ability to retain the GHG benefits of the federal system.

Markets+ has developed and adopted a novel out-of-market GHG accounting solution designed to support the needs of market participants, whether to meet requirements of a state non-pricing program, local requirements, or individual utility goals.[140] The accounting framework will assign to a market participant the dispatched energy for the market participant's owned and contracted-for resources up to the amount of the market participant's load. This will ensure (subject to state GHG reporting rules) that market participants can claim and report the clean resources in which they have invested. Bonneville has confidence that the Markets+ solution will support Bonneville's customers' ability to continue to claim the low-carbon attributes of the federal system regardless of the state in which the customer is located.

EDAM work to develop a similar approach is in progress.[141] In December 2024, CAISO published an issue paper that outlines reporting design options and some tradeoffs.[142] It is uncertain whether the approach CAISO ultimately adopts will support the needs of Bonneville customers. At this time, Bonneville has more confidence that the Markets+ design for accounting and reporting will meet the needs of its customers.

5.2.5.3. GHG Takeaways

Markets+ includes a GHG accounting design that fairly assigns Bonneville's carbon-free generation to Oregon and Washington customers. The EDAM design continues the status quo of California customers obtaining disproportionate credits for out-of-state low-carbon generation. As these market design differences persist, they serve to increase costs for Bonneville's Washington customers who participate in Washington's carbon pricing program, and they result in Oregon customers receiving less credit than they are entitled to meet their state's requirements.

As described above, Bonneville has made an informed comparison between the market designs of EDAM and Markets+ related to GHG accounting. Bonneville believes that the Markets+ GHG accounting approach (the dispatch-based solution for carbon pricing programs combined with a broadly applicable out-of-market resource

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[139] The EIM currently limits attribution of a resource to a GHG pricing area to the difference between the resources Upper Economic Limit and Base Schedule. In the future, for EDAM participants, the CAISO will use the difference between the day-ahead market energy schedule and day-ahead market GHG award. *See id.* § 11.3.3.2; CAISO Extended Day-Ahead Market Final Proposal § 7(b)(3)(c).

[140] *See* SPP, Markets+ GHG Task Force, *available at* https://www.spp.org/stakeholder-groups-list/western-energy-services-stakeholder-groups/marketsplus-stakeholder-groups/marketsplus-independent-panel/marketsplus-participant-executive-committee/marketsplus-design-working-group/marketsplus-ghg-task-force/; SPP Markets+ Protocols § 5.8 ([GHG] Tracking and Reporting).

[141] *See* CAISO, Greenhouse Gas Coordination Work Group, *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Greenhouse-gas-coordination-working-group.

[142] CAISO, Greenhouse Gas: Accounting and Reporting Issue Paper (Dec. 20, 2024), *available at* https://stakeholdercenter.caiso.com/InitiativeDocuments/AccountingandReportingIssuePaper-GreenhouseGasCoordination-Dec202024.pdf.

and emissions assignment available to all market participants) is an equitable approach to the needs of all market participants to meet various reporting programs, and provides a path for Bonneville's customers to continue to report low-carbon attributes associated with purchases from Bonneville. Further, the Markets+ governance structure enabled it to successfully continue to refine a widely supported solution for GHG accounting. In addition, SPP's stakeholder process provides superior flexibility, allowing participants the opportunity to revise the GHG accounting design to account for changes in the GHG reporting landscape. Bonneville recognizes the market participants' ability to make stakeholder-driven improvements and adjustments to market design is particularly important in this complex and evolving area.

5.3. Summary Recommendation

Bonneville recognizes that its day-ahead market Policy direction towards participating in Markets+ will play a critical role in the energy and capacity market landscape for the region, and it will have direct impact on a number of other entities' decisions regarding day-ahead market participation. Bonneville has carefully considered the financial analyses, design comparisons, expected footprints, and various other details through the lenses of our evaluation principles. Bonneville sees participation in a day-ahead market as an important step in maintaining access to trading partners to continue meeting obligations and marketing surplus to maintain low rates for customers.

Bonneville has determined that Markets+ is the best option because of its superior governance and stakeholder process and its superior design, and believes it has the potential to offer financial benefits that are greater than business as usual. While several market design issues described above, such as congestion revenue allocation, GHG accounting, and fast start pricing, cannot be decisively quantified, Bonneville believes the Markets+ design is likely to provide economic benefit and partially offset the financial benefits attributed to EDAM by the PCM studies. Bonneville will work diligently to meet the needs of its power and transmission customers, including by maintaining access to trading partners and minimizing market-to-market friction. Bonneville acknowledges the potential financial tradeoff and potential increased implementation and participation complexity given differing decisions by other adjacent entities. However, these tradeoffs must be evaluated along with potential mitigation and the business drivers associated with relevant quantitative and qualitative factors. Based on comprehensive business evaluations presented in this Policy, Bonneville concludes that the design of Markets+ is best positioned to satisfy Bonneville's business needs, statutory and contractual obligations, and the broad and evolving needs of Bonneville's customers.

6. Preliminary Implementation and Participation Considerations for Markets+

Throughout Bonneville's public process, Bonneville explained generally how a day-ahead market will affect Bonneville and its customers. Bonneville discusses a summary of Markets+ implementation and participation elements in this section. Further details will continue to be developed as Bonneville progresses through implementation of day-ahead market participation in Markets+.

Bonneville's Policy direction to join Markets+ impacts all generation and load in the Bonneville BAA to some degree. In addition to requirements laid out in the market tariff and associated supporting documentation, Bonneville will memorialize requirements and rate information specific to its BAA in its tariff, rate schedules, and business practices as part of the public processes it carries out for each of these documents.

6.1. Generation Resource Participation in Markets+

Bonneville anticipates the following details of participation framework in Markets+.

All output is settled

In Markets+, all resources above a certain size[143] in Bonneville's BAA will be subject to the market tariff and rules,

[143] In the WEIM, Bonneville requires all generators above 3 MW to be modeled. *See* Bonneville Power Administration, Energy Imbalance Market (EIM) Business Practice V.5 §§ D.3, G.6 (May 30, 2023).

which Bonneville will propose to incorporate into its Tariff and business practices.[144] Under the terms of the Markets+ Tariff, all generation output will be settled at market prices.[145] The basic energy settlement equations are described in Section 6.6.[146]

All resources participate, but can self-schedule

In the context of the WEIM, "participating resources" are resources registered directly with the WEIM that can offer flexible range to the market via a bid curve, and "non-participating resources" are all other resources that do not bid directly into the market. In both day-ahead markets, all resources are considered "participating" because their full output impacts the market solution, and they are settled for that full output. However, this does not mean that all resources must offer flexibility. In addition to the ability to offer price-sensitive energy between a minimum and maximum generation point, both markets also allow for "self-scheduling" which is an indication to the market that a resource plans to generate a specific MW amount and is not offering price-sensitive flexibility to the market. The resource will still be settled for that submitted self-schedule at the relevant market LMP, as the submitted self-schedule becomes the day-ahead market solution award for that resource, and that resource will still be settled for real-time output relative to that day-ahead award.

Resources can still export out of the BAA

Joining Markets+ will not prevent or limit resources in the Bonneville BAA from transacting with entities outside the Markets+ footprint. Entities can still export from their resources out of the footprint as long as the export is properly tagged, as is required today to sell an export out of the Bonneville BAA. Note that this does not require a resource to opt their transmission out of the market. Resources can schedule on their transmission to indicate the export, and then either self-schedule enough output to serve the export or offer the resource into the market and let the market choose the most economic resource mix to serve the export obligation. This is further discussed in section 6.8.

Resources and loads must have a direct relationship with the Market Operator

In Markets+, all registered resources and loads must have a direct relationship with the Market Operator via a Market Participant[147] Agreement. Multiple resources and multiple loads can be registered under a single market participant. The market operator will directly receive data submissions from the market participant and will settle directly with the market participant for nearly all charge codes. This differs from the WEIM framework, where the market settles with the BA for all loads and non-participating resources and the BA subsequently sub-allocates the charges. At this time, Bonneville has not determined whether it will offer options for resources in its BAA to schedule into the market through Bonneville (e.g., simply by submitting a schedule to Bonneville via e-tag or Bonneville's Customer Data Exchange, as is done for non-participating resources in the Bonneville BAA for WEIM today). Note that for the few charge codes paid to the TSP or BA, Bonneville will determine the suballocation of those funds in a future Rate Case proceeding.

Independent resources do not have an automatic must-offer obligation

The Markets+ Must-Offer Obligation is measured at the market participant level. Independent resources do not have individual must-offer obligations unless they have export schedules (in which case, they must offer or self-schedule their resource to fulfill the export schedules). Otherwise, individual resources contribute to meeting the Must Offer

[144] *See* Section 5.1.1.6 (Power Business Line) above and Section 6.6 (Markets+ Settlements) below for more details.
[145] SPP Markets+ Tariff, Attach. A § 6.2(6). An MP must register all gen in footprint above 0.1 MW unless behind the meter under 10MW (note: the BPA BA uses 3MW, not 10MW, for BTM in EIM, as indicated in the previous footnote).
[146] *See also* SPP Markets+ Tariff, Attach. A §§9.2 (Day-Ahead Market Settlements), 9.3 (Real-Time Balancing Market Settlements).
[147] Pursuant to the Markets+ Tariff Definitions: "Market Participant (MP): An entity that executes the Market Participant Agreement in Attach. E, or on whose behalf an unexecuted Market Participant Agreement has been filed at FERC."

Obligations of market participants with load by being a resource within that market participant's registration. The market participant can also indicate a contract with the resource that they put toward their must-offer obligation.

Resources must provide offer information in accordance with market timing

The timing for the day-ahead market run to "close" (at which point the day-ahead market optimization begins, and no new input information can be incorporated) in Markets+ is 10 a.m. on the day prior to the relevant operating day, with results expected to be posted by 1:30 p.m. Markets+ runs the Reliability Unit Commitment (RUC) process at least every four hours between the day-ahead market solution and real time. The RUC provides unit commitment information to resources that have indicated their willingness to be committed by the market but is otherwise not financially binding for purposes of energy settlement. The timing for the real-time market run to close is 30 minutes prior to the relevant operating hour ("T-30"). Offer information, including MW amounts and associated pricing, can be changed after the 10 a.m. day-ahead close at any point until the T-30 deadline and is incorporated into any subsequent RUC and real-time optimizations.

Potential for non-BA requirements

Note that the information in this section generally pertains to participation based on Markets+ requirements and the expected framework in the Bonneville BAA. For resources that are owned by or contracted to power customers of Bonneville Power Services, there may be further requirements. Those requirements will be determined as part of a public process as discussed in Section 6.7.

6.1.1. Federal Generation

Markets+ will allow resources to be registered as individual units or as aggregated resources. Bonneville intends to use the same resource aggregations as is used in WEIM. Resource aggregates are further discussed in Section 6.1.1.2.

Bonneville will prioritize its statutory obligations such as fish passage and flood control over market actions, as it does today, which may limit Bonneville's ability to participate in the market during times of limited hydraulic flexibility.

Bonneville expects to use self-schedules and offer ranges to ensure the FCRPS operates within its limits while allowing for system optimization. In addition to hourly minimum/maximum constraints, Markets+ has also developed an additional constraint, allowing Bonneville to communicate a daily energy maximum for each resource in the day-ahead optimization in addition to the hourly offer range limits. Setting a daily energy maximum helps ensure that Bonneville can honor operational obligations and constraints while still allowing for economic optimization of the system. Further, because offers can be updated through real-time, Bonneville will be able to make adjustments to its planned operations in the market as fuel certainty materializes.

6.1.1.1. Impacts on Hydro Operations in Relation to Fish & Wildlife

In Markets+, Bonneville will continue to meet its statutory obligations, including those under the Northwest Power Act, Endangered Species Act (ESA), and National Environmental Policy Act (NEPA). Bonneville's power marketing services and activities, and its actual power operations to meet load obligations, are conducted consistent with applicable Biological Opinions and are within existing operating constraints and normal operating limits of FCRPS projects. The Markets+ framework allows Bonneville to manage FCRPS operations with other project purposes and system-wide operating constraints, including operations to support ESA-listed fish and to provide equitable treatment for fish and wildlife with other system purposes as required by the Northwest Power Act.

6.1.1.2. Use of aggregation model for Federal resources

As part of the decision to enter the WEIM, Bonneville opted to use the aggregation model to represent the Big 10

hydro resources.[148] The aggregation model has worked well in the WEIM, and Bonneville plans to maintain this approach for day-ahead market participation in Markets+.

The resources within an aggregation model are hydraulically interdependent; water released out of upstream resources will affect the operation of downstream resources within a matter of hours. Hydro operators must account for this relationship along with fuel uncertainty (e.g., expected water flows versus real water flows due to weather, third party resource operations, etc.). This dynamic, combined with the various non-power constraints and physical project limitations, results in the need for hydro operators to have flexibility to adjust between resources as necessary. Aggregation of hydro resources allows Bonneville and its federal partners to maintain this flexibility to manage the impacts of market activity and uncertainty in operational and hydraulic objectives.

In the WEIM, Bonneville uses three aggregations to provide maximum flexibility for hydro operators while providing the market with maximum ability to redispatch resources for congestion relief. Bonneville grouped the resources that were most interconnected based on river reach area (Upper Columbia,[149] Lower Snake,[150] and Lower Columbia[151] areas).[152]

Bonneville has worked closely with SPP and stakeholders in the Markets+ process to design an aggregation model for use in Markets+. Bonneville has not yet determined if there are other groups of resources in the federal hydro system that would benefit from aggregation but plans to consider that question during implementation.

6.2. Ensuring Adequate Supply in Markets+

Today, Bonneville works across all timeframes to preserve and maximize the value of the FCRPS for customers through prudent operational planning and marketing practices. Bonneville sets its system up to provide the most economic and reliable energy supply to customers while planning for contingencies and required operations such as those for fish and wildlife. Bonneville also plans the system to make economic purchases and high-value surplus sales to bring added revenue to help lower firm power rates. Bonneville's primary goal in its proposed participation in Markets+ will be a continuation of what it does today: provide firm power supply for its long-term power sales contracts. Bonneville will continue to plan for its long-term firm power load service obligations by managing its existing resources and by acquiring resources in advance based on forecasted need. Bonneville does this in its Pacific Northwest Loads and Resources Study (also known as the White Book) and through its Resource Program, both of which supplement the regional power plan prepared by Northwest Power and Conservation Council pursuant to the Northwest Power Act.

Bonneville's future participation in WRAP binding operations and Markets+ will provide greater transparency and documentation as to how these obligations are met. Bonneville's loads and resources planning for its long-term power customers will be reflected for long term planning in its WRAP obligations and for short term planning in the requirement that Bonneville meet the Markets+ resource sufficiency mechanism, the Must Offer Obligations. The Must Offer Obligation is a minimum requirement for each market participant in Markets+ with load and/or export obligations to bring enough supply to "cover" those obligations. Through its long-term planning (reflected in the WRAP Forward Showing program and Bonneville's White Book), and its short-term planning practices (demonstrated in the Must Offer Obligations and WRAP Operations Program), Bonneville will ensure that its long-term firm power sales contract obligations are satisfied.

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[148] The "Big 10" Hydro Resources are: Grand Coulee, Chief Joseph, Lower Granite, Little Goose, Lower Monumental, Ice Harbor, McNary, John Day, The Dalles, and Bonneville Dams.
[149] Aggregation of Grand Coulee and Chief Joseph Dams.
[150] Aggregation of Lower Granite, Little Goose, Lower Monumental, and Ice Harbor Dams.
[151] Aggregation of McNary, John Day, The Dalles, and Bonneville Dams.
[152] For more information on this decision, please see Bonneville Power Administration, EIM Participation Letter to the Region, Attach. A § III.e.1 (June 20, 2019), *available at* https://www.bpa.gov/-/media/Aep/projects/energy-imbalance-market/20190620-western-energy-imbalance-market-letter-to-the-region.pdf.

6.3. Ancillary and Control Area Services

Ancillary and Control Area Services (ACS) are services necessary to support the transmission of energy and capacity while maintaining reliable operation within and among BAAs. Bonneville is required to offer ancillary services under its Tariff, and transmission customers may purchase certain ACS from Bonneville or self-supply through a customer's own resources. In general, ACS are necessary to maintain the reliability of the BAA. There are typically two components to most ACS: capacity (the ability to produce energy when needed) and energy (the actual production of energy). Energy and Generation Imbalance, which are used for the sub-hourly provision of energy to maintain load-resource balance within the BAA, are two important ACS that Bonneville currently offers. Bonneville currently provides Energy and Generation Imbalance service through the WEIM under Schedules 4E and 9E of Bonneville's Tariff.[153] There is currently no centrally organized market for the capacity component of ACS proposed for Markets+ or EDAM, which Bonneville provides under Schedules 3 and 10 of its Tariff.

Participation in Markets+ does not eliminate Bonneville's requirement to offer ACS, as the market operator will not be taking over this responsibility. Markets+ includes the Real-Time Balancing Market (RTBM), which is similar to the WEIM. The RTBM is an intra-hour (or real-time) centralized energy market used to economically dispatch participating generation resources to balance supply, transfers between BAAs (interchange), and load across the market's footprint. Like the WEIM, RTBM is not a capacity market. Bonneville does not expect Markets+ to change how ACS is provided. However, Bonneville will likely need to revise its tariff, rates, and business practices to incorporate Markets+. Those revisions will occur separately in the appropriate processes.

6.4. Operational and Commercial Seams

As described by FERC, seams issues include differences in transmission rules as well as differences in power market rules. Operational seams include multifaceted matters such as coordination of generation and transmission maintenance schedules, determining how path flows affect outside areas, congestion management procedures, operating rules for recalling firm transmission capacity, demand response rules, and communication protocols. Commercial seams encompass different market constructs such as bidding rules, market product definitions, market price intervention practices, different business practices, generation and transmission scheduling practices, and processes to verify transactions between market operators and market participants.[154]

Bonneville and other BAAs will need to manage new operational and commercial seams as entities join day-ahead markets. For example, Bonneville has generation and load in other BAAs that are likely to join EDAM, such as the PacifiCorp (PAC) and Portland General Electric (PGE) BAAs. In addition to the obligation to customers located in those BAAs, many entities affected by the implementation of day-ahead markets will need to manage commercial seams and possibly multiple markets. These seams can be mitigated through coordination across the various participants, including market operators, BAAs, market participants, and the various regional groups who coordinate among WECC today.

As explored in detail in Appendix D, the development of day-ahead markets will create new operational seams in the Western Interconnection. Bonneville's transmission system covers large portions of the Pacific Northwest and is not always contiguous. There are also a number of transmission asset owners, BAAs, and transmission capacity owners of operational paths within Bonneville's Pacific Northwest service territory, including the Pacific DC Intertie (PDCI) and Northwest AC Intertie (NWACI). Bonneville will be able to manage operational complexities like congestion management by developing coordinated operating agreements like those for WEIM.

CAISO and SPP will have their own RC offerings tasked with ensuring system reliability for their registered

[153] Bonneville is providing imbalance service under Schedules 4 and 9 during the periods that Bonneville pauses WEIM participation.

[154] *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design*, 67 Fed. Reg. 55,452 55,464-65 (Aug. 29, 2002).

Transmission Operators. RCs, market operators, and market participants will develop agreements to manage seams to support reliable operations, like they have in the eastern states for decades. The ability of a region with multiple energy markets in it to effectively manage congestion is strongly dependent on both markets calculating impacts on a path the same way, so that actions taken during congestion management have the desired effect in both market footprints.

6.4.1. Commercial Seams

As also explored in detail in Appendix D on seams management, the development of day-ahead markets will create new commercial seams. Today, many of Bonneville's commercial seams are between the bilateral and non-bilateral markets. The industry has created tools and means of transacting which mitigate the impacts of these commercial seams such as ensuring power sales and purchases have some uniform provisions by largely adopting the WSPP, Inc. (formerly Western Systems Power Pool) standardized WSPP Agreement.[155] Multiple day-ahead markets within the West would require the development of new tools and methodologies to manage commercial seams.

6.4.2. How market participation may impact transmission congestion issues

Bonneville has observed the ability of WEIM to manage operational constraints and expects even greater congestion management effectiveness with the addition of a security constrained day-ahead market optimization. However, Bonneville acknowledges that two day-ahead markets will create a need for operational coordination between the markets, particularly given the non-contiguous nature of the potential market footprints. The ability of an energy market to effectively manage transmission system congestion depends on the footprint and size of that market. This includes the size, location, and offered flexibility of the resources supplying energy to that market, the size and location of the loads purchasing that energy, and the volume of transmission available to that market relative to those resources and loads. The day-ahead schedules and awards from each market, if properly implemented and coordinated, should be physically feasible within the market-available transmission capacity.

Bonneville is likely to have generation, load, and transmission participating in or impacted by both markets. Appendix E discusses in more detail those impacts as they are related to congestion management. Bonneville expects agreements, constraints, and market design to mitigate operational and commercial seams issues. Given the complexity of the Western Interconnection, the potential for non-contiguous market and RC footprints, and the number of parties involved, multiple types of agreements will be necessary.

6.5. Operational Tools

Bonneville employs many operational tools to reliably operate the federal power and transmission systems to meet its Tariff, compliance, and environmental requirements. At this time, Bonneville expects to continue to use a majority of these operational tools in Markets+.

Some of these tools will require adjustments to work within the framework and day-ahead market timelines of Markets+. Bonneville will continue to identify which operational tools will require adjustments as part of implementation scoping and will work with the market operators as necessary as part of that scoping process.

6.5.1. Curtailment Advisor

Bonneville anticipates adjusting its Curtailment Advisor tool used for performing transmission curtailments in real time when flow on a path exceeds the established limit. Today, when initiated, Curtailment Advisor curtails e-tag schedules impacting the given path in real time according to NERC curtailment priority. In the real-time market, the market optimization will redispatch every five minutes in real-time to maintain market flows within the established market transmission limit. If the market is unable to redispatch enough to avoid violating the limit, responsibility reverts to the TOP to determine if actions are needed to protect the path. However, because BAA-to-BAA e-tags with "system" sources are typical in a day-ahead market framework, Bonneville will need to develop

[155] *See WSPP, Inc.*, FERC Docket No. ER25-178, Letter Order (Dec. 13, 2024).

a method to address effective transmission curtailments based on NERC priority. Bonneville anticipates working through this topic as part of its implementation phase.

6.5.2. Operational Controls for Balancing Reserves (OCBR)

OCBR is a real-time operational tool used by Bonneville to manage reliability when balancing reserve capacity is depleted. Balancing reserve capacity is capacity held to address sub-hourly load and generation error as measured against an hourly schedule across the Bonneville BAA. Incremental or "INC" capacity is deployed when there is under-generation relative to load and decremental or "DEC" capacity is deployed when there is over-generation relative to load.

Before Bonneville's entrance into the WEIM, the use of OCBR for an INC depletion event resulted in the curtailment of hourly schedules to actual generation levels for significantly under-generating resources. The use of OCBR for a DEC depletion event resulted in limiting generation to the scheduled amount for significantly over-generating resources.

Upon joining WEIM, Bonneville adjusted the design of the OCBR tool to better fit with the real-time market structure and leverage the additional sub-hourly energy available in the market. For example, Bonneville shifted the measurement of balancing reserve depletion to consider only the portion of balancing reserves served exclusively by Bonneville's own resources (regulation), and not the portion served by WEIM dispatches (non-regulation).

Bonneville expects few, if any, changes to OCBR when joining Markets+. OCBR[156] is a real-time tool and the day-ahead market elements of Markets+ should not have any impact. As RTBM in Markets+ operates similarly to the WEIM, OCBR should work with the RTBM in the same manner.

6.5.3. Oversupply Management Protocol

Oversupply Management Protocol (OMP) is an operational tool used to address certain environmental conditions in the Columbia River, while maintaining reliability in Bonneville's BAA. During times of high river flows, typically in the spring when loads in Bonneville's BAA are low, water must be passed through the dams in one of two ways: spilled over the dams or run through the turbines to generate electricity. When water is spilled over the dams, it creates bubbles of air in the water that, at certain levels, can be harmful to salmon and other aquatic species. This is referred to as total dissolved gas and is regulated by Oregon and Washington under the Clean Water Act.

When the Columbia River reaches total dissolved gas limits, Bonneville must limit spill by passing water through the generating turbines, thus creating electricity. Bonneville sells this electricity at market rates, but, in the Spring, there are occasions when there is not sufficient load to use the electricity, even at zero cost. As a result, Bonneville adopted Attachment P to its Tariff, creating a least-cost cost curve for displacing generation in the BAA and reimbursing displaced generators for certain costs related to the displacement so that Bonneville can pass water through its generating turbines and maintain load-resource balance. Attachment P has been approved by FERC under section 211A of the Federal Power Act.

Bonneville expects to retain OMP in Markets+ and will review if any process changes are necessary to adapt to market rules and timing. While Markets+ may provide Bonneville additional opportunities to market generation during times of high flows, Bonneville still needs a mechanism to ensure compliance with its environmental responsibilities. As Bonneville gains more experience in Markets+, it will monitor the need to adjust or retain OMP.[157]

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[156] *See* Bonneville Power Administration, Operational Controls for Balancing Reserves, *available at* www.bpa.gov/energy-and-services/transmission/ancillary-services/balancing-reserves/operational-controls-for-balancing-reserves.
[157] *See* Bonneville Power Administration, Oversupply, *available at* www.bpa.gov/energy-and-services/transmission/oversupply.

6.6. Markets+ Settlements

Markets+ will settle directly with each market participant for the majority of its charge codes, including day-ahead awarded energy and imbalance energy. Settlement volume will be larger in a day-ahead market than in a real-time only market. As discussed in section 6.7, Bonneville expects to be the market participant on behalf of Load Following customers in the Bonneville BAA and thus will settle with Markets+ on behalf of those customers. Other market participants[158] will receive their settlements directly from Markets+.

Markets+ settlements are more streamlined than EDAM. Markets+ utilizes a simpler 12-month settlement process with three settlement statements and ~40 charge codes, as opposed to the EDAM settlement period of 24-months with five settlement statements, and a much larger number of charge codes to manage.[159] Markets+ settles directly with market participants. Receiving settlements directly through the Market Operator, rather than suballocated by the BA, as is done in WEIM, allows for more direct payments and charges, as well as more timely financial resolution. These aspects are likely to be especially favorable to independent power producers and other larger participants, as well as to Bonneville and its customers, by reducing the workload and associated costs of handling settlements for large entities within the BAA.

While there are a number of charge codes, the most essential settlements are for day-ahead energy awards and real time imbalance energy. As previously described, the award from the day-ahead solution is settled at the day-ahead LMP and is used as the financial reference point for settlement of energy in the real-time solution.

The general equation for energy settlement[160] for a resource is:

Total Energy Settlement = Day-Ahead Award * Day-Ahead LMP + ((Real-time Output – Day-Ahead Award) * Real-time LMP)

And for a load is:

Total Energy Settlement = -1*(Day-Ahead Cleared Load * Day-Ahead LMP + ((Real-time Load Consumption – Day-Ahead Cleared Load) * Real-time LMP))

In the load settlement equation, multiplication by -1 indicates a settlement in the opposite direction (i.e., a payment versus a charge).

6.7. Bonneville Power Services Customer Participation in Markets+

Bonneville's participation in Markets+ will be consistent with the obligations of its Provider of Choice power sales contracts. These contracts include the terms and conditions of the products and services that Bonneville offers its power customers and defines the obligations that both Bonneville and the power customer must meet. Bonneville will look to accommodate power customers' participation in the market consistent with the obligations associated with their product and service elections.

Bonneville recognizes that it does not currently have enough information to include language in the ongoing development of its next long-term power sales contract that would adequately address all the necessary day-ahead market terms and conditions. The Provider of Choice power sales contracts will include a provision that will enable the parties to amend the power sales contracts as needed. Such amendments will include any necessary changes to align with both an updated Bonneville Tariff and the Markets+ Tariff (including associated settlements under Markets+). Bonneville will hold a public process to review proposed standardized amendment language and offer an opportunity for public comment on that language. The Provider of Choice power sales contracts will also include

[158] *E.g.*, Planned Product customers, independent power producers, etc.
[159] Bonneville has federal resources and preference loads in EDAM BAAs, so to the extent settlements are required, Bonneville will coordinate with EDAM or its participating BAAs and affected customers.
[160] Day-ahead markets contain many other charge codes. This is a simplified example showing basic energy settlement.

a provision establishing that Bonneville will conduct a subsequent public process on the topic of settlements for the Slice Product following Bonneville participating in the day-ahead market.

For Load Following customers, Bonneville expects to be the market participant on behalf of customer loads that are in the Bonneville BAA. Bonneville will work with Load Following customers with load outside the Bonneville BAA to determine the appropriate participation model. Load Following customers for which Bonneville is the market participant and that have dedicated non-federal resources may be eligible to have those resources participate in the day-ahead market consistent with their contractual obligations and requirements. For example, Load Following customers with dispatchable resources may be allowed to offer flexibility to the day-ahead market. Bonneville expects that Load Following customers that elect to offer their own resources into the market for dispatch would be expected to offer capability to the market consistent with any peaking requirements defined in their contracts.

Planned product customers include Slice/Block customers and Block customers. For planned product customers that are in the Bonneville BAA, Bonneville anticipates that a planned product customer will act as the market participant for both their own load and any non-federal resources they wish to bid into the market. Bonneville will work with planned product customers with load outside the Bonneville BAA to determine the appropriate participation model. Bonneville will work with planned product customers to determine how the power supplied by Bonneville is accurately reflected in both Bonneville's and the planned product customers' market participation. Planned product customers will continue to purchase power consistent with their planned obligation and would be expected to be responsible for any day-ahead or real-time load variances.

As an overall observation, Bonneville does not expect day-ahead markets to impact certainty of delivery for power customers. Bonneville would continue to schedule contract deliveries in advance of the market operation based on existing transmission rights as necessary. Transmission customers would continue to be entitled to the same curtailment priority under Bonneville's Tariff as they are today. The market dispatch, however, would account for transmission constraints and attempt to redispatch around them, reducing the need for curtailment and improving certainty of delivery.

6.8. Bonneville Transmission Services Customer Participation in Markets+

Bonneville's Tariff provides two types of Transmission Service: PTP[161] Service and NITS.[162] PTP Service allows the customer to move power from a Point of Receipt to a Point of Delivery and is billed on reservation capacity. NITS is available only for service to network load, billed based on metered network load, and includes planning obligations. Markets+ is consistent with the current terms and conditions for transmission service set under the existing Tariff to a great extent, including through the administration of the Open Access Same-Time Information System, and sale of firm and non-firm transmission service. The Markets+ design recognizes that the market does not assume the role of TSP and respects the prevailing OATT framework in the West.

With day-ahead market participation, Bonneville is anticipating some changes in how its customers may utilize their Bonneville transmission rights. Bonneville transmission contract holders will still have the ability to exercise their transmission rights (e.g., schedule, redirect, and resale existing transmission rights) consistent with Bonneville's Tariff, business practices, and any another relevant agreements as they do today during the day-ahead and real-time horizons, though there may be different implications of doing so.

Bonneville shared its preliminary assessment of how transmission may work in a day-ahead market construct at the

[161] Bonneville Power Administration, Point to Point Transmission Service (PTP): An Overview (rev. Oct. 1, 2001), *available at* https://www.bpa.gov/-/media/Aep/transmission/ptp-service/ptp-product-overview.pdf.
[162] Bonneville Power Administration, Network Integration Transmission Service (NT): An Overview (rev. Nov. 10, 2001), *available at* https://www.bpa.gov/-/media/Aep/transmission/nt-service/nt-product-overview.pdf.

public workshop 8 on July 18, 2024.[163] Bonneville shared a Markets+ process timeline for transmission activities for both the TSP/BA and the transmission customer perspective highlighting the complete cycle from pre-market (registration and modeling set-ups) to day-ahead and real-time activities and concluding with settlements. Bonneville provided examples of how transmission rights, both available for the market and opted-out, would be communicated to the market operator along with the associated Service Flow Constraints[164] (SFCs) that will be configured into the market operator's system(s).

By default, Bonneville's transmission customers' transmission rights and unsold ATC will be made available to the market unless specifically opted out as described in the next paragraph. As described in the day-ahead market framework Section 2.4, on a day-ahead basis, Bonneville will communicate the available transmission capacity on various paths to the Market Operator, and the Market Operator will respect those limits in its market optimization in order to commit and award resources to serve the expected load. In real-time, Bonneville will communicate any changes to ATC to the market, and market flows will continue to be able to use any real-time, unscheduled transmission capability on the Bonneville system.

Markets+ permits transmission customers to "opt-out"[165] their transmission rights according to the market rules, which includes no more than once per month and timely communication to the market operator. Informed by stakeholder input, Markets+ has developed a process for the opt-out communication from the TSP/BA to the MO.[166] Furthermore, the frequency of the opt-out communication was set to align with the TSRs congestion rent eligibility verification timeline. The "opt-out" of transmission rights removes that capacity entirely from reflection in the market and potentially any market settlement implications. However, by doing so, the transmission customer will forego the potential congestion rent revenue on the contracted paths if those paths become binding, as well as use of the market to help meet the schedule. The market rules and associated procedures for transmission opt-outs were set to provide an equitable and timely process for Market Participants that may need to opt-out transmission but to also address market power concerns on transmission usage. While Bonneville believes the current design mitigates any concerns with market power related to transmission usage, the Market Monitoring Unit (MMU) will monitor for transmission withholding by market participants that would violate the Markets+ Tariff.[167] Bonneville transmission contract holders that want to participate in another market (e.g., EDAM) may want to "opt-out" transmission from Markets+ so that generation in that market can be optimized across that transmission. Any additional requirements Bonneville places on transmission opt-outs would be determined in a future Tariff proceeding and/or business practice process.

Note that opting-out transmission is not required in order to (a) self-schedule or (b) individually transact outside of the Markets+ footprint. First, for self-schedules, the market optimization still respects generation self-scheduled within the market footprint. If a generator self-schedules, it consumes a portion of market-available transmission capacity, lowering the amount of transmission across which the market can optimize. This transmission capacity is still "in" the market and the transmission rights holder is still eligible for congestion rent allocation. Second, for transactions that cross the boundary of the Markets+ footprint, those transactions can be established within the

[163] Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day Ahead Market (DAM) Participation - Workshop 8 presentation (July 18, 2004), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/dam-workshop-8-presentation.pdf.

[164] Service Flow Constraints are intended to represent a commercial constraint that manages market flows attributed to the market, not total flow expressed as a mega-watt (MW) value.

[165] SPP Markets+ Tariff, Attach. D § 1.2 (Obligation to Communicate Markets+ Transmission Capacity Availability Changes).

[166] Markets+ TSPs/BAs will need to develop their own opt-out process with its transmission customers that will ultimately feed into the Markets+ opt-out process. SPP Markets+ Protocol, 8.2.2 Markets+ Transmission Capacity Opt-Outs and Exhibit 8-2: Transmission Opt-Out and Congestion Rent Process Timeline.

[167] SPP Markets+ Tariff, Attach. C § 4.5 (Monitoring for Potential Transmission Market Power Activities)

market using an e-tag. [168] The market will incorporate the additional load obligation (for an export) or generation injection (for an import) within the optimization. Markets+ also allows for price-sensitive bidding at the market footprint in the day-ahead optimization, which requires an e-tag as well.

As the region moves towards participation in a day-ahead market, Bonneville understands that utilities, which may also be Bonneville transmission contract holders, are making their own independent market participation decisions and may want to use their Bonneville transmission rights in those markets. As a result, regardless of Bonneville's decision to join a day-ahead market, Bonneville may need to reflect tariff revisions and/or business practice updates to clarify the requirements for transmission customers to use their transmission rights for their respective market participation.

Bonneville will need to address necessary tariff changes for implementation. Bonneville will discuss potential tariff changes through the tariff process. Bonneville may also need to update its business practices for implementation and will do so through the established business practice process.

6.8.1. Transmission Product Availability

As discussed previously, Bonneville does not expect the general transmission products or terms and conditions to change due to Bonneville joining Markets+. However, joining Markets+ will impact the reservation and scheduling timelines of its short-term products, specifically, the hourly firm, hourly non-firm, and non-firm secondary products. Currently, Bonneville's hourly firm transmission window opens at 9 a.m. Pacific Time of the WECC preschedule day, and non-firm window for hourly and secondary products opens at 10 a.m. of the WECC preschedule day.[169] These transmission windows will need to be evaluated because the availability of these short-term products will need to conform to the day-ahead market timelines for the day-ahead (e.g., 10 a.m. deadline for the day-ahead market clearing process to start and initial RUC) and real-time horizons (e.g., intra-day RUC and T-30 for each operating hour), in order to afford customers enough time to buy transmission and meet market deadlines. Transmission customers in WECC are accustomed to navigating TSP timing windows for reserving transmission, not just Bonneville's, which vary and may be set in different time zones. Understanding the updated TSP timing windows for reserving transmission for day-ahead markets will be another consideration to navigate in the near future.

In addition, participating TSPs are required to pause processing of TSRs in the queue for the next operating day during the day-ahead market clearing process (approximately from 10 a.m. to 1:30 p.m. Pacific Time on day-ahead) so the market optimization has a static set of transmission constraints to develop the market solutions. While the queue is paused, transmission customers will have the ability to submit TSRs but those TSRs will remain in the queue in queue order. Once the market operator posts the awards associated with the market solutions and the TSPs have accounted for any incremental transmission used by the market, TSPs will resume processing TSRs in the queue.

As noted above, Bonneville understands that it will have transmission customers that may wish to use their Bonneville transmission rights for transactions/schedules that source or sink outside the BAA or for wheeling across the BAA, including for optimization in another market (e.g., EDAM). Bonneville will need to address how it will make its transmission available for use in other markets, as well as implementation of the reservation timelines in a future tariff proceeding and, as necessary, through the business practice process.

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[168] E-tags are used to schedule power transactions that include who is supplying the power, how much power (expressed as MWs), timeframe, purchasing/selling entities involved, BAAs involved, the transmission paths, and who is receiving the power.

[169] Bonneville Power Administration, Requesting Transmission Service Business Practice V.47 § C.1 (Jan. 22, 2024), *available at* https://www.bpa.gov/-/media/Aep/transmission/business-practices/tbp/requesting-transmission-service-bp.pdf.

6.8.2. Transmission Losses

As energy is physically delivered across a transmission system, there is a natural degradation or "loss" that occurs because of physical factors such as distance and the overall loading of transmission facilities. Transmission losses represent additional physical generation that is necessary to make up the difference between a scheduled amount of energy from a generator and what is "lost" on the way to serving a load. Bonneville currently requires transmission customers to either designate to return transmission losses in kind (e.g., with a physical delivery of energy concurrently) or settle them financially.

In joining the WEIM, Bonneville did not need to make significant adjustments to the provision of losses because the majority of losses still occurred outside of the market (associated with the base schedules submitted ahead of the market). However, for the WEIM, Bonneville elected the "donation model" of Transmission Rights by Interchange Rights Holders[170] to be used for WEIM transfers that source or sink in the Bonneville BAA. The donation of these transmission rights into WEIM does not eliminate the transmission loss obligation of the Interchange Rights Holders, yet to avoid "double-payment," Bonneville exempted loss returns for WEIM transfers using Bonneville transmission during WEIM participation because the market accounts for losses associated with incremental market transfers within the optimization.

In Markets+, both the day-ahead and real-time optimizations procure sufficient energy to serve losses across the market footprint. Transmission losses for both the day-ahead awards and the incremental real-time dispatches are settled financially by the market and reflected in the LMP. Bonneville will discuss with stakeholders the extent to which Markets+ may lead to changes in Bonneville's current policies regarding transmission losses. Specifically, Bonneville will need to focus on two areas: 1) transmission that is not available to the market, and 2) transactions/schedules that use Bonneville transmission but source or sink outside the Markets+ footprint. Bonneville will address these details in applicable rates, tariff or business practice proceedings.

7. NEPA & Environmental Obligations

Consistent with NEPA, 42 U.S.C. § 4321 et seq., Bonneville is in the process of assessing the potential environmental effects that could result from the proposed participation in a day-ahead market. Bonneville believes this proposal appears to be the type of action typically excluded from further NEPA review pursuant to U.S. Department of Energy NEPA regulations, which apply to Bonneville. However, Bonneville will consider all public comments concerning NEPA compliance and/or potential environmental effects of the proposal that Bonneville received during the public discussions for this proposal.

8. Tribal Obligations

The Day-Ahead Market Policy does not impact tribal treaty rights or resources. First, the Policy is a decision on a policy direction, it is not a binding implementation decision to join Markets+. Any decision to join a day-ahead market will be made after further consideration. Second, any future DAM participation will not change Bonneville's ability to meet obligations under existing laws and contracts, including FCRPS operations, river management, or fish and wildlife mitigation. As discussed in section 6.1.1, Bonneville can communicate various operational constraints for its generators as part of its market offers in order to meet both power and non-power obligations, and will continue to prioritize meeting all obligations. Therefore, this Policy does not impact Bonneville's tribal treaty or general trust responsibilities.

9. Conclusion and Next Steps

The preceding Day-Ahead Market Policy represents an extensive analysis of the options available to Bonneville in

[170] Bonneville Power Administration, Energy Imbalance Market (EIM) Business Practice V.5 § J.

response to the developments of day-ahead markets in the West. Bonneville examined the market designs of both EDAM and Markets+ with a particular focus on the elements pertaining to governance and stakeholder process; RA and resource sufficiency; price formation and market power mitigation; transmission and congestion rent; and GHG accounting. Additionally, Bonneville has carefully considered the operational complexities, implementation challenges, and potential for sunk costs presented by each market option. The results of this analysis have been weighed against each of Bonneville's day-ahead market participation principles. Throughout this analysis, Bonneville has held a series of 11 public workshops to provide transparency into Bonneville's evaluation, responses to comments received, day-ahead market offerings, Pathways, and impacts to various aspects of Bonneville's business and products.

Governance has specifically been a central factor in Bonneville's evaluation. Markets+ successfully developed and implemented a governance structure that met Bonneville's criteria. In the meantime, Pathways performed significant work to develop recommendations to improve independence of the governance of the CAISO-run WEIM and EDAM markets. To date, its recommendations have resulted in an approved future transition to primary authority for the independent WEM Governing Body. Several entities have requested that Bonneville delay its day-ahead market decision until the end of 2025 to allow more time for the California legislature to act on proposed legislation to move the Pathways vision forward and for the governance model to continue to evolve towards full independence. While Bonneville applauds the considerable work done by Pathways, its recommendations do not enable the level of independence that is offered by Markets+. The legislation that has been introduced would confirm this limited scope of independence. For that reason, Bonneville does not see benefit in waiting for California's legislative consideration.

The Pathways Step 2 proposal suggested future considerations to expand the independence, and the market services offered. Those subsequent steps to greater independence would be incremental and subject to further studies and likely further legislative authorization. Ultimately, Bonneville prefers the stakeholder-driven governance structure of Markets+. Bonneville contends that the Markets+ development has resulted in a superior market design that is available today and believes it will remain a durable, equitable form of governance in the future.

Bonneville's analysis presented complex results regarding each day-ahead market option, including the status quo. The PCM studies showed a wide range of potential economic outcomes, including meaningful trends that joining EDAM could yield a greater financial benefit for Bonneville and that joining Markets+ has potential for significant monetary benefits under multiple scenarios. It is important to note that these results are not due to differences in market design but are driven from higher prices that come with being in a market with California and the connectivity offered by the current expected EDAM footprint. In almost every scenario, this potential greater monetary benefit was dependent on the assumption that Bonneville would continue to enjoy surplus generation, which adds uncertainty to the results as Bonneville's load and generation forecasts demonstrate a potential erosion of its surplus generation over time. As demonstrated, the benefits in the expected Markets+ footprint improved as hurdle rates were reduced, closing the gap between EDAM and Markets+ benefits and resulting in benefits above BAU.

Additionally, PCMs do not account for market design features, such as congestion rent, market power mitigation, and price formation, that can significantly impact monetary benefits realized from a day-ahead market. These design features are discussed in detail in this analysis and Bonneville believes the Markets+ design is likely to provide economic benefits to Bonneville and our customers through these features that at least partially offset the EDAM benefits estimated in the PCM studies. These design features in Markets+ were all constructed via an inclusive stakeholder process that should result in these market design features accounting for unique needs of market participants, and Bonneville is confident that the Markets+ stakeholder process will be responsive to requests to revisit these design elements if unexpected or unsatisfactory results are realized once the market is live. Bonneville has determined that the trends toward greater potential monetary benefits under the previously discussed assumptions and caveats in EDAM and in the short term for status quo do not outweigh the strategic benefits and

superior market design presented with Markets+.

The option of Bonneville remaining only in the WEIM while its neighbors join day-ahead markets was an option that Bonneville carefully considered, and one that the PCM results showed could bring significant monetary benefit. While Bonneville agrees this option shows short term appeal, Bonneville continues to have significant concerns about the long-term viability of this option due to the operational and economic risks, such as reduced liquidity in the bilateral market, that accompany this option. Remaining in WEIM would likely foreclose the option to join Markets+, leaving EDAM as the only day-ahead market option for Bonneville should it choose to pursue day-ahead participation in the future. Because the Pathways Step 2 proposal does not achieve desired independence, and legislation remains speculative, this option carries significant strategic risk. Other important elements that Bonneville examined in this process are the market seams and the potential operational complexities that will be present with multiple markets in the Pacific Northwest. Bonneville acknowledges that a single market in the Northwest would be operationally simpler, but the decisions of Bonneville's neighboring BAAs suggest that two markets are likely to operate in the Pacific Northwest. The presence of these challenges should not prevent Bonneville from joining a market with superior design and independence. Bonneville places great importance on its operational and reliability responsibilities in the region and stands ready to work with the entities in EDAM and within the region to collaboratively resolve these jointly owned issues.

Throughout this evaluation process, Bonneville has experienced the powerful impact of competition in motivating both SPP and CAISO to significantly improve market offerings in order to attract participants. Without this competition, Bonneville believes many of the creative market design solutions benefitting consumers that both market operators are pursuing may have never materialized. Bonneville also believes many of the changes contemplated and implemented in the CAISO governance and stakeholder processes and the recent urgency with which they have been pursued are a direct result of competition from another market operator. These CAISO initiatives are resulting in an improved market for entities that have or may choose EDAM participation. The continuation of this competition benefits Bonneville, its customers and all consumers in the west regardless of market participation choices by maintaining pressure on market operators to continue innovating and improving.

After thorough evaluation, analysis, and weighing of its participation principles, as well as the governance, market design, and strategic benefits presented by Markets+, Bonneville has concluded that its participation in Markets+ is the best long-term strategic direction for Bonneville, its customers, and the Northwest.

Bonneville would like to express profound appreciation for those who have engaged in the public process and provided insights to make this a robust, transparent, and effective evaluation of its potential participation in a day-ahead market. Bonneville looks forward to ongoing public review and input as implementation details are developed. Bonneville will be developing a stakeholder engagement plan to provide market design updates and technical implementation that will incorporate customer input. Bonneville will be utilizing the '6-step process' as a way to collaborate with customers on the policy issues through the tariff and rates proceedings.

Appendix A

Legal Assessment

1. Legal Authority to Join Markets+

Bonneville's decision to join any market must comport with multiple grants of authority, including, but not limited to, power marketing, providing transmission service, and operating in a business-like manner. In exercising such authorities, the Administrator must balance his ability to meet multiple statutory obligations, such as providing preference and priority in the sale of power when there are conflicting or competing requests, making firm power sales under section 5(b) of the Northwest Power Act, providing transmission service and operating the transmission system, setting rates sufficient to repay the federal investment, and fulfilling environment, fish and wildlife obligations. This legal assessment describes how Bonneville could meet these obligations while participating in Markets+. At a high-level, Bonneville would join Markets+ by agreeing to a set of contracts incorporating a day-ahead market tariff.

Bonneville would exercise its contracting authority under section 2(f) of the Bonneville Project Act[171] to agree to a day-ahead market tariff. This would be similar to actions Bonneville has taken to participate in WEIM and WRAP.[172] Similar to the WEIM and WRAP agreements, and like any contract with a market operator implementing a day-ahead market subject to an applicable tariff, an agreement to participate in a day-ahead market must expressly acknowledge and not infringe upon Bonneville's authority to meet its statutory obligations and contractual requirements. Based on the day-ahead market tariff offerings to date, Bonneville has not identified legal barriers to satisfying its statutory obligations while participating in a day-ahead market.

Bonneville has the business flexibility to participate in a day-ahead market.

Since its inception, Congress has imbued Bonneville with broad statutory authority to market the power produced by federal hydropower generating projects. In the Bonneville Project Act of 1937, Congress granted Bonneville broad contracting authority for the specific purpose of allowing Bonneville to operate like a business in the marketing of federal power.[173] As the designated "marketing agent" for all electric power generated by the Federal Columbia River Power System,[174] Bonneville's statutes are unique with repeated focus on the business-related aspects of the agency's authority.

Both Congress and the courts have reaffirmed Bonneville's authority to operate in a businesslike manner. As summarized in a 1977 Senate Report:

> [The] legislative history [of the statutes governing Bonneville's operations] reflects a congressional recognition of the significant role played by [Bonneville] in the Pacific Northwest, and an effort to enable this organization to operate in a businesslike fashion and to free it from the requirements and restrictions ordinarily applicable to the conduct of Government business. The transfer of the functions of [Bonneville] from the Department

[171] 16 U.S.C. § 832a(f).

[172] Bonneville Power Administration, Energy Imbalance Market Policy, Administrator's Record of Decision at 54-56 (Sept. 2019) (WEIM Policy ROD), *available at* https://www.bpa.gov/-/media/Aep/projects/energy-imbalancemarket/rod-20190926-energy-imbalance-market-policy.pdf; Bonneville Power Administration, Bonneville's decision to participate in the Western Resource Adequacy Program Phase 3B (Dec. 16, 2022), *available at* https://www.bpa.gov/-/media/Aep/projects/resource-adequacy/wrap-final-closeout-letter.pdf.

[173] Bonneville Project Act, 16 U.S.C. § 832a(f); *see* S. Rep. No. 79-469, at 13 (1945) ("[BPA] operates a business enterprise . . . .") (letter from Interior Secretary Ickes).

[174] Transmission System Act of 1974 § 8, 16 U.S.C. § 838f.

> of the Interior to the Department of Energy is not intended to diminish in any way the authority or flexibility which is a requisite to the efficient management of a utility business.[175]

The ability of Bonneville to adapt to the ever-changing landscape of the wholesale electric power industry like a business is particularly important because the Administrator must implement many, and often competing, statutory directives.[176] Similarly, the U.S. Court of Appeals for the Ninth Circuit has noted that "[The Administrator] must continue to run [Bonneville] like a business on a sound financial basis, enabling it to repay its debt to the federal treasury in a timely fashion, while discharging costly new public duties assumed after the Northwest Power Act's passage."[177]

In 1995, Bonneville adopted a Business Plan with a market-driven direction and a goal to be a more active participant in the competitive market for power, transmission, and energy services.[178] As stated in the 1995 Business Plan Record of Decision, Bonneville's objective is to use its success in markets to ensure the financial strength necessary to better produce the public benefits that Bonneville affords to the region.[179] The market-driven approach is designed to increase the value of Bonneville's business and generate expanded benefits to share with customers and constituents-including energy conservation and fish and wildlife mitigation.[180] By evaluating potential participation in a day-ahead market, Bonneville is continuing its long-standing business strategy to pursue options that could produce value for Bonneville's customers and the region.

This Policy discusses how Bonneville and the region as a whole are experiencing significant and unprecedented changes in the industry. Faced with competitive drivers and new regulatory requirements, electric utilities are devoting significant resources to develop and transition to market-based solutions that aim to reduce inefficiencies, improve power and transmission system reliability, lower production costs, and bolster resource adequacy, among other things. Bonneville and other utilities' participation in the Western Energy Imbalance Market are an example of one such development. These new competitive drivers are creating opportunities for Bonneville to modernize its business to preserve and enhance the value Bonneville provides to its customers pursuant to its statutory mission.

As Bonneville evaluates potential participation in a day-ahead market, some of its key objectives rooted in statute are to ensure an adequate, efficient, economical, and reliable power supply, and to encourage the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles. Therefore, Bonneville continues to assess whether participation would provide value for customers in terms of greater efficiency, lower costs, and increased reliability.[181]

2. Bonneville would fulfill its preference obligations and Northwest Power Act Section 5(b) firm power sales obligations while participating in a day-ahead market.

Bonneville's authority to market federal power is included in several statutes: the Bonneville Project Act

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[175] S. Rep. No. 95-164, at 30 (1977), reprinted in 1977 U.S.C.C.A.N. 854, 884.
[176] *Ass'n of Pub. Agency Customers v. Bonneville Power Admin.*, 126 F.3d 1158, 1170-71 (9th Cir. 1997).
[177] *Id*.
[178] Bonneville Power Administration, Business Plan Record of Decision (Aug. 15, 1995), *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/1995-rod/rod-19950815-business-plan-final-environmental-impact-statement.pdf.
[179] *Id.* at 1.
[180] *Id.* at 11.
[181] Bonneville Power Administration, Staff Recommendation on Day-Ahead Market Participation at 2-3 (Apr. 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/02-day-ahead-market-attachment-1-staff-recommendation.pdf.

of 1937, the Flood Control Act of 1944, the Pacific Northwest Consumer Power Preference Act of 1964, the Federal Columbia River Transmission System Act of 1974, and the Pacific Northwest Power Planning and Conservation Act of 1980. Collectively, these statutes form the basis for Bonneville's broad authority to market power. For Bonneville to participate in Markets+, it must market power consistent with these statutory authorities.

Bonneville recognizes that many stakeholders have requested explanations of how Bonneville will meet obligations in these statutes to provide public bodies and cooperatives preference and priority to federal power, and to offer contracts for the sale of electric power under section 5(b) of the Northwest Power Act, considering the paradigm shift that a day-ahead market would represent. As explained below, Bonneville will continue to meet its preference and section 5(b) obligations included in these authorities if it participates in a day-ahead market.

a. Bonneville must provide preference in sales of power at all times in the event of competing or conflicting applications for power.

Bonneville will continue to provide preference in the sale of power to public bodies and cooperatives in the event of competing applications. Bonneville would continue to offer long-term power sales contracts to 5(b) customers and would incorporate the day-ahead market dispatch framework into the contract terms and rates for such sales. Section 4(a) of the Bonneville Project Act of 1937 specifies, "[i]n order to insure that the facilities for the generation of electric energy at the Bonneville project shall be operated for the benefit of the general public, and particularly of domestic and rural customers, the administrator shall at all times, in disposing of electric energy generated at said project, give preference and priority to public bodies and cooperatives."[182] Section 4(b) further explains, "in the event that . . . there shall be conflicting or competing applications for an allocation of electric energy between any public body or cooperative on the one hand and a private agency of any character on the other, the application of such public body or cooperative shall be granted."[183] The Flood Control Act of 1944 similarly states that "[p]reference in the sale of such power and energy shall be given to public bodies and cooperatives."[184] Thus, Bonneville's earliest legislation established the foundational principle that Bonneville shall afford preference to public bodies and cooperatives in the event of competing or conflicting requests for power. Bonneville understands that providing preference in the event of competing applications is a fundamental component of its power marketing obligation that it will continue to meet if it chooses to participate in Markets+ for the benefit of its customers.

Section 5(a) of the Northwest Power Act reaffirms the preference and priority provisions from Bonneville Project Act by stating, "[a]ll power sales under this chapter shall be subject at all times to the preference and priority provisions of the Bonneville Project Act of 1937 . . . ."[185] The Northwest Power Act was enacted to resolve regional power customer fears about an impending allocation of low-cost Federal power. The House Report of the Commerce Committee on the Northwest Power Act emphasized that sales by the Administrator would be subject to existing preference provisions:

> The purpose of this provision is clear. The Committee wants to ensure that all preference customer contract requirements will continue to have a priority over sale to other customers

[182] 16 U.S.C. § 832c(a).

[183] 16 U.S.C. § 832c(b); *see also Aluminum Co. of Am. v. Cent. Lincoln People's Util. Dist.*, 467 U.S. 380, 393 (1984) ("[T]he preference system merely determines the priority of different customers when the Administrator receives 'conflicting or competing' applications for power that the Administrator is authorized to allocate administratively." (citing section 4(b) of the Bonneville Project Act)).

[184] 16 U.S.C. § 825s.

[185] 16 U.S.C § 839c(a)

> and other sales would be, in effect, subordinate to preference provisions of the Bonneville Project Act, including the 5-year withdrawal features for contracts with non-preference customers and the 20-year limitation on the terms of the contract.[186]

Bonneville finds that it will be able to continue to satisfy preference when there is a competing or conflicting application for power in a day-ahead market. As described above, in a day-ahead market context, Bonneville would continue to make long-term forward sales of power and would apply preference if faced with a limited supply of power. After the day-ahead market clears, any out-of-market requests for electric power from Bonneville are likely to fall within the context of a surplus sale. Bonneville would continue to meet its preference obligations for both long-term sales and surplus sales as described below.

b. Bonneville is authorized to acquire resources to meet all eligible customer requests for electric power under section 5(b) of the Northwest Power Act.

Bonneville's acquisition authority generally ensures that Bonneville can acquire to meet the needs of all customers requesting contracts for electric power and thereby avoid a preference allocation among competing or conflicting requests for power. Historically, there was no need for Bonneville to apply preference because Bonneville had an abundance of power. However, in the 1970s, projections showed that because of increased power demand, the Administrator would be required to apply preference and allocate the limited amount of federal power. Upon expiration of the power sales contracts with non-preference customers, the Administrator would no longer be able to sell power to non-preference entities because the preference clauses would obligate him to allocate the limited supply to public bodies and cooperatives. Congress drafted the Northwest Power Act to prevent the need for an allocation of power.[187] The Act solved the pending allocation and reduces the potential application of preference in the future by providing the Administrator with resource acquisition authority to meet his sales obligation.

Section 5(b)(1) of the Northwest Power Act provides,

> Whenever requested, the Administrator shall offer to sell to each requesting public body and cooperative entitled to preference and priority under the Bonneville Project Act of 1937 . . . and to each requesting investor-owned utility electric power to meet the firm power load of such public body, cooperative or investor-owned utility in the Region to the extent that such firm power load exceeds [customer resources].[188]

Section 5(b) thus establishes the Administrator's obligation to offer a contract for the sale of electric power to meet the firm power loads of any requesting regional public body, cooperative, or investor-owned utility in excess of non-federal resources used by the customer to serve such load. The Act not only requires the Administrator to offer a contract for the sale of electric power to all eligible requesting customers but also directed the Administrator to offer new power sales contracts to then-existing direct service industry customers.

To implement the Act in a timely matter, Congress deemed the Administrator to have sufficient resources and, most importantly, granted the Administrator authority to acquire resources to meet Bonneville's long-term power supply obligations. In sections 6(b), (c), and (d) of the Northwest Power Act, Congress granted

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[186] H.R. Rep. No. 97-976, Pt. I, at 34 (1980).

[187] As the Supreme Court has explained, "Congress moved to avert what appeared to be an emerging customer struggle for [Bonneville] power by enacting the [Northwest Power Act]." *Aluminum Co. of Am.*, 467 U.S. at 383. And as Congressman Swift remarked, "[t]he basic concept of this bill is simple: It permits BPA to avoid the need for an administrative reallocation of power by giving BPA the means to reduce loads and to acquire resources so that it should be able to meet the needs of all classes of customers . . . . This is a bill to solve a power allocation problem . . . ." 126 Cong. Rec. H27818 (daily ed. Sept. 29, 1980) (remarks of Rep. Swift).

[188] 16 U.S.C. § 839c(b).

Bonneville the authority to acquire resources to meet his long-term power supply obligations.[189] It is important to note that while section 5(b) requires the Administrator to supply the power requirements of all requesting public and investor-owned utility customers and to acquire resources when necessary, Congress also provided protections for preference customer rates when establishing rates pursuant to section 7(b).[190]

Importantly, section 5(b) contracts are not a response to "competing or conflicting" requests for power that would require an allocation of electric energy. The section 5(b) sales obligation operates in conjunction with long term loads and resource planning and the section 6 resource acquisition authority so that, in general, Bonneville does not need to allocate power among conflicting or competing applications. When a customer has a long-term power sales contract, they receive power under that contract and preference is not triggered.

While the obligation remains of paramount importance, preference only triggers if Bonneville is unable to acquire resources to satisfy its 5(b) obligations due to an insufficiency of resources or if Bonneville is offering to sell surplus electric power. The insufficiency and surplus scenarios are discussed in the following two sections.

c. Bonneville must apply preference in an allocation scenario.

In a scenario where Bonneville is faced with a limited supply of power in the planning horizon, preference would apply. In general, section 6 of the Northwest Power Act provides Bonneville with acquisition authority designed to ensure he can meet all requests for power. Section 11(b)(6) of the Transmission System Act also provides Bonneville with the authority to purchase electric power on a short-term basis to meet temporary deficiencies in power it is obligated to supply.[191]

Bonneville's ability to acquire power to meet its supply obligations generally avoids Bonneville having a limited amount of power that must be allocated through the operation of preference. Northwest Power Act section 5(b)(5) requires the Administrator to provide contractual mechanisms to apply preference in the unlikely event that Bonneville cannot acquire resources to meet its power supply obligations.[192] If the Administrator "cannot be assured on a planning basis of acquiring sufficient resources to meet such loads during a specified period of insufficiency" he is obligated to apply preference and allocate electric energy among customers in accordance with the section 5(b)(6) allocation provisions. [193]

If Bonneville were to determine that it cannot be assured on a planning basis to meet its long-term firm power sales, Bonneville would allocate power based upon the insufficiency and allocation methodology.[194]

Additionally, Bonneville's participation in a day-ahead market is likely to substantially mitigate the risk of an insufficiency. Bonneville will maintain its existing Resource Program, which incorporates guidance from Northwest Power and Conservation Council's Power Plan; continue to plan its resources on an annual, monthly, daily, and real-time basis to assure a firm power supply to meet its firm power sales obligations; and participate in WRAP. In the long term, day-ahead markets should lead to improved regional resource planning. Markets+ requires each participant, including Bonneville, to demonstrate a commitment that it has sufficient resources available to meet its forecast load obligations in the planning horizon by participating in the WRAP. Based on Bonneville's continued efforts and the benefits that coordination

[189] 16 U.S.C. § 839d(b)-(d).
[190] 16 U.S.C. § 839e(a)-(b).
[191] 16 U.S.C. § 838i(b)(6).
[192] 16 U.S.C. § 839c(b)(5).
[193] *Id.*; 16 U.S.C. § 839c(b)(6).
[194] *See* Notice of Publication of the Insufficiency and Allocations Exhibit for the Power Sales Contract, 61 Fed. Reg 11,389 (Mar. 20, 1996).

through a market will bring, there will be an even lower chance that Bonneville would be required to allocate power based on a projected insufficiency on a planning basis.

d. Bonneville will apply preference for competing and conflicting applications for surplus power.

The most common application of statutory preference is when Bonneville offers to make a surplus power sale. The Bonneville Project Act of 1937[195] and the Pacific Northwest Consumer Power Preference Act of 1964[196] specify the application of statutory preference when Bonneville markets surplus power. The Regional Preference Act specifies that, in the event of competing applications for available surplus power, and terms and conditions are mutually agreed upon, Bonneville will meet customer requests in the following order: 1) Pacific Northwest public utilities, 2) Pacific Northwest investor-owned utilities and direct-service industrial customers, and 3) Southwest public utilities. Thereafter, if additional power is available, Bonneville may also make surplus sales to non-preference customers.

In the Western Energy Imbalance Market Policy Record of Decision, Bonneville explained the specific mechanics of the notice of surplus power. Consistent with that analysis, in a day-ahead market, Bonneville intends to continue the regional notice format the agency has used for over 20 years.[197] Since the advent of modern markets, Bonneville has provided notice to its preference customers regarding the availability of short-term surplus power using a combination of: (1) annual letters providing notice of surplus availability and how regional customers may exercise their rights; (2) product specific letters/emails when Bonneville is preparing to sell a new type of product to a non-preference customer; and (3) a standing daily notification on Bonneville's website regarding the availability of surplus power and instructing regional customers on how to obtain it if they are interested. Bonneville is unaware of any instance during the past 20 years where regional preference customers took issue with the format of Bonneville's notice requirements. This format has been an efficient and effective way for Bonneville to participate in the short-term market while also notifying regional customers that Bonneville may have surplus power available for sale on a rolling basis.[198]

When Bonneville began to participate in the Western Energy Imbalance Market, it updated its daily standing notice to specify that, if surplus remains available prior to the market run, Bonneville may bid such surplus power into the market at its discretion. In a day-ahead market, Bonneville would follow the same approach. The agency would continue to provide public preference and Pacific Northwest regional preference to requests for surplus power before and after the day-ahead market run. Bonneville would continue to welcome customer inquiries regarding potential purchases of surplus power before and after the day-ahead market submission timeframe.

Similarly, Bonneville's participation in a day-ahead market will not impact its surplus sales approach. Bonneville will continue to market surplus power when available, prior to the day-ahead market generation and load bid submission window, and thereafter prior to the real-time market bid submission window. The day-ahead market resource schedule output does not ultimately determine real-time dispatch, the real-time market bid submission window allows for Bonneville to make additional sales if surplus power remains available. Bonneville will continue to meet its regional preference obligations when marketing uncommitted surplus power.

For the reasons described above, Bonneville's legal assessment is that it can participate in a day-ahead market consistent with its preference obligations, 5(b) firm power sales obligation, obligations to allocate power consistent with preference in the event of insufficiency, and obligations to provide preference when

[195] 16 U.S.C. § 832 *et seq.*
[196] 16 U.S.C. § 837 *et seq.*
[197] WEIM Policy ROD at 62.
[198] *Id.*

making surplus sales.

3. Day-ahead market participation would be akin to an interregional exchange of power.

Since the enactment of the Bonneville Project in 1937 through the passage of the Pacific Northwest Electric Power Planning and Conservation Act in 1981, Congress contemplated and included within the scope of the Administrator's authorities the authority to interconnect with power systems both within and outside the Pacific Northwest region and leverage these interconnections to make mutually beneficial interregional exchanges. For example, section 2(b) of the Bonneville Project provides:

> In order to encourage the widest possible use of all electric energy that can be generated and marketed and to provide reasonable outlets therefor, and to prevent the monopolization thereof by limited groups, the administrator is authorized and directed to provide, construct, operate, maintain, and improve such electric transmission lines and substations, and facilities and structures appurtenant thereto, as he finds necessary, desirable, or appropriate for the purpose of transmitting electric energy, available for sale, from the Bonneville project to existing and potential markets, and, *for the purpose of interchange of electric energy, to interconnect the Bonneville project with other Federal project and public owned power systems* constructed on or after August 20, 1937.[199]

The Northwest Power Act also includes provisions promoting interregional exchanges. Section 6(l)(1) provides:

> The Administrator is authorized and directed to investigate opportunities for adding to the region's resources or reducing the region's power costs through the accelerated or cooperative development of resources located outside the States of Idaho, Montana, Oregon, and Washington if such resources are renewable resources, and are now or in the future planned or considered for eventual development by nonregional agencies or authorities that will or would own, sponsor, or otherwise develop them.[200]

Section 6(l)(2) further provides:

> The Administrator is authorized and directed to investigate periodically opportunities for mutually beneficial interregional exchanges of electric power that reduce the need for additional generation or generating capacity in the Pacific Northwest and the regions with which such exchanges may occur.[201]

Congress understood that interregional transmission interties between the Pacific Northwest and adjoining regions, such as the Pacific Northwest Pacific Southwest Intertie, offer substantial benefits. At the time of the enactment of the Northwest Power Act, existing transactions reduced the need for new generating capacity, helped provide more reliable service to load, reduced the need to rely on fossil fueled resources, and reduced the costs of electricity. In a June 1981 report on Interregional Resource Potentials, Bonneville committed to continuing to work with entities in the region and adjoining regions to optimize the use of existing generating facilities and reduce the need for new generating facilities through mutually beneficial exchanges and other transactions.

Bonneville has a longstanding definition of interchange energy in the power marketing context.[202] Interchange energy means energy received by one utility system from another, usually in exchange for

[199] 16 U.S.C. § 832a(b) (emphasis added).
[200] 16 U.S.C. § 839d(l)(1).
[201] 16 U.S.C. § 839d(l)(2).
[202] *See* Bonneville Definitions (1993).

energy delivered to the other utility at another time or place. It is distinguished from a direct purchase or sale, although accumulated energy balances are sometimes settled in cash. Through interchange and interconnection, Bonneville has been able to enter into power-for-power exchanges, including some with payments of money incidental to the power that were justified as a suitable exchange term. Indeed, exchanges need not be simultaneous and the places where an exchange occurs may vary.

A day-ahead market will operate similar to an exchange of power because all market participants must bring sufficient resources to the market to serve their loads, which is designed to prevent participants from leaning on other participants. Rather than a bilateral exchange of power, power exchanged in the market will flow among the participants to make the most economical use of the transmission system. Thus, the power available under a day-ahead market is in effect exchanged between and among the participants resulting in all participants maintaining their load and resource balance. Here, Bonneville's participation in the interregional Markets+ day-ahead market falls within the scope of the section 6(l) directives to investigate such markets and the resources exchanged therein, including to increase supplies of electric power produced by renewable resources.

4. Bonneville policies will ensure that section 5(b) customers receive power with environmental attributes reflecting the system resource mix.

Bonneville's preference customers have requested acknowledgement of the inherent value of the low-carbon resources from which Bonneville supplies power. Bonneville committed in its Provider of Choice Policy to convey the environmental attributes of the power sold, including emissions and any Renewable Energy Certificates commensurate with a customer's firm power purchase amount and rate elections. Bonneville believes it is reasonable to conclude that these non-power characteristics should accompany Bonneville's physical sales of power. Bonneville's objective as an active participant in developing the day-ahead market GHGs framework designs has been to ensure that it can uphold its policy that non-power characteristics will accompany Bonneville's sales of power.

Bonneville markets power from the system mix of federal and non-federal resources, and this will not change in a day-ahead market. While some jurisdictions have concluded that environmental attributes are associated with power, such environmental attributes are defined through variously differing state laws and local regulations and are subject to change and are not applicable to Bonneville. Nevertheless, Bonneville believes a policy consideration regarding participation in a day-ahead market is whether the market rules support conveyance of environmental attributes associated with sales of power to Bonneville's public customers. Bonneville finds the Markets+ Tariff to meet its policy objectives notes that many of Bonneville's public power customers also support its greenhouse emissions accounting mechanisms. Bonneville will continue to work with its customers, and in the appropriate market design forums, as work on GHG accounting continues.

5. Bonneville would participate in a day-ahead market consistent with its authorities to provide transmission service and operate the transmission system.

Bonneville has broad authority under its governing statutes to set the terms and conditions of transmission service, as well as how to operate the system in order to provide transmission service and maintain reliability.[203] While participating in Markets+, Bonneville will continue to offer transmission service and Ancillary and Control Area Services under its OATT, which ensures that Bonneville and its customers take transmission service on a comparable basis. Bonneville will also be able to make transmission available for

[203] *See Cal. Energy Comm'n v. Bonneville Power Admin.,* 909 F.2d 1298, 1314 n.17 (9th Cir. 1990) (holding that the Administrator's authority to operate the transmission system "is broad, allowing the Administrator substantial discretion" and that "[t]his discretion is tempered only by the implied limitation that the Administrator's action not be inconsistent with other congressional decrees.").

market use, which is authorized under section 2(b) of the Bonneville Project Act.[204]

Joining a day-ahead market will require that transmission be made available for market use. Making transmission available for day-ahead market use falls within Bonneville's broad transmission authorities. Bonneville is monitoring day-ahead market policies to ensure benefits to transmission rights holders including through congestion rent policies, and to ensure compensation for any lost transmission sales through market transmission use charges. In addition, Bonneville will work through issues presented by entities holding transmission rights on the Bonneville system that want to participate in various day-ahead markets, as well as with Bonneville customers in other balancing authority areas that may be affected by a transmission provider's market participation.

6. Congress granted federal utilities authority to join transmission organizations.

In the Energy Policy Act of 2005 (EPAct '05), Congress provided authority for federal utilities, including power marketing administrations, to participate in transmission organizations, such as RTOs, consistent with their existing statutory authorities, obligations, and limitations.[205] When considering EPAct '05, the House Committee on Energy and Commerce, Subcommittee on Energy and Air Quality discussed the economic dispatch associated with organized markets and its potential benefits for fostering competitive electric markets and ultimately reducing costs to the consumer.

By 2005, RTO and ISO market designs had matured significantly since deregulation formally began in 1996.[206] RTOs had formed in many parts of the country and some included day-ahead and real-time energy markets based upon economic dispatch. Congress enacted the EPAct '05 with awareness of the context of evolving electricity markets, including Federal Energy Regulatory Commission Order No. 2000 regarding RTOs, which FERC Commissioner Bromwell explicitly discussed in her House committee testimony regarding the bill. Commissioner Bromwell explained that "RTOs that are fully independent of market participants can ensure non-discriminatory operation of the transmission facilities under their control. RTOs have FERC-approved market monitors, implement FERC-approved market mitigation plans, and conduct long-range planning all for the protection of customers. RTOs can perform economic dispatch over large geographic areas that will ensure the selection of least-cost generators. Finally, RTOs can offer organized markets and one-stop shopping that reduce transaction costs, provide transparent market rules and allow the opportunity for price discovery." [207]

Consistent with this sentiment, Bonneville views its EPAct '05 authority and Congress's understanding of organized markets as informative for its consideration of whether to participate in a day-ahead market. A day-ahead market is one element that is present across RTOs. In contrast to a full RTO, the proposed day-ahead market designs allow Bonneville to retain substantial control over its transmission assets and preserve its BAA responsibilities. Moreover, as the Supreme Court explained, "[t]he intention of Congress can be

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[204] *See* Bonneville Project Act, 16 U.S.C. § 832a(b) ("[T]o encourage the widest possible use of all electric energy that can be generated and marketed . . . the administrator is authorized and directed to provide, construct, operate, maintain, and improve such electric transmission lines . . . as he finds necessary, desirable, or appropriate for the purpose of transmitting electric energy . . . to existing and potential markets . . . .").

[205] 42 U.S.C. § 16431.

[206] Order No. 888, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities*; *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 75 FERC ¶ 61,080 (1996); *Open Access Same-Time Information System and Standards of Conduct*, Order No. 889, FERC Stats. & Regs. ¶ 31,035 (1996), *order on reh'g*, Order No. 889-A, FERC Stats. & Regs. ¶ 31,049 (1997), *order on reh'g*, Order No. 889-B, 81 FERC ¶ 61,253 (1997), *order on reh'g*, Order No. 889-C, 82 FERC ¶ 61,046 (1998); Order No. 2000, *Regional Transmission Organizations*, 89 FERC ¶ 61,285 (Dec. 20, 1999).

[207] *Comprehensive National Energy Policy: Hearings Before the Subcomm. on Energy and Air Quality of the Comm. On Energy and Commerce*, 108th Cong. 57 (Mar. 5, 2003) (Serial No. 108-7).

gleaned, at least in part, by reference to prior law, as Congress is presumed to be knowledgeable about existing law . . . ."[208] Thus, while the development of a day-ahead market is not an RTO, it is reasonable to conclude that Congress contemplated federal utilities would be authorized to participate in subcomponents of an RTO, like a day-ahead market, as part and parcel of that express authority.

7. Bonneville participation in a day-ahead market must be effectuated through rates and tariff terms and conditions.

If Bonneville participates in Markets+, it will continue to establish its power and transmission rates in Northwest Power Act section 7(i) rate proceedings, and it will set the terms and conditions for transmission service in tariff proceedings.[209] Under Section 7(a)(1) of the Northwest Power Act, the Administrator establishes "rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. Such rates shall be established . . . to recover . . . the cost associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment . . . over a reasonable period of years and the other costs and expenses incurred by the Administrator . . . ."[210] Under section 7(a)(2), the Federal Energy Regulatory Commission reviews Bonneville's proposed rates to ensure they are 1) sufficient to assure repayment of the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs, 2) based upon the Administrator's total system costs, and 3) insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system.[211]

In a day-ahead market, Bonneville's rates must continue to be sufficient to recover total system costs including the Fish and Wildlife program, the Residential Exchange Program, amortization of existing debt, Columbia Generating Station financing, conservation, depreciation expenses, costs associated with achieving financial policy objectives, and costs associated with market participation. Bonneville's rates must also equitably allocate the cost of the transmission system between federal and non-federal uses. Bonneville's rates are based on forecasts and risk adjustment mechanisms respond holistically to actuals differing from forecast. Bonneville anticipates aggregate treatment of market benefits, which may vary based on products and services. In a section 7(i) rate proceeding, Bonneville would assess how to reflect the costs and benefits of market participation in rates, considering the interaction of any new mechanisms with existing policies. Participation in a day-ahead market would not change the Administrator's obligation to set rates to recover total system costs.

In addition to rate updates, the agency would need to make changes to the terms and conditions of transmission service it provides to customers to enable participation in a day-ahead market. Bonneville's governing statutes grant the Administrator broad discretion to set the terms and conditions of transmission service, which would include any terms and conditions necessary to join a day-ahead market. Several statutory provisions provide the basis for Bonneville's authority to determine the terms and conditions of transmission service.[212] In general, these statutory provisions grant Bonneville the discretion to act in a business-like manner when selling transmission at cost-based rates and to make decisions to effectuate that goal. While the details of such changes would depend on the market design, Bonneville would continue to sell and provide transmission service under its OATT as it does today. Bonneville will continue to monitor the development of market rules associated with transmission, including potential changes in transmission

[208] *Native Village of Venetie I.R.A. Council v. State of Alaska*, 944 F.2d 548, 554 (9th Cir. 1992) (citing *Goodyear Atomic Corp. v. Miller*, 486 U.S. 174, 184–85 (1988)).
[209] 16 U.S.C. § 839e(i).
[210] 16 U.S.C. § 839e(a)(1).
[211] 16 U.S.C. § 839e(a)(2).
[212] 16 U.S.C. §§ 832a(b), 832a(f); 16 U.S.C. § 837e; 16 U.S.C. §§ 838b, 838d.

revenue due to market impacts and congestion rent design, to assess potential transmission customer impacts. Bonneville would conduct a terms and conditions proceeding to update its tariff with any changes necessary to enable day-ahead market participation. Section 9 of Bonneville's OATT describes the process for changing terms and conditions. Such a proceeding would be in accordance with Section 212(i)(2)(A) of the Federal Power Act.[213]

8. Bonneville will continue to meet its environmental obligations, including those under the Northwest Power Act, Endangered Species Act, and National Environmental Policy Act.

Another important set of Bonneville responsibilities involves the operation of the hydro system in coordination with the U.S. Army Corps of Engineers and the Bureau of Reclamation. The agencies manage the Federal Columbia River Power System for multiple project purposes including flood control, navigation, irrigation, fish and wildlife, power production, and recreation. Bonneville's participation in Markets+ cannot conflict with meeting non-power objectives, and Bonneville must continue to meet its environmental statutory obligations. As discussed herein, the designs include special considerations for hydro bid curves to recognize obligations and operational flexibilities of hydropower projects. The Markets+ designs do not appear to present a conflict with meeting these objectives, but as more details are developed it is essential that Bonneville maintain the flexibility and discretion necessary to meet non-power objectives. Bonneville will continue to ensure that Federal Columbia River Power System projects are managed for all project purposes and recognize system-wide operating constraints.

In a day-ahead market context, Bonneville would maintain operations to support ESA-listed fish species. Bonneville would also continue to meet Northwest Power Act requirements. Bonneville's power marketing services and activities, and its actual power operations to meet load obligations, would continue to be conducted consistent with applicable Biological Opinions and within existing operating constraints and normal operating limits of the projects. If Bonneville were to pursue participation in a day-ahead market, it would also assess the potential environmental effects that could result from implementing the decision consistent with the National Environmental Policy Act.

9. Conclusion

Bonneville's decision to join any market must comport with its legal obligations including to provide preference and priority in the sale of power, make firm power sales under section 5(b) of the Northwest Power Act, provide transmission service and operate the transmission system, set rates sufficient to repay the federal investment, and fulfill environment, fish and wildlife obligations. Bonneville has not identified any legal impediment to meeting these objectives if it joins Markets+.

[213] 16 U.S.C. § 824k(i)(2)(A).

Appendix B

West-Wide Governance Pathways Initiative Overview and Assessment

In July 2023, the West Wide Governance Pathways Initiative was launched with a mission to develop and form a new and independent entity with an independent governance structure capable of overseeing an expansive suite of West-wide wholesale electricity markets and related functions. This effort was led by a Launch Committee comprised of representatives from across a wide range of sectors. While its working meetings were closed, the Launch Committee held monthly public stakeholder workshops to provide updates on progress. Work products were released throughout the process and there was an opportunity for public comment. It is worth noting that the Western Area Power Administration, another Federal power marketing administration, participated on the Launch Committee. Bonneville participated in all public stakeholder meetings and provided comment at every opportunity. Bonneville was also an active participant in Pathways Step 2 work groups and contributed significant staff time to that effort.

The Pathways initiative resulted in two outcomes: Step 1 proposed a transition of the WEM Governing Body from a governance model of joint authority to one of primary authority with a provision for dual filing by the WEM Governing Body and CAISO Board of Governors at FERC in the case of an unresolvable dispute (discussed above). Step 2 proposes a significant transition to create a Regional Organization (RO) with an independent board that governs the WEIM and EDAM Tariff. Under the proposed approach, CAISO would continue to operate the market, would hold all financial and contractual liability, and maintain a shared tariff between CAISO and the RO. Some limited staff responsibilities may shift to the RO; however, the specifics of staffing remain open at the time of the final Step 2 proposal to be determined during the formation of the RO. The final proposal recommends that the new RO undertake a feasibility study within 9 months of formation to evaluate further advancements in market independence. The full Step 2 proposal can be found here.

Assessment of Pathways Step 1

Bonneville has evaluated the outcomes of the Pathways initiative as part of its day-ahead markets decision process. Bonneville believes that Step One, by itself, does not achieve the level of independence from any one state's authority that is necessary for a regional market. Bonneville does not view Primary Authority as more independent than Joint Authority. Bonneville is concerned that the transition to Primary Authority could lead to the CAISO Board of Governors being disconnected from WEIM and EDAM issues and could increase conflict between the Board of Governors and the WEIM Governing Body.

Under Step 1, the CAISO Board of Governors would retain sufficient authority to take back the steering wheel when certain conditions arise (to maintain fiduciary responsibility under California law) described as exigent circumstances. "Exigent circumstances" is a very broad concept, and by its nature, would likely be called upon during a crisis, e.g., a reliability event, a price spike, or a call by California-elected officials to take action. Such events will be sudden and chaotic. It would be concerning for parties outside of California to be exposed to a sudden assertion of control by the CAISO Board of Governors when the WEM Governing Body, by the nature of its primary focus on the market, may have superior understanding of the issues.

The Step 1 proposal does not achieve independent market governance to meet Bonneville's principle.

Assessment of Pathways Step 2

As described above, the Step 2 final proposal represents a significant shift from the current governance structure of the WEIM and EDAM. It moves governance of those markets to a Regional Organization with an independent board. Market operations would remain under the single CAISO Tariff that includes

CAISO's administration of its BA. The RO would hold sole authority for sections of the CAISO Tariff applying to market operations and joint authority with the CAISO BOG for tariff provisions of overlapping application to both markets and the CAISO BA. The RO acts as a policy organization, governing policy related to the markets. Operation of the market remains with CAISO, as does corporate and financial liability related to the market. The step 2 final proposal also describes significant changes to the stakeholder process to enhance the role of stakeholders and shift away from the staff-driven process that CAISO uses today.

In evaluating the Step 2 proposal, Bonneville assessed whether the proposed approach achieves independent governance for markets. Under the proposal, the RO board members would be nominated and chosen through an independent sector-based process; they would not be selected by the California governor and confirmed by the California Senate, which is an advancement from the current state. However, market operations and administration would remain under the direction of the CAISO Board of Governors and, therefore, would not achieve full independence from the State of California.

Bonneville does not believe the Pathways Step 2 achieves the independent governance contemplated in Pathways' charter. This appraisal is not a matter of subjective opinion about what degree of independence would be good enough; the proposal creates conflicts that undermine any claim of independent governance and operations. As discussed below, the Regional Organization proposed by Pathways does not achieve independent market operations, an independent tariff, independent contracts, and the ability to provide RTO services absent future legislation. The market contemplated by the proposal remains California's market, adding an independent policy board with limited authority for market operations and administration.

1. Independent Market Operations

First, the Regional Organization would not have independent oversight and administration of market operations. Instead, the market would continue to be operated by the market's largest BAA, CAISO. This sets up a conflict of interest. For governance to be independent, CAISO should have the same role as any other BA in the market.

The RO board may find itself in a frustrating situation. While it has authority in market design, it would have no executive authority to manage operations to ensure the market is faithfully implemented. Further, the RO will be forced to take market operations services from a single provider without regard to potential competitive market operation services. The proposal notes that, while a typical arms-length contract allows a dissatisfied party to choose to not continue doing business with the other, "[t]he RO would be more or less required to use the CAISO[.]" Operations would answer to a state entity, with no remedy available to the Regional Organization.

Without legislative change, CAISO and its employees would remain subject to California legal requirements to act for the benefit of California. *See* Cal. Pub. Util. Code § 345.5. The market would be operated by a single BA in the market footprint with duties to itself and its state. Pressure to favor California could manifest in subtle ways, such as how issues are framed and presented, and in prioritizing work under time and staffing constraints. Bonneville believes that California regulatory agencies and the state's legislature will retain disproportionate influence on policy development. The Pathways proposed role for the Regional Organization to weigh in on select hiring decisions is a small step forward but ultimately does not get to the heart of the issue.

Bonneville is also concerned that this conflict of interest and lack of operational authority for the RO will have impacts on participants in emergency or shortage situations. The Pathways proposal states it is standard practice for operators to be able to act in an emergency without seeking advance blessing from a board. Bonneville is not advocating for emergency operations to be brought to a board before responding to a crisis. Instead, it is imperative that operations are independent, so the operators have no incentive to

favor one participating BA. Until CAISO's load service responsibility and Western energy market operator responsibilities are performed by completely separate entities, the market will not be independent.

2. Independent Tariff

Second, the proposal recommends an integrated tariff with continued joint authority over many tariff sections. The Regional Organization would not have sole authority over the tariff. The CAISO tariff would remain the relevant tariff. An integrated tariff creates conflicts over who has authority over which provisions, and who decides how certain initiatives are classified. An independent market would not intentionally choose to integrate its tariff with that of a single participating BA. From a practical standpoint, joint management of a tariff would be needlessly cumbersome and inefficient. From a legal standpoint, the ambiguity regarding authority could result in unjust and unreasonable implementation of the tariff.

Joint provisions are not necessary. General provisions could be copied and pasted to create two separate tariffs. Provisions specific to CAISO BAA could be unwound from sections that should be under the Regional Organization's sole authority. For the Regional Organization to have independent authority, it must be clear what authority it possesses. If the reluctance to separate tariffs is driven by cost considerations or the difficulty of precisely defining CAISO's new role, it is worth the investment now to address the issues to ensure unambiguous, just, and reasonable terms and conditions rather than in the heat of a future controversy. In order to achieve an independent governance structure, separate tariffs are a necessity.

3. Independent Contracts

Under the Step 2 proposal, CAISO would remain the counterparty to contracts with other market participants. This status is unique among participating BAs. It creates conflicts if CAISO interprets the contract differently than the Regional Organization. This could be a problem for CAISO if CAISO disagrees with the Regional Organization over what market rules are required or prohibited by the contracts. This is problematic for the Regional Organization if it adopts market rules applicable to scheduling coordinators and participating generators but lacks privity to enforce any related contract action. It is not clear that the Regional Organization would have any authority to amend contracts if it determines such amendments are necessary or desirable. Even if CAISO and the Regional Organization attempt to coordinate and align on interpretations, this continues to give one market participant undue influence over contracts with all other market participants. One participating BA should not be able to wield influence over the contracts of all market participants. As proposed, this contractual influence would not be shared or checked even by the Regional Organization itself.

These conflicts would not simply be philosophical differences of opinion. Under option 2.0, CAISO would retain financial responsibility, liability, and compliance obligations, which represents significant risk for CAISO. Therefore, when conflicts occur, the stakes will be high, and CAISO will naturally be incented to act in its own interest. The party that sets market rules should be impacted by the practical financial and legal ramifications of those rules. When the relationship between authority and impact is severed, as they are in the Step 2 proposal, conflict is inherent.

Despite the foregoing critique, Bonneville supports and appreciates the advancements made in the stakeholder process in the Step 2 final proposal. It has been Bonneville's experience that a more stakeholder-driven approach leads to increased collaboration, compromise, and ultimately better outcomes for market stakeholders. The Pathways Step 2 proposal introduces a stakeholder process with an increased role for stakeholders, including a more empowered stakeholder representative committee and indicative voting. The final proposal also includes an appropriate role and representation for federal power marketing administrations in both the stakeholder process and public interest process.

Appendix C

Potential Regional Transmission Organization Formation

Consistent with Bonneville's strategic plan, Bonneville is considering an incremental approach to market expansion. While Bonneville is only considering day-ahead market participation in this process, Markets+ may offer more potential for further integration into an RTO. SPP is a fully independent entity that does not require any legislative changes to meet FERC's requirements for RTO operation. In contrast, Bonneville has not observed a similar pathway for CAISO to support a full, multi-state RTO, including BAA consolidation. Even the most aggressive Pathways Initiative phase results in California as an ISO with the potential for a separate RTO operating outside of California in multiple states. SPP also has decades of experience operating a multi-state RTO, and its stakeholder-driven governance framework effectively navigates complex issues, while building trust among stakeholders. Accordingly, the Markets+ design is better positioned to provide additional market evolution and business opportunities for Bonneville as it confronts an increasingly dynamic electric utility business environment. If Western utilities begin to contemplate RTO formation in the future, Bonneville would conduct a transparent public process to evaluate the potential impacts of joining an RTO.

Appendix D

Seams Assessment

1. Transmission Operations, Seams, and Related Agreements

Seams are not a new concern for utilities, load serving entities, merchants, or marketers operating in the Western Interconnection. There is a mix of both bilateral trading and participation in organized markets, such as CAISO markets (day-ahead, hour-ahead, and WEIM) and WEIS. Bonneville has a service territory spanning seven states and is a significant provider and operator of high-voltage transmission service in the Pacific Northwest. Bonneville also operates a BAA in the Pacific Northwest that is adjacent to 18 BAAs (~360 individual ties) and 15 TSPs, including several TSPs that are embedded within Bonneville's BAA. Further, Bonneville is currently participating in the WEIM along with 14 of its adjacent BAAs.

While many diagrams and maps of the WECC and the Pacific Northwest often show tidy contiguous borders between BAAs and TSPs, the reality is much more complicated, especially in the Pacific Northwest, where many BAAs are often non-contiguous with loads and resources pseudo-tied across multiple TSPs and geographic zones, including generation-only BAAs. Bonneville also plays an integral role in the WECC as a key TSP, TOP, and TO of transmission assets that provide connectivity both within the Pacific Northwest and between the Pacific Northwest and the rest of the WECC footprint.[214] Given the numerous and complex commercial and operational seams that Bonneville and other WECC entities deal with daily and that have been refined over 75+ years, the region and Bonneville will need to work collaboratively to address the introduction of multiple new day-ahead market seams.

Seams exist today and produce operational and commercial friction and inefficiencies that must be carefully managed. Bonneville will likely have generation, load, and transmission participating in or impacted by both markets requiring various agreements, constraints, protocols, procedures, and market designs to ensure operational and commercial seams issues are addressed. With the introduction of multiple day-ahead markets with their own footprints, designs, protocols, and procedures, avoiding negative operational and commercial externalities will be critical.

The operational and commercial situation in WECC stands in stark contrast to the RTOs/ISOs that exist in the Eastern Interconnection.[215] In eastern RTOs,/ISOs, they are vertically aligned among roles[216] as well as having mostly contiguous footprints (relative to WECC). As such, the types of seams and the negotiation of seams among the various operational and commercial concerns involve far fewer parties and less complexity. The introduction of additional day-ahead market seams in WECC will involve many more entities than would be present under an RTO/ISO regime.

To combat these complexities, Bonneville will engage entities early and with ideas of how to decrease the relative complexity. Depending on the footprint, multiple MOs and RCs will need to be involved in these conversations. Bonneville has extensive experience in developing transmission and operating agreements with multiple BAAs and Bonneville will bring that experience and understanding to the conversation.

The discussion below identifies examples of the types of commercial and operational seams that the region and Bonneville will need to address to implement multiple day-ahead markets in the WECC.

1.1. Operational Seams

1.1.1. Balancing Authority Area

[214] *E.g.*, Northwest AC Intertie (NWACI) and Pacific DC Intertie (PDCI).
[215] *E.g.*, SPP, Pennsylvania, New Jersey and Maryland Interconnection, Mid-Continent Independent System Operator.
[216] *I.e.*, RC, MO, BAA, TSP.

BAAs may experience increased operational complexity due to the need to manage interactions with multiple day-ahead markets simultaneously. Each market may have its own scheduling, dispatch, and settlement processes, requiring BAs to coordinate their activities to ensure integration of market transactions while maintaining reliability.

1.1.2. Reliability Coordination

Multiple non-contiguous RCs in the Pacific Northwest with complex seams will make it potentially more difficult to reliably manage operational issues when they arise given the additional coordination and lack of complete regional authority. Existing multiple RCs in the Pacific Northwest have much simpler seams today.

This may be further complicated by the difference in BAA and TOP areas (geographical or electrical). Bonneville is the TOP for facilities that are not in the Bonneville Transmission BAA (e.g. Heyburn/Unity are in Idaho Power's BAA and Drummond/Swan Valley are in PAC East's BAA). Under the NERC Rules of Procedure *(ROP Section 500, 1.4.1)*, all areas *(geographic or electrical)* are required to be "under the oversight of one and only one RC." There are currently no situations in the Pacific Northwest where a BA or TOP takes services from multiple RCs. If there are multiple markets within the Pacific Northwest with each taking primary RC services from the respective MO organization, this creates a possibility that some entities that perform these functions over areas that transcend the footprints of more than one market may be required to take services from more than one RC. This complexity may make it more difficult to reliably manage certain operational issues when they arise, as well as increase the communication and compliance burden.

RC-RC coordination will be critically important to minimize reliability risks. Bonneville has not made any determination regarding whether if Bonneville will switch RCs. However, having multiple non-contiguous RCs and MOs in the Pacific Northwest will pose many operational and commercial challenges due to:

- Potentially complex and non-contiguous boundaries;
- Competing priorities and objectives;
- Unique requirements, business practices, and complex coordination needs;
- Complex seams agreements.

These types of seams pose many challenges that, if not addressed and mitigated, will impact reliability. Through implementation, Bonneville will seek to lessen these impacts and risks.

1.1.3. Transmission Operations

The Pacific Northwest to California transmission corridor is one of the most important in WECC. A problem along this corridor can have serious implications for the entire Western Interconnection, and specifically, entities within the Pacific Northwest that depend on the Bonneville Transmission System. Further, many of the paths for which Bonneville is the TOP are shared amongst multiple asset or capacity owners and TSPs. These include, but are not limited to:

- **NWACI:** Many entities are involved in the NWACI. Bonneville is the operator and the BAA of the facilities north of the California Oregon Border. There are multiple asset owners (Bonneville, PAC, Portland General Electric [PGE]) and capacity owners, many who also provide service under an OATT as a TSP. The facilities that make up the NWACI support important transfers with CAISO, PAC, PGE, Idaho Power Company, BANC, and Nevada Energy, all of whom have either declared a leaning to join EDAM or signed an implementation agreement to join EDAM.
- **PDCI:** The PDCI is a controllable DC transmission path between the PNW (Bonneville

Transmission) and Southern California (LADWP), where LADWP has chosen to join EDAM. North of Nevada Oregon Border (NOB), Bonneville is the sole owner while south of NOB the ownership is split amongst multiple entities (LADWP, CAISO, Glendale, and Burbank). As operators of the DC converter stations at Celilo and Sylmar, Bonneville and LADWP control the PDCI dispatches and jointly manage the path.

- **South of Allston:** South of Allston is a shared path between Bonneville, PGE, and PAC, with the latter two having signed EDAM implementation agreements. Like other paths, Bonneville manages the path and determines the total transfer capability, which is subsequently allocated.
- **Other Shared Paths Include:** North of Echo Lake, West of Hatwai, North of Pearl, Montana-Northwest, and the Northern Intertie.

These types of shared paths impact multiple TSPs and BAAs and must be carefully managed and coordinated. Situations that increase the amount of coordination and seams issues on paths like these may increase the risk of adverse commercial and operational outcomes. Depending on the ultimate RC and market footprints, new agreements and procedures may need to be developed in order for everyday operations to continue to be reliable and efficient.

1.1.4. Mismatch Between Market Processes and Real-Time Operations

Each market may have differences in processes such as interchange scheduling rules, scheduling intervals, timing requirements, intertie bidding, rules for submitting bids and offers, and market clearing timelines. This misalignment can lead to difficulties in coordinating generation and transmission schedules between the two markets and aligning market schedules and dispatches with real-time operations. As part of implementation, Bonneville will need to consider all of these aspects as procedures and protocols are developed. The details will not be known until implementation.

1.1.5. Transmission Constraints and Market Congestion

Differences in how transmission constraints are modelled, market flows are calculated, and how subsequent flows are managed in each market can result in congestion at interfaces between or within the two market footprints. This "market congestion" or "commercial congestion" may affect the efficient utilization of transmission capacity and lead to suboptimal dispatches and pricing outcomes. Transmission opt-outs, SFCs, Transmission Corridor Constraints, ETSRs, and other nuances of each market's management of transmission constraints may cause the market(s) to be commercially constrained even though the transmission system is not physically overloaded.

1.1.6. Congestion Management

There is a potential of physical congestion occurring on transmission lines that serve as interfaces between the markets or transmission lines/flow gates/paths internal to one or the other market footprint. This congestion can occur regardless of being part of a market, but the management of congestion on transmission being used by two markets will likely require a more complex and nuanced approach. Managing congestion can also be more complex when market participants seek to arbitrage price differentials between markets, leading to potential congestion on specific transmission paths or flow gates. Seams agreements will likely be needed between the impacted entities[217] and the market operators to try and manage these types of operational risks.

1.1.7. Dynamic Transfer Capability (DTC)

Bonneville has numerous facilities with DTC limitations, such as the Northern Intertie, NWACI, PDCI,

[217] *E.g.*, BAAs/TSPs/TOPs.

Montana Intertie, and more generally across the Bonneville network. These limitations impact the ability of the system to reliably support large sub-hourly changes in flows and are addressed in Bonneville's Dynamic Transfer Business Practices. If there are multiple real-time markets within the Pacific Northwest, DTC will need to be allocated among multiple markets and managed via market constraints.

Further, the lack of DTC between two non-contiguous market zones (e.g., PNW and DSW) will limit sub-hourly optimization between the zones. Each zone, and the BAAs it contains, will need to manage intra-hour imbalances without the market's ability to economically transfer incremental energy dynamically between the zones. As a result, and to maintain reliability, the need for flexible resource capacity may increase, requiring either additional market procurements and/or additional reserves to be held by BAAs within each zone.

1.1.8. Interconnection Reliability Operating Limits (IROL)

Bonneville is currently subject to two IROLs, the Oregon Net Export IROL[218] and the NW WA Import IROL. Today, RC West is largely responsible for both IROLs. Having multiple non-contiguous RCs involved in managing IROLs, especially the Oregon Net Export IROL, will require the RCs to be tightly coordinated. Bonneville will continue to support large margins when studying and observing IROL limitations and also support the identification of a lead RC for each IROL.

1.1.9. Network Model Management / Coordination

Accurate models are critical to maintaining reliability. If there are multiple RCs, they will need to ensure they always have the same network models and that they communicate consistently to all BAs and TOPs. Bonneville will continue to advocate that RCs ensure network model alignment.

1.1.10. Operational Studies (assumption, datasets, outages, etc.)

Operational studies require not only an accurate network model, but also robust and accurate datasets and the ability to apply realistic assumptions. With multiple RC and market footprints in the Pacific Northwest, this may be a challenge and present risks across various time horizons.[219] Bonneville will continue to receive the assumptions from WECC as part of its offline studies, while the real-time contingency analysis tool will be using remote terminal units to receive real-time data and then perform state estimation.

1.1.11. Outage Coordination

Coordinating and managing outages across multiple MOs and RCs is critically important. In addition to using different Outage Management Systems, RCs and MOs may have differing requirements for outage submittals and timings and a single outage may require careful coordination with all entities depending on the nature of the outage. As part of any implementation, this will need to be further explored and coordinated.

1.2. Commercial Seams

1.2.1. Market Timing and Process Requirements (bi-lateral, day-ahead, real-time)

Differences in timing and process requirements between the various markets (day-ahead, real-time) may impact the ability to efficiently trade between market footprints. Business practices will need to be developed to address efficiency and accurate operation.

1.2.2. Resource Adequacy Programs (i.e., WRAP and CPUC)

Multiple RA programs may be difficult to reconcile across market footprints. There will need to be market-

[218] The Oregon Net Export IROL addresses the interactions between the NWACI and Path 75/Path 14.
[219] Week-ahead, day-ahead, hour-ahead, real-time contingency analysis, etc.

to-market coordination to ensure generation capacity, and any energy deliveries are accounted for.

1.2.3. Jointly Owned Transmission (network and interties)

Managing existing jointly owned (asset or capacity) transmission agreements, along with any commercial arrangement and operational protocols, may be more difficult than they already are if the owners are spread across multiple non-contiguous RCs and markets. This is especially acute when one TSP and owner is located within a BAA that is participating in a different market. It will take time and engagement from all entities in the Pacific Northwest to ensure reliable operation and market efficiency.

1.2.4. Remote Load (i.e., load service in another BAA via transfer service)

Many utilities, including Bonneville, have generation and load in other BAAs. If the entity with remote load, such as Bonneville, has a different RC or the two BAAs are in different day-ahead and real-time markets, Bonneville acknowledges that it may be more difficult to service that load as it would likely require merchants to participate in both markets as well as deal with market-to-market energy transfers and it will need to be further explored upon implementation.

1.2.5. ATC ID, OATT, Business Practice Discrepancies between Adjacent TSPs or Joint Owners

While ATC ID, OATT, and business practice discrepancies exist today, depending on the design of the markets (timings, transmission donation processes, TSR queue pausing, etc.) and how transmission availability is calculated and reserved, adjacent TSPs may end up with impactful differences. These differences may cause bilateral trading and market-to-market friction. Affected parties will need to coordinate to minimize potential impacts.

1.2.6. Price Formation (between markets)

A critical concern of all organized markets is price formation methodology. Differences in these methodologies, both temporal and procedural, may result in structural price differences between markets that create incentives that work against both markets objectives or produce unintentional hurdles that limit efficient bilateral trades or efficient transactions between markets.

1.2.7. Commercial Transmission Rights (Congestion Revenue Rights, ATC, etc.)

Markets need access to transmission to effectively operate. Markets may leverage donated rights, unused ATC within the market footprints, physical capability of the system, or any combination of the above. Timing and access to transmission for day-ahead market participants and customers not participating in a day-ahead market may be complex to coordinate. Parties will need to establish methods to determine priority, transmission rights, and dispute resolution to avoid over or under-utilization of the transmission system. Proper incentives will more effectively manage congestion. Bonneville believes these complexities can be addressed through the standard tariff, rates, and business practice processes.

1.3. Other Seams Considerations

There are many other potential impacts to multi-RC/multi-MO environment that will need to be carefully weighed, such as:

- State Carbon Policies and GHG accounting
- Remedial Action Schemes
- Rate Pancaking (market to market)
- Data Sharing
- Market Flow Calculation and Management

- Reserve Sharing (market to market)
- Interchange Scheduling (timing requirements, etc.)
- System Integration and communication between markets
- Oversupply Protocols
- Transmission Loss Accounting
- NT redispatch (FCRPS and Non-Federal redispatch)
- Standardization of scheduling timelines between markets
- Water Management (Bi-Op)
- International Treaties
- Jurisdictional Status
- Blackout Restoration

1.4. Seams Agreements

Bonneville is likely to have generation, load, and transmission participating in or impacted by both markets. Bonneville expects agreements, constraints, and market design to mitigate operational and commercial seams issues. Given the complexity of WECC, the potential for non-contiguous market and RC footprints, and the number of parties involved, multiple types of agreement will be necessary.

2. Seams Conclusion

Bonneville recognizes the operational and commercial challenges posed by multiple markets and RCs, the impacts of their potential footprints, and the resulting seams. Bonneville also recognizes and is aware of the complexities posed by seams, both operational and commercial. So long as more than one RC, MO, BAA, and TSP exist in WECC, seams will exist. However, some create more operational and commercial challenges and complexity than others. Bonneville and others will need to work collaboratively to manage these seams while continuing to prioritize reliability.

Appendix E

Congestion Impacts

In a day-ahead market, congestion occurs when available least-cost energy cannot be delivered to some loads because transmission facilities do not have sufficient capacity to deliver the energy, or there is insufficient transmission rights made available. Market optimization will create a plan to dispatch least-cost resources until the optimization reaches an identified limit, at which point it will begin to add to the dispatch plan the next least-cost resource that does not further impact the "binding" limit. An indication that congestion is occurring is "price separation" between two locations; the next least-cost resource that does not further impact the limit that can serve load on one side of the constraint may have a different price than the next least-cost resource on the other side of the constraint. To see an example of congestion, please see materials from public workshop 7 on June 3, 2024.[220]

The market optimization engine delivers day-ahead awards with resource schedules different from those that may have been established bilaterally. Unlike bilaterally established resource schedules, the planned dispatch pattern that results from participating in a day-ahead market is security-constrained (i.e., factors generation and transmission constraints when creating the optimized dispatch). Bonneville Transmission Services would be using scheduling limits established from internal studies to determine the capability of each path. The planned dispatch pattern could fully use the capacity over a path based on the data it had been supplied. However, congestion may still occur.

On the next operating day, in real-time, operational constraints may deviate from what was expected in the day-ahead optimized dispatch. In real-time, resources are redispatched to reflect updated constraints as other inputs such as load changes, variable energy resource output changes, and generation or transmission outages and derates are adjusted relative to the day-ahead solution.

As stated in Section 6.4, Bonneville has had positive experiences leveraging the WEIM to manage operational constraints and expects even greater congestion management effectiveness with the addition of a security constrained day-ahead market optimization

Bonneville is likely to have generation, load, and transmission participating in or impacted by both markets. It is possible that in a multi-day-ahead market scenario, the Pacific Northwest region will continue to see commercial congestion, rather than a reduction. Physical congestion represents the actual flow on a transmission element reaching the established reasonable maximum amount. Commercial congestion represents a limit to potential physical flow despite the physical limit not being reached. Because Bonneville will likely have transmission customers in both day-ahead markets, as well as in no market, Bonneville will have to determine how to allocate transmission capacity to each market. If each market is allocated a certain number of MWs on a flow-based path that are reflective of the transmission rights of that market's participants, each market may congest due to the commercial limits even though the physical limitation is not close to being reached. This could produce a less efficient solution for each market, especially in the day-ahead market, compared to if there was only one market or compared to how things are today in a bilateral market. This could also happen in the real-time horizon.

Another inefficiency that could be introduced is internal flow-based paths with expected counterflow and transmission rights that were originally sold based on non-coincidental use. Each market will have a unique portion of capacity for the same path, defined within their respective market. There could be the situation that the sum of all of the rights in a single direction add up to more than the capability of the path, in which

[220] *See* Bonneville's Public Engagement for Establishing a Policy Direction on Potential Day Ahead Market (DAM) Participation - Workshop 7 presentation (June 3, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/dam-workshop-7-presentation-060324.pdf.

case scheduling limits would be needed for each market to fit the path limit. This would exacerbate the commercial congestion identified previously, because the non-coincident users may not be distributed between the markets in the same pattern as the coincident users. This might only be in the day-ahead market and then in the real-time market, scheduling limits could be relaxed based on the scheduled use.

As discussed in Appendix D, Bonneville plans to encourage the two market operators to begin developing a seams agreement that maximizes the efficient use of the transmission system while maintaining the reliable operations of the grid. With these future complexities in mind, Bonneville is proactively taking part in the Enhanced Curtailment Calculator Working Group (ECCWG) to advise on solutions for uniform congestion management process.

In summary, Bonneville believes there are likely congestion management benefits to transmission operations with Bonneville participating in a day-ahead market. In July 2023 and October 2024, Bonneville announced that it had identified multiple new transmission substation and line projects necessary to reinforce the Pacific Northwest's electric grid.[221] The completion of these projects will add capacity to Bonneville's transmission system, and the day-ahead market can deliver even more efficient dispatch solutions.

[221] *See* Press Release, Bonneville Power Administration, BPA takes major step to advance transmission projects for reliability and expansion (July 12, 2023*)*, *available at* https://www.bpa.gov/-/media/Aep/about/publications/news-releases/20230712-PR-08-23-bpa-accelerates-work-on-transmission-projects-final.pdf; Press Release, Bonneville Power Administration, BPA maintains transmission expansion momentum with 13 new proposed projects (Oct. 15, 2024), *available at* https://www.bpa.gov/-/media/Aep/about/publications/news-releases/20241015-PR-18-24-bpa-maintains-transmission-expansion-momentum-with-13-new-proposed-projects.pdf.

Appendix F

Implementation Feasibility Assessment

In order to evaluate the implementation feasibility for Bonneville's Markets+ participation, a capability gap analysis was conducted, and 12 projects were determined to close the identified capability gaps in the following areas:

- Bidding and self-scheduling
- Data integration
- Settlements
- Price and dispatch
- Load and renewable forecast
- Metering
- Outage management
- Transmission scheduling and operations technology
- AGC modification
- RC Switch (if applicable)
- End-to-end billing process
- Post go-live technical support

Bonneville is in the process of developing an implementation plan to execute these projects, including changes in software, hardware, data integration, business processes, policies, and staffing. The implementation plan also includes market entry preparation, such as staff training, systems testing, market simulation, parallel operations, and production cutover. Initial estimates for funding and resources necessary to support this effort were included in Table 8 in section 5.1.2.3.

The main challenge of this implementation effort is the transition between two organized energy markets (i.e., WEIM to Markets+), which could require more resources to maintain two sets of systems and processes during the transition period. In many cases, discreet hardware, software, and network connectivity will be required to operate in parallel. Bonneville will strive to minimize the staffing impact by setting an appropriate timeline for implementation activities to space out the workload over time.

Bonneville will focus on deliberate timing, adequate funding, and appropriate staffing in the implementation process while leveraging prior experience implementing the WEIM. In addition, Bonneville plans to get support from a consulting services firm specializing in the energy utilities industry with expertise in market-to-market transition as a critical component to a successful and effective market entrance.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-94:
Power Council 2024 Resource Program Results

Jeffery C. Allen
Chair
Idaho

Ed Schriever
Idaho

Doug Grob
Montana

Mike Milburn
Montana

Northwest **Power** and **Conservation** Council

KC Golden
Vice Chair
Washington

Thomas L (Les) Purce
Washington

Ginny Burdick
Oregon

Louie Pitt, Jr.
Oregon

January 7, 2025

MEMORANDUM

TO: **Council Members**

FROM: **Jennifer Light, Director of Power Planning**

SUBJECT: **Bonneville's 2024 Resource Program Results**

BACKGROUND:

Presenters: Suzanne Cooper, Senior Vice President of Power Services
Ryan Egerdahl, Manager of Long Term Power Planning
Allie Mace, Manager of Market Analysis and Policy
Eric Federovitch, Manager of Long Term Power Sales and Purchase

Summary: Bonneville has finalized its 2024 Resource Program (also known as RP-24). Bonneville's resource program is an analysis of potential system needs and resources available to meet those needs. Bonneville staff will join the Council to share the results from the 2024 Resource Program and early thinking on preparations for its next resource program, which is planned to be completed in September 2026.

Relevance: The Resource Program is informational and not a decision-making process, nor a decision document, but the results do inform Bonneville's resource acquisition strategies. For the past several years, Bonneville has been working with its customers and the region on new contracts for the post-2028 period. These conversations have highlighted that Bonneville may need to acquire additional resources to serve its obligations under these new contracts. Bonneville has stated that the 2024 Resource Program is expected to provide insights to

customers on potential resource types that Bonneville might pursue to serve that obligation.

When acquiring new resources, Bonneville is required to act consistent with the Council's power plan. Therefore, it is critical for the Council to understand the results of the current resource program, and how the results align with the Council's current power plan (the 2021 Power Plan).

It is also worth keeping in mind that Bonneville is starting to work on its 2026 Resource Program (RP-26), which it plans to complete by September 2026. The timing of this next resource program overlaps significantly with the Council's planned development of its Ninth Power Plan.

Background: Bonneville recently completed its 2024 Resource Program and presented the results in a public workshop on December 19th, 2024. Bonneville has stated publicly that this resource program is expected to provide insights to customers around the types of resources it might acquire should it need to acquire new resources to meet its future obligations.

The 2024 Resource Program includes results for a base scenario along with several sensitivities, including sensitivities that look at market prices, market reliance, and load growth. Bonneville also conducted a specific study exploring potential resources for Tier 1 augmentation.[1] Bonneville will walk through the findings of this analysis at the January Council meeting.

The Council's current power plan, the 2021 Power Plan, provides specific recommendations to Bonneville, which include:

- Acquire between 270 and 360 aMW of cost-effective energy efficiency by the end of 2027, of which at least 243 aMW must be from programmatic savings, and at least 865 aMW by 2041
- Work to enable and encourage its customer utilities to pursue low-cost and high value demand response, including time-of-use rates and demand voltage regulation
- Look to mid-term and long-term market resources for additional energy when needs are beyond those met by the recommended energy efficiency and demand response resources
- Compare market products, both in price and capacity, to renewable power purchase agreements to ensure that the lowest-cost product that suffices to meet any need is identified.

[1] Under the Bonneville Provide of Choice Policy, which is guiding its post-2028 contract development, Bonneville has agreed to sell 7250 aMW of power at a Tier 1 rate. Based on the existing system capability, Bonneville may need to acquire additional resources to meld into the existing Federal Base System in order to meet that obligation. This study focused specifically on the question of which resources would be least-cost to meet that obligation.

It is worth noting that Bonneville's near-term results across all sensitivities (i.e. pre-2030 builds) and its Tier 1 augmentation study are consistent with the 2021 Power Plan recommendations. Staff recommend the Council focus more on these near-term results, given the Council is working to complete its next power plan by the end of 2026 and Bonneville will have an updated resource program in a similar timeframe.

While the near-term results make sense, and are consistent with the Council's power plan, staff does have some questions regarding the longer-term results. Staff shared these concerns with Bonneville at the December 19th public workshop. They include:

Modeling of Emerging Resources: Bonneville included one emerging resource option, small modular reactors (SMRs), in RP-24. Council staff recommend Bonneville consider more emerging resource options in RP-26. Since different emerging resources have different attributes, analyzing more options will provide better information to Bonneville on the types of resources needed for the long-term. For reference, Council staff are planning three emerging resource options for the next plan. Council staff also recommend Bonneville rethink some of the SMR specific assumptions, particularly around online date and lifetime. Bonneville assumed the SMR was available in the model as soon as 2030. The Council understands the online date for SMRs would be 2035 at the earliest based on statements from Energy Northwest staff. The timing of emerging resource availability may change resource decisions across the planning horizon. The Council plans to explore different online dates for emerging resources in its scenario modeling to understand the implications of this uncertainty. Additionally, Bonneville assumed a 60-year life for the SMR. The assumed lifetime can significantly change the economics of a resource, with a longer lifetime making a resource look cheaper in the modeling. In the 2021 Power Plan, the Council used a 40-year life, and utilities across the region have used a range of assumptions from 30-years to 60-years. Council staff are still working with its advisory committees on the best assumptions for the upcoming plan.

Improved Understanding of Modeling Approach: Bonneville developed a new approach to its resource optimization modeling for RP-24. The newly developed optimizer provided a good step forward for Bonneville over the previous approach. Council staff are interested in better understanding the model, particularly as some of Bonneville's results are counter intuitive. As we have found with our own model development, there is significant value in opening up the models to experts in the region. The rapidly changing power system requires new modeling approaches, which the whole region is struggling to resolve. Having the opportunity to dive deeper will increase understanding and ultimately improve the modeling for all parties.

Council staff intend to work closely with Bonneville on the development of the Ninth Power Plan and Bonneville's next Resource Program.

More Info: Materials related to Bonneville's Resource Program development are available on its website: https://www.bpa.gov/energy-and-services/power/resource-planning.



BPA 2024 Resource Program & Next Steps

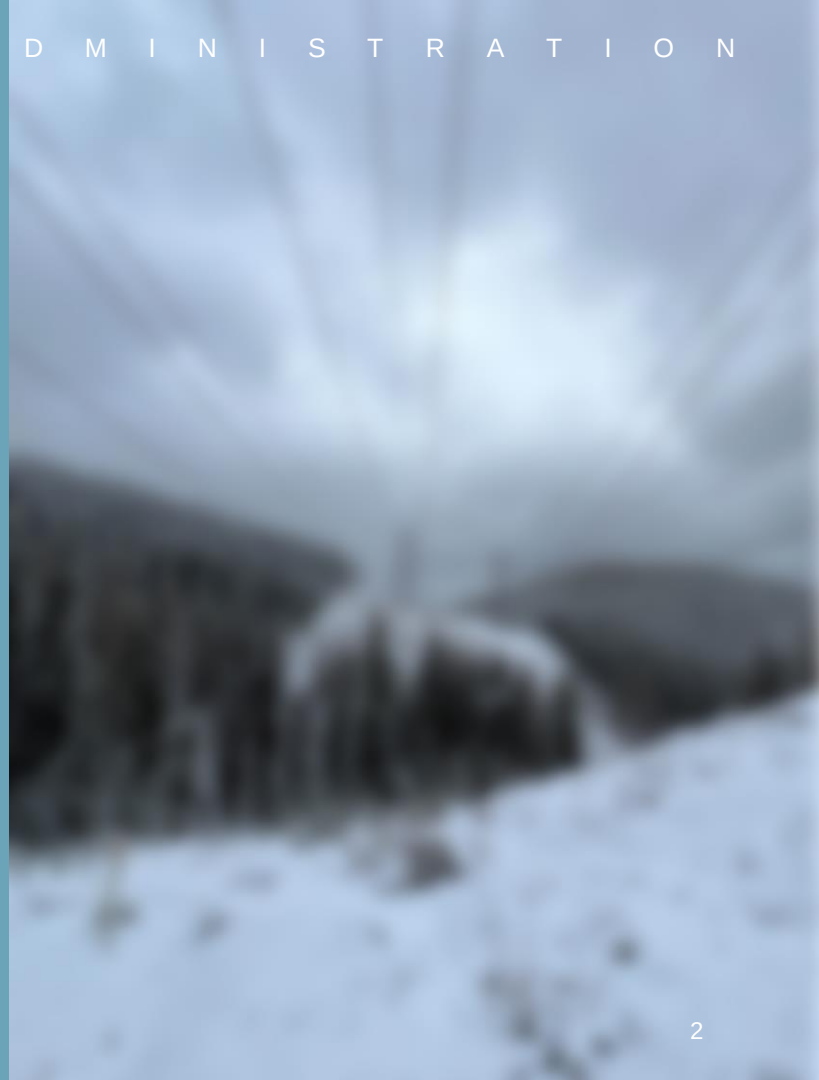
Presented to the Northwest Power and Conservation Council

January 14th, 2025

Introductory Remarks

Suzanne Cooper

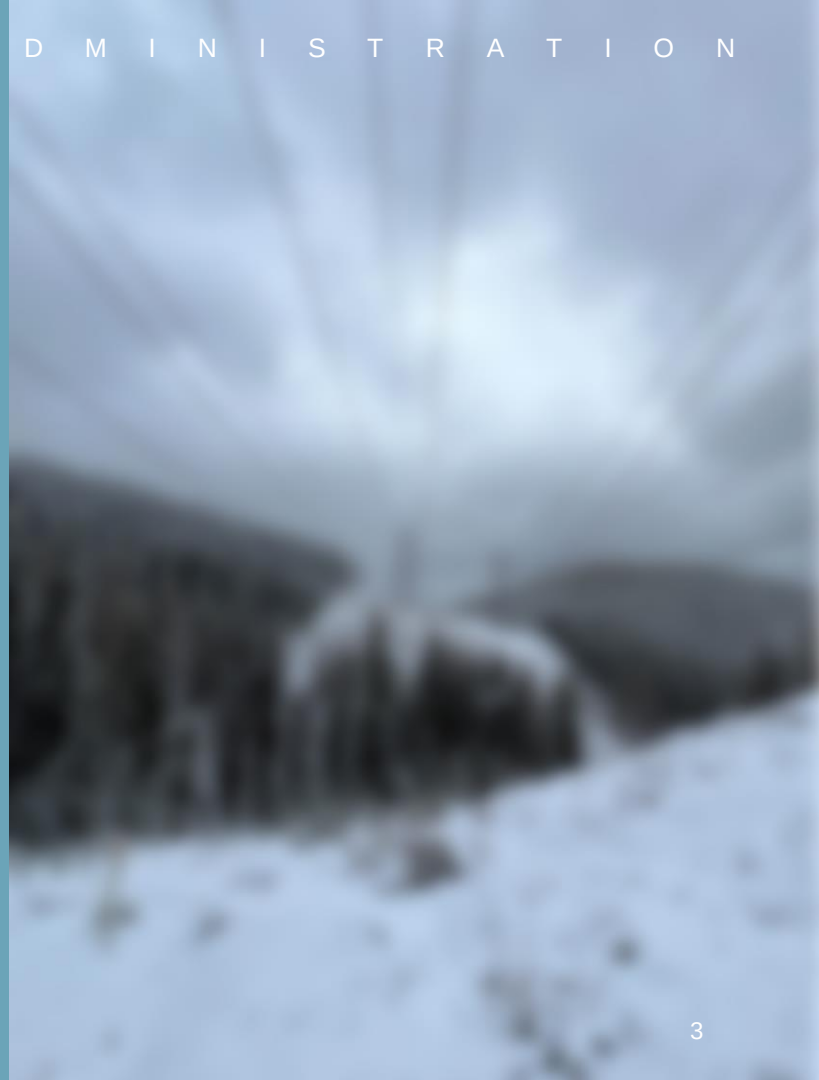
Senior VP, BPA Power Services



Resource Program Process Update and Next Steps

Ryan Egerdahl

Manager, Long Term Power Planning



Agenda

- Resource Program Process Update and Next Steps
- RP24 Resource Solutions
- Power Services Resource Acquisition Process

Reminder: Power Planning at BPA



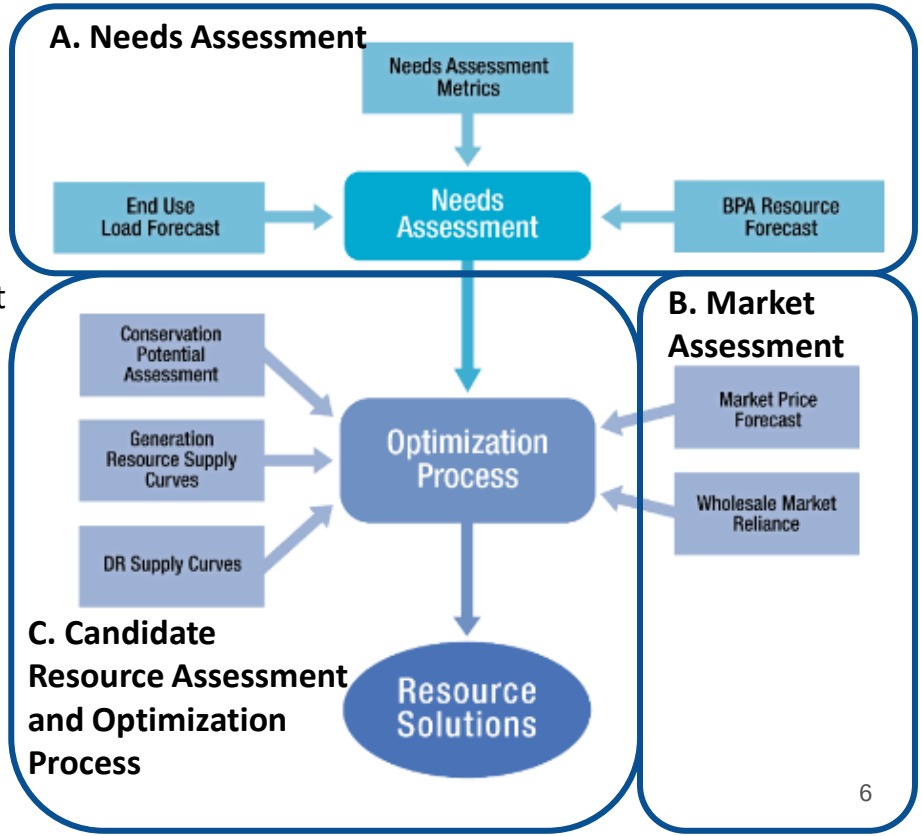
- Each year, BPA publishes the Pacific Northwest Loads and Resources Study – often referred to as the **White Book** - which analyzes BPA's projections of retail loads, contract obligations, contract purchases, and resource capabilities over a 10-year study horizon and describes expected energy and capacity surplus/deficits under varying water conditions.
- On a biennial basis, BPA conducts an IRP-like assessment collectively referred to as the **Resource Program** which examines uncertainty in loads, water supply, natural gas prices, and electricity market prices to develop least-cost portfolios of resources that meet BPA's obligations.
- These processes are voluntarily undertaken to inform acquisition strategies and provide valuable insight into how Bonneville can meet its obligations cost-effectively. They are neither decision documents nor a process required by any external entity.

Resource Program Process

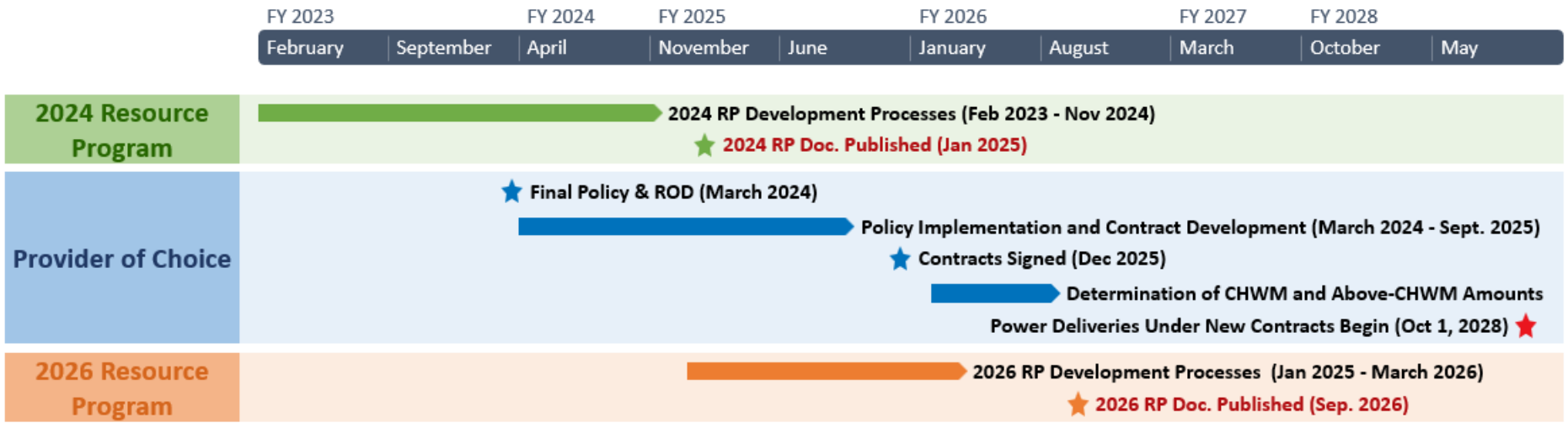
A. The **Needs Assessment** measures the federal system's expected generating resource capabilities to meet projected load obligations

B. The **Market Assessment** simulates the evolution of power markets in the Western Interconnect to generate a long-term forecast of Mid-Columbia prices and market availability under a variety of generation, load, and economic conditions

C. The **Candidate Resource Assessment and Optimization Process** explores how the varying costs, performance, and availability of candidate demand-and-supply-side resources (including conservation, demand response, market purchases, and generating resources) as well as wholesale market reliance can be used to provide a least-cost resource strategy for meeting identified needs



Resource Program and Provider of Choice



Possible Enhancements for RP26

- Based on feedback to RP24, BPA will consider exploring a range of modeling enhancements for RP26, including but not limited to:
  - Assess capacity metric under extreme weather and low water
  - Reintroduce balancing reserves study to Needs Assessment
  - Connect resource solutions to WRAP forward showing position
  - Include additional candidate resource options
  - Refine and refresh characteristics for candidate resources, including performance of renewables
  - Enhance linkages between resource solutions, market assessment, and needs assessment modeling
- We will also solicit additional feedback from stakeholders as RP26 planning gets underway

Next Steps and Additional Information

Next Steps:

- Publication of 2024 Resource Program expected in January 2025
- Release of BPA and Energy Northwest joint CGS EPU business case and RP24 addendum study expected spring 2025
- 2026 Resource Program to kick off in winter 2025; publication expected September 2026

Resource Program Contacts:

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Find Us:

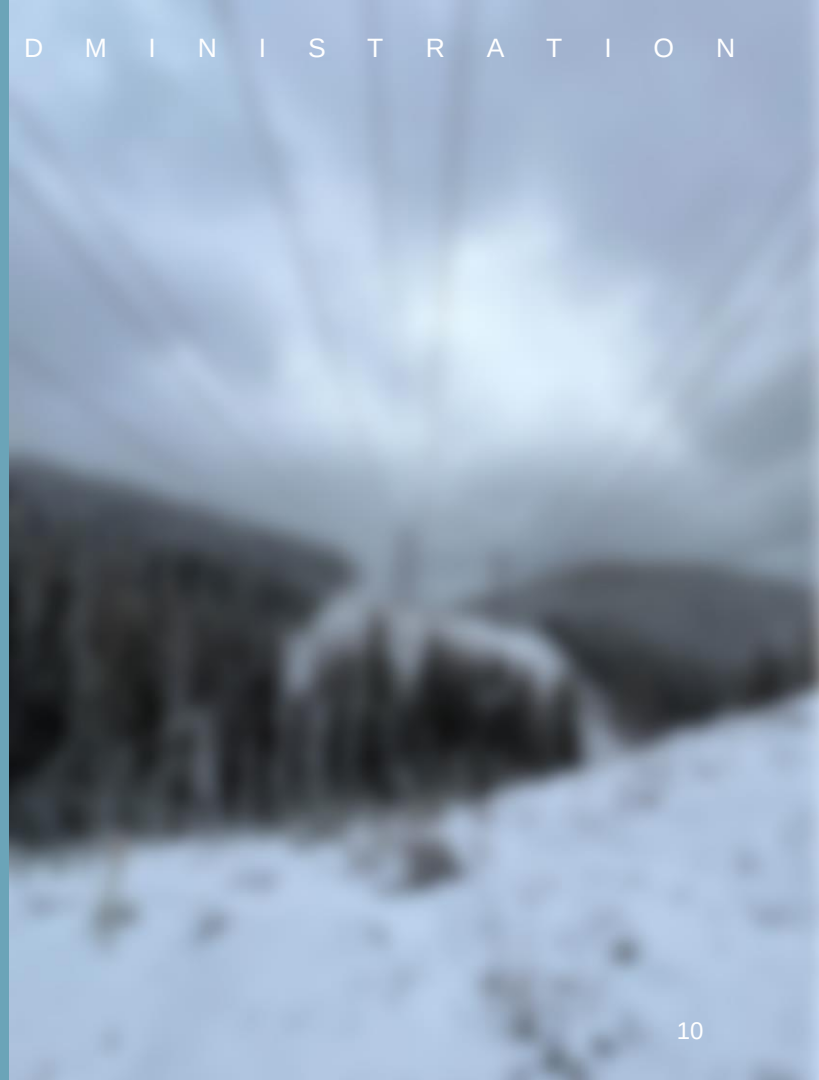
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Resource Solutions

Allie Mace

Manager, Market Analysis and Policy



Key Takeaways – Resource Solutions

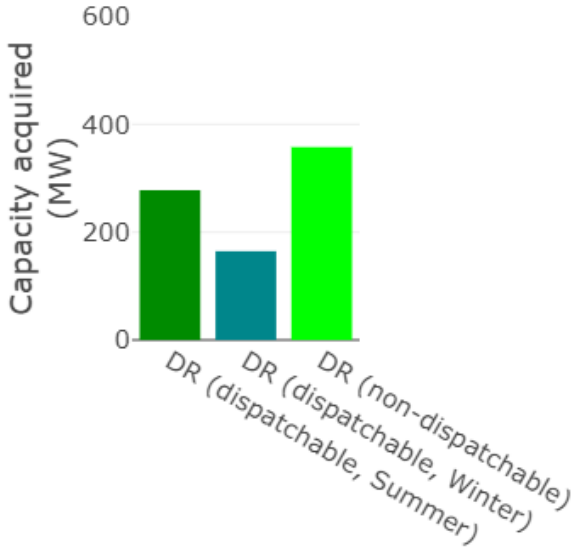
- We continue to rely heavily on **energy efficiency, demand response, and market purchases** to meet BPA needs.
- As loads grow or we add further limits on access to the market, resource acquisitions grow quickly.
- Acquisitions are driven primarily by **Flat** and **HLH energy needs**, rarely by super-peak or 18-hour capacity needs. There is not a single binding metric.
- Supply side acquisitions tend to focus on **solar** and **wind** resources due to their low costs and their contributions to energy needs.
- Supply side acquisitions in SWEDE are needed only if loads are higher than in the base scenario.
- **Resources in the model cannot meet needs in 2 sensitivities**: no market and high load. Shortfalls are in **winter/April 2026-2028**.

Base scenario: Key takeaways

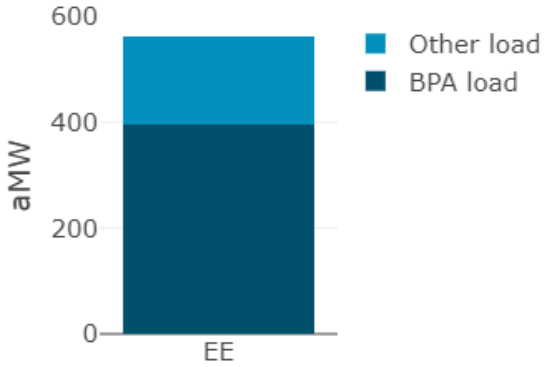
- P10 needs are met primarily by market purchases and energy efficiency (EE)
- Lowest-cost portfolio also includes several demand response (DR) programs and 300 MW solar power

Base scenario resource acquisitions

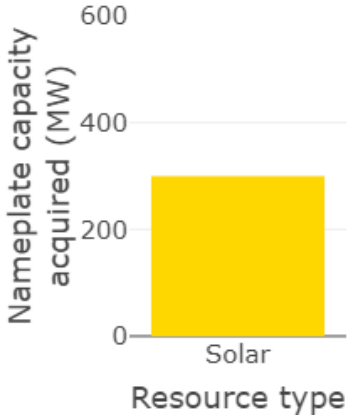
Demand response (DR):



Energy efficiency (EE):



Supply-side:



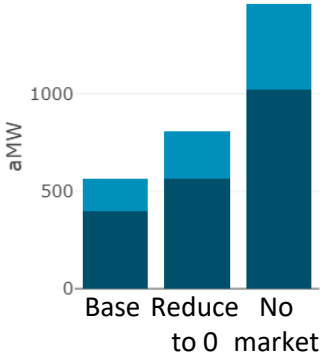
All values are for 2045. Nameplate capacities of supply-side resources represent maximum output under optimal conditions. Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity. Capacity value for non-dispatchable DR is sum of max. capacity across all products.

Market limit sensitivities

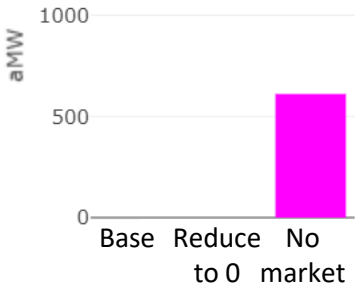
- **Reduce SPK/HLH by 25%:** Limits to SPK and HLH purchases are 75% of forecast market depth
- **Reduce SPK/HLH by 50%**
- **Reduce all market purchases by 50%**
- Reduce to 0: Limits start at 50% of forecast market depth and decline to 0
- **No market**: No market purchases allowed

Market limits: resource acquisitions

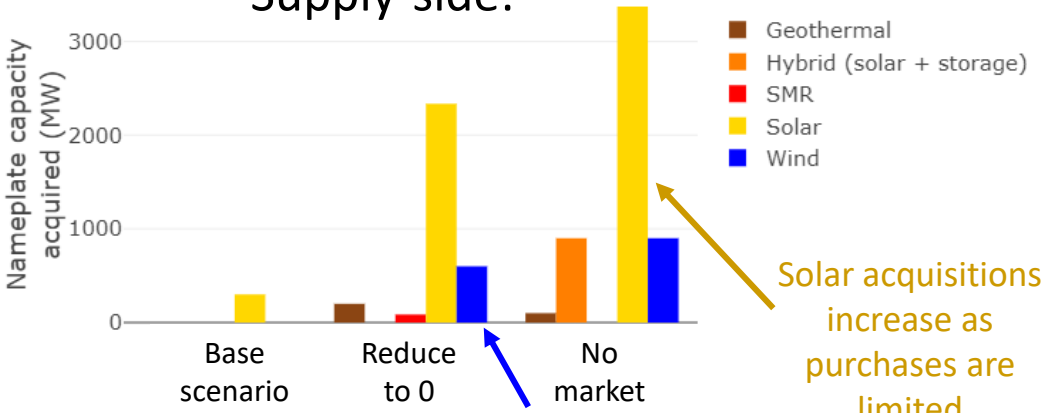
Energy efficiency:



Unmet needs:



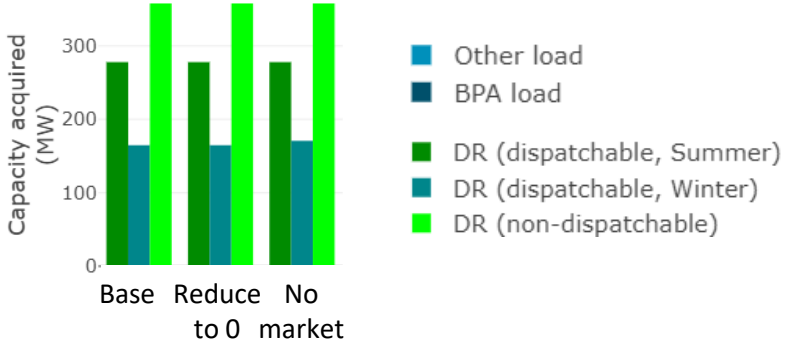
Supply-side:



Solar acquisitions increase as purchases are limited

Wind acquisitions are present whenever LLH purchases are limited

Demand response:

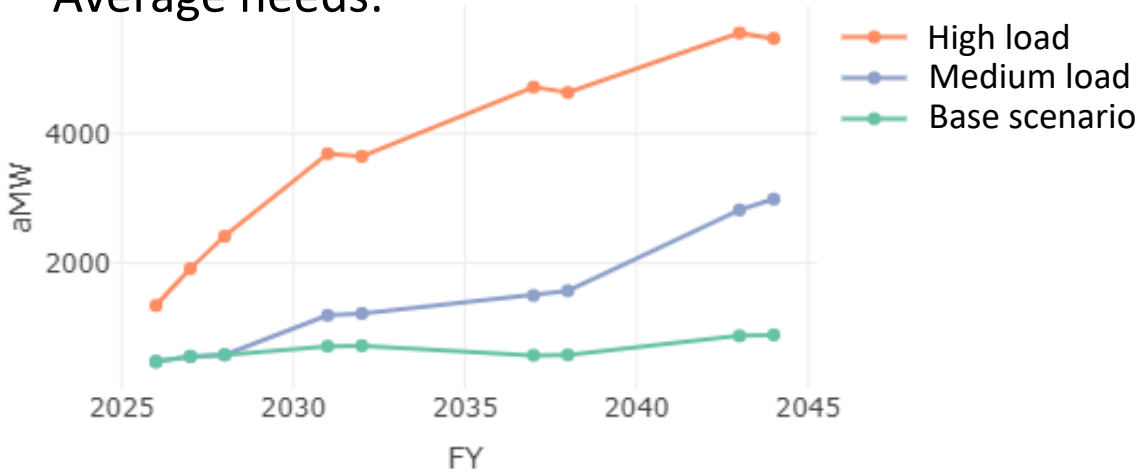


All values are for 2045. Nameplate capacities of supply-side resources represent maximum output under optimal conditions. Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity. Capacity value for non-dispatchable DR is sum of max. capacity across all products.

Load adder sensitivities

- **High load adder (aka, NR)** is a flat block load added to every hour uniformly across the year.
- **Medium load adder (aka, T2)** is shaped load added to each hour. Shaping is based on current Slice Block load shape.

Average needs:

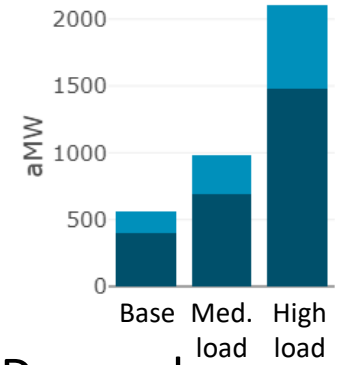


Load adder sensitivities: Key takeaways

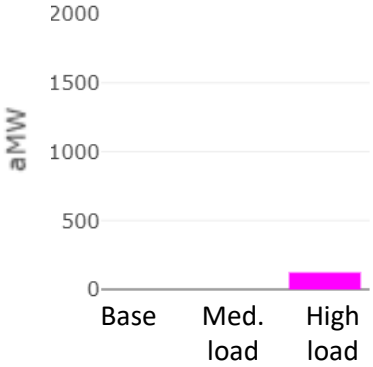
- Acquisitions are primarily driven by HLH energy needs
- Loads in the high load adder sensitivity are difficult to serve:
  - We do not have enough resources in the model to meet needs in 2026-2028 (but the shortfall is relatively small)
  - Portfolio cost is > $35 billion
- Solutions to both sensitivities include large (1,000+ MW) acquisitions of SMR
- Most acquisitions in the medium load adder sensitivity happen late, in 2043

Load adder sensitivities: resource acquisitions

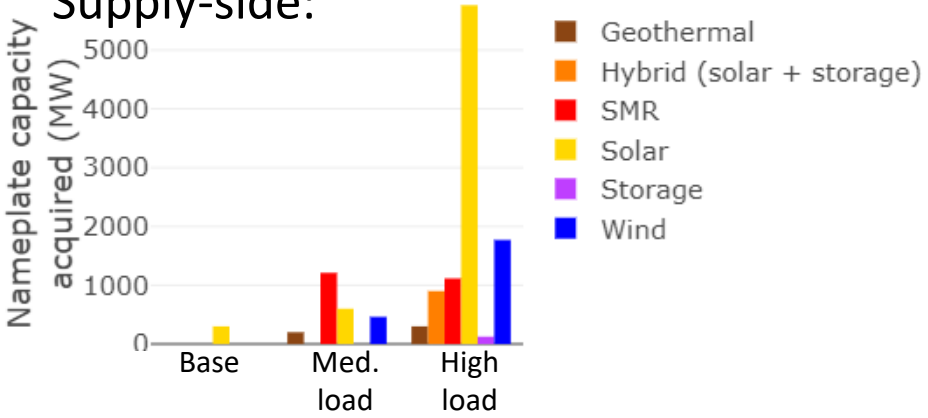
Energy efficiency:



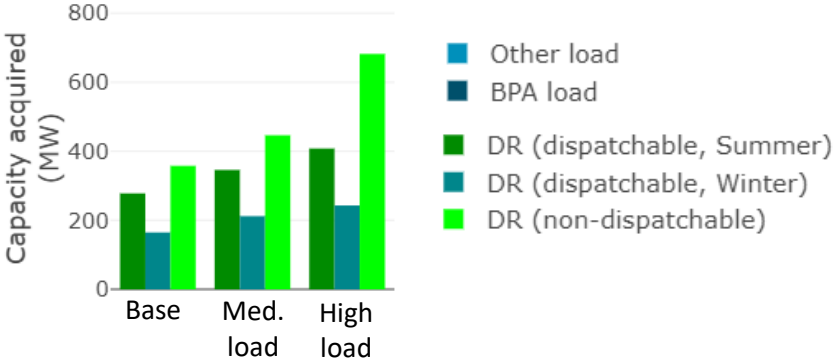
Unmet needs:



Supply-side:



Demand response:



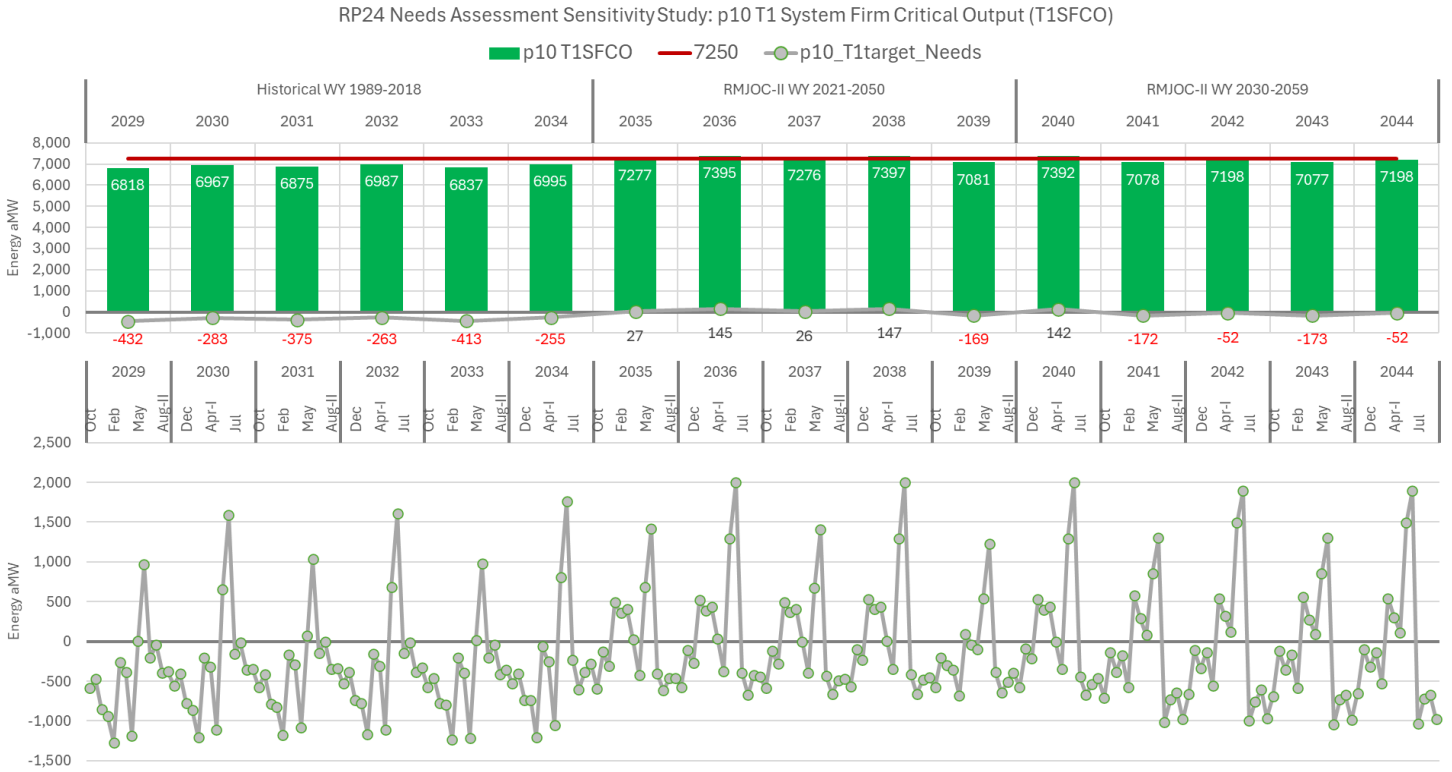
All values are for 2045. Nameplate capacities of supply-side resources represent maximum output under optimal conditions. Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity. Capacity value for non-dispatchable DR is sum of max. capacity across all products.

Tier 1 augmentation

- This sensitivity grows the T1 System Firm Critical Output (T1SFCO) to **7250 annual aMW** shaped to reflect **forecasted hourly shape of T1 obligations**, starting in **2029**
- Needs are modeled as average monthly energy needs at the **whole-system level** (no distinction between SWEDE and Mid-C zones)
- **Only supply-side resources** are allowed to contribute to the growth in T1SFCO
- **Current results are preliminary**: **CGS uprate** is not yet in the model. We expect to repeat this analysis when those inputs become available.

T1SFCO vs Target Augmentation

- Annualized view of output (top) masks variation at monthly level (bottom)
- Fluctuations in resource capability due to CGS refueling, system operations, and streamflow sets over 20-yr study horizon



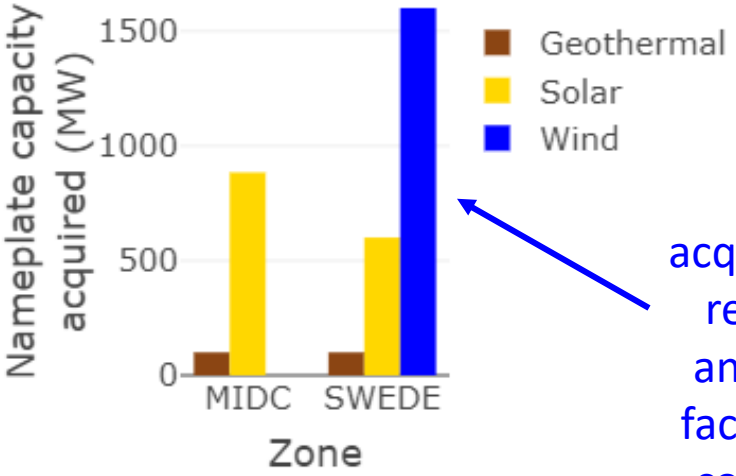
Tier 1 augmentation – Key takeaways

- Meeting T1 load exclusively with supply-side resources requires very substantial acquisitions:
  - P10 needs in the tightest month drive acquisitions
  - Generation greatly exceeds needs most of the time
- Augmentation is achieved with wind, solar, and geothermal power
- In the least-cost portfolio, most energy is generated in the SWEDE region

T1 augmentation: Resource acquisitions

We did not allow EE, DR, or market purchases to contribute to the T1 augmentation

Supply-side:



Large wind acquisitions in SWEDE reflect lower costs and higher capacity factors in that region compared to Mid-C

All values are for 2045. Nameplate capacities of supply-side resources represent maximum output under optimal conditions. Annual aMW output of resources such as solar and wind are substantially less than nameplate capacity.

Natural Gas Assessment

- Consistent with the previous resource program, we are not including natural gas (NG) resources as options directly in the solver.
- The diversity of carbon policies across the BPA service territory complicate the modeling of natural gas in the optimization process. This would significantly expand the scope of the resource program modeling as multiple approaches would be needed for each scenario and sensitivity.
- Modeling natural gas also includes other technical challenges that led to the decision to not include it in the model.
  - Incorporation of NG price risk modeling, this model has caused significant delays and errors in other applications
  - Uncertainty around costs and availability of firm fuel
  - Uncertainty around costs and key characteristics of transitioning NG resources to clean fuels (H2 / biofuels)
- The exclusion of NG resources from the solver does not preclude BPA from acquiring any resource necessary to meet needs at the lowest cost / in a cost-effective manner, as outlined in the Northwest Power Act and consistent with sound utility practice.

- We will gather feedback on NG modeling for RP26 and determine direction for future modeling.

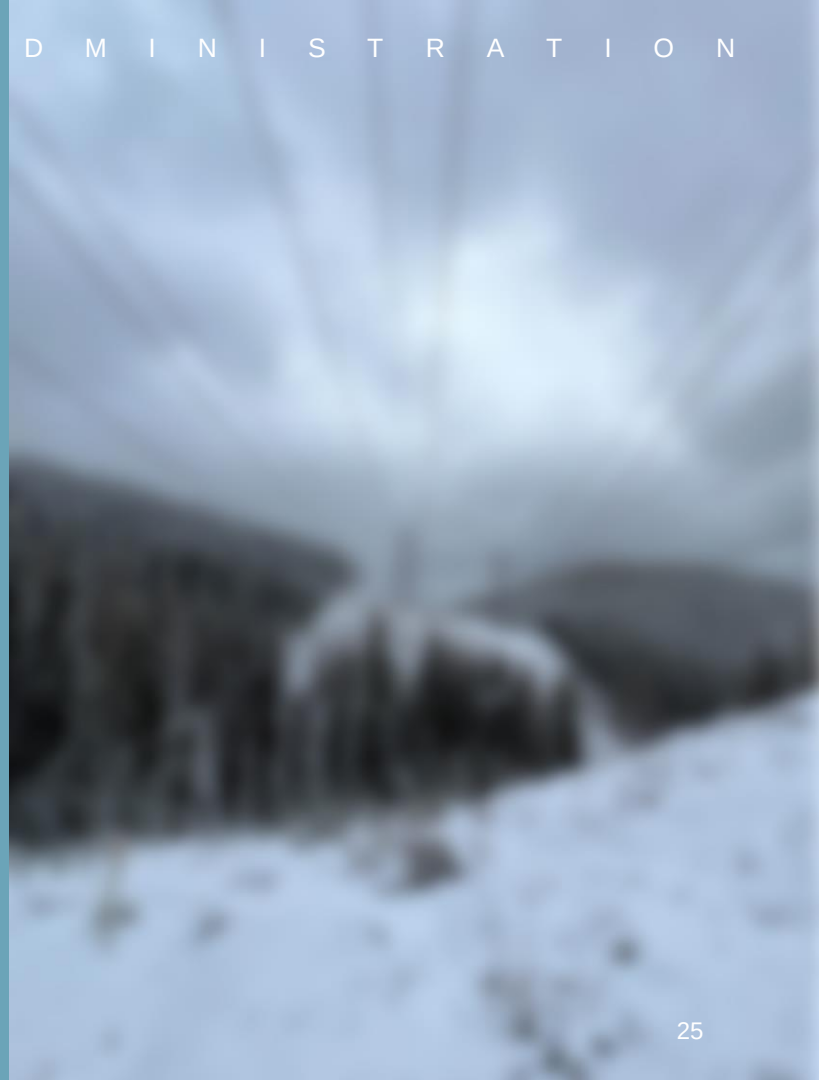
Natural Gas Assessment: Key takeaways

- Including new NG would not change results or lower portfolio costs for the base case or any associated sensitivities. This depends on the following assumptions:
  - A new NG plant built for BPA could not be online before 2035 and would only serve as a bridge resource until 2045
  - Carbon emission costs are considered
  - SMRs beginning operation in 2035 are available and eligible for Inflation Reduction Act tax credits, will not cost substantially more than baseline estimates, and will remain online for 60 years
- Using the above assumptions, the NG assessment for RP24 tests whether the solver would have selected a new NG resource.

Resource Acquisition Process

Eric Federovitch

Manager, Long Term Sales and Purchases



BPA Power Services and Resource Acquisition

- BPA is defining its processes for potential resource acquisitions, and refining existing ones related to assessing and implementing cost-effective uprates of existing FCRPS projects

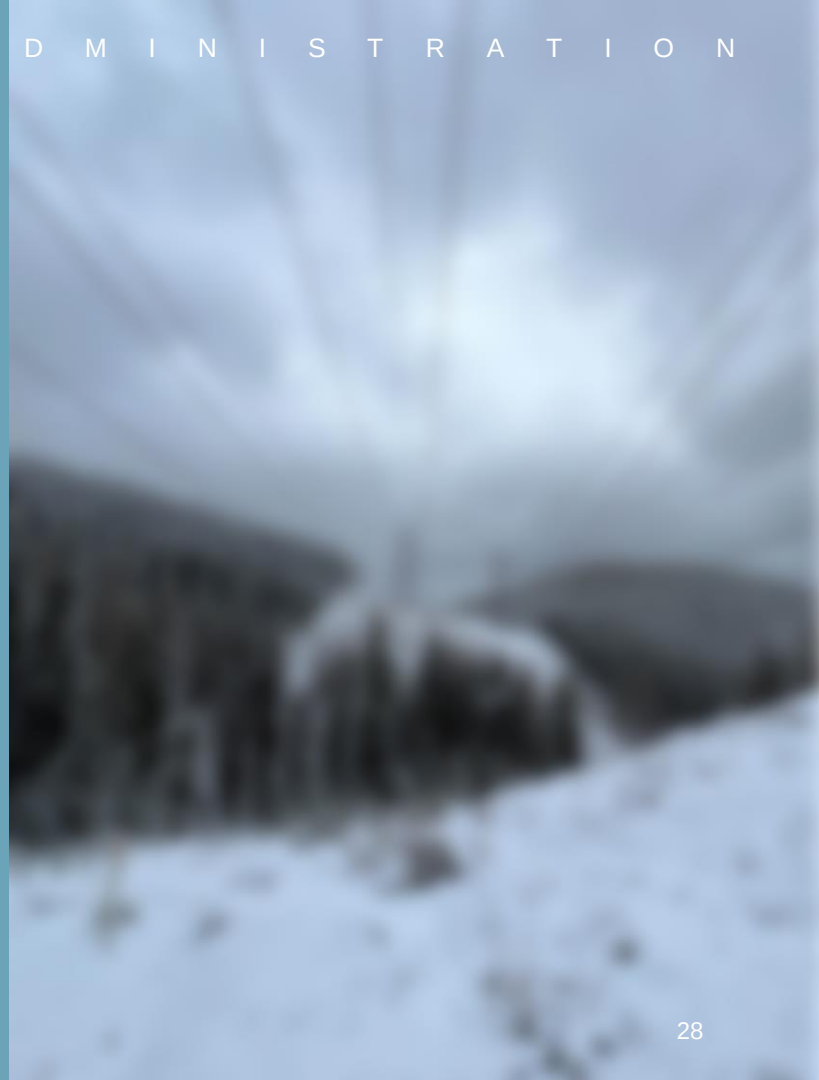
- We continue to explore the possibility of solidifying a resource acquisition commitment before new long-term power sales contracts are signed, as well as opportunities to modernize 6(c) procedures and policy in collaboration with the Northwest Power and Conservation Council

- RP26 will provide information on the type, timing, and quantity of potential resource solutions which may be used to inform a formal resource solicitation process

Acquiring Major Resources – Summary

- Provider of Choice process and Resource Programs inform major resource acquisition decisions, but are not the decision making processes
- BPA is aware of and considering potential approaches to acquire resources on the timeline needed to meet customer obligations post-2028
  - BPA and Council staff are reviewing the current Section 6(c) Policy and considering revisions to update the Policy consistent with the NW Power Act and efficient acquisition practices
  - BPA has benchmarked processes of other utilities to gather best practices and insights to incorporate into process for potential resource acquisitions
- Continuing to explore cost effective opportunities e.g. FCRPS uprates, cost-effective market purchases and minor supply-side acquisitions, experimental 6(d) acquisitions
- Under development project plan to include: Commercial solicitation and contracting, legal/6(c), environmental compliance, transmission considerations, financial

Questions and Discussion





Appendix

Resource Solutions

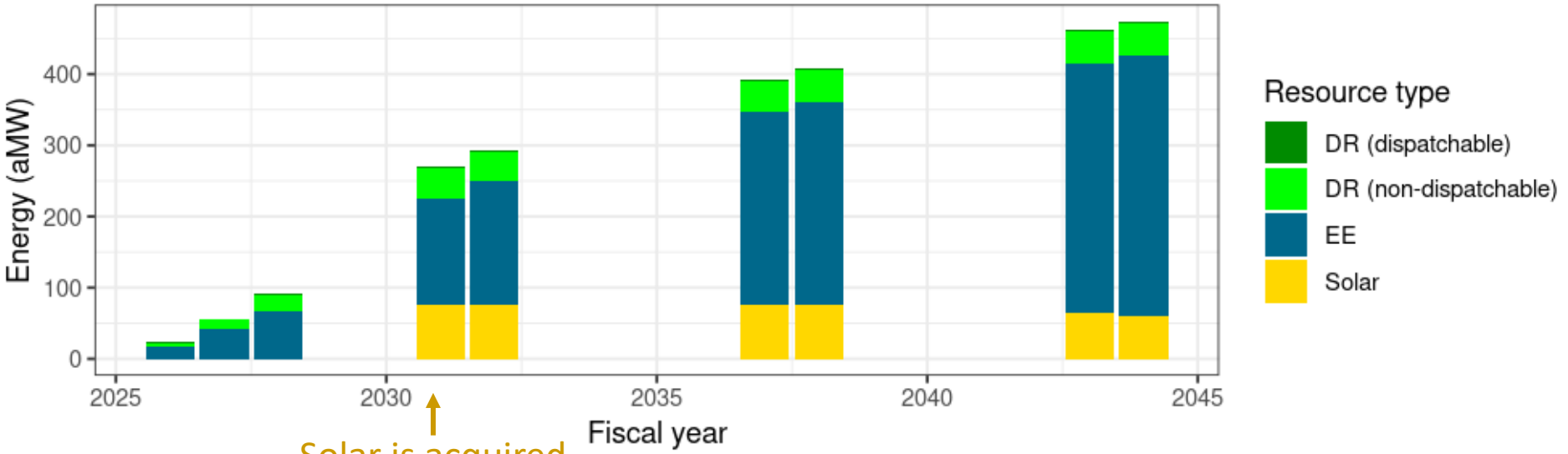
Base scenario: EE and DR

- Non-dispatchable DR programs acquired:
  - Residential Time of Use (TOU) Pricing
  - Utility Demand Voltage Reduction (DVR)
- Dispatchable DR programs acquired:
  - Commercial, industrial, and residential Critical Peak Pricing (CPP)
- EE achieved by 2045:
  - Total: **564 aMW**
  - Serving BPA load: **395 aMW***
- More in-depth EE + DR analysis to come

*About 70% of the total EE achieved by BPA reduces the BPA load obligation. The remainder reduces customer obligations. The percentages vary by EE measure and by customer, but for modeling purposes, we assume 70% for all EE programs.

Base scenario: Mid-C annual aMW

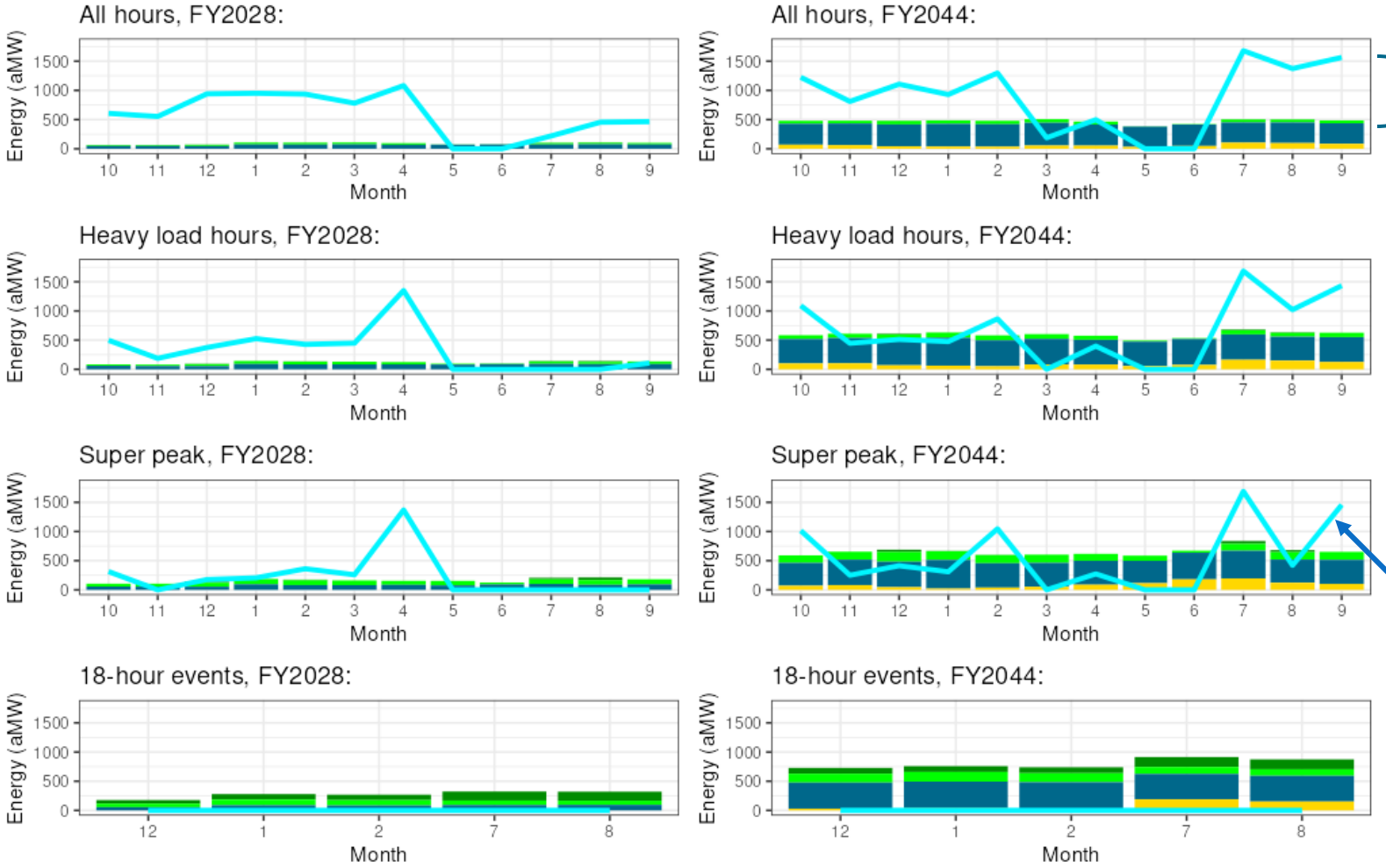
EE and DR programs are started in 2026 and ramp up over time



Solar is acquired in 2031

EE aMW shown is the portion serving BPA load. Total EE acquired in Mid-C is 30% higher.

Base scenario, Mid-C needs and resource contributions:



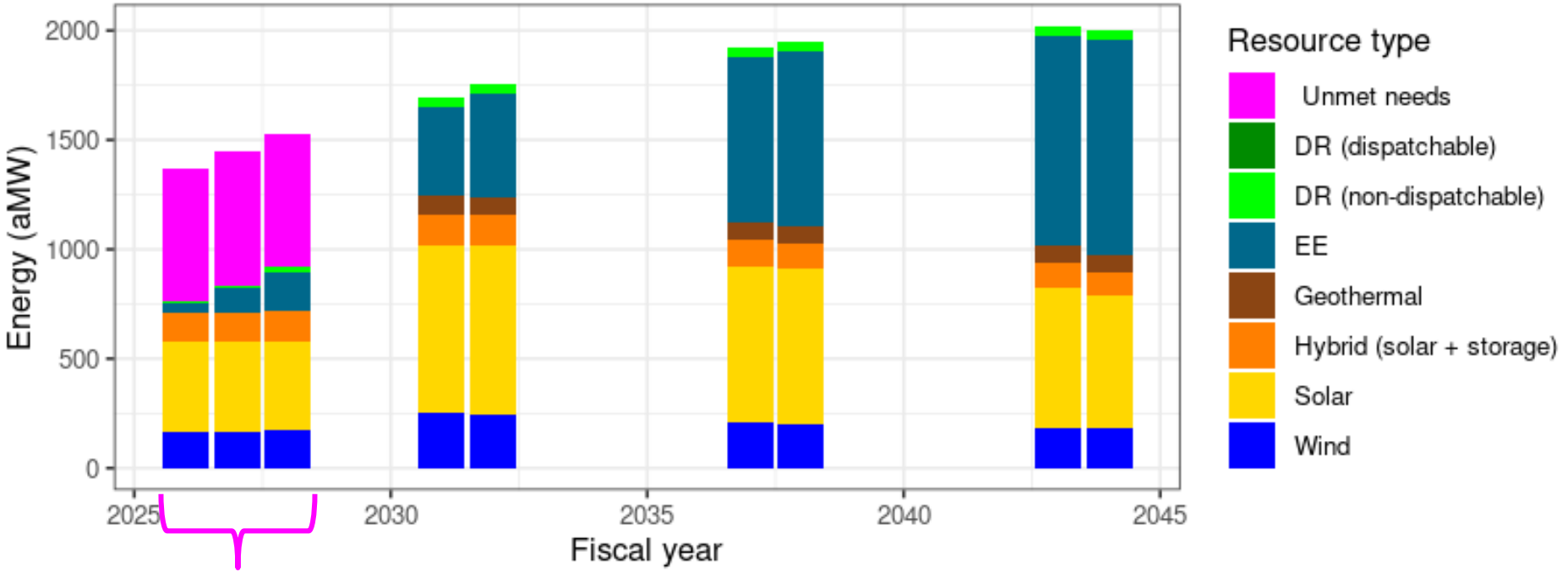
Market purchases fill in remaining needs

Needs are for P10 water conditions (except 18 hr capacity)

Market limits sensitivities: Key takeaways

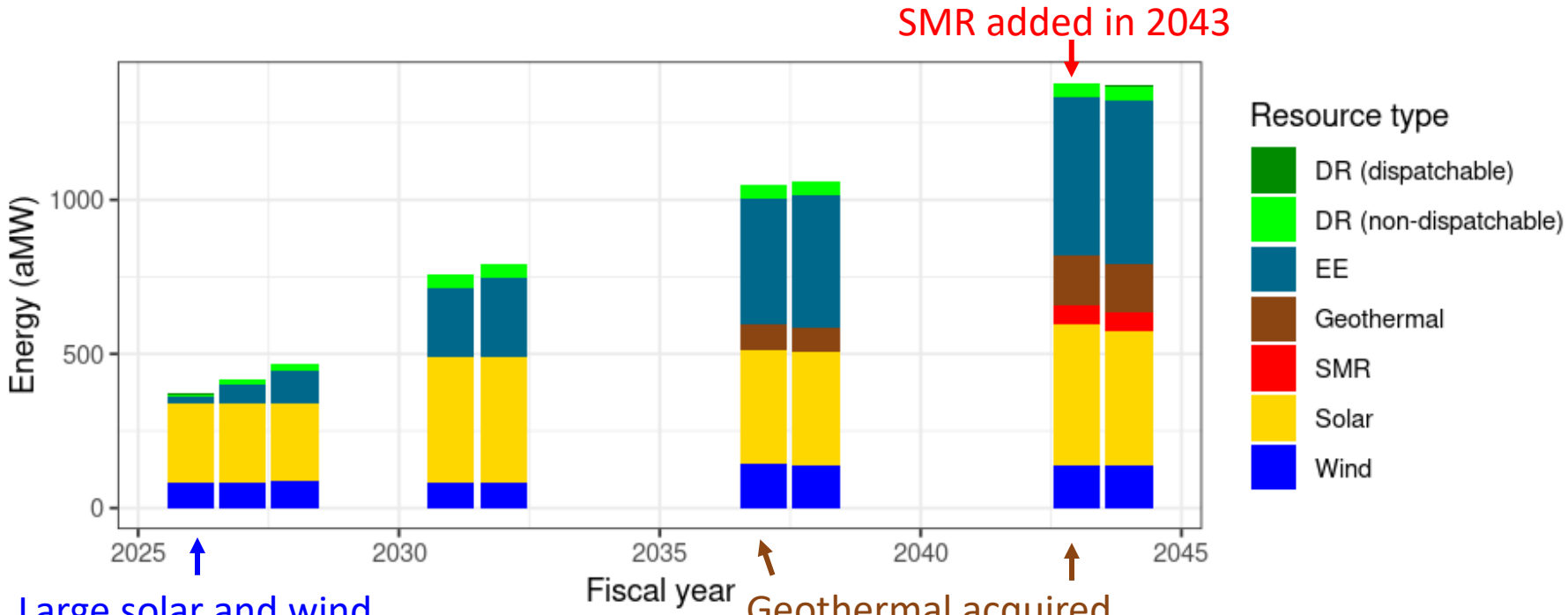
- Needs in 2026-2028 have a strong influence on results
  - Meeting needs in winter and April in this period requires large market purchases (or resources not currently in the model)
- Resource acquisitions are driven primarily by flat energy needs
- Market purchases are replaced primarily with solar and wind

‘No market’ sensitivity: Mid-C annual aMW

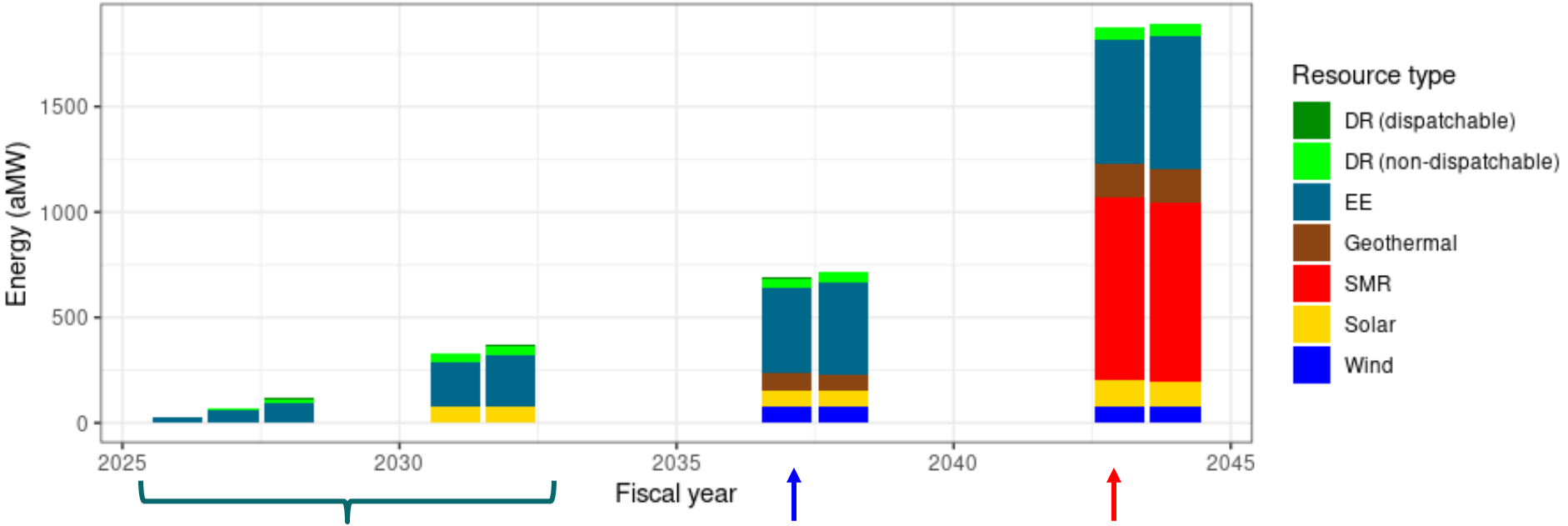


Months without enough resources to meet needs: Nov – Feb and April

‘Reducing market purchases to 0’ sensitivity: Mid-C annual aMW



Medium load adder: Mid-C annual aMW



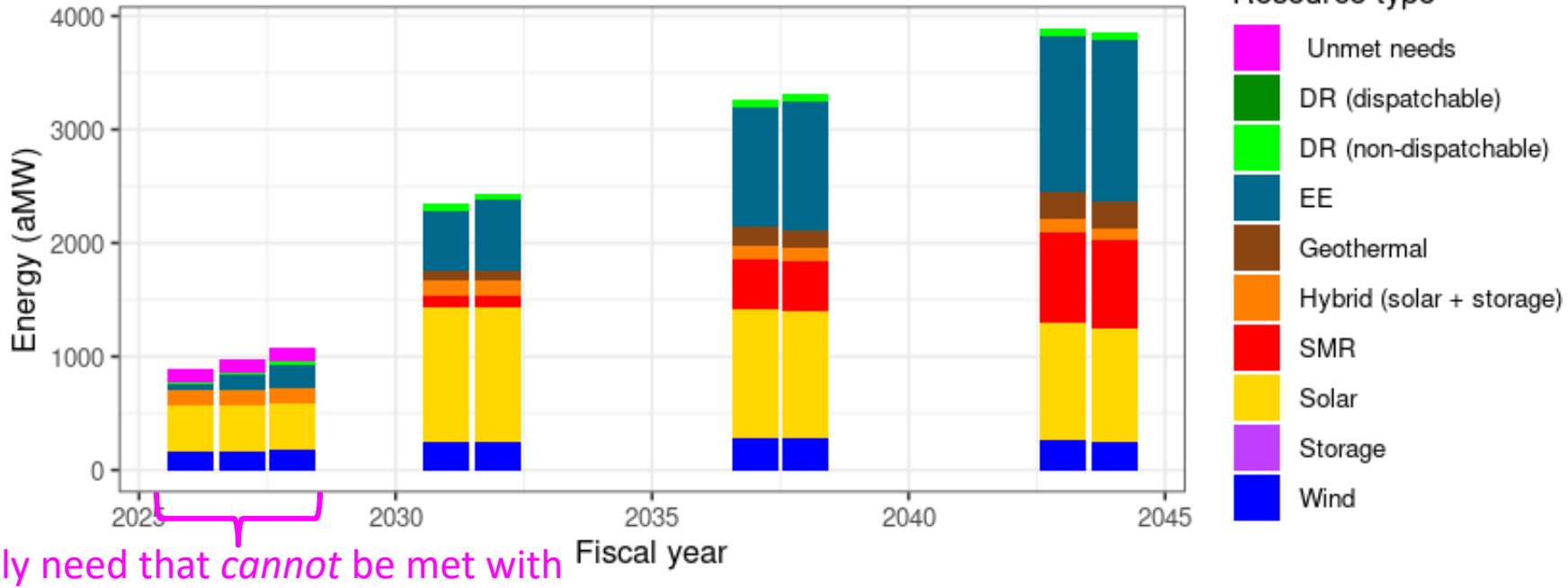
2026-2032 acquisitions same as Base Scenario

Wind and geothermal added in 2037

Most acquisitions happen in 2043

High load adder: Mid-C annual aMW

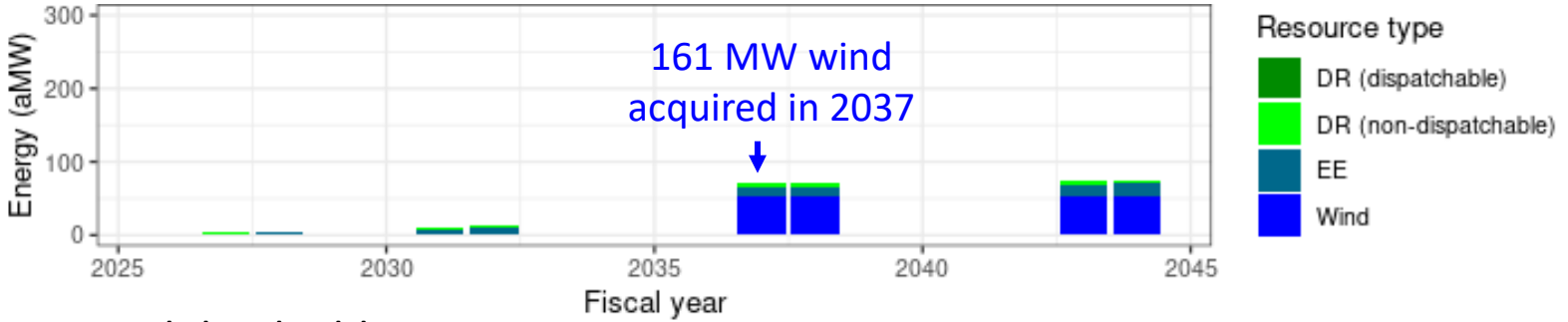
New, large acquisitions made in every available year
(i.e., 2026, 2031, 2037, and 2043)



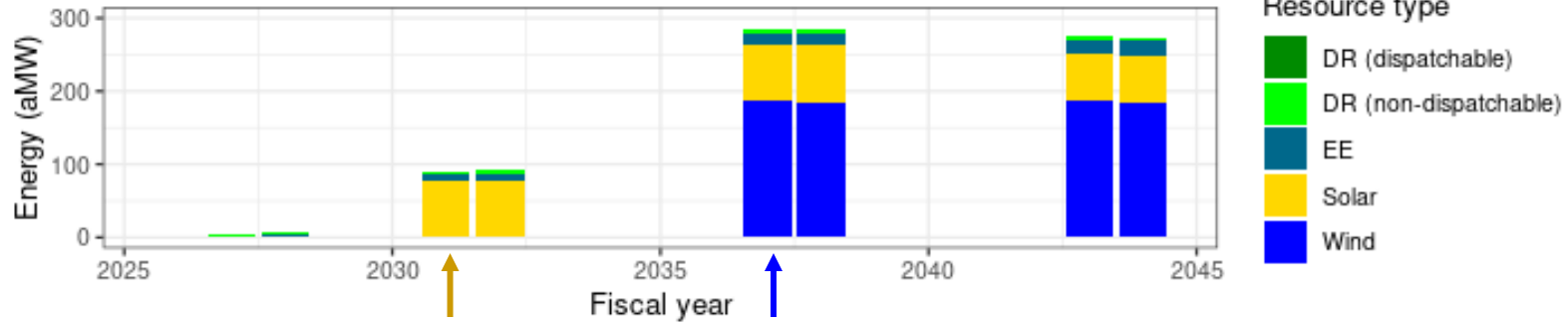
Only need that *cannot* be met with resources in the model: Apr '28 HLH

Load adders: SWEDE annual aMW

Medium load adder:



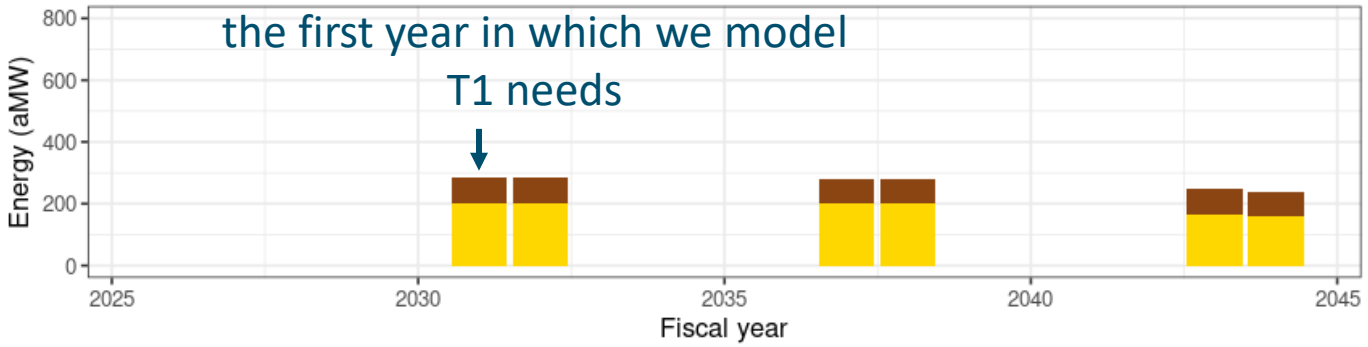
High load adder:



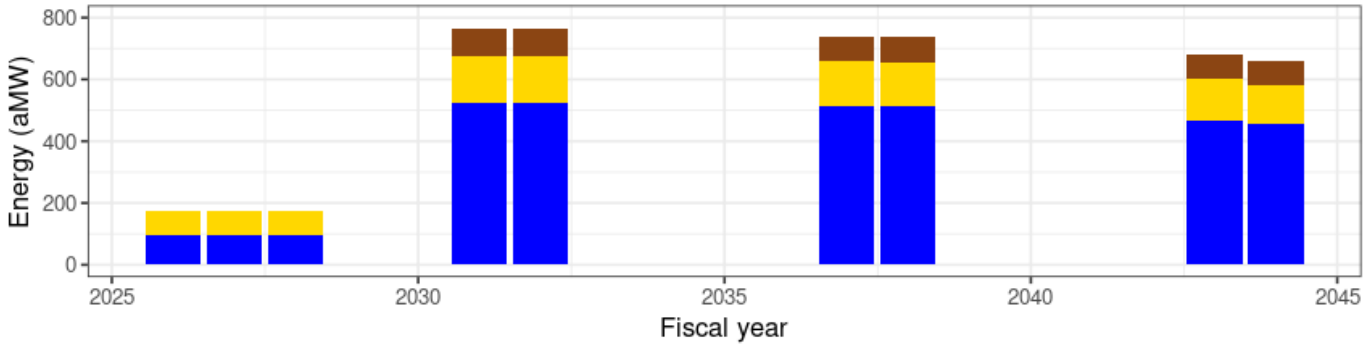
Tier 1 augmentation: annual aMW

MIDC:

Resources all acquired by 2031, the first year in which we model T1 needs



SWEDE:

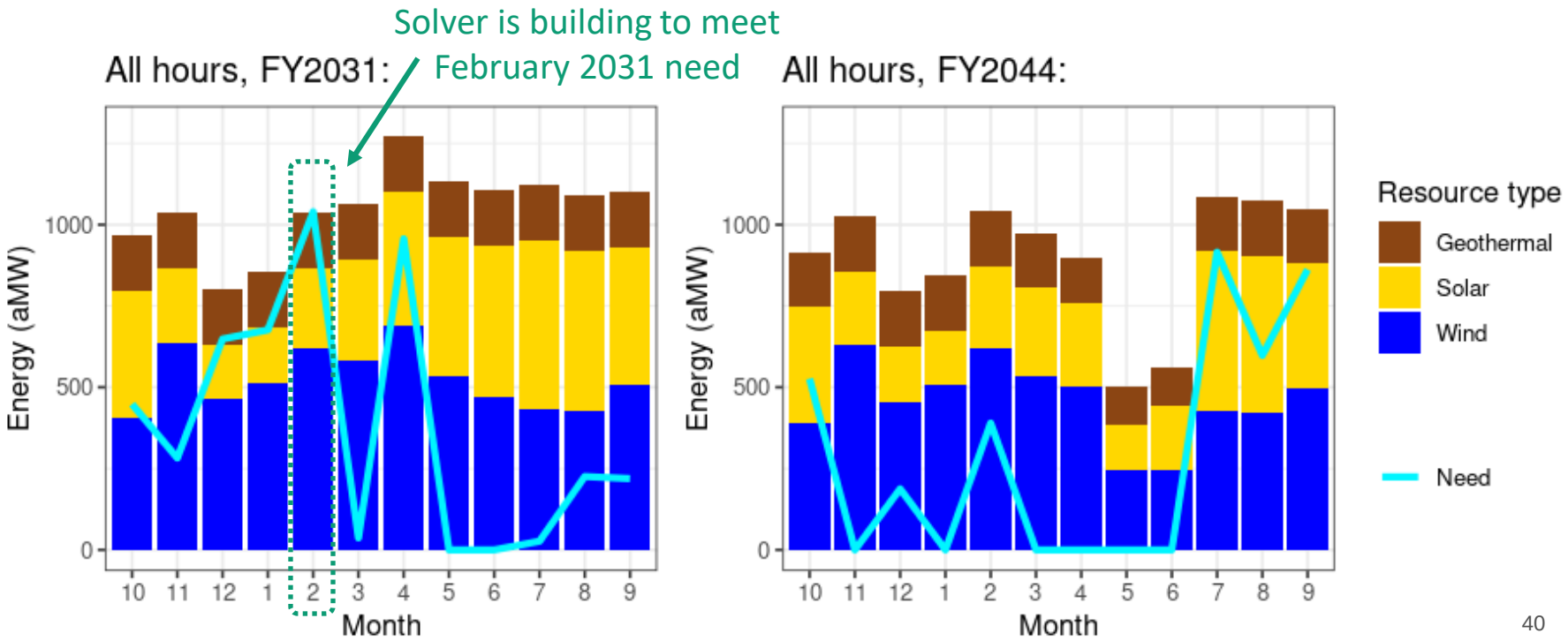


Resource type
Geothermal
Solar
Wind

Most of the energy is generated in SWEDE

Tier 1 augmentation: monthly aMW

In most months, generation is much greater than needs, even under P10 conditions



Natural Gas Assessment

	Base scenario	Market limits				High Mkt Price	Loads	
		Reduce 25%	Reduce 50%	Reduce 50% All	Path to 0		Med Load	High Load
2029-2034								
*2035-2040								
2041-2045								

	Not Selected
	Likely Selected if Available
	Likely Selected

*2035 is the earliest date we've assumed BPA could have a new resource online considering EIS, interconnection, and other necessary processes.

If BPA could get a NG resource online sooner, temporarily acquire output from an existing plant, or invest in NG resources that transition to zero emissions (through clean fuels or carbon sequestration), NG resources may help reduce costs of meeting needs under more sensitivities.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-95:
Centralia Summary by TransAlta



Facts & Figures

Location:	**Centralia, WA**
Legacy Fuel:	**Coal**
Capacity (MW):	**670**
Ownership:	**100%**
Operator:	**Yes**
First on-stream:	**1971**
Revenue Source:	**LTC/Merchant**
Builder:	**No**

Facts & Figures	
Contract Expiry:	**Unit 1 - 2020; Unit 2 - 2025**

Back

Centralia

On December 31, 2020, TransAlta retired Unit 1 of our Centralia facility, decreasing the facility's capacity to 670 MW. Throughout its lifetime, Unit 1 provided a total net generation of just over 176,660,518 MWh with an average availability of 85.66 per cent. Unit 2 of the facility is set to retire at the end of 2025, as part of TransAlta's transition to a 100 per cent clean electricity future.

In **December 2025**, TransAlta Corporation's subsidiary, TransAlta Centralia Generation LLC, received an order (the Order) from the United States Department of Energy. The Order mandates that Centralia Unit 2 in Washington State, remain available for operation for a period of 90 days, until March 16, 2026. TransAlta is currently evaluating the Order and will work with the state and federal governments in relation thereto. The coal-to-gas conversion project, announced on December 9, 2025, remains a priority for TransAlta. Further information regarding the Order will be provided as it becomes available in due course.

The reliable and steady supply of power from the Centralia Coal Plant is essential for keeping the west-coast electrical grid stable. The facility is a merchant plant, which means that costs such as environmental upgrades cannot be passed on to customers. TransAlta has invested more than US$300 million in pollution control technology at Centralia Plant, including scrubbers and low nitrogen dioxide burners. Today, the facility is one of the cleanest coal-fired power plants in North America.

Fuel for Centralia Plant is delivered by train from the Powder River Basin in the U.S. Midwest. The plant's coal unloading facility is considered one of the most efficient and environmentally friendly in North America.

In preparation for the retirement of Unit 1 in 2020, and the upcoming retirement of Unit 2 in 2025, TransAlta has invested $55 million USD to support energy efficiency, economic and community development and education and retraining initiatives in Washington

State, $20 million USD of which is dedicated to the *Economic and Community Development Board,* which will fund education, retraining, economic development and community enhancement for those impacted by the units retirement.

Coal Combustion Residuals (CCR) rule compliance data and information

TransAlta is committed to providing information to the community about our facilities. The information below is intended to satisfy the requirement under the *CCR Rule 40 CFR 257.107* to maintain a publicly accessible internet site (CCR site) containing the required information. The required information will be posted when it is accomplished and is available.

Location restrictions

Unstable areas

Operating criteria

CCR fugitive dust control plan

Run-on and run-off control plan

Annual fugitive dust control report

Annual CCR Fugitive Dust Control Report – 2016

Annual CCR Fugitive Dust Control Report – 2017

Annual CCR Fugitive Dust Control Report – 2018

Annual CCR Fugitive Dust Control Report – 2019

Annual CCR Fugitive Dust Control Report – 2020

Annual CCR Fugitive Dust Control Report – 2021

Annual CCR Fugitive Dust Control Report – 2022

Annual CCR Fugitive Dust Control Report – 2023

Annual CCR Fugitive Dust Control Report – 2024

Annual CCR Fugitive Dust Control Report – 2025

Annual engineering inspection reports

CCR Annual Inspection January 11, 2016

CCR Annual Inspection January 5, 2017

CCR Annual Inspection January 4, 2018

CCR Annual Inspection January 3, 2019

CCR Annual Inspection January 7, 2020

CCR Annual Inspection January 6, 2021

CCR Annual Inspection January 5, 2022

CCR Annual Inspection January 5, 2023

CCR Annual Inspection January 5, 2024

CCR Annual Inspection January 15, 2025

Groundwater monitoring and corrective action

Annual groundwater monitoring and corrective action Report – 2024

Annual groundwater monitoring and corrective action Report – 2023

Annual groundwater monitoring and corrective action Report – 2022

Annual groundwater monitoring and corrective action Report – 2021

Annual groundwater monitoring and corrective action Report – 2020

Annual groundwater monitoring and corrective action Report – 2019

Alternative Source Demonstration Nov-2-2018

Annual groundwater monitoring and corrective action Report – 2018

Annual groundwater monitoring and corrective action Report – 2017

Addendum to 2017 Annual CCR Groundwater Monitoring Report

Groundwater monitoring system certification

Statistical method certification

Notification of assessment monitoring program

Notification of return to detection monitoring program

Notification of Appendix IV exceedances

Notification of corrective measures assessment

Corrective measures assessment

Semi-annual corrective action report

Notification of completion of corrective action

Closure and post-closure care

Closure plan

Time extensions for initiating closure

Time extensions for completing closure

Notification of intent to initiate closure

Notification of completion of closure

Notification of intent to comply with alternative closure requirements

Annual progress reports for alternative closure

Notification recording a notation on property deed

Post-closure care plan

Notification of completion of post-closure care