Western Resource Adequacy Program

Detailed Design

MARCH 2023

Western Power Pool

WESTERN POWERPOOL

ACKNOWLEDGEMENTS

This document is the culmination of effort by the WPP WRAP Participant Committee, with support from Southwest Power Pool and Sapere Consulting.

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ACRONYMS

BAA	Balancing Authority Area
BPM	Best Practice Manual
CAISO	California Independent System Operator
CCH	Capacity Critical Hours
CEO	Chief Executive Officer
CONE	Cost of New Entry
COSR	Committee of States Representatives
CP	Coincident Peak
CR	Contingency Reserves
DR	Demand Response
EEA	Energy Emergency Alerts
EFDH	Equivalent Forced Derating Hours
EFOF	Equivalent Forced Outage Factor
EFOR	Equivalent Forced Outage Rates
ELCC	Effective Load-Carrying Capability
ESR	Energy Storage Resource
FERC	Federal Energy Regulatory Commission
FOH	Forced Outage Hours
FS	Forward Showing
FSPRM	Forward Showing Planning Reserve Margin
GADS	Generator Availability Data System
HE	Hour Ending
ICAP	Installed Capacity

IE	Independent Evaluator
IOU	Investor-Owned Utilities
JCAF	Joint Capacity Attestation Form
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
LRE	Load Responsible Entity
LRZ	Load and Resource Zone
LSE	Load Serving Entity
MMBtu	Metric Million British Thermal Unit
MOU	Memorandum of Understanding
MW	Megawatt
MWh	Megawatt Hour
NC	Nominating Committee
NCP	Non-Coincident Peak
NERC	North America Electric Reliability Corporation
NP	Nameplate
OASIS	Open Access Same-time Information Systems
OATT	Open Access Transmission Tariff
P50	1-in-2 Peak Load Seasonal Values
PA	Program Administrator
PO	Program Operator
POU	Publicly-owned Utilities
PRC	Program Review Committee
PRM	Planning Reserve Margin
PS	Preschedule
QCC	Qualified Capacity Contribution

RA	Resource Adequacy
RAPC	Resource Adequacy Participant Committee
RoR	Run-of-River
SAC	Stakeholder Advisory Committee
SMEC	System Marginal Energy Cost
SPP	Southwest Power Pool
TDF	Transmission Distribution Factors
TSP	Transmission-Service Provider
UCAP	Unforced Capacity
VER	Variable Energy Resource
WECC	Western Electricity Coordinating Council
WIEB	Western Interstate Energy Board
WPP	Western Power Pool
WRAP	Western Resource Adequacy Program
WRAPA	Western Resource Adequacy Program Agreement

WPP Western Resource Adequacy Program Detailed Design

Executive Summary

AUGUST 2022

WESTERN POWERPOOL

WRAP

POWERED BY WPP

ES1. Background

The integrated regional power system in the West is in transition. The retirement of thermal generation within and outside the region mixed with increased dependency on variable energy resources has led to concerns about the adequacy of supply during critical hours and highlighted the need for a regional reliability planning standard similar to the resource adequacy standards that have been adopted in other regions of the US and throughout the world. The regional transformation of supply resources, if not properly addressed, will not only risk supply disruptions, but could also hinder the achievement of some states' environmental goals.

Beginning in early 2019, the Western Power Pool (WPP) coordinated a coalition to explore these challenges and develop concensus around a regional reliability standard to meet future load in a reliable and cost effective manner. It was also important that all parties do their part to ensure reliable supply for the grid and that the program include compliance mechanisms to oversee this cooperative aspect of the program. The program, which was given the moniker of Western Resource Adequacy Program (WRAP), includes both a planning component, known as the Forward Showing Program (FS Program) and an Operational Program (Ops Program). The FS Program is applied on a regional basis in order to take advantage of load and resource diversity among the Participants, so the Ops Program needs to facilitate the sharing of resources within the group during stress periods on the regional grid in order to deliver this diversity benefit in operations.

This WRAP Design Document summarizes the WRAP governance structure, the FS Program, and the Ops Program. It is meant to be utilized by WRAP Participants and the public to ensure a broad understanding of how the programs work and to support the development of business practice manuals that will provide the detailed processes and procedures to guide implementation of the programs. The Design Document is intended to be a resource for those interested in understanding the program, and aims to weave together design materials generated over the past three years. **This document itself is not a governing document**; the WRAP Tariff [approved by the Federal Energy Regulatory Commission (FERC) on February 10, 2023, effective January 1, 2023], future WRAP business practices, and a suite of WPP corporate governance documents will govern the program and the organization, respectively. This document is strictly informational.

The WRAP is a capacity-based resource adequacy program that requires adequate deliverability for the capacity. The WRAP requirements are expected to evolve and change over time as the region and the Partcipants gain a better understanding of how well the initial program design works in practice.

The WRAP dovetails with and builds upon the resource planning processes used by states and provinces and the regulatory requirements of the FERC, North America Electric Reliability Corporation (NERC), and Western Electricity Coordinating Council.

ES2. WRAP Benefits

The WRAP improves the reliability of the system while reinforcing existing responsibilities for reliable resource planning and operations. Planning and procurement are currently distributed within the region and there are no common standards or enforcement. This patchwork and uncoordinated approach can lead to gaps and lower grid reliability.

Additionally, individualized planning make it challenging for regulators, the public, and load responsible entities (LRE) to determine where, when, and if new capacity is needed in the region. WRAP metrics are set by performing regional reliability assessments utilizing data from all participants, rather than individually applying standards to each LRE; this facilitates regional diversity sharing and savings for electric customers, but also ensures a coordinated regional look at necessary capacity build not previously available in the West. Participants will have lower capacity procurement obligations than they would have if they were meeting the same capacity planning standard on their own.

The Ops Program facilitates the deployment of this diversity and allows the WRAP Participants to collectively manage periods of capacity stress by sharing available capacity within the region.

ES3. WRAP Governance

The WRAP includes changes to the WPP that are driven by FERC's oversight of certain elements of the WRAP and the WPP's role in administering the WRAP. Since the effective date of the approved WRAP tariff (January 1, 2023) the WPP is a "public utility" as defined by the Federal Power Act and needs to meet specific independence requirements established by FERC. Independence includes financial independence from individual Participants and classes of Participants in order to ensure that the WPP cannot be unduly influenced by such entities.

Committees related to the governance of WRAP are chartered through the WRAP Tariff, including the creation of a Resource Adequacy Participant Committee, a Committee of State Representatives, and the sector-based Program Review Committee, tasked with facilitating the process to make changes to the WRAP. A sector-based Nominating Committee, charged with nominating new directors to the WPP board, was chartered through updates made to the WPP's bylaws.

The WPP will continue to provide the legacy and contract services it has historically provided (governance of these programs will be unaffected by the changes described in this document), and the WPP will be the primary entity responsible for offering the WRAP services, providing administrative and facilitation support for the governance and administration of the WRAP. The WPP has procured the services of a Program Operator to provide the actual operational services and augment the technical expertise for WRAP. An Independent Evaluator will also review program design and operations.

Additional details related to program governance, timing of FERC filing, committees, etc. can be found in the Governance section of this Design Document.

ES4. Forward Showing Program

The FS Program will consistently apply metrics and methodologies to the region's capacity planning activities within the existing bilateral market framework. Participants will continue to be responsible for determining what resources to use to meet the regional capacity planning standards, procuring those resources, and working with their regulators, as required. The WRAP will also work within and rely upon the existing Open Access Transmission Tariff (OATT) framework. The program will be voluntary, in that entities may choose to join the program. Once they have have joined, however, the obligations and charges for failures to perform become binding on the Participants. Table ES-1 presents a summary of key components of the FS Program.

Table ES-1 Summary of WRAP FS Program.

WPP WRAP FS Program Snapshot	
Program Structure	Bilateral; Participants will continue to be responsible for determining what resources and products to procure from other Participants or suppliers.
Binding Seasons	Two binding seasons: Summer (June 1 – September 15) and Winter (November 1 – March 15).
FS Deadline	Participants will demonstrate compliance with FS reliability metrics seven months in advance of the start of the binding seasons with an opportunity to cure if they fail.
Reliability Metric	FS Program will set the capacity needed to meet a 1 event-day in 10 years loss of load expectation target.
Load Forecasting	Entities will utilize accepted load forecasting methodologies to ensure consistency.

WPP WRAP FS Program Snapshot	
FSPRM	A monthly Planning Reserve Margin will be determined for the Summer and Winter seasons and expressed as a percentage of each Participant's monthly P50 load forecast.
Resource Capacity Accreditation	*Wind and Solar Resources*: Effective Load-Carrying Capability (ELCC) analysis. *Run-of-River Hydro*: Historical output on Capacity Critical Hours (CCH) *Storage Hydro*: Hydro model that considers the past 10 years generation, potential energy storage, and anticipated operational constraints. *Thermal*: Unforced capacity method. *Energy Storage:* ELCC analysis *Energy Storage Resources hybrid resources*: "Sum of parts" method – Energy Storage will use ELCC and generator will use appropriate method *Demand Side Resources*: controllable and dispatchable demand response can be utilized to reduce the P50 load for the compliance metric or considered as a capacity resource.
Transmission	Participants must ensure deliverability of resources in the FS Program by demonstrating they have NERC Priority 6 or 7 transmission rights to deliver at least 75% of the resources claimed in the FS portfolio from source-to-sink. 100% firm/conditional firm source-to-sink is required in the Operational time horizon or the Participant is exposed to noncompliance charges.
Payment for Noncompliance	The FS Deficiency payment is based on Cost of New Entry for a new peaking gas plant.

ES5. Operational Program

The Ops Program provides centralized day-ahead (six days in advance) and within-day monitoring of the load-resource balance of the Participants. When any Participant is forecasted to be deficient, a sharing event is initiated and other Participants hold capacity for delivery to the deficient Participant(s). In this manner, the WRAP ensures that the capacity of its Participants is deployed to ensure the planned reliability standards of the program are met before Particpants are allowed to sell such energy and capacity in the regional markets.

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WPP Western Resource Adequacy Program Detailed Design

Section 1. Governance

FEBRUARY 2023

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INTRODUCTION

The Western Power Pool (WPP) is a non-profit organization whose customers are electrical utilities and marketers that own generating plants, sell power, and/or serve load throughout the Western United States and Canada. The WPP provides grid coordination services to its customers to increase efficiency and reliability.

The WPP and its participating resource adequacy customers (Participants) and stakeholders have developed the following approach for governance, structure, and function changes associated with full implementation of the Western Resource Adequacy Program (WRAP). The WPP released its initial governance proposal in June 2020 in consultation with a multi-sector Stakeholder Advisory Committee (SAC) which provided written comments on the proposal in September of 2020. There were three SAC meetings (October 2020, April 2021, and June 2021) that discussed and provided input into updates to the approach. Additional outreach with Western regulators was facilitated by the Western Interstate Energy Board (WIEB) including six workshops with state regulators throughout 2021. The WPP held quarterly public webinars discussing the governance approach.

WPP staff participated in more than 80 industry-related events and other meetings to discuss the WRAP, established a public listserv with several hundred recipients to provide updates on WRAP development, and hosted numerous public webinars and other public outreach including (among others):

October 2, 2019	Public resource adequacy symposium
February 7, 2020	Public webinar providing an overview of the WPP resource adequacy effort, timeline of project and program design objectives and design elements, timeline and opportunities for public involvement, and feedback received to date from the stakeholder advisory committee
April 24, 2020	Public webinar on RA program organization, Forward Showing (FS) and Operations Programs, and regulatory and jurisdictional considerations
September 11, 2020	Public webinar on the preliminary program conceptual design and status update, including an overview of the feedback from the stakeholder advisory committee
January 29, 2021	Public webinar on WRAP status update, FS Program and Operations Program, and next steps

May 14, 2021	Public webinar on proposed WRAP governance to gather feedback
May 21, 2021	Public Load Service Information Forum #1 – this forum was created to build awareness and understanding of the WRAP to encourage broader participation
June 12, 2021	Public Load Service Information Forum #2
July 14, 2021	Public Load Service Information Forum #3
July 16, 2021	Public webinar on WRAP governance and design updates
July 28, 2021	Release of the WRAP "Detailed Design Document"
August 4, 2021	Public resource adequacy symposium
August 12, 2021	Public Load Service Information Forum #4
November 17, 2021	Public webinar to discuss public comments on WRAP design document
January 12, 2022	Public webinar on stakeholder engagement opportunities within the Nominating Committee and Program Review Committee
January 26, 2022	Public webinar on general WRAP design update, load forecasting, and resource accreditation
February 4, 2022	Public webinar on WRAP governance
March 2, 2022	Public webinar on WRAP design, cost of new entry charge, settlements and pricing, and load forecasting
May 11, 2022	Public webinar on legacy contracts and WRAP cost allocation
June 30, 2022	Public webinar on transmission demonstration, participation scenarios in the WRAP, and FS capacity requirements
July 14, 2022	WRAP Tariff published for public review
July 25, 2022	Public webinar to review the WRAP Tariff and allow public comment
September 25, 2022	Public webinar to review preliminary modeling results and program data

February 24, 2023	Public webinar to review the Federal Energy Regulatory Commission (FERC) order approving the WRAP Tariff and an overview of the governance transitions being undertaken by the WPP

These are just a subset of the numerous public outreach efforts in which WPP has engaged during the multi-year effort to develop the WRAP Tariff which was filed with FERC on August 31, 2022 (ER22-2762). An amended tariff was filed with FERC on December 12 to address questions from FERC staff received in a November 21 deficiency letter. FERC issued an order accepting the proposed tariff on February 10, 2023. FERC issued an order accepting the proposed tariff on February 10, 2023. At the time of publishing this document, the WPP is in efforts to transition to the governance structure outlined in the WRAP tariff and described in this document.This document is intended to be a guide as to how the WPP is implementing governance changes in response to the favorable order from FERC. In the future, aspects of governance that impact the ongoing aspects of WPP business and decision-making will be incorporated into other documents, including the WRAP business practice manuals (WRAP BPM). **Importantly, this document is not a governing document, and is intended for informational purposes only. This document has served as a basis for writing the WRAP tariff and updates to WPP bylaws and will inform business practice development in 2023 (all of which are governing documents with established review and acceptance processes).. While this document memorializes extensive work and review by regional stakeholders, it should be recognized that the upcoming drafting, review, and adoption of business practices will likely supersede the usefulness of this document.**

Currently, the WPP provides a number of contractual services. The diagram in Figure 1 presents the key services and their relationship with the current Board of Directors (henceforth known as "Board", or individually as Directors) and staff.

This plan includes a number of changes such that the WPP and the Board will meet: (i) the necessary requirements as a public utility under the Federal Power Act and FERC regulations; and (ii) FERC's independent board of directors' criteria[1]. Independence has been constructed as financial independence from Participants and classes of Participants in order to ensure that any such interests do not contribute to undue discrimination by the WPP. In addition to

[1] FERC notes that "while the Commission must ensure that the WRAP proposal's governance structure satisfies the requirements of FPA section 205, [it is] not evaluating the proposed governance structure under the requirements developed for RTOs/ISOs… Those rulemakings are not applicable here because WPP is not proposing to establish an RTO/ISO. [The Commission] nevertheless acknowledge[s] that WPP and stakeholders voluntarily strove to benchmark the WRAP governance structure against the Commission's standards for RTO/ISO governance, including standards for transparency, board independence, and stakeholder engagement. In doing so, [it] note[s] that the WRAP committee structure represents a broad base of stakeholders, including state utility commissions and non-Participant entities." *Order Accepting Proposed WRAP Tariff*, Docket Nos. ER22-2762-000 and ER22-2762-001 ¶50.

prohibiting direct financial conflicts, the WPP will require criteria intended to eliminate other types of conflicts-of-interest, as well as situations that lead to an appearance of bias[2]. On October 12, 2022, the Board approved a unanimous resolution to incorporate certain changes into the WPP bylaws that became effective and binding on WPP when FERC approved the WRAP Tariff on February 10, 2023.The bylaw changes include:

- Adoption of a conflict-of-interest policy which requires Directors and officers to disclose any interest that constitutes or could result in a conflict of interest and sets out procedures for reviewing and resolving such matters in accordance with law.

- Affirmation that the WPP will be governed by an independent board requiring each Director to always exhibit financial independence from all Participants of the WRAP.

- Affirmation that the WPP Board will be selected by a sector-based Nominating Committee (discussed further below) and confirmed by the seated board.

- Various other updates aimed at increased transparency, accountability, and stakeholder engagement.

These changes became effective on February 21, 2023.

In addition to continuing to provide and facilitate the various services that the WPP currently delivers, the WPP now serves as the public utility [i.e., Program Administrator (PA)] responsible for offering WRAP services, provides administrative support for the governance and administration of the WRAP, and relies on the expertise, experience, and input of the Program Operator (PO) to provide the operational services and technical support for the WRAP, including both the FS Program and the Operational Program (Ops Program). The PO, an entity with extensive Resource Adequacy (RA) implementation, operations, and modeling experience, reports to the independent Board in an advisory capacity and will work collaboratively with the WPP to bring its expertise to all supporting committees.

The following sections outline how the changes are being implemented. As noted, the WPP Board transitioned to an independent board to serve as the ultimate decision-making body for future governance and supporting committees to accomplish all other ongoing functions. Going forward, directors will be nominated by the Nominating Committee (NC), a sector-representative committee that screens potential Directors before proposing a slate of new

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[2] With respect to indirect financial conflicts or conflicts of interest that may arise from outside activities, secondary employment, or other activities, the WPP intends to follow corporate best practices in order to instill a sense of confidence in the WPP. In general, the WPP will adopt policies that prohibit Board members from engaging in any outside business activity that interferes or materially decreases the Director's impartiality, judgement, effectiveness, productivity, or ability to perform Director's duties and functions at WPP. In some instances, such conflicts may be waivable with notice and consent.

Directors to the current Board for confirmation. As part of the conditional resolutions approved by the Board on October 12, 2022, the Board also adopted and approved the NC and the NC process described above, which are nor formally part of the WPP corporate governance. Current services, programs, and committees will not substantively change based on the new governance structure, nor by the addition of the WRAP. The new WRAP governance structure includes three organizational groups:

Resource Adequacy Participant Committee (RAPC) – RAPC will be the main venue for participants in the program to engage in program implementation and compliance, as well as the highest form of participant engagement in the governance and decision-making of the program. The RAPC will be recommended changes to the program design as they relate to participation in the program and vote on all proposed changes prior to Board review. RAPC recommendations will be considered by the Board in conjunction with feedback from the public, stakeholders, and other committees. To prepare for the governance changes required by the WRAP Tariff, the WPP stood up the RAPC on an informal basis beginning in October 2021.

Program Review Committee (PRC) – The sector-representative PRC will be responsible for receiving, considering, and proposing changes to the WRAP design. The PRC will also be responsible for documenting proposed changes and overseeing public and committee comments and feedback processes to inform consideration of those recommendations by the RAPC and Board. In developing recommendations, the PRC will incorporate feedback and suggestions from the public process, Participants, committees, the PA and PO, and the Board. To prepare for the governance changes required by the WRAP Tariff, the WPP stood up the PRC on an informal basis beginning in March 2022.

Committee of State Representatives (COSR) – State regulators and energy offices have always served an important role in RA, and the COSR will be formed exclusively for state representatives, with one representative from each state or provincial jurisdiction which has load represented by a Participant. When RAPC has approved a proposed change to the Tariff of Business Practices, the COSR will be responsible for assessing whether the RAPC substantively altered the proposal from that which was previously reviewed by the PRC, COSR, and public prior to such a proposal being reviewed by the Board. The scope and role of the COSR is meant to facilitate participation in the WRAP decision-making process by the state authorities.The vast majority of the operations, processes, and procedures will be left to them to determine. Key elements of the COSR include a designated representative of the COSR on the PRC, attendance of a designated representative of the COSR at all meetings of the RAPC, an enhanced process for COSR engagement in RAPC decision-making, and a commitment by the WPP to work with COSR to review governance structures and procedures, including the role of the COSR, in the event the WPP seeks to expand the WRAP to include market optimization or transmission planning services.

The WPP will also work with an Independent Evaluator (IE) to review program design and operations. The IE will provide an annual independent assessment of the performance of the WRAP and any potential beneficial design modifications, as well as an analysis of prior year program performance and accounting and settlement. The IE will not have any decision-making authority regarding the WRAP or design modifications, but IE will report directly to the Board. The WPP has not yet identified an IE but plans to define a process for identification and retention of a qualified IE sometime in 2023 to allow the IE to provide prior year analysis for the non-binding seasons of the WRAP, prior to the transition to binding program operations as early as 2025. The WPP anticipates the need for additional committees or subcommittees to support the WRAP and provisions are established to allow for their formation as may be needed.

GOVERNANCE – ACTORS AND PARTICIPANTS

1.1. Board of Directors

The following elements reflect the discussions by WRAP Participants regarding the WPP Board of Directors. These elements provide the thinking of how the Board structure might best serve the WRAP, and all changes to the WPP Board of Directors structure and governance are approved and being put into place. Considerations for Board transition issues are addressed in Section 1.1.1.

1) There will be one independent Board for the WPP. The transition to an independent Board was effective on February 21, 2023.
2) The independent Board will oversee the WRAP as well as the other services already provided by the WPP.
3) The Board will have five voting seats.
4) The NC will identify and recommend individuals for nomination to three-year Board terms. Nominees will be confirmed by the currently seated Directors whose terms are not expiring[3].
5) Directors were previously selected by the Board and seated without term limits.
6) Director's terms will be staggered to maintain continuity.
7) A Director may serve up to two three-year terms which may be served non-consecutively. In the case of initial seats with shorter terms to establish the staggered terms, no Director may serve more than six years total.
8) The WPP Chief Executive Officer (CEO) will be an ex officio advisory member of the Board and may also participate in the RAPC as an ex officio advisory member. The WPP Board may dismiss the CEO for certain discussions.

1.1.1. Board of Directors Transition

To prepare for the governance changes required by the WRAP Tariff, the WPP formed the NC in February 2022 with the purpose of identifying an independent Board of Directors for the WPP. The NC followed a rigorous, continent-wide selection process, including developing selection criteria and a compensation recommendation and partnering with WPP staff to hire executive search firm ZRG. The NC reached consensus on a proposed slate, which was presented to the Board in October 2022. On October 12, 2022, the Board unanimously

[3] See Sections 1.1.1 and 1.2 for additional details including exceptions and special circumstances.

approved a resolution to conditionally approve the proposed slate to become effective and binding on WPP after FERC approves the WRAP Tariff and a requisite number of Participants agree to fund WRAP services.

Consistent with this resolution and the occurrence of the conditions precedent, a new independent Board was seated on February 21, 2023.

1.1.2. Board of Directors Duties Common to all WPP Services

The Board will be governed at a high level by the WPP Bylaws and by a suite of governance documents for more detailed governance issues. WRAP participants and stakeholders reviewing this governance proposal for WRAP were particularly interested in identifying some key considerations for the future functioning of the Board for consideration by the new independent Board. These important considerations, many of which are in practice or already included in WPP bylaws, include a number of practical and common best practices. For example:

1) At all times the Board will act in the best interest of the WPP in its management, control, and direction of the general business of WPP.
2) In reaching any decision, the Board must execute its duties in an unbiased, professional, respectful, and collaborative manner that promotes integrity, teamwork, trust, and a professional work environment.
3) Unless otherwise restricted (see Section 1.1.4), the Board will have full authority to change the WPP bylaws.
4) The Board will have the authority to review the performance of the WPP corporation, its officers, and staff, unless such authority has been specifically delegated to WPP staff. When evaluating the performance or compensation of the CEO, the CEO will be appropriately excluded from deliberations of the other Directors. With respect to duties delegated to WPP staff, the Board may rely on reports from WPP staff but must continue to exercise oversight over those duties.
5) The Board will review and approve the finances of the WPP, including budget, expenses, and projected expenses, to ensure the WPP is financially sound and has the appropriate funding to meet its contract requirements.
6) The Board will review the goals and directions set by the WPP CEO and committees to understand the impact on WPP and its employees, including the impact on longer-term employment for WPP employees, corporate risk, and potential impacts on the structure of the WPP.
7) The Board will ensure the WPP has appropriate insurance for its business operations, Directors, officers, and staff.

8) The Board will ensure the WPP has appropriate retirement funding as established by the corporate retirement plan.

9) The Board will ensure the WPP has appropriate employee benefits as established by the corporate benefit plan.

10) The Board will ensure the WPP is meeting all its legal requirements and that it has sufficient legal resources to support regulatory processes and regulatory filings.

11) The Board will hire the officers of the WPP and address succession plans.

12) The Board will elect from its membership officers consistent with the WPP bylaws.

13) The Board will meet at least three times per calendar year (in-person or virtually). The Board will also meet upon the call of the Chair or upon concurrence of a majority of Directors.

14) Directors will be compensated and be reimbursed for actual expenses reasonably incurred in the performance of their duties.

In addition, and specific to the WRAP, the Board will exercise an appropriate degree of independence from Participants.

1.1.3. Board of Directors Duties for Specific Programs or Functions

The Board will authorize filings with regulatory bodies. With respect to the WRAP, the Board will consider regulatory filings that are recommended to it through the PRC change control process. If the RAPC approves a filing and the filing is not subject to additional procedures with COSR, the filing will be placed the consent agenda for the next Board meeting. During that meeting, any person in attendance can request to have any consent agenda item placed on the regular agenda for discussion and the Board will consider the request. If RAPC disapproves a proposed filing submitted to it for approval, any stakeholder (e.g. COSR participant, RAPC Participant, PRC, member of the public) may ask the Board to entertain that filing despite RAPC's disapproval. Thus, any action, or inaction, taken by the RAPC may be brought before the Board for ultimate resolution.

Upon approval by the Board, the WPP is authorized to submit regulatory filing(s) required to implement that proposal with respect to the WRAP.

Regulatory filings made on behalf of participants in programs other than the WRAP are not subject to this process. For example, participants in the Reserve Sharing Group and Western Frequency Response Sharing Group have named the WPP as their agent for compliance for certain North American Electric Reliability Corporation (NERC) reliability standards. Program governance and committees for these programs are governed by the Northwest Power Pool Agreement, and program decisions are made by these committees, rather than the WPP

Board. The WPP staff will continue to work with these program participants to coordinate such filings, which do not require Board authorization. Agreement, and program decisions are made by these committees, rather than the WPP Board. The WPP staff will continue to work with these program participants to coordinate such filings, which do not require Board authorization.

Board meetings for the WRAP will be open and publicly noticed for all meetings except when in executive session. Executive sessions (open only to Directors and parties invited by the Chair) will be held as necessary upon agreement of the Board to safeguard confidentiality of sensitive information. Matters for consideration in executive session may include personnel, litigation, and proprietary, confidential or sensitive information.

All Board meetings addressing WRAP issues will include a public comment period as well as reports from the PO, the RAPC, the PRC, and the COSR, as appropriate. Additionally, the Board will include a report from the IE at a minimum of one meeting per year. WPP staff will prepare information packages for matters presented to the Board for decision. These packages will include the opinions of the PRC, the PA and PO, COSR, and any stakeholder that has communicated its opinion to the WPP staff via stakeholder comment processes. Opinions on proposals should be presented to the RAPC for deliberation and not raised for the first time before the Board. All written materials which are not privileged or confidential and which are submitted to the Board in connection with a matter subject to discussion at an open meeting will be made available to the public reasonably in advance of a Board meeting.

Any stakeholder may address the Board during open meetings public comment period with respect to WRAP.

On WRAP-related items for Board consideration, a quorum for any meeting of the Board will be two-thirds of the voting Directors then in office. The affirmative vote of a majority of the voting Directors then in office will be the act of the Board. Each voting Director will have one vote. The Board will fix its own time and place for meetings. There will be no restriction on the number of Directors who can attend committee/sub-committee meetings.

1.1.4. Board of Directors Limitations for the RA Program

Regarding the WRAP, the Board will be prohibited from taking certain actions, as noted below:

1) Participants' will retain existing functional control and responsibility over their generation and transmission assets.
2) Participants will retain full autonomy and responsibility to ensure the reliable and efficient planning and operation of their generation and transmission systems.

3) Participants will retain existing autonomy and responsibility over transmission operations and transmission service, including the administration of open access transmission tariff (OATT) requirements and transmission planning functions.
4) Participants will retain full autonomy and responsibility related to the operation of their generation resources, as well as the development of resource plans and ongoing compliance with those plans. This means that the Board will not impose must-offer obligations on any Participant or their resource(s).
5) Participants who administer a Balancing Authority Area (BAA) will retain responsibility for ensuring compliance with applicable reliability standards within their BAA boundaries, and all other reliability standard requirements for applicable NERC functional designations.
6) Participants will retail responsibility for administering OATT service, engaging in BAA operations, imposing transmission planning requirements or assuming any transmission planning responsibilities.
7) The Board will be prohibited from forming an organized market, including a capacity market, or establishing a Regional Transmission Organization, unless such action was also approved by the RAPC.
8) The Board will be prohibited from requiring anything beyond the imposition of financial or consequences, the limitation or suspension of participation, or other similar measures in response to any failure by a Participant to mee the WRAP requirements.

These limitations are reflected in the WRAP Tariff.

1.2. Nominating Committee

The NC will screen and recommend candidates to serve as Board Directors. The NC will be comprised of certain stakeholder representatives as explained below. The NC is also responsible for recommending compensation for the Directors. The NC will work with the WPP staff and any executive search firm retained to identify candidates and recommend compensation.

1.2.1. Makeup of the Nominating Committee

The NC will be comprised of 14 individuals from stakeholder sectors as detailed below:

Thirteen (13) Voting Members:

Two (2): RAPC/Participant Investor-owned Utilities (IOUs)[4]

Two (2): RAPC/Participant Publicly-owned Utilities (POUs)

[4] This category also includes international Participants (e.g., Powerex).

One (1): RAPC/Participant Retail Competition Load Responsible Entity (LRE)

One (1): Federal Power Marketing Administration

One (1): Independent power producers/marketers

One (1): Public interest organizations

One (1): Retail customer advocacy group

One (1): Industrial customer advocacy group

One (1): WPP Agreement Signatory (not on RAPC and not a Market Operator)

One (1): Load Serving Entity (LSE) (or representative) with loads in the WRAP represented by another LRE and otherwise not eligible for any other sector

One (1): COSR (chair or vice chair)

One (1) Non-voting Member: One (1) Director from the Board

Each sector will appoint its representatives to the committee. An entity that qualifies for more than one sector may only participate in and represent one of the sectors. In the event that a particular sector cannot reach consensus regarding its representative, the NC may proceed with normal activities without a fully staffed NC. The minimum term of service will be one year; however, each sector may designate a representative for a multiple-year term at its own discretion.

The two sectors with more than one representative will consider regional, operational, and other forms of diversity representation when selecting the representatives for their sector. If possible, sectors with two representatives shall ensure that representatives come from two different regions:

West Coast: WA, OR, CA

Rockies: MT, WY, UT, ID, SD

Southwest: AZ, NM, NV, CO

International: Canada, Mexico

1.2.2. Selection of NC Representatives

Not less than 150 days prior to the scheduled expiration of any Director’s term, and at other times as may be necessary to fill a vacancy on the Board, the staff of the WPP will work with each sector to ensure it has designated representative(s) for the NC.

The staff of the WPP will issue a public notice that the NC will be convened. The public notice will include a list of the NC representatives. This will allow sector members to self-identify in order to receive communication from the sector organizer.

For any sectors that does not have a currently serving NC representative, WPP staff will designate an organizer from one of the entities in the sector to facilitate the selection of a representative. Each sector organizer must make reasonable efforts to notify all entities that are qualified for participation in its sector about meetings or teleconferences for the sector. These efforts will include issuing, with assistance from WPP staff, a notice no less than seven calendar days in advance of the meeting or teleconference.

The entities in each sector should make their best efforts to amicably resolve any disagreements about which entities belong within the sector and thus are entitled to participate in the sector's selection of a representative to the NC. Any disagreements that cannot be resolved by the sector entities may be referred to the senior management of the WPP for resolution. The CEO (or designee) and the General Counsel will hear from the interested parties and make a decision which will be issued in writing and publicly posted. Their decision will be binding on the sector.

Sector organizers will certify their sector's representative within 40 days. If a sector organizer is unable to make a certification, the Board may select a representative for the sector. The WPP staff will post the name and contact information of each sector representative on its website.

1.2.3. Nominating Committee Operations

The NC will convene no less than 100 days prior to the scheduled expiration of any Director's term to identify potential candidates for each open seat. The NC will convene as soon as practicable when Board vacancies arise unexpectedly.

If a Director whose term is expiring wishes to be nominated for a new term and is still eligible, the NC will determine whether it will re-nominate the Director without interviewing other candidates. If the NC does not re-nominate the Director, then it will ask the executive search firm (hired by WPP) to identify and present at least two additional qualified candidates. The NC will interview the sitting Director and at least two of the additional qualified candidates presented by the executive search firm or nominated by NC representatives or sectors.

The NC will adhere to the following guidelines in its Director selection and recommendation process:

1) The NC will work with WPP staff to direct and coordinate progress with an executive search firm to be retained by the WPP.
2) The NC will identify at least two qualified candidates to interview.
3) A candidate who has a prohibited relationship or financial interest will not be considered unless the candidate commits to promptly end any prohibited relationship after being

appointed and before exercising the duties of the office, and to dispose of any prohibited financial interests within six months after appointment.

4) The NC will develop a job description and job posting with assistance from the executive search firm.

5) The NC will strive to ensure diversity of expertise on the overall Board as a selection criterion. The following skillsets and expertise should be considered:

    a. Electric industry operations and management, including expertise in generation and transmission;

    b. Regulatory, particularly utility and energy regulatory environments; and

    c. General management/leadership/legal/financial experience.

6) The NC will strive to ensure diversity with respect to race, gender, and ethnicity.

7) The NC will strive to ensure geographic diversity and no one state or sub-region should have excessive representation.

8) The NC will strive to ensure that the Board includes at least one Director with expertise in Western electric systems, markets, or utility resource planning.

9) The deliberations of the NC will be confidential. The candidate selection process is highly sensitive and neither candidate information nor details regarding the deliberations of the NC will be shared publicly by NC representatives. NC sector representatives may confer with their sector members regarding the candidates. The NC will coordinate throughout the process regarding the timing and extent to which they will share the names of candidates in connection with a particular search.

10) The NC will meet as required to perform its responsibility, including such open public meetings as the NC determines are beneficial.

11) The NC will strive to achieve full consensus of its members in recommending a Director to the Board. In the event full consensus cannot be obtained, a two-thirds majority of the NC members must be obtained in an appropriate voting procedure to approve recommending a Director to the Board. All seated members of the NC would have an equal vote with the sole exception of the non-voting Director. The non-voting member may share their views about the candidate and otherwise participate fully in deliberations.

Except as otherwise provided here or in other future WPP governance documentation, the NC will establish its own procedures.

1.2.4. Nominating Committee Nominations Process to the Board

The NC will submit recommendations for Directors for approval by the Board. If more than one seat is open, the NC shall recommend a slate for all openings. The Board decisions to be approve or reject such recommendations will be made in public session and the slate shall be approved or rejected as a whole. If the decision occurs before the end of the expiring terms, the Director(s) whose terms are expiring will be recused from the decision.

For example, assuming two sitting Directors' terms are expiring, the NC would convene and select two qualified candidates to comprise the slate of candidates recommended to the Board for approval. The two Directors whose terms are expiring would be recused from the decision, and the three non-expiring sitting Directors would vote on the slate as a whole, either approving or rejecting, in public session.

If the slate is accepted, the nominees will become Directors.

If the slate is rejected, the sitting Directors will provide the NC with an explanation. The NC will re-convene and establish a new slate of nominees, which must not be identical to the prior slate (though the NC may retain one or more nominees from a prior slate involving multiple nominees). After the NC submits its second slate of nominees, the Board will decide, in public session, to approve one of the two slates that was submitted by the NC.

1.3. Resource Adequacy Program Participant Committee

A WRAP Participant is an LRE serving load within the WRAP footprint that has signed the Western Resource Adequacy Participation Agreement (WRAPA).

1.3.1. Resource Adequacy Participant Committee

The RAPC will be comprised of Participants.

The RAPC will be the main forum for Participants to discuss and recommend modifications to WRAP policies, procedures, and systems, including making recommendations for Tariff and business practice modifications to the Board. The RAPC will work in collaboration with the other WRAP working groups, committees, and task forces.

The RAPC can discuss and recommend that the Board approve amendments to the WRAP Tariff. The RAPC can also consider, approve, or reject program rules if such rules solely apply to the administration of the WRAP and have no application to any other program and/or contract service provided by the WPP. To the extent such rules do apply to any other service provided by the WPP, the RAPC will be afforded the opportunity to provide input to the WPP Board to resolve any issues. This will be accomplished by a collaboration with the WPP on the development of WRAP provisions, business practices, and interregional agreements to promote transparency and efficiency in the operation of the WRAP.

The RAPC can evaluate and provide consultation to WPP on the WRAP administration budget and budget allocation to Participants, including modifications or adjustments of the WRAP Administration Rate, in accordance with the WRAPA.

Each Participant will appoint one representative to the RAPC. Each representative designated will be a senior level management employee with financial decision-making authority. The RAPC representatives will appoint a chair and vice chair of the RAPC.

The RAPC will form and organize all the organizational groups needed to discharge its responsibilities. Each working group, committee, or task force reporting to the RAPC will be assigned a WPP staff secretary, who will attend all meetings and act as secretary to the group. Staff secretaries of all working groups, committees, and task forces are non-voting.

The quorum for a meeting of the RAPC or any working group, committee, or task force reporting to the RAPC will be one-half of the representatives of such working group, committee, or task force, but not less than three representatives; provided, that a lesser number may adjourn the meeting to a later time.

In the RAPC, each representative will have one vote which will be weighted in two ways.

The RAPC "House" weighting will weight each Participant representative's vote according to the median of their nine Monthly P50 loads for the last two FS Submittals that have been validated by the PO. The RAPC "Senate" vote will be equally weighted for all RAPC representatives.

For a RAPC voting matter to be approved, it must pass both the House and the Senate vote as follows:

1) Resolutions brought to the RAPC with support from the PRC will be approved with 67% affirmative votes of both House and Senate vote tallies.
2) 80% affirmative vote to modify the limitations on board authority noted in Section 1.1.4.
3) All other votes will require a 75% affirmative vote of both House and Senate tallies.
4) If at any time, a single LRE holds more than 25% of the House weighting, such a participant's vote will be capped at 1% less than the amount at which they would have create such a veto.

Table 1-1. Example of House and Senate style voting approach.

Entity	P50 in Megawatt (MW)	P50 (House) Weighting	Vote
A	1500	3.07%	No
B	9000	18.42%	Yes
C	400	0.82%	Yes
D	2200	4.50%	Yes
E	850	1.74%	No
F	3500	7.16%	Yes
G	11000	22.52%	Yes
H	4200	8.60%	Yes
I	8700	17.81%	Yes
J	7500	15.35%	Yes
Total P50 Load (MW)	48850	100%	N/A
House Tally (P50 weighting)			95%
Senate Tally (Equal weighting)			80%

In the example presented in Table 1-1, the vote passes. For the Senate tally, which equally weights all Yes votes, the result is 80% affirmative. For the House tally, which weights all Yes votes according to the P50 load, the result is 95% affirmative. This is higher than the Senate tally because the two dissenters are smaller LREs. If another entity (of any size) were to vote "no," the vote would pass for a PRC-approved vote but fail for any other vote, as the Senate tally would drop to 70% affirmative, which is below the 75% required threshold. Similarly, if entity G dissented instead of entity E, the vote would pass for a PRC-approved vote but fail for any other vote, as the Senate tally would drop to 72.67% affirmative the vote, below the 75% threshold. Note that RAPC support requires affirmative votes to tally – absences and abstentions do not impact the number of affirmative votes required for an issue to gain RAPC support, although absences and abstaining votes are counted as no votes.

This House and Senate voting process will only apply to the full RAPC. Working groups, committees, or task forces formed by the RAPC will act by simple majority votes with each member having an equally weighted vote.

The RAPC is the highest level of participation for WRAP Participants. The Board will provide independent oversight of the WPP's administration of the WRAP under the WRAPA and may interact directly with any of the WRAP committees at their Board meetings.

Meetings of the RAPC will consist of both open and closed meetings. Closed meetings are limited to RAPC members as well as a representative(s) of the COSR, as described in Section 1.6.1. Open meetings are open to all interested parties; and written notice of the date, time, place, and purpose of each meeting will be publicly provided in advance. RAPC decisions items will only be conducted in open meetings that are properly noticed to provide sufficient time for deliberations and public comment.

1.3.2. Participant Withdrawal and Termination

Participation in the WRAP is voluntary, subject to the terms and conditions of the WRAPA and the Tariff. There are three ways that a Participant may leave the program: Normal Withdrawal, Expedited Withdrawal, and Expulsion.

1) Normal Withdrawal: A Participant may withdraw from the WRAP by providing written notice to WPP no less than twenty-four months prior to commencement of the next binding FS Program period. The first day of the next binding FS Program period is the “Withdrawal Date” The time between the notice of intent to withdraw and the Withdrawal Date is the “Withdrawal Period”.

    a. During the Withdrawal Period, all terms and conditions of the WRAPA, other than voting as explained in subitem c below, will remain in effect with respect to the withdrawing Participant, including provisions of the FS Program and Operations Program and obligation to pay all costs associated with the WRAP.

    b. All financial obligations incurred prior to and during the Withdrawal Period are preserved until satisfied.

    c. During the Withdrawal Period, the withdrawing Participant is not eligible to vote on any actions affecting the WRAP that extend beyond the Withdrawal Period.

2) Expedited Withdrawal: A Participant may withdraw from the WRAP with less than the required twenty-four-month notice as set forth below. The Withdrawal Date will be determined at the mutual agreement of the withdrawing Participant and the WPP.

    a. Involuntary Expedited Withdrawal: A Participant may request a withdrawal with less than 24 months’ notice (“Expedited Withdrawal”) if there is an extenuating circumstance that requires their withdrawal with shorter notice (“Extenuating Circumstance”). The Participant’s request for Expedited Withdrawal must be submitted in writing to the WPP, explaining the Extenuating Circumstance and specifying the Participant’s desired Withdrawal Date. The Board will review and confirm the Extenuating Circumstance, the Expedited Withdrawal, and the Withdrawal Date. The withdrawing Participant must work cooperatively with the WPP to minimize the impact of the Expedited Withdrawal on other Participants and WPP. All financial obligations of the withdrawing Participant shall remain in effect until satisfied. Circumstances that may appropriately precipitate an expedited are:

i. A governmental authority takes an action that substantially impairs the participant's ability to continue to participate in the WRAP.

ii. Continued participation in the WRAP conflicts with governing statutes or other applicable legal authorities or orders.

iii. Composite or aggregated data is released which the Participant believes harms the Participant in some material way (pursuant to further detail provided in the Tariff). This is only applicable if the Participant (1) voted against the RAPC determination to release such data, and (2) disagreed with the Board decision to release such data. This right must be exercised promptly after the first time the Board determines that the form and format of aggregated data sufficiently protects against the release of confidential or commercially sensitive Participant data. Failure to exercise this right promptly constitutes a waiver of the right to expedited withdrawal for any future disclosures of composite or aggregated data in the same or substantially similar form.

iv. FERC, or a court of competent jurisdiction, requires the public disclosure of a Participant's confidential or commercially sensitive information, provided however that such right to expedited withdrawal is exercised promptly upon the exhaustion of all legal or administrative remedies aimed at preventing the release.

b. No-Harm Expedited Withdrawal: A Participant may also request an Expedited Withdrawal if the impact of Participant's withdrawal on WRAP operations can be calculated with a high degree of confidence and the Participant pays an exit fee, the calculation of which will be made by the WPP. Such exit fee will 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 FS 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 financial loss incurred by other Participants due to the voluntary Expedited Withdrawal.

c. Tariff Section 3.4 Amendment Expedited Withdrawal: In the event that amendments to Section 3.4 of the Tariff (limiting the scope of the program and the actions the Board can take – as detailed in Section 1.1.4) 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 satisfies all obligations in the FS Program and Operations Program and satisfies all other financial obligations incurred prior to the date that the changes will be made effective by FERC.

3) Expulsion: The Board, in its sole discretion, may terminate any Participant's participation in the WRAP and terminate its WRAPA for cause, including but not limited to material violation of any WPP rules or governing documents or nonpayment of obligations. The Board would provide any Participant reasonable notice of a contemplated expulsion and afford that Participant a reasonable opportunity to cure the situation to the Board's satisfaction. Any expulsion would only take effect after an affirmative vote consistent with the Board's standard voting procedures.

1.4. Program Operator

The WPP has engaged Southwest Power Pool (SPP) as the PO, providing implementation services for the WRAP. As a Regional Transmission Organization operator, SPP has market and utility operations expertise appropriate to support 24/7 WRAP program deployment. WPP and SPP have executed a contract which accounts for review of scope and services every five years, but which is expected to be a lasting relationship upon which this enduring resource adequacy program.

The PO role (and its relation to the WPP) will be as follows:

1) The PO will contract with WPP and report directly to the WPP Board.

2) The WPP will retain administrative responsibility for the WRAP, including legal and federal regulatory obligations including meeting all the functions required of a public utility. The WPP will also be responsible for billing, collection, and payments under the WRAP.

3) While the WPP will retain the responsibility for ensuring the proper management of the WRAP, it is expected that the PO will be responsible for managing certain aspects of the FS and Operations activities under contract and at the direction of the WPP. These will include:

    a. Modeling and system analytics

    b. Loss of Load Expectation study to derive the Planning Reserve Margin

    c. Analysis of qualifying capacity contributions

    d. Forward Showing Assessments

    e. Methodology for calculating and verifying P50 values

    f. Necessary technology design and implementation

g. Forward Showing and Operational Program design refinement
h. Monitoring of and responding to real-time operations
i. Calculation of required settlements
j. Assessment of charges for noncompliance
k. Maintenance of technology resources

4) The PO will support the RAPC and other committees to provide comments, input, solutions, and problems. The PO also could be asked to provide input to the WPP Board.

1.5. Independent Evaluator

The IE is an important element of a well-functioning regional RA program. The IE will provide an outside, independent assessment of the performance of the program. The IE will be established before the conclusion the non-binding stage of the WRAP and will provide an annual review of the WRAP. The scope for the IE could change over time as needed.

The IE is charged with the following responsibilities and limitations:

1) Once per year, analyzes operations, accounting/settlement, and design of program and makes recommendations for changes in a written evaluation report;
2) Does not monitor WRAP Participants;
3) Does not have decision-making authority; and
4) Reports their findings to all WRAP committees (subject to confidentiality considerations).

The IE will not have any day-to-day operations responsibilities for the WRAP (these are maintained by a combination of the PA and PO). Independent program monitoring and evaluation must be transparent, but the IE will be expected to adhere to data confidentiality processes established for the WRAP. A non-confidential version of the IE's annual report will be made available to the public.

The IE will be an outside entity to be recommended and hired by the WPP following approval by the Board and will report directly to the Board.

1.6. Other Committees and Structural Functions

1.6.1. Committee of State Representatives

The Committee of State Representatives (COSR) is comprised of state representatives, either from the public utility commission or state/provincial energy office, at each state's discretion. There should be one representative from every state/provincial jurisdiction that regulates one or more WRAP Participant(s). The COSR will determine its leadership, including a chair and vice chair. The chair or vice chair of COSR will be requested to attend open sessions of the RAPC and to provide input and advice. In addition, the COSR shall assign an independent COSR support staff member(s) to attend and audit closed meetings of the RAPC under a non-disclosure agreement.

There will be an enhanced process for COSR engagement in RAPC decision-making under certain circumstances. If the COSR determines that a proposal approved by RAPC is substantively different from the proposal submitted to the RAPC by the PRC (on which the COSR will have provided comments – see Section 1.6.2 for more information), the COSR can call for additional public review and comment before a RAPC recommendation goes to the Board. Such call for additional review will be made in a timely manner so that decision-making for the WRAP is not unreasonably delayed (i.e., no more than 14 calendar days). The COSR may also formally opposes or appeal a RAPC's recommendation to the Board. If this occurs, the RAPC will be required to engage with the COSR, including at least two discussions to attempt to reach a mutually agreeable solution. These discussions will be open meetings with public notice provided and may be held virtually or in person. The COSR may determine additional procedures for conducting these discussions.

Support provided to COSR will be determined in collaboration with state regulators using a collaborative approach between WIEB and the WPP. In August 2022, WIEB and the WPP entered a Memorandum of Understanding (MOU) setting forth the understanding for how the WPP will support WIEB to receive funding to provide the technical expertise, staff resources, and office space necessary to support the ongoing efforts of the COSR. The milestones and actions of the MOU include:

1. By end of year 2022, WPP will convene and collaborate with state-regulated WRAP Participants subject to the compliance requirements of WRAP to discuss potential terms and conditions for funding provided to WIEB;
2. By end of Q2 2023, the WPP will endeavor to complete a draft term sheet; and

3. By end of 2023, WIEB and the WPP will work together to identify and complete whatever agreements are necessary to effectuate the funding and service provisions identified in this MOU.

In the event the WPP pursues the expansion of the WRAP to include market optimization or transmission planning services, the WPP will conduct a full review of governance structures and procedures, including the role of states in cooperation with the COSR and other WRAP committees. If the COSR does not support any revised governance structure approved by the Board, the WPP agrees to file an alternative COSR-supported governance structure with its filing at FERC. Any such alternative governance structure must obtain at least 75% support from COSR representatives.

1.6.2. Program Review Committee

The PRC is a multi-sector stakeholder committee charged with receiving, considering, and proposing design changes to the WRAP. The PRC will act as the clearing house for all recommended design changes not specifically identified as time-sensitive or of high RAPC priority (see below). Recommended changes may come from Participants, the COSR, the Board, other committees, stakeholders, or the public. Figure 1-1 provides an overview of the PRC process.

The PRC will be provided with facilitation support from the WPP and program design/technical support from the PO. If a stakeholder wishes to request changes to the WRAP, the stakeholder should submit a written explanation of the requested change, including any supporting information or data, to the PRC via the WPP's website.

PRC will review and prioritize requested changes into a draft work plan (suggesting which proposed changes will be developed into full recommendations for review by all committees) and a schedule for such development; the workplan will be reviewed by all WRAP-related committees and the public before being approved by the Board (see Figure 1-1).

The PRC will identify task forces to refine requested changes into full proposals for program updates, working with the PRC and the WPP and PO staff (see Figure 1-2). Proposals will be reviewed by WPP, the COSR, the PO, stakeholders, and the public at large, providing comments and recommendations to inform the proposal before being considered for approval by the WPP Board of Directors (see Figure 1-3).

The PRC will primarily have open meetings for taking public input and comments. During the WRAP non-binding stage, the PRC will refine this process for reviewing and proposing changes.

The PRC will be comprised of members from the following sectors[5]. Each sector will appoint its own representatives.

1) Four (4): RAPC Participant IOUs[6]
2) Four (4): RAPC Participant POUs
3) Two (2): RAPC Participant Retail Competition Load Serving Entity
4) Two (2): RAPC Participant Federal Power Marketing Administration
5) Two (2): Independent power producers/marketers
6) Two (2): Public interest organizations
7) One (1): Retail customer advocacy group
8) One (1): Industrial customer advocacy group
9) One (1): LSE, or designated representative, with loads in the WRAP represented by other LREs and is otherwise not eligible for any other sector
10) One (1): COSR (chair, vice-chair, or designated representative)

Sectors with more than one representative should strive for regional, operational, and other forms of diversity representation. The two- and four-seat sectors shall ensure that their representatives come from two or four different geographic regions, respectively. The four geographic regions for this purpose are grouped as follows:

1) West Coast: WA, OR, CA
2) Rockies: MT, WY, UT, ID, SD
3) Southwest: AZ, NM, NV, CO
4) International: Canada, Mexico

The PRC will endeavor to operate by consensus, but votes may be taken if a proposal needs to be acted upon and full consensus has not been reached. PRC voting will be by sector and proposals will be affirmatively approved for recommendation to the RAPC with the affirmative vote of five (5) or more of the sectors.

1) For sectors with four seats, three out of four representatives must approve for the sector to be considered to be in favor of the action
2) For sectors with two seats, two out of two representatives must approve for the sector to be considered to be in favor of the action

The PRC will present all proposals to the RAPC regardless of the PRC's recommendation; the PRC will provide the RAPC with their final version of the proposal, all feedback received,

[5] PRC members may include representatives of trade groups serving the identified sectors.

[6] This category also includes international LREs (e.g., Powerex).

summaries of public comments and feedback providing during public meetings, along with their own recommendation. The PRC may also provide both minority and majority opinions. Proposals submitted to the RAPC affirmatively recommended by the PRC will pass the RAPC and be recommended to the Board with a lower voting threshold of 67% approval from both house and senate tallies, while proposals not recommended by the PRC will require a 75% RAPC approval for both tallies to be recommended to the Board in contradiction to the PRC recommendation.

The PRC will develop a code of conduct for member participation. Membership on the PRC will require, at minimum:

1) Representing their sector and working in the best interests of the regional program;
2) Communicating with their sector to ensure accurate representation of the sectors' needs and concerns;
3) Consistent attendance and engagement at PRC meetings by the identified PRC representative; and
4) Collaboration with other PRC members to propose feasible, reasonable design changes in a timely manner.

Exigent design changes (e.g., those mandated by FERC order, those with immediate reliability impacts, those with significant impacts to utility service) may utilize an expedited review process. In these circumstances, the RAPC will work with the WPP to prepare the design change and may recommend such change directly to the Board. The PRC, COSR, and public could participate and comment directly with the Board on such time-critical proposals. This process is outlined in Figure 1-5.

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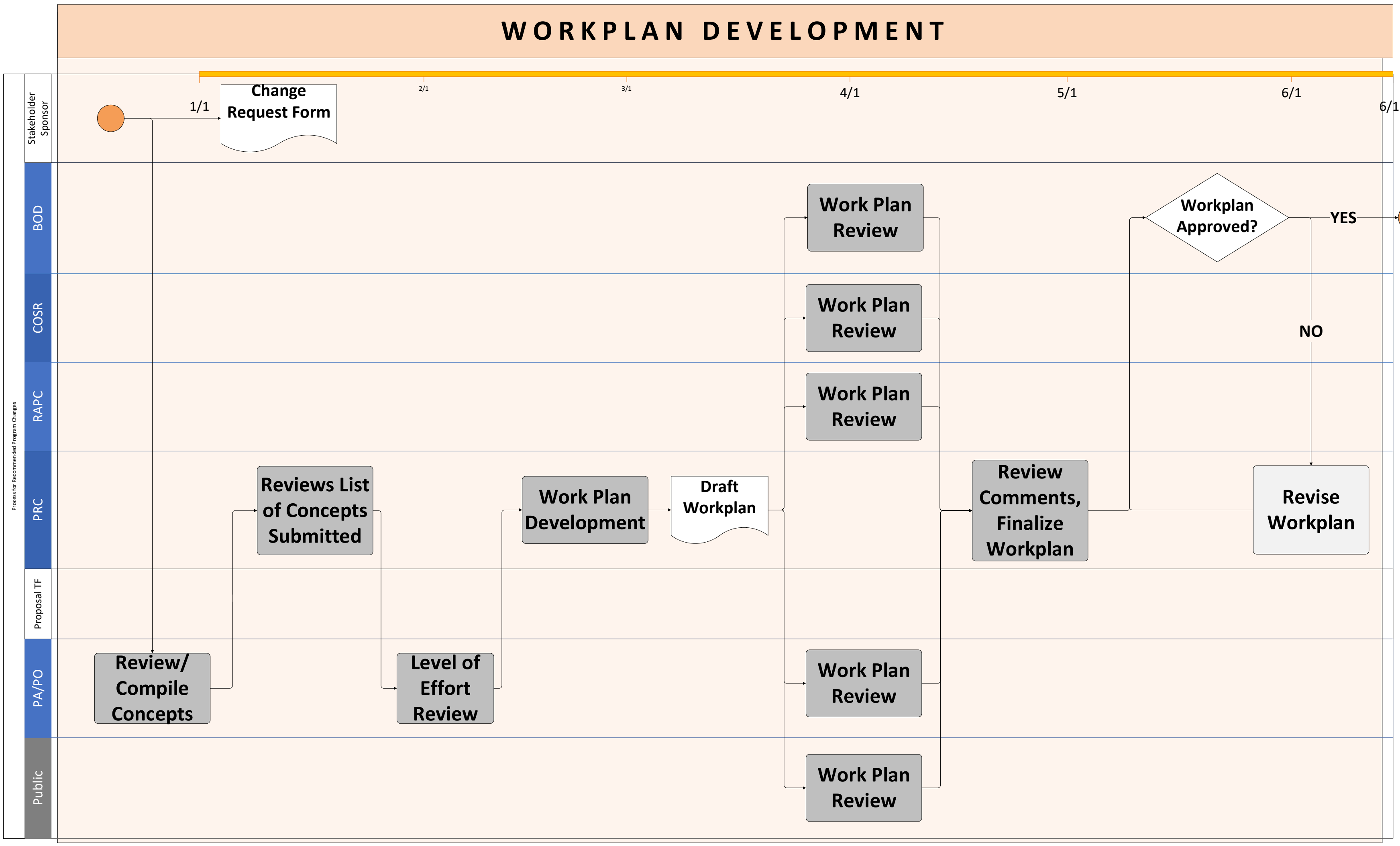

Figure 1-1. PRC workplan development process. With support from the PA and PO, the PRC will receive recommended updates to the WRAP tariff and/or business practice manuals throughout the year. Annually, the PRC will review and prioritize the recommendations and propose a workplan (with schedule) for developing recommendations into change proposals. The draft workplan will be provided to stakeholders for comment before being approved by the Board.

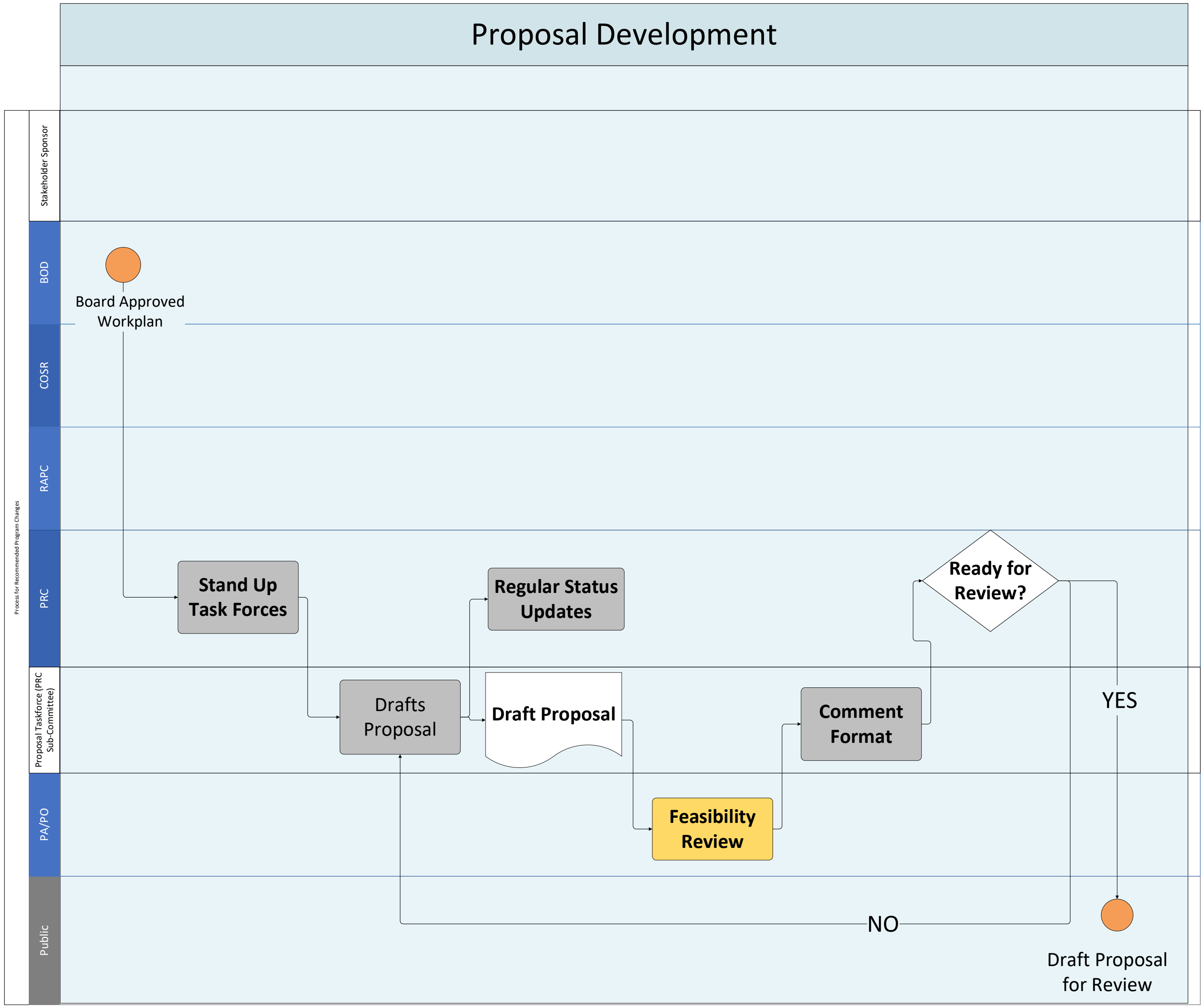

Figure 1-2. Proposal Development. The PRC will manage development of recommended changes in to full proposals, utilizing task forces and support from the PA and PO.

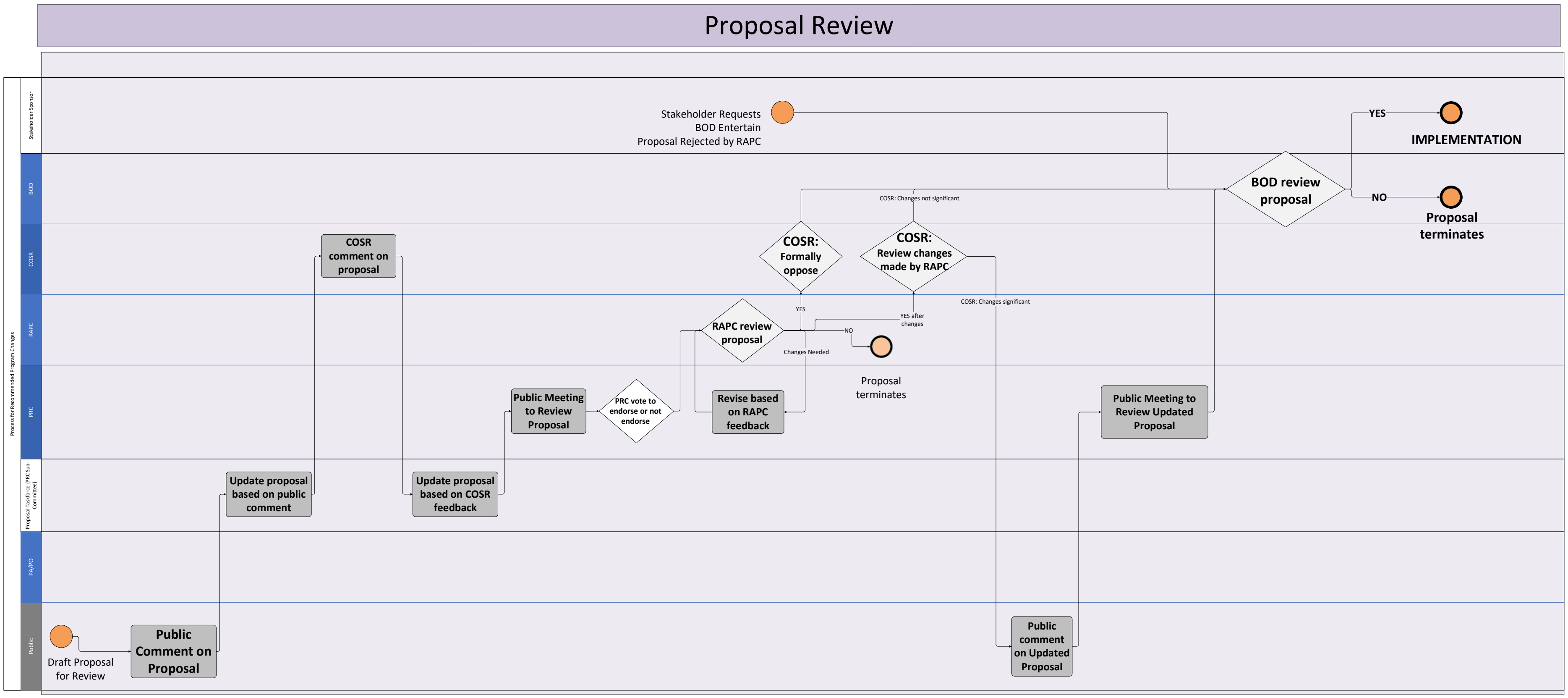

Figure 1-3. Proposal Review. Proposals are reviewed by the public, COSR, PRC, and RAPC before being considered for approval (or disapproval) by the Board. The COSR has unique opporunities to consider any changes made by RAPC make recommendations to the Board or require an additional round of public comment (more details on these COSR rights can be found in the Tariff).

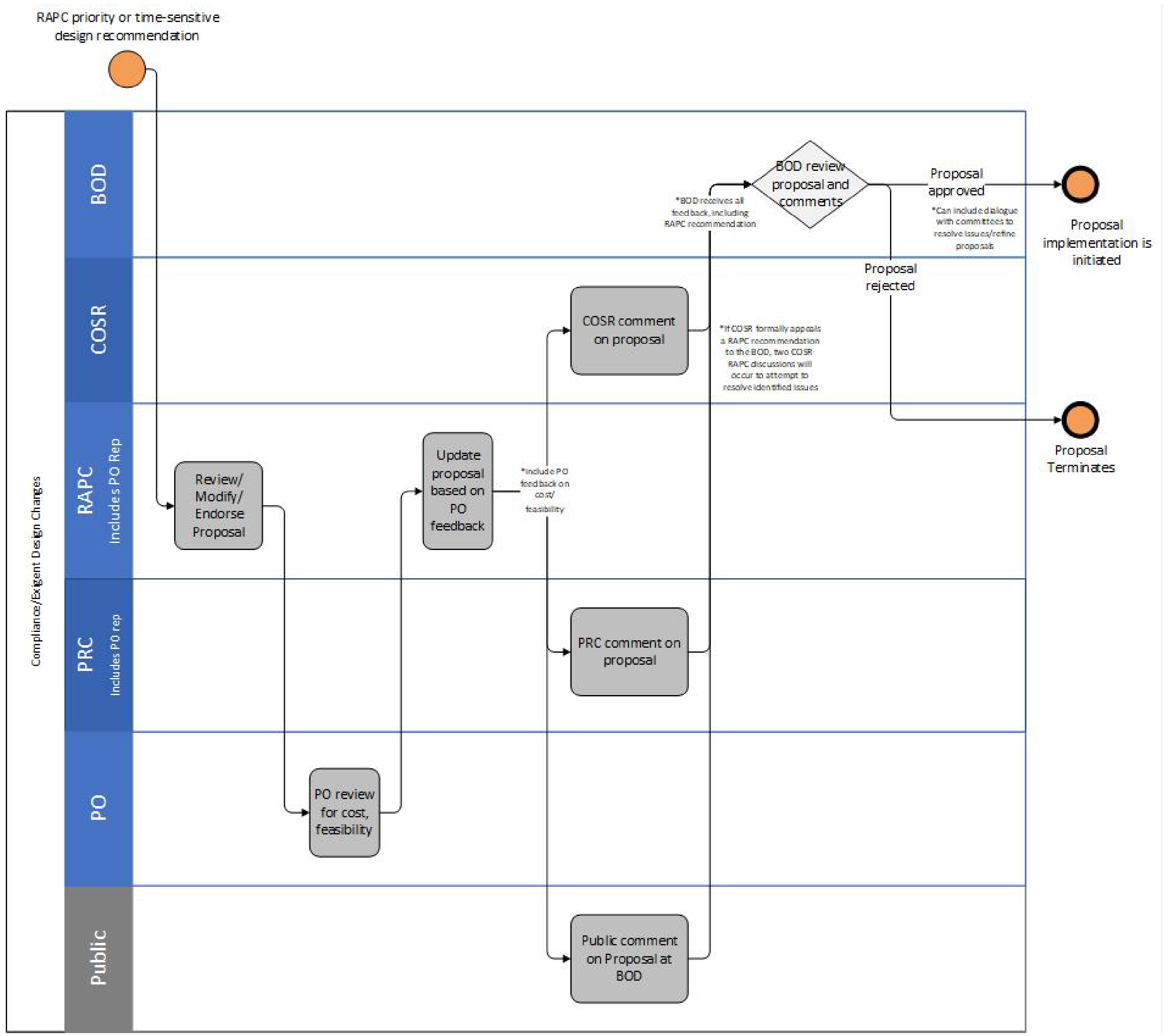

Figure 1-4. RAPC expedited process.

1.6.1. Additional Subcommittees and Work Groups

Each committee may establish subcommittees, work groups, or task forces (or similar groups) as it determines are necessary or efficient for addressing issues or tasks within the committee's purview. These subcommittees (and similar groups) will meet and perform their assignments in the manner of their choosing. Each parent committee retains the ultimate authority and accountability for its assigned responsibilities.

1.7. Cost Allocation

1.7.1. Allocating Costs to the WRAP Participants

WPP costs to administer and operate the WRAP (WRAP Administration Charge) will be paid by the WRAP Participants. The costs will be allocated between base costs (Base Costs), load costs (Load Costs), and dual benefit costs (Dual Benefit) as described in Table 1-2.

Table 1-2. Cost Allocation for Participants.

	BASE COSTS	LOAD COSTS	DUAL BENEFIT
Program Administration (non-participant)		100%	
Program Administration (Participant engagement, RAPC facilitation)	100%		
WRAP portion of WPP Board costs			50%/50%
Program Operations Staffing and Overhead		100%	
Program Operations Technology		100%	
Legal Services		100%	
Independent Evaluator		100%	

The WRAP Administration Charge will include an initial assessment to provide an operating reserve of about 6% of the expected annual WRAP Administration Charge. This reserve will reviewed annually and adjusted as necessary to refund excess or collect additional shortfalls in the reserve.

The Base Costs plus half of the Dual Benefit Costs (Base Charge) will be charged to Participants evenly on a monthly basis. The Load Costs plus the other half of the Dual Benefit Costs (Load Charge) will be charged to Participants each month and will be allocated based on the Participants' Median Monthly P50 Peak Load.

The maximum annual Base Cost collected by the WPP will not exceed $59,000/year and the maximum annual Load Costs collected by the WPP will not exceed $199/MW. These rates are included in Schedule 1 of the Tariff (where additional information about cost allocation can be found) and are expected to be somewhat conservative. The WPP will provide three-year estimates of WRAP budgets, the allocation between the three charge types, and the charges expected to be assessed to each Participant over that period for participants informational purposes.

The WPP will also maintain working capital reserves equal to nine-twelfths of the expected annual PO costs; this is necessary to ensure WPP is able to make timely payment of the annual payment to SPP for program operator support. These reserves will be allocated and collected from Participants in the same manner as the Load Charge (based on their share of the total Participants' Median Monthly P50 Peak Load). The WPP will maintain an accounting of the working capital reserves on hand and may assess additional charges to the Participants to replenish the reserves as necessary.

WPP Western Resource Adequacy Program Detailed Design

Section 2. Forward Showing

MARCH 2023

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SECTION 2. FORWARD SHOWING DESIGN: TABLE OF CONTENTS

FORWARD SHOWING PROGRAM DESIGN

The Western Power Pool's (WPP) Forward Showing Program (FS Program) is the forward-looking planning portion of the Western Resource Adequacy Program (WRAP). This includes the Advance Assessment that determines a regional planning reserve margin (PRM) and sets the Qualified Capacity Contribution (QCC) for each resource and capacity type.

The FS Program objective is to ensure the WRAP footprint has sufficient capacity to adequately serve the projected peak load under a variety of possible scenarios. The FS Program uses a Loss of Load Expectation (LOLE) threshold of one event day in 10 years where capacity is inadequate to meet load plus contingency reserves (CR), which will determine the FS Planning Reserve Margin (FSPRM) that will be applied for each of the months in the Binding Seasons.

Participants demonstrate their resource adequacy in the FS Program by providing their projected load and resource portfolio data to the WPP who will review the submittals to validate that all Participants have sufficient capacity resources to meet the capacity planning standards of the FS Program. If a Participant is not compliant with the FS capacity requirements, they will be afforded an opportunity to cure the deficiency and then charged a deficiency payment if they do not cure the deficiency. A snapshot of the detailed design is presented in Table 2-1.

Table 2-1. Snapshot of detailed design, additional detail on the FS Program is found in the materials that follow.

WPP WRAP FS Program Snapshot	
Participant Responsibility	Participants will continue to be responsible for determining what resources and products to procure from other Participants or suppliers.
Compliance Periods	Two binding seasons: Summer and Winter.
FS Deadline	FS deadlines will occur seven months in advance of the start of the binding seasons, with a two-month cure period from notification of any deficiency by the Program Operator (PO).
PRM	Monthly PRMs will be determined as part of the Annual Assessment for each of the months in the Summer and Winter seasons and expressed as a percentage of the monthly 1 in 2 peak (P50) load forecast of the Participant. See Appendix A-F for more information on Annual Assessments.
QCC	The QCC determined for each resource. The methods for determining the QCC for different resource types is detailed in this Section 2 of the Detailed Design Document.
Transmission	Firm resources must have sufficient transmission to support their claimed capacity in the FS Program. Resources, including contracted imports must have at least 75% of assigned QCC secured as firm transmission from generating source to load.
Payment for Non-compliance	Deficiency payment for non-compliance is based on cost of new entry (CONE) of a new peaking gas plant.

1.1. SHOWING AND COMPLIANCE TIMING

Advance Assessment -The purpose of the Advance Assessment is to determine the FSPRM for each of the WRAP subregions for each month of the Binding Seasons being analyzed. Participants will provide load, resource, and other data to the WPP to support the Advance Assessment. Data collection is expected to be performed annually at the beginning of each year for both upcoming (Winter and Summer) studies. The Advance Assessment will be completed and shared with participants no later than 12 months prior to the FS Deadline. The Board will review and approve the recommended subregional monthly FSPRM values no later than 9 months prior to the FS Deadline

Forward Showing: Seven months ahead of the start of each Binding Season (see Table 2-2 and Figure 2-1, Participants will submit their FS Submittal, which will include their projected peak loads, resources, and firm transmission information for the months of such Binding Season along with supporting information as required to facilitate validate the projections. The peak loads and the QCC for the resources will be determined in accordance with the FS Program rules.

Table 2-2. Compliance seasons and deadlines.

Season	Duration	FS Deadline	Cure Period
Winter	Nov 1– Mar 15	Mar 31	Jun 1-Jul 31
Summer	Jun 1– Sep 15	Oct 31 (Of prior year)	Jan 1 – Feb 28

The WPP will review the FS Submittals and will notify Participants within 60-days following the FS deadline i) of the Participant's FS Capacity Requirement and Transmission Requirement, ii) affirm that the Participant's QCCs exceed the FS Capacity Requirement or notify them of a deficiency, and iii) affirm that the Participant's FS Transmission and Monthly Transmission Exceptions exceed the FS Transmission Requirement or notify them of a deficiency. Participants notified of any deficiencies will have 120 days from the FS deadline or 60 days from such notification, whichever is later, to cure the deficiency without incurring and noncompliance charge. In order to cure the deficiency, the deficient Participant will submit revisions to their FS Submittal.

Participants that fail to revise their FS Submittal in such a way to cure a deficiency will be assessed the FS Deficiency Charge.

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MODELING PROCESS TIMELINES

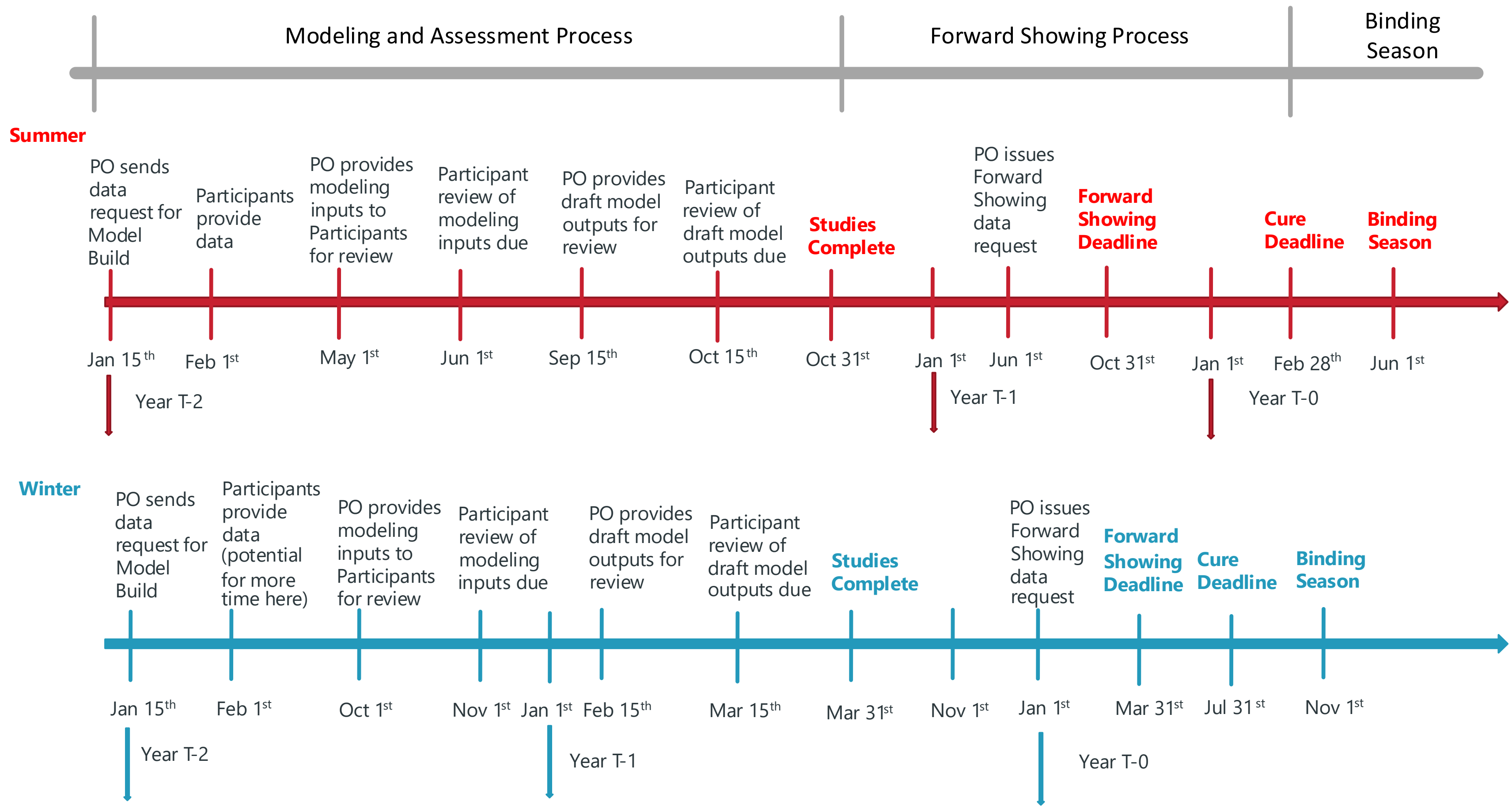

Figure 2-1. Program timeline, including binding Summer and Winter periods, FS deadlines, and cure periods. Non-binding Spring and Fall periods included for reference.

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WRAP Program Metrics

2.1.1. FS Planning Reserve Margin

The FSPRM is obtained through probabilistic LOLE analysis and represents the amount of dependable capacity needed in excess of the P50 load forecast to meet periods of high demand, resource outages, and other variable conditions while maintaining the WRAP's reliability threshold of one failure to meet load in a ten-year period (see Appendix B). The FSPRM is expressed as a percentage multiplier (e.g., 12%) that is applied to the P50 Peak Load forecast.

The FSPRM is applied to the P50 load forecast of each Participant to set the amount of qualified capacity expressed in megawatts (MW), needed to meet the reliability standard each month of the Binding Season[7]. The FS Program uses a hybrid approach, applying Effective Load-Carrying Capability (ELCC) for Variable Energy Resources (VERs) and Energy Storage Resources (ESR), Unforced Capacity (UCAP) for traditional generators, installed capacity (ICAP) for demand response (DR), and a stand-alone methodology for storage hydro for modeling the capacity of resources to determine the FSPRM (as discussed in Appendix C). The intent of the capacity modeling approach is to represent resources with respect to their availability. This approach to calculating the FSPRM is known as the UCAP PRM methodology[8]. The FSPRM for the FS Program will be a UCAP value. The approach will identify the total capacity required to meet the 1-in-10 LOLE objective for the WRAP footprint.

The FSPRM for each month will be determined and expressed as a additional percentage of the P50 monthly peak of the aggregated load across the WRAP subregion footprints. The FSPRM is equivalent to the aggregate amount of capacity in excess of the P50 load forecast needed within the WRAP footprint.

The FSPRM can be represented by the following formula:

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[7] The calculation of the FSPRM includes an embedded assumption of the allocation of CRs but regulating reserves and other BAA-specific reserves will not be included in the FSPRM calculation. In accordance with North America Electric Reliability Corporation (NERC) Standard BAL-002-WECC-2a, BAAs in the western interconnection are required to carry CRs equal to three percent of hourly integrated load plus three percent of hourly integrated generation. In the FS capacity requirement, the allocation of CR to each Participant will require a calculation of each Participant's position regarding import and export transactions. Participants with a net import position will necessarily carry a lower capacity requirement than Participants with a net export position. See Appendix A.1 Planning Reserve Margin for additional information.

[8] Alternative to a UCAP FSPRM methodology would be the ICAP method, which bases the FSPRM on the maximum tested capability of the generation of the Program.

$$\boldsymbol{FSPRM}\ (\%) = \frac{\boldsymbol{LOLE\ Capacity\ - P50\ Load}}{\boldsymbol{P50\ Load}} * \mathbf{100}$$

Where:

FSPRM = the FS Planning Reserve Margin for a specified month in the Binding Period
LOLE Capacity = The Capacity required to meet the one outage in ten year reliability planning standard
P50 Load = The P50 Peak Load forecast for the specified month

2.2. Load Forecasting

Participants will provide their forecasted seasonal peaks as well as their historic load data (10 years of hourly data, adjusted for curtailed loads, deployed DR, and known incremental energy efficiency measures not already captured)[9] to the WPP for both the Advanced Assessment and for the Forward Showings. The methods for determining the P50 Peak loads are described below.

Advanced Assessment - For the Advance Assessment, the following method will be used to forecast each Participant's loads:

1) Use the median of each year's peak load by month for the prior five years and apply a program-wide annual growth rate of 1.1% to all participating Load Responsible Entities (LREs)[10].

2) For the LOLE study, the load will be varied based on historical information; small changes to the load forecast utilized will have minimal impact on the actual FSPRM output from the modeling exercise.

3) This load forecast will not limit or determine the load to be used for the Participant's FS submittal.

[9] Participants will also provide relevant forward-looking data and forecasts for the applicable study horizon timeframes on either a monthly or seasonal peak basis, supported by evidence, to help inform the PO's evaluation of the Participant's load forecasting methodology. There will be an established process for Participants to resolve disputes/discrepancies with the PO's review of load forecast.

[10] 1.1% was identified by an informal survey of published load growth and demand projections from ten participating LREs as well as publicly available load forecast information from the Northwest Power and Conservation Council and other groups. Values ranged from –0.6% to +4.5 load growth.

Forward Showing - For the FS Submittals, each Participant may forecast their seasonal P50 Peak Loads according to one of the two following methods at their election. The Participant should clearly indicate in their FS Submittal which method was used.

<u>Method 1: Base Load Plus Established Growth Rate</u>

Use the median peak load of the previous five years, with any additions and removals of load in the historical record and with any known additions and removals of load in the forecast window. The reasons for additions or removals of load should be validated with supporting information.

Established program-wide growth rates will be determined by the WPP for regions that account for geographic differences, entity type, customer makeup, weather and other key factors that might cause Participants to have similar growth rates. The details of this methodology for determining established growth rates will be developed by the Program Review Committee (PRC) and follow the appropriate approval process. Any Participant using this method to calculate their forecasted peak loads would not be subject to validation or revisions by the WPP.

Participants may still use their own separate methodologies for forecasting loads in their IRP or other infrastructure planning processes.

<u>Method 2: Participant Alternative Growth Rate</u>

If a Participant believes that Method 1 does not accurately reflect their anticipated peak loads, they may request an alternative growth rate to be validated by an independent entity, likely the Program Adminstrator, PO, or the Independent Evaluator (to be determined during drafting and review of BPMs).

The independent entity will evaluate the alternative growth rate against a set of principles developed by the PRC and stakeholders. These might include things like

1) Objective, robust and have a data-driven basis
2) Includes weather adjusted input data
3) Includes factors that are relevant to determining peak load (economic growth, climate etc.)

Method 2 should only be used only when:

1) The proposed growth rate produces a peak load forecast that is higher or lower than the peak load forecast resulting from the default load forecast by at least 5%; and

2) The requesting Participant covers the additional program costs incurred to review and implement Method 2 on their behalf.

Demand Response or other Load Modifiers are handled separately as specified in Section 2.4.

Monthly Load Forecasting Process - Using P50 peaks of each month (versus the P50 peaks of each season) may understate the load forecast of each Participants. This is common among Participants that peak in different months of the season depending on the year. To protect against understated load forecasts, a seasonal peak will be calculated and the forecasts for the off-peak months will be determined using a 'forecast ratio'.

The following process is followed to determine the 'forecast ratio'.

1) Take the Participant 5-year historical load shape data (8760 hour data).
2) Determine the Seasonal Forecast using one of the two methods above
3) Capture the monthly peak from each month of each year.
4) Determine the average peak for each month.
5) Determine the peak month.
6) Calculate the load forecast ratio by apply the average peak of the peak month to the average peak of the month of interest. For example, the peak month will have a forecast ratio of 1.0. The second highest month may have a forecast ratio of 0.95 while the third highest month may have a forecast ratio of 0.92, etc. etc.
7) Once the ratio has been determined for each month, the ratio is applied to the seasonal peak forecast (P50 seasonal) peak forecast to calculate a monthly forecast (See Table 2-3).

Table 2-3. Monthly Load Forecasting.

Month	Average peak (month)	Max Average peak month of season	Forecast ratio	FS P50 load based on 2448 MW seasonal forecast
Jan	2361	2361	1	2448
Feb	2337	2361	0.99	2423
Mar	2027	2361	0.86	2101
Nov	2084	2361	0.88	2161
Dec	2196	2361	0.93	2277

2.2.1. Participant FS Capacity requirement

A Participant's FS Capacity Requirement is their forecasted monthly P50 load during the binding season multiplied by 100% plus the applicable monthly FSPRM according to the following equation:

$$\boldsymbol{Monthly\ FS\ Capacity\ Requirement = Monthly\ P50 * (100\% + Monthly\ FSPRM)}$$

Where:

Monthly P50 = Expected load for the month in question as determined by the Load Forecasting methodology

Monthly FSPRM = determined in the Advanced Assessment for each month of the binding period

2.2.2. Capacity Critical Hours

Capacity Critical Hours (CCH) are those hours where the net regional capacity need is above the 95th percentile based on the WRAP historic gross loads, synthesized historic variable energy resource performance, and interchange.

$$\boldsymbol{Net\ Regional\ Capacity\ Need\ (MW) = Load - Wind - Solar - RoR + Interchange}$$

Where (all values in MW):

Load = Gross hourly load

Wind = Synthesized hourly generation of the current installed wind resources

Solar = Synthesized hourly generation of the current installed solar resources

Run-of-River (RoR) = Synthesized hourly generation of the current installed RoR resources

Interchange = modified interchange as calculated in Section 2.2.3.

2.2.3. Regional Interchange Assumptions

WRAP Participants are located within subregions within the broader WRAP footprint. Regional interchange into and out of the WRAP footprint needs to be accounted for when determining the CCHs. The WPP will make data-driven estimates of the hourly imports and exports. The assumptions will be included in the LOLE/FSPRM assessments for the start of the FS Program and will later re-evaluate the method of developing and/or collecting the import and export data.

Hourly regional interchange patterns has changed drastically in the past three years from near constant export level in the 3,000-5,000 MW range (Figure 2-2) to an export with a significant mid-day dip (Figure 2-3). This new regional interchange shape appears to be in response to increased solar generation in California.

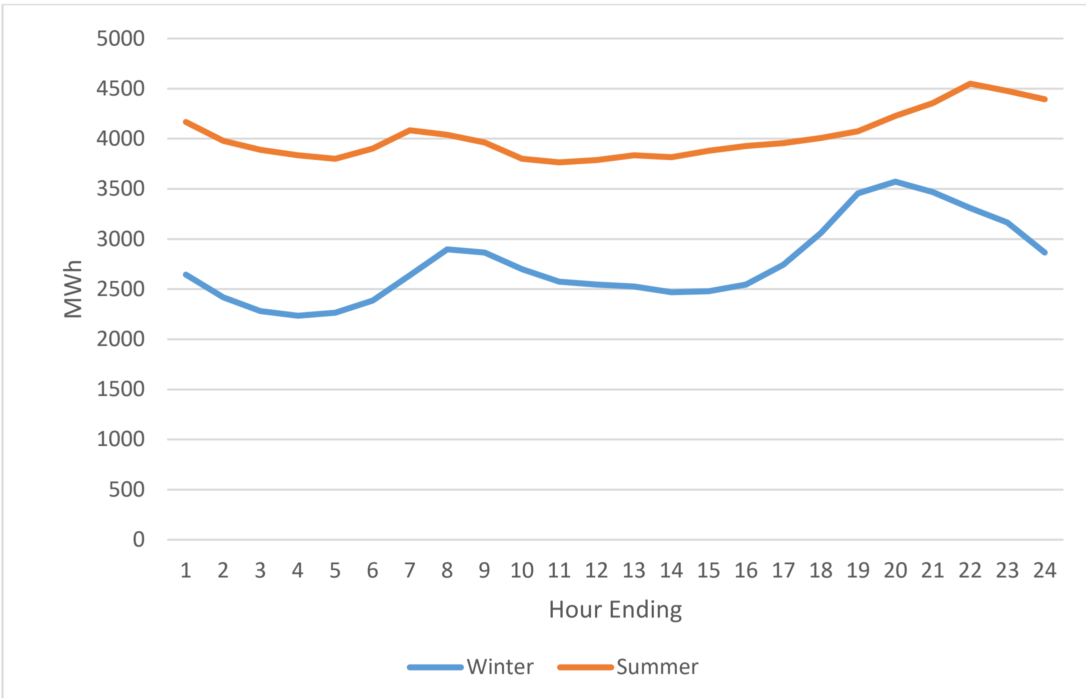

Figure 2-2. Raw regional interchange from the WPP footprint 2010-2017 – a relatively flat/consistent interchange profile for both seasons where positive values represent exports from the WPP footprint.

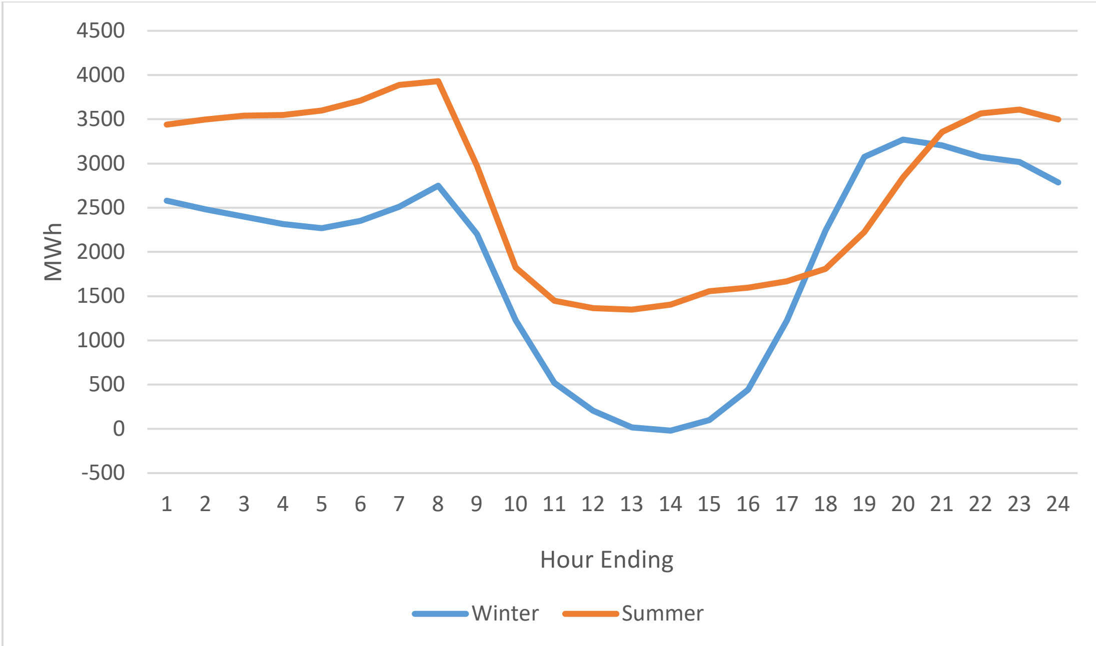

Figure 2-3. Raw regional Interchange 2018-2020 - declining daytime exports and peaks in morning and evenings. Roughly follows California solar production.

The methodology for WRAP adapts the seven-year period (2010-2017) to be more reflective of this recent set of interchange patterns.

Hour ending 19 (HE19) interchange values were held the same as observed throughout the 10-year period. The interchange for all hours (HE01-HE24) for years 2018-2020 was averaged for all like hours (All HE01 hours averaged together, etc.). See Figure 2-4. The average interchange in hour HE19 was compared to all other hours of the hourly average interchange shape created in the previous step. The algebraic difference between each hourly average and the HE19 hourly average was then applied to the daily observations for the 2010-2017 time period. This produced a new hourly interchange shape for the entire 10-year period closely resembling interchange shape for 2018-2020 while retaining the export amounts for HE19 each day.

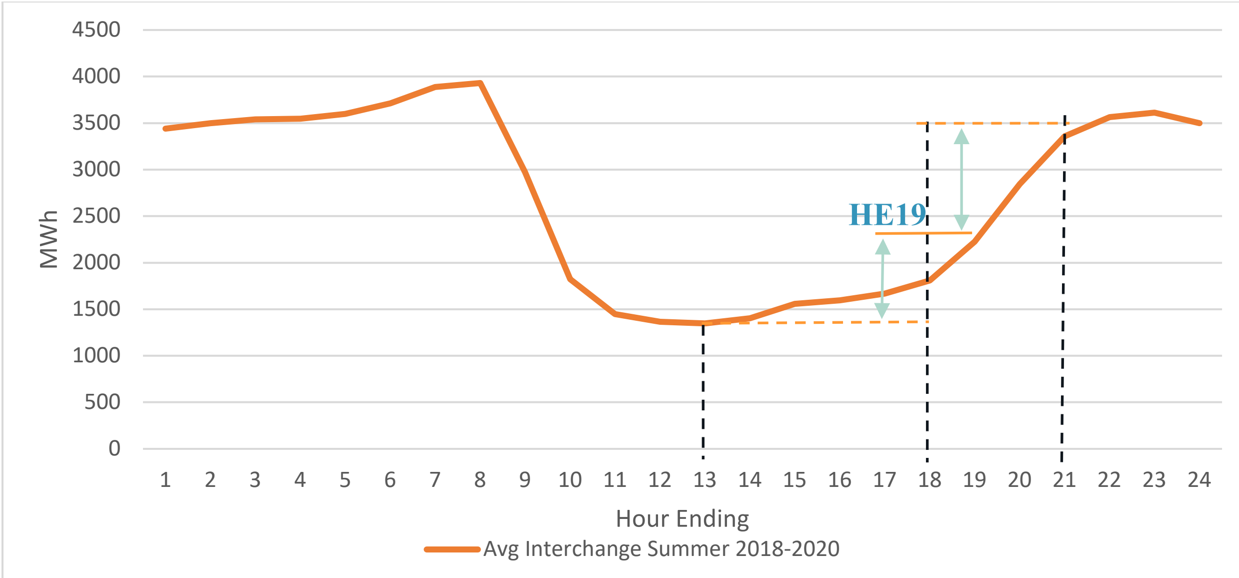

Figure 2-4. 2018-2020 hourly average loads were analyzed to determine appropriate offsets to apply to 2010-2017 load shapes. The green arrows show how hourly average loads were compared against the HE19 average load to determine an appropriate offset for each hour. Each hour's offset was applied to the corresponding hour average in the 2010-2017 data set to arrive at an adjusted hourly load profile accounting for the changed resource mix.

Further modifications to the load shape were made to account for market conditions that resulted in high export periods where the capacity that was exported may have otherwise been able to have been used for the benefit of the WRAP footprint (had the program existed at the time). For example, if exports occurred during periods of excess capacity (e.g., high RoR output) within the WRAP footprint, and the energy price outside of the WRAP footprint was at or below typical market prices, the capacity may not have been exported if the footprint were to have a need for the capacity, as future conditions anticipate.

The following categories were created to evaluate these exports:

Economic sales: made possible by excess generation in WRAP footprint, it was assumed this capacity would have been available for the WRAP footprint, had it been needed.

Scarcity sales: in times of high market prices in areas outside of the WRAP footprint, it was assumed that historical exports made during those time periods would not have been available if required by WRAP Participants.

In order to categorize the exports, criteria were developed based on historic market conditions. The criteria are as follows:

1) The market-clearing heat rate (price of power divided by price of natural gas) for California was used as a proxy for external demand.

2) When the heat rate was less than 10 MMBtu/MWh, it was assumed that there was not a scarcity event and exports from WPP were assumed to be Economic Sales and therefore available to WPP. Export interchange was reduced to zero.

3) When the heat rate was greater than 15 MMBtu/MWh, exports from WPP were deemed to be Scarcity Sales and these values were not changed.

4) When the heat rate was greater than 10 but less than 15 MMBtu/MWh, exports were linearly reduced from their values at 15 MMBtu/MWh to zero based on the observed heat rate relative to 10 and 15 MMBtu/MWh.

5) Starting in 2013, a carbon adjustment of $6/MWh was applied to California market price before determining the market clearing heat rate.

6) Imports were not changed regardless of market conditions.

The results of these modifications produced the load shapes in Figure 2-5.

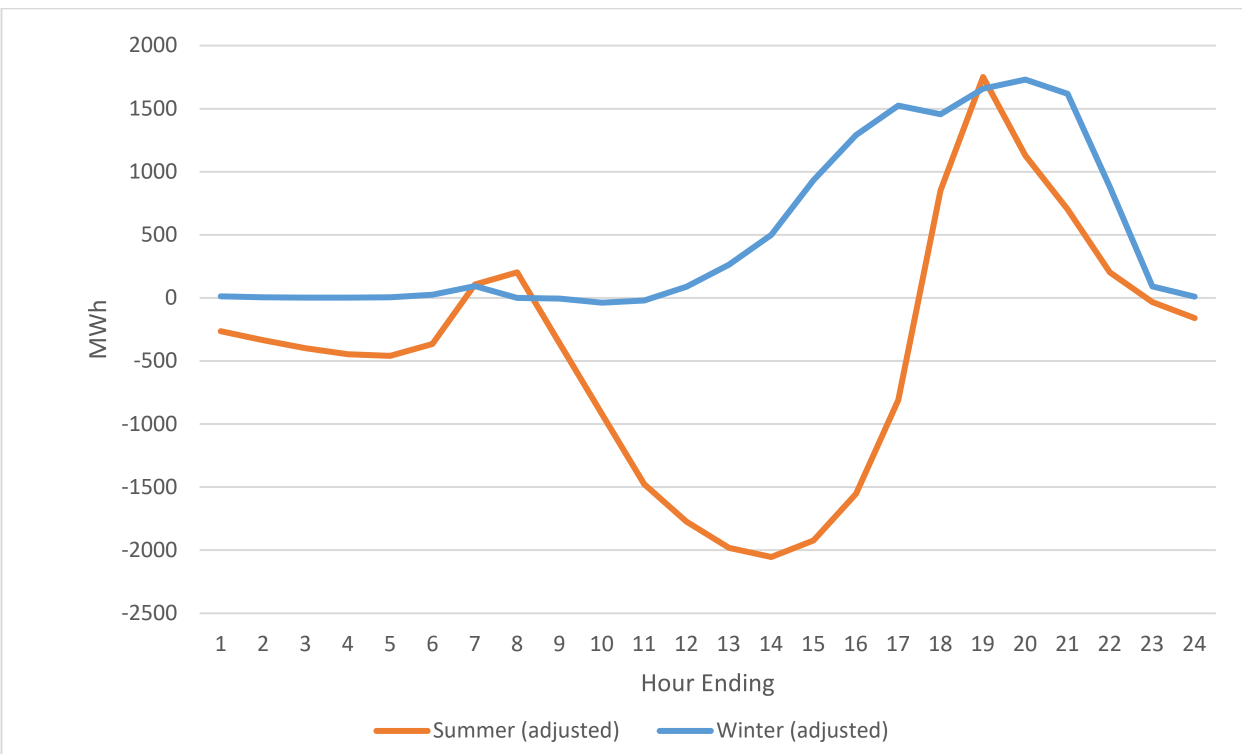

Figure 2-5. 2010-2020 hourly average interchange adjusted for California solar penetration and criteria for scarcity events outside the WPP footprint.

Double-Counting Issue

Historical interchange includes both firm and non-firm transactions. Firm import and export transactions submitted by Participants for the Advance Assessment should not be included in the studies if they are already represented in this analysis.

Future Changes

It is expected that these import/export shapes will continue to change. A review of the methodology for adjusting interchange assumptions will be repeated annually. If recent years shows a significant trend not in line with the methodology, changes to the methodology will be discussed and adjustments developed by the Resource Adequacy Participant Committee.

2.3. Resource Eligibility and Qualification

Participant owned and contracted resources capable of providing capacity may be used to meet a Participant's FS Capacity Requirement. In order to receive a QCC for these resources, a Participant must provide necessary information and data to the WPP. The WPP will develop and maintain a registration and certification process for all resources identified for the FS Program.

2.3.1. Resource Eligibility

All generation resources owned (or jointly owned) and/or operated by a Participant and any resources (e.g., contracts or demand-side resources) claimed by a Participant on its FS portfolio will be required to register with the PO in order to receive a QCC value. There may be exceptions allowed as discussed later in this section.

Generation from resources owned/operated by non-Participants will also be encouraged to register with the PO in order for Participants to claim capacity from these resources toward their FS capacity requirements – see the following sections for additional detail on registration by sellers and/or purchasers. Certain allowances will be made for contracts that are considered "grandfathered" – those agreements with an effective date before the effective date of the RA Program WRAP (or a date otherwise agreed to). Although allowances may be granted, limitations will be placed on these units and associated contracts. Participants will need to provide the PO the information listed in Table 2-4, at a minimum.

The proposed minimum resources must be 1 MW or larger to qualify for certification. The information in Table 2-4 will be submitted with the registration. The WPP will assign the QCC for the resource, which may be used to meet the Participant's FS Capacity Requirement. A resource with a valid QCC is a Qualifying Resource.

Table 2-4. Registration and certification information.

The registration and certification process for all resources will require, but will not be limited to, the following items:	
Resource information	Owner, operator, technology, and fuel type
Name	Facility common name
Location	Balancing Authority Area (BAA), physical location, and interconnection information
Maximum capacity (nameplate)	Summer and Winter values
Demonstration of operational and capability testing	Historical performance showing Real Power output Capability testing – Testing requirements to be determined during BPM drafting and review process. Testing will likely be similar to North America Electric Reliability Corporation (NERC) MOD-025 where appropriate.
Outage Data	NERC Generator Availability Data System (GADS) data (or equivalent) for thermal and storage hydro resources. Outages will not be necessary for wind, solar, or RoR.
Historical Output	Historical hourly output for wind, solar, RoR, and storage hydro resources.

2.4. Qualified Capacity Contribution of Resources

Qualified Capacity Contributions will be determined for all resources submitted for certification by the WPP (Table 2-5). Upon certification, the QCC of that resource may be used to meet a Participant's FS Capacity Requirement. The QCC calculations for all resources will be updated during the Advance Assessments and the FS process as appropriate.

Table 2-5. Resource types and QCC methodologies.

Resource	QCC Methodology
Storage Hydro	The calculation is the actual generation during the CCHs during the prior 10 years plus the amount generation could have been increased by dispatching additional flow for generation, subject to available water.

Resource	QCC Methodology
	If data is not available for 10 years, a comparable facility may be utilized or some other reasonable approach that provides similar (or better) confidence in the computed QCC may be adopted at the discretion of the WPP. The Participant will provide all required detailed data for the project.
VERs	Zonal QCCs for VERS will be based on ELCC analysis for the VERs zones. The Zonal QCCs will be allocated to the VERs in the VERs zone using the actual or synthesized performance during the CCHs.
Run-of-River Hydro[11]	QCC will be set to the monthly average performance of the project during CCHs over the 10-year historical period
Thermal resources	UCAP approach for all hours of the prior six years using unit testing to determine the useful installed capacity of the unit and a forced outage rate based on historical performance during CCHs over the six-year period.
Short-term Storage	Storage resources will use the ELCC method similar to the VERs processes. Only storage devices with at least 4 hours of storage will be evaluated in the ELCC study. The QCC for 4-hour batteries will be scaled up or down for ESRs that have more or less energy storage capability.
Demand Response	Demand Response resources will have a QCC equal to the load reduction capacity times the number of hours the load can be reduced divided by five. DR may only qualify as a Qualifying Resource if it can be demonstrated to be controllable/dispatchable by the PRT or host utility, and must not have already reduced the PRT's P50 Peak Load Forecast
Hybrid Resources	A sum of parts method will be used for hybrid resources. For example, an ESR paired with a wind facility would use the appropriate ELCC methodology, while the wind QCC will be determined according to the wind ELCC methodology. The QCCs for each component will be summed but also limited to the interconnection capacity limit if less.
Customer Resources	Load modifier – needs to be controllable and dispatchable, should demonstrate control of program and meet testing criteria or demonstrate load reduction for periods of up five continuous hours.

[11] Methodology is based on data that reflects the actual operation of the facilities during past high-load periods and reflects the complexities that went into the operation of the resources during those periods.

Resource	QCC Methodology
	Capacity Resource – need to meet testing criteria and demonstrate load reduction for periods of up to five continuous hours. Customer resources (behind-the-meter resources) can be aggregated to the 1 MW requirement to be considered a capacity resource, granted that they are in the same BAA, controllable and dispatchable, and visible to the Ops Program.

2.4.1. Storage Hydro

The Storage Hydro[12] QCC methodology is based on the ability of Storage Hydro to maximizes output during CCH each calendar day during the historical record while adhering to operational limitations of each project. Limitations include water availability and all constraints that restrict the use of the installed capacity. These constraints include things such as discharge limits, tailrace and forebay elevation limits, rate of change limits, and others.

The methodology considers each resource's actual generation output, residual generating capability, water in storage, reservoir levels (if applicable), and flow or project constraints over the previous 10-year historical period. The QCC of the Storage Hydro project is determined using a calculation of how much historical actual generation during the CCHs could have been increased during CCHs by redispatching generation within each calendar day of the historical record while respecting all operating constraints. The QCC is the monthly average of the hypothetical increased generation during the CCHs for the same months of the historical record. The impact of forced outage rates will be based on historical outage information. GADS data will be used as the outage data unless the resource does not submit GADS data, in which case the Participant shall submit their outage data with a Performance Data Attestation for Resources that do not have GADS requirements. The resulting QCC is determined as the average contribution to the CCHs for each Winter and Summer season over the previous 10 years. See Appendix D, Section D.1 for more details. The WPP Storage Hydro QCC Workbook captures the Storage Hydro QCC methodology and is available for use by WRAP Participants.

2.4.2. Variable Energy Resources

Wind and solar resources are considered VERs. VERs will have their QCC determined using a version of ELCC methodology. During the Advance Assessment, an ELCC analysis will be

[12] Storage hydro resources are defined as hydro resources with the capability to store at least one hour worth of water.

performed to determine the VERs QCC for each month of the Winter and Summer seasons. The ELCC will be performed for each identified VER Zone.

A VER Zone is a geographic area delineated such that the VERs in that area are anticipated to have similar generation patterns as they are comparably affected by meteorological or other expected conditions.

At least three years of hourly historical output will be used to calculate the QCC of VERs. Curtailed energy, if known, will be added to the historical output for purposes of the ELCC analysis.

New resources or resources in service less than three years will be able to use data from nearby facilities (or facilities within the same VERs zone until they have been in operation for three years). Alternatively, the Participant will have the ability to provide forecast data based on historical meteorological information. For repowered facilities, a Participant may use forecast data based on a facility's previous operations data adjusted for the repowered specifications.

A detailed description of the ELCC methodology and analysis can be found in Appendix D, D.3.1. Effective Load-Carrying Capability Modeling.

2.4.3. Thermal Resources

For resources that use conventional thermal fuels such as coal, gas, and nuclear, the FS Program will use a UCAP methodology[13] to determine QCC.

The QCC will be determined by applying a capability test to the unit to establish the operational capacity of the resource reduced by a season Equivalent Forced Outage Factor (EFOF) calculated in line with the NERC GADS. The CCHs will be used to determine the hours to be used in calculating the EFOF for each unit. The EFOF calculation will be performed for each year of the 6-year historical look-back period. The equivalent outage rate is calculated by removing the year with the lowest EFOF (for each Summer and Winter seasons) and then taking an average of the remaining five years of data. The final calculated EFOF will be assigned as the UCAP amount for the thermal generator for the entire binding season.

Planned outages and outages properly reported as "outside management control" are not included in EFOF calculations. Planned outages are incorporated into the FS portfolio review, but will not negatively impact QCC values.

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[13] Most RA programs use an ICAP or UCAP to determine the QCC of thermal resources. The ICAP methodology is generally a temperature-adjusted test against the nameplate capacity of a resource. The UCAP methodology adjusts a resource's ICAP value to account for forced outages.

For units new to the FS Program that do not have sufficient data over the historical period used for determining a QCC, class average data for units of similar size, age, and technology type may be used. For such units, operating performance data will replace the class average data as operating history is accumulated while the class average data is used to complete the data for the remaining time requirement. For units that have been in service more than six years, but lack sufficient data over the historical period, discounted QCC values to the class average will be applied.

Further information about the thermal QCC analysis can be found in Appendix C.

2.4.4. Energy Storage Resources

The QCC for ESRs such as pumped storage facilities or battery storage systems will be determined using the similar ELCC methodology as VERs, but will be limited to ESRs that have the capability to store energy equal or greater than 4 hours of operation at peak delivery. There will be no ESR zones that are subject to fuel availability (like wind or solar), but the ELCC of ESRs will be determined on a sub-region basis, which will have the same impact of VER zones.

2.4.5. Hybrid Facilities

Hybrid facilities are resources that have at least two different resource types at a common location where one of those resources is an ESR. The QCC for Hybrid resources will be determined by applying the appropriate methodology to each component of the facility and summing them and capping the total at the interconnection limit.

2.4.6. Customer Resources

Resources that are generally located on the customer side of the meter can be included in the FS Program, including DR programs, behind-the-meter generation or energy storage, and energy efficiency programs. In order to be eligible as a Qualifying Resource, the customer resource must: 1) be controllable and dispatchable by the Participant and/or host transmission operator, and 2) not already been used to modify the Participant's load forecast (i.e., serving a portion or all of the load not included in load forecast).

There are two potential methods of accounting for the RA impacts of customer resources that are controllable and dispatchable:

Load modifier – A load modifier simply reduces the Participant's forecasted net peak demand (reduction in load) resulting in a reduction to the submitted P50 Load Forecast. Planning reserves are not required for resources that are considered load modifiers. Demand response programs that register as a load modifier will need to be controllable and dispatchable and should be able to demonstrate such control and meet testing criteria for load reduction for periods of up five continuous hours. Demand response programs that register as a load modifier will be listed as a separate line item in a Participant's FS submittal and will be subtracted directly from the Participant's P50 load responsibility[14].

Capacity resource – A capacity resource is a resource that is considered to serve the Participant's load and can be separately identified or metered. Capacity resources are subject to being backed up by planning reserves (e.g., a 10 MW resource would need 1.5 MW of planning reserves if FSPRM is 15%). However, if a DR program is registered by a Participant as a capacity resource because of its controllability and composed strictly of shedding load, then the DR program may qualify as a capacity resource that does not have to be backed up by planning reserves. DR programs that register as capacity resources will need to meet testing criteria and demonstrate load reduction for periods of up to five continuous hours.

Table 2-6 gives examples of various types of customer resources and how they may be classified as load modifiers and capacity resources.

Table 2-6. Examples of customer resource types and recommended default treatment by the program; not a comprehensive list, and treatment by the program will be assessed during the registration process.

Resource Example	Default Treatment
Traditional rooftop solar installations or unmetered generation	Load modifier
Energy efficiency	Load modifier
Time of use/Voluntary load conservation	Load modifier
Residential DR (e.g., thermostat or HVAC)	Load modifier
Large customer DR (e.g., tariff programs)	Either
Automated DR	Either
Customer on-site generation or distribution resource (separately metered)	Either

[14] DR programs that are not controllable or dispatchable are included in and are submitted with the Participant's load forecast.

Demand response programs that are restricted to or used solely for CRs will need to be able to be deployed for no less than a full hour starting at the beginning of the hour (xx:00) although actual conditions may necessitate multiple hour deployments. Demand response programs serving to replace CRs do not need to meet the requirements of the FS Program and will be governed by the NERC standard regarding CRs. Demand response programs serving to replace CRs will serve only to reduce the Participant's forecasted CR requirement included in the FSPRM and will not be able to exceed that value in meeting the Participant's FS capacity requirement.

Customer resources can be aggregated to meet the FS Program minimum requirement of 1 MW. Aggregated resources must reside in the same BAA and be controllable and dispatchable. Behind-the-meter resources that have aggregated to the minimum 1 MW threshold shall be treated and assigned QCC values as any other resource of similar fuel type and must register with the PO.

Behind-the-meter resources that have not been aggregated and remain less than 1 MW may not be visible to the PO. These non-controllable and non-dispatchable resources will be considered load-modifying resources, and their impacts will be captured in the Participant's load forecast.

2.4.7. Contracts

The WPP shall determine the Net Contract QCC for each Participant. The Net Contract QCC is the sum of a Participant's capacity rights and obligations under all of its capacity and power agreements that are intended to be able to meet the FS Capacity Requirement. The Net Contract QCC may be positive (net supply of capacity) or negative (net obligation of capacity).

Firm capacity sales to parties outside the WRAP footprint must be declared and included as a capacity obligation in the Participant's FS portfolio. Non-firm capacity exports will not be deducted from a Participant's FS portfolio but must be curtailable in the operational timeframe. In other words, they must still be curtailable after the determination of any Sharing Event in the Ops Program.

Joint Capacity Attestation Form – In order for a contract to be eligible to meet a Participant's FS Capacity Requirement, the Participant is required to complete a Joint Capacity Attestation Form (JCAF). The JCAF form is available on the WPP Sharepoint site and includes sufficient information for WPP to determine the QCC value of the contract. The JCAF is required to be executed by both the Participant and the other parties to the contract for which QCC is being claimed. The intent of the JCAF is ensure double-counting of capacity does not occur. The JCAF is intended to be used for Participant to Participant transactions as well as transactions for Participants that are participating in contracts with external parties for which the capacity could conceivable be used for other purposes than the WRAP. An example of a transaction that does not require a JCAF would be a Participant that has signed a 100% off-take power purchase agreement with a wind farm operator. Another example would be a Participant has a 'must-take' contract with a Public Utility Regulatory Policies Act Qualifying Facility.

To guide Participants in completing their JCAFs and to guide WPP in the determination of the QCC, Capacity Agreements, System Sales, and Legacy Contracts will be assigned QCC values as follows.

Capacity Agreements shall only qualify for a QCC if i) the contract is specific to a generating resource, ii) the resource is identified, iii) there is an assurance that the generating capacity will not be used for another entity's resource adequacy requirement, iv) an assurance that the supplier will not fail to deliver in order to meet other supply obligations, v) there is an affirmation of NERC priority 6 or 7 PTP or network integration transmission service from the resource to the buyer's load, and the identified resource meets the QCC accreditation requirements for its resource type.

System Sales shall qualify for Net Contract QCC provided that if the seller is not a WRAP Participant, then i) the system capacity sold is deemed surplus to the seller's needs, ii) there is an assurance that the seller will not fail to deliver to meet other commercial obligations, and iii) there is an affirmation of NERC priority 6 or 7 PTP or network integration transmission service from the resource to the buyer's load. Such demonstrations by seller may be provided by a Senior Official Attestation. System sales contract made by a WRAP Participant will be validated using the information provided by the buyer and the seller. In this case, the buyer shall add the QCC to their resources in their FS Submittal and the seller shall debit the QCC from their resources in their FS Submittal.

Legacy Contracts entered into prior to October 1, 2021 may qualify for QCC. If the contract does not specify a generation source, it must be possible for the WPP to presume a source which may be conveyed as a written assent from the supplier. If a specific resource cannot be presumed, then the Legacy Contract will not qualify for WRAP QCC.

2.4.7.1. Transfer of FS Capacity Requirement

WRAP Participants may agree to transfer their FS Capacity Requirement amongst one another. Such transfer must be submitted by both Participants to the WPP along with the transmission service arrangement between the two Participants' systems supporting such transfer. Upon verification, the amount requested will be transferred from one Participant, reducing their total FS Capacity Requirement, to the other Participant, increasing their FS Capacity Requirement by the same amount for the same period.

2.4.8. Transmission Service Requirements

Participants must demonstrate firm transmission rights equal to at least 75% of its FS Capacity Requirement (FS Transmission Requirement). Transmission rights must be from the Participant's Qualifying Resources or contracts included in the Net Contract Resources to it load. Transmission in excess of a Qualifying Resources' QCC will not count as meeting this obligation. Transmission must be NERC Priority 6 or 7 firm Point-to-Point or Network Integration Service. Capacity Benefit Margins may be used to meet th FS Transmission Requirement. Meeting the FS Transmission Requirement does relieve a Participant from noncompliance chanrges if there is an Energy Delivery Failure during the Ops Program.

The WRAP does not replace other transmission planning processes; however, it may provide indications of when the WRAP footprint is becoming transmission deficient or constrained.

The WRAP expects that Participants will manage, change, and re-optimize their firm transmission for their portfolio after the FS Submittal.

2.4.8.1. Demonstration

The FS Workbook includes tabs for a Participant's transmission service rights including the relationship to Qualifying Resources and contracts claimed in the FS Submittal.

The Participant will list all transmission service rights for the program. Terminology mirrors terms used in standard form Open Access Transmission Tariffs (OATTs) and on Open Access Same-time Information Systems (OASIS). OASIS reservation numbers are used to uniquely identify each reservation. TSRs are checked for each month to determine if there is a sufficient amount for the use by associated Qualifying Resources.

2.4.8.2. Exceptions

Participants may request exceptions for meeting their FS Transmisison Requirement for four reasons:

1) Enduring Constraints
2) Future Firm ATC Expected
3) Outages and Derates
4) Counterflow of an RA Resource

These categories are described in greater detail below.

Category 1: Enduring Constraints

This exception will be granted when there are enduring transmission constraints, but only when the following criteria are met:

1) **One segment limit** – Participant is unable to demonstrate sufficient 7-F/6-CF/6-NN rights on any single segment of a source to sink path for an RA resource (i.e., exceptions will not be granted for two segments of a source-to-sink path); AND
2) **No Firm ATC available** - Participant demonstrates no 7-F/6-NN ATC posted by a Transmission-Service Provider (TSP) at FS deadline on the applicable segment for the FS time period or less months needed; AND
3) **Senior Official Attestation** - Participant submits a Senior Official Attestation stating the following; AND
   a) The Participant has taken commercially reasonable effort to procure firm Transmission,
   b) The Participant has posted Firm Transmission Requirements on an appropriate bulletin board prior to the FS deadline
4) Participant must demonstrate:
   a) That there was remaining available transmission transfer capability (i.e., non-firm ATC after the fact) for all CCHs in the same season in the previous year, OR
   b) If the path was constrained in at least one capacity critical hour in previous year's same-season – Participant must demonstrate that it is:
      i) Constructing or contracting for a new local resource for at least the amount of the exception requested, OR
      ii) Pursuing long-firm rights by entering the long-term queue and taking all appropriate steps for at least the amount of the exception requested.

Category 2: Future Firm ATC Expected

This exception will be granted when there is a reasonable expectation that firm ATC will be made available following the FS Submittal deadline based on the following criteria:

1) NERC Priority 7-F/6-NN ATC is not posted/available prior to the FS deadline, AND
2) Participant provides evidence that TSP has released additional NERC Priority 7-F/6-NN ATC in every one of the previous year's CCHs[15] for the appropriate Binding Season on the applicable path following the FS Submittal deadline; AND

[15] The previous year's CCHs means the most recent year for which CCHs have been calculated.

3) Limited volume – Participant demonstrates that the volume being requested for exception is equal or less than the minimum volume of NERC Priority 7-F/6-NN rights ATC released in the previous year's CCHs for the appropriate Binding Season, AND

4) The total amounts of exceptions on specific paths will be limited to the amount of transmission demonstrated to likely become available.

If multiple participants have requested a Category 2 exception on for the same path, available volume will be assessed on a pro-rata basis to those requesting based on the size of their requests.

Category 3: Transmission Outages and Derates

This exception will be granted when:

1) A Participant provides evidence that an applicable segment of their existing Transmission Service Rights from their source to sink path for their Qualifying Resource is expected to be derated or out-of-service and that additional ATC for NERC Priority 7 or 6 Firm PTP or Network Integration Service is not otherwise available.

2) Limited duration – participant demonstrates that the duration of the exception request coincides with the months of the outage or derate

3) Limited volume – Participant demonstrates that the volume of the exception being requested is either:

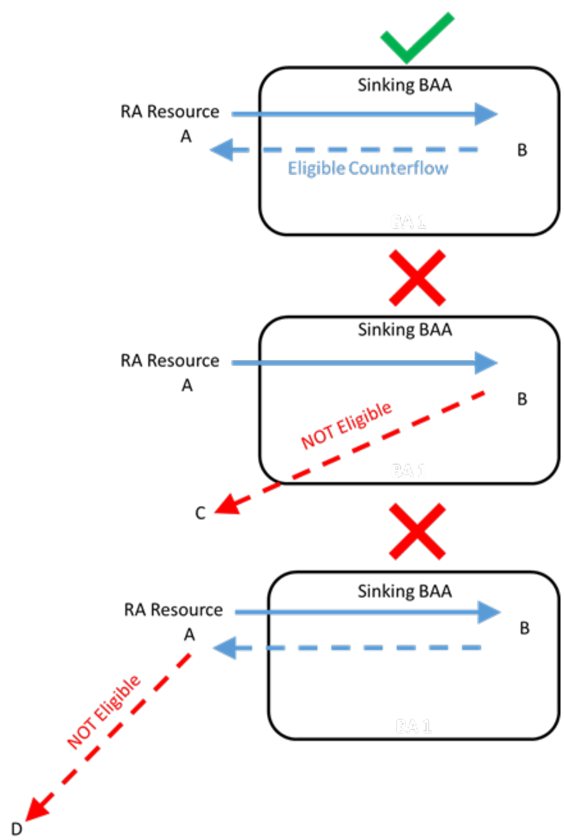
    a) equal or less than the reduction in the Participant's existing Transmission Service Rights on that path for the applicable derate/outage period, or

4) equal or less than the NERC Priority 7 or 6 Firm PTP or Network Integration Transmission for the applicable derate/outage period that would otherwise be posted and available for reservation were it not for the transmission limitation

Category 4: Counterflow of an RA Resource

An exception may also be granted if a 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.

The following grahic shows that a the counterflow must be directly between two BAAs. Other counterflow examples that involve three or more BAAs as sources and sinks do not qualify.



2.4.8.3. Applying for an Exception

Participants should submit requests for Transmission Exceptions with their FS Submittals. Requests should inclue a Senior Official Attestation and evidence supporting the request, including information from transmssion service providers and OASIS posting information. Participants will note in the FS workbook any exceptions sought on the TSR List tab and map the exceptions to resources on the TSR Demo tab, just as they do with any OASIS reservation.

Exception Timeline

The WPP will notify Participants of the exception request status within 60 days after the FS deadline. Partcipants granted an exception will complete a monthly transmission exception report demonstrating that the circumstanced necessitating the exception have not changed, transmssion has become available and the Participant has acquired it, or the Participant has acquired a different resource with associated firm transmission and no longer requires the exception.

If the exception is denied (either because it is invalid or because circumstances changed and transmission has become available during the review period), the Participant will have the opportunity to cure their transmission deficiency during the 60-day cure period. The Participant may also appeal the rejection to the Board.

2.4.8.4. Planned Resource Outages

Participants are expected to take their planned resource outages from their surplus capacity. Any planned outages taken on a resource during a binding season will result in the QCC of that resource being reduced to zero for the month of the planned outage. Construction of a Participant's FS Portfolio

A Participant's FS capacity requirement, the QCCs of their resources and contracts, and their FS portfolio compliance will be calculated and reported[16] at a monthly granularity for the Binding Seasons.

The Participant shall complete the FS Workbook and submit it by the FS Submittal deadline with all other related documents and information.

2.4.9. Resource QCC

Each Participant will register all its owned generating resources by inclusion in their FS Submittal. The WPP will have needed to previously[17] calculate the QCC for all resources owned by the Participant (except for storage hydro resources, which will be calculated by Participant using the WPP Storage Hydro QCC Methodology). The summation of all QCC values for each Participant owned resource is referred to as the Participant's "Resource QCC," which will be calculated for each month of a binding season.

$$\boldsymbol{Resource\ QCC = \sum QCC\ of\ all\ Participant\ owned\ resources}$$

[16] QCC will be calculated for thermal resources on a seasonal basis but will be used on a monthly basis – each month of the season will have an identical QCC unless other factors such as planned outages impact this value.

[17] Through proper data submittals for the applicable Advanced Assessment period.

2.4.10. Net Contract QCC

Each Participants will include all RA contracts (purchases and sales) in their FS Submittal. The WPP will assign a monthly QCC value to all contracts provided prior to the FS deadline, dependent upon the nature of the contract.

The net contracted QCC is a monthly value equal to the sum of the Participant's contract QCCs (see example in Appendix F - Table 2-26). Import contracts (purchases) are additive to the Participant's QCC value and exports (sales) are a negative QCC value. The net contract QCC formula is as follows:

$$\boldsymbol{Net\ Contract\ QCC} \\ \boldsymbol{= \sum QCC\ of\ all\ Participant\ qualified\ contracts}$$

2.4.11. Resource Adequacy Transfers

Resource adequacy transfers are added to the purchasing Participant's QCC value and subtracted from the selling Participant's QCC value. The contracts for these transfers will be provided to the PO for validation.

$$\boldsymbol{Total\ RA\ Transfer = \sum Participant\ RA\ transfer\ contracts}$$

Operational considerations indicate that it may be important for Participants to be exclusively sellers or exclusively purchasers of RA transfers. Further consideration will be given in future phases to whether a "net" approach is feasible.

2.4.12. Forward Showing Portfolio and Calculation

A Participant's total portfolio QCC is defined as the Participant's resource QCC plus their net contract QCC plus their total RA transfer.

$$\boldsymbol{Portfolio\ QCC} \\ \boldsymbol{= Resource\ QCC + Net\ Contract\ QCC} \\ \boldsymbol{+\ Total\ RA\ Transfer}$$

Each Participant's portfolio QCC should be at least equal to the Participant's FS capacity requirement for each month of the binding season. Provided the Participant's portfolio QCC has met or exceeded that threshold, the FS capacity requirement has been satisfied.

$$\boldsymbol{Portfolio\ QCC \geq FS\ Capacity\ Requirement}$$

Any portfolio QCC in excess of the Participant's FS capacity requirement will increase the Participant's obligations during the Ops Program. A Participant's additional planned maintenance or short-term sales will be made from their excess Portfolio QCC. Table 2-7 presents an example of a FS portfolio and calculation.

Table 2-7. Forward Showing portfolio summary example.

FS Monthly Summary				
Month	**FS Capacity Requirement (P50+FSPRM)**	**Portfolio QCC**	**Additional Planned Outages (if any)**	**Met FS Capacity Requirement**
2022-11	1125	1125.5	0	TRUE
2022-12	1125	1295.5	0	TRUE
2023-01	1125	1475.5	250	TRUE
2023-02	1125	1543.5	300	TRUE
2023-03	1125	1225.5	75	TRUE

2.5. Deficiency Payment for Noncompliance

A Participant who fails during the cure period to resolve identified deficiencies in either or both of its FS Capacity Requirement and its FS Transmission Requirement 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 (MW) = 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 and validated by the WPP.

Monthly Deficiency (MW) = Maximum of (Monthly Capacity Deficiency, Monthly Transmission Deficiency)

A Participant's Deficiency Charges shall be calculated as set forth in this Section subject to the Transition Period rules in Section 2.5.1, and shall take account of multiple Monthly Deficiencies within an FS for a single Binding Season, and multiple Deficiencies across a FS Year, consisting of a Summer Season and the immediately succeeding Winter Season, in accordance with the following:

A deficient Participant will be charged amount based on the largest Monthly Deficiency in the FS for a Summer Season as follows:

Max Monthly Summer Deficiency (MW) × Annual CONE ($/kW-year) × 1000 × Summer Season Annual CONE Factor

Any Monthly Deficiencies in the Participant's FS for other months in the same Summer Season shall be assessed an additional charge equal to the following formula. This charge will be additive for all months with such deficiencies and added to the charge based on the Max Monthly Summer Deficiency.

Additional Summer Deficiency (MW) × (Annual CONE ($/kW-year)/12) × 1000 × 200%

Any Monthly Deficiency in the FS for the immediately succeeding Winter Season that is larger than the Max Monthly Summer Deficiency shall be assessed a Deficiency Charge on the incremental deficiency value greater than the Max Summer Season Deficiency as follows:

Maximum of (Max Winter Deficiency – Max Summer Deficiency, 0) (MW) × Annual CONE ($/kW-year) × 1000 × Winter Season Annual CONE Factor

Any Monthly Deficiencies in the Participant's FS for other months in the same Winter Season shall be assessed a Deficiency Charge equal to the following formula. This charge will be additive for all months with such deficiencies and added to the charge based on the Max Winter Deficiency:

Additional Winter Capacity Deficiency × (Annual CONE/12) × 1000 × 200%

The CONE is the estimated cost 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 shall not consider 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.

The WPP shall review the CONE annually. Any proposed changes in the CONE shall be subject to review through the stakeholder process for program rule changes.

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:

1) If the Summer % Deficit is less than 1%, the Summer Season Annual CONE Factor = 125%
2) If the Summer % Deficit is greater than 1% but less than 2%, the Summer Season Annual CONE Factor = 150%
3) If the Summer % Deficit is greater than 2% but less than 3%, the Summer Season Annual CONE Factor = 175%
4) If the Summer % Deficit is greater than 3%, the Summer Season Annual CONE Factor = 200%

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:

1) If the Winter % Deficit is less than 1%, the Winter Season Annual CONE Factor = 125%
2) If the Winter % Deficit is greater than 1% but less than 2%, the Winter Season Annual CONE Factor = 150%
3) If the Winter % Deficit is greater than 2% but less than 3%, the Winter Season Annual CONE Factor = 175%
4) If the Winter % Deficit is greater than 3%, the Winter Season Annual CONE Factor = 200%

If there is either a Summer Deficit or a Winter Deficit in an FS Year, then for the immediately following FS Year, both the Summer Season Annual CONE Factor and the Winter Season Annual CONE Factor shall be 200%.

Subject to the Transition Period rules, revenues from Deficiency Charges shall be allocated among those Participants with no Deficiency Charges for that Binding Season, pro rata based on each non-deficient Participant's share of all such Participants' Median Monthly P50 Peak Loads for such Binding Season.

2.5.1. Reduced Charges during Transition Period

During the Transition Period, a deficient Participant can pay a reduced Deficiency Charge to the extent the Participant has 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 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 do so because the supply of such resources on a timely basis and on commercially reasonable terms is inadequate. Excused Transition Deficits are not resource specific.

During the Transition Period the maximum permissible Excused Transition Deficit shall equal 75% of the FSPRM capacity for each of the 2025 Summer Season and 2025-2026 Winter Season, 50% for each of the 2026 Summer Season and 2026-2027 Winter Season, and 25% for each of the 2027 Summer Season and 2027-2028 Winter Season.

A Participant will pay a reduced Deficiency Charge as to the portion of its Monthly Capacity Deficiency for which it obtained an Excused Transition Deficit. The Deficiency Charge otherwise applicable to such Participant shall be reduced by a percentage value equal to 75% for each of the 2025 Summer Season and 2025-2026 Winter Season, 50% for each of the 2026 Summer Season and 2026-2027 Winter Season, and 25% for each of the 2027 Summer Season and 2027-2028 Winter Season. The Participant will be assessed a Deficiency Charge 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.

Whether or not a Participant obtains an Excused Transition Deficit for a Binding Season, the Participant may reduce a Monthly Capacity Deficiency 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 the Tariff and the WRAP BPM related to transition (planned for drafting in 2023). 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 sign the accreditation form. The reduction in Monthly Capacity Deficiency permitted by this Section as to any Participant for all FS Submittals submitted by such Participant for any Binding Season during the Transition Period shall not exceed a capacity 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 for Excused Transition Deficits for the same Binding Season.

A Participant that pays no Deficiency Charge for a Binding Season as a result of Transition Period reductions shall not be deemed a "Participant with no Deficiency" and shall not receive any allocation of revenues collected from deficient participants that Binding Season.

SECTION 2: APPENDIX A - ANNUAL ASSESSMENTS

A.1. Planning Reserve Margin

The FSPRM for the WRAP footprint will be calculated annually for both the Summer and Winter Binding Seasons during the Annual Assessment process. Annual assessments will be completed at least 12 months in advance of the FS deadline for the following year. Studies for the Summer season will be completed by Oct 31 (T-2); studies for the Winter season will be completed by March 31 (T-1). See Table 2-8.

Table 2-8. Timing the determination of Summer season FSPRM.

Example: Timing of the determination of Summer season FSPRM
In calendar year 2025 (T-2), FS Program Participants will provide data for the Summer season study by October 31, 2025. – The study determines a binding FSPRM for the 2027 (T-0) Summer season. – The study determines an advisory FSPRM for the 2030 (T+3) Summer season.
In calendar year 2026 (T-2), the process begins anew, and the Summer season study is completed by October 31, 2026. – This study provides a binding FSPRM for 2028 (T-0) Summer season. – This study provides an advisory FSPRM for 2031 (T+3) Summer season.

A.1.1. Qualified Capacity Contribution

The QCC of all FS Program resources will be calculated on an annual basis as part of the Annual Assessment process. This calculation is handled in accordance with the resource type. QCC analyses and ELCC studies will be performed annually for each Summer and Winter Binding Season. The completion dates will be no later than October 31 (T-2) for the Summer season and March 31 (T-1) for the Winter season.

A.2. Model Input Update Process

To support the annual assessments, an RA model will be developed to represent the WRAP footprint. Inputs to this model will be submitted by the Participants and will represent each of the Participant's systems. No later than January 15 of each calendar year, the updated data requests will be sent out to the Participants for the items described in Table 2-9 necessary to complete the annual assessment for that calendar year.

Table 2-9. Participant provided modeling data.

Annual Assessment Data Items
Load data - Participant 8,760-hour actual historical load data for the previous year (initial request will need at least 10 years of data, subsequent request will add an additional year annually)
Separate load shapes that are split between different zones
Historical temperature values, for each area/load center, for the previous year (initial request will need at least 10 years of data)
Participant conventional resource data for new units added during the previous year (initial request will include data for all Participant units) including: – Fuel type In-service and retirement date (if known)
– Wind, solar, RoR resources (by resource) added in the previous year (initial request will include all units)
Hourly generation profiles for the last 10 years (for existing units)
ICAP by hour (for existing units)
All data required by the WPP Storage Hydro QCC Methodology necessary to determine QCC for resources (i.e., data needed to populate the WPP Storage Hydro QCC Workbook)
NERC GADS or equivalent outage data that can be used to calculate equivalent forced outage rates (EFOR) for the last six years (for existing units)
Minimum capacity

All information from Participants must be received no later than February 1 of each year.

Some data from previous FS submittals may be used for the annual assessments. The data points in Table 2-10 will be taken from the Participant's previous FS Submittal. New Participants to the Program will be required to provide these data points in a separate request.

Table 2-10. Modeling data taken from FS Submittals.

Data Items
Firm import/export transactions that each Participant wants included in the forward-looking model (one-three years in the future)
Capacity value of transaction
DR program/resources
Forecast peak demand
Timeframe of transaction

A.3. Participant Review and Verification Process of Input Data

Once all necessary data has been inputted into the RA model, Participants will be allowed to review the input data for their respective systems. This review will occur between May 1 - June 1 (T-2) for the Summer season and between October 1 - November 1 (T-2) for the Winter season. This review will occur before the model simulations commence.

As stated previously, Participants may review input data for their respective systems. Participants may not review input data of any other Participants. If required by law, regulatory and oversight bodies may review the data.

A.4. Draft Modeling Output Results Sharing

By September 15, T-2 (for the Summer season) and February 15, T-1 (for the Winter season), draft modeling results will be provided to the Participants for review. The modeling outputs that will be available for Participant review are listed in Table 2-11.

Table 2-11. Output from modeling results.

Outputs
Resource index
QCC values by resources owned or contracted by the Participant
Proposed FSPRM for the season under study
Peak coincident load of the WRAP footprint
Transmission limitations (if the Participant is located in a transmission-constrained zone)

Participants will have the opportunity to review the draft results and work with the WPP to analyze any potential discrepancies from expected results. Any discrepancies will be reviewed and resolved no later than October 15 (T-2) for the Summer season and March 15 (T-1) for the Winter season.

A.5. Final Modeling Output Results Sharing

The final modeling output results will consist of a LOLE study report that gives details of the study analysis, makes recommendations for a proposed FSPRM for the year two Binding Season, and provides an advisory FSPRM for the year five Summer/Winter seasons. QCC studies/reports will include the ELCC studies for wind, solar, and RoR hydro, as well as QCC results for storage hydro resources, thermal resources, short-term storage resources, and customer resources. A summary of studies and the output results are provided in Table 2-12.

Table 2-12. Final modeling output results.

Study		Output Results
LOLE		– FSPRM for the upcoming binding Summer/Winter season.
QCC Studies	VER (ELCC)	– QCC values by month for all wind, solar, and RoR resources. – QCC values for all wind, solar, and RoR resources will be available to all Participants.
	Thermal (UCAP)	– QCC values by month for all thermal resources. – QCC values for all thermal resources will be available to Participants. o Calculations for determining the QCC of thermal resources will be available to the resource owner.
	Storage Hydro (WPP Storage Hydro QCC Methodology)	– QCC values by month for all storage hydro resources. – QCC values for all storage hydro resources will be available to all Participants. o Calculations for determining the QCC of storage hydro resources will be available to the resource owner.
	Short-Term Storage (ICAP Testing and hybrid resources – "Sum of Parts")	– QCC values by month for all short-term storage and hybrid resources. – QCC values for all short-term storage and hybrid resources will be available to all Participants. o Calculations for determining the QCC of short-term storage and hybrid resources will be available to the resource owner.
	Customer Resources (capacity resource or load modifier)	– QCC values by season for customer-side resources. – QCC values for all customer-side resources will be available to all Participants. o Calculations for determining the QCC of customer-side resources will be available to the resource owner.

SECTION 2: APPENDIX B - MODELING ADEQUACY STANDARD AND FSPRM

B.1. Introduction

Determination of the FSPRM will be supported by a probabilistic LOLE study, which will analyze the ability of generation to reliably serve the WRAP footprint's P50 Peak Load forecast. The FSPRM will be studied such that the LOLE (while maintaining CRs) for the applicable planning year does not exceed one event in 10 years for the Summer season and one event in 10 years for the Winter season. At a minimum, the FSPRM will be determined using probabilistic methods by altering capacity through the application of generator forced outages and forecast demand through the application of load uncertainty to ensure the LOLE does not exceed the aforementioned reliability metrics.

B.2. Software Used

The LOLE study will be performed using a software that is capable of performing LOLE and ELCC analyses. The software may be an industry recognized software package or may rely on custom developed elements or packages to support the design of the Program. The software should be readily supportable and adaptable to evolutions of the Program.

B.3. Area Modeling

For the LOLE study, WRAP footprint will be modeled as load and resource zones (LRZs) that have been determined in discussions with the WRAP Participant transmission group and area TSPs. If a specific LRZ is determined to be transmission constrained, that the constrained LRZ may have a higher FSPRM requirement applied than the remainder of the WRAP footprint.

The LOLE study will utilize a pipe and bubble methodology for modeling the transmission system. The load and resources of an individual LRZ will be modeled as a "bubble" representing each zone. For the LOLE simulations, import and export capabilities ("pipe sizes") between LRZs will not be constrained when determining the footprint's FSPRM value. After the footprint's FSPRM value has been found, an analysis of each LRZ will be made to determine if a zone is transmission constrained.

B.4. Load Modeling

Historical hourly load data from the previous 10 years will be used to produce 8,760 hourly load profiles for each LRZ. The historical data will be provided by Participants in the annual data request. If a Participant's load spans more than one LRZ, then the Participant will need to submit their data based on each LRZ in order to adequately model each Participant's peak demand and load shapes for the applicable LRZs.

The median historical peak year will be determined for each season (Summer or Winter). The median year (for each season) will then be scaled to match the Participant provided forecast peak loads for the years studied for the LOLE analysis. For example, if year 2014 is the median peak year for weather years 2011 to 2020 Summer seasons, then the load shape for that calendar year will be scaled to the forecasted peak demand of the applicable study year (either year (T-0) binding or year (T+3) advisory). If the actual Summer peak demand for 2014 was 1,000 MW and the forecasted demand is 1,100 MW, then the peak, along with all hours in the applicable season, will be scaled up by 10%. If 2012 had a historical peak of 1,200 MW, then the relationship between 2012 and 2014 will still be represented by scaling the 2012 Summer season weather shape up by 10% as well.

For multiple Participants located in one LRZ, their load shapes will be aggregated into a single load shape and the loads will be scaled to the appropriate LRZ peak. Load and time zone diversity will be considered when deriving the load shapes for each zone in such a manner that the modeled forecasted peak of each zone is not overstated by simply adding the P50 peaks of all Participants in a zone and setting that value as the peak.

B.4.1. Load Forecast Uncertainty

Load forecast uncertainty (LFU) is an important component in a LOLE study and can be represented in multiple ways depending on the capability of the software used. The following method should be adequate if monthly load uncertainty can be derived either using economics, historical weather patterns based on temperature, or historical rain fall amounts, or the main underlining factor driving load uncertainty and variability for each Participant's load and can be adequately represented probabilistically. The LFU should include deviations below and above the 50th percentile to capture the full array of forecast uncertainty deviations from a "P50" forecast.

A user-defined uncertainty pattern and a probability distribution will be used to add uncertainty to the load values. A different load uncertainty distribution pattern will be modeled monthly for each LRZ. A load model will the peak-demand multipliers used to modify forecast peak demand. The daily peak is selected and regressed against historical peak temperatures, previous day's peak load, weekday or weekend identification, and holiday identification from the previous 10 years.

The probability distributions of temperatures observed at key weather stations throughout the WRAP footprint will be analyzed. A forecast will then be created for both study years (T-0 and T+3). Based on the forecasts, multipliers will be calculated and populated in a user-defined uncertainty pattern. The user-defined uncertainty pattern allows users to provide seven monthly demand patterns. Each LRZ has a different value for each month multiplied by seven probabilities (84 values). The load uncertainty allows for unexpected increases of demand in addition to the adjusted testing reserve margin.

B.5. Generation Modeling

B.5.1. Thermal Generators

Thermal generators will be modeled as units at their ICAP tested values with forced and planned outages applied as necessary in accordance with their EFOR[18] and planned outage rates. The ICAP values will be provided by each Participant in their annual data submittal. All thermal resources will be modeled in the LOLE and ELCC studies, unless otherwise noted by a retirement date, future in-service date, or for any other reason identified by the Participant.

Forced outage modeling for thermal resources will consist of using the EFOR values (EFOR equation as defined by NERC GADS), forced outage durations and maintenance scheduling parameters, and outage events sourced from NERC GADS (or equivalent) data provided by Participants. For thermal resources that do not submit such data, an average forced outage rate will be applied based on size, fuel type, and age of the resource. At least five years of historical NERC GADS (or equivalent) data will be considered in the LOLE and ELCC analysis. All ELCC and LOLE studies will use the same outage rates and method for the modeled resources. The models will be updated every year to reflect the latest outage rates.

Planned outages for thermal resources will be modeled using the LOLE software's scheduled maintenance function (e.g., SERVM by Astrapé) by switching the status of

[18] EFOR is a metric used in the LOLE study for determination of *system* FSPRM. This is a different metric than is being used for the determination of QCC for thermal resources (EFOF). EFOR takes system outages, regardless of time during the year, including potential extreme events and events outside of plant management control, into account for the determination of FSPRM. The determination of QCC is *plant* focused, determined primarily on CCH, and excludes outages outside of plant management control.

each resource to "offline" to account for expected outage duration and unit start time. Previous planned outages will be taken into consideration when modeling the maintenance window for each resource. For Monte-Carlo based software, annual maintenance rates and planned outage rates will be considered at a minimum for all thermal generators, as determined by the historical NERC GADS (or equivalent) data.

A "commit all" approach will be used for Monte-Carlo based software, meaning all resources will be treated as available at any given hour if the resource is not on outage. Use of physical unit limitations may be considered in the future as WRAP evolves.

B.5.2 Storage Hydro

The WPP Storage Hydro QCC Methodology will establish QCC values for all storage hydro plants on a monthly basis. For the LOLE study, storage hydro plants will be modeled at their QCC values for each month. The methodology utilized to assess QCC values for hydro facilities accounts for the availability of storage such that in the LOLE modeling, it is appropriate to assume the facility has enough stored energy to output the monthly QCC value for each hour in the simulation. No outage information will be applied to the resources in the simulation, since the QCC values also already consider historical outages.

B.5.3 Wind, Solar, RoR Hydro Resources

The study model will include all wind, solar, and RoR hydro resources currently installed or proposed to be in-service in the WRAP footprint prior to the study year; hourly generation profiles will be assigned to each resource. Hourly generation is based upon historical profiles correlated with the yearly load shapes (previous 10 years), as provided by Participants. New facilities that do not have historical generation profiles will be assigned shapes consistent with the resource-specific zone in which they are located or assigned historical shapes by the nearest site; alternatively, Participants can submit forecasted shapes based on historical hourly meteorological data.

B.5.4 Demand Response Programs

When controllable and dispatchable DR is reported in FS portfolios, equivalent thermal resources will be added to the model with high fuel costs, such that these representative "thermal" resources would be dispatched last by the model to reflect DR operating scenarios. Forced outage rates will not be assigned to the DR programs. Any DR Ops Program restrictions provided by the Participant will be modeled in the LOLE study. DR programs not reported in the data submissions should be considered as load reductions in the P50 forecasted peak demand for each season.

B.5.5 Behind-the-Meter Generation

Behind-the-meter generation reported by Participants as capacity resources that are controllable and dispatchable by the Participant will be modeled as generation. See also Customer Resources Section 2.4.6. These resources will be assigned parameters and forced outage information from equivalent-sized resources. Behind-the-meter generation not reported in data submissions would be accounted for in load reductions in the P50 forecasted peak demand for each season.

B.5.6. External Capacity Modeling

Any external capacity transactions that are supported by firm commitments in the FS portfolios will be modeled as hourly generators in the applicable LRZ. External transactions are any firm capacity transactions or obligations to non-participating entities either internal or external to the WRAP footprint. If the transaction is a sale to a non-participating entity, it will be an export of capacity. If the transaction is a purchase from a non-participating entity, it will be modeled as an import of capacity; forced outage rates will not be assigned to these transactions.

Non-firm regional interchange will be modeled in LRZs that border adjacent BAAs south of the WRAP footprint, which may include non-participating entities in California, New Mexico, and Arizona.

B.6. Determination of 1 Event-Day in 10-Year Threshold

For the LOLE study, loss of load events will be tabulated during the hours of the binding season for determination of the 1-in-10 LOLE metric. Loss of load events that occur during hours outside of the binding season will not be included in the calculation of the FSPRM.

Pure negative (or pure positive if the system is generation deficient) capacity with no outage rate will be added to the model until the WRAP footprint reaches the 0.1 day per year reliability threshold. The pure negative (or positive) capacity value assigned in the LOLE study will be the same amount for all hours in the season of interest.

Summer and Winter season FSPRMs will be determined separately.

B.7. FSPRM Calculation

As discussed in Section 2.1.1, the Program FSPRM will be given on a UCAP basis. To calculate the FSPRM on a UCAP basis, the capacity value determined in Section B.6 must be converted to a UCAP value (see Table 2-13 for details on this conversion).

Table 2-13. Resource capacity conversion to UCAP for FSPRM calculation.

Resource type	Conversion to UCAP
Thermal Generation	UCAP capacity values from the QCC analysis are used to replace the ICAP (nameplate) value of all thermal resources.
VER	UCAP capacity values for each VER type will be taken from the QCC VER amounts calculated from the WRAP ELCC analysis.
Storage Hydro	No conversion needed - The QCC values determined through the Hydro QCC method will be used in the calculation.
Short-term storage/ hybrid resources/ DR	No conversion needed - ICAP capacity (at the Program time duration requirement) is used for the UCAP calculation.
Pure Capacity adjustment to meet 1-in-10 LOLE	No conversion needed.

After the UCAP conversion is complete, the UCAP FSPRM is calculated:

$$\boldsymbol{PRM\ (UCAP)\ (\%)} = \frac{\boldsymbol{Capacity\ (@1-in-10)-Demand}}{\boldsymbol{Demand}} * \mathbf{100}$$

B.8. Simulation Process

The probabilistic LOLE study will model random forced outages for resources in the WRAP footprint during each hour of the study. Each simulation will account for a different variation of forced outages, wind output, and load uncertainty for all hours of the year. The stop criterion for the modeling simulation is when the LOLE convergence factor is greater than or equal to 95% for consideration of probabilistic indices. The software will calculate the convergence factor to determine if additional simulations are needed.

SECTION 2: APPENDIX C - FSPRM ALLOCATION METHODOLOGIES

The FSPRM represents a “safety margin” of capacity that is required by the WRAP footprint to maintain the reliability of the area. For the most part, the FSPRM is determined on a system-wide basis. Once the FSPRM has been calculated, each Participant’s FS Capacity Requirement must be identified.

The FS Program will allocate the capacity requirement of the FSPRM to each Participant based on their individual P50 Peak Load forecast using the Non-Coincident Peak (NCP) of each Participant. By allocating the FSPRM requirement in this manner, Participants will have a simple, straightforward method for determining their reserve requirement, with equal sharing of load diversity benefits. Table 2-14 provides an example of the FSPRM capacity allocation calculations.

The calculation appears as shown below:

$$\textit{Allocated capacity requirement} = \left(\frac{\textit{Participant's P50 load}}{\sum \textit{All Participant's P50 load}}\right) * \textit{regional capacity need}$$

Table 2-14. Example FSPRM Capacity Allocation Methodology Calculations.

NCP load of the WRAP footprint **= 5,025 MW**
Participant "A" – P50 load = 1,000 MW (load at WRAP Peak = 950 MW)
Participant "B" – P50 load = 2,000 MW (load at WRAP Peak = 1,925 MW)
Participant "C" – P50 load = 2,200 MW (load at WRAP Peak = 2,150 MW)
Regional FSPRM is calculated to be 15% of the WRAP Coincident Peak (CP) load through the LOLE study
With the calculated FSPRM, the total capacity needed for the region is:
1.15*5,025 MW = 5,779 MW
The effective PRM for all Participants becomes:
PRM = 5,779 MW/5,200 MW = 11.1%
Calculation of capacity (can use equation above or if the effective PRM is known, multiply by the effective PRM).
Participant "A" – (1,000 MW /5,200 MW) *5,779 MW = 1,111 MW
Or 1,000 MW * 1.111 = 1,111 MW
Participant "B" – (2,000 MW/5,200 MW) * 5,779 MW = 2,223 MW
Or 2,000 MW * 1.111 = 2,223 MW
Participant "C" – (2,200 MW/5,200 MW) * 5,779MW = 2,445MW
Or 2,200 MW * 1.111 = 2,445 MW

C.1. Impact of CRs on FSPRM

In accordance with standard BAL-002-WECC-2a, a BAAs total CR needs are based on the requirement to carry reserves on three percent of hourly integrated load and three percent of hourly integrated generation; this will result in different total requirements depending on Participants' generation portfolios and load profiles.

The LOLE study and resulting FSPRM assures that during a loss of load event, Participants' CRs are maintained. To ensure this, the LOLE study assumes an average 6% CR requirement when determining the FSPRM. Once the FSPRM for the region is identified, appropriately allocating those CRs to Participants requires consideration of which Participants are responsible for the 3% of generation CR obligation. For example, in a scenario where Participants' P50 loads exactly match their portfolio QCC, the allocation of the CR requirement to each Participant is equal to 6% of P50 load. Given that we expect some Participants to own, operate, and register large fleets (greater portfolio QCCs than their P50 loads), and others to rely primarily on importing generation, we must adjust the showing requirement to reflect this nuance. To arrive at a Participant's FS Capacity Requirement (accounting for differing resource positions), the regional FSPRM (with the embedded 6% of P50 load assumption) will be adjusted based on the net of a Participant's purchases and sales submitted in the FS. A Participant with a negative net of purchases and sales will be deemed to be a net importer (assumes purchases as indicated with a negative (-) sign, as they decrease the CR obligation). A Participant with a positive net of purchases and sales will be deemed to be a net exporter. The adjustment to arrive at the FS Capacity Requirement will be ((-purchases + sales) * .03). For a Participant with total purchases of 150 MW and total sales of 100 MW the adjustment to the FS Capacity Requirement would be -1.5 MW or ((-150 +100 * .03). For a Participant with total purchases of 150 MW and total sales of 300 MW the adjustment to the FS Capacity Requirement would be 4.5 MW or ((-150 + 300) * .03).

Thus, the FS Capacity Requirement includes an approximation of a Participant's CR under the circumstances modeled throughout the FS metric setting (a P50 load day where all resources are performing at their QCC). The sharing calculation in the Ops Program includes a delta CR term which will adjust for differences between the FS CR assumptions and the forecasted CR obligations in the Ops timeframe.

SECTION 2: APPENDIX D - QUALIFIED CAPACITY CONTRIBUTION MODELING

D.1. Storage Hydro

D.1.1. Time Period Approach for Summer and Winter Binding Requirements

The WRAP Development Project Steering Committee recommended that a “time period” approach be taken to determine the potential Qualifying Capacity Contribution (QCC) of storage hydro. A time period approach consists of a historical look-back of the generation output during CCH to determine how much capacity should be expected to be available during high load periods in the future. While this approach is not intended to be perfect, it does establish a common and transparent method for determining the QCC for storage hydro.

One of the main benefits of using a time period approach is that the methodology is based on data that reflects the actual operation of the facilities during past high load periods, and reflects the myriad of considerations, constraints and complexities that went into the operation of the resources during those periods. It can be very difficult for any model to accurately capture and reflect the various operational and non-power constraints, while meeting flow and storage targets of hydro resources, and then associate the considerations that go into the dispatch decision-making processes. The time period approach is a way to estimate the QCC in a manner that objectively reflects these various considerations. It must also be recognized that the time period approach reflects historical market conditions and constraint parameters. Care must be taken to ensure the modelling of the hydro QCC is constantly reviewed and updated as warranted by any significant changes to those parameters to ensure the results can be properly interpreted and applied.

In order to ensure that the modelled QCC of the footprint’s hydro fleet is properly stated, it is anticipated that the hydro methodology proposed here would be used in conjunction with a portfolio analysis of all RA resources for the WPP footprint, in order to ensure that the footprint’s RA fleet works collectively to meet the system needs.

Consistent with the RA metric recommended by the Steering Committee, the time periods that will be considered are the Summer season (June through September 15) and Winter season (November through March 15).

D.1.1.1. Ten-Year Historical Period

To capture a wide range of variability around the operating conditions of storage hydro resources, it was determined that 10 years of historical data should be considered. A 10-year look-back is expected to provide enough operations data to include a range of hydrological conditions. The data should reflect associated elevation and storage impacts on the hydro generation over a sufficiently broad range of conditions, for the purpose of evaluating hydro QCC. If assessing firm energy capability in the future, looking to a much longer period of time that includes critically low stream-flows would be needed. The current model utilizes data from 2010 through 2020 and will be updated moving one year forward each year.

D.1.1.2. Use of Capacity Critical Hours

The storage hydro capacity contribution evaluation will use the CCH identified in the LOLE study and assessment of WRAP metrics (see Section 2.2.2).

D.1.1.3. QCC Determination

The time period approach taken to evaluate storage hydro resources evaluates the QCC of a storage hydro resource by considering the actual generation of the resource, as well as any additional capacity theoretically available, as identified as usable energy in the storage reservoir. Usable storage can increase the QCC value up to the maximum capacity of the resource. As a simple example, a hydro resource with a maximum capacity of 125 MW (based on the elevation of the reservoir at that time) that was generating at 75 MW during a CCH, could have a QCC on that hour of the full 125 MW if it could be shown that there was sufficient *useable* energy in storage for that hour to generate at 125 MW. On the other hand, if there was no useable energy in storage at that resource (i.e., the resource was just passing inflows), the QCC of the resource would be limited to the 75 MW of actual generation.

A reasonable approach to the treatment of multiple CCHs occurring on the same day is to limit the additional capacity claimed beyond actual generation to the total usable energy in storage *on that day*. As an extension of the simple example above, if the resource was generating at 75 MW for two contiguous CCHs on a calendar day and had an additional 50 MWh of available energy in storage, *in total*, over those same hours, there would be insufficient energy in storage to run at its maximum capacity in both hours, but the resource could be operated at an average output of 100 MW across the two-hour period. As such, the QCC would be limited to 100 MW for the two CCHs.

When performing the evaluation, to ensure the methodology reasonably reflects the operational flexibility of the resource, the actual historical generation of the resource in *non*-CCHs is left unchanged (i.e., it cannot be assumed that generation in non-CCHs could have been backed down to make more energy in storage available in future CCHs).

The following methodology would be used to determine the QCC value using the time period approach described above, and Table 2-15 summarizes the resource information required to apply the methodology.:

- For each day found to contain one or more CCHs, the hydro resource will be evaluated to determine the maximum available capacity for each CCH, based on the conditions of the storage associated with the hydro resource on that day.

- For each hydro resource, for each CCH, determine:

o Generation output during the CCH

o Useable energy in storage at the end of the CCH

o QCC for each hour, which would be the generation output plus useable energy in storage, up to the maximum generation capability (adjusted for reservoir elevation head as applicable), taking into account plant or unit-specific limitations (e.g., units on a common penstock, transformer limitations, etc.) and the resource's EFOR.

▪ For calendar days with multiple CCHs, the QCC will be limited to the actual generation, plus the usable energy in storage over that day

o Non-power operational constraints that limit the use of energy in storage

Table 2-15. Resource information required to apply the methodology.

Information Needed	Notes
Reservoir elevation range	Min and Max – this may be seasonally adjusted
Reservoir Storage Curve	Indicating energy in storage based on the reservoir elevation
Resource Pmax vs Elevation	Indicating maximum capacity of resource as the elevation of the reservoir changes
Power as a function of discharge	For the "Discharge Method"
H/K as a function of elevation	For the "Elevation Method"
Hourly Historical Data	– Actual generation – Starting reservoir elevation – Ending reservoir elevation – Any applicable resource generation restrictions (seasonal flow restrictions, etc.) – Any applicable reservoir elevation restrictions reflected as a minimum water in storage value – Other non-power operation constraints limiting the use of water in storage

From the information in Table 2-15, the hourly values in Table 2-16 can be estimated for each CCH:

Table 2-16. Hourly values that can be estimated.

Estimated Values	Notes
Actual water in storage	Using the elevation and storage (kcfsh) tables
Additional capacity available beyond the actual generation	Subject to elevation restrictions
Cumulative additional generation	The running total of the additional generation claimed in each CCH for the calendar day, used to deplete the elevation of the reservoir to validate the feasibility of using additional capacity in each CCH on each calendar day
Hourly QCC	The sum of the actual generation plus the additional capacity available

The hydro capacity contribution towards the RA requirement is calculated by the resource owner as the simple average of the hourly QCC values in each CCH over the 10 seasons studied. These QCC values are averaged over each month in each season to determine final monthly QCC values.

Figure 2-6 illustrates the application of the methodology to the Rocky Reach hydro facility.

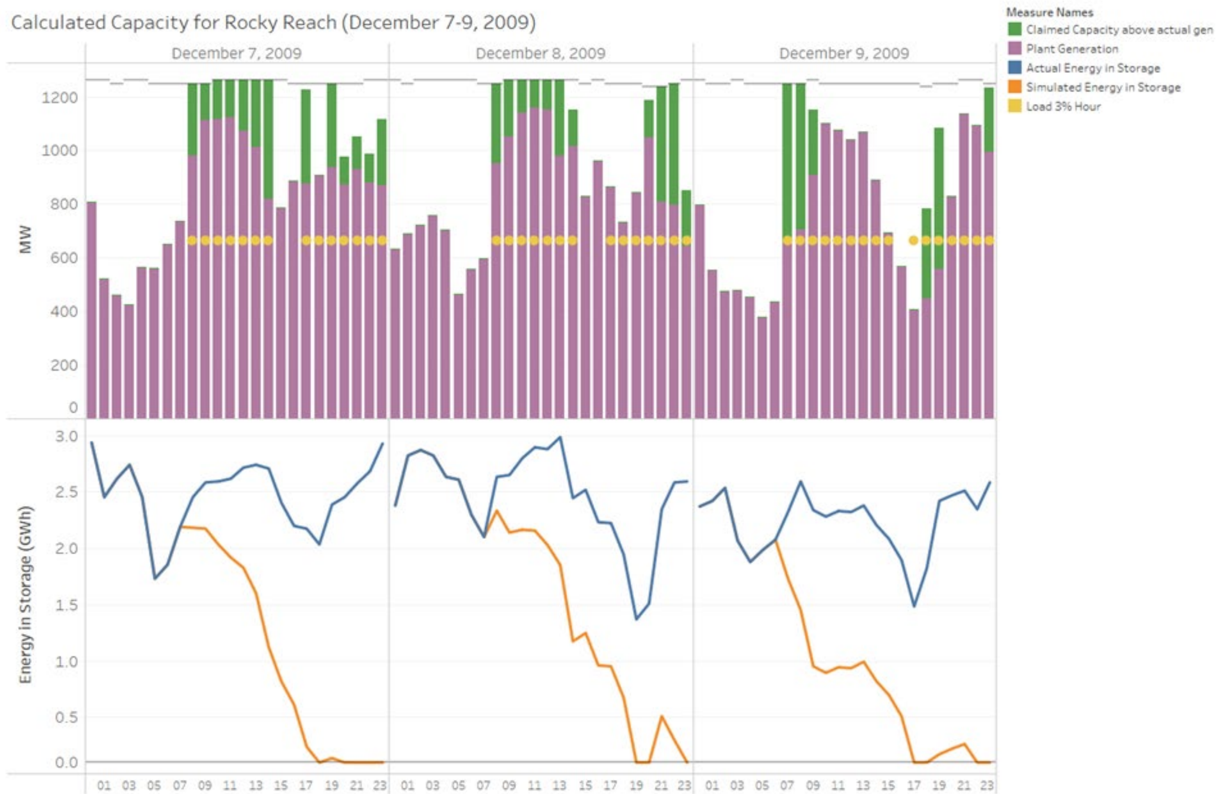


Figure 2-6. Example application of the storage hydro QCC methodology for Rocky Reach.

The Steering Committee recommended that an UCAP methodology based on forced outage rates be applied to hydro resources to account for forced outages, consistent with the treatment of the other dispatchable (thermal) resources. The UCAP methodology is generally expressed as

$$\boldsymbol{UCAP = ICAP * (1 - EFORd)}$$

Where:

ICAP is the installed (nameplate) capacity of a thermal unit or the maximum operational capacity if it is less than nameplate (hydro)

$EFOR_d$ is the resources Equivalent Demand forced outage rate, calculated by looking at historical outage statistics for the resource (GADS data, or equivalent).

The UCAP ratings will be used as the maximum capacity of hydro units when applying the WPP Storage Hydro QCC Methodology.

D.1.1.4. Treatment of Planned Outages

In addition to accounting for forced outages, the workgroup proposes that UCAP values used in the FS workbooks be reduced for planned outages. This will ensure that QCC is calculated correctly in hours limited by insufficient storage (occurs most often over multiple, consecutive CCHs in the same day).

Table 2-17 and Table 2-18 below illustrate the QCC calculation over a four-hour consecutive period using the UCAP methodology and the UCAP + planned outages methodology.

Table 2-17. Calculating QCC using UCAP = 125MW.

Consecutive CCHs	Historical Generation	Historical Storage	UCAP (125 MW)	Draft to maximize Capacity	Storage Hydro after draft	QCC
	MW	MWh	MW	MWh	MWh	MW
1	50	250	125	75	175	125
2	50		125	75	100	125
3	50		125	75	25	125
4	50		125	25	0	75
Storage empty after 25 MW draft				4-hour average		113

Table 2-18. Calculating QCC using UCAP + Planned Outages = 100 MW.

Consecutive CCHs	Historical Generation	Historical Storage	UCAP + Planned outages (100 MW)	Draft to maximize Capacity	Storage Hydro after draft	QCC
	MW	MWh	MW	MWh	MWh	MW
1	50	250	100	50	200	100
2	50		100	50	150	100
3	50		100	50	100	100
4	50		100	50	50	100
A 25 MW planned outage decreased QCC by 13 MW				4-hour average		100

The four consecutive CCHs in Table 2-17 illustrate how the QCC is limited due to insufficient storage. In Table 2-18, the UCAP is reduced by a 25 MW planned outage. This reduced capacity requires less draft from storage in CCHs 1-3 to maximize the QCC in those hours. This reduction in draft provides sufficient storage in CCH 4 to maximize the QCC.

For FS purposes, the workgroup proposes that planned outages be included in the QCC calculation.

D.1.1.5. Treatment of Non-Power Constraints

Each Participant is asked to review methodology and incorporate the specific non-power constraints that are applicable to the individual projects, thus reducing the QCC value of each plant to a level that is believed to correspond to today's operational capability. This is done through creating additional constraint logic in the spreadsheet that adds today's non-power constraint to all 10 years' worth of evaluation.

While the addition of non-power constraints is an "ask" under the methodology, it is expected that Participants/LREs will include those non-power constraints that limit their operational capability. Given that the QCC values of Storage Hydro transfer directly into the Ops Program, Participants/LREs would be disadvantaged to not account for those constraints and then be called upon to deliver capacity from those resource when it was not available.

D.1.1.6. Treatment of Cascaded and Coordinated Hydro Systems

A Cascaded Dual Plant methodology was also developed specifically for cascaded and coordinated hydro systems. For cascaded hydro resources on the same river systems that are operated in a coordinated manner, when determining the QCC, the useable energy in storage at the downstream resource could be enhanced by the operations at the upstream resource, thereby maximizing the contribution of the combined cascade systems. The Cascaded Dual Plant methodology does not attempt to optimize use of the upstream storage to maximize the combined QCC, but it does allow the downstream project to utilize the additional discharge from the upstream project. The additional discharge from the upstream project can come in the form of spill. Spill is not a component of the single plant model.

D.2. Areas of Further Exploration

The following areas of potential further study have been identified:

D.2.1. Ten-Year Period

Because the results of any time period approach will be very sensitive to water supply conditions and associated reservoir levels, it was identified that a rolling 10-year look-back may not capture the wide range of water conditions that could be experienced. To address this concern, the look-back period could be extended to look further back in time. However, since hydro operations and reservoir management has changed over time, the older data captured may not be indicative of expected operations looking forward, making the resulting capacity contribution results less reliable. As such, consideration should be given to the trade-offs associated with using a larger data set.

D.2.2. Interaction with WRAP Modelling

It will be critical to understand how the hydro capacity contribution methodology fits together with the other elements of the RA modelling effort, in order to properly identify and address any gaps in the hydro methodology or how it might be applied.

D.2.3. Stress Case Analysis

After the completion of the non-binding program (anticipated to be three seasons) the WRAP will undertake an analysis to understand the impact of persistent fuel supply limitations (an energy adequacy stress case), particularly as it relates to storage hydro, on participants ability to meet their WRAP compliance metric. The “stress case” will include both the Summer and Winter seasons, utilize exceptionally high loads and a reduced hydro QCC resulting from water year conditions similar to 2001. The WPP Storage Hydro QCC Methodology may not be re-run for all storage hydro using critical water, but an attempt will be made to understand the impact on projects with a range of storage and flexibility. The reduction in QCC to the representative plants will be used as a proxy for the impact to the region-wide fleet. An assessment can be made of how deficit the footprint might be in each season under these stress scenarios. The deficit will then be allocated to 1) deficiency in CRs and 2) reliance on imports (beyond the WRAP’s import/export assumptions), or, if no imports are available, load curtailment. This will allow for informed discussion about the impact of extreme tail events and the tradeoff between covering these events and being exposed to them. As time and resources allow, a more thorough assessment of tail events could be made by incrementally reducing the amount of hydro QCC available in the model, increasing the load and observing the impact to the LOLE/FSPRM.

D.3. Variable Energy Resources

The QCC for VER resources will be determined annually for each month through the use of an ELCC analysis. With some exceptions, the models for the ELCC study will be the same as the model used for the year two (T-0) LOLE study. The exceptions mainly are based on using actual historical loads instead of forecasted peak demand for the modeled areas.

D.3.1. Effective Load-Carrying Capability Modeling

Table 2-19 shows are how certain parameters of the VER ELCC study will be handled.

Table 2-19. VER ELCC modeling parameters.

Parameter	Notes
Area modeling	Specific resource zones will be used in the ELCC study. The loads and generation in each resource zone will be modeled separately.
Load modeling	Handled in accordance with the LOLE study, except that load will not be scaled to forecast peak.
Load Forecast Uncertainty	No LFU will be taken into account.
Generator modeling	– Thermal generators – modeled existing resources with the same parameters and assumptions as in the LOLE study. – Storage hydro generators – modeled existing resources only with the same parameters and assumptions as in the LOLE study. – VERs – modeled existing and projected resources for the year and season of interest with the same parameters and assumptions as in the LOLE study. – Other generation – modeled existing resources only with the same parameters and assumptions as in the LOLE study.

Effective load-carrying capability will be determined for the VERs in the WRAP footprint. The ELCC study will consist of analyses utilizing LOLE metrics to determine the capacity provided by the VERs being analyzed. The LOLE benchmark metric to be used in the ELCC accreditation study will be a one event in 10-year threshold. The ELCC of VERs will be calculated on a monthly basis. For the ELCC study, loss-of-load events will be tabulated during the Binding Season hours for determination of the 1-in-10 LOLE. Loss-of-load events that occur outside of the Binding Season hours will not go into the calculation of the capacity value of VERs.

Other generation types (non-VERs) will be removed (or added) from (to) the model to make a determination of whether the WRAP footprint reaches the 0.1 day per year reliability threshold. Perfect capacity will be simulated for these determinations.

D.3.1.1. Simulation Process

The ELCC study will be conducted by performing probabilistic simulations in a manner that resources in the WRAP footprint will be randomly forced out of service during each hour of the study. Each simulation accounts for a different variation of forced outages and load uncertainty for all hours of the year, similar to the LOLE Study.

Simulations will be performed for each month of the Binding Season. These will be broken down as follows:

- Summer: June, July, August, September 1-15
- Winter: November, December, January, February, March 1-15

Each historical year will be analyzed separately. The ELCC results from each year will be averaged together for a final result.

D.3.2. Effective Load-Carrying Capability Study Process

To determine total ELCC, a LOLE value for the benchmark system will be calculated. The benchmark system is defined as load supplied by all conventional (coal, gas, etc.) and storage hydro generation in the WRAP footprint. The VER of interest will be excluded from the benchmark system. All other VER types will be included. For example, if the wind resource type is being analyzed, only wind will be excluded from the benchmark system.

If the resulting LOLE is greater than the 0.1 day per year threshold, “pure capacity” will be added until the 0.1 threshold is achieved. *(“pure capacity” refers to adding same amount of capacity for every hour of the year or season without an assigned forced outage rate.)*

If LOLE is less than the 0.1 day per year threshold, “pure negative capacity” will be added until the 0.1 threshold is achieved.

The capacity calculated is designated in Figure 2-7 as "Pure Capacity 1."

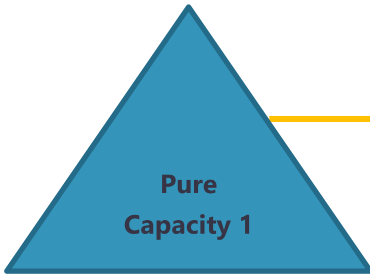


Figure 2-7. Diagram of system without renewable resources.

Next, a LOLE value for all wind generating units will be determined, repeating the steps described previously. The pure capacity value calculated is designated in Figure 2-8 as "Pure Capacity 2."

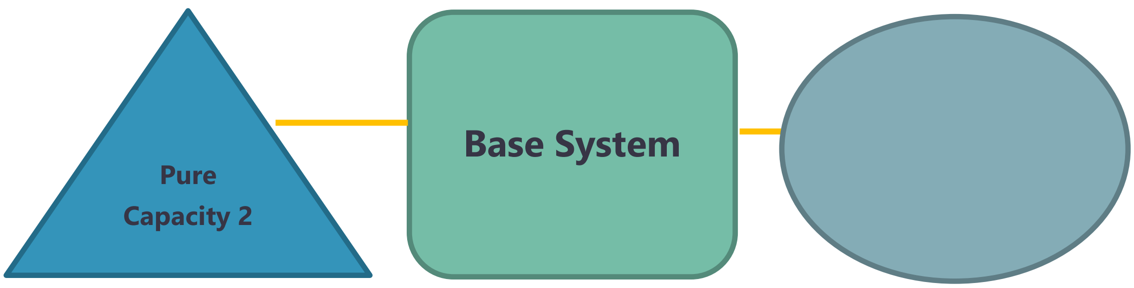


Figure 2-8. Diagram of system with renewable resources.

The difference between the results of these two steps is considered the ELCC accredited value of the resources being studied.

$$\boldsymbol{ELCC\ of\ VER\ (under\ study) = Pure\ Capacity\ 1 - Pure\ Capacity\ 2}$$

These processes are repeated to determine QCC for each year that is studied. This process is repeated for Summer and Winter separately.

D.3.2.1. Determination of VER Zones

The ELCC study will determine the amount of capacity provided by all VERs (of the specified type: e.g., wind) analyzed in the WRAP footprint. This overall capacity contribution value must be allocated to individual VERs to enable Participants to properly claim their resources' QCC value.

The FS Program will determine and demarcate geographic VER zones for each VER resource type and assign existing VERs to a zone. Effective load-carrying capability studies will be performed for each VER zone (and VER type), calculating a total capacity value of the resource of interest in that zone. The capacity calculated for each zone will be allocated to VERs of that type in that zone on a pro-rata basis.

To ensure that over-accreditation of VERs does not occur, an ELCC study of the entire WRAP will be conducted and a total capacity value for all VERs (of each type) in the WRAP footprint will be calculated. After each VER zone capacity total (for each VER type) has been determined, the sum of the VER zone totals will be compared to the footprint total. If the sum of the zones is greater than the footprint total, all VER zone totals will be scaled down until the totals match the footprint total. Table 2-20 provides an example of the calculations to determine total VER (in this case: wind) capacity.

Table 2-20. ELCC study of WRAP footprint to calculate total wind capacity.

A study of four wind zones reveals the following capacity values for wind in each zone:				
Zone 1	Zone 2	Zone 3	Zone 4	**Total**
1,000 MW	800 MW	700 MW	1,000 MW	**3,500 MW**
A study of the region **reveals the following capacity value for the region's wind:**				
Regional wind = 3,200 MW				
The zones will be recalculated as follows:				
Zone 1	Zone 2	Zone 3	Zone 4	**Total**
1,000 * (3,200/3,500)	800 * (3,200/3,500)	700 * (3,200/3,500)	1,000 * (3,200/3,500)	
914 MW	732 MW	640 MW	914 MW	**3,200 MW**

At this time, the FS Program has not made a final determination of VER zones for any VER resource types.

D.3.3. Determination of ELCC for Future VER Resources

It is understood that as VERs are added to a system, the capacity value provided by all similar VERs as a function of the nameplate value of those resources will decrease. It, therefore, becomes important for Participants to have an understanding of how VER QCC values may change over time as the penetration of VERs increases.

For each VER zone, after the QCC of all existing and near-term planned VERs have been calculated and allocated, additional ELCC studies will be performed to account for future

VERs (of each type) in each zone. It is proposed to study incremental additions of wind and solar resources in each wind and solar zone of 2,000 MW, 4,000 MW, and 6,000 MW[19]. These additional wind and solar resource amounts will be created by scaling up the number of wind turbines (nameplate capacity) or solar photovoltaic in each zone. An ELCC curve will be provided to determine future capacity values for new resources dependent upon the penetration of resources in that zone.

D.3.4. Treatment of Other Classes of VERs in the ELCC Analysis

One complexity of performing ELCC analyses for multiple classes of VERs is the complementary/antagonistic impact that VERs may have on each other. For example, if many wind resources are in the base case for a study on solar resources, the solar resources could be impacted negatively. However, if no wind resources are included in the base case, the solar resources may receive more capacity credit than they should. There could be a positive impact if the wind resources are found to be providing capacity during hours when solar resources may not be able to provide capacity. However, if there is an amount of wind that is so great that it shifts the capacity need for solar resources into an hour where sunlight is not plentiful, then those solar resources may be negatively impacted. For consistency, the FS Program will include all VERs not being analyzed in the base case when studying the resources of interest. The wind ELCC study will include all solar and RoR hydro resources. The solar ELCC study will include all wind and RoR hydro resources. The RoR hydro study will include all wind and solar resources.

D.4. Short-Term Storage

Short-term ESRs will have their capacity value determined by the value the resource is able to produce during its capability test for the required duration of the test. Short-term ESRs will be modeled in the manner of a thermal resource whose maximum power capability is equal to the capacity value. If an outage rate history can be obtained for such resources, it will be utilized.

To determine the duration requirement for short-term ESR (Table 2-21) a review of the top 5% of CCHs was undertaken for the previous 10 years of Summer and Winter Binding Seasons. The number of CCHs in a day was tracked. The total weighting of each value was multiplied by the % of days that had that value. The weighting methodology

[19] It may not be necessary to study incremental amounts of RoR hydro resources.

resulted in a duration of five hours for the Summer binding season ESRs and 4.7 hours for the Winter binding season ESRs.

Table 2-21. Duration requirement for short-term storage.

	Duration of CCH in Day	% of CCH Days	Weight
Summer (4-hour minimum)	4	61.00%	2.44
	5	13.00%	0.65
	6	10.00%	0.6
	7	7.00%	0.49
	8	5.00%	0.4
	Total Weighting (Summer)	100.00%	4.96
Winter (4-hour minimum)	4	74.00%	2.96
	5	9.00%	0.45
	6	6.00%	0.36
	7	4.00%	0.28
	8	3.00%	0.24
	9	2.00%	0.18
	10	1.00%	0.1
	11	1.00%	0.11
	Total Weighting (Winter)	100.00%	4.68

D.5. Thermal Units

The QCC for thermal units will be calculated with a performance-based methodology. The methodology will calculate UCAP using NERC GADS (or equivalent) data and a seasonal EFOF equation using the term "EFOF (CCH)."

Participants will provide their NERC GADS (or equivalent) data in the annual data request. The QCC values will be calculated for all thermal resources using the following guidelines:

$$EFOF(CCH) = 1 - \frac{\sum FOH_{cch} + EFDH_{cch}}{total_{CCH}} * 100\%$$

Where:

FOH_{cch} is Forced Outage Hours occurring on CCHs,

$EFDH_{cch}$ is Equivalent Forced Derating Hours occurring on CCHs

$Total_{cch}$ is total number of CCHs for the timeframe of interest

Definitions of FOH and EFDH can be found in Table 2-22.

Table 2-22. Definitions of FOH and EFDH.

Definitions	
FOH	Sum of all CCH experienced during Forced Outages (U1, U2, U3) + Startup Failures.
EFDH	Each forced derating (D1, D2, D3) transformed into equivalent full outage hour(s). This is calculated by multiplying the actual duration of the derating (hours) by the size of the reduction (MW) and dividing by the net maximum capacity. These equivalent hour(s) are then summed by CCH. $$\frac{Derating\ Hours * Size\ of\ Reduction}{Net\ Maximum\ Capacity}$$

- Perform calculation for each resource seasonally and for each historical year. QCC will be assigned to each resource for the entire binding season.

- Six years of data will be used for the calculation. The worst performing year will be removed from the calculations, allowing for a five-year average.

- Only forced outages or derates occurring during CCHs will be used to calculate QCC. Outages during hours that are not deemed to be capacity critical will not negatively impact QCC.

- All years (of the five years) to have equal weighting.

- Outside of Management Control outages as reported under NERC GADS Appendix K[20] (or equivalent) will be excluded from the calculation.

- For Participants relying on resource specific transactions external to the FS Program, those resources will follow the same UCAP structure for thermal resources and the Participant will be responsible to make sure the information is provided.

- Each event will need to be broken out by hour. If the NERC GADS (or equivalent) data is reported in minutes, then the hour that contains the outage will need to be equalized to account for the minutes. For example: if an outage starts on 6/1/2020 at 4:25, then the hour duration for that hour will be less than one since the outage does not start at the top of the hour. The total hours for 6/1/2020 on hour beginning 4:00 would be 0.583 *([60 Minutes – 25 minutes] / 60 minutes in an hour).*

- Diversity of time zones will need to be considered.

- When comparing the event hours to the CCH hour ending identification should be consistent.

D.5.1. Methodology for Units that Do Not Have At Least Six Years of Outage Data

For units that have been in service for at least six years but provide only five years of data, all five years will be included in the analysis and the worst performing year will *not* be excluded.

For units that have been in service for at least six years but provide less than five years of outage data, the outage data provided will be used to determine the QCC. Years with no outage data provided will be treated as years with zero QCC in the overall calculation.

For new units that have been in service less than six years, class average data will be used at the discretion of the WPP.

[20] Appendix K of NERC GADS: https://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/Appendix_K_Outside_Management_Control_2021_DRI.pdf

D.5.2. Methodology for Units that Do Not Report NERC GADS (or Equivalent) Data

Resources that have been in services for more than six years but have not had their NERC GADS (or equivalent) data provided will not meet qualification and registration requirements of the FS Program.

SECTION 2: APPENDIX E - TRANSMISSION MODELING CONSIDERATIONS

The WRAP has worked with the WPP and Participant TSPs to develop a set of LRZs that depict the presence of transmission constraints that are known transmission congestion paths or points in the WPP area. These LRZ boundaries have been determined by review of historical usage of the transmission system and the resulting constraints that have been identified. The LRZs have been set as described in Table 2-23.

Table 2-23. Transmission service-related LRZs.

Zone designation	General description	Participants located in zone	Transmission paths identified as constraints to imports and exports
Zone 1	British Columbia	BC Hydro - Powerex	Path 3
Zone 2	Western Washington, Northwest Oregon	PGE, Tacoma, EWEB, Seattle, PacifiCorp, BPA	Path 4, Path 5, Dixonville
Zone 3	Eastern Washington and Oregon, Southwest Oregon, Northern Idaho	PacifiCorp, BPA, Puget Sound, Douglas, Chelan, Avista, Grant	Path 3, Path 4, Path 5, Dixonville, Path 66, Path 76 Path 14/75, Path 8
Zone 4	Montana	Northwestern, BPA	Path 8, Path 18, Path 80
Zone 5	Southern Idaho	Idaho Power, BPA	Path 14/75, Path 16, Path 18, Path 19, Path 20
Zone 6	Wyoming, Utah	PacifiCorp, BPA	Path 19, Path 20, Path 29, Path 80
Zone 7	Nevada	Nevada Energy, BPA	Path 16, Path 29, Path 76
Zone 8	Colorado	PSCo	Various paths separating eastern Colorado from the rest of the WPP footprint
Zone 9	California	TID, BANC	

The FS Program will determine Participant usage of the transmission system through firm reservations provided by Participants in their FS portfolios. A complete listing of firm reservations will be gathered. Additionally, the transmission usage will be determined by Participant submitted resources that have not demonstrated firm transmission in the FS window[21].

Each transaction will be analyzed by simulating a 1 MW transfer using the point of receipt and point of delivery. For each reservation, transmission distribution factors (TDFs) will be captured on all transmission paths identified as constraints to imports and exports. For each reservation, the total reservation amount (in MW) will be multiplied by the TDF for each constraint to capture the MW flow on the constraint. Flows will be captured in both directions to account for counterflows. An example is shown in Table 2-24.

Table 2-24. Reservation – 100 MW from Northwestern to Portland General Electric.

1 MW transfer is simulated from NWMT → PGE	
The following TDFs are captured:	The following flows are added to the paths:
Path 8 = 0.5	Path 8 = 50 MW
Path 4 = 0.5	Path 4 = 50 MW
Path 18 = 0.25	Path 18 = 25 MW
Path 14/75 = 0.2	Path 14/75= 20 MW
Path 5 = 0.3	Path 5 = 30 MW

Once the total reserved capacity on all paths has been determined, this information will be used in the determination of whether LRZs have sufficient import capability to maintain the regional FSPRM value or whether the LRZ will be considered a transmission constrained zone.

E.1. Determination of a Transmission Constrained Zone

To determine whether an LRZ is transmission constrained, it must be determined that the zone needs a specified amount of transmission import capability in the LOLE analysis for the zone to meet the reliability threshold of one event-day in 10 years. In order to make such a determination, the LOLE analysis for each LRZ will analyze the ability of the resources located within the LRZ to serve the load within the LRZ while

[21] The amount of firm transmission service required for resources to be shown in the Forward Showing window is being determined and will be available in the "Transmission Memorandum."

allowing no imports. If an LRZ is determined to be capacity adequate (e.g., can meet the 1-in-10 LOLE metric) then the LRZ is not transmission constrained because imports are not required to meet the 1-in-10 LOLE metric for the LRZ.

If an LRZ is determined to be capacity deficient in meeting the 1-in-10 LOLE, the capacity deficiency will be quantified by determining the amount of capacity that must be added to bring the zone up to the 1-in-10 LOLE metric. Then, this capacity deficiency will be compared to the import capability of the LRZ to determine if adequate import capability into the LRZ exists that will allow the LRZ to utilize capacity outside the LRZ. If sufficient import capability is found to exist, the LRZ may maintain the regional FSPRM requirement. If insufficient import capability is found to exist, and unless additional transmission capacity is able to be obtained or demonstrated, a new FSPRM value will be determined for the transmission constrained LRZ. The new FSPRM value will take into account the contracted import capability (i.e., transmission reservations) the LRZ has to import capacity.

For example, if it is seen that a certain LRZ needs 4,000 MW of firm import capability to meet the 1-in-10 LOLE, a review of transmission reservations from the resources that have firm service submitted by the zone Participants (that are located outside the zone) to the zone will be performed. If there are not enough transmission service reservations to account for the needed import capability, the LRZ is potentially transmission constrained. Options to remedy this situation can be either for additional transmission capacity to be obtained or to calculate a higher FSPRM for the zone.

The results of this analysis will be shared with the TSPs of the FS Program. Each TSP, at their own option, will take the transfer capability limitations of the paths and run additional simulations to determine transfers across their own internal congested path(s) if they have any.

SECTION 2: APPENDIX F - PORTFOLIO CONSTRUCTION DETAILS AND EXAMPLES

Each Participant's FS Capacity Requirement, the QCCs of their resources and contracts, and their FS portfolio compliance will be calculated and reported[22] monthly. Table 2-25, Table 2-26, and Table 2-27 provide examples for a Participant's resources QCC ledger, net contract QCC ledger, and total RA transfers.

Table 2-25. Example of a Participant's resource QCC ledger.

Resource Registration									
Asset Owner/Operator: PARTICIPANT A									
ID	**Resource Name**	**Resource Type**	**Resource Subtype**	**Nameplate Capacity**	**Forced Outage Rate**	**Accred-itation**	**Start Month Year**	**End Month Year**	**QCC / UCAP**
1	Hydro 1	Hydro	RoR	600		0.4	2022-11	2022-11	240
1	Hydro 1	Hydro	RoR	600		0.4	2022-	2022-	240
1	Hydro 1	Hydro	RoR	600		0.4	2023-	2023-	240
1	Hydro 1	Hydro	RoR	600		0.4	2023-	2023-	240
1	Hydro 1	Hydro	RoR	600		0.4	2023-	2023-	240
2	Hydro 2	Hydro	Storage	1200	0.03		2022-	2022-	950
2	Hydro 2	Hydro	Storage	1200	0.03		2022-	2022-	1050
2	Hydro 2	Hydro	Storage	1200	0.03		2023-	2023-	1000
2	Hydro 2	Hydro	Storage	1200	0.03		2023-	2023-	980
2	Hydro 2	Hydro	Storage	1200	0.03		2023-	2023-	1000
3	Thermal	Thermal	Natural	700	0.05	0.95	2022-	2022-	665
3	Thermal	Thermal	Natural	700	0.05	0.95	2022-	2022-	665
3	Thermal	Thermal	Natural	700	0.05	0.95	2023-	2023-	665
3	Thermal	Thermal	Natural	700	0.05	0.95	2023-	2023-	665
3	Thermal	Thermal	Natural	700	0.05	0.95	2023-	2023-	665
4	Wind 4	Wind		70		0.15	2022-	2022-	10.5

[22] QCC will be calculated for thermal resources on a seasonal basis but will be reported monthly – each month of the season will have an identical QCC unless other factors such as planned maintenance impact this value.

Resource Registration									
4	Wind 4	Wind		70		0.15	2022-	2022-	10.5
4	Wind 4	Wind		70		0.15	2023-	2023-	10.5
4	Wind 4	Wind		70		0.15	2023-	2023-	10.5
4	Wind 4	Wind		70		0.15	2023-	2023-	10.5
5	Hydro 5	Hydro	Storage	400	0.06		2022-	2022-	300
5	Hydro 5	Hydro	Storage	400	0.06		2022-	2022-	360
5	Hydro 5	Hydro	Storage	400	0.06		2023-	2023-	320
5	Hydro 5	Hydro	Storage	400	0.06		2023-	2023-	350
5	Hydro 5	Hydro	Storage	400	0.06		2023-	2023-	350

Table 2-26. Example of a Participant's net contract QCC ledger.

Contractual Obligations Against Fleet									
FROM ENTITY	TO ENTITY	PURCHASE / SALE	RESOURCE NAME	% SHARE	WITHIN FOOTPRINT	START MONTH YEAR	END MONTH YEAR	AMOUNT	FORCED OUTAGE CLAIMANT
ENTITY A	ENTITY B	SALE	SYSTEM		YES	2022-11	2022-11	-200	ENTITY A
ENTITY A	ENTITY B	SALE	SYSTEM		YES	2022-12	2022-12	-200	ENTITY A
ENTITY A	ENTITY B	SALE	SYSTEM		YES	2023-01	2023-01	-200	ENTITY A
ENTITY A	ENTITY B	SALE	SYSTEM		YES	2023-02	2023-02	-200	ENTITY A
ENTITY A	ENTITY B	SALE	SYSTEM		YES	2023-03	2023-03	-200	ENTITY A
ENTITY A	ENTITY C	SALE	HYDRO 2	0.4	YES	2022-11	2022-11	-380	ENTITY C
ENTITY A	ENTITY C	SALE	HYDRO 2	0.4	YES	2022-12	2022-12	-420	ENTITY C
ENTITY A	ENTITY C	SALE	HYDRO 2	0.4	YES	2023-01	2023-01	-400	ENTITY C
ENTITY A	ENTITY C	SALE	HYDRO 2	0.4	YES	2023-02	2023-02	-392	ENTITY C
ENTITY A	ENTITY C	SALE	HYDRO 2	0.4	YES	2023-03	2023-03	-400	ENTITY C
ENTITY A	ENTITY D	SALE	SYSTEM		YES	2023-01	2023-01	-150	ENTITY A
ENTITY A	ENTITY D	SALE	SYSTEM		YES	2022-12	2022-12	-700	ENTITY A
ENTITY A	ENTITY E	SALE	SYSTEM		YES	2023-02	2023-02	-75	ENTITY A
ENTITY A	ENTITY E	SALE	SYSTEM		YES	2023-03	2023-03	-75	ENTITY A
ENTITY A	ENTITY F	SALE	SYSTEM		YES	2022-11	2022-11	-200	ENTITY A
ENTITY A	ENTITY F	SALE	SYSTEM		YES	2023-03	2023-03	-200	ENTITY A
ENTITY A	CAISO	SALE	SYSTEM		NO	2023-03	2023-03	-150	ENTITY A
ENTITY A	ENTITY G	SALE	WIND 4		YES	2023-03	2023-03	-5	ENTITY A
ENTITY S	ENTITY A	PURCHASE	SYSTEM		YES	2022-11	2022-11	50	ENTITY S
ENTITY Z	ENTITY A	PURCHASE	SYSTEM		YES	2022-11	2022-11	500	ENTITY Z
ENTITY A	ENTITY Y	SALE	SYSTEM		YES	2022-11	2022-11	-800	ENTITY A

Table 2-27. Example of a Participant's total RA transfers.

RA Transfers						
FROM ENTITY	**TO ENTITY**	**TRANSACTION TYPE**	**PURCHASE/ SALE**	**START MONTH YEAR**	**END MONTH YEAR**	**AMOUNT**
ENTITY A	ENTITY B	RA TRANSFER	SALE	2022-11	2022-11	25
ENTITY A	ENTITY B	RA TRANSFER	SALE	2022-12	2022-12	10
ENTITY A	ENTITY B	RA TRANSFER	SALE	2023-01	2023-01	10
ENTITY A	ENTITY B	RA TRANSFER	SALE	2023-02	2023-02	10
ENTITY A	ENTITY B	RA TRANSFER	SALE	2023-03	2023-03	20

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SECTION 2: APPENDIX G – INDICATIVE ANNUAL ASSESSMENT RESULTS

The process for performing Annual Assessments is given in Appendix A-F.

G.1. Disclaimer

This Appendix G relays indicative results of the Annual Assessments that were performed to determine a “proof-of-concept” of the program design. These results are based on input data provided by the Participants during the detailed program design. The input data provided by the Participants was not validated by the Program Developer as these simulations were not intended to provide any justification for a business case to the Participants. The results do not include any potential impacts from the Transmission and Deliverability policy which was still in development when these simulations were performed. <u>These results are very likely to be impacted by ongoing review and refinement of design parameters (in upcoming project phases and beyond). Figures and ranges are provided only for context on the program design and as continued support for the value of a regional WRAP – they should not be utilized without accompanying design information and/or appropriate understanding of their approximate nature at this time.</u>

G.2. Planning Reserve Margin

The process for determining the FSPRM is detailed in Appendix B.

G.2.1. Resources Used in Analysis

The dispatchable resources submitted by Participants for review in the indicative analyses are shown below in Table 2-28. The values for thermal resources (natural gas, coal, etc.) are the nameplate values. Approximate storage hydro QCC values were determined by the Hydro QCC Methodology, where the January values represent the Winter MWs, and the August values represent the Summer values. Note that these hydro QCC values are shown as approximate, as there was no validation of the application of the methodology during this simulation.

Table 2-28. Participant dispatchable resources.

Modeled Resources by Fuel Type	Summer MW	Winter MW
Storage Hydro – approx. QCC Value	38,897	42,271
Natural Gas	22,058	23,085
Coal	10,377	10,407
Demand Response	1,944	547
Nuclear	1,181	1,163
Geothermal	502	502
Pumped Storage	324	324
Petroleum	202	223
Biomass	86	87
Other	173	173
Total	75,744	78,781

Variable Energy Resources included in the analysis are listed below in Table 2-29. These values are nameplate (NP) capacity values.

Table 2-29. Participant VER.

Modeled Fuel Type	Summer MW	Winter MW
Run-of-river hydro (NP)	4,766	4,766
Solar (NP)	7,346	7,346
Wind (NP)	16,432	16,432

Firm imports into the Program footprint are given below in Table 2-30.

Table 2-30. Firm transactions.

Modeled Imports	Summer MW	Winter MW
Firm Imports	717	717

G.2.2. Demand Values Used in Analysis

Load and demand values as submitted by Participants are listed below in Table 2-31. These values reflect a total summation of the individual peaks of Participants. These values do not represent the CP of the program. These values do not represent the loads of any non-Participants in the Program. These values were grossed up to include the approximation of transmission losses (3% of peak demand).

Table 2-31. Participant demand.

Modeled Demand	Summer (MW)	Winter (MW)
2023 Peak Demand – summation of all individual Participants peaks (NCP) grossed up to include 3% transmission losses	61,351	60,635
Exports – includes a) Firm exports to non-Participants embedded in WPP footprint and b) Regional Interchange (not including firm imports and not including interchange with embedded non-Participants)	4,936	4,680
Total – Demand (NCP)	66,286	65,316

G.2.3. Loss of Load Expectation Analysis

As detailed in Appendix B, LOLE probabilistic simulations were performed. Notable items on the LOLE simulations are listed below (see appendix B for additional detail on the modeling design).

- Simulations performed on 10 years of historical weather years (2011-2020).
- Probabilistic simulations included:
  - Variable forced outages of thermal generation
    - Notably, variable forced outages of storage hydro generation were not performed as average forced outage rates were included in the modeled value for that generation type.
  - Probability weighted load forecast uncertainty which varies load levels (above and below forecasts). 2023 forecasts were modeled as the 50^{th} percentile of occurrence
  - VER generation based on the year of study (2023)

- No planned or maintenance outages were included during the Summer or Winter seasons in the simulations
- Contingency Reserves maintained during simulations (6% of WRAP Demand)
- No transmission constraints between zones modeled
- Only LOLE on binding seasons were considered when determining LOLE for each season

G.2.4. Planning Reserve Margin Calculation

Loss of load expectation simulations were performed to determine loss of load metrics. If the LOLE value was less than the 1-in-10 metric, the inputs were adjusted to attain the required metric. Once the 1-in-10 metric was achieved, the FSPRM was calculated. The capacity values of the resources used in the simulations were determined based on the following procedures:

- Thermal generation – the nameplate value of thermal generation capacity was replaced with the QCC value of thermal generation. QCC values were determined in accordance with Appendix D.
- VER generation – the nameplate value of VER capacity was replaced with a proxy ELCC value.
- Storage hydro – storage hydro values as modeled in the LOLE study at their QCC values are used in the FSPRM calculation.
- Energy storage and DR resources – ICAP values
- Pure capacity – adjustments to capacity to reach 1-in-10 metric for each binding season

After capacity adjustments were made, the FSPRM was calculated using the following equation

$$\boldsymbol{FSPRM\ (UCAP)\ (\%)} = \frac{\boldsymbol{Capacity\ (@1-in-10) - Demand}}{\boldsymbol{Demand}} * \mathbf{100}$$

The WRAP design calls for the FSPRM to be based on an NCP; this will facilitate Participant comparison to their current metrics. For comparative purposes to other WRAPs where PRMs are often applied to CPs, a CP demand for the WRAP footprint was calculated for each season from the LOLE studies. A CP PRM is provided for informational purposes only.

The ranges of results for the Summer season are shown below in Table 2-32. These results do not include any adjustment for transmission or deliverability policy which is still in development.

Table 2-32. Summer UCAP FSPRM.

Summer	Demand	UCAP FSPRM @1-in-10
2023 (NCP)	66,286	9-15%
2023 (CP – not a Program metric)	63,744	12.5-18.5%

The ranges of results for the Winter season are shown below in Table 2-33. These results do not include any adjustment for transmission or deliverability policy which is still in development.

Table 2-33. Winter UCAP FSPRM.

Winter	Demand	UCAP FSPRM @1-in-10
2023 (NCP)	65,316	13-19%
2023 (CP – not a Program metric)	63,000	17-24%

G.3. QCC of Thermal and Storage Hydro Resources

The process for the determination of QCC of Program Resources is discussed in Appendix D. The thermal and storage hydro indicative "proof-of-concept" QCC results are discussed in the following sections.

G.3.1. Thermal Resources

QCC for thermal resources is based on historical performance during CCH as detailed in Appendix C. GADS data was requested from Program Participants for their thermal resources. Data provided from Participants included:

- Total thermal generation submitted – 34,579 MW
    - Thermal generation for which GADS data was provided – 27,175 MW
    - Thermal generation for which no data provided – 7,404 MW

For the thermal generation that had GADS data submitted, the QCC (via the $EFOF_{CCH}$ metric) was calculated. The ranges of results are shown in Table 2-34.

Table 2-34. Thermal Resource QCC.

Season	System weighted UCAP
Summer	94-99%
Winter	94-99%

G.3.2. Storage Hydro

QCC for storage hydro resources is resource specific and is handled in accordance with the Hydro QCC Methodology detailed in Appendix D. The ranges of results are shown in Table 2-35 on a monthly basis.

Table 2-35. Storage Hydro QCC.

Month	Nameplate	QCC %
1	49,226	83-89%
2	49,226	80-86%
3	49,226	87-92%
4	49,226	89-94%
5	49,226	81-87%
6	49,226	76-82%
7	49,226	76-82%
8	49,226	76-82%
9	49,226	74-79%
10	49,226	81-87%
11	49,226	78-84%
12	49,226	80-86%

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WPP Western Resource Adequacy Program Detailed Design

Section 3. Operational Design

MARCH 2023

WESTERN POWERPOOL

WRAP

POWERED BY WPP

SECTION 3. OPERATIONAL DESIGN: TABLE OF CONTENTS

INTRODUCTION

3.1. Overview of Operational Design

The Western Power Pool (WPP) Western Resource Adequacy Program (WRAP) Operational Program (Ops Program) implements a mechanism for sharing capacity among the Participants in operations to ensure that Participants can reliably meet their planned load utilizing the capability of all the Participants as was defined in the Forward Showing (FS) Program. Participants’ RA is monitored one week in advance using forecasted system conditions, and Sharing Events are declared so that Participants with capacity shortfalls may utilize the capacity of surplus Participants to meet their capacity needs. The sharing process accounts for demand projections, forced outages, run-of-river (RoR) and variable energy resource (VER) performance, short-term forecasting accuracy and required reserve margins. If any Participant is projected to have a capacity shortfall on the Preschedule Day, the capacity surplus Participants will be directed to hold a specified amount of such capacity for delivery to the deficit Participant(s). If the capacity shortfalls remain into the actual Operating Day, the deficit Participant(s) may call for the delivery of the held capacity and the associated energy for the hours on which they have a capacity deficit.

The Ops Program implements the regional diversity of loads and resources that is leveraged in the FS Program when determining the Fs Planning Reserve Margin (FSPRM). For example, during times when a subset of VERs is performing above their accredited levels or certain Participants are experiencing a low level of forced generation outages, that additional capacity may be made available to deficient Participants who may be experiencing low VERs performance or higher than average forced outages. In a similar manner, the Ops Program will facilitate the benefits of load diversity across the region. The Ops Program enables Participants to collectively manage periods of capacity stress on the grid.

The Ops Program will be managed year-round. The program will be binding during the binding seasons and advisory outside of the binding seasons as shown in Table 3-1. The defined season configurations may change over time.

Table 3-1. Compliance Seasons.

Season	Binding/Advisory	Duration
Winter	Binding	November 1– March 15
Summer	Binding	June 1– September 15
Spring	Advisory	March 16 – May 31
Fall	Advisory	September 16-October 31

3.2. Operations Program Timeline

The Operations Program (Ops Program) is implemented over a timeline beginning with a forecast up to a week prior ("Multi-Day-Ahead Assessment") to the Operating Day, revised daily through the Preschedule Day, and revised hourly into the Operating Day during any Sharing Event. Figure 3-1 demonstrates a high-level summary of the Ops Program timeline for any given event forecast (all times are shown in Pacific Prevailing Time). Participants submit expected demand and supply conditions for the Sharing Calculations every business day for the next seven days in the forecast window. The Sharing Calculations and Holdback Requirement will be provided daily for the next seven operating days. If there is a Sharing Event, the Sharing Calculations will be updated hourly on the Operating Day to inform the Energy Deployment amount, which can be up to the Holdback Requirement set on the Preschedule Day for each Sharing Event. Any capacity not identified in the Energy Deployment is to be released back to Participants. These steps are described in more detail in sections below.

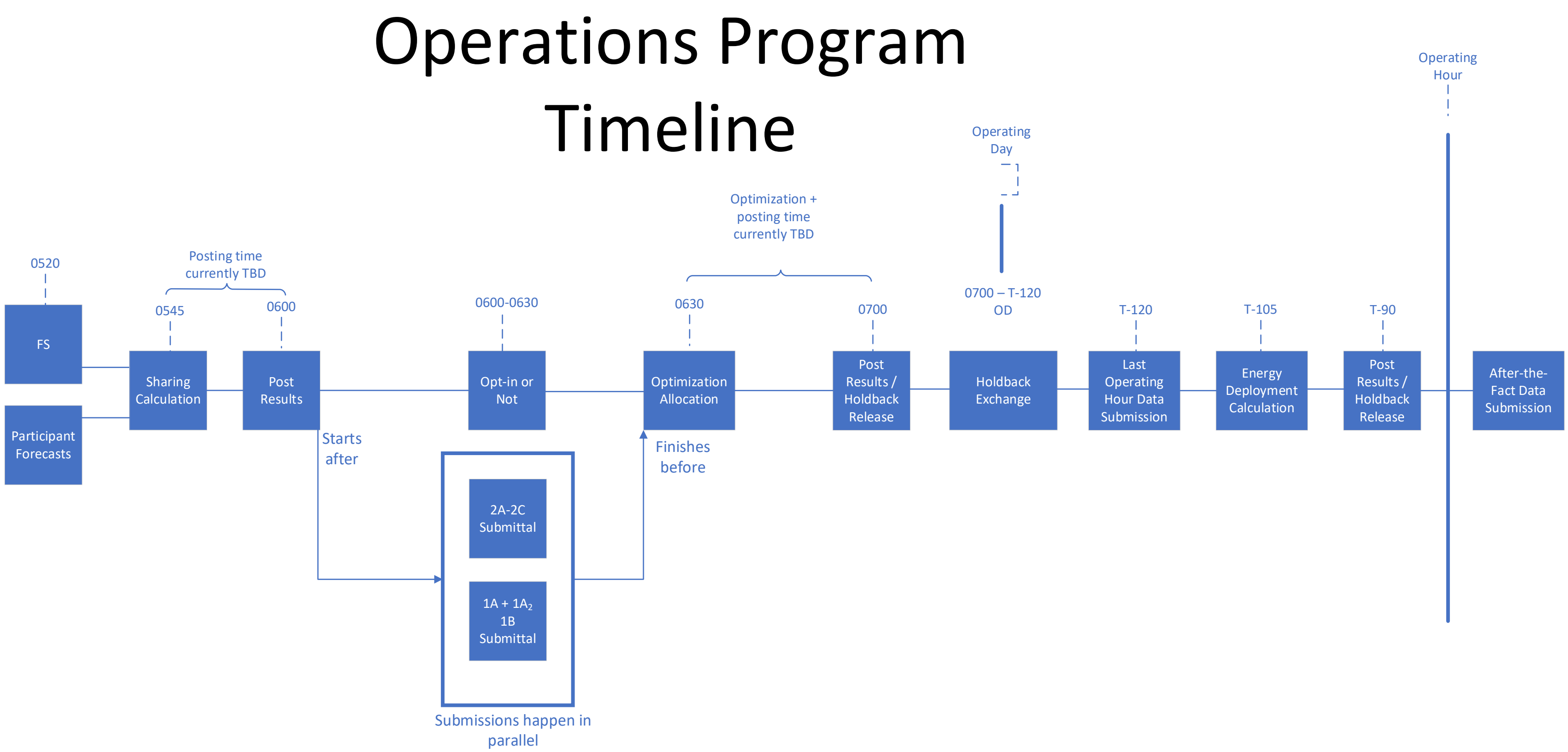

Figure 3-1. Overall Operations Program Timeline.

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3.2.1. Prescheduling Practices

The WRAP will conform to the prescheduling practices of the region, which are defined by the Western Electricity Coordinating Council (WECC)[23] which publishes a prescheduling calendar. At this time, the normal Preschedule Days are:

Scheduling on:	Monday	Tuesday	Wednesday	Thursday	Friday
Scheduling for:	Tuesday	Wednesday	Thursday	Friday & Saturday	Sunday & Monday

For a given Operating Day, the Sharing Calculation assessment will be performed on the WECC Preschedule Day at 04:45 AM. Participants of the Ops Program must submit all requested forecast data for the given Operating Day by 04:30 AM on the prescheduling days. When the Preschedule Day is not the day prior to the Operating Day, the Sharing Calculation will be rerun each interim day (see Section 3.5.1).

Figure 3-2 displays the detailed steps from the identification of an event in the Preschedule Day through the actual event in the Operating Day.

3.3. Sharing Calculation

The Sharing Calculation determines whether Participants need additional capacity or can contribute capacity. A Sharing Event is declared any time a Participant needs additional capacity which is indicated by a net negative result in their Sharing Calculation.

3.3.1. Sharing Calculation

The Sharing Calculation compares each Participant's capacity contribution, adjusted for forced outages and the performance of VER and RoR resources, to their capacity need for each hour in the Multi-Day-Ahead Assessment. If the capacity need is greater than the capacity contribution for any Participant, the result of the Sharing Calculation will be negative and a Sharing Event will be declared for all hours on which the value is negative and, at the Program Operator (PO) discretion, the immediately preceding hour and the immediately following hour when necessary. The details of the Sharing Calculation are presented in Table 3-2.

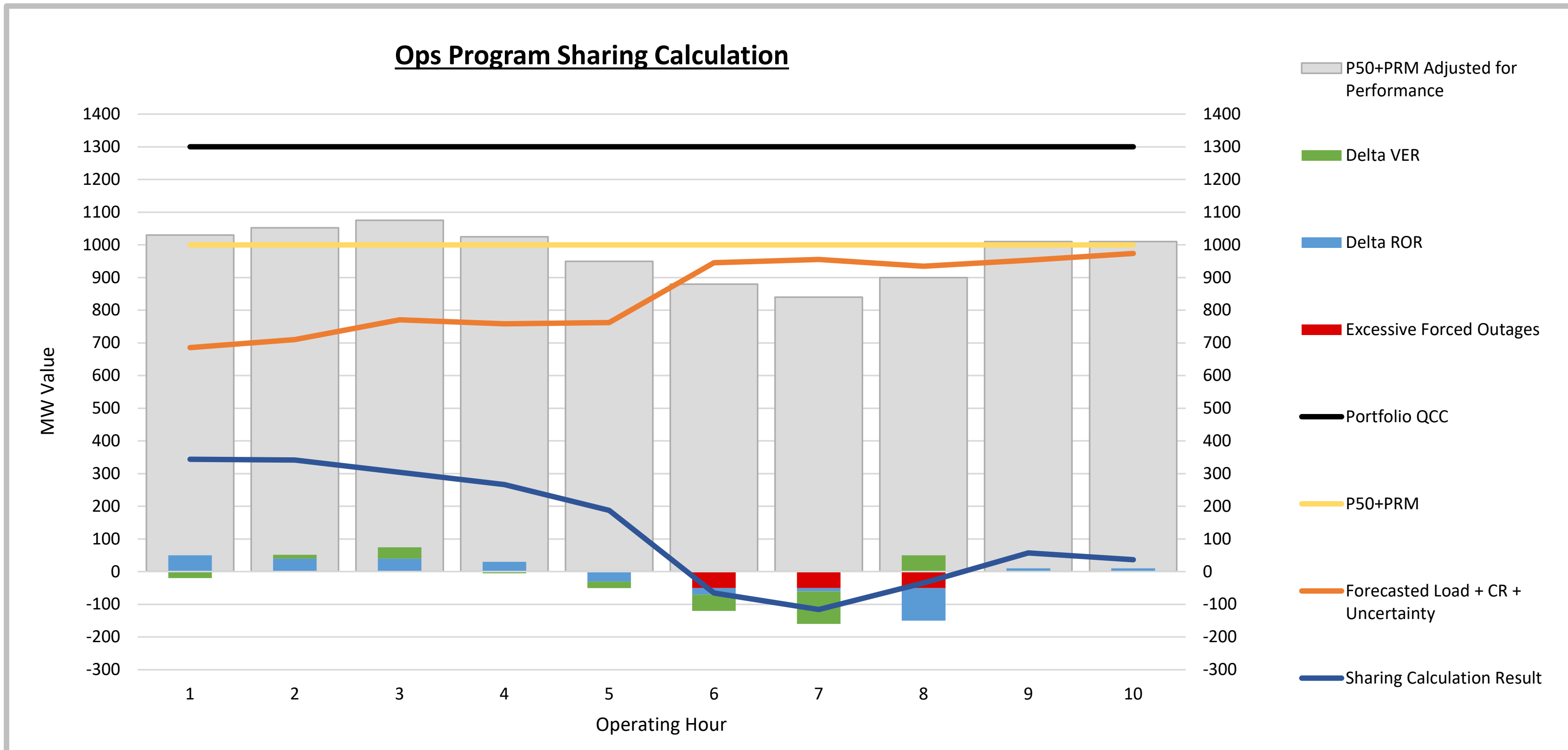
[23]Link to 2023 WECC Scheduling Calendar: https://www.wecc.org/Administrative/09_Fulkerson_2023-WECC%20Preschedule%20Calendar%20Version-1_with%20Sched%20Mtg.pdf

Table 3-2. *Sharing Calculation and Components.*

Definition: Sharing Requirement	
$$\boldsymbol{Sharing\ Requirement = Adjusted\ Capacity\ Contribution - Capacity\ Need}$$ such that $$\boldsymbol{Adjusted\ Capacity\ Contribution = FS\ Capacity\ Requirement + Performance\ Adjustments}$$ where $$\boldsymbol{FS\ Capacity\ Requirement = \mathbf{P50} + \mathbf{FSPRM} - \mathbf{Regional\ Diversity\ Transmission}}$$ $$\boldsymbol{Performance\ Adjustments = \Delta\ Forced\ Outages + \Delta ROR\ Performance + \Delta VER\ Performance}$$ and $$\boldsymbol{Capacity\ Need = Load\ Forecast + \Delta CR + Uncertainty}$$	
P50	The Participant's Monthly P50 Peak Load as set during the FS Program for that binding season.
FSPRM	The capacity in megawatts (MWs) needed to meet the planning reserve requirement, which is calculated by multiplying the FSPRM percentage and the Participant P50 Peak Load Forecast for that month.
Regional Diversity Transmission	Regional Diversity Transmission refers to the MW quantity of additional transmission service rights made available for purposes of regional diversity sharing under the WRAP, as demonstrated by the Participant in its FS Submittal in lieu of demonstrating an equal MW quantity of Portfolio Qualified Capacity Contribution (QCC), as permitted under Part II of the WRAP Tariff; provided that when separate Sharing Calculations are performed for each of two Subregions in which a Participant is responsible for load, the Regional Diversity Transmission shall be equal to the lower of (i) the additional firm transmission service rights (above that required for the FS Transmission Requirement) demonstrated in the Participant's FS Submittal and (ii) the additional firm

Definition: Sharing Requirement	
	transmission service rights (above that required for the FS Transmission Requirement) demonstrated in the Participant's FS Submittal minus any transfer made from the Subregion with the lower FSPRM to the Subregion with the higher FSPRM to address all or part.
Δ Forced Outages	Includes any outages or de-rates associated with thermal generation units, storage hydro units, and transmission outages impacting firm capacity import. Does not include generation on outage for scheduled maintenance.
Δ RoR Performance	Expected RoR hydro generation minus that project's QCC. Includes both over and under performance.
Δ VER Performance	Expected VER resource generation minus that project's QCC. Includes both over and under performance.
Load Forecast:	Forecast of expected hourly loads for the Operating Day.
Δ CR:	Expected Contingency Reserves (CRs) for each hour of the Operating Day minus the CRs that were included in the FS Program for that month. CRs will be determined pursuant to appropriate North America Electric Reliability Corporation (NERC)/WECC guidance as may be adjusted under the WPP CR Sharing Program.
Uncertainty:	The potential variance between Preschedule Day forecasts of load, solar resources, wind resources, and RoR resources, and the Operating Day actual values for such loads and resources based on historic data. In other words, a reasonable margin to account for near-term forecast error.

Figure 3-2 on the following page provides a representation of the Sharing Calculation for the first 10 hours of a sample Operating Day. In this case, the Participant's capacity contribution shown in the light gray bars is less than their capacity need shown as the orange line for hours 6, 7, and 8.



The Ops Program Sharing Calculation will be run for each hour of each Operating Day starting 7-days in advance. The graph to the left is a representation of the calculation for 10 sample hours.

The yellow and black lines represent the Participant's P50+PRM and Portfolio QCC from Forward Showing. The green, blue, and red bars represent the forecasted over/under performance and excessive forced outages. The grey bars represent the Participant's P50+PRM adjusted for forecasted performance and outages. The orange line represents the Participant's Forecasted Load + CR + Uncertainty.

The blue line represents the Participant's Sharing Calculation results. A Sharing Event would be identified when the Sharing Calculation is negative (line below x-axis, e.g., hours 6, 7, and 8).

Figure 3-2. Ops Program Sharing Calculation.

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3.3.2. Forward Showing Capacity Requirement

The FS Capacity Requirement is equal to the P50 Peak Load plus FSPRM minus Regional Diversity Transmission for each Participant. These values were determined during the FS process for each month of the appropriate season. The FS Capacity Requirement represents the amount of capacity the Participant should be able to reliably contribute on a planned basis. Note that Participants whose generation capacity exceeds their FS Capacity Requirement value are not obligated to contribute this excess capacity during Sharing Events. The exception to this is the over performance of wind and solar.

3.3.3. Forced Outages

Participant capacity contributions are adjusted to account for forced outages. Forced outages covers several items: the performance of thermal and storage hydro generation as well as transmission outages that reduce firm capacity import. Both over- and under-performance of thermal generation are included, but only the under-performance of storage hydro generation is included. Storage hydro, for the purpose of the Ops Program, is capped at its QCC.

Specifically, the forced outages term will include:

Thermal generating units (coal, gas, biofuel, nuclear, etc.)

The actual forced outage capacity reduction of each thermal project minus the forced outage capacity reduction that was calculated in the FS process to determine the QCC for the project. The actual forced outage capacity reduction includes both forced outages and reliability de-rates. It does not include forced outages or de-rates caused by a lack of fuel or economic decisions to not dispatch the project.

Storage Hydro generating units:

The greater of zero and the actual forced outage capacity reduction of each storage hydro project minus the forced outage capacity reduction that was calculated in the FS process to determine the QCC for the project. The actual forced outage capacity reduction does not include forced outages or de-rates caused by a lack of fuel or economic decisions to not dispatch the project. Forced outages and de-rates that occur when there is a lack of fuel will not be included in this calculation.

Import Reductions due to Unplanned transmission outages:

Reductions in a Participant’s firm imports when the import meets the following criteria when the Participant (and/or their supplier) had acquired NERC priority 6 or 7 service and the transmission service contract is de-rated. The impacted Participant should make good faith effort to secure additional or replacement NERC priority 6 or 7 services within reason based on the timeline on which the transmission outage occurs.

The inability to secure transmission for the 25% of imports that do not require NERC priority 6 or 7 service does not qualify as a transmission forced outage.

Note: VER and RoR forced outages will be reported in VER and RoR under and over performance reporting, respectively, and not be reported under this metric.

Validation of Forced Outages

If a Participant claims a generation or transmission forced outage, the WPP may request supporting documentation (including, but not limited to, contracts, transmission contracts, etags, etc.) after the fact and may assess charges on the Participant if it is determined that the circumstances did not qualify as a transmission forced outage.

3.3.4. Maintenance Outages

It would be better if maintenance outages could be taken outside of the Binding Seasons, but it is recognized that they may necessarily occur during these periods. Maintenance outages are taken at the risk of each Participant. Therefore, maintenance outages are not included in the Sharing Calculation.   The WPP may ask for documentation supporting the forced and maintenance positions of a Participant's fleet of resources to verify the submission of data.

3.3.5. Variable Energy Resources Over and Under Performance

The Sharing Calculation will be adjusted to account for the actual expected generation from the VER resources (typically wind and solar) in a Participant's generation portfolio. This will include both increases (the resource is expected to generate more than its QCC) and reductions (the resource is expected to generate less that its QCC). The Participants will submit resource-specific forecasts to be incorporated into the Sharing Calculation.

3.3.6. Run-of-River Hydro Over and Under Performance

Similar to VER unit performance, RoR hydro plants also experience an expected performance that may vary from what was reported in the FS Program. Each Participant should submit resource-specific forecasts to be incorporated into the Sharing Calculation.

3.3.7. Load Forecast

The Sharing Calculation will utilize the expected (1-in-2, equally as likely to be above and below the submitted value) Load Forecast for the period in which the calculation is being performed. This Load Forecast should consider the expected weather and expected system conditions. Each Participant will submit their expected forecasts to be used in the Sharing Calculation.

3.3.8. Uncertainty

System conditions are often difficult to predict even during the Preschedule Day and during the Multi-Day-Ahead Assessment. The Uncertainty term in the Sharing Calculation is based on the accuracy of forecasts made one-day to one-week in advance of each Operating Day for the loads and resources included in the Sharing Calculation. This uncertainty value will be determined for each Participant and applied to their Sharing Calculation to ensure that their loads and variable resources are planned in a reliable fashion in the days leading up to each Operating Day.

The specifics of this uncertainty calculation will be determined later and documented in the Business Practice Manuals.

3.3.9. Safety Margin

A Safety Margin may be applied to the Sharing Calculation at a program-wide level. The Safety Margin provides an additional buffer beyond the Participant-level Uncertainty. Specifically, the Safety Margin can be used for situations such as potential large resource trips, heavy transmission outage conditions, significant environmental conditions, or other similar region-wide impacts.

The Safety Margin will be allocated pro rata among Participants with a positive Sharing Requirements. The application of a Safety Margin may not result in a Holdback Requirement greater than a Participant's Sharing Requirement as a Participant's Holdback Requirement is capped at the Sharing Requirement as determined on the Pre-schedule Day.

Participants will be notified when a Safety Margin has been applied including the timeframe, amount, and justification.

3.3.10. Contingency Reserves

Contingency Reserves are the provision of capacity that are set aside and may be deployed to respond to a contingency event or other contingency requirement within ten minutes. For each Participant, the expected CR necessary in each timeframe is equal to 3% of hourly integrated load plus 3% of hourly integrated generation. This program is not intended to modify or change the way in which the WPP CRs Sharing Program operates. This program will continue to operate under the current prescribed rules, terms, and conditions set forth. The Ops Program does not replace or duplicate the WPP CR Sharing Program.

To approximate this value in the WRAP's reliability modeling a proxy of 6% of load will be utilized for the whole footprint. In cases where participant is importing to meets its P50+FSPRM requirement, the approach will overstate the CR requirement and will need to be adjusted down.

The Ops Program will account for any variations in CRs between the Sharing Calculation and FS Program inclusions. The Δ CR term will account for the difference in the utilized CR from the FS and the projected CR in the forecasted operating days of the Program.

3.4. Holdback Requirement

3.4.1. Holdback Requirement Calculation

The Sharing Calculation assessment that is performed on the Preschedule Day sets the Holdback Requirements for that day.

The WPP shall calculate the Holdback Requirements as follows:

1) For subregions with a central transmission hub, the Holdback Requirement shall be allocated proportionately based on the Holdback Requirements and the combined total of all the positive Final Holdback Requirements.

2) For subregions without a central transmission hub, the WPP will first optimize transmission and holdback capacity voluntarily offered by Participants, and will recognize limitations on delivery of Energy Deployment to match and allocate the delivery and receipt of Energy Deployment with the following priorities:

    a. Holdback and transmission services offered during the preschedule day process pursuant to Section 19.5 of the WRAP Tariff;

    b. Transmission service offered pursuant to Section 19.3.1, paired with any holdback offered pursuant to Section 19.5 that is not fully used by category (a) above;

    c. Holdback Requirement matched using the deliverability information provided by the Participants pursuant to Section 19.4 of the WRAP Tariff on a nearest neighbor cluster basis, allocated pro rata among Participants within such cluster;

    d. Holdback Requirement matched pursuant to the deliverability information provided pursuant to Section 19.4 of the WRAP Tariff and allocated among Participants within the same Subregion to the extent not matched and allocated under category (c); and

    e. Holdback Requirement from Participants in another Subregion, paired with any transmission service voluntarily offered between Subregions.

The calculated Sharing Requirement will be communicated to Participants by 06:00 AM. Deficient Participant(s) may waive all or a portion of their negative Sharing Requirement (deficiency) by 06:30 AM, and the Holdback Requirement calculation will be posted by 07:00 AM. Figure 3-3 provides an example of the Holdback Requirement for three Participants.

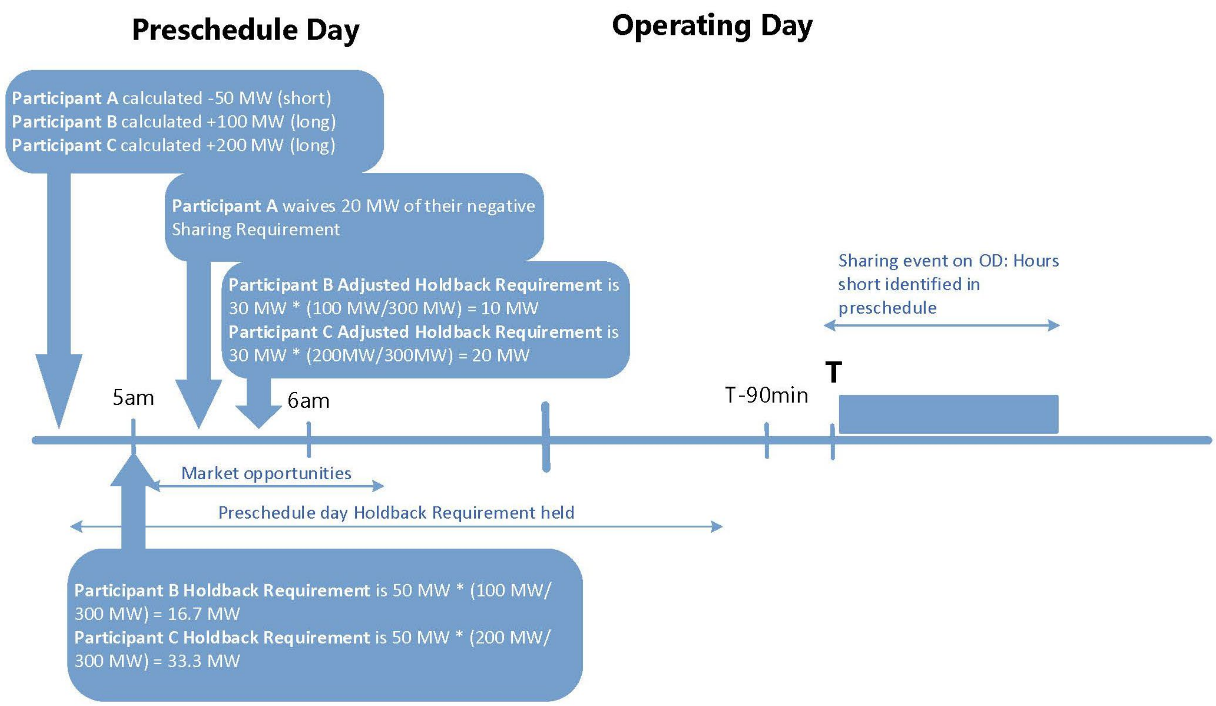

Figure 3-3. Holdback Requirement Example Showing Three Participants.

3.4.2. Holdback Requirement Transfer

Participants may transfer Holdback Requirement between one another for any hour on any Operating Day. Settlement of this transfer is bilateral between Participants outside the Ops Program (Figure 3-4). As such, settlement of any Holdback Requirement exchanged between Participants is the responsibility of such Participants. A Participant may be involved in multiple Holdback Requirement Transfers but must be purely a provider or a receiver of capacity. In other words, a single Participant may not transfer its Holdback Requirement to one Participant while also taking a Holdback Requirement from another Participant for a single Sharing Event. Participants must notify the WPP of Holdback Requirement Transfers at least two hours before the start of the operating hour. The WPP may re-calculate the Holdback Requirements accounting for the Holdback Requirement Transfers. Such transfers shall not change the Holdback Requirements or obligations of any other Participants.

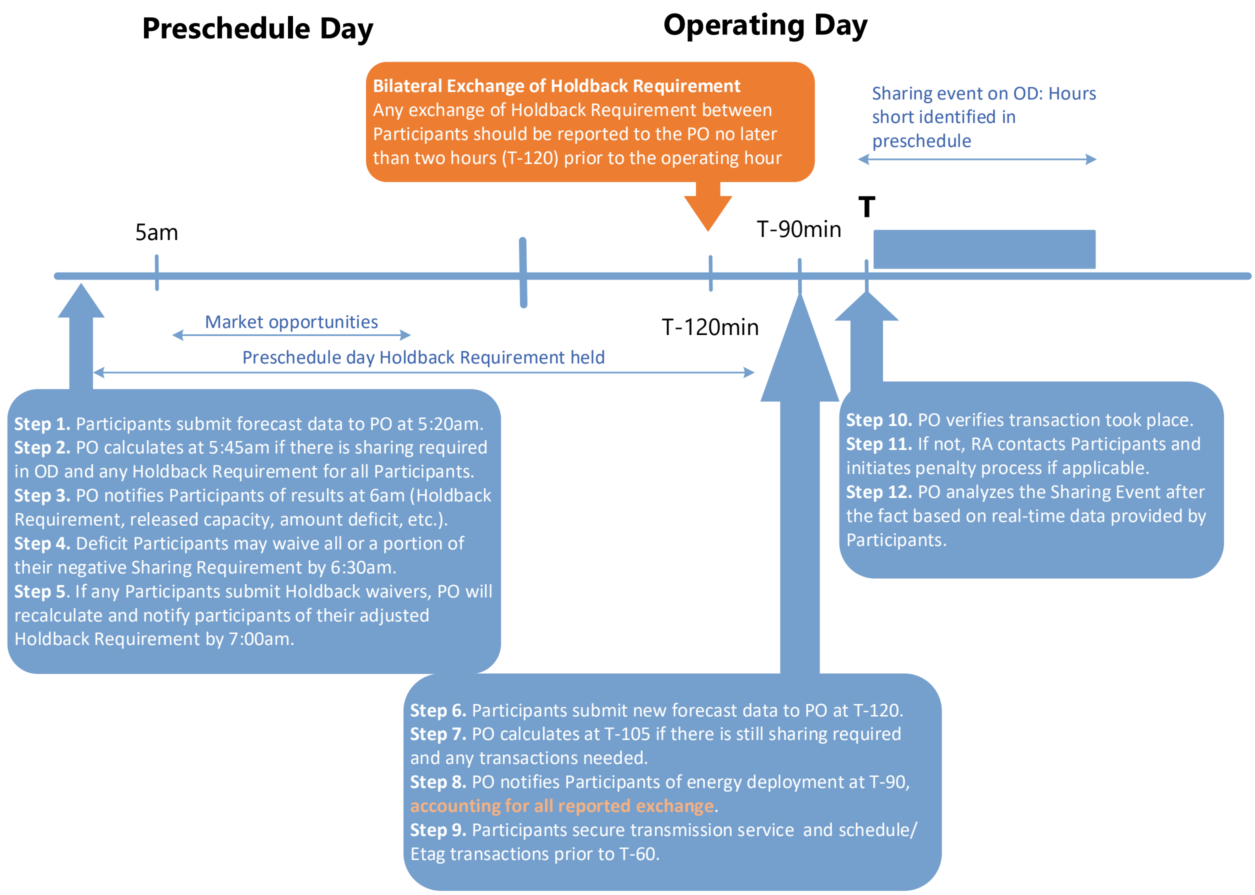

Figure 3-4. Bilateral Exchange of Holdback Requirement Overlaid on Sharing Calculation Timeline.

3.5. Release of Holdback Requirement

3.5.1. Day-Ahead Release of Capacity

Following the establishment of the Holdback Requirement for each hour during the Preschedule Day, any capacity in excess of the established Holdback Requirement will be released for such hour.

With the exception of bilateral exchange of Holdback Requirement activities, a Participant's Holdback Requirement is capped at the initial Sharing Requirement calculated on the Preschedule Day. Subsequently, any additional, unused capacity is released back to the Participant as illustrated in Figure 3-5, where L_{PS} is the net positive Sharing Requirement, S_{PS} the negative Sharing Requirement, and PS refers to preschedule.

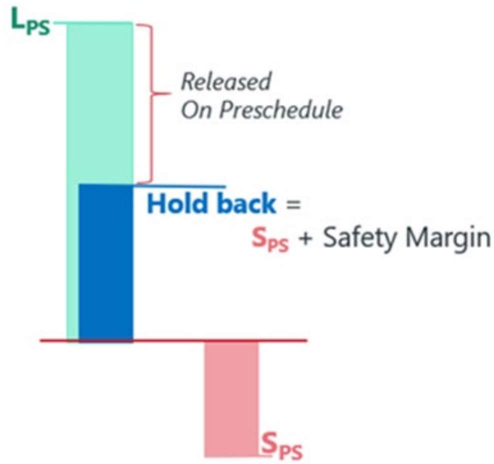

Figure 3-5. Preschedule Release of Excess Holdback Capacity.

3.6. Energy Deployment

3.6.1. Frequency of Data Submission on Operating Day

Participants will deliver up-to-date operational data (e.g., load, VER performance, RoR performance, and forced outages) to the WPP each hour for a forward-looking rolling 24-hour period. For example, by 0100 Participants send their operational data to the WPP for HE04 of the current day through HE03 of the following day. Participants will start sending updated operational data for each Operating Day later than 2200 on the prior calendar day. For more details on data submission types see Section 3.10.

3.6.2. Energy Deployment and Scheduling

Deficient Participants (those with a negative Sharing Requirement) shall notify the WPP of its need for Energy Deployment and confirm the amount of Energy Deployment called upon no later than 2 hours prior to the start of any such clock hour with an indicated deficiency. Such requests and scheduling may be made as early as the Preschedule Day. In no event will the requested Energy Deployment exceed such Participant's negative Sharing Requirement determined on the Preschedule Day.

The WPP shall re-calculate the Holdback Requirements on an advisory basis with updated hourly data supplied by the Participants. Such revised calculations will be performed and posted no later than 105 minutes prior to the start of each hour (T-105) identified in a Sharing Event Window using the latest set of forecast data provided by Participants. Final values will be posted no later than T-90. Any Holdback Requirement in excess of the final Energy Deployment is released at this time.

Participants must schedule their assigned Energy Deployment for each hour no later than 60 minutes prior to the start of such schedule hour (T-60). Participants may agree on alternate delivery provisions for Energy Deployment but must notify the WPP of such alternate delivery no later than the 120 minutes after the close of the Operating Hour.

Participants should notify the WPP as soon as possible if they fail or anticipate that they will fail to deliver the full amount of their Energy Deployment (“Energy Delivery Failure”). Participants with Energy Delivery Failures may request an Energy Delivery Failure waiver. The WPP will review requests and determine, in their sole discretion, whether to grant such waivers. Guidance for evaluating Energy Delivery Failure waiver requests will be developed in the Business Practice Manuals.

3.6.3. Load Shedding Responsibility

Deficient Participants will be eligible to receive up to the full amount of capacity available as defined by the prescheduling day calculations. When the capacity available to the Ops Program is not sufficient to cover deficient Participants, the WPP will implement emergency procedures to call on all Participants to provide support beyond their calculated Holdback Requirement. If the additional support gained from implementing emergency procedures still leaves a Participant with a deficit that Participant would then be responsible to work with their Balancing Authority Area to issue Energy Emergency Alerts (EEA) and implement load shedding as necessary. Participants may have other means outside of the Ops Program to avoid shedding load (NERC Alert, Merchant Alert, EEA, Extended CR Support, Interruptible Load, etc.).

In the event that a Participant fails to deliver their Energy Deployment, and that failure results in load shed by a deficient Participant, the deficient Participant will bear the burden of shedding load.

3.6.4. Emergency Procedure

When the Ops Program actions are insufficient to fully relieve a deficient Participant the WPP may call for additional support from the Participants at large using the communications and processes established under the WRAP. Such requests are purely voluntary for Participants and will not increase the Holdback Requirement or Energy Deployment values for any Participant who does not volunteer to participate. Additionally, any support provided under Emergency Procedures are to be arranged exclusively between the Participants, including all settlements and other factors.

If Sharing Requirement Calculations reveal that the sum of the negative Sharing Requirement is greater than the sum of the positive Sharing Requirement, this indicates that the WRAP footprint as a whole is insufficient. In this instance, all Participants with a positive Sharing Requirement would have the total of their Sharing Requirement assigned as Holdback Requirement and the WPP would issue an insufficiency notification to all Participants, and request for Participants to provide additional capacity to the WRAP footprint.

If the Energy Deployment calculations reveal that the sum of the Holdback Requirement is insufficient to cover the energy needs of deficient Participants, Holdback Requirement will be converted to Energy Deployment at 100% and the WPP will issue an insufficiency notification to all Participants.

3.7. Transmission Service

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 to serve such Participant's expected loads during such hours with their Qualifying Resources.

3.8. Settlements

3.8.1. Energy Deployment and Holdback Settlement

3.8.1.1. Pricing and Settlement Principles

Settlement prices are set to encourage entities with a negative Sharing Requirement to address capacity shortfalls using other means before accessing the WRAP pooled capacity and should adequately compensate those Participants that contribute capacity and energy to the program without being punitive to entities truly in need. Settlements are bilateral payments between parties and are not transacted with any entity acting as a central market. The WPP will calculate settlement prices for the Participants. Settlement prices are computed for each Subregion.

When the provider and receiver of Holdback Capacity and/or Energy Deployment are in different Subregions, the price will be set using the higher of the settlement prices for the two Subregions unless the transmission between Subregions was provided by a third party (not the provider or receiver of the Holdback and/or Energy Deployment). In this case, the provider will be paid the settlement prices based on the Subregion from which the Holdback and Energy Deployment were sourced and the transmission provider will be paid the difference between the Subregions' Total Settlement Price but in no event less than zero.

3.8.1.2. Settlement Price Calculation

The Total Settlement Price is set for each hour and is calculated using a day-ahead index and an hourly shaping factor with a 10% adders. It will not exceed $2,000/MWh or be lower than $0/MWh.

Definition: Total Settlement Price

$$\mathbf{Total\ Settlement\ Price} = \mathbf{Maximum}\left(\mathbf{Minimum}\left(\mathbf{Hourly\ Shaping\ Factor} \times \mathbf{Applicable\ Day\ Ahead\ Index\ Price} \times \mathbf{110\%}, \frac{\$\ \mathbf{2000}}{\boldsymbol{MWh}}\right), \frac{\$\ \mathbf{0}}{\boldsymbol{MWh}}\right)$$

Where:

– The **Hourly Shaping Factor** is selected based on the most recent High-Priced Day. A High-Priced Day is a day when at least a single hour has a system marginal energy cost (SMEC) greater than \$200/MWh. If no High-Priced Day exists in the current season, then the most recent High-Priced Day of the same season in previous years will be used.

$$= \mathbf{1} + \left[\frac{\boldsymbol{CAISO\ Hrly\ DA\ SMEC} - \boldsymbol{CAISO\ Avg\ DA\ SMEC}(\boldsymbol{on\ or\ offpeak\ hours})}{\boldsymbol{CAISO\ Avg\ DA\ SMEC}(\boldsymbol{on\ or\ offpeak\ hours})}\right]$$

– The **Applicable Index Price** is the day ahead heavy load/light load ICE Index price based on the location of the delivering entity. For example, this may be the Mid-Columbia or photovoltaic price published for the day of the Sharing Event.

3.8.1.3. Application of the Settlement Price

The **Total Settlement Price** is then split into two underlying components: the **Energy Declined Settlement Price** and the **Holdback Settlement Price**.

The Energy Declined Settlement Price is the lesser of an applicable hourly index price and 80% of the Total Settlement Price for each hour. The Holdback Settlement Price for each hour is the Total Settlement Price minus the Energy Declined Settlement Price.

A Participant providing Holdback capacity will be paid the hourly Holdback Settlement Price times the capacity they assigned to holdback for the hour.

A Participant that provides Energy Deployment will be paid the Energy Declined Settlement Price times the Energy Deployed to the other Participant.

A Make Whole Adjustment is also calculated associated with each Holdback Requirement and will be added to payments to Participants. The Make Whole Adjustment compensates providing Participants for revenue they may lose by not being able to sell into the day-ahead standard bilateral markets.

Definition: Energy Declined Settlement Price
$$\textbf{Energy Declined Settlement Price} = \textbf{lesser of} \begin{cases} \textbf{\textit{Applicable Hourly Index}} \ (\textbf{\textit{TBD}}) \\ \textbf{\textit{Settlement Price}} \times \textbf{80\%} \end{cases}$$
The 80% factor ensures that holdback providers will receive at least 20% for carrying holdback regardless of energy deployment.
Definition: Holdback Settlement Price
$$\textbf{Holdback Settlement Price} = \textbf{Total Settlement Price} - \textbf{Energy Declined Settlement Price}$$
Settlement for Any Applicable Hour
$$\textbf{Final Settlement (for any applicable hour)} = (\textbf{Holdback Settlement Price} \times \textbf{Holdback Capacity Requested}) + (\textbf{Energy Declined Price} \times \textbf{Operational Energy MWh Dispatched})$$
Make Whole Adjustment = Possible Block Sale Revenue – Final Settlement Revenue – Realtime Value of Declined Energy – Realtime Value of Unheld Energy where: Possible Block Sale Revenue for on-peak or off-peak hours = the maximum Holdback Requirement times the number of hours in the period for that day times the appropriate day-ahead index. Final Settlement Revenue for on-peak or off-peak hours = the total settlement revenues collected by the providing Participant. Realtime Value of Declined Energy = the sum of the Declined Energy times the appropriate Energy Declined Settlement Price, and Realtime Value of Unheld Energy = the sum over all hours of the maximum Holdback Requirement within the applicable on-peak or off peak period minus the Holdback Requirement for each hour, the difference which is multiplied by the Hourly Index Price.

3.8.2. Transmission Service

The delivering Participant is responsible for transmission service charges of delivery. The receiving Participant is responsible for transmission service charges of the receipt.

3.9. Charges for Failure to Deliver

3.9.1. Delivery Failure Review

A process will be developed for the evaluation of delivery failures and assessing whether waivers are to be granted.

The Participants will agree on the details of the review process for Delivery Failures. This process, including a non-exclusive list of valid reasons for waivers, will be set forth in the Business Practice Manuals. The WPP will review all waiver requests and, taking into account the circumstance and all relevant information, will determine whether to grant the wavier. Participants not granted a requested waiver may appeal to the Board of Directors. The WPP shall report the disposition of all waiver requests to the Participants.

3.9.2. Charge Calculations

Participants who fail to deliver their assigned Energy Deployment and do not secure a waiver for that failure will pay a Delivery Failure Charge. The charge for not delivering the assigned Energy Deployment depends on the impact of the failure on the deficient Participant(s) as shown in Table 3-3.

Table 3-3. Charge Calculation Examples.

Definition: Charge for delivery failures	
If a Participant fails to provide energy and that deficit is entirely covered by other Participants of the Program, the charges are as follows:	
First non-waived delivery failure in any rolling 5-year window (Cumulative Delivery Failure Window)	5 times the higher of the applicable Day-Ahead or Real-Time Price Index.
Second non-waived delivery failure in a Cumulative Delivery Failure Window	10 times the higher of the applicable Day-Ahead or Real-Time Price Index.
Third or more non-waived delivery failure in a Cumulative Delivery Failure Window	20 times the higher of the applicable Day-Ahead or Real-Time Price Index.
If a Participant fails to provide energy and that deficit is not entirely covered by other Participants of the Program, the charges are as follows:	
First non-waived delivery failure in a Cumulative Delivery Failure Window	25 times the higher of the applicable Day-Ahead or Real-Time Price Index
Second or more non-waived delivery failure in a Cumulative Delivery Failure Window	50 times the higher of the applicable Day-Ahead or Real-Time Price Index

Delivery failures occurring in multiple hours on the same calendar day are counted as one delivery failure for purposes of calculating these noncompliance charges. The above charge schedules are meant to be used as and are not separate tracks. For example, if a Participant's first non-waived delivery failure is covered by other Participants, the charge would be set at five times the index price. If the Participant then had a second non-waived delivery failure and that failure was not covered by other Participants, the charge would be set at 50 times the index price.

Additionally, any third covered delivery failure or second non-covered delivery failure will trigger a review to determine if the Participant should be expelled from the WRAP.

3.10. Data Submission Requirements for Ops Program

Table 3-4 contains a summary of the data Participants are required to submit for the Ops Program. Figure 3-6 presents a high-level data submission timeline. The data submission guidelines will be developed in the Business Practice Manuals.

Table 3-4. Data to be Submitted by Participants to PO.

Hourly forecast data to be submitted to PO:
Load Forecast data for all hours
Wind forecast data for all hours
Solar forecast data for all hours
Run-of-river forecast data for all hours
Contingency Reserve forecast data for all hours
Derates: • Forced outage and generation de-rates by plant • Reliability generation unit de-rates for all hours • Transmission path de-rates impacting firm contracts from the FS Program

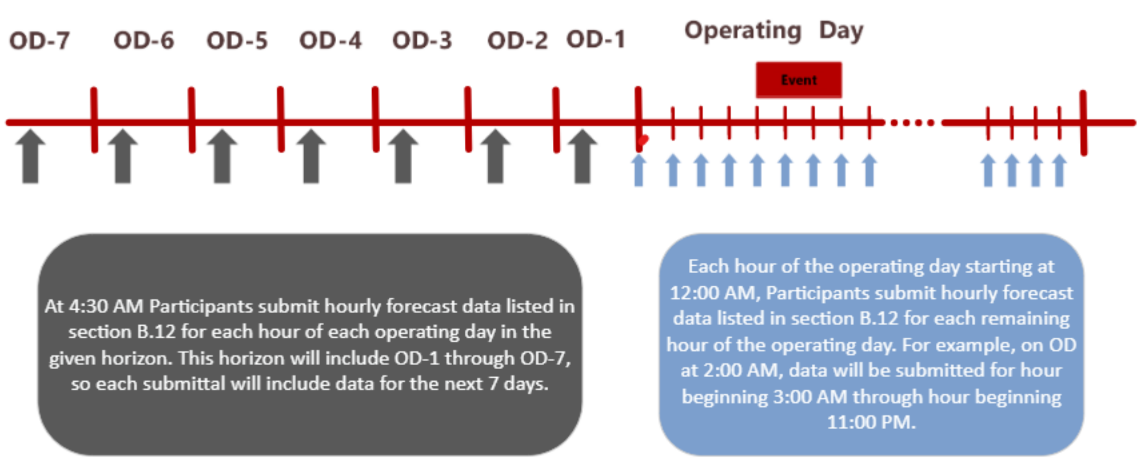

Figure 3-6. High-level data submission timeline for the Ops Program.

3.10.1. Multi-Day Ahead Data Submission

Each day, at 05:20 AM, Participant will submit hourly operations data for each Operating Day OD1 through OD7.

3.10.2. Operating Day Data Submission

Each Participant shall send the data listed in Table 3-4 for each hour for the successive 24-hour period. For example, on OD by 02:00 AM, data will be submitted for HE05 through HE04 the subsequent day.

3.10.3. Data Submission Errors and Validation

Data submitted will be checked for errors, including incorrect or missing submissions, stale data, or any other causes for data errors. If data errors are detected, the Participant will be asked to correct the data. If this is not possible, the last good data set will be used.

3.10.4. After Fact Data Submission

Each Participant will also submit after-the-fact actual data for the data sets listed in Table 3-4 plus data for Energy Deployments. Data will not be shared with any external parties unless compelled such as may be required by regulatory agencies. The timelines for submission of this data will be developed by the WPP at a later date.

WPP Western Resource Adequacy Program Detailed Design

Glossary

MARCH 2023

WESTERN POWERPOOL

WRAP

POWERED BY WPP

GLOSSARY

The terms used herein use the definitions that are included in the WRAP Tariff, which are provided here for reference. In the event that definitions here conflict with the definitions included in the WRAP Tariff, the definitions in the Tariff shall prevail.

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.

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 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 historic 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 Counterparty: Central Counterparty shall have the meaning provided in Part I of this Tariff.

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 bring calculated.

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.

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 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.

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.

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 a reduction in the otherwise applicable 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 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:

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

2) 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;

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

4) 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: 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, a Binding Season that occurs during the Transition Period prior to the first Binding Season for which the Participant has elected to be subject to Parts II and III of this Tariff.

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.

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.

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.

Sharing Requirement: A requirement applicable to a Participant with a positive Sharing Calculation result for a given hour or hours of an Operating Day to potentially provide an Energy Deployment to a Participant with a negative Sharing Calculation result for those same hours, as determined in accordance with Part II 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 power sale in which the generation is sourced, at the seller's discretion, from a group of two or more identified Qualifying Resources.

Transition Period: The Binding Seasons within the time period from June 1, 2025, through March 15, 2028, 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.

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.