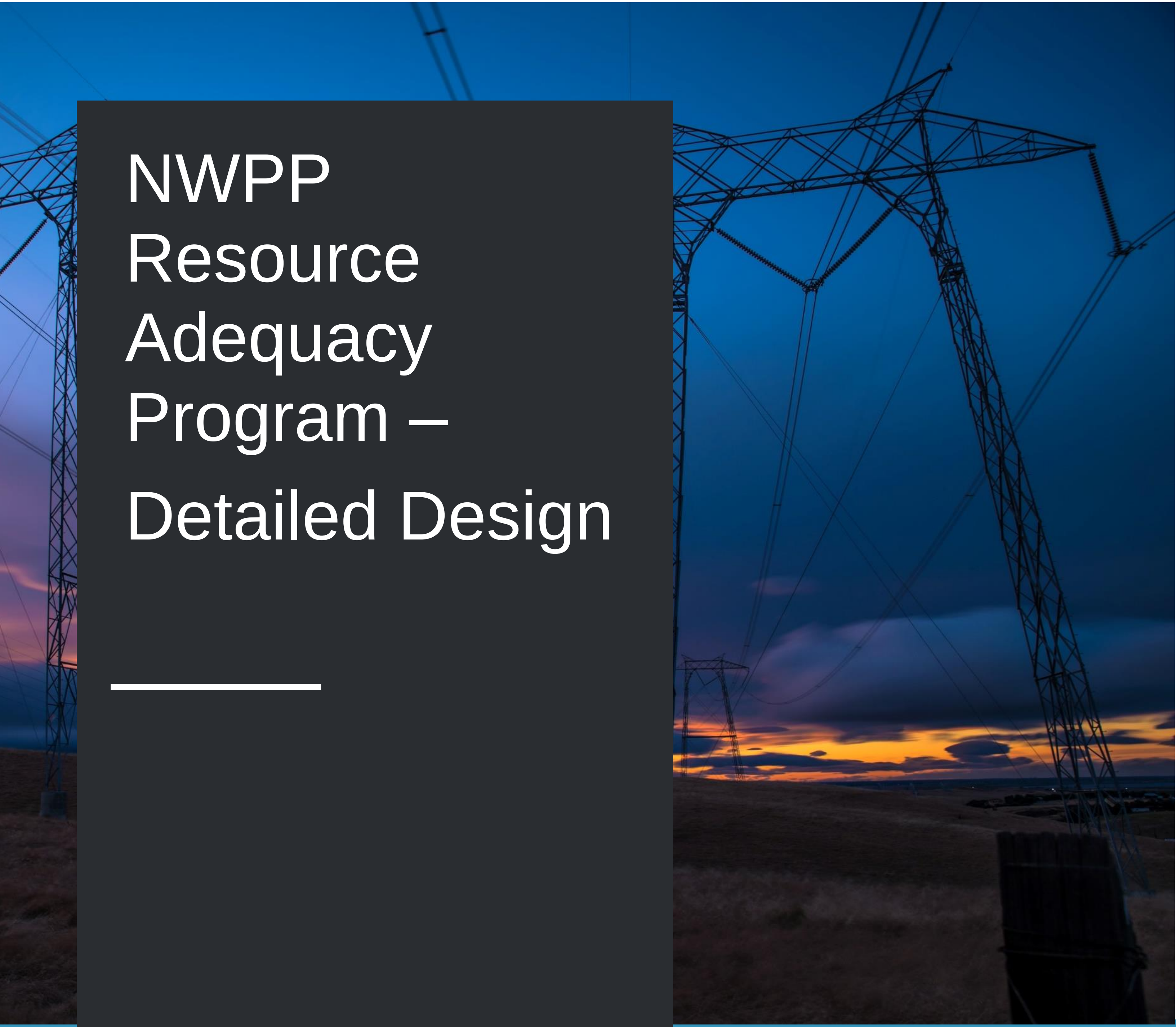

NWPP Resource Adequacy Program – Detailed Design

July 2021

Northwest Power Pool

NORTHWEST PowerPool

ACKNOWLEDGEMENTS

This document is the culmination of 13 months of effort by the NWPP Resource Adequacy Steering Committee, with support from Southwest Power Pool, Sapere Consulting, Public Generating Pool, Munro Advisors, Wright & Talisman P.C., and McDowell Rackner Gibson P.C.

The Steering Committee consists of representatives from:

- Avista
- Balancing Areas on Northern California
- Bonneville Power Administration
- Calpine
- Chelan County PUD
- Douglas County PUD
- Eugene Water and Electric Board
- Grant County PUD
- Idaho Power
- NorthWestern
- NV Energy
- Northwest Power Pool
- PacifiCorp
- Portland General Electric
- Powerex
- Public Service of Colorado
- Puget Sound Energy
- Seattle City Light
- Snohomish County PUD
- Tacoma Power
- Turlock Irrigation District

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ACRONYMS

BA	Balancing Authority
BAA	Balancing Authority Area
BOD	Board of Directors
CAISO	California Independent System Operator
CCH	Capacity Critical Hours
CEO	Chief Executive Officer
CONE	Cost of New Entry
COS	Committee of States
CP	Coincident Peak
CR	Contingency Reserves
DR	Demand Response
EDAM	Extended Day-Ahead Market
EEA	Energy Emergency Alerts
$EFDH_{cch}$	Equivalent Forced Derating Hours Occurring on CCH
EFOF	Equivalent Forced Outage Factor
EFOR	Equivalent Forced Outage Rates
$EFOR_d$	Equivalent Demand Forced Outage Rate
EIM	Western Energy Imbalance Market
ELCC	Effective Load-Carrying Capability
ESR	Energy Storage Resource
FERC	Federal Energy Regulatory Commission
FOH_{cch}	Forced Outage Hours Occurring on CCH
FS	Forward Showing

GADS	Generator Availability Data System
HE	Hour Ending
ICAP	Installed Capacity
IRP	Integrated Resource Plan
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
LRE	Load Responsible Entity
LRZ	Load and Resource Zone
LSE	Load Serving Entity
MW	Megawatt
MWh	Megawatt Hour
NC	Nominating Committee
NCP	Non-Coincident Peak
NERC	North America Electric Reliability Corporation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
OD	Operating Day
P50	1-in-2 Peak Load Seasonal Values
PD	Program Developer
PO	Program Operator
PRM	Planning Reserve Margin
PS	Preschedule
QCC	Qualified Capacity Contribution
RA	Resource Adequacy
RAPC	Resource Adequacy Participant Committee
SAC	Stakeholder Advisory Committee

SC	Steering Committee
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
WRAA	Western Resource Adequacy Agreement
WSPP	Western System Power Pool

NWPP Resource Adequacy Program Detailed Design

Executive Summary

JUNE 2021

NORTHWEST
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ES1. Background

The integrated regional power system is in transition. The impending retirement of several thermal generators within and outside the region (the Western US and Canada) mixed with increasing variable energy resources (VERs), has led to questions about whether the region will continue to have an adequate supply of electricity during critical hours. In the past four years, several studies have identified an urgent and immediate challenge to the regional electricity system's ability to provide reliable electric service during high demand conditions.

These developments threaten to upset the balance of loads and resources within the region and, if not properly addressed, will increase the risk of supply disruptions during Winter and Summer, increase financial risk for utility customers, and hinder the ability of the system to meet environmental goals and legal requirements.

Beginning in early 2019, the Northwest Power Pool (NWPP) has coordinated a broad coalition to explore the nature of the challenge and investigate mechanisms to assure a high likelihood of adequate supply to meet customer demand under a wide array of scenarios. These include a Forward Showing (FS) planning mechanism and an Operational Program (Ops Program) to help Participants that are experiencing extreme events meet customer demand through a regional resource adequacy (RA) Program. This work has been led by the Steering Committee with help from subject matter experts from each participating entity and oversight from the Executive Committee. At this point, the Steering Committee has documented design details that enable the next project phase. The Steering Committee fully recognizes that the design will likely be updated and evolve as the RA Program is stood up; the design proposed here is a starting point and does not solve every issue facing the region (energy adequacy, climate change, etc.), but is a significant and important incremental step toward increased regional coordination, which will better position the region to continue to tackle these big issues.

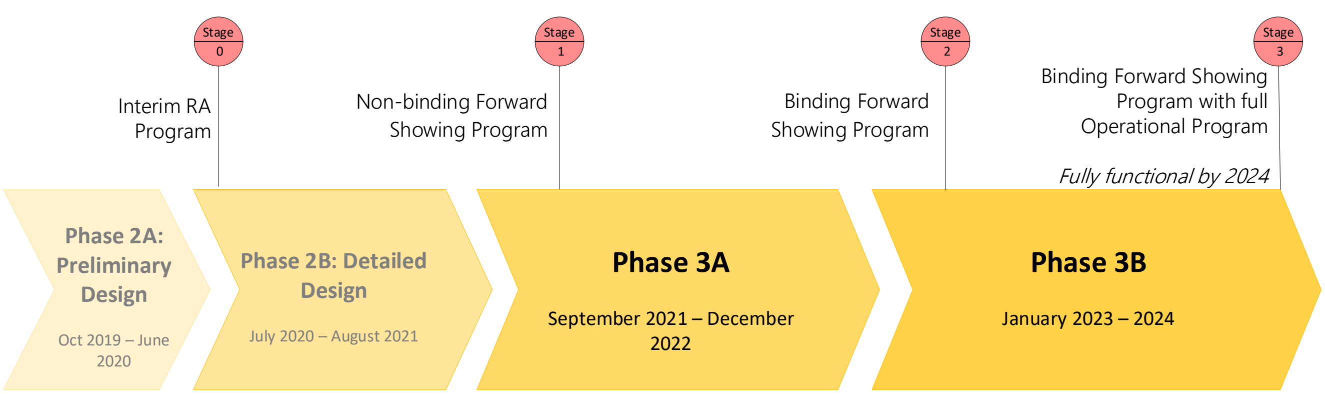

Figure ES-1. RA Program development project timeline.

Regional RA Programs have been developed across North America, and throughout the world, to ensure reliability by providing a regional framework that enables Participants to leverage load and resource diversity benefits by meeting their collective needs jointly rather than individually. It also establishes a robust, standardized, and transparent view of regional loads and resources.

The documents provide a proposed design for a capacity-based RA Program. While this is a detailed design document, there is still work to be done in the next phase to add and refine detail of the program through the implementation phase.

While there are many ways to improve reliability and many forms of RA (capacity, flexibility, energy), this program will focus on creating a capacity RA Program with a demonstration of deliverability. Additional adequacy programs may also be necessary and anticipate the need for such additions following the implementation of the capacity program. The region may also benefit from other forms of coordination, and while the structure and processes associated with the RA Program may serve as foundational building blocks to additional regional coordination, the NWPP and its Participants are only working to implement the capacity RA Program at this time. If additional programs are desired, a similarly discrete decision and implementation process would need to be undertaken to design and implement such programs. The proposed RA Program does not replace or supplant the resource planning processes used by states or provinces or the regulatory requirements of the Federal Energy Regulatory Commission (FERC), North America Electric Reliability Corporation (NERC), or Western Electricity Coordinating Council (WECC). The program is designed to be supplemental and complementary to those processes and requirements.

ES2. Resource Adequacy Program Benefits

The RA Program provides benefits of enhanced coordination and increased visibility and transparency across the regional power system. It seeks to enhance and increase reliability for the system while maintaining existing responsibilities for reliable operations and observing existing frameworks for planning, purchasing, and delivering energy. Current planning and procurement to meet RA needs is handled by individual entities under the oversight of regulators, cooperative boards, and city councils. Typically, individual entities develop plans and procure resources that are sufficient to meet their forecasted peak load requirements plus a stipulated planning reserve margin (PRM) or other estimates of uncertainty. In order to meet those requirements, entities rely on combinations of self-owned generation, bilateral contracts, planned market purchases, and available transmission capacity. This entity-by-entity planning framework is sufficient to meet regional RA needs if (and only if):

1. Each Load Responsible Entity (LRE)[1] calculates its own generation and transmission needs using a robust methodology;
2. Each LRE builds, or enters into firm contracts with, physical resources and acquires the sufficient transmission to meet its own needs;
3. New resources are approved in a timely manner, relative to utility needs;
4. LREs do not collectively rely excessively on "market purchases" that exceed the physical capability of the Western resource and transmission systems to meet their service obligations; and
5. LREs have accurately (and consistently) assessed the capacity contribution of their resources.

If these criteria are not met, the total generation and transmission capacity available to the region could fall below what is required to maintain reliability. Today, the individualized nature of the current planning framework can make it difficult for regulators, board members, stakeholders, and utilities to understand whether, where, and when new capacity is needed in the region. The RA Program would augment these existing frameworks to increase visibility into the true status of resources and transmission in the region and work to fill in these gaps.

Further, even if the region had enough capacity installed to meet projected needs, without the RA Program there is no guarantee that capacity or firm transmission for deliverability is appropriately contracted to meet the region's needs in the most critical hours. Without regional coordination, the footprint's capacity could be contracted to other regions experiencing ever-growing capacity shortfalls or may not be scheduled in such a way as to meet the needs of neighbors within the footprint without the centralized communication and coordination provided by the proposed RA Program.

One of the key benefits of the program is its ability to unlock the load and resource diversity within the region. By ensuring availability and access to that diversity via the Ops Program, LREs participating in the program (Participants) have the potential to carry less PRM going into a peak season than they would otherwise have to carry on a stand-alone basis. For example, the Ops Program will allow Participants to maximize the benefit of the load diversity across the region during periods of which one Participant is peaking and another Participant is experiencing lower load levels. In addition, during times when VERs are performing above their accredited levels or Participants are experiencing a low level of forced generation outages, that additional capacity may be made available to deficient Participants by the Ops

[1] An LRE is an entity that (i) owns, controls, and/or purchases capacity resources, or is a Federal Power Marketing Agency, and (ii) has the obligation, either through statute, rule, contract, or otherwise, to meet energy or system loads at all hours. Subject to the aforementioned criteria, an LRE may be a load serving entity ("LSE") or either an agent or otherwise designated as responsible for an LSE or multiple LSEs or load service under the RA Program.

Program during times of generation shortfall, excessive forced outages (generation and transmission), or load excursion.

The Ops Program allows Participants to collectively manage periods of risk of capacity shortfall by prescriptively sharing available capacity and deliverability plans.

As designed, the RA Program will help provide transparency, regional insights, and coordination as the region collectively plans for the future.

ES3. Program Design

The RA Program design and implementation will have two components: an FS Program and an Ops Program. The FS Program establishes regional metrics for the footprint, the qualified capacity contribution (QCC) and effective load-carrying capability (ELCC) of various resources, deliverability expectations, and determines the periods for demonstrating adequacy. The FS Program ensures the footprint has enough demonstrated capacity, well in advance of required performance, to meet the established reliability metrics.

The Ops Program creates a framework to provide Participants with pre-arranged access to capacity resources in the Program footprint during times when a Participant is experiencing an extreme event. An extreme event could be when a Participant's load is in excess of their FS forecast or resources (generation and transmission) are experiencing unexpected outages; this portion of the program unlocks the footprint's load and resource diversity. The Program seeks to achieve a balance between planning in a reasonably conservative manner but also to provide flexibility in order to protect customers from unreasonable costs.

ES4. Governance

The NWPP and the Steering Committee have developed a straw proposal to address governance of the future RA Program, which is critical for successfully launching the binding stages of the program (i.e., Stages 2 and 3). In order for the changes contemplated by the proposal to be understood, it is helpful to understand the existing governance and structure of the NWPP Corporation, referred to as NWPP, today. Currently, NWPP provides a number of contractual services; particularly, services to facilitate and administer the NWPP Agreement and other major multilateral agreements (e.g., NorthernGrid, Pacific Northwest Coordination Agreement). These programs and agreements exist outside of the NWPP: these agreements are not governed by the existing NWPP Board of Directors, nor are committees created within the auspices of the NWPP bylaws. Currently the NWPP does not have members, rather the agreements to which it provides services have signatories that have traditionally been referred to as 'members of the NWPP.' Additional information about the current structure of the NWPP can be found in the straw proposal.

This straw proposal includes a number of proposed changes to the NWPP that are driven by FERC's oversight of certain elements of the RA Program and the NWPP's proposed role in administering the RA Program. Under the NWPP's proposed role, the NWPP would become a "public utility" as defined by the Federal Power Act. Because certain RA Program elements will be subject to FERC oversight, the NWPP will also need to meet specific independence requirements established by FERC. Independence is understood as financial independence from individual Participants and classes of Participants in order to ensure that such aspects do not allow for undue discrimination for the NWPP. In addition, committees related to the governance of the RA Program would be chartered through updates to the NWPP's bylaws, including the creation of an RA Participants' Committee (RAPC) and a Committee of States, with the potential for additional stakeholder committees to be created as determined necessary and prudent.

In addition to continuing to provide various contractual services that the NWPP currently provides, the NWPP would be the primary entity responsible for offering RA Program services, providing administrative and facilitation support for the governance and administration of the Program. The NWPP would rely on the expertise, experience, and input of the Program Operator (PO) to provide the actual operational services and technical expertise for the RA Program. The NWPP will also work with an Independent Evaluator (IE) to review program design and operations.

Members of the RAPC are anticipated to be LREs who elect to join the RA Program voluntarily (recognizing that future regulatory changes could alter the voluntary nature of the program for certain entities). The LRE concept is intended to allow flexibility for participation, enabling the variety of scenarios the footprint may encounter (e.g., a Power Marketing Administration, marketer, or other such service provider assuming the obligations of one or more entities).

Additional detail related to program governance, timing of FERC filing, committees, etc. can be found in the straw proposal.

ES5. Forward Showing Program

The FS Program aims to provide reliability benefits (increased visibility, transparency, consistent application of metrics and methodologies) while working within existing systems and bi-lateral market frameworks to the extent possible. Importantly, the autonomy of the Participants will be preserved. Participants will continue to be responsible for determining what resources to use to meet the regional metrics, working with their regulators where applicable, and independently conducting resource planning as may be required. All entities will maintain their current reliability obligations and the RA Program will work within the existing Open Access Transmission Tariff (OATT) framework. The program will be voluntary (absent any contractual or other regulatory requirements) – entities will choose to join the program and opt in to binding consequences for non-compliance. Table ES-1 presents a summary of key components of the FS Program.

Table ES-1 Summary of RA FS Program.

NWPP RA 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.
Compliance Periods	Two binding seasons: Summer and Winter. Fall and Spring seasons are advisory (no penalties for non-compliance).
FS Deadline	Participants will demonstrate compliance with FS reliability metrics seven months in advance of the start of the binding seasons; if notified of deficiency by the PO, entities will cure issues by three months prior to the start of the binding season.
Reliability Metric	FS Program is designed to identify the capacity needed to meet a 1 day in 10 years loss of load expectation target.
Load Forecasting	Entities will forecast their own loads, working with the PO to use acceptable forecasting methodologies. The PO will use load forecasts and historical data to identify a P50 (1-in-2) peak load for each month in the binding season; the highest monthly P50 will be used for all months of that season.
PRM	Seasonal PRM will be determined for Summer and Winter seasons and expressed as a percentage of each Participant's identified seasonal P50 load forecast.
Resource Capacity Accreditation	*Wind and Solar Resources*: ELCC analysis. *Run-of-River Hydro*: ELCC analysis. *Storage Hydro*: NWPP-developed hydro model that considers the past 10 years generation, potential energy storage, and current operational constraints. *Thermal*: Unforced capacity (UCAP) method. *Energy Storage and Energy Storage Resources hybrid resources*: Determined by operational testing until higher penetrations show a need for a performance-based methodology. *Demand Side Resources*: Operational testing and historical performance.
Transmission	Rely on existing OATT frameworks to facilitate transmission-related requirements in FS and Ops. Will not infringe on Transmission Service Providers' and Balancing Authorities' responsibilities, nor diminish Participants' OATT responsibilities.

NWPP RA FS Program Snapshot	
	Demonstrates deliverability of resources claimed in the FS on NERC priority 6 or 7 transmission (firm, conditional firm, network service – in some conditions); demonstrate at FS deadline having procured or contracted for transmission rights to deliver at least 75% of the resources (or contracts) claimed in the FS portfolio from source to load. When sharing is forecasted in the Ops Program, prepare to demonstrate firm transmission for resources not previously shown to have NERC priority 6/7 transmission.
Payment for Noncompliance	Deficiency payment based on cost of new entry for a new peaking gas plant.

ES6. Operational Program

In the Ops Program, the PO monitors the Participants' forecasted load, uncertainty, and reserve requirements, along with forced outages and VER performance, to determine when a Participant may not have sufficient capacity to cover the projected demand. When a Participant is forecasted to be deficient relative to their FS projection, the PO will initiate a sharing event and call on other Participants that have prescriptively held back capacity and can deliver energy to the deficient Participant(s). The FS Program will determine the baseline values for the components of the Sharing Calculation (e.g., P50+PRM, baseline forced outage rate, etc.) while the Ops Program will determine real-time differences in these values to initiate a qualifying sharing event.

The Ops Program is implemented through sequentially comparing forecasts to the FS metrics beginning six days before the preschedule day, identification of sharing events and required capacity holdback on the preschedule day, and energy deployments on the operating day (OD). The sharing calculation is performed using Participant provided data updated on at least a daily basis from six days before preschedule, through the preschedule day for identification of potential sharing events, and the data is updated hourly on the OD to inform actual sharing.

Similar to the FS Program, the Ops Program aims to provide these diversity and reliability benefits within existing frameworks, to the extent possible. Participants will settle any exchanges or energy delivery bilaterally (using agreed-upon index-based prices). Energy will be scheduled on transmission and delivered through existing systems. All Participants will maintain their current reliability obligations. The Ops Program is not a new market, rather it is an option available to Participants to assist in maintaining reliability during extreme events.

ES7. Next Steps

As seen in Figure ES-1, we are at the end of Phase 2B: Detailed Design and planning to move to Phase 3A this summer. We are working with stakeholders and potential interested RA Program Participants to develop understanding and interest in the RA Program. Based on the staging of functionality (pink bubbles in Figure ES-1) we plan to pursue the first Non-Binding FS season in Winter 2022, meaning we need to begin data collection and modeling in Fall 2021. The Stage 1 Non-Binding seasons will serve as a “beta-test” for the program design proposed in the attached documents.

The Steering Committee has held quarterly meetings with a Stakeholder Advisory Committee (SAC) that includes representation from many sectors, regulatory bodies, and industry groups. Through that process, the SAC has provided comments on program design and process. The Steering Committee has successfully incorporated many of the suggestions into the detailed design provided here, such as a commitment to analyze low water years and their effect on the capacity contribution of storage hydro, making space for specific contracting mechanisms, and hosting several technical workshops to dive deeper into subjects such as state Integrated Resource Plan interplay, demand response, and program benefits.

After more than two years of hard work designing a revolutionary program to meet increasingly dire regional needs, the NWPP RA Steering Committee is ready to begin implementation of the program in late summer with the following anticipated activities:

- Contracting with and onboarding a PO to assist in implementing the program.
- Inviting LREs from across the West to participate in the next phase (3A) – this is an expansion of participation as compared to past project phases, which were only open to NWPP Agreement signatories. This sign-up period is for Stage 1 only – there will be an offramp and separate sign up for the binding Stage 2.
- Collecting and validating data from 3A Participants to run modeling to arrive at adequacy metrics (PRM and resources’ QCCs) for a first non-binding FS deadline in Spring 2022 (for Winter 2022).
- Advances at NWPP to support the non-binding and future binding RA Program activities and governance, including updates to board structure, bylaws, and staffing.

As we are in the midst of what many believe may be a capacity-tight summer season, the NWPP is again facilitating the ‘interim’ RA Program, as was available in both Summer and Winter 2020. The program provides communication and best-effort support to entities experiencing capacity deficits and was utilized once during Summer 2020.

The Steering Committee and NWPP appreciate the continued support of participating entities and executives, state and federal regulators, and regional stakeholders and is looking forward to beginning implementation shortly.

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Resource Adequacy Program Development Project

Section 1. Governance

JUNE 2021

NORTHWEST PowerPool

SECTION 1. GOVERNANCE: TABLE OF CONTENTS

INTRODUCTION

The Northwest Power Pool (NWPP) and the Steering Committee have developed the following straw proposal for the future state of the NWPP with governance, structure, and function changes associated with implementation of Resource Adequacy (RA) Program Stages 2 and 3; this document does not address: 1) transition issues and steps that would need to be taken to implement the recommended changes (transition issues and procedures will be addressed in a future proposal; and 2) governance and structural approach for RA Program Stage 1 (also referred to as Phase 3A). This proposal should be interpreted as a starting point. This recommendation will be further refined in future phases.

Currently, NWPP provides a number of contractual services. The diagram in

Figure 1-1 presents the key services and their relationship with the current Board of Directors (BOD) and staff.

This proposal includes a number of changes to the NWPP, including a role for the NWPP to administer the RA Program and to meet: (i) the necessary requirements for being a public utility under the Federal Power Act and the Federal Energy Regulatory Commission's (FERC) regulations; and (ii) FERC's independent board of directors criteria, which will be very helpful in obtaining FERC acceptance of the RA Program.[2] For purposes of this straw proposal, ***independence should be understood primarily 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 NWPP***. In addition to prohibiting direct financial conflicts, however, the NWPP would also impose criteria intended to eliminate other types of conflicts-of-interest, as well as situations that lead to an appearance of bias.[3]

In addition to continuing to provide or facilitate the various services that the NWPP currently delivers, the NWPP would be the primary entity responsible for offering RA Program services, would provide administrative support for the governance and administration of the RA

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[2] We note that neither the Federal Power Act, FERC's regulations, nor legal precedent establishes a clear requirement that non-Regional Transmission Organization/non-market regional programs such as the RA Program require an independent BOD. However, FERC will most likely look more favorably on the RA Program with an independent BOD.

[3] With respect to indirect financial conflicts or conflicts of interest that may arise from outside activities, secondary employment, or other activities, the NWPP should follow corporate best practices in order to instill a sense of confidence in the NWPP. In general, the NWPP should adopt policies that prohibit BOD 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 NWPP. In some instances, such conflicts may be waivable with notice and consent.

Program, and would rely on the expertise, experience, and input of the Program Operator (PO) to provide the actual operational services for the RA Program. The diagram in Figure 1-2 is an illustration of the proposed future structure of NWPP.

The following sections outline aspects of how the Steering Committee anticipates the changes shown in Figure 1-2 will be implemented. Generally, this includes the evolution of the existing NWPP BOD to an independent board to serve as the ultimate decision-making body for future governance and supporting committees to accomplish all other ongoing functions. Directors on the BOD will be nominated by a sector-representative committee, the Nominating Committee (NC), which will seek and vet potential Directors before proposing a slate of new Directors to the current BOD for confirmation.

A RA Participants Committee (RAPC) will work with support from the NWPP and a PO to consider and recommend design updates, compliance considerations, and other daily program operations; these recommendations will stand unless challenged to or by the BOD.

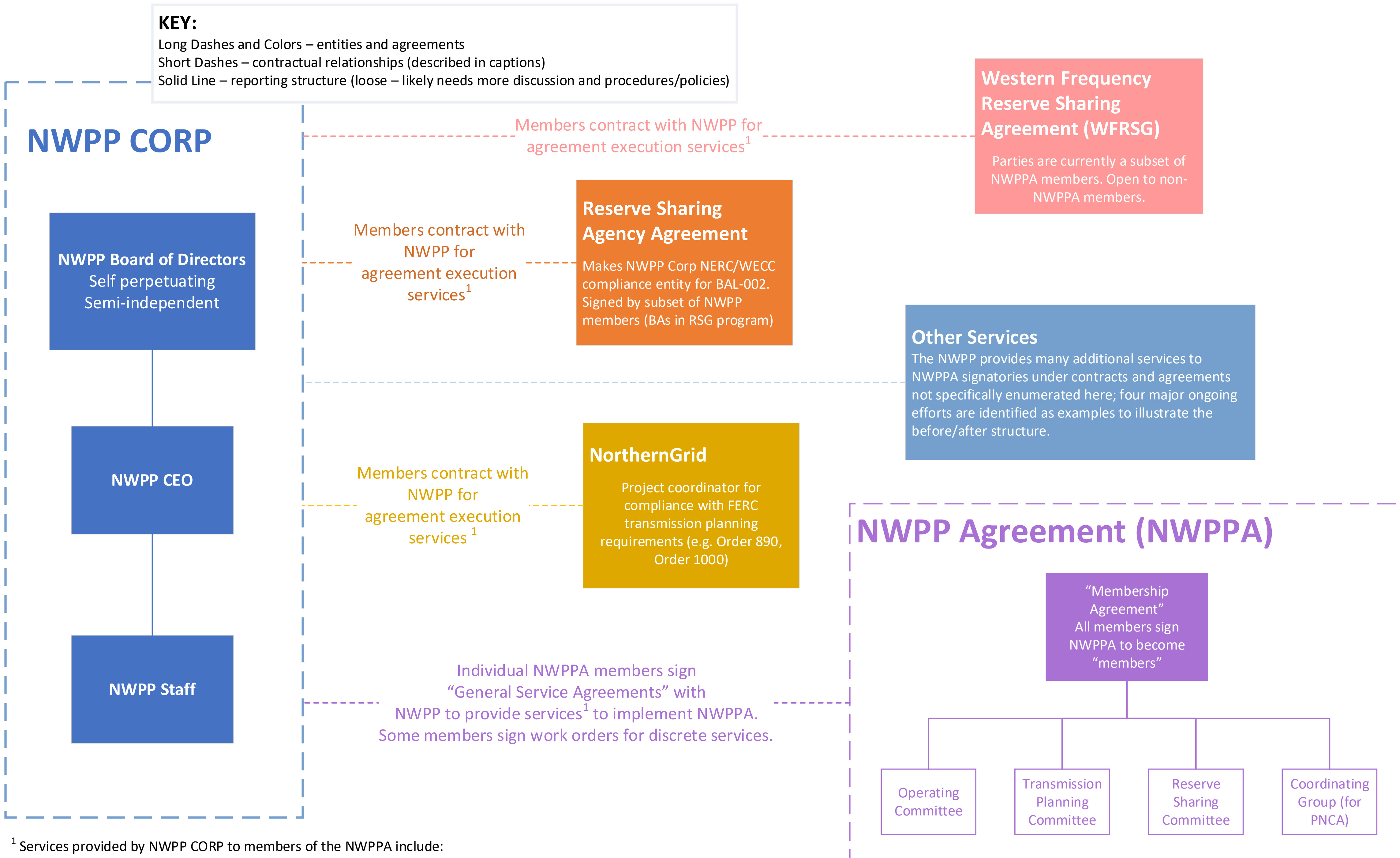
Another sector-representative committee, the Program Review Committee (PRC), will field recommendations for changes to program design and will document proposed changes and run public and committee comment processes to inform consideration of those recommendations by the RAPC and BOD.

State regulators and energy offices have always served an important role in RA, and the proposed design recommends a committee exclusively for state representatives, a Committee of States (COS). The scope and role of this committee will be informed through ongoing collaboration with state representatives in upcoming phases.

The Steering Committee anticipates the need for additional committees or subcommittees to support program operations and continuous improvement. Additional committees, their scope and authority will be considered throughout implementation phases and into the future, but it is not currently anticipated that their addition would substantially alter the scope or substance of the committees recommended in later sections.

The PO, an entity with extensive RA Program implementation, operation, and modeling experience, will report to the independent BOD and will work collaboratively with the NWPP to bring their expertise to all supporting committees. The NWPP will also work with an Independent Evaluator (IE) to review program design and operations.

The governance framework will be reviewed after 3-5 years of operations to ensure it is sufficiently meeting the needs of the Participants and the region.



[1] Services provided by NWPP CORP to members of the NWPPA include:

- Staffing and administrative support to enable the NWPPA signatories to implement the NWPPA;
- Coordination and documentation activities for standing NWPPA committees;
- Facilitation of member activities and monitoring of compliance with committee/program rules and standards;
- Acting as agent for member compliance with various reliability standards (e.g. above agreements); and
- Developing training modules and providing individual member training platform to train member employees and employees of member RCs.

For additional information on services provided by the NWPP CORP, see Appendix A.

Figure 1-1. Diagram of NWPP today.

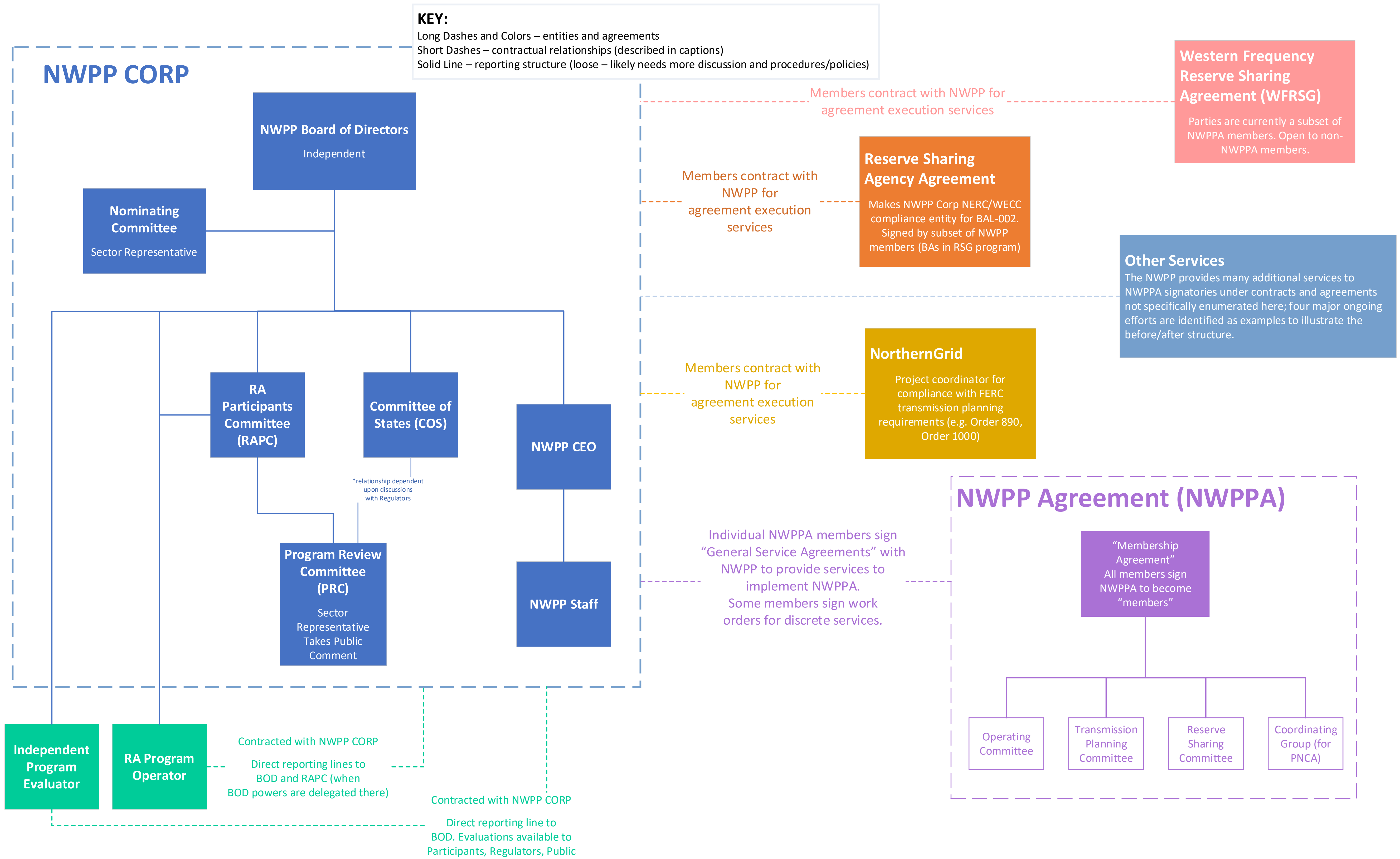


Figure 1-2. Diagram of Future NWPP.

GOVERNANCE – ACTORS AND PARTICIPANTS

1.1. Board of Directors

The following elements are proposed for the future NWPP BOD:

- There will be one independent BOD for the NWPP.
    - Currently, there is one BOD for NWPP, which is semi-independent (i.e., some members would likely be determined to be financially independent, and others would not).
- The BOD will oversee the RA Program as well as those responsibilities currently assigned to the BOD for the other services provided by or facilitated by the NWPP.
- The BOD will be composed of up to five to seven persons, but no less than three persons.
    - Currently, there are five members of the NWPP BOD.
- Directors are selected and nominated by the NC (see Section 1.2 for more information) to three-year terms and confirmed by the Directors which are currently seated and whose terms are not expiring.
    - Currently, the Directors are selected by the current BOD without term limits.
- The terms of the Directors will be staggered in order to maintain continuity.
- A Director may serve up to two three-year terms which may be served non-consecutively.
- A Director who is not term-limited but wishes to be considered for an additional term must provide appropriate notice of this intention.
- The NC will interview the Director whose term is expiring regardless of whether the Director is seeking re-appointment. If the Director is seeking re-appointment, the purpose is to determine if the NC wishes to advance the Director for another term without interviewing other candidates; if the Director is not seeking re-appointment, the purpose is an exit interview.
- The NC will determine whether it wants to re-nominate the departing Director without interviewing other candidates.

- If the NC does not decide to re-nominate the departing Director, then it should seek to identify at least two qualified candidates to interview, in addition to the sitting member.
- The NWPP Chief Executive Officer (CEO) is proposed to be a voting member of the BOD, provided the CEO also passes the independence requirements.

1.1.1. Board of Directors Transition

Specific transition issues relating to the current NWPP BOD will be addressed in a future version of this proposal; however, it has been recommended by the existing NWPP BOD and staff that this proposal address a specific approach for how the existing NWPP BOD can ensure its fiduciary duty to the current NWPP.

The future RA Program and the governance and structural changes have the potential to change the overall shape, direction, and priorities of the NWPP and how the NWPP delivers the services that it is currently responsible to provide. As such, the current NWPP BOD must support and approve the proposal to transition to an independent BOD.

Allowing for limited duration, limited scope engagement by a limited number of current BOD members is a vehicle for giving the current BOD trust in the transition so that they can confidently support the actions needed for the NWPP to evolve.

The following approach is recommended for achieving these objectives:

- Two supplemental seats to the proposed NWPP BOD would be allocated to two current Directors who volunteer to be considered (e.g., assuming the new NWPP BOD consists of five Directors, the two supplemental seats would bring the total to seven);
- The two Directors for the supplemental seats would be selected by the NC (discussed below); the NC would apply financial independence criteria in order to select the two supplemental Directors;
- The two supplemental seats would serve in a strictly advisory capacity for RA Program matters but would serve in their regular capacity for all other programs and services provided by the NWPP;
- The two supplemental seats would serve a maximum of two, three-year terms (not staggered); and
- Any current NWPP BOD Directors can apply for the regular seats on the future BOD and would be considered along with all other qualified candidates considered by the NC.

1.1.2. Board of Directors Duties Common to all NWPP Services

1) At all times the BOD will act in the best interest of NWPP in its management, control, and direction of the general business of NWPP.

    The current BOD has this same fiduciary duty, which is derived from corporate law.

2) The BOD will exercise an appropriate degree of independence from Participants.

    The current BOD is not structured as an independent BOD, so this would be a change.

3) In reaching any decision, the BOD Directors must execute the duties of the BOD in an unbiased, professional, respectful, and collaborative manner that promotes integrity, teamwork, trust, and a professional work environment.

    This is not an explicitly codified requirement for the current BOD but is exercised in practice.

4) Unless otherwise restricted (see Section 1.1.4), the BOD will have full authority to change the bylaws.

    In general, the current BOD has this same authority, derived from corporate law. In the case of the current set of governing documents, the committees created by the NWPP Agreement are not part of the current bylaws and thus cannot be changed by the current BOD.

5) The BOD has the authority to review the performance of the corporation, its officers, and staff, unless specifically delegated to NWPP staff. When evaluating the performance or compensation of the CEO, the CEO will be appropriately excluded from deliberations of the other BOD members. With respect to duties delegated to NWPP Staff, the BOD may rely on reports from NWPP Staff but must continue to exercise oversight over those duties. This BOD obligation is relatively standard. The day-to-day decisions about hiring, salaries, executive management, etc., are the responsibility of the CEO.

    The current BOD is similarly responsible for evaluating the performance of the corporation, its officers, and staff. Currently the CEO is not a Director and thus need not be excluded from deliberations about CEO performance.

6) The BOD has the authority to evaluate the performance of individual BOD members and the BOD as a whole. When evaluating the performance of individual BOD members, that

BOD member will be appropriately excluded from deliberations of the other BOD members.

The duty to evaluate the performance of individual BOD members is an existing BOD obligation.

7) The BOD will review and approve the financial position of the NWPP (including the RA Program), including its budget, expenses, and projected expenses, to ensure the NWPP is financially sound and has the appropriate funding to meet its contract requirements.

   The existing BOD has this same obligation.

8) The BOD will review the goals and directions set by the NWPP, its programs and committees to understand the impact on NWPP and its employees, including the impact on longer-term employment for NWPP employees, corporate risk, and potential impacts on the structure of the NWPP.

   The existing BOD has this obligation. Here, "goals and directions set by the NWPP" refers to the goals and directions set by the signatories to the NWPP Agreement through the programs and committees set up under that agreement; the NWPP has a contractual obligation to support those programs and committees.

   The BOD currently emphasizes that the NWPP is currently viewed as a service or consulting organization to facilitate the goals of the signatories to the NWPP Agreement. The obligation to continue such services will continue even upon development of an RA Program.

9) The BOD will ensure the NWPP has appropriate insurance for its business operations, Directors, officers, and staff.

   The existing BOD has this same obligation.

10) The BOD will ensure the NWPP has appropriate retirement funding as established by the corporate retirement plan.

    The existing BOD has this same obligation.

11) The BOD will ensure the NWPP has appropriate employee benefits as established by the corporate benefit plan.

    The existing BOD has this same obligation.

12) The BOD will ensure the NWPP is meeting all its legal requirements and that it has sufficient legal resources to support regulatory process and regulatory filings.

The existing BOD has this same obligation, though the scope of the regulatory filings under the NWPP's purview would be expanded if an RA Program were established; legal requirements include tax filings (nonprofit status) as well as regulatory filings.

13) The BOD will hire the officers of the NWPP and address succession plans.

The existing BOD has this same obligation.

14) The BOD will elect from its membership a Chair and Vice Chair for two-year terms.

The current NWPP Bylaws state that the NWPP will have a BOD Chair and a Vice-Chair.

15) The BOD will meet at least three times per calendar year (in-person or virtual) and additionally upon the call of the Chair or upon concurrence of at least a majority of Directors.

BOD meeting requirements for the current BOD are established by the Bylaws and require the BOD to conduct at least one annual meeting and one additional regular meeting each year; special meetings are conducted upon the call of the Chair or upon concurrence of at least three Directors.

16) Directors will receive compensation and be reimbursed for actual expenses reasonably incurred or accrued in the performance of their duties.

Current Directors are reimbursed for actual expenses and receive compensation for meeting attendance.

1.1.3. Board of Directors Duties for Specific Programs or Functions

The BOD will authorize filings with regulatory bodies, except for the RA Program when the BOD will authorize, and the NWPP will submit filings only after consideration by the RAPC. If the RAPC approves an action and such action is not appealed to the BOD, the action is deemed to be approved by the BOD, and NWPP is authorized to submit any applicable required regulatory filing(s). Any action, or inaction, taken by the RAPC may be brought before the BOD for ultimate resolution. Currently the NWPP makes regulatory filings on behalf of program Participants who have named the NWPP the agent for compliance with certain NERC reliability standards; NWPP Staff works with Reserve Sharing Group and Western Frequency Response Sharing Group participants to coordinate such filings.

1) BOD meetings for the RA Program will be open and noticed to all stakeholders for all meetings except when in executive session. Executive sessions (open only to Directors and to parties invited by the Chair) will be held as necessary upon agreement of the BOD to safeguard confidentiality of sensitive information.

   Current BOD meetings do not involve stakeholders and are not open to the public.

2) The Chair of the BOD will grant any stakeholder's request to address the BOD during open public meetings for a prescribed period of time with respect to RA Program.

   Current BOD duties do not require a stakeholder process.

1.1.4. Board of Directors Limitations for the RA Program

Regarding the RA Program, the BOD will be prohibited from engaging in the following:

1) Changing the Participants' existing functional control and responsibility over their generation and transmission assets.
   a) Participants will retain full autonomy and responsibility to ensure the reliable and efficient planning and operation of their transmission systems.
   b) 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.
   c) 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 provision includes a restriction that the BOD will not impose must-offer obligations on any Participant or their resource(s).
   d) Participants who administer a Balancing Authority (BA) will retain responsibility for ensuring compliance with applicable reliability standards within their BA boundaries, and any other reliability standard requirements for applicable NERC functional designations.
2) Administering OATT service, engaging in BA operations, imposing transmission planning requirements or assuming any transmission planning responsibilities.
3) Taking action to form an organized market, including a capacity market, or establishing a Regional Transmission Organization, unless such action was also approved by the RAPC.

4) In response to a failure to meet program requirements, requiring anything beyond the imposition of financial or penalty consequences, the limitation or suspension of participation, or other similar measures.

These limitations will be addressed in the updated bylaws of the NWPP by requiring additional committees' support (e.g., RAPC, COS) for bylaw changes that expand the scope the BOD and the NWPP to include such activities.

1.2. Committee Nominating the BOD

An NC is proposed to be used for selecting the members of the BOD. The following proposal is based in large part on the NC procedures that have been successfully used for the Western Energy Imbalance Market. The BOD will be selected by a NC comprised of certain stakeholder representatives. This proposal explains the selection and composition of the NC, how the NC will select a slate of nominees for each open position, and how that slate of nominees will be subject to a vote of approval on the slate by the BOD. The NC will nominate a slate with one nominee for each open seat on the BOD for which the term is scheduled to expire.

The NC is responsible for nominating proposed BOD members for approval by the sitting BOD. The NC is also responsible for recommending compensation for the BOD. The NC is the primary committee responsible for identifying a recommended nominee or nominees for open positions on the BOD, working with the NWPP staff and an executive search firm.

1.2.1. Makeup of the Nominating Committee

- The NC will be comprised of 12 individuals from stakeholder sectors and such sectors will have the following designated number of seats on the NC and the following voting designation.
    - Proposed sectors include:
        - RAPC/Participants, ensuring appropriate representation among these types of Participants:
            - Investor-owned Utilities (IOUs) (2) - voting
            - Cooperative-owned utilities (COUs (2) - voting
            - Retail Competition Load Responsible Entity (LRE) (1) - voting
            - Federal Power Marketing Administration (1) - voting
        - Independent power producers/marketers (1) - voting
        - Public interest organizations (1) - voting
        - Customer advocacy groups (1) – voting

- NWPP member (not on RAPC) (1) - voting
- BOD (a member who is not rolling off, not the NWPP CEO) (1) – non-voting
- COS (chair or vice chair) (1) – non-voting (but voting in the event of a tie)

Each sector will appoint its representatives to the committee. In the event that a particular sector cannot reach consensus regarding their representative, the NC normal activities may continue without a full NC. The NC will strive for and will act on the consensus of its members. However, in the event consensus cannot be obtained, voting procedures will be utilized and at least a simple majority must be obtained to approve a candidate to the slate. Non-voting members are expected to share their views about the candidates and to participate fully in deliberations.

Each sector will determine its own method of selecting a representative(s) to serve on the NC, and the term of service. A sector may designate a term of service for multiple years if it wishes to avoid the need to meet in the following year(s) to select a representative. The minimum term of service will be one year.

1.2.2. Selection of Sector Representatives to the Nominating Committee

Not less than 150 days prior to the scheduled expiration of any BOD member's term, and at other times as may be necessary to fill a vacancy on the BOD, the staff of the NWPP will ensure that each sector of the NC has identified their respective representative(s).

The staff of the NWPP will issue a notice that the NC will be convened in parallel with the NC representative's sector outreach. The public notice will include a list of the NC representatives. The purpose of this notice is to provide an opportunity for sector members to self-identify in order to receive communication from the sector organizer.

If one or more of these sectors does not have a currently serving representative to the NC, the staff of the NWPP will designate a person from one of the entities in the sector to serve as a sector organizer to facilitate selection of a representative. Each sector organizer must make reasonable efforts to notify all entities that are qualified for participation in its sector about the initial organizational meeting or teleconference for the sector. These efforts will include issuing, with assistance from 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 entities in a sector may be referred to the management of the

NWPP for resolution. The CEO (or his or her designee) and the General Counsel will hear from the interested parties and make a decision. Their decision will be binding on the sector.

Within 40 days after the NWPP staff designates a sector organizer to facilitate selection of a representative, the sector organizer will certify the choice of the sector representative. If a sector organizer has been unable to make a certification because the sector has been unable to reach agreement on its representative, the BOD will select a representative for the sector. The NWPP staff will post the name and contact information of each sector representative on its website.

1.2.3. Operation of the Nominating Committee

Once organized, the NC should convene no less than 100 days prior to the scheduled expiration of any BOD member's term to begin the process of identifying potential candidates for each open seat, or as soon as practicable when other vacancies arise.

If a BOD member whose term is scheduled to expire has expressed a desire to be nominated for a new term (and has not reached their term limit), the NC should determine whether it wants to re-nominate the departing member without interviewing other candidates. If the NC does not decide to proceed in this manner, then it would ask the executive search firm to identify at least two qualified candidates to interview, in addition to the sitting member.

The NC will apply the following criteria in its selection process:

- Working with NWPP staff, the NC will engage and work with an executive search firm to identify at least two qualified candidates to interview.
    - The executive search firm may not consider a candidate who has a prohibited relationship or financial interest, 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.
- With assistance from the executive search firm, the NC will develop a job description, job posting, identify, and select the best qualified candidates available in the United States.
- Optimally, the NC's selections should ensure that the overall composition of the BOD reflects diversity of expertise so that there is not a predominance of Directors who specialize in one subject area, such as operations or utility regulation. The following skillsets and expertise should be considered:
    - Electric industry — such as former electric utility senior executives currently unaffiliated with any market Participant or stakeholder; present or former executives of electric power reliability councils; present for former executives

from power pools; retired military officers with relevant experience; or present or former executives of firms that perform professional services for utilities;

    - Regulatory — executives or attorneys with extensive background in the regulated utility industry, resource or transmission planning; former state or federal regulators with applicable experience; or academics or consultants with relevant experience; and
    - General corporate/legal/financial — such as present or former management consultants or service industry executives; present or former chief executives; chief financial officers; chief legal officers or chief information officers of profitmaking companies; present or former national law firm partners; present or former senior executives of financial institutions, investment banking or financial accounting/auditing organizations.

- In addition, the NC should give consideration to diversity with respect to race, gender, and ethnicity.
- The NC will consider geographic diversity and no one state or sub-region in the West should have excessive representation — meaning members whose place of residence or work history tends to associate them with a particular Western state.
- The NC should strive to ensure that the BOD includes at least one member with expertise in Western electric systems, markets, or utility resource planning.
- The deliberations of the NC will be confidential. The candidate selection process is highly sensitive and candidate information, and the deliberations of the NC should not be shared publicly. However, the NC sector representatives may confer with their sectors to enable sector alignment and support for candidates. The NC sector representative may communicate with their sector as part of the process of evaluating candidates. The NC should have a common understanding about the extent to which they will share the names of candidates in connection with a particular search (timing, level of detail, etc.).
- The NC will meet as required to perform its responsibility.
- Except as otherwise provided here, the NC may establish its own procedures.

1.2.4. BOD Nomination Recommendations and Election

The slate submitted by the NC will be subject to approval by the BOD in an open session. If the decision occurs before the end of the expiring terms, the BOD Director(s) whose terms are expiring will be recused from the approval decision. The BOD must accept or reject the slate as a whole.

For example, assuming two sitting BOD members' terms are expiring, the NC would be convened and would work with the executive search firm to screen and identify qualified candidates. Through this screening, review, and interview process, the NC will select two qualified candidates and these candidates will comprise the slate of candidates recommended to the sitting BOD for approval. The sitting BOD will vote on the slate as a whole, either approving or rejecting.

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

If the slate is rejected, the NC must re-convene and establish a new slate of nominees. The new slate 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 BOD will decide, in public session, to approve one of the two slates that was submitted by the NC.

1.3. Resource Adequacy Program Participants

The following are the qualifications for Participants:

1) Participants must be an LRE.
2) Participants must have either a physical transmission connection or rights to use transmission to at least one other Participant or a trading hub used by Participant(s).
3) Participants must sign the Western Resource Adequacy Agreement (WRAA) that includes terms and conditions and comply fully with those terms and conditions and any other agreements necessary to facilitate the RA Program.
4) Participants may be required to be a signatory to the WSPP, formerly known as the Western System Power Pool, or an enabling agreement given that the RA Program is built around leveraging existing bilateral structures.
5) Participants are expected to register their entire fleet of resources that can be called on to serve their respective loads so that the RA Program will have visibility to all resources the Participant is relying on within the program.
6) Participants will sign a data sharing and confidentiality agreement essential for the operation of the RA Program.

1.3.1. Resource Adequacy Participant Committee

1) The RAPC is comprised of Participants and is responsible for developing and recommending policies, procedures, and system enhancements related to the policies and administration of the RA Program by NWPP.

2) Participation in RAPC is limited to Participants. Therefore, the RAPC is a committee with limited membership; this is more conservative than what was proposed and approved by FERC for Southwest Power Pool's (SPP) Western Markets Executive Committee.

3) The RAPC is responsible, through its designated working groups, committees, and task forces, for developing and recommending policies, procedures, and system enhancements related to the policies and administration of the RA Program by NWPP under the WRAA in the Western Interconnection. This is similar to what SPP provided through its Western Markets Executive Committee.

4) In carrying out its purpose, the RAPC will provide the forum for Participants that have executed a WRAA with NWPP. The RAPC can approve or reject proposed amendments to the RA Program Tariff prior to the filing of such amendments at FERC. The RAPC can also consider, approve, or reject program rules if such rules solely apply to the administration of the RA Program and have no application to any other program and/or contract service provided by NWPP. To the extent such rules do apply to any other service provided by NWPP, the RAPC will be afforded the opportunity to provide input to the NWPP BOD to resolve any issues. This will be accomplished by a collaboration with NWPP on the development of RA Program provisions, business practices, and interregional agreements to promote transparency and efficiency in the operation of the RA Program.

5) The RAPC can evaluate and provide consultation to NWPP on the RA Program administration budget and budget allocation to Participants, including modifications or adjustments of the RA Program Administration Rate, in accordance with the WRAA. There are other responsibilities that can be added to the detail as this proposal is filled out.

6) 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 the chair and vice chair of the RAPC.

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

8) 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 thereof, but not less than

three representatives; provided, that a lesser number may adjourn the meeting to a later time.

9) In the RAPC, each representative will have one vote. Voting will utilize a "House and Senate" style approach. The "House" vote will be weighted based on each representative's P50 load, as determined in the FS Program (see 2.3 for additional information on the determination of the P50 load). The P50 metric is used to allocate requirements and benefits of the RA Program throughout both time horizons; in the FS, it determines the FS capacity requirement, and in the Ops Program, it is a key component of the Sharing Calculation (determining a Participants' ability to access pooled resources). "House" voting will use the higher of a Participant's two seasons' P50s (e.g., Winter-peaking Participants will use their Winter season P50 value in voting) and will be weighted as a portion of the sum of all Participants' higher-season P50 loads. The "Senate" vote will be equally weighted for all RAPC representatives. For a resolution to be approved, it must pass both the "House" and the "Senate" vote.
    a. Resolutions brought to the RAPC with support from the PRC will be approved with 67% affirmative votes from both "House" and "Senate" vote tallies.
    b. All other votes will require an affirmative vote of 75% or greater of both "House" and "Senate" tallies.
    c. If at any time, a single LRE is responsible for more than 25% of the total non-coincident high-season P50 loads (creating an effective veto power), a review of the voting thresholds would be triggered.

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

Entity	P50 (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**

In the example presented in Table 1-1, the vote passes; the pro-rata (Senate) vote tally is 80% affirmative, while the P50-weighted (House) tally is 95% affirmative, since the two dissenters are small entities. 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 pro-rata vote would drop to 70% affirmative, below the 75% 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 pro-rata vote would drop to 72.67% affirmative the vote, below the 75% threshold.

10) The RAPC is the highest level of authority for representation by Participants. The NWPP BOD will provide independent oversight of NWPP's administration of the RA Program under the WRAA. If the RAPC approves an action and such action is not appealed to the NWPP BOD, the action is deemed to be approved by the NWPP BOD, and NWPP staff is authorized to submit any applicable required regulatory filing(s). Any action, or inaction, taken by the RAPC may be appealed by any stakeholder to the NWPP BOD for ultimate resolution.
11) Meetings of the RAPC are open to all interested parties; and written notice of the date, time, place, and purpose of each meeting will be provided as described below. However, the RAPC may limit attendance during specific portions of a meeting by an affirmative vote of the RAPC in order to discuss issues that require confidentiality.

1.3.2. Exit Provisions

A Participant can exit the RA Program if they are ordered by a regulatory body (jurisdictional) or if they determine (jurisdictional or non-jurisdictional) that exit is required to protect the interests of their customers. A Participant could also decide that it needs to leave the program because the Participant disagrees with a decision being made under the governance model that affects the way the RA Program is administered or their ability to continue participation. A Participant could decide that it needs to leave the program for various business reasons.

The following straw proposal for exit provisions is provided for consideration:

- Participant entry and exit from the program will remain voluntary, however, appropriate notice must be given prior to exit.
- Options for standard notice provision:
  - Parties must give at least 24 months written notice prior to the beginning of the next binding FS period. This requirement may result in more than 24 months between when the notice is given and the actual effective date of the exit.
    - For example, if a Participant did not want to participate for the Summer 2025 binding season, the Participant would need to give notice by June

1, 2023. This corresponds with the timeline for the FS Program when Participants would be required to complete review of their inputs to the loss of load expectation (LOLE) model, but prior to the time when the model is run by the PO to provide the binding planning reserve margin (PRM) for the Summer 2025 season in question].

        - The standard notice period could be shorter than what is suggested here, but the timing and logistics on FS and operations would need to be worked through.
    - Options for non-standard exit:
        - The program could also include additional provisions that provide for earlier exit under the following circumstances:
            - Exit for “extenuating circumstances” (such as by order of regulatory authority or additional circumstances to be defined) to be assessed by the BOD and/or PO on a case-by-case basis
            - Exit by fee to ensure that any unreasonable harm from earlier exit is mitigated or compensated by the exiting Participant. The PO would calculate the exit fee. This exit provision would only be available if the exit fee can be calculated by the PO with a high degree of confidence.
            - If a Participant experiences a significant decrease in forecasted peak load after the two-year deadline has transpired, they will work with the PO, and/or third-party neutral, for the purpose of developing an understanding of factual matters for the change, to determine whether there are or would be any resulting impacts to other Participants. Further consideration of what constitutes a “significant” decrease, what solutions are available to address the change, and how the costs of this assessment are allocated will be considered in 3A.
    - Once proper notice is provided, the withdrawing Participant will be in the withdrawal period until exit is effective, during which the withdrawing Participant is required to continue to comply with all requirements of the RA Program, except, however, the withdrawing Participant will recuse themselves from any votes or actions affecting the RA Program for timeframes that extend beyond the withdrawing Participant’s exit effective date.
- In addition, any financial obligations that exist as of the exit date are preserved until satisfied (e.g., the Participant has already been assessed cost of new entry penalties for failure to meet the FS Program).
- A Participant who exited can re-enter provided their entry is negotiated with the PO to commence consistent with the timing of the deadline for the inputs required for the LOLE study needed in the next binding FS Program season.

1.4. Resource Adequacy Program Operator

1) In order to provide a clear direction for the RA Program and how it can be implemented, the following will outline how NWPP and the contracted PO will fulfill all the required functions needed for the RA Program. The PO will report directly to the BOD but will also interface with other committees and NWPP staff as needed to fulfill their duties. Note that NWPP will enter into a contract with the PO that will define the required responsibilities of the PO. Generally, it will be the responsibility of NWPP to provide any needed general logistics and oversight of the contract with the PO to perform FS and operations functions of the RA Program.
2) NWPP will provide all support of the governance outlined above including the compensation for the BOD, responsibility for the expenses and logistics for all their meetings and the committees under the BOD. The support of the contract and compensation to the PO will be the NWPP responsibility, as well as legal and federal regulatory support for the RA Program, including meeting all the functions required of a public utility. NWPP will also be responsible for billing, collection and payments under the RA Program as well as all the other current contracted programs and services of the NWPP.
3) The PO will be responsible for the fulfillment of the contract requirements for the RA Program including the FS and the near-term to real-time operations. These would include modeling and system analytics, the performance or analysis of the LOLE study, PRM analysis, qualifying capacity contributions, FS Assessments, Deliverability for Planning & Reliability Coordination for capacity reserve adequacy, and Generation Assessment & Uncertainty Response activity. These responsibilities will also include the monitoring and responding in the real-time operations. The PO will calculate any required settlements and assess penalties for noncompliance according to the penalty calculation rules set forth in the program. To perform their functions under the contract, the PO will have sufficient information technology resources including systems and people to maintain the systems, meeting requirements of cyber security, backup of data/systems, change control, and system recovery.
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 NWPP BOD.

1.5. Independent Evaluator

The Independent Evaluator (IE) function has been identified by the current NWPP BOD, state regulators, and the Stakeholder Advisory Committee as an important element of a well-functioning regional RA Program to provide an outside, independent assessment of the performance of the program. It has been identified as an element that will be important to FERC as they consider approving the FERC-jurisdictional elements of the RA Program. It is recommended that the IE be established on or near the conclusion of Stage 1 of the RA Program and on an ongoing basis to provide an annual review of the RA Program. This initial scope for the IE could change over time, but this initial recommendation is intended to balance the need for independent review to identify continuous improvement opportunities with cost and administrative burden, especially as RA Program functionality will be implemented in stages over time.

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 program Participants;
3. Does not have decision-making authority; and
4. Reports their findings to all RA Program committees.

The day-to-day operation of the program by the NWPP and PO should be separate from the evaluation of the program by the IE in order to meet FERC's independence requirements. To be effective, independent program monitoring and evaluation must be transparent. Every effort should be made to aggregate data in order to preserve confidentiality, while still effectively communicating program results to stakeholders.

The IE will be an outside entity (not part of NWPP staff) to be recommended and hired by the NWPP (with approval from the BOD) but will report to the NWPP BOD.

1.6. Other Committees and Structural Functions

provides the organizational structure for the NWPP. The following sections describe components of this structure.

1.6.1. Committee of States

The RA Program governance structure will need to include states' perspectives on matters such as integrated resource planning, reserve requirements, emerging policies concerning renewable generation, storage, efficiency and demand resources, and rules for retail choice (e.g., direct access providers and consumer choice aggregators).

The COS is comprised of state representatives, either from the public utility commission or state energy office at each state's discretion. It is envisioned that there would be one representative from every state from which a Participant hails. The COS would have a Chair and Co-Chair.

In partnership with the Western Interstate Energy Board, the NWPP RA Program has commenced a series of meetings and discussion with state representatives to determine the role and functions of the COS. The goals of this process are:

- Learn and understand Stage 1 inputs/outputs; build trust and understanding.
- Evaluate the COS to determine authority structure for future stages pursuant to a set timeline.
- Determine whether a role for public power, either through ex-officio/liaison role, or some other role on the COS is appropriate.

The COS will likely need support from staff; specifics related to staffing support will be further considered in collaboration with state regulators in upcoming phases.

1.6.2. Program Review Committee

The PRC is a sector representative group charged with receiving, considering, and proposing design changes to the RA Program. The PRC is the clearing house for all recommended design changes not specifically identified as time-sensitive or of high RAPC priority (see below). These recommended changes could come from Participants, the BOD, other committees, stakeholders, the public, etc.

Figure *1-3* provides an overview of the PRC review process.

- The PRC will be staffed with facilitation support from the NWPP and program design/technical support from the PO.
- The PRC will establish a process and criteria for receiving design update recommendations.
- When recommendations are received, the PRC will work with the PO and NWPP staff to review recommendations and create proposals for the change; this process will be defined by the initial PRC once identified.
- As part of the PRC's proposal process, they will run a public and stakeholder comment process, also to be established by the first PRC.
- The PRC will also seek input as appropriate from the COS, once their role and authority is determined.
- The PRC will present all proposals received to the RAPC; PRC will provide RAPC with a refined proposal, feedback received from the COS and PO, summaries of public comments received, and their own recommendation (with a minority opinion, if necessary). If the RAPC rejects a recommendation from the PRC, the PRC may decide to appeal that decision by taking the proposal to the BOD.
- In the non-binding stage, the PRC will review and add detail to the proposed process for reviewing and proposing changes. This process will be recommended to the RAPC for consideration, as will proposed changes to the process in the future.
- The PRC will consist of the following sectors and sector representatives, which could also be represented by a trade group that serves that sector. Each sector will be responsible for appointing its representatives:
    - RAPC Participants, ensuring appropriate representation among these types of Participants:
        - IOUs (4)
        - COUs (4)
        - Retail Competition Load Serving Entity (2)
        - Federal Power Marketing Administration (2)
    - Independent power producers/marketers (2)
    - Public interest organizations (2)
    - Customer advocacy groups (2)

- It will be important that the PRC is a functional, working committee to avoid design change bottlenecks. The initial PRC will develop a code of conduct for member participation. Membership on the PRC will require, at minimum:
    - Willingness to represent their sector and work in the best interests of the regional program;
    - Ability and willingness to communicate with their sector to ensure accurate representation of the sectors' needs and concerns;
    - Consistent attendance and engagement at PRC meetings by the identified PRC representative; and
    - Willingness to collaborate with other PRC members to propose feasible, reasonable design changes in a timely manner.
- Similarly, to ensure efficient function of the PRC, membership on the committee should be chosen to provide a diversity of perspectives and expertise within the identified sector representative categories.

Exigent design changes (e.g., those mandated by FERC order, those with immediate reliability impacts, those of high priority to the RAPC) may need to utilize an expedited review process. In these circumstances, the RAPC would work with the PO and NWPP to propose a design change and would propose that change to the BOD. The PRC, COS, and public would participate in a comment process directly with the BOD as they review the RAPC's proposed response to the time-sensitive design issue. This process is outlined in Figure 1-4.

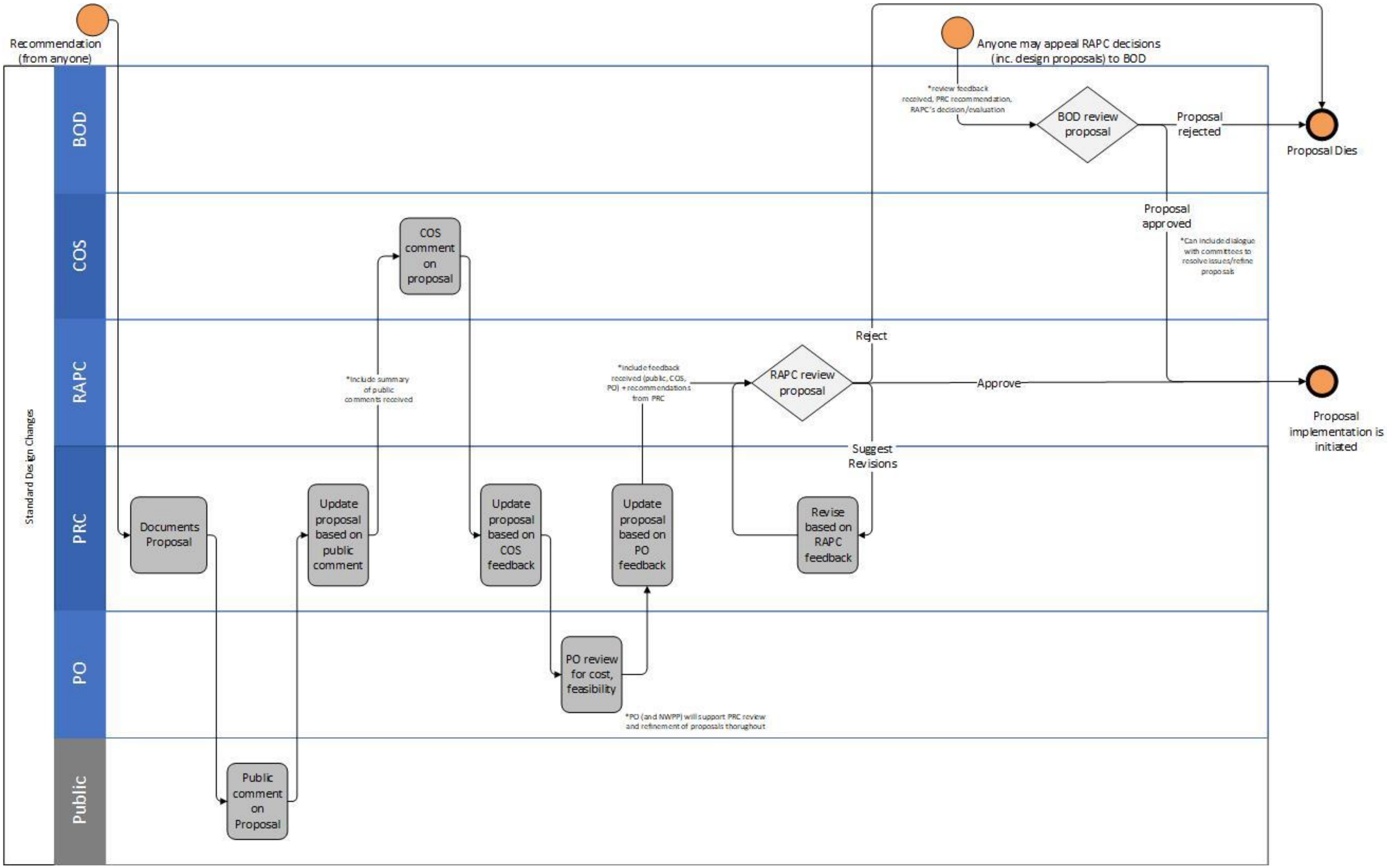


Figure 1-3. *PRC Review Process*

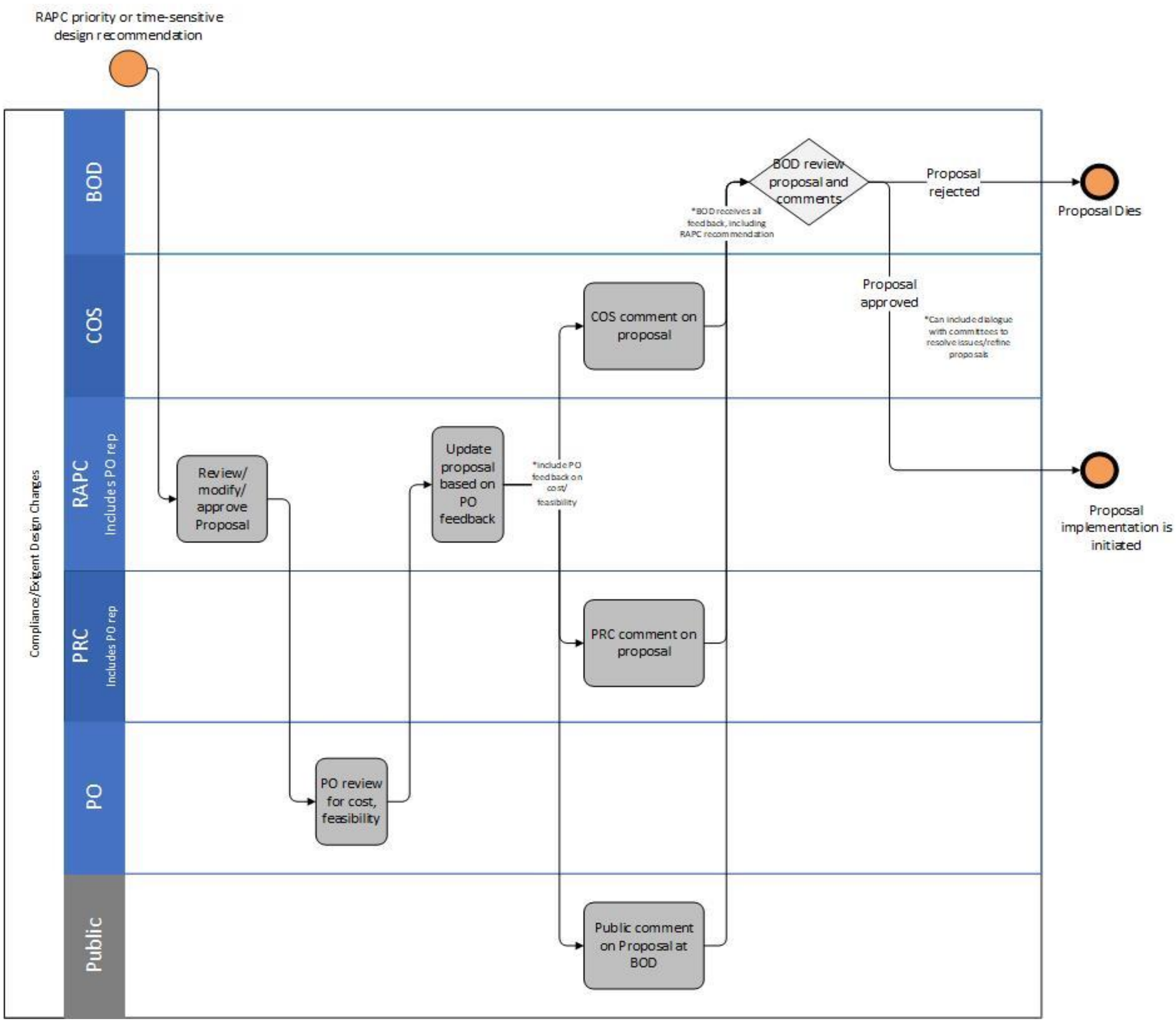


Figure 1-4. PRC expedited review process.

1.7. Cost Allocation Principles

1.7.1. Assigning Costs Incurred to RA Program

Any costs will need to be assigned based on the costs incurred in providing contracted program services, including costs of the BOD, administrative personnel, and shared services with other NWPP services that are provided outside the RA Program.

When possible, costs associated with specific services or programs (e.g., staff time, program-specific software, etc.) will be direct assigned.

If direct assignment is not possible where costs support multiple services or programs (e.g., cost of BOD, office lease costs, etc.), costs will be allocated using a reasonable cost allocation methodology.

1.7.2. Allocating Costs to RA Program Participants

Costs assigned to the RA Program will be allocated to Participants on a basis consistent with the “house and senate” voting described previously. 50% of the costs assigned to the RA Program will be allocated on a pro-rata basis to Participants. The other 50% of costs will be allocated based on P50 of each Participant.

NWPP Resource Adequacy Program Detailed Design

Section 2. Forward Showing Design

NORTHWEST PowerPool

JUNE 2021

Prepared in collaboration with the Southwest Power Pool, as Program Developer

SPP Southwest Power Pool

SECTION 2. FORWARD SHOWING DESIGN: TABLE OF CONTENTS

FORWARD SHOWING PROGRAM DESIGN

The Northwest Power Pool's (NWPP) Forward Showing (FS) Program is the forward-looking planning portion of the Resource Adequacy (RA) Program. In the FS Program, the Program Operator (PO) performs assessments and analyses in accordance with the FS Program requirements. These assessments and analyses include the Annual Assessment that determines a planning reserve margin (PRM) and the qualified capacity contribution (QCC) of Participants' resources and contracts.

The main component of the FS Program is the FS portfolio submittal and review, in which Participants provide their data submittals showing that the Participant has met the FS capacity requirement of the FS Program. When it is determined a Participant is not compliant with the FS capacity requirements, the PO will apply approved deficiency payments to the Participant. Table 2-1 presents a summary of key components of the FS Program.

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

NWPP RA 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.
Compliance Periods	Two binding seasons: Summer and Winter. Fall and Spring seasons are advisory (no non-compliance payments).
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 PO.
PRM	Seasonal PRM will be determined as part of the Annual Assessment for Summer and Winter seasons and expressed as a percentage of the 1 in 2 peak (P50) load forecast of the Participant.
QCC	Wind and solar resources: effective load-carrying capability (ELCC) analysis. Run-of-river hydro: ELCC analysis. Storage Hydro: NWPP-developed hydro model that considers the past 10 years generation, available water in storage, and current operational constraints. Thermal: unforced capacity (UCAP) method. Energy storage resources (ESR) and hybrid resources: determined by operational testing until higher penetrations show a need for a performance-based methodology. Customer-side resources: operational testing and historical performance.
Transmission	Deliver showing resources on firm/conditional firm transmission; demonstrate at FS deadline having procured or contracted for transmission rights to deliver at least 75% of the FS capacity requirement from source to load.
Payment for Non-compliance	Deficiency payment based on cost of new entry (CONE) of a new peaking gas plant.

2.1. Showing and Compliance Timing

The FS Program will be binding for the Summer and Winter seasons. The FS deadline will be seven months ahead of the start of each binding season (see Table 2-2 and

Figure 2-1); at the FS deadline, Participants must demonstrate that they own or have contracted sufficient QCC to meet their FS capacity requirement, which is based on the regional metrics as defined by the RA Program and calculated by the PO (e.g., the PRM; see Section 2.2).

Analysis of 10 years of historical NWPP regional load showed peaks in both Winter and Summer seasons, necessitating the program observe two binding seasons. This analysis observed a decline in load and an increase in the availability of capacity for the last half of September (for the Summer season) and the last half of March (for the Winter season), enabling the mid-month season delineation.

The Spring and Fall seasons will be advisory; the PO will provide advisory metrics. There will be no FS deadline or PO review for those seasons, and thus there will be no deficiency payments for noncompliance for Spring or Fall. However, the PO may conduct analyses with available data in an advisory manor, and to allow for future advice to the RA Program and Participants.

Table 2-2. Compliance seasons and deadlines.

Season	Binding/Advisory	Duration	FS Deadline	Cure Period
Winter	Binding	Nov 1– Mar 15	Mar 31	Jun 1-Jul 31
Summer	Binding	Jun 1– Sep 15	Oct 31 (Of prior year)	Jan 1 – Feb 28
Spring	Advisory	Mar 16 – May 31	N/A	N/A
Fall	Advisory	Sep 16-Oct 31	N/A	N/A

After Participants submit their FS portfolio at the FS deadline (i.e., March 31 and October 31), the PO will validate submittals from Participants (e.g., generator test reports, power purchase and sales agreements, transmission service arrangements). The PO has a 60-day period following the FS deadline for validation of the submittals. After validation, the PO will notify Participants of deficiencies; any deficient Participant will have 120 days from the FS deadline or 60 days from the PO's notification whichever is later to cure the deficiency before deficiency payments are assessed.

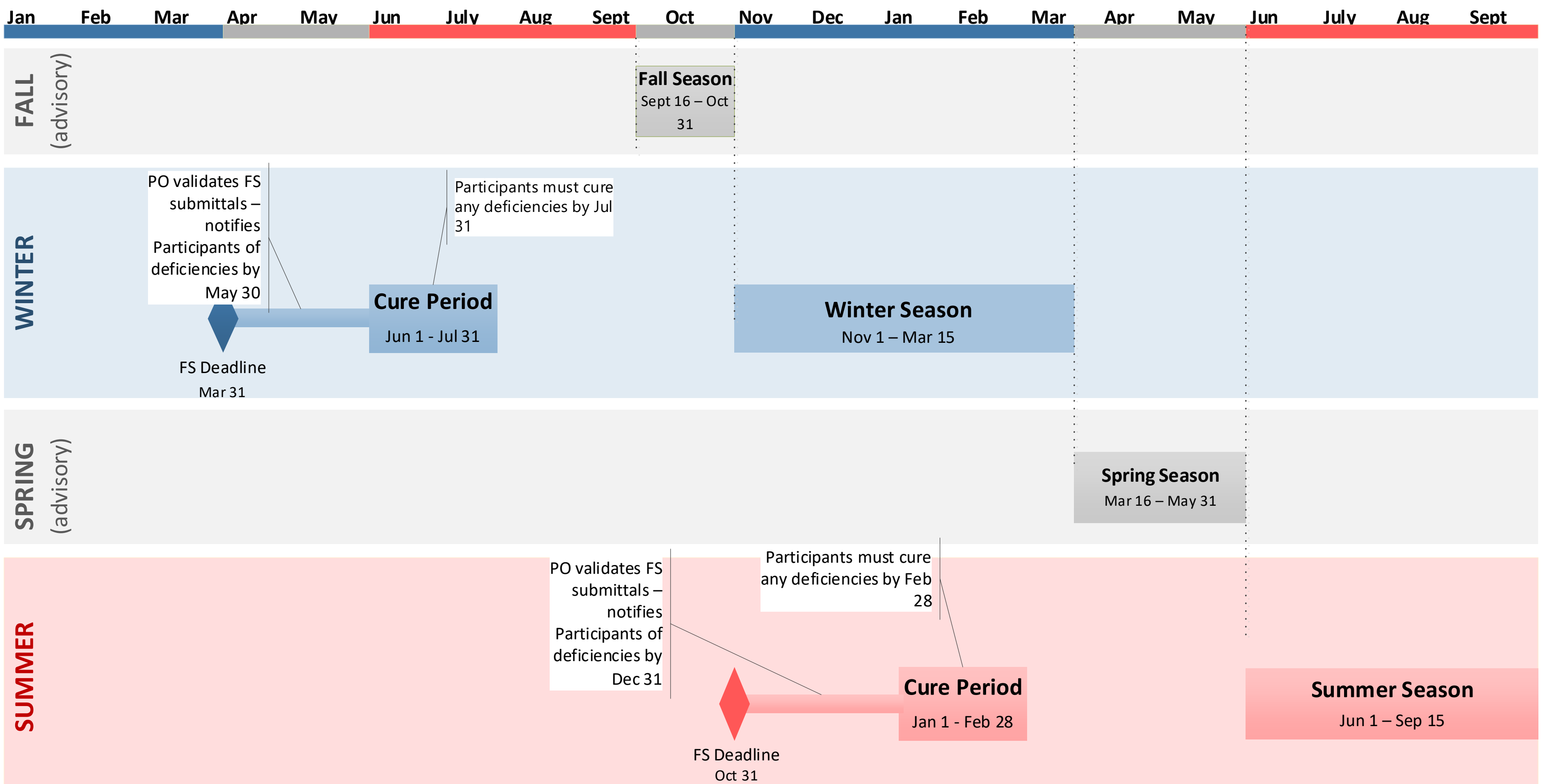


Figure 2-1. Program timeline, including binding (Summer and Winter) and advisory (Spring and Fall) seasons, FS deadlines, and cure periods.

2.2. RA Program Metrics

2.2.1. Program Objective

The regional RA objective is intended to ensure the RA Program footprint has sufficient capacity to adequately serve load under a variety of possible scenarios.

The FS Program is designed to identify the capacity needed to meet a loss of load expectation (LOLE) objective of one event in 10 years where capacity is expected to be inadequate to meet load plus contingency reserves (CR). An event could be a single hour or multiple hours in a day; hours of loss of load in a single day, whether consecutive or inconsecutive, will constitute a single event. Seasonal LOLE objectives of 1-in-10 will be calculated by the PO for Summer and Winter seasons, as defined by the FS Program.

2.2.2. Planning Reserve Margin

The PRM is obtained through probabilistic LOLE analysis and represents the amount of dependable capacity needed beyond the P50 load forecast to meet unforeseen periods of high demand, unexpected resource outages, and other unexpected conditions. Commonly, the PRM is expressed as a percentage multiplier (e.g., 12%).

The PRM is a key component in determining the necessary amount of qualified capacity (expressed in megawatts (MW)) needed to meet the demand (load) projections for each season.[4] For the purposes of the FS Program, a hybrid approach consisting of ELCC for variable energy resources (VERs), UCAP for traditional generators, installed capacity (ICAP) for ESR and demand response (DR) and a stand-alone methodology for storage hydro will be employed for modeling the capacity of resources to determine the PRM (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

[4] The calculation of the PRM includes an embedded assumption of the allocation of CRs but regulating reserves and other BAA-specific reserves will not be included in the PRM 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.

PRM is known as the UCAP PRM methodology.[5] The PRM for the FS Program will be a UCAP value. The PO will identify the total MW capacity required to meet the 1-in-10 LOLE objective for the RA Program footprint.

The PRM for each season will be determined and expressed as a percentage of the P50 seasonal peak of the aggregated load across the RA Program footprint. The PRM is equivalent to the aggregate amount of capacity needed within the RA Program footprint. Individual Participant allocation is determined by multiplying the PRM by their non-coincident P50 load (individual P50 load forecast). The capacity requirement is met by Participants showing a commensurate amount of QCC to meet their P50 load forecast plus the PRM.

The PRM can be represented by the following formula.

$$\boldsymbol{PRM}\ (\%) = \frac{\boldsymbol{QCC\ - P50\ Load}}{\boldsymbol{P50\ Load}} * \mathbf{100}$$

2.3. Load Forecasting for Forward Showing

Load forecasting is a critical aspect of setting metrics appropriately. Participants will provide the PO their forecasted monthly peaks as well as their historic load data (i.e., 10 years of hourly data, adjusted for curtailed loads, DR, and known incremental energy efficiency measures not already captured).[6] The PO will represent the forecasted coincident peak (CP) demand of the footprint by modeling each Participant's historical load output and aggregating all Participant loads to a regional load shape.

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

[6] 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.

The Participant load forecasts will serve as the basis for P50 load value for each applicable study horizon and binding season (Table 2-3). The P50 load value that the Participant is required to provide capacity (and associated PRM) for in each FS season is monthly peak (of that season) that has the highest P50 load forecast.

Table 2-3. Example P50 load forecast.

Participant provides monthly forecasts for the Summer season				
Month	June	July	August	September
P50 Forecast	100 MW	120 MW	130 MW	120 MW
The August load forecast will serve as the P50 value for the Participant.				

Annually, the PO will collect Participant load forecasts and accompanying forecast methodologies. The PO will review forecasts and methodologies for consistency. At the outset of the FS Program, the PO will perform a postseason review to compare the Participant's peak loads against the loads forecast for that season. The PO will make recommendations to individual Participants to help improve forecast error and will make recommendations to the Participant Committee about ways to improve the load forecasts that improve the overall effectiveness of the Program. At some point, the RA Participant Committee (RAPC) may recommend to the NWW Board of Directors) that the PO develop its own load-forecasting function to serve as an independent load forecast for the purposes of validation; future design work (in 3A) will identify a triggering threshold for review of the Participant-led load forecasting methodology and consideration of the PO's role in this area.

2.3.1. FS Capacity requirement

To derive a Participant's FS capacity requirement for the season, the maximum of their forecasted monthly P50 load (of the binding season) is multiplied by 100% plus the PRM and is calculated using the following equation:

$$FS\ Capacity\ Requirement = max\{monthly\ P50\} * (100\% + seasonal\ PRM)$$

2.3.2. Capacity Critical Hours

Key to the FS Program design is the concept of capacity critical hours (CCH). Capacity critical hours may be different from the peak load hours of the region, as the concept considers other factors that impact when capacity may be in short supply. Determination of CCH considers the highest capacity need of the RA Program considering the gross load of the RA Program footprint, the performance of VERs, as well as the interchange across the footprint to arrive at a net regional capacity need:

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

Where:

Load = Participant gross load in MW from 2010-2020

Wind = 2020 installed wind resource output in MW synthesized back to 2010

Solar = 2020 installed solar resource output in MW synthesized back to 2010

Run-of-River = 2020 installed run-of-river resource output in MW synthesized back to 2010

Interchange = modified interchange in MW for 2010-2020 as calculated in Section 2.3.3.

Capacity critical hours are those hours where the net regional capacity need is above the 95th percentile (highest capacity need hours).

Distinguishing the CCH from peak load hours is important because there may be peak load hours where the resource capacity in the RA Program footprint will have more availability than in other hours. For example, while there may be instances of high loads during the month of June, there is also usually an abundance of run-of-river hydro generation. Since the output from run-of-river hydro must be used at that time, this could result in periods of excess capacity even though loads are generally high. As the NWPP footprint continues to see an increase of wind and solar resources, this potential capacity condition will become more applicable to those resources as well.

The following FS Program concepts rely on the CCH:

- NWPP Storage Hydro QCC Methodology determination (see Section 2.5.1)
- Thermal Resource QCC determination (see Section 2.5.3).

2.3.3. Regional Interchange Assumptions

In setting the PRM and identifying CCH, it is important to understand how much of the capacity residing within the RA Program footprint will be available to Participants under stressed grid conditions. While Participants of the RA Program are located within a defined footprint, the broader Western region remains an interconnected system and regional interchange (e.g., imports and exports) should be expected during all seasons. Due to the bilateral nature of the existing market, the PO will need to make data-driven assumptions regarding the magnitude of imports and exports to appropriately set the PRMs; this is especially true in initial seasons in order to arrive at metrics and program rules which will compel Participants to provide additional insight into planned firm interchange. The PO intends to include the results from this analysis as an input into the LOLE/PRM assessments to set an appropriate PRM for the initial start of the Program and will re-evaluate as the Program obtains more operating experience .

A review of the regional interchange data from 2010-2020 showed regional interchange has changed drastically in the past three years: from near constant flat NWPP export level (in the 3,000-5,000 MW range, see Figure 2-2) to a shape that shows exports in late evening and early morning hours (in the 3,000-5,000 MW level) with declining exports in the daytime hours (Figure 2-3). This new regional interchange shape appears to closely follow the timeframes of solar output in California.

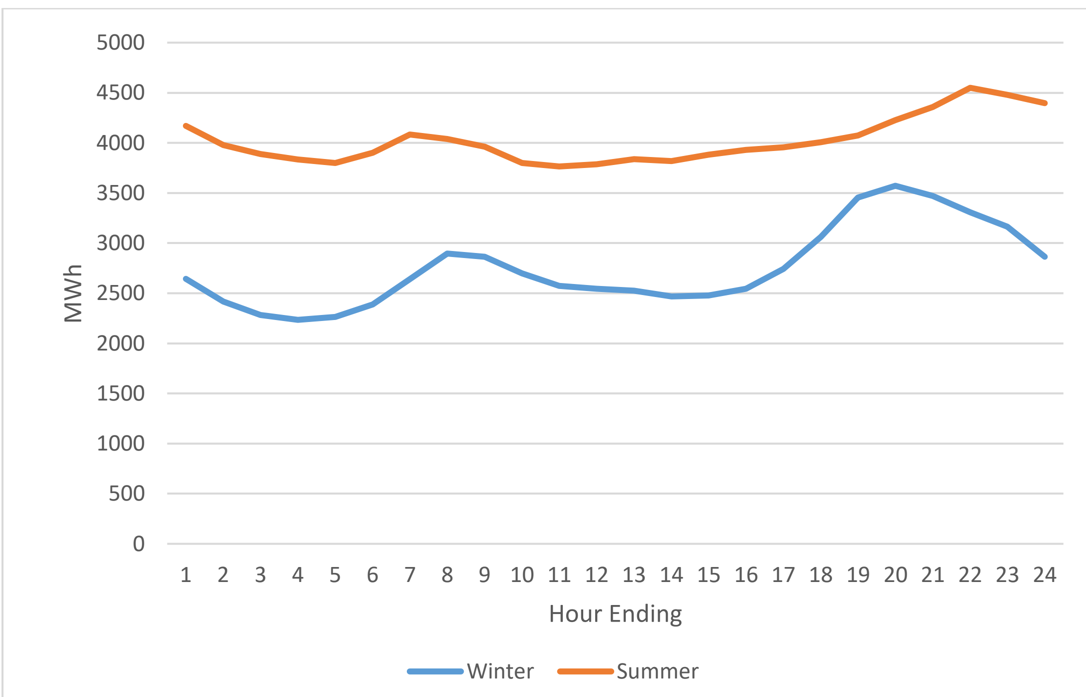


Figure 2-2. Raw regional interchange from the NWPP footprint 2010-2017 – a relatively flat/consistent interchange profile for both seasons where positive values represent exports from the NWPP footprint..

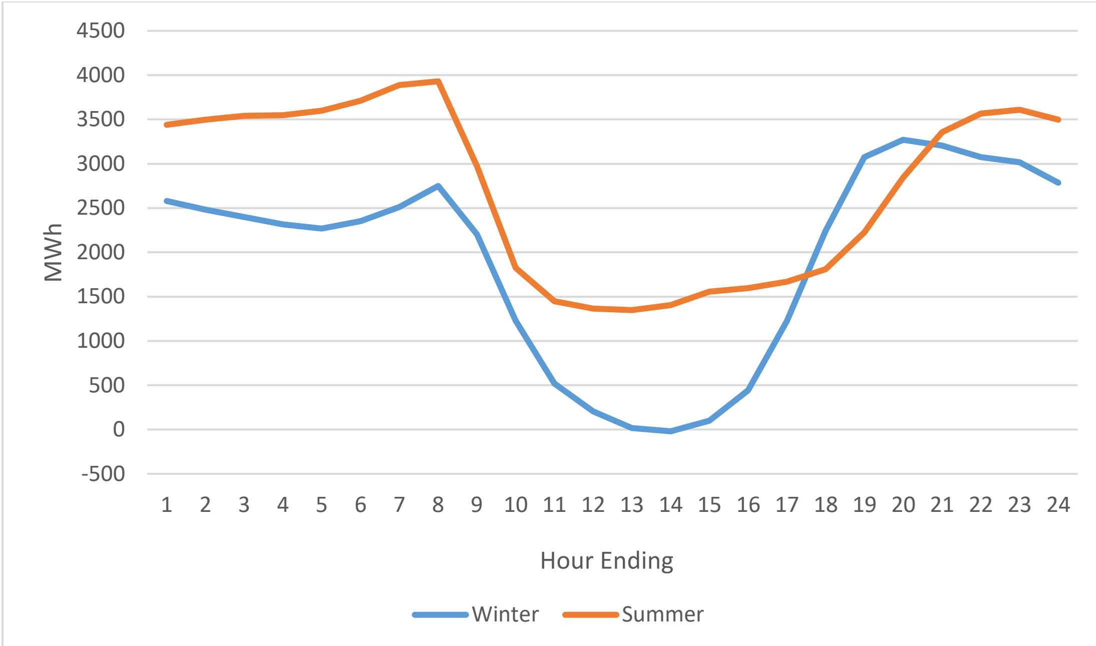


Figure 2-3. Raw regional Interchange 2018-2020 - declining daytime exports and peaks in morning and evenings. Roughly follows California solar production.

Assuming the recent interchange shape is most representative of future patterns, a methodology was established to adapt the previous seven-year period (2010-2017) to be more reflective of future resource mix assumptions driving recent interchange patterns (high solar resource penetration in California that results in a reduction of NWPP exports during the day, followed by high NWPP exports in the off-solar hours). The objective of applying this methodology was to establish a realistic dataset for use in determining CCH (Section 2.3.2).

It was assumed that hour ending 19 (HE19) interchange should remain unchanged from its historical value throughout the 10-year period. This assumption accounts for the lack of solar at this hour and sets a basis for further calculations for other hours. Next, the interchange for all hours (HE1-HE24) for years 2018-2020 was averaged on an hourly basis (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 difference of the averages (e.g., HE19 compared to each individual hour, see green arrows on Figure 2-4) of these interchange values from the 2018-2020 calendar years was then applied to the hourly interchange of all years in the 10-year period (2010-2020). This resulted in a new hourly interchange shape for the entire 10-year period closely resembling interchange shape for 2018-2020 but retaining interchange amplitudes (for HE19) of the original data sets.

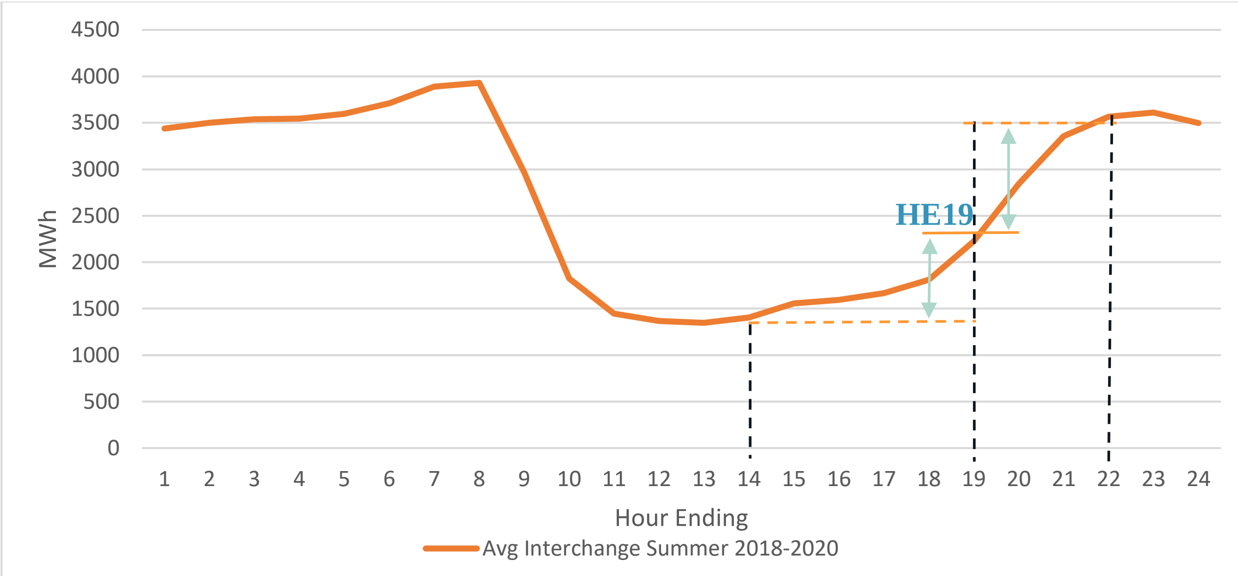


Figure 2-4. 2018-2020 hourly average loads were analyzed to determine appropriate offsets to apply to 2010-2017 load shapes. The green arrows show how hourly average loads were compared against the HE19 average load (presumed to remain unchanged, due to lack of solar in this hour) to identify an appropriate 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 RA Program footprint (had the program existed at the time). For example, if exports occurred during periods of excess capacity (e.g., high run-of-river output) within the RA Program footprint, and the energy price outside of the RA Program footprint was at typical market (or below 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 RA Program footprint, it was assumed this capacity would have been available for the RA Program footprint, had it been needed.
>
> *Scarcity sales*: in times of high market prices in areas outside of the RA Program footprint, it was assumed that historical exports made during those time periods would not have been available if required by RA Participants.

In order to separate exports into the above two categories, energy market conditions were analyzed, and criteria developed to determine whether exports may be economic sales or scarcity sales. The criteria are as follows:

- The market-clearing heat rate (e.g., price of power divided by price of natural gas) for California was used as a proxy for external demand:
  - For conditions when the heat rate is less than 10mmBTU/MWh, exports from NWPP were determined available to NWPP; export interchange was reduced to zero (imports were unchanged). This low level of heat rate indicates that market prices were not reflecting scarcity events and the exports were economic.
  - For conditions when the heat rate is greater than 15mmBTU/MWh, exports from NWPP were considered to be scarcity sales so these values remained in interchange and were not used as a load modifier (imports were also unchanged). This higher heat rate is reflective of traditional peaking units, which are commonly operated and exported under scarcity conditions.
  - For conditions when the heat rate was greater than 10 but less than 15, exports were linearly reduced from their values at 15 to zero.

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

For import transactions, it was assumed that these imports would continue to be brought into the RA Program footprint regardless of market conditions. The results of this modification of the load shape resulted in the load shapes in Figure 2-5.

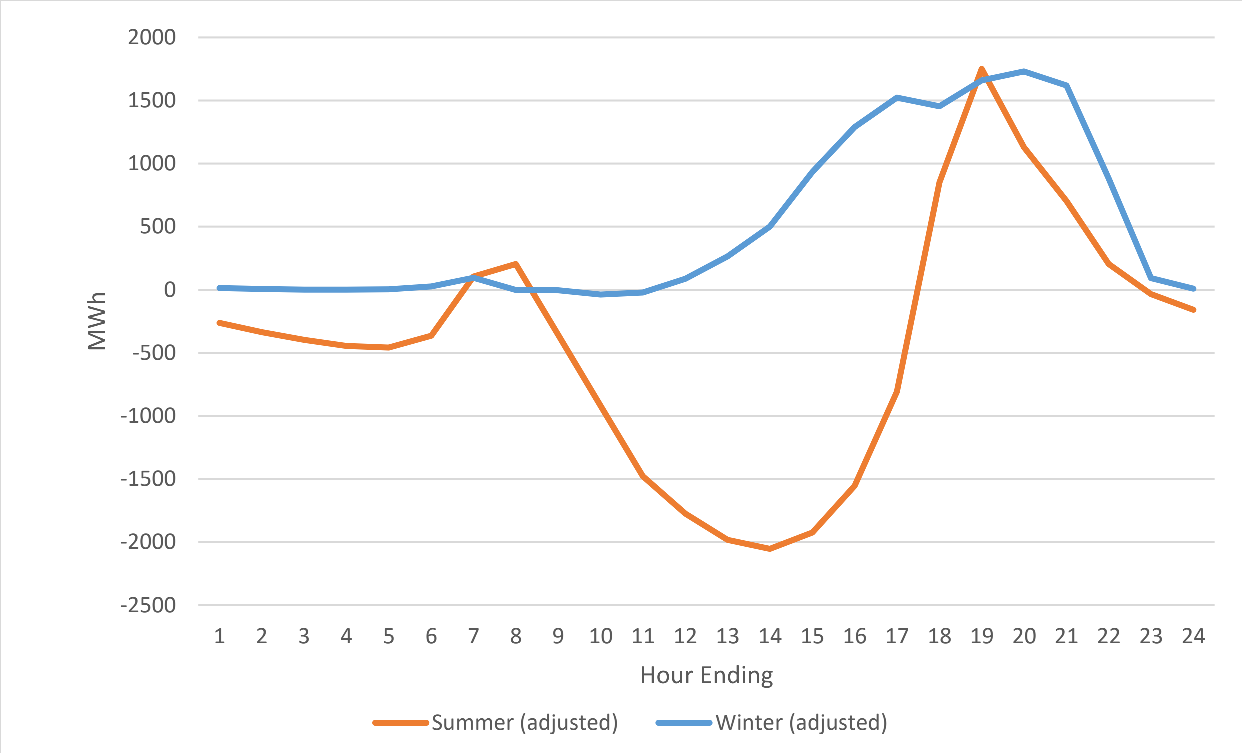


Figure 2-5. 2010-2020 interchange adjusted by CA heat rate analysis. Hourly average interchange was modified to account for economic and scarcity sales. Scarcity sales (high market-clearing heat rate) were presumed to be unavailable to the RA footprint and were unchanged, while capacity sold in economic sales was presumed to be available to the RA footprint if necessary. These hourly averages also include adjustments for resource mix changes, as described in Section 2.3.3.

Other Items of Consideration for Regional Interchange

The interchange values reviewed are based on actual historical interchange. The interchange includes both firm and non-firm transactions. Special care must be taken by the PO to ensure that certain transactions are not "double-counted." For example, if a transaction is included in a Participant's FS portfolio, it will not be included (again) in the determination of interchange transactions to/from the RA Program footprint for the studies that determine the PRM.

Future Changes for Treatment of Interchange

It is understood that conditions have changed in the most recent 10 years, and it is possible that they will continue to change going forward. A review of the methodology for adjusting load based on interchange assumptions will be repeated annually to assess appropriateness as well as the results of the current methodology to determine latest trends. If most recent year(s) shows a significant differing trend from the presented methodology, changes to the methodology will be discussed and adjustment sought with RAPC for adoption, as necessary.

2.4. Resource Eligibility and Qualification

Participant resources and non-Participant resources (under contract) are capable of providing capacity necessary 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 PO. The PO will develop and maintain a registration and certification process for all resources identified for the FS Program.

2.4.1. 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 (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 resource size for recognition by the RA Program is 1 MW. Load Responsible Entities (LREs) with responsibility for individual resources of less than 1 MW could aggregate them to meet this requirement.

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) and physical location information related to zone determination (applicable for transmission, ELCC, and thermal QCC analysis)
Maximum capacity (nameplate)	Summer and Winter values
Demonstration of operational and capability testing	Historical performance showing Real Power output will meet the operational test requirements for existing resources operational data from within the two years prior to the FS date is acceptable for the verification of Real Power Capability testing – Either the RA Program can develop its own testing requirements, or existing testing requirements may be adopted. Testing should, at a minimum, meet the requirements of North America Electric Reliability Corporation (NERC) MOD-025
Outage Data	NERC Generator Availability Data System (GADS) data (or equivalent) for thermal and storage hydro resources will be incorporated into the determination of QCC. Outages will not be necessary for wind, solar, or run-of-river, as the ELCC methodology already considers that information.
Historical Output	Historical output shapes (hourly) to be provided for wind, solar and run-of-river resources. For storage hydro resources, historical output shapes along with other data required by the NWPP Storage Hydro QCC Workbook.

2.4.2. Sale and Purchase Transactions

To be counted toward meeting a Participant's FS capacity requirement, power supply contracts will need to include certain provisions. The different contractual products envisioned to meet these requirements are discussed below, and generally fall into two categories: energy (plus RA capacity) contracts and capacity contracts. There are also considerations made for existing contracts (grandfathering).

Generally, requirements for eligible contracts include (additional detail to follow):

- Identified source (e.g., resource or system must be specified);
- Exclusive rights to the capacity claimed - assurance this capacity is not being relied upon for another entities' RA and will not be cut prior to emergency load shedding procedures; and
- Firm, conditional firm, or secondary network transmission from the resource to the load (as further detailed in Section 2.4.3).

Purchase and sale transactions that meet FS Program requirements (either from within or from outside the RA Program footprint) will be submitted by each Participant. The amount of the transaction will be reflected as an RA capacity resource for the buyer and an RA capacity obligation for the seller, so long as the requirements in the following sections are met.

Firm capacity sales to parties outside the RA Program footprint must be declared and included as a capacity obligation on 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.

2.4.2.1. Energy (plus RA capacity) Contracts

In order to be eligible for inclusion in a Participant's FS portfolio, energy contracts must include both firm energy and capacity. These energy contracts are envisioned to be similar to existing WSPP Schedule B (resource-specific sale) and Schedule C (system/fleet sale) contracts, though additional requirements must be met in order to be eligible.

These requirements can be satisfied with an exhibit or an attachment that contains provisions to qualify for consideration in the FS portfolio review; expectations for demonstration of meeting these requirements is discussed in the following sections.

Resource-Specific Contracts

Resource-specific (Schedule B-type) energy contracts can be executed between Participants or with external parties. In either case, to be counted the resource(s) that is the subject of the agreement must be registered with the PO, and the PO will calculate the resource's QCC.

If both buyer and seller are Participants, the seller will already have registered their fleet of resources with the PO; the resource(s) in question will have an established QCC. The purchasing Participant will claim the QCC in their FS portfolio and the selling Participant will debit the QCC value from their FS portfolio.

If the seller is a non-Participant, the resource(s) that is the subject of the agreement shall be registered by the owner with the PO. If the resource in question has not been registered by the owner, depending on circumstances, additional options are available to buyer Participants:

- If the Participant has adequate data to register the resource for the owner, the Participant will collect the data and submit to the PO. The PO will then determine the QCC of the resource. The QCC of the resource will be claimed by the Participant in their FS portfolio.
- If the Participant does not have adequate data to register the resource for the owner, and the agreement is considered to be grandfathered, then the Participant will be able to claim a discounted average QCC value for the resource type in their portfolio. In this case, the Participant is not required to submit a waiver request.7It is important to note that resource-specific contracts may have a stated MW value that differs from their determined QCC value. For example, a resource-specific sale from a 100 MW gas peaking facility may have a QCC of 90 MW. The QCC is used exclusively for the purposes of the FS Program and is not necessarily equal to the contracted capacity.

System Sales

For energy contracts that are system sales (Schedule C-type) between Participants (buyer and seller are both Participants), the system/fleet that is the subject of the agreement will be registered with the PO[8]. The PO will have previously determined the cumulative QCC of the system in question. Once verified, the purchaser (Participant

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[7] At this time, the amount of the discount and the allowable threshold (percentage of portfolio allowed to contain this discounted type of resources) has not been determined.

[8] Participants will register each resource within their system/fleet, not a single registration value representing their aggregated system/fleet.

claiming capacity) will claim the full capacity of the contract in their FS portfolio and the seller will decrement the full capacity of the contract from their FS portfolio. If the contract is a slice-of-system type contract, the capacity value of the contract will generally be determined by multiplying the seller's Resource QCC value by the percentage share of the purchaser. Some slice-of-system contracts may not be for a seller's entire resource portfolio, in which case the percentage may be taken from some other aggregation of owned resource QCCs.

The PO will not have knowledge of specific contractual requirements regarding the assignment of damages or deficiency payments for the FS or Ops Program, nor will the PO be a party to the commercial agreement between buyer and seller.

For energy and capacity contracts that are system transactions (Schedule C-type) in which the seller is a non-Participant, the system/fleet capacity that is the subject of the agreement shall need to be deemed surplus to the seller's estimated needs and must be subject to full replacement of the capacity at the seller's cost; this replacement cannot be resolved with liquidated damage provisions. This demonstration will be accomplished through an attestation by the seller. The attestation should include specifications as to what the seller deems to be "surplus" capacity, such as:

- The transaction is supported by physical generation capacity that is surplus to the expected capacity requirements/obligation of the seller;
- The seller is not relying on the future procurement of capacity in short-term markets to support the delivery;
- The contracted product will be backed by any required operating reserves; and
- The transaction will meet the transmission requirements of the FS Program.

Once verified, the purchaser (Participant claiming capacity) will claim the full capacity value of the contract in their portfolio. In the Ops Program, firm block system sales will not be subject to variations in performance. Slice-of-system type contracts will experience over and under performance as compared to their assessed QCC capacity value; treatment of these variations in performance will be assessed on a contract-by-contract basis. Similar to resource-specific contracts, the PO will not have knowledge of specific contractual requirements regarding the assignment of damages or deficiency payments for the FS or Ops Programs, nor will the PO be a party to the commercial agreement between buyer and seller. The purchaser (Participant claiming capacity) will have the performance responsibility in the Ops Program and will be responsible for contracting in accordance with its business practices and requirements.

Grandfathered Agreements

Participants may have long-standing agreements that precede the life of the RA Program. The RA Program is expected to honor these "grandfathered agreements" to the extent possible. These contracts may be either resource-specific or system based and may be executed with Participants or non-Participants. Participants are encouraged to pursue the above registration and verification process for their existing processes (registration and/or attestation), rather than a grandfathering exemption.

There are some grandfathered agreements in existence in which a source/resource is not identified in the agreement. For these agreements, it must be possible for the PO to presume a source or sources (potentially with the assistance of the agreement parties) for the contract.

- If the source can be presumed by the PO to be a resource(s) or system(s) already registered with the Program, the selling Participant will debit their system in their FS portfolio and the buyer will claim full capacity value of the contract on their FS portfolio.
- If it is determined that the source(s) are non-Participant owned resources, the Participant will work with the PO to determine the appropriate capacity value of the contract and the Participant will seek an attestation (as described in Section 2.4.2.1). The Participant will be able to claim the accepted value on their FS portfolio and retains the operational performance obligation.

If the Participant has an agreement with a non-Participant that is considered a "grandfathered agreement," a source is identified or can be presumed, and an attestation cannot be obtained, the Participant will work with the PO to determine the appropriate capacity value of the contract, which will then be allowed to be claimed on the Participant's FS portfolio. At this time, a maximum threshold for such a contract arrangement type (grandfathered without registration or attestation) has not been determined.

If the PO cannot determine a presumed source for such grandfathered contracts, the Participant cannot claim any capacity from the contract on their FS portfolio[9]. No new contracts (after the effective date of the RA Program or other date agreed to by the RA Program) of this type will be accepted for FS Program use. Renewals of any

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[9] The PO will employ discretion upon review of contracts that may include sufficient information to determine a source (e.g., references to generation from a certain BAA).

grandfathered agreements after the commencement of the RA Program will require review and approval of the PO.

Non-Performance of External Resources

Resources that are owned by non-Participants and exhibit poor performance during the Ops Program will be subject to having their QCC value re-evaluated by the PO in accordance with program expectations in subsequent seasons. Poor performance will be at the judgment of the PO and will include factors such as persistent unexcused delivery failures.

2.4.2.2. Capacity Contracts

For capacity contracts, the purchaser has rights to capacity, but energy is only delivered under specific circumstances allowed in the contract. Like energy contracts, capacity contracts must meet the general contract requirements listed at the beginning of Section 2.4.2.

Traditional Capacity Contracts

Capacity contracts must have clear provisions that demonstrate how the purchaser is able to call on the capacity during applicable binding seasons. The determination of QCC for contracts that come from resources (fleet or resource specific) inside or outside the RA Program footprint will follow the same rules as applied for energy and capacity contracts in Section 2.4.2.1.

Transfer of FS Capacity Requirement

In an “RA Transfer Agreement,” a new type of contract being developed for use in the RA Program, the selling Participant takes on some of the FS capacity requirement of the purchasing Participant. This type of contract can only be executed between two RA Program Participants. The transmission service arrangements must be included in the agreement (determined by contract as to whether the purchaser or the seller provides). The subject capacity of these agreements is represented as a decrement to the purchaser’s FS capacity requirement and as an addition to the seller’s FS capacity requirement. Table 2-5 provides an example.

Table 2-5. FS capacity requirement transfer contract.

Participant "A" contracts with Participant "B" to purchase 100 MW of FS capacity requirement transfer	
Prior to the transfer	Participant "A" FS capacity requirement is P50 + PRM = 3000 MW + 450 MW (15% PRM) = 3,450 MW
	Participant "B" FS capacity requirement is P50 + PRM = 4,000 MW + 600 MW = 4,600 MW
After the transfer	Participant "A" FS capacity requirement is now 3,450 MW – 100 MW = 3,350 MW
	Participant "B" FS capacity requirement is now 4,600 MW + 100 MW = 4,700 MW

In addition to transferring all or a portion of the FS capacity requirement from the purchaser to the seller, the capacity specified in the RA Transfer Agreement is subject to be called upon by the PO to address the purchaser's Ops Program capacity deficit (resulting from load, VER over/under performance or uncertainty), if any, prior to having capacity and/or energy provided to the purchaser by other Participants in the Ops Program. See Section 3.4.4 for additional details on how RA Transfers are deployed in the Ops Program.

2.4.3. Transmission Service Requirements

While designing the RA Program, the Steering Committee considered the following objectives and constraints:

- Encourage procurement of firm transmission service sufficient to demonstrate deliverability of resources to load, while recognizing the need for flexibility where necessary or appropriate.
- Enhance overall visibility with respect to deliverability (from generator to load) for resources used for program compliance, supporting situational awareness and regional planning.
- Support and enhance reliability across the region without supplanting existing responsibilities of Balancing Authorities, LREs/Load Serving Entities (LSEs), Transmission Service Providers (TSPs), and others.

- Rely on existing Open Access Transmission Tariff (OATT) frameworks to facilitate transmission-related requirements for demonstration of RA and sharing of diversity across the RA Program footprint.
- Respect program Participants' OATT rights and responsibilities and Participants' other legal obligations, including contractual commitments and statutory requirements.
- Design the Program in a manner that achieves deliverability objectives in a manner that is consistent with continued market efficiency in the operational time horizon.

Additional work will be undertaken in Phase 3A to further consider an identified gap in RA related to third party LSEs that either a) do not participate in the program or b) economically displace their RA resources with other resources (including on non-firm transmission products) and do not make available their RA resources for dispatch (resulting in use of NERC schedule 4 or 9 to fill the gap).

2.5. Qualified Capacity Contribution of Resources

Qualified capacity contributions (QCC) will be determined for all resources contributing to a Participant's FS portfolio. The QCC of a resource will represent the amount of MW of "accredited" capacity determined to be reliably available from the resource. The QCC of a Participant's system will be the sum of all QCCs for each resource (contracted and owned) in their fleet. The QCC calculations will be updated by the PO on an annual basis. The methodology for assessing resources will effectively reflect a resource type's capacity contribution during the region's CCHs. Table 2-6 presents a summary of QCC methodologies.

Table 2-6. Resource types and QCC methodologies.

Resource	QCC Methodology	Notes
Storage Hydro	Time-period approach to estimating capacity contribution in a manner that objectively reflects operational restrictions and targets of hydro resources, and the associated considerations that go into the dispatch decision-making processes. QCC values will be calculated for each month. See Appendix D, Section D.1 for NWPP Storage Hydro QCC Methodology.	The RA Program footprint is unique due to the abundance of hydro generation, no existing RA Program has employed an approach to qualifying capacity that would be appropriate. The NWPP Storage Hydro QCC Methodology includes a range of hydrological conditions and is verifiable by the PO. It assesses output during CCHs, as well as ICAP and usable energy in storage, to determine how much capacity should be available during CCHs in the future. The storage hydro capacity contribution evaluation will use the historical CCH identified RA metrics analysis (PRM, LOLE, load forecasting, etc.), as described in Section 2.3.2.
VERs	Capacity based on ELCC analysis of historical data (minimum of three years historical data, as available); ELCC will be evaluated by month and by zone.	Zones will be climate/fuel supply-based (versus transmission-based); these zones will need to be defined in Phase 3A.
Run-of-River Hydro[10]	Capacity based on ELCC analysis of historical data (Steering Committee proposes minimum of three years historical data, as available); ELCC will be evaluated by month and by zone.	Run-of-river is less than one hour of storage, not in coordination with another project. Zones will be climate/fuel supply-based (versus transmission-based) and will be defined in 3A.
Thermal resources	UCAP approach for all hours.	Using six years of historical data[11] (removing the worst performing year) for each season.
Short-term Storage	ICAP Testing – ability of the resource to maintain the value over the specified duration represents its capacity value.	

[10] 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.

[11] North America Electric Reliability Corporation GADS or similar with a validation process – accommodating Canadian/Federal entities not using NERC GADS

Resource	QCC Methodology	Notes
Hybrid Resources	"Sum of parts" method ESR will use ICAP Testing. Generator will use appropriate method as outlined above.	For example, an ESR paired with a wind facility would use ICAP Testing for the ESR and ELCC for the wind facility.
Customer Resources	Customer resources can either register as a load modifier or as a capacity resource.	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. 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.

The PO will monitor to determine if the above methodology is accurately capturing the contributions of each resource type at larger scale. Modifications in the future may be necessary, and the PO will work within the RA Program definitions, rules, and governance processes to raise any proposals.

2.5.1. Storage Hydro

Due to the significant amount of storage hydro[12] resources in the RA Program footprint and the complexity of operations across the region, and from project to project, a specific storage hydro methodology for QCC treatment was developed for the FS Program (NWPP Storage Hydro QCC Methodology).

The methodology presents a "capacity view" that maximizes output during CCH for each calendar day while considering water limitations and the unique limitations/operations of each project. The NWPP Storage Hydro QCC Methodology is used by Participants to

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

calculate the QCC of their storage hydro resources through the use of the Storage Hydro QCC Workbook.

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 methodology then determines the QCC of the storage hydro project by assessing the historical actual generation occurring during the CCH on any given day and the ability to increase generation during CCHs on the same calendar day, subject to useable water (energy) in storage, inflows/outflows, and expected project operating parameters/constraints and limitations. The impact of forced outage rates, based on historical NERC GADS (or equivalent) information, as well as planned outages are also incorporated into the storage hydro. The resulting QCC is determined as the average contribution to the top 5% of CCH for each Winter and Summer season over the previous 10 years. See Appendix D, Section D.1 for more details.

2.5.2. Variable Energy Resources

The FS Program considers wind, solar, and run-of-river resources to be VERs; VERs will have their QCC determined using a version of ELCC methodology. In advance of each FS deadline, an ELCC analysis will be performed to determine the QCC for each month of the Winter and Summer seasons. A QCC will be assigned to all VERs on a zonal basis in the RA Program footprint.

The PO will require at least three years of hourly historical output data from the resource to calculate the QCC of VERs. For facilities with known and measurable curtailments, curtailed energy will be added back for purposes of having the resource studied in 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 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, Section D.3.1.

2.5.3. Thermal Resources

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

The UCAP methodology will use a season equivalent forced outage factor (EFOF) calculation in line with the NERC GADS. The top 5% of 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 historical look-back period. Participants will be required to provide the PO with NERC GADS (or equivalent) outage data for the previous six years. The PO will calculate the equivalent outage rate 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 are not included in UCAP calculations. Planned outages are considered during the FS portfolio review (i.e., units on planned outages are not included as showing resources during the applicable season). This means planned outages should be planned in advance of the FS deadline.

Due to the possibility of certain high impact outages affecting multiple calendar years, which would hamper the effectiveness of the practice of removing the worst performing year, Participants will have the option to request an exception for certain high impact outages to not contribute towards the calculation of the EFOF. The PO will establish a process and criteria for requesting exceptions and determine the validity of an exception request. The PO's decision may be appealed in accordance with general RA Program dispute resolution procedures.

For units new to the FS Program, the PO may use class average data for units of similar size, age, and technology type. 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.

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

2.5.4. Energy Storage

Energy storage resources such as pumped storage facilities or battery storage systems have a limited amount of storage capability compared to most storage hydro resources

[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.

in the RA Program footprint. The methods used by other RA Programs include the following:

- Installed Capacity Testing – ICAP testing methodology relies on the ability of the ESR to perform for a specified duration. The ability of the resource to maintain the value over the specified duration represents its capacity value. This methodology is simple to apply and has been shown in other areas to have accuracy for lower penetrations of ESRs.
- Effective Load-Carrying Capability – ELCC methodology is performed similar to ELCC methodology for VERs. Information on the ESRs' storage capability is required to determine its ELCC value. While ELCC may provide an accurate value of the capacity such resources provide (even in larger penetrations on a system), the methodology can be complex and administratively burdensome.
- Performance-Based – performance-based methodologies rely on the tracking of historical performance of ESRs during times of system capacity need. This methodology has components similar to the NWPP Storage Hydro QCC Methodology.

With the low penetration of pumped storage and battery storage ESRs located in the RA Program footprint at this time, it was determined that the best method for capacity value calculation is the ICAP Testing methodology. The top 5% of CCHs was analyzed to aid in the determination of the duration requirement necessary for the ICAP Testing methodology specifically for battery storage systems. This analysis provided the following results:

- 61% of Summer days contained a total of 4 or fewer CCH.
    - The weighted average CCH per day for the Summer season was 5 hours.
- 74% of Winter days contained a total of 4 or fewer CCH.
    - The weighted average CCH per day for the Winter season was 4.7 hours.

The FS Program will use a five-hour duration requirement for the ICAP Testing methodology to determine battery system ESR QCC. Table 2-7 contains example QCCs associated with different duration ESRs.

Table 2-7. Example QCC determination for battery storage.

MW (maximum output)	Duration	Weighting	QCC
100 MW	2 hours	2/5 = 40%	100 MW * 40% = 40 MW

100 MW	4 hours	4/5 = 80%	100 MW * 80% = 80 MW

Further information about the short term QCC analysis can be found in Appendix D, Section D.4.

2.5.5. 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. A common practice that has been observed among hybrid resources is oversizing generating capacity compared to the size of the interconnection service as studied and provided by the TSP. An example would be a generating resource that has a Generator Interconnection Agreement for 200 MW but consists of a 100 MW ESR resource coupled with a 150 MW solar resource.

The FS Program will follow a similar methodology as for short-term ESRs and use an ICAP Testing methodology for the ESR portion of the hybrid facility. When the ESR is coupled with a VER resource, the remaining capacity is determined by the ELCC methodology used for VERs. This approach to hybrid resources is referred to as the "Sum of the Parts" methodology. Under this methodology, the PO will implement a limit to prevent the QCC from exceeding the amount of interconnection service obtained by the Participant and will request such information from the Participant.

2.5.6. Customer Resources

Resources that are generally located on the customer side of the meter can be included in the FS Program. These customer resources are commonly captured through DR programs and behind-the-meter generation or energy storage. Energy efficiency programs may also fit into this category. Customer resources are generally identified as a demand side resource or a behind-the-meter resource, which in order to be eligible for capacity credit in the FS must: 1) be controllable and dispatchable by the Participant and/or host transmission operator, and 2) not already be used as a load modified in the Participant's load forecast (i.e., serving a portion or all of the load not included in load forecast). As a general concept in addressing customer resources, capacity impacts from resources that are typically spread across a Participant's system (across its retail customer base), are non-controllable and non-dispatchable will be expected to be accounted for in the Participant's annual load forecasts that are provided to the PO. Examples of these resources include disaggregated rooftop solar installations and some types of energy efficiency programs.

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

- Load modifier - A load modifier is considered a reduction of the Participant's forecasted net peak demand (reduction in load). 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 5 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 PRM 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 5 continuous hours.

Table 2-8 gives examples of various types of customer resources and how they may be classified as load modifiers and capacity resources. .

Table 2-8. 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

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

Resource Example	Default Treatment
Residential demand response (e.g., thermostat or HVAC)	Load modifier
Large customer demand response (e.g., tariff programs)	Either
Automated demand response	Either
Customer on-site generation or distribution resource (separately metered)	Either

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 PRM 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.

2.5.7. Resource Outages

2.5.7.1. Planned Outages

As is the practice currently, Participants will have full autonomy in planning their generation outages. However, Participants are encouraged to plan outages, to the extent possible, in advance of the FS deadline to minimize the occurrence of new planned outages after the FS deadline.

Planned outages will not be taken into account in the QCC methodologies[15] while forced outages will be considered in the calculations for thermal resources. Planned outages will be accounted for in a Participant's FS portfolio. For a resource that has a planned outage or capacity de-rate, the impacted portion of the resource's QCC will be decremented from the Participant's shown capacity for the month(s) of the planned outage.

Participants will provide planned outage information to the PO by the FS deadline by including the planned outages in their FS portfolio (Figure 2-6). The information must include the plant or unit on outage, the capacity (nameplate) impacted, and dates for the outage. The PO will factor in the planned outage when assessing the Participant's FS portfolio to determine if the Participant is adequate or deficient.

To avoid a deficiency in the FS Program that may be caused by a potential planned outage, Participants may acquire capacity for the month(s) of the binding season that are impacted. The replacement/substitute capacity will need to meet all supply requirements of the original capacity – including unit registration, contract qualifications, transmission service demonstration, etc. If the substitution is accomplished by a power supply contract, at a minimum, the term of the contract shall be for the entire duration of the outage. Lack of adequate documentation may result in the substitution not being accepted by the PO.

If a proposed planned outage in the FS Program that comprises a partial month causes a potential deficiency, for which the Participant has not demonstrated substitution, a qualified acceptance may be provided by the PO provided the deficiency is for less than five days and the deficiency is less than 500 MW. This qualified acceptance is based on the condition that the Participant will either acquire the required capacity prior to or in the operational timeframe – or will receive an exception to provide the capacity from the PO in the Ops Program. If the Participant does not either acquire the capacity prior to or in the operational timeframe or receive an exception from the PO, deficiency payments will apply as they are determined by the Ops Program.

[15] At Participant option – planned outages may be included in storage hydro QCC calculations.

Some planned outages may need to occur after the FS deadline due to a variety of reasons including a change in the scope of maintenance work, contractor availability, or unforeseen issues. For planned outages that are scheduled after the FS deadline:

- Participants with portfolio QCC, net of the planned outage that exceeds their FS capacity requirement: no action required.
- Participants with portfolio QCC, net of planned outage that is less than their FS capacity requirement: will still be expected to have access to capacity sufficient to meet FS capacity requirement during the Ops Program, should take measures to ensure additional capacity is available to cover net difference.
- The PO will compile all outages by resource, MW and QCC impact, start date, and end date to provide to the Ops Program for further upkeep and maintenance during the operations timeframe.
- This process will be further fleshed out during program implementation.

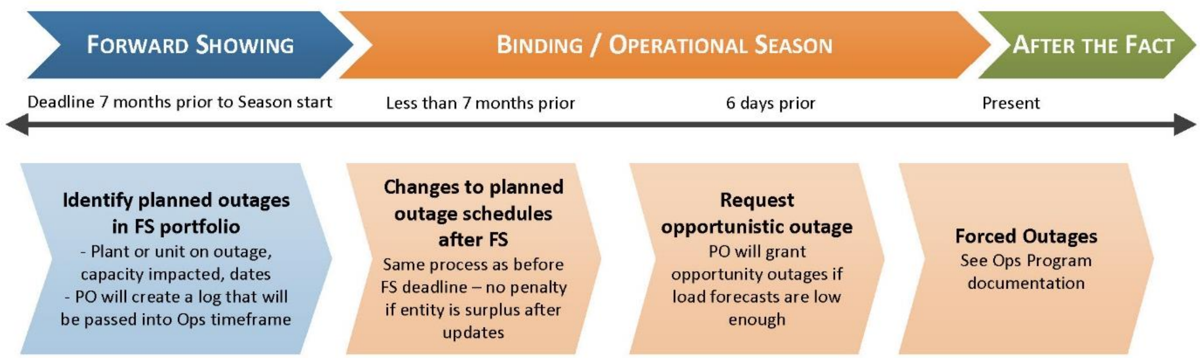

Figure 2-6. Planned Outages.

2.5.7.2. Forced Outages

The QCC methodologies for the various types of resources each consider the impact of forced outages when determining the QCC.

2.6. Construction of a Participant's Forward Showing 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. All calculations described throughout this section will be performed for each month of the binding season. The Participant will be responsible for providing the necessary information to the PO, who will complete the final calculations to determine if the Participant has met their FS capacity requirement.

Participants may review input data for their respective systems. Participants may not review input data of any other system or data supplied by other Participants. If required by law, the PO may allow the review of data by regulatory and oversight bodies.

2.6.1. Resource QCC

As described in Section 2.4.1, each Participant will register all its owned generating resources by providing the registration data required by the PO. The PO will calculate the QCC for all resources owned by the Participant (except for storage hydro resources, which will be calculated by Participant using the NWPP Storage Hydro QCC Methodology and reviewed by the PO) in accordance with the applicable subsection of Section 2.5. As necessary, planned outages will be considered when de-rating each resource's available monthly QCC. 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.

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

2.6.2. Net Contract QCC

As described in Section 2.4.2, Participants will provide all RA contracts (purchases and sales) to the PO for verification of FS Program requirements. The PO will assign a

[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.

monthly QCC value to all contracts provided prior to the FS deadline, dependent upon the nature of the contract (described more fully in Section 2.4.2).

Once all contracts have been verified and assigned a QCC (i.e., the contracts have been qualified), the net contracted QCC will be calculated on a monthly basis for each Participant's contracts (see example in Appendix F - Table 2-30). For accounting purposes, import contracts (purchases) are additive to the Participant's QCC value and exports (sales) are a negative QCC value. The net QCC of all a Participant's contracts is the "net contract QCC," and is calculated monthly for the binding season.

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

2.6.3. 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.

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

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.

2.6.4. 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.

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

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.

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

Any portfolio QCC in excess of the Participant's FS capacity requirement is considered outside of the Program. A Participant's additional planned maintenance or short-term sales will be made from their excess Portfolio QCC. Table 2-9 presents an example of a FS portfolio and calculation.

Table 2-9. FS portfolio summary example.

FS Monthly Summary				
Month	**FS Capacity Requirement (P50+PRM)**	**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

2.7. Deficiency Payment for Noncompliance

If a Participant fails to meet their FS capacity requirement after the cure period, the FS Program will assess some multiple of a CONE payment against the noncompliant Participant (see Table 2-10). The CONE is based on publicly available information (i.e., information provided by the Energy Information Administration) relevant to the estimated annual capital and fixed operating costs of a hypothetical natural gas-fired peaking facility. The CONE value does not consider the anticipated net revenue from the sale of capacity, energy, or ancillary services nor does it consider variable operating costs necessary for generating energy.

The RA Program's CONE value will be derived by the PO and reviewed annually; any changes will be proposed by the PO pursuant to the RA Program rules and approved by the appropriate governing body or committee pursuant to the RA Program rules. The

CONE deficiency payment is intended to be significant enough that Participants are not expected to fail to meet their FS capacity requirement with any regularity and are encouraged to act in good faith to address their respective share of RA. Any FS payments assessed to Participants will be used to offset costs of the Program.

Table 2-10. CONE Payment.

Proposed Calculation for Deficiency Capacity and Payment
$\boldsymbol{Entity's\ Deficiency\ Capacity}\ (\boldsymbol{MW}) = \boldsymbol{Portfolio\ QCC} - (\boldsymbol{Forward\ Showing\ Resource\ Requirement} + \boldsymbol{RA\ Transfers})$
$\mathbf{Entity's\ Deficiency\ Payment/Penalty} = \mathbf{Deficient\ Capacity} \times \mathbf{CONE} \times \mathbf{CONE\ factor}$
CONE Factor: – 125% @ FS Program has capacity in excess of 8 percent (or greater) above the required PRM. – 150% @ FS Program has capacity excess of more than 3 percent above, but less than 8% above the required PRM. – 200% @ FS Program has capacity excess of less than 3% above the required PRM.

2.8. Transmission and Deliverability

At the FS deadline, Participants must demonstrate having transmission rights to deliver at least 75% of its FS resources claimed in the FS portfolio from RA resource to load (for at least the QCC value associated with a specific resource). Transmission demonstrated must be (at minimum) NERC priority 6 or 7 transmission service.

Transmission rights demonstrated will be associated with specific resources claimed in the FS portfolio to support the requirement to demonstrate transmission from 'resource to load.' Contracts requiring use of NERC priority 6 or 7 transmission will satisfy this requirement.

If a Participant intends to use 6-NN / 7-FN to satisfy this requirement, they must demonstrate to the PO (e.g., via written contracts/approval from their applicable TSP) their ability to use network service; 6-NN reservations need not be shown for the leg to which they apply, if the Participant adequately demonstrates their ability to use such service. In future phases, the RA Program must consider how paths constrained for 7-FN will be handled. On these constrained paths, 6-NN may not be acceptable (this would be TSP specific)

The PO may request additional details from Participants to confirm contracts and/or supporting agreements used in the FS portfolio comply with the FS transmission eligibility requirements. Business processes and specific showing expectations will be determined in Phase 3A. Examples of additional information the PO may require include:

- Confirmed priority 6/7 transmission reservations
- Demonstration of ability to use 6-NN service
- Transmission provisions in supply contracts claimed in entities' FS portfolio

Examples

Example 1: if Participants have an on-system resource, they must demonstrate a TSP will allow 6-NN to be counted and that they have rights to 6-NN

Example 2: an off-system resource, Participant must demonstrate that a TSP will allow 6-NN to be counted, that they have access to 6-NN, + must show priority 6/7 transmission to the local TSP boundary.

Participants will also indicate an expected transmission path for the remaining 25% of resources shown in their FS portfolio. These expectations are informational only. The PO will aggregate this information in the FS window to the flowgate level to view anticipated additional transmission needs. In Phase 3A, additional consideration will be given to the ability to utilize this data for additional situational awareness or planning purposes (e.g., providing to TSPs 2-5 months in advance of the season for consideration in planning maintenance or advising on potential issues). Use of this data would be conditional upon it being appropriately aggregated or otherwise protected to ensure confidential or commercially sensitive data is not shared or used inappropriately, as determined in these upcoming discussions.

If a Participant has not demonstrated sufficient procurement of transmission rights or contracts and/or specified necessary transmission information by the FS deadline (at least 75% of their FS capacity requirement, but taking into consideration approved exceptions), the Participant can remedy during the established two-month cure period to avoid a FS failure penalty (see section 2.1 for additional detail).

Participants are expected to use good faith efforts to timely cure any other changes to its transmission arrangements after the FS demonstration. The FS Program will utilize a zonal approach to evaluate the ability of the NWPP system to support generation-to-load transfers and facilitate the utilization of generation diversity across the RA Program footprint.

2.8.1. Showing Exceptions

Given the need to work within existing transmission frameworks, there may be situations requiring exception from the basic FS requirements identified above. Exceptions will be evaluated by the PO on a case-by-case basis to ensure reliability of the RA Program will not be impacted.

If insufficient NERC priority 6 or 7 transmission service is available prior to the FS deadline on a specific path (or in a specific circumstance), a Participant may request an exception from the 75% requirement. Requests will be dependent on what type of exception is sought. Examples include:

- Exception due to an enduring constraint that affects a Participant's ability to deliver showing resources to load on firm transmission.

    In this circumstance, the value of the exception would be subtracted from total portfolio QCC value, and Participant would demonstrate having appropriate transmission rights or contracts for 75% of remaining QCC value.

    The Participant will work with the PO and TSP (as applicable) to identify an approved (near-term and longer-term) mitigation plan to remedy this issue (e.g., building additional resources local to load pocket, have entered transmission queue for long term service). This exception is not intended to be indefinite, indicating that the Participant must be able to demonstrate pursuit of this plan.

- Exception due to a particular path or circumstance where short-term firm transmission is consistently available but not posted on a long-term basis, such as firm counterflow transmission.

    In this circumstance, the Participant may petition to acquire this transmission after the FS period. An approved exception of this type counts is considered demonstration of transmission for impacted RA resources and counts toward the 75% requirement

- Exception due to excessive outages: Participant demonstrates that the constraint is temporary and requests an exception for the time of the outages.

An approved exception of this type counts is considered demonstration of transmission for impacted RA resources and counts toward the 75% requirement

Further consideration of the exception process is intended for upcoming phases.

2.8.2. Load Resource Zones

Load and resource zones (LRZs) have been identified at the end terminus of major transmission constraints or paths, considering interties and the critical flowgates within (and ties to) Participants' footprints (see Appendix E). For example, loads located west of the Cascades have been designated as an LRZ.

If a local zone cannot access capacity from Participants outside the zone because of transmission congestion, then Participants within that zone may need to procure an additional local capacity for the season to maintain system reliability.

Details regarding the ability of specific LRZs to support load within the zone and the need for additional import capability, whether through the acquisition of firm service or other means of constructing new transmission infrastructure have not yet been fully determined. These details will also help in the determination of whether certain LRZs will be required to have a higher PRM than the Program requirement.

Additional details of the transmission and deliverability process can be found in Appendix E.

2.9. Modeling Data from the FS Program Provided to the Ops Program

Upon completion of FS Program processes, a minimum of two months prior to the start of the binding season, the focus of the RA Program will shift to the Ops Program. The FS Program will provide the inputs listed in Table 2-11 to the Ops Program. The details of data submission requirements will be developed in the next phase of the project.

Table 2-11 FS Program inputs to the Ops Program

Non-Coincident Peak (NCP) P50 load provided in FS	Notes
P50 will be a Participant peak value (equivalent to an NCP, not coincident with FS Program peak)	
PRM will be on a UCAP, NCP basis	Outside of CR implications, most Participants should have the same PRM requirement – unless they are located in a transmission constrained area
Portion (if any) of CR that are included in the PRM will be stated (i.e., all CR are included, 50% are included, etc.).	
Resources:	
ICAP MW value – accomplished through unit testing.	
List of planned outages submitted in the FS portfolio.	
QCC value – accomplished through UCAP analysis	QCC (UCAP) MW value – accomplished through review of outages [EFOF(CCH)].
Planned outages	
DR resources	
QCC values	
Contract imports (fleet)	
QCC values	
Contract imports (resource specific – not registered)	
QCC values	
Contract exports	
ICAP values	

2.10. Modeling Process Timelines

The RA model will be capable of supporting regular analyses with repeatable findings and will be transparent and auditable by Participants, utility regulatory and oversight bodies, and other regional stakeholders to the extent possible.[17] It is recommended the model input data be updated with a corresponding stakeholder process and model results shared with Participants before each FS deadline. Protocols will be adopted allowing detailed and/or confidential information to be shared with specific Participants for review and vetting and aggregated information to be shared with all Participants.

Each year, the PO will begin a new set of annual LOLE/PRM and QCC assessments (annual assessments) that will be used for determining the PRM and QCC for FS Program resources. These studies are to be completed each year no later than October 31 for the Summer season and no later than March 31 for the Winter season to allow 12 months for Participants to prepare for the next binding season. Proposed modeling timelines are illustrated in Figure 2-7.

Figure 2-7 outlines the timelines associated with both the Summer and Winter season modeling processes. It should be noted that the terminology T-X is used with regards to the calendar year in which these deadlines occur. In this terminology, T-2 would be the upcoming or current calendar year, T-1 would be one year out in the future, T-0 would be two years out, and T+3 would be five years out.

Each year, the PO will begin a new set of assessments that will be used for determining the PRM and QCC for program resources. There will be one study run for the Summer season and one study run for the Winter season. Both studies will follow a similar process. The process will begin with a data request sent to Participants by the PO. Participants will then submit data to the PO and be given a chance to review their model inputs prior to the model being run. Once the model has been run, the PO will provide Participants with their draft model outputs and allow time for Participants to review these model outputs prior to the study completion dates. Study results will be finalized 12 months prior to the associated FS deadline.

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[17] Individual Participant data will not be available to anyone except the Participant and the PO for confidentiality.

MODELING PROCESS TIMELINES

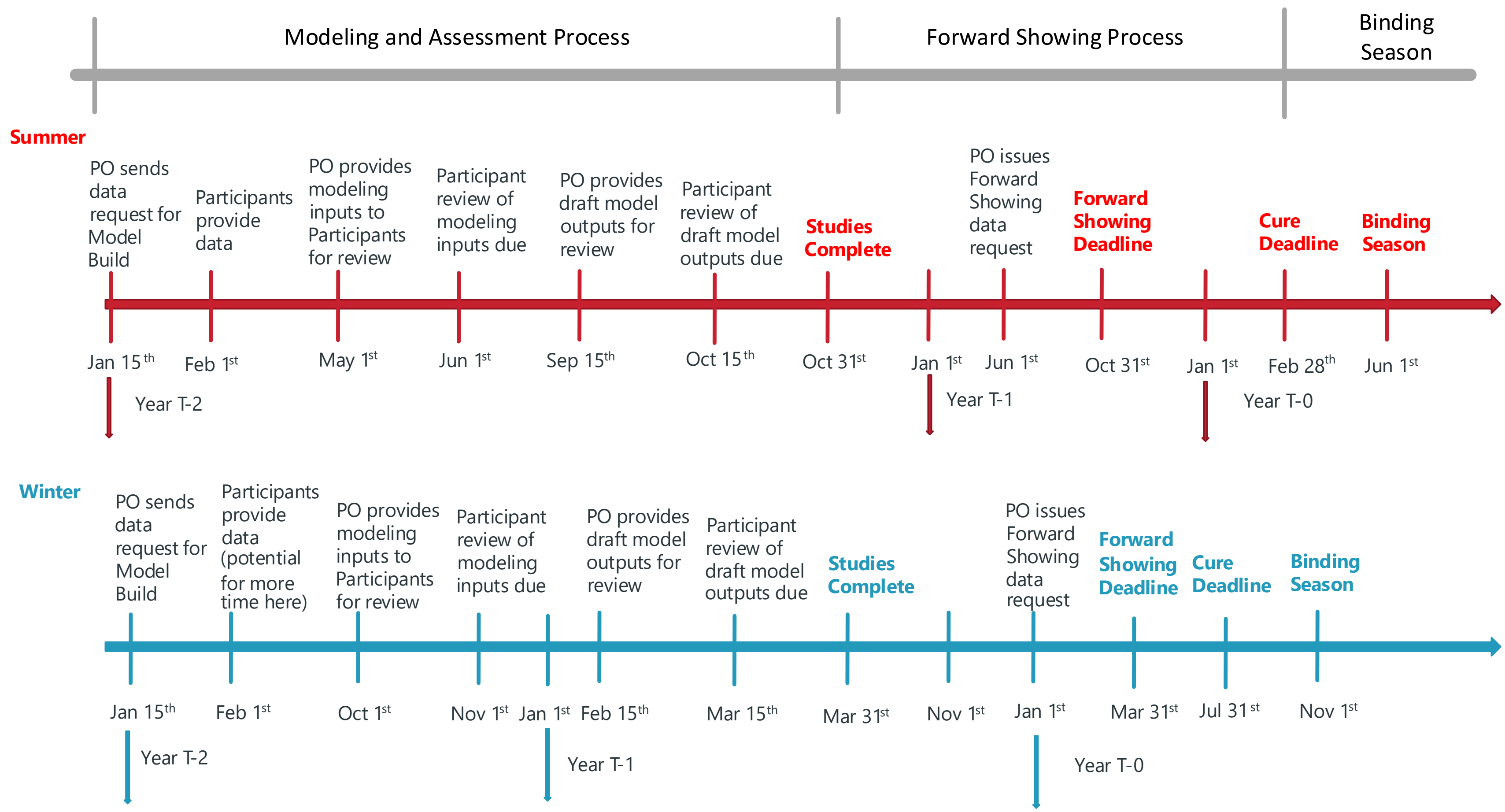


Figure 2-7. Proposed Modeling Process Timelines.

SECTION 2: APPENDIX A - ANNUAL ASSESSMENTS

A.1. Planning Reserve Margin

The PO will calculate the PRM for the RA Program footprint 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 2-12.

Table 2-12. Timing the determination of Summer season PRM.

Example: Timing of the determination of Summer season PRM
In calendar year 2025 (T-2), FS Program Participants provide data to the PO, who completes the Summer season study by October 31, 2025. – The study determines a binding PRM for the 2027 (T-0) Summer season. – The study determines an advisory PRM 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 PRM for 2028 (T-0) Summer season. – This study provides an advisory PRM for 2031 (T+3) Summer season.

A.1.1. Qualified Capacity Contribution

The PO will calculate the QCC of all FS Program resources 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, the PO will develop an RA model that represents the RA Program 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 PO will send out updated data requests to the Participants for the items described in Table 2-13 necessary to complete the annual assessment for that calendar year.

Table 2-13. 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, run-of-river 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 NWPP Storage Hydro QCC Methodology necessary to determine QCC for resources (i.e., data needed to populate the NWPP 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

The PO will need to receive all information from Participants 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 2-14 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 2-14. 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 the PO has input all necessary data into the RA model, Participants will be allowed to review the input data (in the format used by the RA model or a format developed by the PO) 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 PO begins model simulations.

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, the PO may allow the review of data by regulatory and oversight bodies.

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), the PO will provide draft modeling results to the Participants for their review. The modeling outputs that will be available for Participant review are listed in Table 2-15.

Table 2-15. Output from modeling results.

Outputs
Resource index
QCC values by resources owned or contracted by the Participant
Proposed PRM for the season under study
Peak coincident load of the RA Program 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 PO 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 provided by the PO will consist of a LOLE study report that: gives details of the study analysis; makes recommendations for a proposed PRM for the year two binding season; provides an advisory PRM for the year five Summer/Winter season. QCC studies/reports will include the ELCC studies for wind, solar, and run-of-river 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 2-16.

Table 2-16. Final Modeling Output Results.

Study		Output Results
LOLE		– PRM for the upcoming binding Summer/Winter season.
QCC Studies	**VER (ELCC)**	– QCC values by month for all wind, solar, run-of-river resources. – QCC values for all wind, solar and run-of-river 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 (NWPP 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 PRM

B.1. Introduction

Determination of the PRM will be supported by a probabilistic LOLE study, which will analyze the ability of generation to reliably serve the RA Program footprint's P50 load forecast. The PRM 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 PRM 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, RA Program footprint will be modeled as LRZs that have been determined in discussions with the RA Program Participant transmission group and area TSPs (see Section 2.8). If a specific LRZ is determined to be transmission constrained, that the constrained LRZ may have a higher PRM requirement applied than the remainder of the RA Program 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 PRM value. After the footprint's PRM value has been found, an analysis of each LRZ will be made to determine if a zone is transmission constrained and must be addressed as detailed in Section 2.8.2.

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 an 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 RA Program 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 outages 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)

[18] EFOR is a metric used in the LOLE study for determination of *system* PRM. 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 PRM. The determination of QCC is *plant* focused, determined primarily on CCH, and excludes outages outside of plant management control.

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 5 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 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 the RA Program evolves.

B.5.2 Storage Hydro

The NWPP 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, Run-of-River Resources

The study model will include all wind, solar, and run-of-river hydro resources currently installed or proposed to be in-service in the RA Program 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 2.5.6. 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 RA Program 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 RA Program 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 PRM.

Pure negative (or pure positive if the system is generation deficient) capacity with no outage rate will be added to the model until the RA Program 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 PRMs will be determined separately.

B.7. PRM Calculation

As discussed in Section 2.2.2, the Program PRM will be given on a UCAP basis. To calculate the PRM on a UCAP basis, the capacity value determined in Section B.6 must be converted to a UCAP value (see Table 2-17 for details on this conversion).

Table 2-17. Resource capacity conversion to UCAP for PRM 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 RA Program 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/ Demand Response (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 PRM is calculated:

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

B.8. Simulation Process

The probabilistic LOLE study will model random forced outages for resources in the RA Program 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 - PRM ALLOCATION METHODOLOGIES

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

The FS Program will allocate the capacity requirement of the PRM to each Participant based on their individual P50 load forecast using the NCP of each Participant. By allocating the PRM requirement in this manner, Participants will have a simple, straightforward method for determining their reserve requirement, with equal sharing of load diversity benefits. Table 2-18 provides an example of the PRM capacity allocation calculations.

The calculation appears as shown below:

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

Table 2-18. Example PRM capacity allocation methodology calculations.

NCP load of the RA Program footprint = **5,025 MW**
Participant "A" – P50 load = 1,000 MW (load at RA Program Peak = 950 MW)
Participant "B" – P50 load = 2,000 MW (load at RA Program Peak = 1,925 MW)
Participant "C" – P50 load = 2,200 MW (load at RA Program Peak = 2,150 MW)
Regional PRM is calculated to be 15% of the RA Program CP load through the LOLE study
With the calculated PRM, 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 Contingency Reserves on PRM

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 PRM 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 PRM. Once the PRM 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 PRM (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 and total sales of 300 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 NWPP RA Program 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 NWPP 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 15th) and Winter season (November through March 15th).

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 ten years of historical data should be considered. A ten 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 RA Program metrics (see Section 2.3.2).

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:

- 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:
    - Generation output during the CCH
    - Useable energy in storage at the end of the CCH
    - 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
    - Non-power operational constraints that limit the use of energy in storage

Table 2-19. 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 2-19, the hourly values in Table 2-20 can be estimated for each CCH:

Table 2-20. 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 2-8 illustrates the application of the methodology to the Rocky Reach hydro facility.

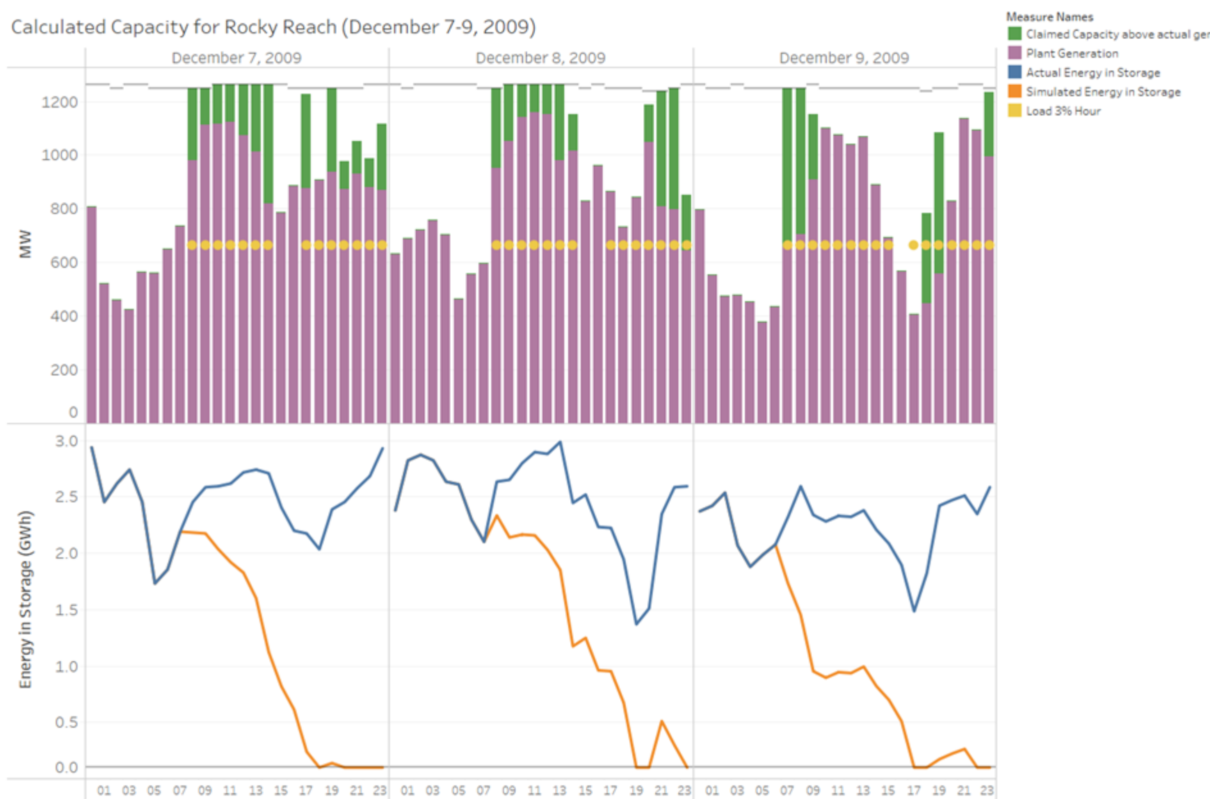


Figure 2-8. Example application of the Storage Hydro QCC Methodology for Rocky Reach.

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

$$UCAP = ICAP * (1 - EFORd)$$

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 NWPP 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 2-21 and Table 2-22 below illustrate the QCC calculation over a four-hour consecutive period using the UCAP methodology and the UCAP + planned outages methodology.

Table 2-21. 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 2-22. 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 2-21 illustrate how the QCC is limited due to insufficient storage. In Table 2-22, 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. 10 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 ten-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 RA Program 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 RA Program 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 RA program 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 NWPP 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. The group will ask the PO to make an assessment 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, 2) reliance on imports (beyond the RA Program’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/PRM.

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 2-23 shows are how certain parameters of the VER ELCC study will be handled.

Table 2-23. 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 loads 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 RA Program 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 RA Program 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 PO will conduct the ELCC study by performing probabilistic simulations in a manner that resources in the RA Program 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, an 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 RA Program 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 2-9 as "Pure Capacity 1."

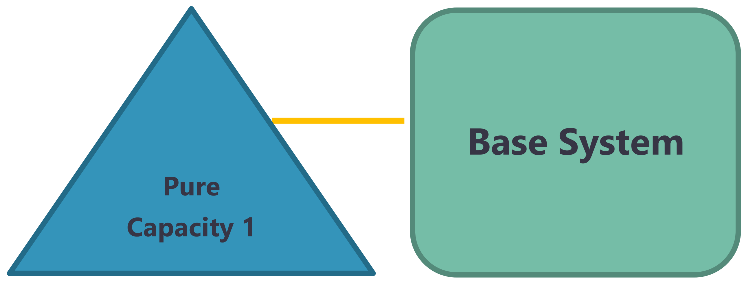


Figure 2-9. Diagram of system without renewable resources.

Next, an LOLE value for all wind generating units will be determined, repeating the steps described previously. The pure capacity value calculated is designated in Figure 2-10 as "Pure Capacity 2."

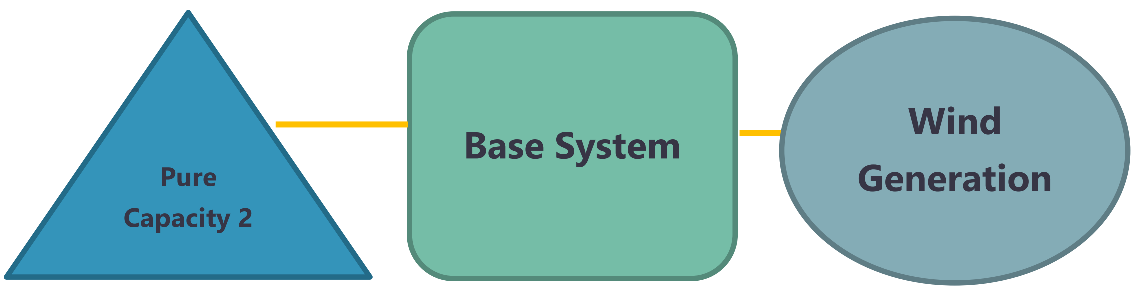


Figure 2-10. Diagram of system with renewable resources.

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

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

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 RA Program 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, the PO will conduct an ELCC study of the entire RA Program and calculate a total capacity value for all VERs (of each type) in the RA Program footprint. 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 2-24 provides an example of the calculations to determine total VER (in this case: wind) capacity.

Table 2-24. ELCC Study of RA Program 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. The PO will provide an ELCC curve that can be used 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 run-of-river hydro resources. The solar ELCC study will include all wind and run-of-river hydro resources. The run-of-river hydro study will include all wind and solar resources.

[19] It may not be necessary to study incremental amounts of run-of-river hydro 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 2-25) a review of the top 5% of CCHs was undertaken for the previous 10 years of Summer binding seasons and the previous 10 years of 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 resulted in a duration of 5 hours for the Summer binding season ESRs and 4.7 hours for the Winter binding season ESRs.

Table 2-25. 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 to the PO in the annual data request to the PO. The PO will calculate QCC values 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 capacity critical hours, and

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

Definitions of FOH and EFDH can be found in Table 2-26.

Table 2-26. Definitions of FOH and EFDH.

Definitions	
FOH	Sum of all CCH experienced during Forced Outages (U1, U2, and U3) + Startup Failures.
EFDH	Each forced derating (D1, D2, and 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 5 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 to the PO.
- 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 1 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 6 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 PO.

[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 to the PO will not meet qualification and registration requirements of the FS Program.

SECTION 2: APPENDIX E - TRANSMISSION MODELING CONSIDERATIONS

The RA Program has worked with the NWPP 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 NWPP 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 2-27.

Table 2-27. 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 NWPP 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 by the PO. Additionally, the PO will determine the transmission usage 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 2-28.

Table 2-28. 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 by the PO in the determination of whether LRZs have sufficient import capability to maintain the regional PRM value or whether the LRZ will be considered a transmission constrained zone.

[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."

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 1 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 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, the PO will compare this capacity deficiency 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 PRM requirement. If insufficient import capability is found to exist, and unless additional transmission capacity is able to be obtained or demonstrated, the PO will determine a new PRM value for the transmission constrained LRZ. The new PRM 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 PRM for the zone.

The PO will share the results of this analysis 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

As stated in Section 2.6, a 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 2-29, Table 2-30, Table 2-31 provide examples for a Participant's resources QCC ledger, net contract QCC ledger, and total RA transfers.

Table 2-29. 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	Run-of-	600		0.4	2022-11	2022-11	240
1	Hydro 1	Hydro	Run-of-	600		0.4	2022-12	2022-12	240
1	Hydro 1	Hydro	Run-of-	600		0.4	2023-01	2023-01	240
1	Hydro 1	Hydro	Run-of-	600		0.4	2023-02	2023-02	240
1	Hydro 1	Hydro	Run-of-	600		0.4	2023-03	2023-03	240
2	Hydro 2	Hydro	Storage	1200	0.03		2022-11	2022-11	950
2	Hydro 2	Hydro	Storage	1200	0.03		2022-12	2022-12	1050
2	Hydro 2	Hydro	Storage	1200	0.03		2023-01	2023-01	1000
2	Hydro 2	Hydro	Storage	1200	0.03		2023-02	2023-02	980
2	Hydro 2	Hydro	Storage	1200	0.03		2023-03	2023-03	1000
3	Thermal	Thermal	Natural	700	0.05	0.95	2022-11	2022-11	665
3	Thermal	Thermal	Natural	700	0.05	0.95	2022-12	2022-12	665
3	Thermal	Thermal	Natural	700	0.05	0.95	2023-01	2023-01	665
3	Thermal	Thermal	Natural	700	0.05	0.95	2023-02	2023-02	665
3	Thermal	Thermal	Natural	700	0.05	0.95	2023-03	2023-03	665
4	Wind 4	Wind		70		0.15	2022-11	2022-11	10.5
4	Wind 4	Wind		70		0.15	2022-12	2022-12	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	2023-01	2023-01	10.5
4	Wind 4	Wind		70		0.15	2023-02	2023-02	10.5
4	Wind 4	Wind		70		0.15	2023-03	2023-03	10.5
5	Hydro 5	Hydro	Storage	400	0.06		2022-11	2022-11	300
5	Hydro 5	Hydro	Storage	400	0.06		2022-12	2022-12	360
5	Hydro 5	Hydro	Storage	400	0.06		2023-01	2023-01	320
5	Hydro 5	Hydro	Storage	400	0.06		2023-02	2023-02	350
5	Hydro 5	Hydro	Storage	400	0.06		2023-03	2023-03	350

Table 2-30. 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 2-31. 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

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. 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 RA Program – they should not be utilized without accompanying design information and/or appropriate understanding of their approximate nature at this time. .

G.2. Planning Reserve Margin

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

G.2.1. Resources Used In Analysis

The dispatchable resources submitted by Program Participants for review in the indicative analyses are shown below in Table 2-32. 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 2-32. 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 2-33. These values are nameplate capacity values.

Table 2-33. 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 2-34.

Table 2-34. 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 Program Participants are listed below in Table 2-35. These values reflect a total summation of the individual peaks of Program 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 2-35. 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 NWPP 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 ten (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 was 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 50th 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 RA Program Demand)
- No transmission constraints between zones modeled
- Only LOLE on binding seasons were considered when determining LOLE for each season

G.2.4. PRM 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 PRM 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 PRM calculation.
- Energy storage and Demand Response resources – ICAP values
- Pure capacity – adjustments to capacity to reach 1-in-10 metric for each binding season

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

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

The RA Program design calls for the PRM to be based on a non-coincident peak (NCP); this will facilitate Participant comparison to their current metrics. For comparative purposes to other RA Programs where PRMs are often applied to coincident peaks (CP), a CP demand for the RA Program 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 2-36. These results do not include any adjustment for transmission or deliverability policy which is still in development.

Table 2-36. Summer UCAP PRM.

Summer	Demand	UCAP PRM @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 2-37. These results do not include any adjustment for transmission or deliverability policy which is still in development.

Table 2-37. Winter UCAP PRM.

Winter	Demand	UCAP PRM @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 2-38.

Table 2-38. 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 2-39 on a monthly basis.

Table 2-39. 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%

NWPP Resource Adequacy Program Detailed Design

Section 3. Operational Design

NORTHWEST PowerPool

JUNE 2021

Prepared in collaboration with the Southwest Power Pool, as Program Developer

SPP Southwest Power Pool

SECTION 3. OPERATIONAL DESIGN: TABLE OF CONTENTS

INTRODUCTION

3.1. Overview of Operational Design

The Northwest Power Pool (NWPP) Resource Adequacy (RA) Program – Operational Design, also referred to as the Operational Program (Ops Program), is the operational portion of the RA Program. In the Ops Program, the Program Operator (PO) monitors the RA of Participants, forecasted load, uncertainty, and reserve requirements, along with forced outages and Variable Energy Resource (VER) performance, to determine when a Participant may have insufficient capacity to cover the projected demand. When a Participant is forecasted to be deficient, the PO will initiate a Sharing Event and call on other Participants that have a surplus to hold back capacity (via a Holdback Requirement) and deliver energy (via an Energy Deployment) to the deficient Participant(s). The Forward Showing (FS) Program, the RA forecast counterpart of the Ops Program, will determine the baseline values for the components of the Sharing Calculation [e.g., P50+Planning Reserve Margin (PRM), Forced Outage, etc.] and the Ops Program will determine real-time differences from these values to initiate a qualifying Sharing Event.

The Ops Program is implemented through iteratively (see Section 3.2) applying a Sharing Calculation (see Section 3.3) beginning with a Multi-Day Ahead Assessment (see Section 3.5), identification of Sharing Events with a Holdback Requirement on the preschedule day (see Section 3.4), and Energy Deployments on the Operating Day [(OD), see Section 3.6]. The Sharing Calculation is performed using Participant provided data updated on at least a daily basis for Multi-Day Ahead Assessment through the preschedule day for identification of Sharing Events and the data is updated hourly for the OD for Energy Deployments (see Section 3.12).

3.1.1. Ops Program Anticipated Benefits

The Ops Program facilitates access to the diversity of resources across the region of Participants. For example, during times when VERs are performing above their accredited levels or Participants are experiencing a low level of forced generation outages, that additional capacity may be made available to deficient Participants by the Ops Program during times of generation shortfall. Additionally, the Ops Program will allow Participants to maximize the benefit of the load diversity across the region during periods of which one Participant is peaking and another Participant is realizing lower load levels. The Ops Program allows Participants to collectively manage periods of risk of capacity shortfall. The Ops Program reduces the uncertainty risk for each Participant of the NWPP RA Program through sharing available capacity.

3.1.2. Binding Seasons of Ops Program

The Ops Program will be operated by the PO during the binding seasons, as defined by the FS Program. Table 3-1 includes the proposed duration of the binding Winter and Summer seasons. The Ops Program will initially be operated according to this schedule. After the inception of the Ops Program, the PO may conduct analysis to evaluate whether changes to the binding seasons are appropriate. The Winter and Summer seasons of this program will be binding for Participants who are engaged in the program. The Spring and Fall season will be conducted in a similar manner, but this will be advisory only (i.e., penalties will not be assessed).

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

3.1.3. Design Principles for the Ops Program

The Ops Program applied the following design principles to guide in making determinations when presented options for how to construct the Ops Program.

- The Ops Program will be a capacity program not an energy program.
- The Ops Program will perform assessments for short-term horizons that will identify opportunities to use regional diversity in demand and supply.
    - The methodology will determine when a Participant may access the Program.

    - The methodology will determine when a Participant will be obligated to provide capacity support to other Participants that are deficient.
- The design should be simple and cost-effective. This should be considered in determining:
    - Tools of PO.
    - Data exchange between Participants and PO.
    - Calculations performed by PO.
    - Validations performed by PO.
    - Communication between Participants and PO.
    - Settlements.
    - Tools required by Participants.
- The Ops Program should provide equitable benefits for all Participants.
- The Ops Program should maintain a healthy balance for all Participants both accessing and providing capacity to the Program.
- Ensure short-term sharing commitments have appropriate transmission service with low risk of curtailments in order to maximize reliability.
- Ensure that Balancing Authority Areas (BAAs) and Load Serving Entities (LSEs) and Load Responsible Entities (LREs) can continue to operate safely, efficiently, and reliably.

While designing the Ops Program, several design elements were set at lower priority. These design elements are deemed to have merit but were considered too complex for the initial Ops Program and not in line with the initial design principles summarized above. After the Ops Program has been in place for at least one season, the PO may review these future design elements, using historical data from the Ops Program to determine their benefit and work with Participants to make enhancements to the Ops Program where applicable. Design principles that would be applicable to this next phase or phases of design effort are listed below. This is not a complete list and is meant as a starting point for future discussion. These concepts are covered in more detail in Sections 3.15 and 3.16 .

Design Principals to be considered later:

- Optimizing Holdback Requirements across RA Participants.
    - Minimize transactions.
    - Minimize transmission costs and losses.
    - Minimize risk of curtailments.
    - Maintain balanced benefits for all RA Participants.
- Assess and improve, if applicable, on the design principle of equity to all RA Participants regardless of the fuel mix of the RA Participant.
- Assess and improve, if applicable, on the design principle of being fair to all RA Participants regardless of the geographic location of the RA Participant within the RA footprint.
- Perform a look ahead assessment beyond the 7-day horizon to forecast the Holdback Requirements and allow RA Participants to use the results to schedule maintenance outages.
- Minimize the Sharing Events assuring settlement and compensation levels are set correctly to incentivize RA Participants to solve capacity deficits before holdbacks or energy deployments are issued.
- Minimize the Sharing Events by implementing incentives for RA Participants to use their available capacity before leaning on RA Program even if they are eligible.

OPS PROGRAM DESIGN FOR GO LIVE

3.2. Ops Program Timeline

The Ops Program is implemented over a timeline beginning with a forecast up to a week prior, revised daily through the preschedule day, and revised hourly into the OD. Figure 3-1, below 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 hourly forecasts and operating information to the PO. The PO performs Sharing Calculations and provides a Multi-Day Ahead Assessment for up to the next 7 days in the forecast window. On the preschedule day the PO will provide Sharing Calculations and Holdback Requirement for the forecasted ODs. The Sharing Calculations are performed hourly on the OD to determine the Energy Deployment up to the Holdback Requirement for each Sharing Event. Any capacity not identified in the Energy Deployment to be released back to Participants. These steps are described in more detail in sections below.

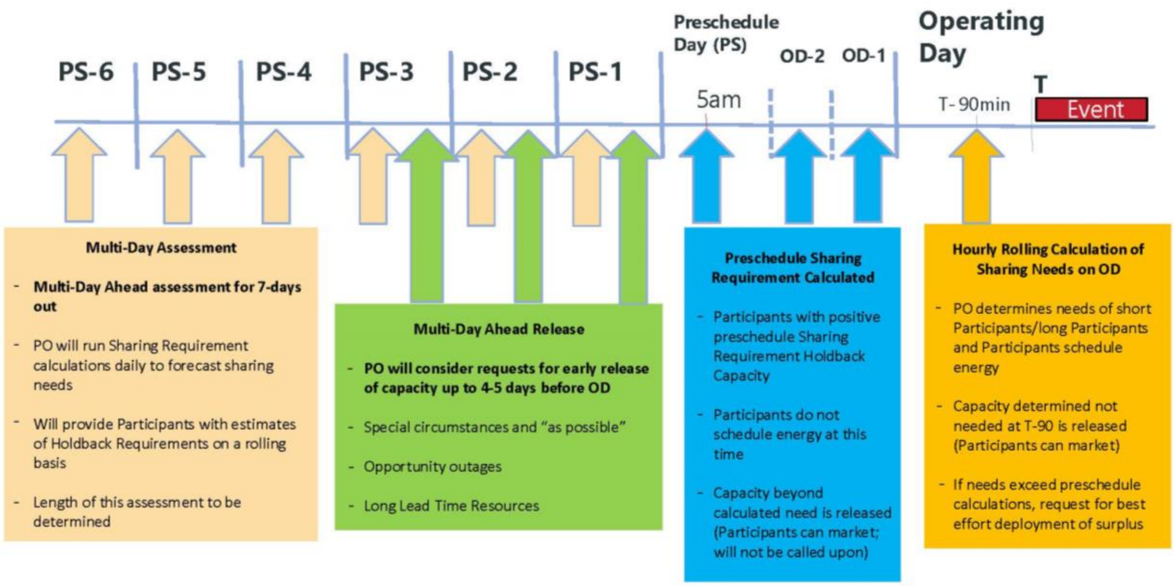


Figure 3-1. Overall Ops Program Timeline.

The steps the PO takes for the preschedule and ODs are shown below in more detail in Figure 3-2. This timeline covers the actions taken by the PO from the identification of an event in the preschedule day, through the actual event in the OD.

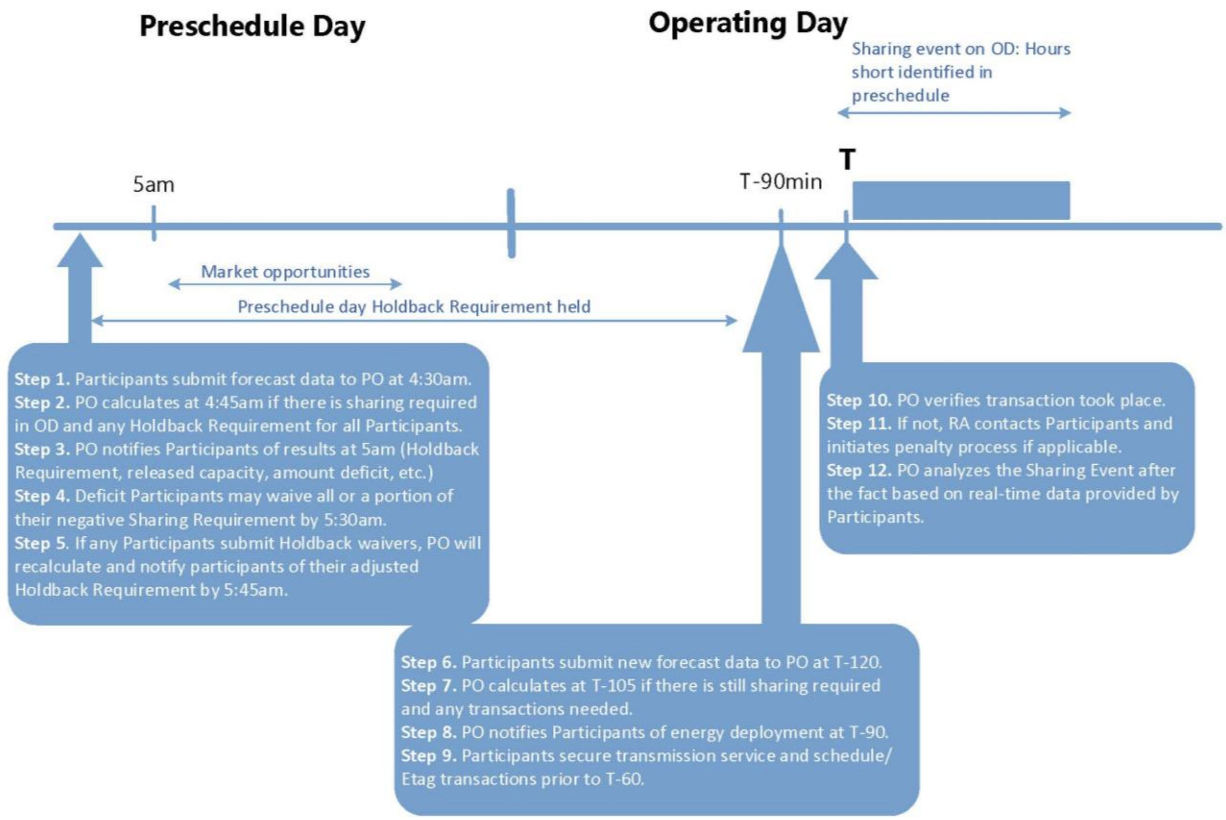


Figure 3-2. Preschedule & OD Timeline.

3.3. Sharing Requirement Calculation

The Sharing Calculation determines if Participants are either needing to access the Ops Program for capacity shortfall or are positioned to contribute capacity to the Ops Program. This Sharing Calculation drives the determination of when Sharing Events are triggered by the PO. Any Participant positioned to contribute to the Ops Program will be calculated as having a net positive Sharing Requirement, whereas any Participant needing to access the Ops Program will be calculated as having a net negative Sharing Requirement.

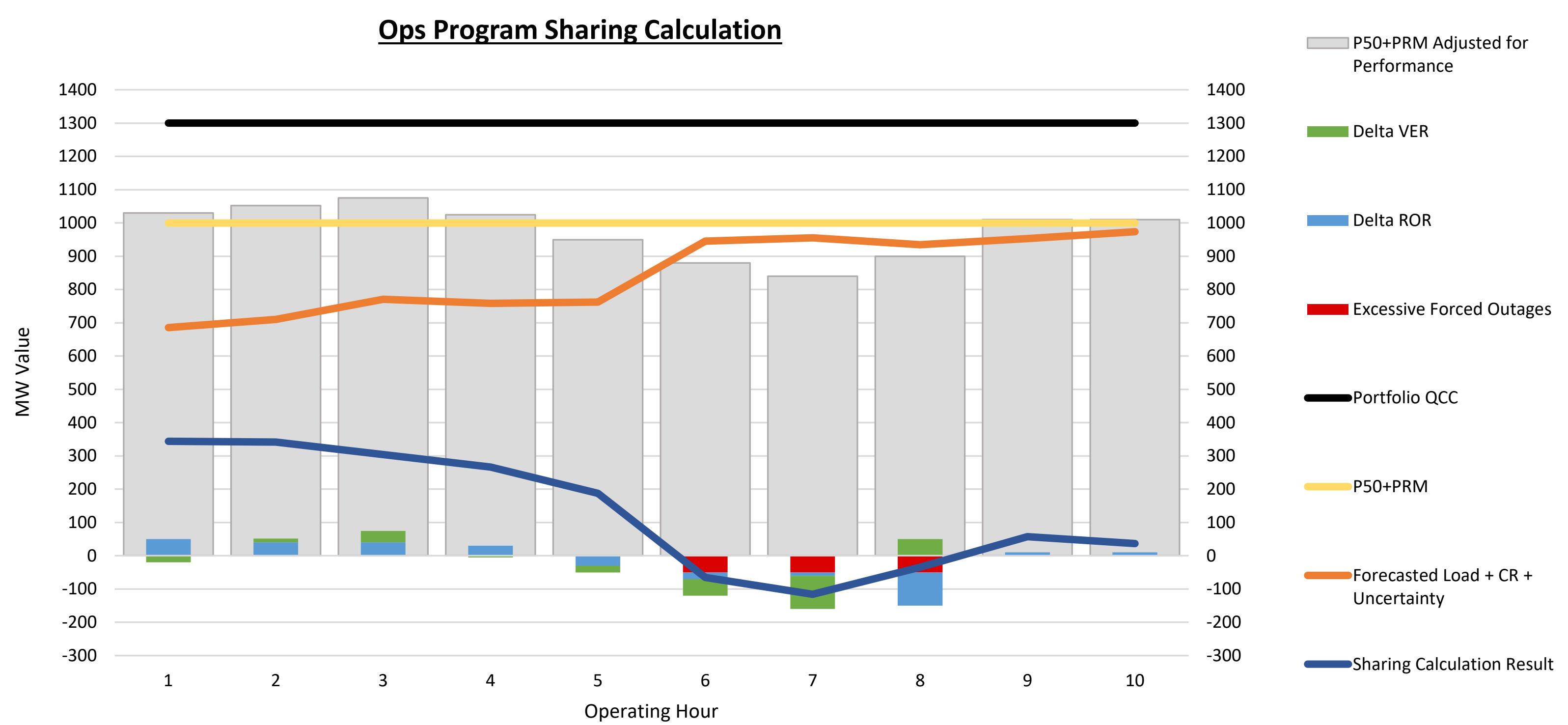
3.3.1. Sharing Calculation

The Sharing Requirement is described in the Sharing Calculation presented in Table 3-2.

Table 3-2. Sharing Calculation and components.

Definition: Sharing Requirement	
$$\begin{aligned}&\boldsymbol{Sharing\ Requirement}\\&\quad= [\boldsymbol{P50} + \boldsymbol{PRM} - \boldsymbol{\Delta\, Forced\ Outages}\\&\quad+ \boldsymbol{\Delta RoR\ Performance}\\&\quad+ \boldsymbol{\Delta VER\ Performance}] - [\boldsymbol{Load\ Forecast} + \boldsymbol{\Delta CR}\\&\quad+ \boldsymbol{Uncertainty}]\end{aligned}$$	
P50	The 1-in-2 peak load seasonal values as submitted in the FS Program for the forecasted upcoming two years.
PRM	Percentage of dependable capacity needed above the 1-in-2 peak Load Forecast to meet unforeseen increases in demand and other unexpected conditions. See the FS Design document for more details.
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 VER Performance	Comparison of forecasted VER production vs. qualified capacity contribution (QCC) of VER. Includes both over and under performance of wind and solar plants.
Δ Run-of-river Performance	Comparison of forecasted run-of-river production vs. QCC of run-of-river hydro. Includes both over and under performance.
Load Forecast:	Forecasted load for the OD considering the forecasted weather conditions of OD.
Uncertainty:	Forecast of potential error of the Load Forecast, VER forecast, and run-of-river forecast.
Δ CR:	Comparison of contingency reserves (CRs) that were included in the FS Program and CR requirement in Ops Program. Contingency reserves will be carried into the operating hour as required by the NWPP CR Sharing Program.

The Sharing Calculation as described above will be utilized to identify any potential Sharing Events. A Sharing Event is defined as any hour in which the Sharing Calculation identifies any given Participant as a net negative (i.e., needing to access Ops Program capacity). Due to the difficulty in forecasting precisely when an event will occur over the horizon of the OD, the PO, at its discretion, may add an hour before and after each identified event. This Sharing Event Window will ensure that the total possible duration of the Sharing Event is covered by the Ops Program. For example, if on the preschedule day the PO forecasts a Sharing Event at hour beginning 04:00 PM PPT of the OD the PO may extend the Sharing Event to cover hour beginning 03:00 PM – 05:00 PM. Figure 3-3 provides a representation of the Sharing Calculation for a period of ten hours.



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 3-3. Ops Program Sharing Calculation.

3.3.2. Forward Showing Capacity Requirement (P50+PRM)

The starting point for the Sharing Calculation is the FS Capacity Requirement (defined as P50 + PRM). As previously discussed, this data will be determined in the FS Program and remain set in the Ops Program. Each Participant will have a P50 representing the predicted peak forecasted load of any given season, plus the associated PRM for that same season. As stated, this is the starting point for the calculation and represents what a Participant "should have" during any given calculated horizon in the Ops Program. Components that impact the sharing calculation, as identified in Table 3-2, are explained further in sections below. It is important to note that each Participant will have a unique FS Capacity Requirement determined by its configuration of load and resource portfolio. Additionally, there will be a unique FS Capacity Requirement per season of the Ops Program (i.e., Winter and Summer).

3.3.3. Forced Outages

The forced outages term in the Sharing Calculation covers several items. This term is utilized by the Program to capture the performance impact of thermal and storage hydro generation, as well as impacts from transmission outages that impact firm capacity import. This term will capture both over and under performance on thermal generation, but only capture under performance on storage hydro generation. This is due to the fact that storage hydro, for the purpose of this program, is capped at QCC from the FS in relation to over performance but may be lowered for reliability impacts.

Specifically, this term will cover:

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

- Over and under performance as related to the forced outage rate utilized in the FS to define the QCC.
- This will include the impact of both forced outages as well as reliability de-rates for the associated generation plants.
- It will not include forced outages or de-rates related to fuel or economic decisions.
- QCCs will be modified upward for over performance and downward for under performance. This can impact the availability of a generating plant from a value over the QCC, up to the maximum capability of the plant, down to zero.

Storage Hydro generating units:

- Under performance only as related to operational reliability impacts and compared to QCC from FS.
- Performance will be capped at QCC from the FS for over performance.
- Will not include fuel related forced outages or de-rates or economic decisions.
- Forced outages and derates will only be reported if the Participant also had the fuel available such that they could have otherwise provided the QCC of the Storage Hydro unit but for the outage/derate condition.
- QCCs will be modified downward only for under performance. This can impact the availability of a generating plant from a max of the QCC of the plant, down to zero.

Unplanned transmission outages:

- Participant (and/or their supplier) has acquired North America Electric Reliability Corporation (NERC) priority 6 or 7 service and service contract is de-rated.
- Participant will notify the PO of any de-rate impacts when they are identified so that impacts will be seen in Sharing Calculations.
- Will be reported in relation to impact on total QCC availability of the import contract (outage = (service contract de-rate/total service contract)*RA resource)
- QCCs will only be modified downward for contract imports, as related to the transmission derate impact, otherwise QCC will be defined according to the principles established above.
- Participants should be able demonstrate good faith effort to secure NERC priority 6 or 7 and unforeseen circumstances (e.g., de-rate before procurement, preempted without ability to match), as applicable considering the timeline on which these changes occurred.
- The PO may determine that a forced outage was inappropriately claimed. If this was the fault of a Participant’s supplier, it is anticipated that the Participant would be able to pass this penalty on to the supplier through their commercial agreement if they choose to do so. The PO will track this behavior to identify ‘bad actors. ’

- Inability to secure transmission (e.g., remaining 25% not previously demonstrated at FS deadline) on NERC priority 6 or 7 is not a valid reason on its own to claim a forced outage in the Ops Program; doing so may result in penalty.
- If a Participant claims a transmission-related forced outage, the PO may request documentation (including, but not limited to, contracts, transmission contracts, etags, etc.) to support the Participant's forced outage report after the fact.

Each Participant will submit reliability-driven outages and derates to the PO to be utilized in the Sharing Calculation on a generating plant granularity. The PO will utilize the principles outlined above in order to calculate the actual unit availability of each generating plant participating in the Program, in respect to the QCC as defined in the FS. These values will be aggregated from a plant level granularity to a Participant level and are utilized in the Sharing Calculation, as defined in previous sections.

Note: Generation maintenance outages will not be added to forced outage submissions.

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

Note: Outages or de-rates associated with economic decisions are not allowed to be submitted to the PO.

3.3.4. Maintenance Outages

Maintenance outages are necessary and expected during the course of the Ops Program. However, Participants should minimize the amount of maintenance outages that are taken over periods of the season in which capacity shortfall has an increased likelihood of occurring. As such, maintenance outages are taken at the risk of each Participant. The Ops Program binding season covers the Winter and Summer peaks of all Participants. As such, it is expected that each Participant will make the generation available to the Ops Program as calculated in the FS Program.

Any maintenance outages occurring over the horizon of the Ops Program calculations will not be included in determination of Sharing Requirement, as these plants should be available in the same manner as determined in the FS Program. It is expected that Participants will limit planned maintenance over forecasted Sharing Events to ensure they can fully support the Ops Program. Any capacity accredited from the FS Program should be available to the Ops Program during these Sharing Events.

3.3.5. Transmission Outages

Transmission system outages that impact path limits and affect the ability of a Participant to import firm contracted capacity should be reported to the PO. All efforts should be made by the Participant to resupply the power up until T-105. These outages will be tracked through the forced outages variable in the Sharing Calculation and will include the megawatt (MW) amount of the import capability that is reduced for a Participant.

Participants who are experiencing any impacts from transmission system outages associated with existing firm import contracts should report these impacts to the PO, as soon as practical, such that the PO can coordinate across the Ops Program to account for these system conditions and update the Sharing Calculations to accommodate. For example, if a Participant is experiencing transmission outages that are impacting its ability to deliver, the Participant should notify the PO. The PO will make a determination on these reports on a case-by-case basis to determine how and if they may impact Ops Program results and any potential delivery failures associated (see sections below for more details).

3.3.6. Variable Energy Resources Over Performance and Under Performance

Each VER (typically wind and solar) in a Participant's generation portfolio will provide capacity to the Ops Program on a variable basis given forecasted weather and system conditions. As such, the Ops Program needs to track the performance of these resources on an hourly basis. The FS Program will determine a QCC for each resource, respectively. Each Participant should submit resource-specific forecasts to the PO such that these variations can be considered in the Sharing Calculation.

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

Similar to VER unit performance, run-of-river 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 the PO such that these variations can be considered in the Sharing Calculation.

3.3.8. Load Forecast

The Sharing Calculation will need to consider the Load Forecast for the period in which the calculation is being performed. This calculation is conducted on an hourly basis for all forecast windows, as described in Section 3.12, below, using the data submitted by each Participant. This Load Forecast should consider the expected weather forecast and expected system conditions. Each Participant will submit forecasts to the PO such that these variations can be considered in the Sharing Calculation. This Load Forecast is a metric to determine what a Participant should need on any given day and will be modified by load uncertainty and CR, as described in section 2.3. The Sharing Calculation will demonstrate the projections for each Participant relative to their expected peak to forecast the availability of capacity or need for Ops Program support. This value will be reported as MW on an hourly basis. The granularity of this data submission is given in more detail in Section 3.12.

3.3.9. Uncertainty

System conditions are often difficult to predict. As such, the PO will include a level of uncertainty in the Sharing Calculation to account for potential variance. Uncertainty is the relationship of the accuracy of the performance of historical forecasts, by Participant, in comparison to historical actuals. This uncertainty will be Participant specific and include adjustments for possible variations in load, solar/wind, and run-of-river forecasts. The purpose of this offset is to ensure that, should system conditions change, the Ops Program is still able to deliver the necessary support to Participants needing to access the Ops Program.

The level of uncertainty utilized by the PO will be a variable that will continue to improve as the PO gets more experience with the performance of load, wind, and solar forecast of each of the Participants. Uncertainty requirements are expected to be variable and associated closely with the level of risk of each given operating horizon. It will be under the discretion and authority of the PO to set uncertainty levels to offset these risks. This value will be a MW value for each hour represented in the Sharing Calculation.

The specifics of this uncertainty calculation will be determined later in the RA Program when the PO has access to sufficient amounts and quality of forecast and actual data for each Participant. After phase 2B of the RA Program (see Figure ES-1), the PO and Participants should continue to review, evaluate, and improve the uncertainty calculation. As shown in the initial Proof of Concept work by presented by Southwest Power Pool (SPP) on April 23rd, 2021, accurate forecasts are critical in the reduction of Holdback Requirement allocation that does not materialize into actual Sharing Events.

Participants who submit forecasts which are unreliable have been shown to greatly increase the magnitude of potential Sharing Events in the Program. The PO will work with Participants to communicate on any discrepancies and issues seen with more forecast data is available.

3.3.10. Safety Margin

The PO has the discretion to determine the need for a Safety Margin to the Sharing Calculation at a program-wide level. The Safety Margin is an additional amount of uncertainty beyond the Participant level Uncertainty calculation described in Section 3.3.9. Specifically, this term can be used for situations such as potential large resource trips, heavy transmission outage conditions, significant environmental conditions, and other similar region-wide impacts. The additional uncertainty MWs will be split pro rata amongst those Participants with a positive Sharing Requirement and result in a larger Holdback Requirement for impacted Participants. The application of a Safety Margin will not result in a Holdback Requirement greater than a Participant's Sharing Requirement as a Participant's Holdback Requirement (as defined in Section 3.4) is capped at the Sharing Requirement (as defined in Section 3.3). To maintain transparency, the PO will notify all Participants when a Safety Margin has been applied including the timeframe, MW amount, and reasoning. The PO shall develop and maintain a list of criteria for when to consider implementing a Safety Margin. The criteria will be refined over time as the PO gains experience.

3.3.11. Contingency Reserves

NOTE: This item is still under discussion and pending a decision prior to determination.

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. For each Participant, the expected CR necessary in each timeframe is equal to 3% of total generation plus 3% of total load. This program is not intended to modify or change the way in which the NWPP 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 NWPP CR Sharing Program.

The Ops Program will account for any variations in CRs between the Sharing Calculation and FS Program inclusions. For example, if the FS Program decides to forego adding CR to its determination, then the Ops Program would include all CR. If the FS Program decides to include CR in its determination, then the Ops Program would forego the addition of this level of CR and only be adjusted to account for any variations in what was assumed in the FS Program. In that case, this term would change to ΔCR.

3.4. Holdback Requirement Calculation

3.4.1. Prescheduling Practices

The Ops Program will respect the Western Electricity Coordinating Council (WECC) Prescheduling Calendar. The default prescheduling days are:

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

For a given OD, the PO will conduct the Sharing Calculation assessment on the WECC prescheduling day at 04:45 AM. Participants of the Ops Program must have all requested forecast data for the given OD submitted to the PO by 04:30 AM on the prescheduling day. Exceptions to the default prescheduling practice will be accommodated for holidays and new months as specified by WECC. When the prescheduling day is not the day prior to the OD, the PO will rerun the Sharing Calculation each interim day (see Section 3.5.1).

The Sharing Calculation assessment that is performed on the prescheduling day sets the Holdback Requirement, and comparable forecast calculations are performed multiple days ahead as described in Section 3.2. While no action is required by the Participants ahead of the preschedule day, the forecast calculations will give Participants a good indication of the state of the footprint, and the ability to estimate what their final Holdback Requirements or assistance amounts will be on and after the preschedule day.

3.4.2. Sharing Event

The PO performs the Sharing Calculation on the preschedule day and any other interim days between the preschedule day and the OD. A Sharing Event may be identified by the PO when a Participant was calculated for one or more consecutive hours as having a net negative Sharing Requirement. Due to the difficulty in forecasting precisely when an event will occur over the horizon of the OD, at the discretion of the PO, a Sharing Event Window may begin an hour prior to the Sharing Event and conclude an hour following the Sharing Event. For example, if the PO forecasts a Sharing Event at hour ending 17, the PO may identify a Sharing Event Window from hour ending 16 –18. When the Sharing Event Window is expanded, the appended hours will reflect the risk that the hour of deficit MW may extend beyond the window identified in the Sharing Calculation. This Sharing Event Window will ensure that the total possible duration of the Sharing Event is covered by the Ops Program.

The Sharing Event calculation is performed during the Multi-Day Ahead Assessment, though the results are not binding. This information will be provided to Participants for situational awareness (see Section 3.5.2).

3.4.3. Holdback Requirement

For a given hour during a Sharing Event, on preschedule day, the PO will calculate the Holdback Requirement. Participants with a positive Sharing Requirement will be assigned an hourly Holdback Requirement in MW. This Holdback Requirement amount will be the pro rata share among Participants with a positive Sharing Requirement equal to the total of net negative Sharing Requirements. For hours with no Sharing Event, Participants will not have a Holdback Requirement. Pro rata sharing is defined with the formula in Table 3-3.

Table 3-3. Participant Holdback and pro-rata sharing calculations.

Definition: Participant Holdback Requirement
$$\textbf{Participant Holdback Requirement} = \textbf{Participant Sharing Ratio} * \textbf{Total Program Sharing Requirment}$$
Where: $$\textbf{Participant Sharing Ratio} = \frac{\textbf{positive Sharing Requirement}_{\boldsymbol{Participant}}}{\sum \textbf{net positive Sharing Requirement}_{\boldsymbol{Participant}}}$$ $$\textbf{Total Program Sharing Requirment} = \sum \textbf{negative Sharing Requirement}_{\boldsymbol{Participant}}$$

During the performance of the Sharing Requirement and Holdback Requirement calculations, when any Participant is found to be deficient, the PO will notify each Participant with a negative Sharing Requirement to verify. Participants who are assigned a Holdback Requirement are also notified and asked to confirm the obligation. The calculated Holdback Requirement will be posted by 05:00 AM. The deficient Participant may waive all or a portion of their negative Sharing Requirement by 05:30 AM and the PO will adjust the Holdback Requirement calculation accordingly; whether the deficient Participant would need to affirmatively request the holdback is pending decision. In the event that a Participant submits a waiver of Sharing Requirement, the calculated Holdback Requirement will be re-posted by the PO by 05:45 AM. Figure 3-4 provides an example of the Holdback Requirement for three Participants.

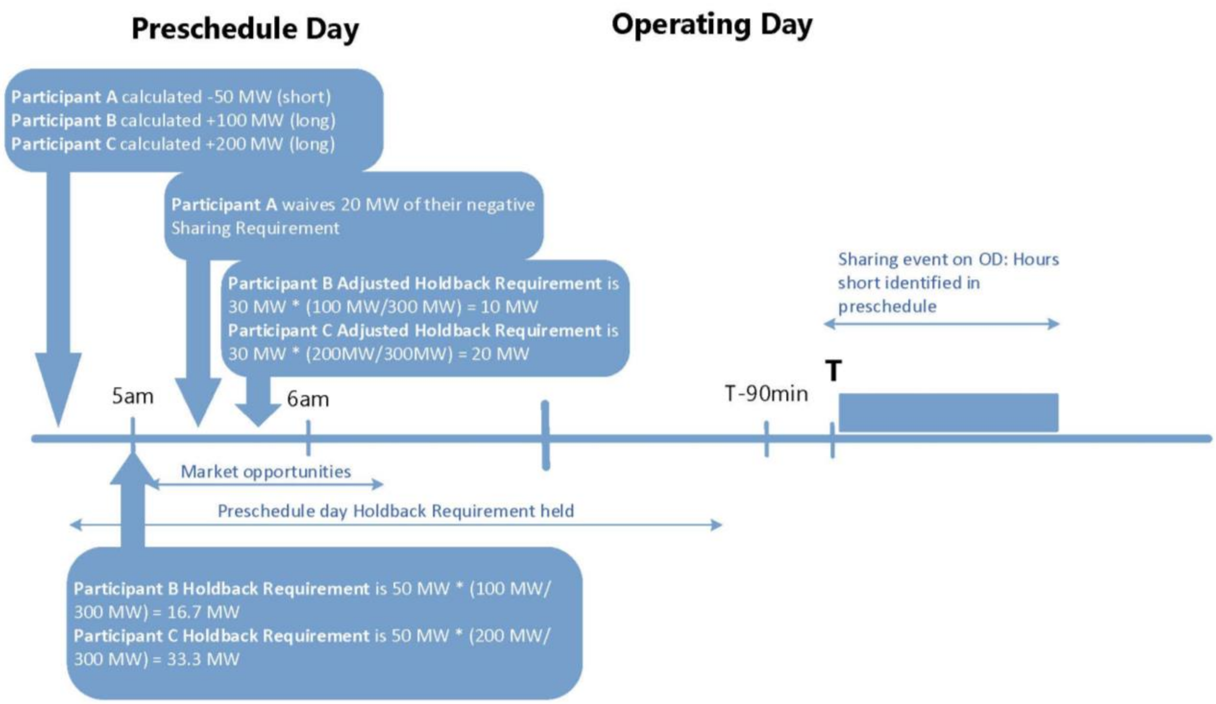


Figure 3-4. Holdback Requirement example showing three Participants.

3.4.4. RA Transfers

Participants may elect to transfer capacity between one another to meet their FS capacity requirement out of the FS Program. Settlement of this capacity transfer is between Participants with no interaction from the PO. Adequate transmission service should be available as described in section 3.7. This is to ensure that the Ops Program is not exposed to any potential deliverability issues and to ensure that capacity transfers cannot be used as a mechanism to get around transmission showing requirements. A Participant may be involved in multiple RA transfers, but must be purely a purchaser of capacity, or a seller of capacity. In other words, a single Participant may not purchase capacity from one Participant while also selling capacity to another Participant for a single Sharing Event.

In the case where a Participant who had purchased a transfer was calculated as having a negative Sharing Requirement, that transfer will first be utilized to serve the deficiency. In the case where a Participant who had purchased a transfer was calculated as having a positive Sharing Requirement, that transfer contract will be fully utilized before the purchasing Participant is required to use their own resources to meet their Holdback Requirement. This approach ensures that capacity transfers between Participants does not inadvertently affect the Holdback Requirement Calculation for the remaining Participants. In the case of multiple contracts, the contracts will serve the Holdback Requirement, either positive or negative, on a pro-rata basis up to 100%.

The PO will calculate the Sharing Requirement with (first pass) and without (second pass) consideration of the transfer in order to determine if the transfer should be provided to the purchasing entity in the case that they have a negative Sharing Requirement or provided to another Participant in the case that the purchasing entity has a positive Sharing Requirement. Table 3-4 provides examples of several scenarios for Sharing Requirement Calculations.

Table 3-4. Examples of Sharing Requirement Calculations.

<table>
<tr><th colspan="3">Example: Participant A contracts with Participant B to assume 100MW of Participant A's RA Obligation.</th></tr>
<tr><th></th><th>Participant A</th><th>Participant B</th></tr>
<tr><td>FS Obligation Prior to Transfer:</td><td>FS Capacity Requirement = 3450 MW</td><td>FS Capacity Requirement = 4600 MW</td></tr>
<tr><td>FS Obligation After Transfer</td><td>3450 MW – 100 MW = 3350 MW</td><td>4600 MW + 100 MW = 4700 MW</td></tr>
<tr><td colspan="3">Note: If Participant A is calculated as having a negative Sharing Requirement, Participant B would serve the first 100 MWs to Participant A. If Participant A is calculated as having a positive Sharing Calculation, Participant B would serve the first 100 MWs of Participant A's Sharing Requirement.</td></tr>
<tr><th colspan="3">Example 1</th></tr>
<tr><td colspan="3">In the first pass of the Sharing Requirement Calculation, Participant A is calculated 125 MWs deficient when considering the 100 MW transfer to Participant B. In this case Participant B serves the first 100 MWs. The second pass of the Sharing Requirement Calculation results in a deficit of the remaining 25 MWs that would be served pro-rata by the Participants with positive Sharing Calculations, including Participant B.</td></tr>
<tr><th colspan="3">Example 2</th></tr>
<tr><td colspan="3">In the first pass of the Sharing Requirement Calculation, Participant A is calculated 25MWs deficient when considering the 100 MW transfer to Participant B. In this case Participant B serves the entire 25 MW deficit. In the second pass, the remaining 75 MWs of transfer is shown as a positive Sharing Requirement for Participant A, with Participant B being responsible to serve any Holdback Requirement assigned to Participant A, up to 75 MWs.</td></tr>
<tr><th colspan="3">Example 3</th></tr>
<tr><td colspan="3">In the first pass of the Sharing Requirement Calculation, Participant A is calculated as having a positive 200 MW Sharing Requirement when considering the 100 MW transfer to Participant B. Since Participant A is not deficit there is no need to call on Participant B and the transfer. In the second pass of the Sharing Requirement Calculation, Participant A is calculated as having a positive 300 MW Sharing Requirement when not considering the 100 MW transfer to Participant B. In this case Participant B would be responsible to serve any Holdback Requirement assigned to Participant A, up to 100 MWs, with Participant A being responsible for any Holdback Requirement in excess of the 100 MW transfer.</td></tr>
</table>

3.4.5. Bilateral Exchange of Holdback Requirement

The Ops Program will support the bilateral exchange of Holdback Requirement capacity between Participants. Figure 3-5 shows a bilateral exchange of Holdback Requirements overlaid on a Sharing Calculation timeline. The PO will host a virtual bulletin board system where Participants can coordinate this exchange. After the preschedule day calculations have run, and Participants are notified by 05:00 AM of their Holdback Requirement, and potentially updated at 05:45 AM. Participants may then utilize the bulletin board to initiate contact with other Participants to exchange part or all of their Holdback Requirement.

Securing transmission service for a potential energy delivery of the exchanged capacity is the responsibility of the partnering Participants. Likewise, settlement of any capacity obligation exchanged between Participants will be the responsibility of the partnering Participants, with no involvement from the PO (described further in sections below).

Any exchange of Holdback Requirement between Participants should be reported to the PO no later than two hours (T-120) prior to the operating hour for which the Holdback Requirement was assigned (T). The PO will use the Holdback Requirement values for each Participant, accounting for all reported exchange, when performing the pro-rata Energy Deployment calculation at T-105.

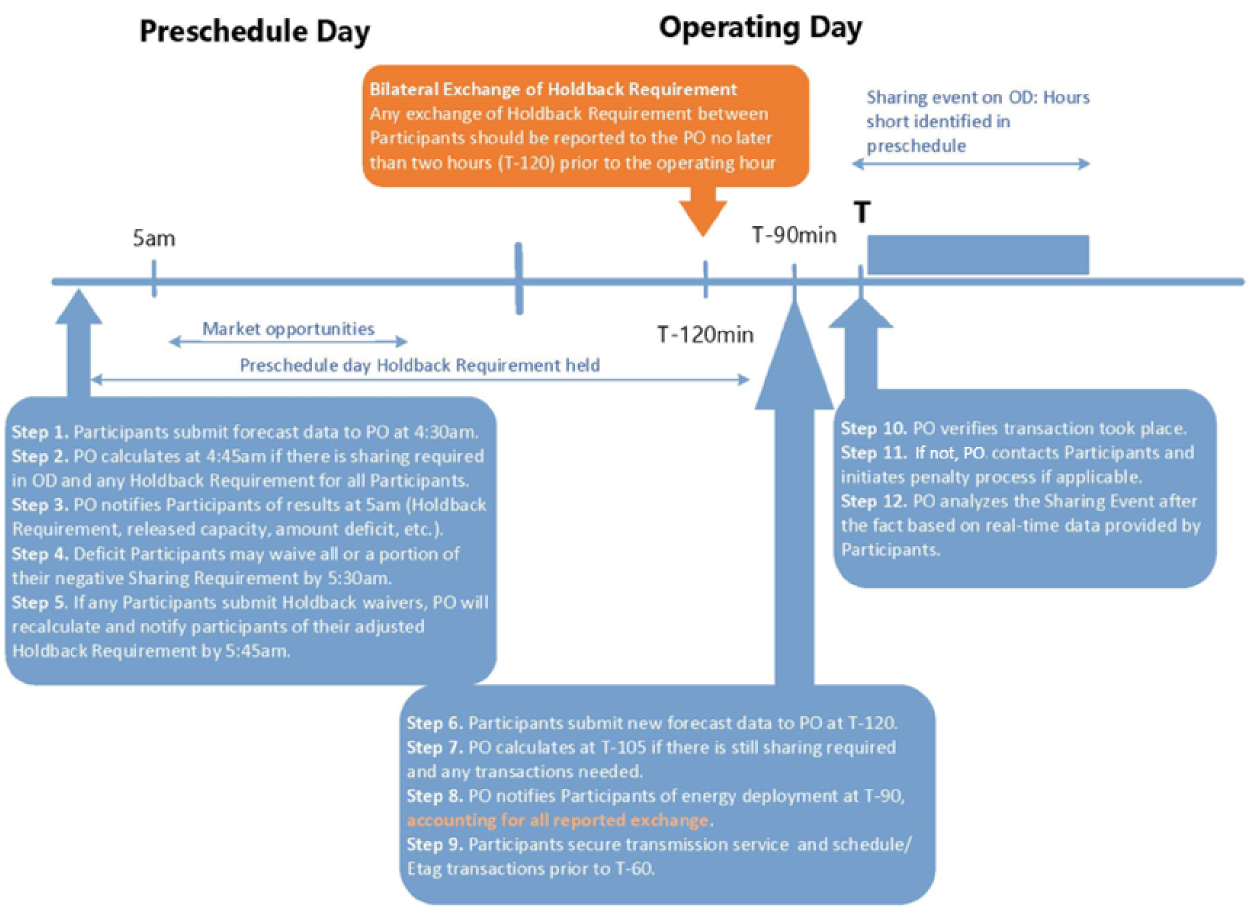


Figure 3-5. Bilateral Exchange of Holdback Requirement overlaid on Sharing Calculation timeline.

3.5. Release of Capacity

3.5.1. Day-Ahead Release of Capacity

After performing Sharing and Holdback Calculations on the prescheduling day, the PO will set the hourly Holdback Requirement for each Participant. If no Participant is calculated to be deficient for the given OD, and the PO has not applied a Safety Margin to that OD, all capacity will be released. If during the preschedule day calculations, the PO defines a Sharing Event for the given OD, the hourly Holdback Requirement for each Participant will be set. With the exception of bilateral exchange of Holdback Requirement activities, a Participant’s Holdback Requirement is capped at the initial value calculated on the preschedule day. Subsequently, any additional, unused capacity is released back to the Participant as illustrated in Figure 3-6, where L_{PS} is the net positive Sharing Requirement and S_{PS} the negative Sharing Requirement. PS refers to preschedule.

Figure 3-6. Preschedule Release of Excess Holdback Capacity.

In instances where the preschedule day is not the day prior to the OD, the Holdback Requirement will be recalculated on each incremental day.

When the preschedule day is not the day prior to the OD, the PO will rerun the Sharing Calculation each interim day. For example, on a typical Friday the PO will perform the Sharing Calculations for the coming Sunday and Monday ODs and will also rerun the Sharing Calculation on Saturday for Sunday and Monday ODs and again on Sunday for Monday OD. Each rerun of the Sharing Calculation may result in a reduction to the Holdback Requirement values for Participants, but will be capped at, and never higher than, the prior Holdback Requirement values.

Additional release of excess Holdback Requirement capacity may occur through Energy Deployment as described in Section 3.6.2.

3.5.2. Multi-Day Ahead Assessment

The Ops Program will include a Multi-Day Ahead Assessment which will provide a look ahead at the next seven ODs and determine the need for and magnitude of potential Sharing Events (see Figure 3-7). For example, on a Monday, the Multi-Day Ahead Assessment would consider Tuesday (OD-6) through the following Monday (OD). Once daily, Participants will submit hourly load, wind, solar and forced outage forecast data for the next seven ODs to the PO. The PO will then perform a look ahead calculation considering historical levels of uncertainty for forced outages and load, wind, and solar forecasts. This assessment will mimic the Sharing Calculation but will not result in assignment of Holdback Requirement to Participants. This information will be given to Participants through the Program Interface Tool.

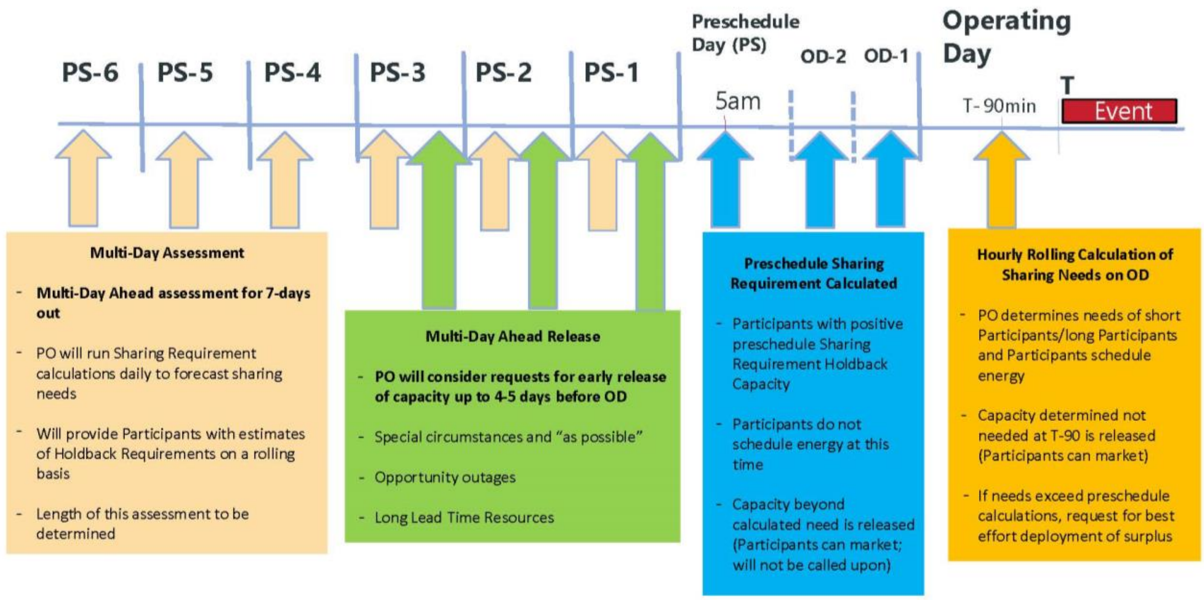


Figure 3-7. Overall Ops Program Timeline.

If the Multi-Day Ahead Assessment indicates a low risk of a potential Sharing Event, the PO may consider early release of a portion, and up to all, of the capacity held by Participants. Additionally, if the Multi-Day-Ahead Assessment indicates a potential for a large Sharing Event, the PO will notify the Participants, providing notice that they might not be able to fully rely on the Ops Program for a given timeframe, allowing Participants time to look for alternatives to meet their demand. This is anticipated to be rare event and the PO will conduct the Ops Program to avoid these situations.

3.5.3. Multi-Day Ahead Release of Capacity

Based on the results of the Multi-Day Ahead Assessment, the PO may consider the release of capacity back to the Participants. This may range from a collective release of capacity for all Participants, to an ad-hoc release of capacity at the request of Participants. Participants may submit a request to the PO for consideration of early release of a portion, and up to all, of their capacity. The PO will review requests for early release and assess the associated risks. Once capacity has been released back to a

Participant that capacity is no longer available to be called on by the Ops Program. The PO will make appropriate adjustments to the Sharing Calculation, if necessary.

The PO will create and maintain a list of acceptable reasons for Participants to request an early release. The list may include but is not limited to urgent outages that do not qualify as “forced” and long lead resources that cannot be started within the timeframe needed. The PO will develop a process for assessing a high volume of release requests where more capacity is being requested for release than what is available for early release.

NOTE: Pending a future Program Decision. Potential options are: by order of when the request was made, pro rata of all requests or prioritization by category of request. If PO determines that a Participant is regularly requesting release and therefore not contributing to holdback needs, future releases can be denied without reason.

3.6. Energy Deployment

3.6.1. Frequency of Data Submission on Operating Day

On a given OD, Participants will send data (e.g., load, VER performance, run-of-river performance, and forced outages) hourly to the PO for all remaining hours of the OD, starting at 12:00 AM on the OD. For example, at 01:00 AM a Participant would send forecast data to the PO for hour beginning at 02:00 AM through hour beginning at 11:00 PM. At 02:00 AM a Participant would send forecast data to the PO for hour beginning at 03:00 AM through hour beginning at 11:00 PM. For ease of setting up the data exchange, Participants may elect to send forecast data to the PO in a rolling 24-hour window, with the hours beyond the given OD going unused except as a last good data set due to submission errors. For more details on data submission types see Section 3.12.

3.6.2. Energy Deployment Calculation

As the Ops Program enters the OD, the Holdback Requirement that is a capacity (MW) value will be converted to an Energy Deployment which is an hourly energy (MWh) value. Energy Deployment calculations will be performed by the PO starting at 105 minutes prior to each hour (T-105) identified in a Sharing Event Window using the latest set of forecast data provided by Participants from T-120. Final Energy Deployment values (in whole MWh increments) will be communicated back to Participants at T-90.

All capacity that was not part of final Energy Deployment values is released back to Participants at this time.

The total Energy Deployment needed will equal the sum of the MWs that short entities are calculated deficient for a given hour. The Energy Deployment allocated to long entities will be a pro rata calculation of a Participant's final Holdback Requirement. Final Energy Deployment values will be set at T-120, and any exchange of Holdback Requirement amongst Participants should be reported to the PO by this time. In summary, forecast values and Holdback Requirement exchange will be provided to the PO by T-120, the PO will run Energy Deployment calculations at T-105, and final Energy Deployment values will be communicated to Participants at T-90. Figure 3-8 shows an example timeline for a Sharing Event Window from hour beginning 01:00 PM through hour beginning 03:00 PM. Any deficiencies in this calculation are covered in section 3.13.

During the performance of the Energy Deployment calculations, when any Participant is found to be deficient, the PO will notify each Participant with a negative or positive Sharing Requirement to verify. The deficient Participant may waive all or a portion of the energy due to be scheduled to them, and the PO will adjust the Energy Deployment calculation accordingly.

In the event that a Participant was calculated deficient in the prescheduling day but is no longer deficient for the hour in question based on forecast values from T-120, that Participant's Energy Deployment is set at zero. While the Participant may have excess capacity available, they did not receive an initial Holdback Requirement, and therefore will not be made to deploy energy. This is consistent with maintaining a Participant's Energy Deployment as no greater than the previously calculated Holdback Requirement. Any extreme situations for this Energy Deployment are covered in section 3.13.

3.6.3. Tagging Energy Deployment

Tagging of assigned Energy Deployment must be completed by T-60. Participants providing capacity will be responsible for deploying and tagging energy to a centroid[23]. Deficient Participants will be responsible for receiving and tagging energy from the same centroid. Participants may agree on alternate delivery, when more efficient and/or economic means of delivery are available and agreed upon between the impacted

[23] A central location on the electric grid utilized to transact power to and from in order to provide for a known location to enact RA Program deliveries.

Participants. The PO will audit actual Energy Deployments for given events, as covered in Section 3.11.

The default use of a centroid will require a hosting BAA to approve tags and ensure tags to and from the centroid initiated by the Ops Program net to zero. This will require a BAA volunteering to take on this responsibility. The volunteering BAA would have the Point of Receipt/Point of Delivery that represents the centroid within their BAA boundary. The PO may need to develop additional functionality to assist the hosting BAA in balancing the tags to and from the centroid. If the PO cannot reach an agreement with a BAA to host a centroid, tagging will be done directly between Participants.

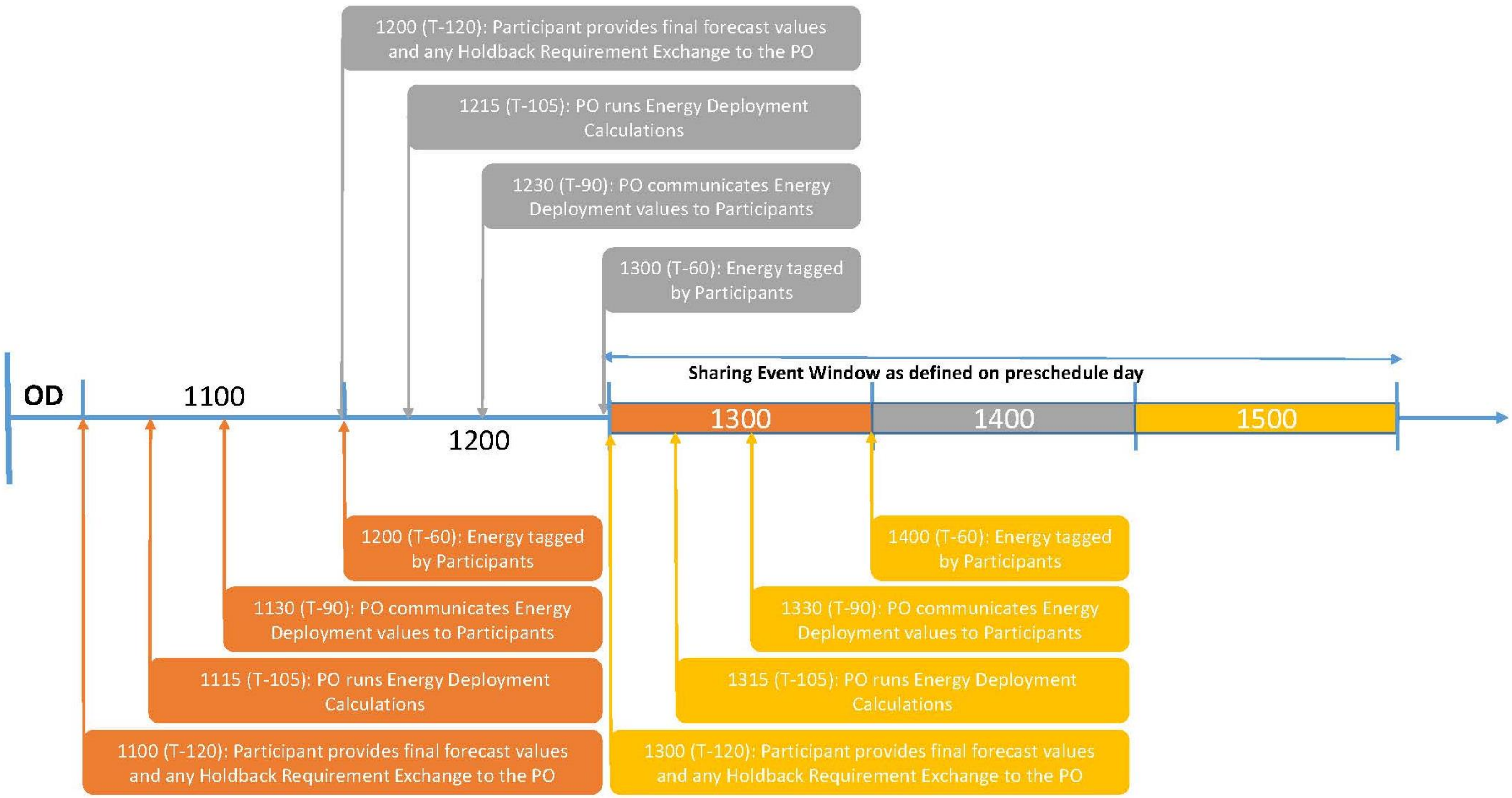


Figure 3-8. Energy Deployment Timeline Example.

3.6.4. Centroid Options

Note: Pending a Program Decision prior to determination. There is debate between the Program starting with a single centroid or up to two centroids. This section would be updated to reflect that decision once it is made.

Using centroids simplifies delivery and receipt of energy, without requiring direct Participant to Participant scheduling. This is especially helpful in instances where there are multiple deficient Participants, as a Participant may only need to deliver to a single centroid with a single tag instead of being required to tag energy to multiple Participants. Use of a centroid may also simplify allocation by the PO and exchange by Participants of Holdback Requirement and Energy Deployment. There are multiple approaches for implementing the centroid design which are discussed in the following subsections. Note that with all of these options, Participant to Participant exchange of Holdback Requirement and Energy Deployment is allowed. Bypassing a centroid to tag energy directly between Participants is also acceptable.

3.6.4.1. Single Centroid

The single centroid approach is the most simplistic option and would most likely make use of the existing Mid-C Trading Hub. By default, all energy delivered through the Ops Program would source to and from the one centroid. A single centroid would allow for an aggregation of schedules in the case that multiple Participants are delivering energy to the same deficient Participant. The approach also simplifies exchange of Holdback Requirement and Energy Deployment between Participants and simplifies settlements. The major drawback to using a single centroid is that there is not a single delivery point in the footprint that is equally accessible by all Participants and use of the Mid-C Hub would require potentially expensive legs of additional transmission by a subset of Participants.

3.6.4.2. Two Centroids without Shared Transmission between Centroids

The two centroid approach would likely use the Mid-C Trading Hub as one of the centroids, and then identify a second centroid that is more easily accessible by Participants not located close to Mid-C. There are a few ways in which the two centroid approach may be implemented. Specifically, an option without exchange between the centroids, covered here, and an option without exchange between the centroids, covered in the following section.

In the method without exchange between the centroids, each Participant chooses which centroid they want to interact with, and all assigned delivery to or receipt of energy takes place at that centroid. This essentially splits the Program into two, with Participants only sharing diversity benefit with other Participants that are associated with the same centroid.

A possible variation of the approach without exchange is for Participants to continue to deliver energy to their preferred centroid, but deficient Participants take receipt of energy from both centroids, as available. In this variation, the burden is placed on the deficit

Participant to receive energy as provided by the delivering Participants to their chosen centroids. If multiple Participants are deficient, the PO may optimize delivery of energy between the two centroids.

The two centroid approach increases accessibility to the Ops Program for those Participants that are not located near Mid-C and may facilitate Ops Program expansion due to that accessibility. Depending on how the second centroid is implemented, diversity benefit may be impacted. This option also complicates the PO's role of allocating Holdback Requirement and Energy Deployment, while also complicating settlements. Ideally, the two centroid approach will maximize value with these centroids having ample delivery between each other, as covered below in section 3.6.4.3.

3.6.4.3. Two Centroids with Shared Transmission between Centroids

This two-centroid approach is similar to the option described in the section above, with the addition of transmission between the centroids being reserved on behalf of the Ops Program with associated costs being shared by all Participants. Each Participant would choose their preferred centroid and would deliver and receive all energy from that centroid. The PO would calculate the net of energy to be delivered from one centroid to the other.

Like the previous two centroid option, this approach increases accessibility to the Ops Program for those Participants that are not located near Mid-C and may facilitate Ops Program expansion due to that accessibility. This approach also allows for access to the entire footprint's diversity without complicating the PO's role of allocating Holdback Requirement and Energy Deployment.

There are several challenges with this approach. It is unclear who would be responsible for reserving centroid-to-centroid transmission, and it potentially complicates settlement of Energy Deployment. This approach also complicates the exchange of Holdback Requirement and Energy Deployment between Participants. It would most likely be acceptable for Participants with the same assigned centroid to exchange these products. However, exchange of Holdback Requirement between Participants with different assigned centroids might not be allowed if the result was an increase of the potential centroid to centroid transfer. Also, exchange of Energy Deployment between Participants with different assigned centroids would not be allowed as it would change the amount of energy to be tagged between centroids, and the PO would need that value to be static once Energy Deployment values were assigned 90 minutes prior to a given hour on the OD. Lastly, how transmission service will be allocated between centroids, across the RA Program footprint.

3.6.5. Scheduling Deadline

The Ops Program will use T-60 as the scheduling deadline for tagging Energy Deployment. Participants will receive their final Energy Deployment value for a given operating hour at T-90 and have until T-60 to tag that energy. The T-60 timeframe allows for the tagged energy to be included in the Western Energy Imbalance Market (EIM) energy sufficiency tests and other data inputs to the EIM. The PO will not verify tags during OD. This check will be done after the fact as defined in Section 3.12.4 below.

3.6.6. Bilateral Exchange of Energy Deployment

Participants will be allowed to exchange Energy Deployment. Participants will receive their final Energy Deployment value for a given operating hour at T-90. Participants then have up until T-60 to exchange their Energy Deployment with other Participants as long as all final Energy Deployments are tagged prior to T-60. The PO will host a virtual bulletin board to help match Participants wanting to lower their assigned Energy Deployment with Participants requesting to take on additional Energy Deployment. Participants will utilize the bulletin board to initiate and coordinate the exchange of their Energy Deployment with other Participants. Participants will notify the PO of any changes made to their assigned Energy Deployment after the fact.

3.7. Transmission Service

Transmission service will be required to support the delivery of energy in the Ops Program. This section of the report covers the requirements of transmission service in the Ops Program.

3.7.1. Securing Transmission for Delivery to Load

On PS-1, if at least one entity is forecasted by the PO to have a negative sharing calculation for at least one hour, all entities will be responsible for demonstrating additional NERC priority 6/7 transmission for that hour(s). FS Program requirements for procuring transmission from generating resource to load and transmission firmness apply (see Section2.8).

The additional procurement obligation will be the difference between a Participant's transmission demonstrated at FS and what is forecasted necessary for their load [Hourly PS Tx obligation = hourly load forecast – (0.75*FS Requirement) + forecasted hourly holdback]. As in the FS portfolio, this requirement can be met with transmission rights or contracts with appropriate transmission provisions. Transmission must be acquired by the end of the PS day.

Example

Participant A's P50+PRM is 1000 MW, has demonstrated >750 MW. PS-1 forecasts a Participant (different Participant) with a negative sharing calculation. Participant A's forecasted load is 800 MW, and they are forecasted for a 30 MW holdback. They will be responsible for demonstrating NERC priority 6/7 transmission for an additional 80 MW from an RA resource or an alternative reliable source of supply.

3.7.2. Firmness of Transmission Service Requirements

Unless coordinated otherwise between Participants, transmission service will be scheduled for Energy Deployment to a centroid for delivery in the Ops Program. (See Section 3.6.3). In this arrangement, Ops Program Participants who are scheduled long will be designated to deliver energy to a centroid. Ops Program Participants who are scheduled short will be designated to take delivery from this same centroid. This will result in a set of delivering Participants and one or more receiving Participants.

It will be the obligations of the delivering Participant that the service available is dependable and reliable in delivery. The delivering Participant will enact delivery either to the centroid or in a direct-delivery arrangement (as described in Section 3.6.4). As such, the delivering Participant is strongly encouraged to secure firm transmission service for the Ops Program. If the delivering Participant secures firm transmission service and is still unable to deliver the energy due to transmission complications, such as curtailment, then the delivering Participant will be exempt from Delivery Failure Penalties. If the delivering Participant utilizes non-firm transmission service for delivery, and the delivery results in failure, then that Participant will be exposed to Delivery Failure Penalties (see Section 3.11).

The receiving Participant is responsible for securing transmission service for receipt of energy from the centroid or in a direct-delivery arrangement (as described in Section 3.6.4). It is strongly encouraged that the receiving Participant secure firm transmission service for the delivery. However, the receiving Participant will secure the available transmission service at its own risk and at the level, which is reasonably reliable. Failure of the receiving Participant to secure transmission does not relieve the receiving Participant of requirements to pay settlement for requested Energy Deployment.

Participants should be aware of and follow current Open Access Transmission Tariff (OATT) practices when securing transmission service. Each Participant, when redirecting long-term firm service, needs to be aware of how these redirects will change the prioritization of that service (e.g., long-term firm being redirected as short-term non-firm).

3.7.3. Securing Transmission Service

Each Participant shall assess the need for securing transmission service for the Ops Program months ahead, day-ahead, or hour-ahead. This assessment should be based on the likelihood of the need to deliver energy in these periods, the risk associated with the securement of service, and the cost associated with carrying the service. For example, for paths that have a known risk for the award rate of service, Participants should work to anticipate this risk and potentially secure transmission. Conversely, for paths that are low risk for being denied transmission service, it may be more prudent for a Participant to secure service on a day-ahead or hour-ahead basis.

Additionally, while the transmission service associated with the FS Program typically is configured for delivery to each Participant's respective load, the Ops Program is configured for delivery to a centroid or receipt from a centroid. While it may be possible to redirect long-term transmission service, as needed, Participants need to be aware of what is available and the impact on prioritization of service.

3.7.4. Role of PO with Respect to Transmission Service

The PO may review Participant's transmission obligations as outlined above, and the PO will always review delivery failures of RA resource when there is a sharing or reliability event. Participants that request a sharing holdback or delivery, fail to provide a holdback or energy deployment when requested, or experience a reliability event are subject to such review. The PO may request information from Participants pursuant to such review activities. Consequences and penalties for issues identified in these reviews will be considered further in Phase 3A and will be viewed in light of whether: 1) another entity is harmed, or 2) no harm is experienced. There may be exceptional regional events where penalties would be waived. Further considerations related to potential repercussions could relate to delivery of specific resources (e.g., increasing the transmission demonstration quantity at showing deadline for the following year by failure quantity).

Ultimately, it is the responsibility of each Participant to secure transmission service such that it has a reasonable likelihood of being awarded in times of shortfall. The Participant should work with the PO on known issues with the procurement of transmission service. The PO will maintain a list of paths which are known to have risk to the award rate and provide notice of when these paths are to be needed in the determination of delivering and receiving parties.

3.8. Deliverability Assessment & Path De-Rates

The PO will not make engineering calculations as to the availability of the transmission service. This responsibility will remain the role of the Transmission Service Provider (TSP) facilitating the acquisition of service. The PO will not be responsible for monitoring transmission system outages that affect deliverability. The role of the PO is in the reporting and facilitation of information in situations where a transmission path may pose risk to the reliability of energy delivery. In these situations, the PO will post information on at-risk transmission paths to the notice of all Participants. Additionally, if Participants become aware that a path may be at-risk, it is obligated to report this information to the PO for consideration. The PO will post this information on a bulletin board system such that all affected Participants are aware of the situation.

If the path de-rate happens prior to the preschedule day, the PO will recalculate the Holdback Requirements on an as needed basis. This will result in a total Holdback Requirement that takes into consideration the inability to secure delivery across the affected transmission paths due to known path de-rates. For path de-rates that occur any time after the preschedule day, the Holdback Requirements will not be recalculated and will remain as posted. The existing Holdback Requirements include both uncertainty, as well as a safety margin, that is meant to account for variance between the preschedule and OD. These additional buffers should be sufficient to account for the majority of these occurrences. In instances where the margins are not adequate, and there is still a shortfall for Participants, emergency procedures will be enacted (see Section 3.14).

3.9. Settlements

3.9.1. Energy Deployment and Holdback Settlement

3.9.1.1. Pricing and Settlement Principles

To ensure a well-functioning RA Program, it is critical that the settlement pricing be calculated appropriately. Pricing should encourage entities with a negative Sharing Requirement to address capacity shortfalls using other means before accessing the program's pooled capacity. When those entities with a positive Sharing Requirement holdback and/or deliver energy, the pricing should adequately compensate their contribution to the program without being punitive to entities truly in need.

The calculation of settlement price should conform to the following principles:

- Utilize existing systems/processes (bilateral transactions)
- The Program Operator or Administrator may calculate the settlement amount but has no role in the transaction
- Requests for holdback capacity and requests for energy delivery should each be priced to incent Participants to utilize pooled capacity as the resource of last resort
- Energy delivery prices should not be punitive to buyers. Though, an entity truly in need of help should pay a fair price.
- Sellers should be fairly compensated for requested holdback capacity and/or delivered energy. Prices should include opportunity costs.

3.9.1.2. Settlement Price Calculation

The proposed settlement price is based on the California Independent System Operator (CAISO) methodology for implementing Federal Energy Regulatory Commission (FERC) Order 831. This methodology has the benefit of having been developed with significant stakeholder input, was presented to, and accepted by FERC, is shaped using a shaping factor that reflects changes in energy/capacity value from hour to hour and can be based on locational indices (Mid C, Palo Verde (PV) as examples.

The settlement price is based on a regional index price, shaped hourly, plus a 10% adder.

Definition: Total Settlement Price
$$\textbf{Total Settlement Price} = \textbf{Hourly Shaping Factor} \times \textbf{Applicable Index Price} \times 110\%$$
Where: – The **Hourly Shaping Factor** is selected based on the most recent High-Priced Day. A High-Priced Day is a when at least a single hour in the day has a system marginal energy cost (SMEC) greater than $200. If no High-Priced Day exists in the current season, it will look to the most recent High-Priced Day of the same season in previous years. $$= 1 + \left[\frac{\boldsymbol{CAISO\ Hrly\ DA\ SMEC - CAISO\ Avg\ DA\ SMEC(on\ or\ offpeak\ hours)}}{\boldsymbol{CAISO\ Avg\ DA\ SMEC(on\ or\ offpeak\ hours)}}\right]$$ – The **Applicable Index Price** is the day ahead heavy load/light load (HL/LL) ICE Index price based on the location of the delivering entity. For example, this may be the Mid-C or PV price published for the day and hour when the holdback and/or energy is requested.

3.9.1.3. Application of the Settlement Price

The Settlement Price is split into two components, 1) a capacity price for confirming the need for a holdback in preschedule, referred to as the **Holdback Settlement Price**, and 2) an energy price charged for any energy dispatched in the operational program after a holdback has been confirmed, referred to as the **Energy Settlement Price**.

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

Definition: Energy Declined Settlement Price
Energy Declined Settlement Price $= \text{lesser of} \begin{cases} \textit{Applicable Hourly Index (TBD)} \\ \textit{Settlement Price} \times 80\% \end{cases}$
80% factor ensures that sellers will receive at least 20% for carrying holdback regardless of energy deployment. Factor can be discussed and adjusted.
Definition: Holdback Settlement Price
Holdback Settlement Price $= \textbf{Total Settlement Price} - \textbf{Energy Declined Settlement Price} + \textbf{Make Whole Adjustment}$
Final Settlement For Any Applicable Hour
$\textbf{Final Settlement (for any applicable hour)} = (\textbf{Holdback Settlement Price} \times \textbf{Holdback MW Requested}) + (\textbf{Energy Settlement Price} \times \textbf{Operational Energy MWh Dispatched})$

3.9.1.4. Other Considerations

It is assumed that the holdback and delivery will primarily occur on Heavy Load hours. The shaping factor is calculated for all hours of the day, so it is possible to calculate a Light Load holdback and delivery settlement price using the corresponding Light Load index. For example, the PO may add additional hours to the start or end of a forecasted sharing event that might include Light Load hours.

As well, in order to ensure that participants asked to provide holdback are kept whole (compared to making a daily market sale), and in keeping with the “last resort” principle above, a Make-Whole Adjustment will also be calculated. The Make-Whole Adjustment will be calculated in such a way as to attempt to ensure that any participant that is required to provide holdback to others will be no worse off than if they were able to sell the maximum hourly amount of the holdback obligation into the daily market, within reason.

This proposal does not address issues such as settlement mechanics, credit/collateral considerations, invoicing etc. It is presumed that these details are of less importance than price formulation and will be addressed in a later phase of the project.

It should be noted that the final details of the deployment and holdback settlements are still being discussed by the participants and will be finalized in coming phases.

3.9.2. Transmission Service

Transmission service charges will follow existing OATT practices for the respective TSP. The delivering Participant is responsible for transmission service charges of delivery. The receiving Participant is responsible for transmission service charges of the receipt.

3.10. Interaction of Ops Program and EIM / EDAM

There will be minimal coordination required between the Ops Program and the EIM and Extended Day-Ahead Market (EDAM).

Note: EDAM is still pending, and these details are highly subject to change. Currently, there are no expected adverse impacts of the EIM or EDAM and the NWPP RA Program.

The Sharing Calculation for Holdback Requirement is done on the preschedule day and any interim ODs at 05:00 AM, prior to the EDAM Sufficiency Evaluation performed between 09:00-10:00 AM. Participants with an assigned Holdback Requirement will not bid that capacity in the EDAM. If a Participant has exchanged their assigned Holdback Requirement to another Participant prior to the EDAM Sufficiency Evaluation, that Participant may then bid that capacity in the EDAM. Participants that are deficient and are expecting support from the Ops Program based on the results of the Sharing Calculation may count the expected support as capacity in the EIM/EDAM sufficiency evaluation.

Tagging of assigned Energy Deployment from the Ops Program is to be done no later than 60 minutes prior to the operating hour (T-60). This timing requirement ensures that Energy Deployment tags are considered as inputs for the EIM calculations.

3.11. Failure to Deliver Energy Deployment

3.11.1. Notification of Failure to Deliver Energy Deployment

An Ops Program Participant that receives an hourly Holdback Requirement is responsible for Energy Deployment up to that assigned Holdback Requirement value as identified by the PO during the preschedule day. If a Participant with a Holdback Requirement anticipates that they will not be able to cover an Energy Deployment that Participant should notify the PO as soon as possible and at least 120 minutes prior to a given hour (T-120) during the OD. A Participant has up until T-120 to exchange their Holdback Requirement and may pursue this exchange to avoid a potential delivery failure. The PO will then adjust the pro rata Energy Deployment calculation for the anticipated shortfall, resulting in a higher Energy Deployment for the remaining Participants that have a Holdback Requirement. In the case where there is not enough Holdback Requirement to cover the deficiency after accounting for any anticipated delivery failure, Energy Deployment will be capped at the Holdback Requirement values and the PO will implement emergency procedures (Section 3.14). A Participant who notifies the PO prior to T-120 of a potential failure to deliver Energy Deployment is seen as having a delivery failure, regardless of whether remaining Participants are able to cover the shortfall.

If the PO is notified by a Participant after T-120 of a potential delivery failure, the PO will not make adjustments to Energy Deployment for that potential delivery failure. In this instance of late notification of delivery failure, the PO will implement emergency procedures where applicable.

3.11.2. Assessing & Waiving Penalties for Delivery Failure

A Participant that notifies the PO of a potential failure to deliver Energy Deployment, and/or fails to deliver their assigned Energy Deployment, may be subject to penalty. The PO will develop and maintain a process for the evaluation of delivery failures as agreed upon by the Participants. The PO will utilize this process to assess and grant waivers to Participants for failing to deliver Energy Deployment.

If the PO determines that the Participant’s reason for delivery failure is valid, penalties may be waived. All cases of delivery failure will be reviewed by a Committee of Participants, described in the section below. The Review Committee will look for persistent delivery failures, as well as review special case circumstances.

3.11.3. Delivery Failure Review Committee

The RA Program will create a committee to review waiver disputes from Participants and excessive delivery failures by individual Participants for a given season. The RA Program will be responsible for developing and maintaining a process for selecting committee members, and that committee will agree on the details of the review process.

The committee will convene, first reviewing any waiver disputes submitted by Participants for delivery failures during that season, and then assessing if any Participants had an excessive number of delivery failures during that same season. Any Participant that has three or more non-waived instances of delivery failure in a single season will be subject to review by the committee. The Participant will be given the opportunity to explain the circumstances that led to their failure to deliver, and the committee will then make an assessment. Possible consequences of excessive delivery failure range from increasing the FS Capacity Requirement by the average capacity that the Participant failed to deliver, to expulsion from the RA Program. Expulsion may be permanent or for a defined number of seasons.

The RA Program and a review committee will allow for flexibility in the first binding season of the Ops Program and refine the details of the review process as experience is gained. The review process will be aligned with criteria for entering and leaving the RA Program.

3.11.4. Load Shedding Responsibility

In the event that Holdback Requirement totals are less than the need from deficient Participants and load shed is imminent, the deficient Participant(s) will bear the burden of shedding load via existing procedures and programs by the associated BAA. 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 PO 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 BAA 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. The Participant that failed to deliver will not be requested to shed load but would instead be subject to the penalty process.

3.11.5. Penalty for Delivery Failure

Participants who fail to deliver their assigned Energy Deployment and do not secure a waiver for that failure will be subject to penalty (see Table 3-5 for examples of penalty calculation). Collected penalties for failure to deliver Energy Deployment will be used to offset the administrative cost of the RA Program. The penalty for not delivering the assigned Energy Deployment depends on the impact of the failure on the deficient Participant(s).

Table 3-5. Penalty calculation examples.

Definition: Penalty for delivery failures	
If a Participant fails to provide energy and that deficit is entirely covered by other Participants of the Program, the proposed penalties are as follows:	
First non-waived delivery failure	5 times the index price of the default centroid for the undelivered megawatt hours (MWhs)
Second non-waived delivery failure	10 times the index price of the default centroid for the undelivered MWhs
Third or more non-waived delivery failure	20 times the index price of the default centroid for the undelivered MWhs and be cause for review for expulsion by the committee as defined in Section 3.11.3
If a Participant fails to provide energy and that deficit is not entirely covered by other Participants of the Program, the penalties are as follows:	
First non-waived delivery failure	25 times the index price of the default centroid for the undelivered MWhs
Second or more non-waived delivery failure	50 times the index price of the default centroid for the undelivered MWhs and be cause for review for expulsion by the committee as defined in Section 3.11.3

The above penalty schedules are meant to be used as applicable and are not separate tracks. For example, if a Participant's first non-waived delivery failure is covered by other Participants, the penalty would be set at 5 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 penalty would be set at 50 times the index price.

3.12. Data Submission Requirements for Ops Program

Participants are required to submit the data in Table 3-6 to the PO. For each data type, the Participant should submit data for the start of each hour (i.e., hour beginning). Figure 3-9 presents a high-level data submission timeline. The data submission guidelines will be further described in more detail during system design in a later stage of the Program design (See SPP presentation on Program Interface Tool). For example, OD 0900 will cover 09:00 AM – 10:00 AM. The data will cover all hours in each operating window, as described in subsequent sections. The generation data will be submitted on a resource level (e.g., wind forecast, solar forecast, forced outages, etc.). The remainder are on a Participant level.

Table 3-6. 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
Megawatts forced out and de-rated generation by plant
Reliability generation unit de-rates for all hours
Transmission path de-rates impacting firm contracts from the FS Program

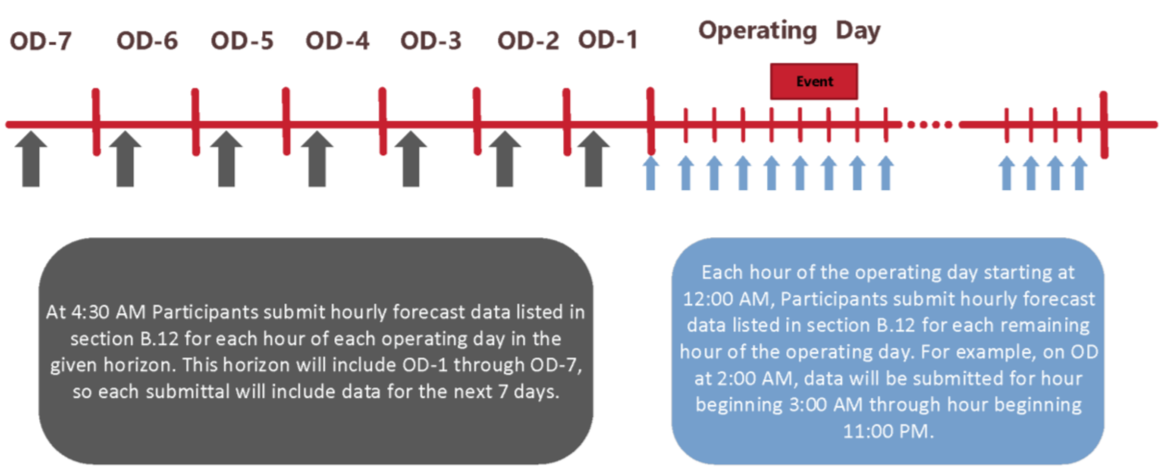


Figure 3-9. Timeline for data submission.

3.12.1. Multi-Day Ahead Data Submission

Each day, at 04:30 AM, Participant will submit data for each OD in the given horizon. This horizon will include OD-1 through OD-7. For each day in the forecast, Participants will submit hourly data listed in Table 3-6. This data submission will include 24 hourly periods for each of the submission days listed.

3.12.2. Operating Day Data Submission

On the OD, starting at 12:00 AM, each Participant shall send the data as listed in Table 3-6 for each remaining hour of the OD. This data will continue on each subsequent hour and include each hour remaining for that OD. For example, on OD at 02:00 AM, data will be submitted for hour beginning 03:00 AM through hour beginning 11:00 PM.

3.12.3. Data Submission Errors and Validation

Data submitted to the PO 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 PO will contact the Participant in order to get the errors rectified. If this is not possible, the PO will use the last good data set in order to increase the accuracy of the Ops Program calculations.

3.12.4. After Fact Data Submission

Each Participant will submit to the PO actual data for the data sets listed in Table 3-6. This data will be used by the PO to perform statistical analysis for increased forecasting accuracy. Additionally, the data will be assessed to verify that Ops Program deliveries and holdback were accomplished according to the instruction of the PO. Data will not be shared with any external parties, with the exception of special requests such as from regulatory agencies. The timelines for submission of this data will be developed by the PO at a later date.

3.13. Notification Process

The PO will facilitate a program interface tool that will be used as the primary means of communication between the PO and Participants. The PO will use this tool to notify Participants of: Multi-Day Ahead Assessment results, known WECC path de-rates, Sharing Events, assigned Holdback Requirement and Energy Deployment. Participants will use this tool to acknowledge receipt of Holdback Requirement and Energy Deployment. Participants may also use this tool to inform the PO of any exchanged Holdback Requirement or Energy Deployment. If the PO does not receive acknowledgement of receipt of Holdback Requirement or Energy Deployment in a timely manner, the PO will follow up with verbal communication to the Participant. Participants should communicate all delivery failure notifications to the PO verbally and in writing.

3.14. Emergency Procedure

In times when the Ops Program is unable to support a deficient Participant through typical procedures, the PO may use the Emergency Procedure to call for additional help from the Participants at large. The Emergency Procedure may be used to call for additional capacity or energy as applicable. Emergency Procedure calls 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.

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 RA footprint as a whole is insufficient. In this instance, all Participants with a positive Sharing Requirement would have 100% of their Sharing Requirement assigned as Holdback Requirement. The PO would then issue an insufficiency notification to all Participants, and request for Participants to provide additional capacity to the RA footprint. The PO would then work with any willing Participants that volunteered additional capacity to the pool and adjust Holdback Requirements as applicable.

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%. The PO will then issue an insufficiency notification to all Participants, and request for Participants to provide additional energy to other Participants. The PO would then work with any willing Participants that volunteered additional energy to the other Participants and adjust Energy Deployment as applicable. Consistent with Section 3.11.4, following exhaustion of the Emergency Procedures, load shedding responsibility or other mitigation of the remaining deficiency rests as the responsibility of the deficient Participant(s).

3.15. Review of Design Elements After First Season

The following sections of the Operational Design document cover topics for future consideration. These are areas that SPP feels the PO should evaluate and monitor to improve the Program. The PO should monitor the health and performance of the RA Program and continually endeavor to make it better. This section provides some key areas in which this work could focus.

After the Ops Program has run for at least one season, the Participants and the PO will have gained experience and may decide to analyze and adjust design elements of the Ops Program. The Ops Program and processes as initially designed are based on assumptions that are believed to provide the best possible results for all Participants. This is done by balancing the following objectives: maintain reliability, operate under an acceptable risk threshold, provide equitable benefits and costs across all Participants, fair treatment of all Participants and a low operating cost. As the PO and Participants gain experience with the Ops Program, adjustments will continue to keep the Ops Program in line with these objectives.

Potential areas to analyze and fine-tune include:

- Number of Sharing Events determined by Sharing Calculation
- Magnitude and use of uncertainty
- Magnitude and frequency of use of safety margin
- Location of centroid(s)
- When to add a buffer hour to the beginning and end of each Sharing Event
- Variance of Participant's load and wind forecast accuracy and whether to incorporate into the Sharing Calculation
- Whether the penalty structure for delivery failures correctly incentivizes Participants to minimize delivery failures
- The impact the Ops Program has on Participants depending on the makeup of their capacity portfolio
- Use of Multi-Day Ahead release of capacity, weighing operational risk against economic benefit

- Compensation/Settlement are correct incentives for Participants to use the program as a Resource of Last Resort, and not the first option

3.16. Review of Design Elements for Future Consideration

While designing the Ops Program, the development of several design elements was put on hold. These design elements were deemed to have merit but were considered overly complex for the initial Ops Program. After the Ops Program has been finalized and in place for at least one season, the PO may review these future design elements, using historical data from the Ops Program to determine their benefit and work with Participants to make enhancements to the Ops Program where applicable.

3.16.1. Multi-Stage Sharing Calculation

Participants that have a generation mix that is heavy in renewables may have a different experience in the participation of their resource fleet compared to more traditional type of generation fleets. This is due to the over performance of wind, solar and un-of-river generation being included in the Sharing Calculation, and those resource types being accredited at a lower percentage than thermal resources in the FS Program. As such, the expected availability of these types of resources can be highly volatile and is reliant on given system conditions.

To account for the impact, the Ops Program could implement a multi-stage Sharing Calculation (see Table 3-7). The first stage would consider only the load diversity benefit of the Ops Program, and not account for over performance of wind, solar and run-of-river generation. If stage one did not provide enough diversity benefit to cover all deficient Participants, stage two would then consider the resource diversity benefit, and include the over performance of wind, solar and run of river in the Sharing Calculation.

Table 3-7. Multi-stage Sharing Calculation.

Definition: Multi-stage Sharing Calculation
Sharing Calculation A: **[FS Capacity Requirement – ΔForced outages – VER under performance + VER over performance – Run-of-river under performance + Run-of-river over performance]** **– [Load Forecast + Uncertainty + CR]**
Sharing Calculation B: **[FS Capacity Requirement – ΔForced outages – VER under performance – Run-of-river under performance]** **– [Load Forecast + Uncertainty + CR]**

The PO would first perform Sharing Calculation A to determine if any Participants are deficient. This ensures that a Participants over performance of VERs and run-of-river resources are considered. If a Sharing Event is identified, the PO would use Sharing Calculation B to calculate the Holdback Requirement for all long Participants. Then, if Sharing Calculation B does not result in enough capacity to cover the deficient Participant, then Sharing Calculation A would be used to supplement the remaining Holdback Requirement. Note that it may be desirable to set the Holdback Requirement from Sharing Calculation B as a minimum value before rerunning Sharing Calculation A. Otherwise, depending on the makeup of a Participants fleet, their Sharing Requirement may be lowered.

3.16.2. Seasonal Look Ahead Assessment of Sharing Events

The Ops Program will be binding for a total of eight months (a four- and one-half month Winter season and a three- and one-half month Summer season) in a twelve-month cycle. For the given binding season, a Participant is required at any time to be able to meet their FS Capacity Requirement as calculated in the FS Program. This obligation may not leave adequate time for Participants to perform planned maintenance outages on their fleet of resources. Though the RA Program is binding throughout the seasons as defined (see Table 3-1), there are times at the beginning and end of a given season when Sharing Events would be unlikely. While a Participant may not have the necessary data to analyze and determine the risk of performing planned maintenance on these seasonal shoulders, the PO does have high-level awareness of the RA footprint and is in a position to help Participants determine the likelihood of a Sharing Event for a specific timeframe.

The PO could perform a look ahead Sharing Requirement Calculation for each upcoming season and share the results with all Participants. The calculation would use historically conservative values instead of forecasted values (high load, low wind, low solar, high forced outage rate) and provide results with weekly granularity. This would approximate a worst-case estimation, calculating the odds of having a Sharing Event for a given week within the season, and provide a potential Holdback Requirement for each Participant. Participants could then use the results of this calculation to schedule maintenance outages while lowering the risk to the RA Program as a whole. One point for further discussion would be what risks Participants are allowed to take in regard to scheduling maintenance outages during a binding season, and if the preschedule day Sharing Calculation will take into account results of the look ahead assessment. Currently, maintenance outages are "at the risk of the Participant". This step would be purely informational to each Participant to use as they see appropriate.

3.16.3. Monitoring the Health of the RA Program

The PO may desire to monitor the health of the RA Program throughout the season. This would require additional data from Participants in order for the PO to calculate the RA of the footprint for each OD.

Potential inputs to the calculation:

- Total usage of capacity of conventional resources
- Scheduled and forced resource outages
- De-rates of conventional generation
- De-rates of hydro considering available water in river and reservoirs
- Load, wind, and solar forecasts based on most accurate available weather forecast
- Known import and export commitments of each Participant
- Offline, longer lead time capacity not available within time frame of the assessment
- Operating reserves

Given the amount of data needed, the PO would need to work with Participants after operating the Ops Program for several seasons to determine the added benefit. Considerations for discussion include: if the Participants can make the required data available to the PO, whether data would be submitted for individual resources or aggregated by resource type, the accuracy of forecast data, how often the health check would be initiated and what actions the PO may take based on results.

3.16.4. Optimizing Holdback Requirement

The PO could do optimization of Holdback Requirement utilizing manual adjustments for efficiency. Prior to the start of a season the Participants would agree on guidelines for optimization. The optimization should result in changes to Holdback Requirement assignments that are more efficient and cost effective.

Some possible guidelines for consideration:

- When several Participants are calculated short, use a zonal approach to match those Participants who are deficient with long Participants that are closest in proximity.
- A minimum threshold for Holdback Requirement such as 5 MW. If a Participant is calculated to have a Holdback Requirement under the defined threshold that Participant's Holdback Requirement would be set to zero, and the corresponding amount would be allocated to the remaining long Participants.

This sort of manual approach would not require sophisticated software and automation but would require more staff time and human intervention which could introduce risk of mistakes or inefficiencies. After implementing a manual optimization process for several seasons, there could then be a decision made of whether to implement more sophisticated optimization software.

Optimization should only be done on the day prior to the OD, and not on the preschedule day when the preschedule day is more than one day prior to the OD. Participants may still utilize Holdback Requirement exchange but should wait until after the optimization by the PO is conducted.

3.16.5. Settlement of Optimized Holdback Requirement

The optimization of Holdback Requirement would necessitate the development of a settlement process for the optimization. The PO could track the unused portion of the Holdback Requirement optimization exchange for each Participant over a season. The balance could be MW based or potentially dollar based if Participants agreed on a pricing mechanism for the exchanged capacity. Participants may settle their balance after each season, or it could be decided to roll balances forward to the next season. The PO would be able to calculate the amount owed from and to each Participant and issue bilateral schedules between Participants to settle all balances.

3.16.6. Capacity Ratio

Note: On 4/09/2021 the Operations Design Team voted on support for Capacity Ratio. The majority of Participants did not feel it was the preferred solution. As such, it has been removed from the base design and deferred for future consideration.

The RA Program may later decide to include a Capacity Ratio, exclude a Capacity Ratio or have it as an option for each Participant to select for their participation in the Program.

To accommodate the reporting of outages across the percentage of capacity in the Ops Program versus surplus capacity beyond the Ops Program, one possible recommendation put forth has been the addition of a Capacity Ratio to the Sharing Calculation, as shown in Table 3-8.

Table 3-8. Capacity Ratio.

Definition: Capacity Ratio
Sharing Requirement = **[FS Capacity Requirement + Capacity Ratio** * (-ΔForced outages + Δ Run-of-river performance + ΔVER performance)] – [Load Forecast + CR + Uncertainty]
Capacity Ratio = **(FS Capacity Requirement)** / Total Portfolio QCC

This additional multiplier would adjust the Sharing Requirement for each Participant and allocate variances in the ΔForced outages, Δ Run-of-river performance, ΔVER performance terms across the portfolio of each Participant. The impact of this addition would decrease the Sharing Requirement for both over and under performance of these terms. This option assumes that during capacity-limited periods, Participants will utilize their surplus in order to help make themselves whole. Additionally, the calculations will increase the surplus of Participants during times of over performance.

SECTION 3: APPENDIX A – PROCESSES & PROCEDURES

A.1. Summary of Processes and Procedures the PO Will Develop & Maintain

Program Administrator processes and procedure framework:

- **PO: Perform Sharing Calculations** – Procedure that the PO will follow for performing the Sharing Calculation in determining Holdback Requirements, Sharing Event Windows, and Sharing Requirements. This includes steps for setting the variable inputs to the Sharing Calculation and provisions for re-running the Sharing Calculation. The procedure also specifies steps for evaluating results and communicating to Participants.
- **PO: Sharing Event Analysis** – Procedure that defines how to perform post Sharing Event analysis, when to initiate the penalty process, and provisions for evaluating penalty waiver requests.
- **PO: Address Participant Notifications** – Procedure guide that outlines the expected PO actions in response to various Participant notifications. This includes, but is not limited to, transmission limitations, replacement capacity concerns, inability to meet Energy Deployments, bilateral exchanges, and early release requests.
- **PO: Emergency Procedure** – Procedure that includes steps for identifying when the Ops Program is unable to support a deficient Participant and how to implement the Emergency Procedure for volunteer assistance.

A.2. Summary of Requirements for RA Participants

Requirements of Participants may be captured in the following manner:

- **NWPP Operational RA Participant Guidelines** – Outlines the requirements and expectations of Participants as they engage in the Program and includes the following topics:

- Data Submission – Descriptive requirements for forecast/actual data submissions, including data formats, periodicity, and communication protocols.
- Notifications – Outline expectations for how and when Participants will notify the PO regarding transmission limitations, at-risk paths and path de-rates, replacement capacity concerns, inability to meet Energy Deployments, bilateral exchanges, early release requests, and others as needed.
- Transmission Service – Captures the guidelines related to securing transmission service, applicable scheduling deadlines, and bilateral exchange.

NWPP Resource Adequacy Program Detailed Design

Appendix - 2B Stakeholder Advisory Committee Engagement and Feedback

JUNE 2021

NORTHWEST PowerPool

The Northwest Power Pool's (NWPP) Stakeholder Advisory Committee (SAC) was formed in late 2019 as the RA Program Development Project began Phase 2A. The stated intent in creating such a committee was to seek broad representation from across the region, with each member acting as the liaison for their sector. The sectors were defined as: state representatives (commissions, state energy offices), public power stakeholder groups, environmental community stakeholders, independent power producers, large consumers, ratepayer advocacy groups, and natural gas utilities. The committee was set up to be advisory to the Steering Committee as they considered program design concepts.

Throughout Phase 2A (October 2019 – June 2020) the SAC met at least quarterly for updates on program design. When the Phase 2A Conceptual Design document was released in August 2020, the SAC asked to provide written comments on the document. This matrix was also provided to Southwest Power Pool (SPP) as the Program Developer and referenced regularly during design meetings to inform Steering Committee discussion on design elements. These comments were included in the Steering Committee's internal 2B design progress matrix, and used to track the evolution of program design details through Phase 2B; as such, these comments were reviewed weekly with the Steering Committee as each design element was considered. The full list of SAC comments of the 2B Conceptual Design and the written responses from the Steering Committee can be found at the end of this appendix.

In Phase 2B, the Steering Committee held quarterly half-day SAC meetings as well as additional technical workshops (2-3 hours) as requested by SAC feedback. Below is a summary of the meetings held and topics covered:

- August 21, 2020 – Quarterly SAC meeting: 2A conceptual design and SAC process improvements
- October 28, 2020 – Technical workshop: Program framework and benefits (by the Program Developer) and interplay with State Integrated Resource Plans (IRPs) [with Maury Galbraith, Western Interstate Energy Board (WIEB)]
- January 14, 2021 – Combined quarterly SAC meeting and technical workshop: Design updates, Energy Imbalance Market (EIM)/ Extended Day-Ahead Market (EDAM) interplay, contracting paradigms, and Q&A of conceptual design questions
- March 12, 2021 – Technical workshop: Comparison with the California Independent System Operator (CAISO) – planning reserve margin (PRM) and unforced capacity (UCAP) methodologies and low water years
- April 28, 2021 – Quarterly SAC meeting: Design updates and governance

- June 9, 2021 – Technical workshop: qualified capacity contributions (QCCs) – hybrid and customer resources, variable energy resource (VER) zones, transmission zones, and grandfathered contracts
- June 30, 2021 – Quarterly SAC meeting: Governance updates, transmission, interchange analysis, contingency reserve in PRM, and proof-of-concept analysis

Within 30 days of each SAC meeting, the Steering Committee hosted a public webinar. These webinars were scheduled for 90 minutes and covered a slightly abridged version of the SAC materials. These were free, open to the public, and advertised on the NWPP webpage; an email was sent to the NWPP mailing list with registration information.

While the SAC is primarily an advisory committee, the Steering Committee took suggestions and comments into consideration and acted on them where possible (acknowledging that comments and requests from different members were at times contradictory). Table 4-1. demonstrates a non-exhaustive list of examples where the Steering Committee was able to be responsive to the SAC and/or the Steering Committee and SAC's comments were aligned.

Table 4-1. Examples of Steering Committee responses to SAC Feedback

Date Received	Comment	Response/Action
8/21/2020	Request for more technical meetings/discussions	Scheduled technical workshops on: Program Benefit, State/IRP Interplay, Demand Response, EIM/EDAM Interplay, Contracting Paradigms, PRM, Low water years.
8/21/2020	Request for technical experts from outside the region	Southwest Power Pool hired as the Program Developer to help with design, bringing extensive experience in RA (both their own program and requested additional research on best practices) - Program Developer spoke at next SAC meeting. Throughout the detailed design process, Steering Committee worked with SPP to consider all available options for design elements (e.g., from other RA Programs across the US and occasionally abroad).
8/21/2020	More consideration for low water years	Presented additional detail for discussion at the March 12, 2021, SAC meeting. Committed to a detailed stress test analysis of hydro QCC methodology – See Section D.2.3. Stress Case Analysis.

Date Received	Comment	Response/Action
8/21/2020	Request for a breakout session on EIM/EDAM linkage	Jan. 14, 2021, SAC meeting focused on this topic.
8/21/2020	Request for technical workshop on contracting	Jan. 14, 2021, SAC meeting focused on this topic.
4/28/2020	Request to fully consider resources from third party providers	Design is technology neutral and will fully accept resources from 3rd party providers. Request that owners register their resources with future PO to determine appropriate QCC value of resources.
4/28/2020	The RA Program should comply with Federal Energy Regulatory Commission (FERC) principles for independence in board composition and program administration, especially when binding	That is the expectation as presented at SAC Apr. 28, 2021.
4/28/2020	Would existing long-term contracts to buy electricity from outside entities (independent power plant operators, power brokers) factor into a utility's RA evaluation? How would the capacity contribution be evaluated and how would the rules include such transactions?	Working on "Grandfathering" methodology. See Section: Grandfathered Agreements (page 69).
4/28/2020	Robust inclusion and fair pricing of DR resources	Included in Section 2.5.6 Customer Resources and presented at technical workshop on Jan 14, 2021. The RA Program will not determine prices for any RA resource contracts – contracts will be negotiated bilaterally.

Date Received	Comment	Response/Action
2/7/2020	Participation of nontraditional elements in a Resource Adequacy Program (customer-owned resources or direct access providers that are not IPPs)	Point of compliance will be the Load Responsible Entities (see Section 1.3 Resource Adequacy Program Participants).
SAC Comments on 2A	Suggest an annual update of seasonal PRM based on changes in load and shift in peak demand hours. This would be essential for RA entities to inform short-term capacity planning as more renewable and storage resources come online.	Included in Section 2.10 Modeling Process Timelines.
SAC Comments on 2A	Pumped hydro storage resources and battery storage resources are essential to long-term reliability, flexibility, and grid integration of renewables	Both are included with QCC methodology in Section 2.5.4 Energy Storage.
SAC Comments on 2A	5-years of historic data for thermal resources	Included in Section B.5.1. Thermal Generators
SAC Comments on 2A	Longer-term multi-year contracting for capacity	This aligns with RA Program design as seen in Section 2.4.2 Sale and Purchase Transactions. Presented at the January 14, 2021, SAC meeting.
SAC Comments on 2A	Obligations transferred among participating entities	Included in Section 2.4.2 Sale and Purchase Transactions.
SAC Comments on 2A	Planned outages will not be included in UCAP calculations - critically important that resources present scheduled outages in the RA workbook to adequately represent the full	This is included in Section B.5.1. Thermal Generators.

Date Received	Comment	Response/Action
	availability of the resource during capacity critical hours	
6/8/2020	Request for a preliminary example FS workbook	Provided example on NWPP website.
4/28/2021	Questions about non-NWPP participation in Program	Stood up Load Service Information Forum to address and educate broader group that may be interested in RA Program.
4/28/2021	Request for consideration of an Independent Program Monitor	Included in Section 1.5 Independent Evaluator.
6/18/2021	Recommend process to engage state regulators on RA Program design and governance.	Stood up series of meetings to engage states in collaboration with WIEB Western Interconnection Regional Advisory Body in late June 2021.
6/18/2021	Request multi-sector nominating committee with voting rights.	Included in Section 1.2.1 Makeup of the Nominating C.
6/24/2021	Recommend that independent board members should have term limits.	Included in Section 1.1 Board of Directors.

Table 4-2. SAC feedback from 2A Conceptual Design

Stakeholder	Comments	Steering Committee (SC) Response
Western Resource Advocates	<u>Governance and Transparency</u> – Recommends that the NWPP SC clearly distinguish the role of the PA versus the role of program oversight and evaluation. The day-to-day operation of the program should be separate from the oversight and evaluation of the program in order to meet FERC's independence requirements. – To be effective, independent program monitoring and evaluation must be transparent. Every effort should be made to aggregate data in order to preserve its confidentiality, while still effectively communicating program results to stakeholders.	– The Steering Committee (SC) anticipates that the fully operational program with binding compliance obligations will contain some functions that are (Federal Energy Regulatory Commission (FERC) jurisdictional; FERC's independence criteria and the implications for oversight (such as a market monitor) versus day-to-day program operations (by the Program Administrator (PA)) will be more fully explored in Phase 2B of the program design. – The SC agrees that transparency is important and expects that the PA will make aggregate data available, where possible, to communicate program results to stakeholders once the Resource Adequacy (RA) program is operational. This level of detail has not yet been determined but will be considered and determined later in the process when the PA is hired.
	<u>Resource Capacity Contribution and Demand Side Resources</u> - An effective and robust regional RA Program should fundamentally be technology agnostic. - While demand-side resources will have a role in the NWPP RA Program, it remains unclear how these resources will be accounted for (i.e., demand side or supply side). RA recommends the SC create a technical workgroup to design an effective implementation pathway for demand-side resources.	- The SC agrees that a regional RA Program should be technologically neutral. This is intended to convey that the qualifying capacity contribution of resources will be determined based on the resource's anticipated contribution to regional reliability in capacity critical hours, the hours within a day where the delta between forecasted net load and generation is the smallest. The intent of the program is not to exclude any resource types that members may choose to meet their requirements, but rather to appropriately accredit capacity based on the operating characteristics of the resource. - The role of demand side resources in the program is being more fully considered as part of the Phase 2B scope and will be further discussed with the advisory committee during Phase 2B.
	<u>Program Interaction with Current and Planned Regional Market Initiatives</u> – WRA believes that the RAPDP, when operational, is likely to have impacts on transmission deliverability and the Resource Sufficiency Test for both the EIM and EDAM. WRA recommends the formation of a technical work group that can analyze the	– The SC intends to discuss the topic of RA Program interaction with current and planned regional market programs and initiatives in a Stakeholder Advisor Committee (SAC) technical workshop. – Further technical discussions with the SC and the Program Developer (PD) will determine the day ahead and real-time requirements and outline the role of the PA in this time horizon. This

Stakeholder	Comments	Steering Committee (SC) Response
	interaction of relevant RAPDP program design elements with the EIM and EDAM.	would include how Participants will be assessed as being compliant during the operational timeframe, which may involve metrics that take into account actual operational conditions. Within the day ahead and real-time windows, member entities also participate in various existing wholesale bilateral and organized markets (e.g., Energy Imbalance Market (EIM)). In Phase 2B, the SC and PD will further consider how the operational program design will integrate with these markets, including the potential overlay between RA and RS metrics in the day ahead timeframe.
Northwest Requirements Utilities	General Remarks - Supports exploring an RA Program and believes it could help capture diversity benefits and ensure proper compensation for the provision of capacity. - NRU members as BPA load-following customers, will not directly participate in the RA Program, but will be impacted by BPA's participation. Any impact to BPA will flow through to NRU members via power rates or system reliability. Further, depending on where the point of compliance is, NRU members will be reliant on BPA to meet those obligations on their behalf.	- The SC appreciates the interest and importance of governance and point of compliance to stakeholders and intends to discuss this further in a technical workshop.
	Stakeholder Engagement - Emphasize the need to continue in-depth stakeholder engagement to ensure broad understanding and input into key decisions in Phase 2B. - BPA will need to engage its customers and discuss potential participation in the RA Program and how this will impact it customers.	- The SC intends to continue in-depth stakeholder engagement in Phase 2B. - The SC acknowledges the importance and impact of Bonneville Power Administration's (BPA) participation in the future program on its customers. Our understanding is that BPA is actively engaging its customers on its future participation and plans to continue to do through the detailed program design phase.
	Program Interaction with Current and Planned Regional Market Initiatives	- The SC intends to discuss the topic of RA Program interaction with current and planned regional market programs and initiatives in a SAC technical workshop.

Stakeholder	Comments	Steering Committee (SC) Response
	- Supports further exploring this topic, for example, would the energy associated with "pooled capacity" be able to be offered into the EIM?	- The PA will evaluate potential need for pooled capacity in the day- (or days-) ahead timeframe and release any pooled capacity determined not necessary for regional reliability. When that capacity is released back to participating entities, they would be free to utilize that unneeded capacity in transactions (e.g., the EIM) as they see fit. - Further technical discussions with the SC and the PD will determine the day ahead and real-time planning requirements and outline the role of the PA in this time horizon. This would include how Participants will be assessed as being compliant during the operational timeframe, which may involve metrics that take into account actual operational conditions. Within the day ahead and real-time windows, member entities also participate in various existing wholesale bilateral and organized markets (e.g., EIM). In Phase 2B, the SC and PD will further consider how the operational program design will integrate with these markets, including the potential overlay between RA and RS metrics in the day ahead timeframe.
	Governance - Governance is a key topic for NRU members, look forward to actively participating in future discussions on this topic. - Recommend that most aspects of the non-binding program ought to mirror the goals of the binding program, including the independence of the PA.	- The SC appreciates the interest and importance of governance of the program to stakeholders and intends to discuss this further in a technical workshop.
Western Interstate Energy Board	General Remarks - A regional RA Program is needed to (1) ensure reliability, (2) deliver investment cost savings to LSE's and their customers, (3) respect state and local autonomy over investment decisions. - The Conceptual Design document is a good start to developing a successful program.	- Thank you for this comment.

Stakeholder	Comments	Steering Committee (SC) Response
	Capacity RA Program - It is reasonable to first design a capacity RA Program and consider Energy RA and Flexibility RA after and the staged implementation of the program. - It is unclear what is meant by a "less formal mechanism" to access pooled resources prior to Stage 3 (see p. 10).	- The staged implementation of the capacity program currently anticipates Stage 1 would be a non-binding forward showing program, Stage 2 would be a binding forward showing program, and Stage 3 would add an operational program to the binding forward showing program. Further consideration is necessary to determine how the binding forward showing program could be implemented in Stage 2 without a full operational program in place to ensure that pooled capacity is accessible by all Participants. In summer 2020, the Resource Adequacy Program Development Project (RAPDP) Participants implemented an interim solution to match entities experiencing exceptionally high loads (P99 loads) with entities with surplus capacity available on the day ahead basis using manual processes. Further consideration is necessary as part of Phase 2B and the Phase 3 implementation plan, as to whether this manual interim solution ("less formal mechanism") is sufficient to enable the binding forward showing to proceed while the full operational solution is implemented, or whether additional steps should be taken to bolster this (or another) solution as part of Stage 2.
	Showing and Compliance Timeline - Transparency and visibility are crucial to establishing a Forward Showing Program that is trusted by all stakeholders. Additional considerations for the Detailed Design of Phase 2B are: - At what level of granularity will the PA publish the results of the compliance showing for the region and the program Participants? - When will the PA publish the results of the compliance showing; prior to the cure period, after the cure period, or both?	- The SC agrees that transparency and visibility are essential to establishing a program trusted by all stakeholders. - The SC appreciates the additional considerations/questions raised regarding how the PA will make data available publicly. As noted above, the SC agrees that transparency is important and expects that the PA will make aggregate data available, where possible, to communicate program results to stakeholders once the RA Program is operational. This level of detail and timing of the release of data has not yet been determined but will be considered and determined later in the process when the PA is hired.

Stakeholder	Comments	Steering Committee (SC) Response
	- When will the PA publish the "CONE Factor" for establishing the non-compliance penalty; prior to the cure period, after the cure period, or both?	
	<u>Regional Metrics</u> - The "perfect capacity" approach to separating the "load" side of the RA evaluation from the "resource" side of the evaluation is important to establishing a transparent program that is fair and unbiased. Using the probabilistic analysis to determine the planning reserve margin for the region and program Participants is reasonable and appropriate. - Use of the PA's load forecasts with a dispute resolution process is likely the most efficient means of obtaining unbiased and accurate load forecasts. - Consideration of what data, information or submittal would be made available to the public (page 18) should include data elements that inform both the "load" side and "resource" side of the RA evaluations. - It is not clear what is meant by "…participating entities may need to change their market activities to accommodate showing standards…" (page 18)? Current market activities follow stringent risk management procedures. The SC indicate how LSE market activities may need to change to accommodate the showing standards. Will LSEs need to change their risk management procedures? Are the anticipated changes likely to increase LSE net variable power costs?	- The SC appreciates your support for the perfect capacity approach, as well as considerations related to the proposed load forecasting approach. Load forecasting methodology will be a topic for further discussion in Phase 2B. The SC recognizes the importance of accurate load forecasts and firm resource commitments in order to determine adequacy and ensure reliability. - It is generally anticipated that some aggregated information related to regional load and resources will be made publicly available through this program, but the Phase 2B detailed design and discussions with the PA in implementation will further refine recommendations for data sharing going forward. Thank you for noting your specific consideration for both load and resource information. - With respect to market activities, in today's markets, entities may wait until a few months, weeks or even days ahead of the operating day to purchase the energy required to meet their load plus other obligations with no regionally agreed on requirement to meet a Planning Reserve Margin (PRM). To comply with the RA Program in the future, entities will be required to contract for capacity and transmission in the forward showing time horizon (5+ months in advance of the season) to meet the RA metrics. - Net variable power cost increase or decrease is expected to be an indicator of regional RA providing appropriate price signals to direct investment.

Stakeholder	Comments	Steering Committee (SC) Response
	Penalty for Non-Compliance - Using a "CONE Factor" to scale the size of the non-compliance penalty to the size of the region's actual reserve margin is reasonable and appropriate. More information about the rationale for the thresholds of the "CONE Factor" would be helpful. A region that meets its Planning Reserve Margin by more than 8 percent is arguably overbuilding capacity, why is a CONE Factor of 125% appropriate (see page 24)?	- The SC's use of the CONE factor as a penalty is intended to strongly motivate Participants to comply with program metrics in the forward showing time horizon. The CONE Factor used in the penalty calculation is intended to decrease as the percentage of capacity above the PRM increases (exact increases will be reviewed as part of Phase 2B). The logic is that the penalty is lower when there is less risk for failure and higher when there is more risk for failure. The thresholds do not assume the region will or should achieve a certain percentage above the PRM. These particular percentages are those utilized in Southwest Power Pool's (SPP) program, which was used as a template (with a similar approach to penalties and compliance design elements); their appropriateness and the logic behind proposed factors will be considered in collaboration with the PA. -
	Accessing Pooled Capacity - More discussion of the equation for the proposed "triggering event" for accessing pooled capacity is needed. It is not clear from the proposed equation that the LSE is necessarily short capacity (e.g., the equation does not include market activities).	- More explicit metrics and equations will be developed for many of these situations (e.g., accessing pooled capacity) as part of Phase 2B. Generally, the intent is to allow a Load Serving Entity (LSE) access to pooled capacity if their actual load (+ extenuating circumstances like net Variable Energy Resource (VER) production) is higher than was planned for in the forward showing stage. An LSE may have the option to use the market to meet their needs rather than accessing the pooled capacity, though the logistics of access will be considered further in Phase 2B.
	Legal and Regulatory Considerations - It is not clear from the discussion which functional elements of an RA Program trigger FERC jurisdiction; is it the implementation of non-compliance penalties, the implementation of an operational program, or both? - It is also not clear if the FERC "public utility" and "independence" requirements are separable (see page 31). In other words, could the PA meet the FERC "independence" requirement, and contract	- The "trigger" for FERC jurisdiction arises, fundamentally, by the creation of a binding regional compact to share diversity benefits. Penalties and operations are specific areas where FERC would assert jurisdiction to ensure the program produces just and reasonable results. - Once a binding RA Program is established its PA will likely be considered a public utility by definition under the Federal Power Act. Because the services it would be providing in a binding setting could create economic impacts or reliability impacts on market

Stakeholder	Comments	Steering Committee (SC) Response
	with a separate entity that performs the functions that trigger the "public utility" requirement?	Participants, the FERC rules prescribe that the public utility must operate independently from any of the other market Participants to ensure a level of fairness in the administration of the market. - The specific functions to be performed in administration of the forward showing and operational programs, and the roles and responsibilities of the associated governing and administration bodies, will be further discussed as part of Phase 2B.
Oregon Citizens Utility Board	General Remarks - CUB supports an RA Program that meets the reliability needs of the region in a manner that optimizes existing resources—while providing for necessary new resources—and leads to cost savings for customers.	- Thank you for the comment.
	RA Program Goals and Objectives - Cost savings are only likely to be realized if the RA Program is designed in a manner that is transparent. CUB supports the inclusion of "transparency across the program" as an objective to help promote an efficient and fair RA Program, as articulated in the joint comments by Renewable Northwest and the NW Energy Coalition. - CUB also supports the distinction made by WRA between the role of the PA versus the role of program oversight and evaluation. - CUB believes this preliminary inventory and subsequent determination of capacity contributions is paramount.	- Thank you for the comment. The SC agrees that transparency is important and expects that the PA will make aggregate data available, where possible, to communicate program results to stakeholders once the RA Program is operational. This level of detail has not yet been determined but will be considered and determined later in the process when the PA is hired.

Stakeholder	Comments	Steering Committee (SC) Response
	Forward Showing Program Conceptual Design - Although certain elements of the program are likely to—and arguably should—remain voluntary in nature, CUB believes the inclusion of LSEs in the program can provide a number of benefits. It would not be helpful to regional reliability if LSEs were left out of the RA Program, as it would create an incentive for customers to leave utility service for direct access in order to avoid paying the costs of reliability.	- Thank you for the comment. The SC agrees that in order for reliability to be adequately supported, RA needs to broadly encompass load service in the footprint of the program. - The SC appreciates the interest and importance of the governance of the program and point of compliance in particular and intends to discuss this further in a technical workshop.
	Regional Adequacy Objective - CUB supports the SC's recommendation to include an LOLE objective of 1 day in 10 years where capacity is expected to be insufficient to meet load plus contingency reserves.	- Thank you for this comment.
	PRM - As the details of the RA Program are being considered by the SC and SAC members, leveraging the benefits of the program to lower the PRM should be top of mind. - In order to reach a place in which we can consider lowering the PRM, an accurate accounting of all available capacity must first be taken. CUB agrees with RNW and NWEC (page 27) that a more granular and probabilistic approach is likely necessary to evaluate intra-seasonal fluctuations due to factors like climate change and electrification.	- The program design is intended to optimize the benefits to all participating entities and take advantage of the diversity in loads and resources across the footprint of the program. An inherent benefit of regional RA is lower overall cost to achieve the same level of reliability that would be possible under individual utility planning for RA. The realization of investment savings is one of the program objectives identified by the SC. The benefits of increased reliability and lower costs and risks will benefit the region as a whole. - The program will accurately account for all loads and resources on at least a monthly granularity in the forward showing program. Factors like climate change and electrification will be accounted for in entities' load profiles that will change as conditions change. Resources that experience impacts from variable weather patterns will be considered for monthly qualifying capacity contribution values to ensure this variability is appropriately managed.
	Load Forecasting for Forward Showing - CUB agrees with RNW and NWEC that load forecasting methodologies should be consistent	- As noted in the question and 2A Conceptual Design (CD), the SC recognizes the need for consistent and accurate load forecasting in order to ensure reliability and RA. Phase 2B design work includes

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	with existing integrated resource planning and should provide an integrated program forecast rather than rolling up the forecasts of participating entities.	further consideration of load forecasting and integration with entities' existing planning processes. - With respect to Integrated Resource Plans (IRPs), the RA Program will not replace the 10-year out IRP process, but will provide a more accurate and up-to-date view in the 1- to 3-year window prior to the operating year.
	Regional Import/Export Assumptions - CUB agrees with RNW and NWEC that additional analysis on how this program will operate within the construct of a regional day ahead market is necessary.	- The SC intends to discuss the topic of RA Program interaction with current and planned regional market programs and initiatives in a technical workshop.
	Resource Eligibility and Qualification - CUB agrees with WRA that the treatment of demand-side resources merits consideration in the program's design. Demand response (DR) has been identified as a significant capacity resource for the region. - Because DR programs take time to develop and require the recruitment of customer participation, identifying how DR participate should be an early priority because it is likely to affect DR program design.	- The SC agrees that treatment of demand-side resources is an important element of the program, and this will be further discussed with the advisory committee in Phase 2B.
Randy Hardy, IPP Consultant	General Remarks - Overall, the Conceptual Design is excellent. The SC has laid out a well-structured program which addresses most, if not all, of the components of a robust, viable RA Program. - Focusing RA standards on critical hours during binding seasons is particularly important.	- Thank you for this comment.
	Dry Water Years	- The SC recognizes that there can be challenges associated with prolonged low water conditions in the region, and as part of Phase

Stakeholder	Comments	Steering Committee (SC) Response
	- Very concerned that the current RA Conceptual Design does not address the potential effect of dry water years on the NWPP hydro capacity contribution to meeting RA standards. - Based on our discussion at the August 21 SAC meeting, it is my understanding that NWPP SC will re-examine this issue to determine the capacity contribution of PNW hydro in dry water years in critical hours. - Appreciate that dry water is an energy and not a strict capacity issue, and that fully incorporating this effect into a capacity RA Program would both greatly complicate RA Program design and lengthen the timeframe to deliver a final RA Program. What I expect, however, is that we can make some rough intuitive RA standards adjustments to try to account for this phenomenon. Perhaps the SC could simply increase the PRM you would otherwise calculate by 2-3 percentage points to account for these potential impacts.	2B's detailed design, will work to evaluate the impact a low water scenario might have on the hydro storage capacity capability during capacity critical hours, the hours within a day where the delta between forecasted net load and generation is the smallest, to determine if changes to the RA requirements should be made.
	<u>Imports/Exports</u> - This area is especially important to ensuring a comprehensive RA Program, and I basically agree with the way the SC is addressing it. Again, focusing on the critical hours when imports are needed, and how many megawatts can be provided during those hours from outside the NWPP footprint, is key to designing a successful program. In this regard, averages, whether annual, season on monthly, are the enemy of accurate reliability planning in general and RA Programs in particular. - Historically, the NWPCC and PNW utilities have assumed a constant 2,500MW of CA imports are	- Thank you for this comment. The SC agrees that the assumptions made about what can be counted on from external regions during capacity critical hours must be carefully considered.

Stakeholder	Comments	Steering Committee (SC) Response
	available (to NWPP) throughout the winter. However, as SC members have pointed out, even in winter months CA is likely constrained from hours 16 to 22 on a typical day given the state's ever-increasing reliance on solar. If these hours fall into the critical category during the NWPP binding winter season, then counting on 2,500MW from CA (or possibly any imports during this period) is probably not prudent.	
Montana Energy Office	<u>Qualifying Capacity</u> - Agree with the SC recommendation that the qualifying capacity of wind resources be evaluated zonally across the Pacific Northwest. - Recommend that the Committee more thoroughly evaluate the implications of zonal quantification of capacity for solar resources. - We agree with the SC that a methodology needs to be created for calculating the capacity contribution of various demand-side management (DSM) resources. Recently, California relied on DSM to minimize and, in some circumstances, avoid rolling blackouts during a period of sustained and widespread hot weather, underscoring its importance in maintaining reliability.	- Thank you for your comments. The SC agrees that VER qualifying capacity contribution should be evaluated zonally across the program footprint. The SC also agrees that treatment of demand-side resources is an important element of the program, and this will be further considered and discussed with the SAC in Phase 2B.
	<u>Governance</u> - Recommend providing additional clarity concerning regarding what a Balancing Authority's responsibility would be for ensuring resource adequacy for choice customers/load serving entities inside their Balancing Authority Area. For example, would load serving entities be responsible for participating independently in this RA Program, and ensuring	- Thank you for the comment. The SC looks forward to further discussing the question of point of compliance with stakeholders in Phase 2B. The SC agrees that in order for reliability to be adequately supported, RA needs to broadly encompass load service in the footprint of the program. There will be a technical workshop on governance.

Stakeholder	Comments	Steering Committee (SC) Response
	their own adequate supply, or would this responsibility fall to the BA?	
	Program Interaction with Current and Planned Regional Market Initiatives - The NWPP RA Program should clarify how the program will interact with the regional Reliability Coordinator and evolving energy imbalance markets. This coordination should aim to reduce redundant services and functions of each entity. It should also align the resource planning requirements or standards of each program/service/market.	- The SC intends to discuss the topic of RA Program interaction with current and planned regional market programs and initiatives in a technical workshop. - Further technical discussions with the SC and the PD will determine the day ahead and real-time planning requirements and outline the role of the PA in this time horizon. This would include how Participants will be assessed as being compliant during the operational timeframe, which may involve metrics that take into account actual operational conditions. Within the day ahead and real-time windows, member entities also participate in various existing wholesale bilateral and organized markets (e.g., EIM). In Phase 2B, the SC and PD will further consider how the operational program design will integrate with these markets, including the potential overlay between RA and RS metrics in the day ahead timeframe.
	Program Participation/Eligibility - The NWPP RA Program should clarify how independent generators (non-utility owned resources, QFs, independent brokers) fit into the program. Would they be treated like utility-owned resources if a utility has contracted for their supply for a particular operational season? - We recommend that NWPP provide a general resource planning template to RA Program Participants that would help integrate this RA Program with the resource planning processes of utilities involved. - The RA Program design should clarify what recourse or action, if any, a load-serving entity has to take to avoid a penalty if between the end of a curing	- The SC recognizes the importance of ensuring all resources (including independent generators) are able to contribute to the program. In Phase 2B, the SC will work through additional resource eligibility questions and contracting requirements; this will be done with consideration of market liquidity and program rigor. Generally, the design will need to ensure all resources (utility-owned, non-utility owned, qualifying facilities (QFs), etc.) meet the same standards for reliability. The SC will further clarify how independent generators fit into the program in Phase 2B. - In Phase 2A, the SC developed an excel workbook to enable utility stakeholders to better understand the mechanics of the forward showing process. The workbook is intended to help stakeholders build intuition about possible impacts on their utilities. The workbook is available for public download on the Northwest Power Pool (NWPP) website.

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	period and the subsequent operational season a generator unexpectedly goes offline. Conversely, if the LSE acquires an asset after the curing period, can that asset still be used in the following operational season?	- The SC will further clarify rules related to the transition between the forward showing and operational portion of the program, resource replacement requirements, and operational program procedures in Phase 2B.
AWEC	General Remarks - We are encouraged by the quality of work done during Phase 2A and the good-faith, collaborative spirit shown by various stakeholders throughout the Resource Adequacy Program Development Project ("RAPDP") process. It is important that at least one independent power producer has joined the SC effort to ensure a diversity of voices are present amongst the ultimate decision-making body. - An acceptable RA Program should not drive up the cost of reliability. Further, whether energy or capacity are used to measure and achieve RA sufficiency, the cost should be less than it would be, absent the regional framework. - In the Southwest, there is no RA Program; however, there is a contractually based regional reliability program called the Southwest Reserve Sharing Group. Has the SC contrasted the costs and benefits of such solutions with the costs and benefits of a more traditional RA Program, given the complications caused by the lack of an organized market?	- The SC values the perspective of stakeholders and expects to continue to engage with them to ensure that diverse perspectives are considered. - As indicated in the CD, we expect that the binding phases of the program will include a governance structure that addresses independence and the opportunity for stakeholder engagement. The SC appreciates the interest and importance of the governance of the program and intends to discuss this further in a technical workshop. - The program design is intended to optimize the benefits to all participating entities and take advantage of the diversity in loads and resources across the footprint of the program. An inherent benefit of regional RA is lower overall cost to achieve the same level of reliability that would be possible under individual utility planning for RA. The realization of investment savings is one of the program objectives identified by the SC. The benefits of increased reliability and lower costs and risks will benefit the region as a whole. - The Southwest Reserve Sharing Group is a program for sharing contingency reserves to respond to forced outages and other emergency conditions, similar to the NWPP's Reserve Sharing Program. This differs from programs such as the NWPP RA Program effort, which focuses on ensuring that members are planning in advance for adequate capacity to meet load during capacity critical hours. In the 2A effort, the SC worked to pull as many relevant best practices as possible while discussing program CD, reviewing similar RA Programs from across North America (especially focused on SPP and California Public Utilities Commission (CPUC) RA Programs).
	Governance/Point of Compliance	- Thank you for the comment. The SC agrees that in order for reliability to be adequately supported, RA needs to broadly

Stakeholder	Comments	Steering Committee (SC) Response
	- Participation in the RA framework by Energy Service Providers/Energy Service Suppliers ("ESPs") is critical to ensure the efficient operation of direct access programs in various states. Likely this means that the initial leaning toward load serving entity level participation is preferable. In the case of a Balancing Authorities level participation, mechanisms to coordinate ESP RA with the local BA showing and reporting will be necessary in order to ensure that customers purchasing RA from their ESPs are not required to also pay for BA-owned or acquired RA. - Because of the prominence of Bonneville Power Administration in the Northwest, it is critical that LSEs and large customers within BPA's footprint understand how, or if, BPA will participate in this framework and how it will pass along the RA costs or benefits to its utility customers, should the Agency participate.	encompass load service in the footprint of the program. If LSEs become the point of compliance for RA, then it is important to address how Energy Service Providers/Energy Service Suppliers (ESPs/ESSs) also participate in RA. The SC looks forward to further discussing the question of point of compliance with stakeholders in Phase 2B during the technical workshop on governance. - The SC acknowledges the importance and impact of BPA's participation in the future program on its customers. Our understanding is that BPA is actively engaging its customers on its future participation and plans to continue to do so through the detailed program design phase.
	<u>Program Interaction with Current and Planned Regional Market Initiatives</u> - The way in which the NWPP RA Program "coordinates" with the EIM—especially if BPA joins the EIM—or how the NWPP RA Program creates a back-up system to access pooled resources must also be explored. This area is fundamental to unlocking the diversity benefits and related, the purposed program cost savings.	- The SC intends to discuss the topic of RA Program interaction with current and planned regional market programs and initiatives in a technical workshop. - Further technical discussions with the SC and the PD will determine the day ahead and real-time planning requirements and outline the role of the PA in this time horizon. This would include how Participants will be assessed as being compliant during the operational timeframe, which may involve metrics that take into account actual operational conditions. Within the day ahead and real-time windows, member entities also participate in various existing wholesale bilateral and organized markets (e.g., EIM). In Phase 2B, the SC and PD will further consider how the operational program design will integrate with these markets, including the potential overlay between RA and RS metrics in the day ahead timeframe.

Stakeholder	Comments	Steering Committee (SC) Response
	Capacity RA Program - Additional information behind the choice to begin with a capacity RA Program would be appreciated. Additionally, an understanding of what it would look like to build an energy or flex RA on top of the capacity framework would be helpful.	- The SC identified capacity RA as the most urgent need facing the region. Further, though its implementation presents a number of challenges, a capacity adequacy program is the most straightforward to implement. - The capacity RA Program will address the needs of the region in the capacity critical hours, the hours within a day where the delta between forecasted net load and generation is the smallest. Once the capacity program is implemented, the SC will explore whether there are other solutions that could build upon this program, such as an energy adequacy standard. Further, the SC recognizes that there can be challenges associated with prolonged low water conditions in the region, and in Phase 2B, will work together to evaluate the impact a low water scenario might have on the hydro storage capacity capability during capacity critical hours to determine if changes to the RA requirements should be made. This topic will be further addressed a SAC technical workshop.
	Program Objectives - According to Section 1.4.2 of the Conceptual Design Document, the RA Program will support nine Objectives, including the following: "[e]nsure that the participation, evaluation, and qualification of resources is technology neutral."24/ Please identify what is meant by "technology neutral."	- The term "technology neutral" is intended to convey that the qualifying capacity contribution of resources will be determined based on the resource's contribution to regional reliability during capacity critical hours, the hours within a day where the delta between forecasted net load and generation is the smallest. The intent of the program is not to exclude any resource types that members may choose to meet their requirements, but rather to appropriately accredit capacity based on the operating characteristics of the resource.
	Capacity Contribution - A large number of industrial and commercial customers within the likely footprint of the NWPP RA Program operate cogeneration resources. It is	- The SC recognizes that some cogeneration resources can and do contribute to RA. However, each situation can vary depending on the type of resource, operating characteristics, and dispatch control. Some cogeneration resources may be suited to contributing in the

Stakeholder	Comments	Steering Committee (SC) Response
	important to understand: 1) how or should these customer-owned resources be accounted for and remunerated for their capacity contributions; and 2) what metric for qualifying capacity would be assigned to cogeneration technology?	same manner as traditional generation resources, while others may be more suited to contributing as a peak load reduction. Any compensation for the capacity of a cogeneration resource would be a commercial arrangement between the generator and the entity claiming it as part of its capacity portfolio.
PPC	General Remarks - Exploration of a potential RA Program for the NW could be a timely solution to address an impending regional capacity shortage. - Success of an RA Program directly depends on how it is designed and implemented. - Continued engagement of the SAC and other stakeholders is important. - Supports the creation of smaller work groups open to SAC members to provide additional opportunities to explore more of the technical details of the program. - Requests that all comments submitted on the CD be shared with members of the SAC, along with any summaries of those comments provided to the SC.	- The SC plans to continue to actively engage in the SAC in Phase 2B. In addition to the half-days meeting which have been held approximately quarterly, we plan to hold a series of technical workshops on topics of interest shared by SAC members. - All comments submitted on the CD document will be shared with the SAC, in addition to this summary matrix of comments and SC responses.
	Program Structure - Supportive of the proposed structural that is voluntary, and technology neutral design is important as well. - Supports proposed capacity forward-showing program with two binding seasons appears to be a good starting point for the program.	- Thank you for this comment.
	Hydro Capacity Contribution	- Hydro capacity contribution will be addressed in a SAC technical workshop.

Stakeholder	Comments	Steering Committee (SC) Response
	- Supports the SC's work to develop a hydro model that will work for the Northwest. PPC requests that this be added to a SAC technical workshop.	
	<u>Governance</u> - There is little information in the CD on governance. Requests that the SC prioritize making additional information available to the SAC regarding governance structures under consideration, for example analysis conducted to-date on FERC jurisdictional elements of the program. - The outstanding question of point of compliance leaves uncertainly for many PPC members on their potential role in the program. The SC should strive to clarify this question as soon as possible. - Impacts of the program on PPC members will be largely dependent on policy decisions BPA makes to implement the program.	- The SC appreciates the interest and importance of the governance of the program and point of compliance in particular and intends to discuss this further in a technical workshop. - The SC acknowledges the importance and impact of BPA's participation in the future program on its customers. Our understanding is that BPA is actively engaging its customers on its future participation and plans to continue to do through the detailed program design phase.
NWEC	<u>Program Scope</u> - Suggest that NWPP include a statement of scope in the next round of program documents. Is the third phase of the program addressing capacity, but energy and flex RA could be addressed in the future?	- The SC identified capacity RA as the most urgent need facing the region. Further, though its implementation presents a number of challenges, a capacity adequacy program is the most straightforward to implement. - The capacity RA Program will address the needs of the region in the capacity critical hours, the hours within a day where the delta between forecasted net load and generation is the smallest. Once the capacity program is implemented, the SC will explore whether there are other solutions that could build upon this program, such as an energy adequacy standard. Further, the SC recognizes that there can be challenges associated with prolonged low water conditions in the region, and in Phase 2B, will work together to evaluate the impact a low water scenario might have on the hydro storage capacity capability during capacity critical hours to

Stakeholder	Comments	Steering Committee (SC) Response
		determine if changes to the RA requirements should be made. This topic will be further addressed a SAC technical workshop.
	Hydro Capacity Contribution - Concerned with the issue of low hydro seasons and how the program assessment, PRM and other aspects of the program will accommodate that possibility.	- The SC recognizes that there can be challenges associated with prolonged low water conditions in the region and will work together to evaluate the impact a low water scenario might have on the hydro storage capacity capability during capacity critical hours to determine if changes to the RA requirements should be made. Hydro capacity contribution will be addressed in a SAC technical workshop.
	Alignment with State Regulation and Policy - Recommends further development of the RA Program should explicitly include coordination with state and provincial regulators and agencies, so that the program aligns with existing policies and processes such as integrated resource planning.	- The SC has begun to conduct state outreach and intends to continue such outreach throughout the program's development.
	Alignment with Western Market Development - Urges NWPP to align the RA Program with other market developments in the Western Interconnection, especially the existing Western Energy Imbalance Market and the proposed Enhanced Day Ahead Market.	- The SC intends to discuss the topic of RA Program interaction with current and planned regional market programs and initiatives in a technical workshop. - Further technical discussions with the SC and the PD will determine the day ahead and real-time planning requirements and outline the role of the PA in this time horizon. This would include how participants will be assessed as being compliant during the operational timeframe, which may involve metrics that take into account actual operational conditions. Within the day ahead and real-time windows, member entities also participate in various existing wholesale bilateral and organized markets (e.g., EIM). In Phase 2B, the SC and PD will further consider how the operational program design will integrate with these markets, including the potential overlay between RA and RS metrics in the day ahead timeframe.
	Standard Products to Facilitate RA Showing	- Procurement and acquisition related to both the forward showing time horizon and the operational program will be further explored in

Stakeholder	Comments	Steering Committee (SC) Response
	- NWEC recommends that the RA Program include an acquisition component to facilitate the RA showing process by developing standard products and reporting, rather than simply leaving that to existing "market structure," which at this point involves a purely ad hoc approach. - An exchange component in the program design might include: (1) a pro forma contract similar to the WSPP Inc. Agreement; and (2) a "bulletin board" or other mechanism to record requests, offers and agreements.	Phase 2B and the suggestions noted here have been identified for future discussion.
	<u>Accelerate Uptake of Flexible RA Resources</u> - NWEC believes the key learning from the events of the last month in California is that rapid uptake of flexible resources is essential to meeting RA needs in this time of dramatic change. - The most important thing that the RA Program can do to achieve rapid uptake of these important and widely available resources is to ensure that the accreditation and counting rules for flexible resources, including storage, demand response, microgrids, etc., are comparable and fair alongside supply resources.	- The SC agrees that it is important to ensure counting rules for all resources, including for flexible resources are fair and will be performing additional work on this topic in Phase 2B and discussing with the advisory committee further. - It is a key RAPDP objective to ensure that the regional RA Program be technologically neutral and designed to not exclude any resource types that members may choose to meet their requirements, but rather to appropriately accredit capacity based on the operating characteristics of the resource.
	<u>Compliance and Penalties</u> - NWEC is not comfortable with the use of the Cost of New Entry concept as traditionally applied, whether for compliance penalties or other purposes. The reference plant construct is not suitable for determining overall system value, whether based on a gas plant or any other resource type, especially as the resource base becomes more diverse and complementary, because all resources have	- Thank you for your comments; we will consider these as we move forward with program design in Phase 2B. - The SC's use of the CONE factor as a penalty is intended to strongly motivate Participants to comply with program metrics in the forward showing time horizon. The CONE Factor used in the penalty calculation is intended to decrease as the percentage of capacity above the PRM increases (exact increases will be reviewed as part of Phase 2B). The logic is that the penalty is lower when there is less risk for failure and higher when there is more risk for failure. The

Stakeholder	Comments	Steering Committee (SC) Response
	limitations and their value is context dependent, in addition CONE does not follow cost causation.	thresholds do not assume the region will or should achieve a certain percentage above the PRM. These particular percentages are those utilized in SPP's program, which was used as a template (with a similar approach to penalties and compliance design elements); their appropriateness and the logic behind proposed factors will be considered in collaboration with the PA.
	<u>Stakeholder Input</u> - NWEC urges the NWPP to formalize a stronger and deeper approach to stakeholder input, not only during the forthcoming Phase 2B design period but going forward into program implementation.	- The SC agrees that stakeholder input is essential to the RA Program development and future stakeholder engagement may evolve into a more formal process as we get closer to implementation and after the PA is hired.
	<u>Adaptive Management</u> - NWEC suggests that NWPP follow a course of adaptive management in program design and implementation. - In particular, recommends that a program evaluation of the first pre-binding phase of the program, including both process and impact assessments, be conducted by an outside evaluator, so that the binding phase of the program can gain the benefit of formal external review.	- Thank you for your recommendation. Further discussion on implementation plans and roles/responsibilities for the PA and/or Program Evaluator/Monitor are planned as part of Phase 2B. These suggestions have been flagged for further discussion as the transition from the non-binding Stage 1 to binding Stage 2 is considered.
NIPPC	<u>General Remarks</u> - Supports the creation of a well-designed RA Program in the Northwest. - Welcomes the addition of Calpine to the SC as this addition brings a more diverse commercial perspective.	- Thank you for this comment.
	<u>Stakeholder Engagement</u> - Supports proposal of holding technical workshops with the SAC, transmission deliverability and RA contracting practices are most important to address.	- Thank you for this comment. The SC intends to address transmission deliverability, RA contracting practices, and interplay with Extended Day ahead Market (EDAM)/EIM in technical workshops and will

Stakeholder	Comments	Steering Committee (SC) Response
	- Workshops on transmission deliverability should cover details of the zonal transmission requirements and how entities with RA obligations could acquire transmission rights in order to access the geographic diversity benefit. - Workshops on contracting practices should encompass a more detailed discussion of function of operational component of the program and interplay with EDAM.	consider the recommendations for specific details the workshops should cover as we develop the meeting agendas.
	<u>Two Binding Seasons/Commitment Periods</u> - NIPPC remains concerned that seasonal approach to commitment periods may disadvantage IPP generators that do not have ratepayer cost recovery recourse. - The cost of procuring capacity under a seasonal requirement is likely to lead to higher RA prices than under an annual requirement as all generators seek to recover annual fixed costs under sub-annual contracts, this may mitigate NIPPC's initial concern. - Opposes shortening the RA commitment periods any further, recognizing that some LSEs prefer a shorter, even monthly, RA obligation. - Urges the SC to explore mechanisms to encourage longer-term multi-year contracting for capacity, noting that SPP's RA Program has requirements that encourage longer term capacity contracting. - The stronger a signal from a regional program that capacity will be adequately compensated over multiple years, the more likely RA will be ensured.	- The SC had to balance the benefits and costs associated with monthly, seasonal, and annual requirements. Currently, we are looking at two binding seasons – one 5 month long and the other 4 months long. These seasons were selected based on when the capacity critical hours, the hours within a day where the delta between forecasted net load and generation is the smallest, occurred. The length of these seasons may change if the modeling shows the capacity critical hours in longer or shorter seasons. Also, these seasons may change as loads, resources, and/or regulatory requirements change. - In general, the seasons need to be long enough to take advantage of the load/resource diversity which should also lower the PRM. Another factor that needs to be considered is the impact on planned outages. We understand that in other RA Programs, generators take all of their planned outages in the non-binding seasons to optimize value.
	<u>Contracting Paradigm</u>	- Thank you for this comment. The SC intends to address RA contracting practices/paradigm in a technical workshop and will

Stakeholder	Comments	Steering Committee (SC) Response
	- Urges the SC to explore in more detail with the SAC and SC members how the contracting paradigm in the region may shift with a regional RA Program. Suggests that SC provide a quantitative analysis (in an aggregate fashion) of existing contracting practices in the region for capacity which should ideally disclose the amount of capacity required by LSEs from other parties in advance of real-time operations and a break-out of the average terms of those commitments in recent years. - The SC should provide illustrative examples of the actual form of an RA contract it envisions between LSE's and other parties. - The mechanics of how a systems-triggering event would impact day ahead and real-time transactions that convert capacity resources into energy should be more fully explored. For example, if regional RA Participants also participate in EDAM, what potential frictions points would exist? Would there be restrictions on making bids into the EDAM while still complying with an RA obligation? - The SC should explore in detail how RA obligations could be transferred among participating entities.	consider the recommendations for specific details the workshops should cover as we develop the meeting agendas. - As you know, in today's markets, entities may wait until a few months, weeks or even days ahead of the operating day to purchase the energy required to meet their load needs. To comply with the RA Program in the future, entities will be required to contract for capacity and transmission in the forward showing time horizon (5+ months in advance of the season) to meet the RA metrics. - The SC will consider, as part of Phase 2B, how contracted capacity would demonstrate meeting program requirements and how transfer of obligation would occur; we will consider your recommendation for an illustrative example of those contracts as those discussions progress. - Similarly, the SC will be considering in much greater detail the operational time horizon, systems-triggering events, and how pooled capacity would be called upon. Phase 2B will specifically consider integration with other ongoing regional programs, including EDAM and EIM. The SC intends to discuss the topic of RA Program interaction with current and planned regional market programs and initiatives in a technical workshop.
	Transmission - Urges the SC to engage with a broader cross-section of transmission customers in the region regarding deliverability requirements. - The proposed zonal approach creates an incentive for transmission operators and customers alike to secure transmission rights within constrained load zones in order to access the geographic diversity benefit of the regional program.	- Thank you for this comment. The SC will further evaluate transmission deliverability in a technical workshop and will consider these recommendations/comments provided. - Also, we are coordinating with all of the Balancing Authorities (BAs) participating in the program (including all of the critical transmission providers) and with the Northern Grid transmission group. We will use the input from these groups in addition to the SC members with transmission to consider transmission constraints etc.

Stakeholder	Comments	Steering Committee (SC) Response
	- SC should evaluate whether zonal approach conforms with OATT's of the region's transmission operators. - Encourages SC to discuss in more detail how a zonal approach would shine a spotlight on transmission constrains for planning purposes.	
	<u>Governance</u> - Urges the SC to propose a specific way to ensure the independence and adequate oversight of the PA of the regional program. - Recommends the SAC and SC evaluate the bylaws of organizations like SPP who have similar RA Programs approved by FERC. - Recommends creation of an independent multi-state regulatory board comprised of state regulatory representatives with a meaningful oversight role with a role for consumer owned utilities and PMA's as well.	- Thank you for these comments and recommendations. The SC will hold a SAC technical workshop on governance. - The SC and the external counsel retained for this effort have spent significant time considering governance structures of FERC jurisdictional programs. We continue to learn from their experiences, pulling what we can to help us navigate our unique situation. - Roles and responsibilities for governing groups will be further considered as part of Phase 2B, and your recommendations for state engagement have been identified for consideration as those discussions progress.
	<u>Point of Compliance</u> - NIPPC supports establishing the RA obligation point of compliance at the LSE level, however it notes that that the Oregon PUC is currently exploring in Docket UM 2024 how retail choice providers in Oregon would participate in a regional RA Program to meet state RA requirements as well as how a state obligation could work in harmony with a regional RA Program and anticipates more detailed discussion on this. - A regional RA Program open to all LSE's is more efficient means than a program limited to as single state.	- Thank you for these comments. The SC looks forward to further discussing the question of point of compliance with stakeholders in Phase 2B. The SC believes that in order for reliability to be adequately supported, RA needs to broadly encompass load service in the footprint of the program. There will be a technical workshop on governance. - The SC has begun work on state outreach, which will continue throughout Phase 2B. We are aware of the Oregon Public Utility Commission's (OPUC) RA docket and have provided updates on the NWPP effort to the OPUC.

Stakeholder	Comments	Steering Committee (SC) Response
	- LSEs should be obligated entities under a regional program. - Non-IOU LSE's serving load within BAAs should be able to choose to procure some of amount of RA directly from the applicable BA to the extent such amounts are available to serve both the BA's native load and nested LSE's load. - If RA obligations are imposed on retail choice providers, states should make participation in the regional program the primary and preferred means of compliance.	
	<u>Additional Questions and Clarifying Recommendations</u> *Contingency reserves* - What is the expected interaction between the NWPP Reserve Sharing Program for contingency reserves and an RA Program during capacity critical hours? - In complying with the RA Program, would LSEs be able to testify to participation in the NWPP Reserve Sharing Program to supply a portion of their RA obligation? - In that case, should explicit cross-participation in the two programs be opened to and encouraged for a broader array of market Participants? *Participation fees* - What is an appropriate possible range of fees for program participation, both on the part of LSEs and the part of generators and marketers? How do other RA Programs assess fees to cover the costs of running the programs? *Underperformance penalties*	- The contingency reserve sharing program is usually available for about 60 minutes during a declared system emergency. Because these events can occur before, during or after capacity critical hours, we expect that the RA capacity and contingency reserves will be separate and distinct. The SC is actively considering this issue in Phase 2B. - The SC anticipates providing approximations for cost of participation in the future program as part of Phase 2B deliverables, and endeavors to have more answers to these questions when the phase is complete. - Similarly, the operational program and non-compliance or underperformance in that time horizon will be considered during Phase 2B. - Stress conditions and reliability events will be a consideration in Phase 2B.

Stakeholder	Comments	Steering Committee (SC) Response
	- What is an appropriate possible range of financial penalties to assess for underperformance or non-performance of participating capacity resources in the event that committed capacity is called on to be converted to energy by a counterparty LSE or by the PA under a systems-triggering event? *RA event simulations* - The SC should examine several illustrative RA stress cases to simulate how the regional program may or may not help avoid or mitigate severe stress conditions, including region-wide reliability events.	
Oregon PUC	Staged Functionality of the Program - It would be helpful if the CD explained what the goal of each stage is after it's description.	- This is a helpful recommendation and in future documentation, the SC will strive to include specific delineation of goals and objectives.
	Capacity RA Program - It seems reasonable that the RA resource sharing part of the plan utilize the same analysis timeframe as the forward showing. If the showing is for "RA" (1-4 years) then the sharing portion should also be on the 1–4-year timeframe. - If the plan is for the RA sharing to be available on a day ahead timeframe, then the forward showing should have a corresponding timeframe.	- The ability of a regional RA Program to access diversity benefits (a.k.a. "sharing") occurs in both the forward showing program and the operational program. The timeframes for the forward showing program and the operational program are different, as are the metrics that are used to evaluate whether a Participant has met all of their requirements. The proposed timeframe for the binding forward showing program is 7 months ahead of the winter and summer season. The regional RA Program is also anticipated to provide Participants with non-binding RA requirement information 2-3 years ahead of the compliance period. The operational timeframe is currently under consideration in Phase 2B. Further technical discussions with the SC and the PD will determine the day ahead and real-time planning requirements and outline the role of the PA in this time horizon. Although different timeframes are involved with these components of the program, diversity benefits are available in each. The manner in which diversity benefits are identified and accessed will differ in the forward showing program and the operational program.

Stakeholder	Comments	Steering Committee (SC) Response
		- During the forward showing time period, the PA will determine the PRM for the entire program footprint as a whole, assuming that the footprint is coordinating its planning. The PA will also determine each Participant's sub-allocated PRM based on the footprint's PRM. In this manner, a Participant's individual PRM may be lower (than it would have been if an entity were attempting to meet the same reliability metrics on its own) because of the RA Program footprint diversity. - The operational timeframe is where additional diversity benefits may become "unlocked" through accessing pooled regional RA resources, taking into account actual operational conditions (something that cannot occur during the forward showing assessment because the forward showing is a "snapshot" at a given point in time). For example, it is possible that a Participant who met all of its forward showing requirements at the forward showing deadline enters the operational timeframe with insufficient capacity based on operational conditions (e.g., because of forced outages, etc.). Conversely, it is possible that a Participant who met all of its forward showing requirements at the forward showing deadline enters the operational timeframe with surplus capacity (e.g., because of unexpected decreases in load due to weather changes, etc.). Under this scenario, the Participants of the program should be able to benefit from being part of the program; the Participant that is short can share the surplus capacity of the Participant that is long. - As explained above, further technical discussions with the SC and the PD will determine the day ahead and real-time planning requirements and outline the role of the PA in this time horizon. This would include how Participants will be assessed as being compliant during the operational timeframe, which may involve metrics that take into account actual operational conditions. Within the day ahead and real-time windows, member entities also participate in various existing wholesale bilateral and organized markets (e.g., EIM). In Phase 2B, the SC and PD will further consider how the operational program design will integrate with these markets,

Stakeholder	Comments	Steering Committee (SC) Response
		including the potential overlay between RA and RS metrics in the day ahead timeframe.
	Capacity Contribution of Resources - ELCC and UCAP both only measure average or expected values of capacity. These are fine for RA timeframe analysis of raw capacity. However, these metrics are not as predictive in a day ahead paradigm and should not be relied on to be accurate in any timeframe shorter than seasonal.	- Agree. Please see response above which addresses the different timeframes and metrics used for the forward showing program and the operational program. Metrics like Effective Load Carrying Capacity (ELCC) and Unforced Capacity (UCAP) are only proposed to be used for the forward showing program. The operational program would utilize metrics that take into account actual operational conditions.
	Forced Outages - I am not sure how ELCC handles forced outages - these are somewhat normal events for VERs.	- Forced outages are already taken into account for ELCC because ELCC looks at actual historical performance of the resource on an hourly basis.
	Transmission and Deliverability - This may prove to be a pivotal aspect of the program. Even if entities are generation rich, if transmission is unavailable to move the energy, the impact on RA is critical. - It may turn out that a transmission sharing program proves as valuable as a generation (capacity) sharing program for RA purposes.	- Thank you for this comment. The SC will further evaluate transmission deliverability in a technical workshop and will consider these recommendations/comments provided.
	Operational Program - It appears to me incongruent to have a forward planning program based on 1-4 year capacity adequacy and then assume that there is an operational timeframe adequacy in the day ahead time period. - This implies that perhaps ALL resources of a participating entity will become "pooled." I assume that an entity's requirement to serve native load takes a priority over any RA sharing - there may be conflicting asks of the same resource.	- The intent of the forward showing program is to ensure in the planning horizon that there is sufficient capacity for the entire footprint to serve load during capacity critical hours, the hours within a day where the delta between forecasted net load and generation is the smallest. In order to benefit from regional load and resource diversity, program Participants will need to have some way to share that diversity in the operating time horizon. - In the forward showing program, participating entities must show they have enough resources to fulfill regional reliability metrics; resources they possess beyond these metrics are not subject to the program unless contracted to another Participant to fulfill that

Stakeholder	Comments	Steering Committee (SC) Response
	- The approach to pooled capacity appears to suggest that the ability for a company to dispatch its own resources to meet its own reserve needs will be superseded by the program. Will utilities be comfortable giving up control of their pooled resources in a crisis?	Participant's metrics. It is only the resources used to meet those metrics that are considered "pooled" capacity. - The ability to access pooled capacity in the operational timeframe will take into account actual operational conditions. Participating entities will retain full control for dispatching their own resources. Entities experiencing high load events will be expected to dispatch the resources they used to meet the forward showing adequacy metrics (or substitutes – for further discussion). Participating entities not experiencing high load events would be responsible for making pooled capacity (that used to meet their own forward showing metrics) to the pool; which resources are dispatched to meet their own or the regions needs would remain in their control.
PNUCC	General Remarks - Overall the Conceptual Design document is very well-done and helpful.	- Thank you for this comment.
	LOLE - Is the increment/metric determined or yet to be decided for the NWPP Region? If not specified yet, it would be helpful to document a couple of elements that are being considered in establishing the appropriate metric and/or the reasons it is a challenge to pick one. And if it is well defined.	- The SC recommends a loss of load expectation (LOLE) objective of 1 day in 10 years where capacity is expected to be insufficient to meet load plus contingency reserves. An event is defined as a time when all reserves (e.g., RA reserves) have been exhausted except those that are set aside as contingency reserves. An event could be multiple hours in a day; loss of load hours in a single day, whether consecutive or non-consecutive, would constitute a single event. The reliability metric will be revisited at the end of Phase 2B.
	Coincident versus Noncoincident Peak Load - Coincident vs. non-confident peak load. If I recall, there was still a question about that, but I'm not sure why.	- At this point there is general consensus among the SC member that the obligations will be allocated based on non-coincident peak loads, but this issue will be re-examined as program design is completed, as we appreciate that many of these design decisions are interrelated.
	Hydro Methodology - The thought is that summer flows are pretty tight, regardless of the assumption the hydro availability won't swing much. However, in winter with such a	- The hydro methodology will be based on an analysis of the capability of the storage hydro facilities during capacity critical hours, the hours within a day where the delta between forecasted net load and generation is the smallest, over a 10-year period, and

Stakeholder	Comments	Steering Committee (SC) Response
	spread in possible flows, will there be a risk of being too optimistic if water conditions are really poor. A few sentences to elaborate on the average water thinking could help.	as such will reflect the capability of hydro in a range of water conditions (and the associated storage conditions) in both the summer and winter seasons. Further, we will consider storage hydro critical hour capabilities in specific low water years to evaluate the impact of low water on the storage hydro fleet's capacity contribution during capacity critical hours. Hydro capacity contribution will be addressed in a SAC technical workshop.
Renewable Northwest and NW Energy Coalition	<u>RA Program Goals and Objectives</u> - Suggest the addition of "resource diversity and transparency across the program" as objectives with respect to information sharing for the purpose of achieving an efficient and fair common pool sharing among RA entities. - Objectives of the RA Program should capture the full range of adequacy risks on an annual, seasonal/monthly and super-peak basis, and should strive to avoid bias toward any specific type of resource. - We suggest adding an emphasis that the program should optimize net benefits to the entire region and assure beneficial results to all Participants. - Recommend engagement with developers and subject matter experts to understand technical and operational characteristics of emerging technologies.	- Thank you for your comments. The SC agrees that a regional RA Program should be technologically neutral and should be designed to not exclude any resource types that members may choose to meet their requirements, but rather to appropriately accredit capacity based on the operating characteristics of the resource. - The program design is intended to optimize the benefits to all participating entities and take advantage of the diversity in loads and resources across the footprint of the program. An inherent benefit of regional RA is lower overall cost to achieve the same level of reliability that would be possible under individual utility planning for RA. The realization of investment savings is one of the program objectives identified by the SC. The benefits of increased reliability and lower costs and risks will benefit the region as a whole. - The SC will consider the recommendation to engage with developers and subject matter experts to understand the technical and operational characteristics of emerging technologies.
	<u>Governance and Regulatory Impacts</u> - We recommend developing a more structured stakeholder participation and input process so that the design decisions and program operation can be made more consistent and forward looking. - We recommend strong coordination with state and provincial regulatory bodies to align the RA	- The SC agrees that stakeholder input is essential to the RA Program development and future stakeholder engagement may evolve into a more formal process as we get closer to implementation and after the PA is hired. - The SC has begun to conduct state outreach intends to continue such outreach throughout program development.

Stakeholder	Comments	Steering Committee (SC) Response
	Program with their existing processes relating to resource adequacy.	
	Forward Showing Program Conceptual Design - How will obligation at the LSE level impact who may offer resources into the program? For non-load serving entities with resources capable of providing capacity, how will the program work to allow participation? - Suggest an annual update of seasonal PRM based on changes in load and shift in peak demand hours. This would be essential for RA entities to inform short-term capacity planning as more renewable and storage resources come online. - Suggest a study of non-coincident peak and multi-day capacity critical hours which may affect individual BAA's system reliability. - Suggest a transparent process for data sharing and dispute resolution on PA's load forecasting methodology and results. This would ensure that potential resources are well-equipped to provide firm capacity into the sharing program.	- Independent generators who have contracted their supply would be treated like utility-owned resources. The SC will further clarify how independent generators fit into the program in Phase 2B. - The SC will consider these suggestions while developing detailed program design Phase 2B. - The SC appreciates your considerations related to the proposed load forecasting approach. Load forecasting methodology will be a topic for further discussion in Phase 2B. The SC recognizes the importance of accurate load forecasts and firm resource commitments in order to determine adequacy and ensure reliability.
	Showing and Compliance Timeline - Relying solely on seasonal showing requirements tends to discount the value of resources and the intra- seasonal variability in demand and supply in the region. - The SC should consider more frequent showing periods during each compliance season based on rigorous modeling to optimize economic performance, fairness, and reliability. As a starting point we suggest publishing monthly capacity-	- The SC will consider these suggestions while developing detailed program design in Phase 2B. - The SC agrees that formulation of capacity critical hours is an important design element. During the Phase 2A discussion, the SC determined that showings requirements timelines need to ensure: 1) that the requirements that each entity has to meet for each upcoming binding season can be known with certainty to facilitate resource acquisition contracting timelines and outage planning for the member entities, and 2) that the PA can do a timely evaluation of the footprint in advance of the binding season such that any issues can be identified and addressed well in advance. The

Stakeholder	Comments	Steering Committee (SC) Response
	critical hours and considering the possibility of quarterly or monthly showing periods. - We recommend a detailed assessment and an evolutionary process to inform the formulation of the capacity-critical hours in the region. These issues are being examined elsewhere, such as the current review of availability assessment hours for the CAISO RA Availability Incentive Mechanism (RAAIM). - We recommend providing a flexible updating process for hydro resources, to avoid the risk of deficiency during the showing period due to changing weather and stream conditions. - An additional factor that must be addressed for all Columbia River hydro resources is the changes in the operation of the Columbia River Treaty starting in 2024.	proposed showings periods were considered to be of the right granularity for modelling purposes, while facilitating those two objectives. - The SC is developing a methodology for capacity qualification of hydro resources. The hydro methodology will be based on an analysis of the capability of the storage hydro facilities during capacity critical hours, the hours within a day where the delta between forecasted net load and generation is the smallest, over a 10-year period, and as such will reflect the capability of hydro in a range of water conditions (and the associated storage conditions) in both the summer and winter seasons. Further, we will consider storage hydro critical hour capabilities in specific low water years to evaluate the impact of low water on the storage hydro fleet's capacity contribution during capacity critical hours. This topic will be further discussed with the advisory committee in Phase 2B.
	<u>Planning Reserve Margin</u> - A more granular and probabilistic approach is needed to evaluate intra-seasonal stress conditions and super-peak periods within seasons which will likely become more prominent with the effects of climate change and increasing electrification of loads. - It will be important to consider calculating more granular monthly LOLE or LOLP values initially to highlight the high-stress periods and allow resources the opportunity to supply that need. - We recommend a technical workshop to study more granular approaches. The Northwest Power and Conservation Council's ARM1 and ASCC metrics can	- The SC will consider these suggestions while developing detailed program design in Phase 2B.

Stakeholder	Comments	Steering Committee (SC) Response
	be considered to assess the interactive effects of a diverse resource portfolio.	
	Load Forecasting for Forward Showing - The Conceptual Design document mentions that "the PA will model either the coincident or non-coincident peak demand for the region". This aspect of the program is critical to set regional metrics and would need to be addressed in Phase 2B. - Load forecasts should be consistent with integrated resource planning methods, including regional planning such as Northwest Power and Conservation Council's Needs Assessment, and provide an integrated program forecast rather than rolling up the forecasts of participating entities.	- At this point there is general consensus among the SC member that the obligations will be allocated based on non-coincident peak loads, but this issue will be re-examined as program design is completed, as we appreciate that many of these design decisions are interrelated. - Thank you for this comment. The SC intends to address RA contracting practices as well as the topic of RA Program interaction with current and planned regional market initiatives in a technical workshop.
	Regional Import/Export Assumptions - An exploration of potential unintended consequences on the utility procurement process to limit competition, increase contract costs, or shift risk to IPPs and consumers should be considered in the planning phase of the program. - Suggest more deliberate analysis on how this program will operate within the construct of a regional day ahead market and also the possibility that the program could at some time operate within a larger wholesale electricity market across the region.	- Thank you for this comment. The SC intends to address RA contracting practices as well as the topic of RA Program interaction with current and planned regional market initiatives in a technical workshop. - Further technical discussions with the SC and the PD will determine the day ahead and real-time planning requirements and outline the role of the PA in this time horizon. This would include how Participants will be assessed as being compliant during the operational timeframe, which may involve metrics that take into account actual operational conditions. Within the day ahead and real-time windows, member entities also participate in various existing wholesale bilateral and organized markets (e.g., EIM). In Phase 2B, the SC and PD will further consider how the operational program design will integrate with these markets, including the potential overlay between RA and RS metrics in the day ahead timeframe.
	Resource Eligibility and Qualification	- The SC has elected to use a pure capacity methodology to assess capacity contributions and agrees that it is imperative that capacity

Stakeholder	Comments	Steering Committee (SC) Response
	- It is our understanding that planned outages will not be included in UCAP calculations. It will be critically important that resources present their scheduled outages in the RA workbook to adequately represent the full availability of the resource during capacity critical hours. - Consistent and accurate calculation of UCAP needs significant attention. Currently, for example, the CAISO is considering an approach that would quantify Forced Outage, Urgent Outage, Planned Outage and Opportunity Outage, but only Forced/Urgent Outage would count as UCAP. These factors should be considered in the NWPP RA Program. - A sound methodology needs to be formulated for assessing capacity contributions of emerging technologies like standalone storage, hybrid, and demand response resources, which will play a pivotal role in future buildouts in the region. Due to lack of operational data for these technologies, initial capacity accreditation method should be reasonably selected, and then revisited by a formal method informed by data collection on operationality and deliverability. The timeline for a formal method could be set after 2 years of operational data collection.	represented in workbooks is accurate and reflective of planned outages. Capacity contributions for individual resources will be evaluated using the identified methodology (thermals using UCAP, for instance). When participating entities claim a resource in the forward showing program, they will be responsible for identifying planned outages and supplying replacement capacity for those times units would be offline. - The SC will further consider outage procedures (for outages planned both before and after the showing deadline, forced outages, etc.) during Phase 2B. It is anticipated that forced outages rates would be accounted for in UCAP calculations, though more detailed consideration of forced outage treatment (as suggested) will be undertaken in Phase 2B. - The SC is committed to ensuring technology neutrality of the program (accurately assessing all resources' contribution to regional reliability during capacity critical hours) and to enabling contribution by all available resources able to meet program requirements. The SC will consider these suggestions while developing detailed program design in Phase 2B, including the need to evaluate capacity contributions of new resources (lacking in historical data).
	Capacity Contribution of Resources - The Northwest Power and Conservation Council has developed methods to assess the complementary effects of coordinated hydro with other resources, thus valuing all resources not merely for their hours of output capability but also their interaction with other resources on the system. Methodologies such	- Thank you for these suggestions; the SC will consider these while developing detailed program design in Phase 2B. We have addressed as many of the suggestions as we currently are able but have noted the others for further consideration. - Capacity contribution of demand response and hybrid resources (e.g., solar and batteries) will be further discussed in Phase 2B; the

Stakeholder	Comments	Steering Committee (SC) Response
	as the ARM and ASCC model this dynamic. This approach should be considered in the NWPP RA Program. - The assessment of demand response should be based on probabilistic models of availability. Phase 2B and the preceding should continuously incorporate new research and best practices for more dynamic modeling of demand response. - Recommend that the penalty amounts for deficiency should be commensurate with resource type. It may not be accurate to apply a CONE methodology using a natural gas fired peaking facility when assessing penalties on solar, wind, or hybrid generators which do not incur the same capital and operating costs. *Wind and Solar* - We recommend a 5-year historical generation forecast instead of a 3 year to inform QC values for wind and solar resources. - Last-in ELCC framework should be considered for informing resource contributions of renewable resources instead of using deterministic methods. This methodology is explained in E3's work3 presented before Oregon PUC in UM 2011 docket on General Capacity Investigation. - More clarity on how wind and solar resource zones are selected would be helpful. The resource zones should be selected based on resource availability and not be constrained by available transmission. - Recommend studying the interaction among solar, batteries, pumped storage, and DR/EE resources, along with dynamic peak assessment and how they	SC appreciates the need to enable these emerging technologies to contribute to a regional RA Program. - The SC's use of the CONE factor as a penalty is intended to strongly motivate Participants to comply with program metrics in the forward showing time horizon. This penalty would not be associated with any particular resource (e.g., solar, wind, etc.), but would be levied against an entity which did not show adequate resources in the forward showing portfolio. In the forward showing program, entities choose what resources to use to meet the adequacy objective. The compliance penalty is associated with the cost of a natural gas fired peaking facility as a proxy to illustrate a way the program could close a gap left by a non-compliant entity; the use of this particular resource type is hypothetical, used to arrive at a basis for assessing the penalty. - The SC is considering appropriate length of historical data requests, balancing the value of additional data against data availability; this will be a topic for further discussion in Phase 2B. - Zones for ELCC studies are not anticipated to be transmission related, but instead based on geographical/fuel-related similarities. This recommendation will be re-assessed as program design is considered in greater detail; the SC recognizes that all program design elements will be interrelated and should be evaluated for consistency in approach.

Stakeholder	Comments	Steering Committee (SC) Response
	can improve the carrying capacity of each resource depending on load profiles and the diversity/distribution of the underlying resources. *Storage* - Pumped hydro storage resources and battery storage resources are essential to long-term reliability, flexibility and grid integration of renewables. - A reasonable option would be to use Pmax as the QC for storage resources which are not under ITC charge restrictions initially and then transition to an ELCC method eventually. Last-in ELCC method could also be used, similar to the approach for solar and wind resources. - *Hybrid Resources* - Since historical data for hybrid resources are not abundant, initially, we recommend a new methodology to calculate the Net Qualifying Capacity (NQC), suggested by SCE and adopted by CPUC5. This methodology accounts for the portion of output from the renewable resource necessary to fully charge the battery and the expected remaining capacity available to the grid for RA, and adds to that the QC value of the battery based upon the amount it can be expected to charge from the renewable device.	
	Transmission and Deliverability - The establishment of transmission and resource zones must be carefully considered so as not to aggravate challenges with deliverability. - We suggest a technical group focused on evaluating the potential impacts to transmission rates and	- Thank you for this comment. The SC will further evaluate transmission deliverability in a technical workshop and will consider these recommendations/comments provided.

Stakeholder	Comments	Steering Committee (SC) Response
	contracting provisions as a result of establishment of zones within and across existing balancing areas. - We suggest that within this technical discussion, the SC evaluates other potential secondary impacts of the RA Program on meeting clean energy mandates. Our concerns include the following: - A preference for utility owned resources to meet RA needs due to transmission requirements. - A challenge for new resources to count towards RA given the lack of clarity on how capacity contributions during capacity critical hours will be evaluated for new resources.	
	<u>Operational Program Design and Linkages with Other Regional Initiatives</u> - During the operational phase of the program, the PA should play a key role to independently determine the day ahead and real-time planning requirements. - We recommend further discussion on interaction of the NWPP RA Program elements like deliverability with regard to existing bilateral transactions, the EIM and future Extended Day- Ahead Market (EDAM) initiative. - Recommend the SC to identify touchpoints with EDAM in future as the NWPP RA Program design gets clearer. - An ongoing stakeholder group should be established to review operational reports and performance metrics and provide input to program refinement.	- Thank you for this comment. The SC intends to address the topic of RA Program interaction with current and planned regional market initiatives in a technical workshop. - Further technical discussions with the SC and the PD will determine the day ahead and real-time planning requirements and outline the role of the PA in this time horizon. This would include how Participants will be assessed as being compliant during the operational timeframe, which may involve metrics that take into account actual operational conditions. Within the day ahead and real-time windows, member entities also participate in various existing wholesale bilateral and organized markets (e.g., EIM). In Phase 2B, the SC and PD will further consider how the operational program design will integrate with these markets, including the potential overlay between RA and RS metrics in the day ahead timeframe.

Stakeholder	Comments	Steering Committee (SC) Response
	- Phase 2B should survey and understand regional distribution system planning, non-wires alternatives and other transmission/distribution interface proceedings and efforts as they relate to local RA conditions and remedies.	
	Legal and Regulatory Requirements - It is still important to create an independent board before the binding program is developed. - How will the program report out to each participating state regulatory body? Recommend regular updates and reporting.	- The SC appreciates the interest and importance of governance of the program to stakeholders and intends to discuss this further in a technical workshop.
PNGC	Governance/Point of Compliance - What entity is required to meet the obligation is one of our primary concerns. Should the compliance obligation reside with an LSE like PNGC and other BPA customers serving retail load, or Balancing Authority's (BA) like BPA/PGE/PAC?	- The SC appreciates the interest and importance of governance of the program to stakeholders and intends to discuss this further in a technical workshop.
	System Requirements - What technology platform/software is needed? - Who pays those costs? - How will the RA Program costs be collected and allocated? - Could this decision change program compliance as expressed in the Conceptual Design document?	- The technology platform and software have not been determined at this time. The SC will work with the PD in Phase 2B to identify any technology needs for final implementation. - Allocation and collection of costs have also not been determined at this time. Cost and the allocation/collection of the full RA Program will be developed towards the end of Phase 2B. - The SC recognizes that many of these design elements are interconnected and may impact one another; we are committed to evaluating the design when it is complete to ensure elements align; in this way, compliance considerations could be impacted by decisions regarding program costs and allocation methodologies, though at this point the SC has not specifically identified this as an issue.

Stakeholder	Comments	Steering Committee (SC) Response
	Access to Pooled Regional Resources - How will this sharing ultimately work, what will the process be to tap into these? - Can non-NWPP entities access the benefits of RA and the pool sharing mechanism?	- Work is being done currently in Phase 2B with the help of the PD on the final design for sharing benefits of a fully implemented RA Program in the operational time horizon. More specific processes, procedures, calculations, etc. will be considered as the detailed design of the operational program is refined. Generally, the intent is to allow an LSE access to pooled capacity if their load (+ extenuating circumstances like net VER production) is higher than was planned for in the forward showing. They may have the option to use the market to meet their needs rather than accessing the pooled capacity, though the logistics of access will be considered further in Phase 2B. - The pooled capacity would only be accessible to NWPP RA Participants, as it would be essential that those accessing the pooled capacity had participated in the forward showing program to demonstrate that they have acquired resources to contribute fairly to the pooled capacity in the operational time horizon.
	Capacity Versus Energy - Agree with approach to start with a capacity program. - Once a regulated entity meets the showing period with capacity the requirement is satisfied. No shorter-term energy requirement is applicable past 2 month true up from the capacity forward showing. - System triggering events - What lead time is provided here? How will the alert be provided? - How will this impact bilateral trading markets like Daily, Weekly, or BOM deals? - How does a regulated entity demonstrate a sale is surplus to seller's needs?	- Correct – no shorter-term (beyond a few hours) energy requirement is being developed by the SC at this time. If an entity meets their capacity showing requirements at the end of the cure period, they will not be required to contract for additional resources after that deadline (barring unforeseen maintenance outage needs, etc.). Entities will be responsible for holding the capacity they claimed in the forward showing until it is either called upon for an event or released by the PA when forecasts indicate that an event is highly unlikely to occur. - The SC is focused on implementation of a capacity RA Program. Once a capacity RA Program is implemented, the SC could build on the program by addressing an energy or flexibility RA Program. - Final design details on lead time and any such impacts on bilateral trading markets are currently being discussed in Phase 2B with the help of the PD. This includes how an entity would demonstrate surplus RA capacity for possible sale in the marketplace.

Stakeholder	Comments	Steering Committee (SC) Response
		- The SC also intends to address RA contracting practices/paradigm in a technical workshop with the SAC.
	Capacity Factor Calculation - Ensure hydro and other resources have similar accreditation calculations. - More insight into storage hydro projects, including pump hydro, needed.	- Although final details on the qualifying capacity contribution for resources are still being determined in Phase 2B, the SC recognizes the unique situation that the Northwest is in with its prevalence of storage hydro resources. Because of this, special consideration will be given to the capacity calculation for storage hydro. The hydro methodology will be based on an analysis of the capability of the storage hydro facilities during capacity critical hours, the hours within a day where the delta between forecasted net load and generation is the smallest, over a 10-year period, and as such will reflect the capability of hydro in a range of water conditions (and the associated storage conditions) in both the summer and winter seasons. Further, we will consider storage hydro critical hour capabilities in specific low water years to evaluate the impact of low water on the storage hydro fleet's capacity contribution during capacity critical hours.
	Unplanned Outages - With how planned outages are discussed we feel keeping just two seasonal periods is optimal. Because it provides certain timeframes to allow for planned maintenance of units outside of showing periods.	- While the SC has identified four seasonal periods, two of these seasons are identified as "advisory." During the Fall and Spring seasons, the PA would supply adequacy objectives, but participating entities would not be penalized for not meeting these metrics; this would allow Participants to plan maintenance during these "advisory" shoulder seasons.
	Transmission Procurement Obligation - Could a resource be downgraded in capacity value due to lack of firm or conditional firm transmission? - How would secondary network transmission (6-nn) be valued compared to Conditional Firm?	- The SC recognizes the importance that firm transmission plays in both the contribution of capacity in a forward showing period and the ability to deliver RA benefits in the operational period. - Final details on capacity contribution for resources are still being developed in Phase 2B with the help of the PD and Regional Transmission Organizations. - The SC intends to address transmission deliverability and RA contracting practices in a technical workshop and will consider the

Stakeholder	Comments	Steering Committee (SC) Response
		recommendations for specific details the workshops should cover as we develop the meeting agendas.
Washington UTC	General Remarks - The production of the Conceptual Design working document represents a major first step in developing a Resource Adequacy (RA) program that has the potential to help the region meet its capacity needs as it transitions off of carbon based fuels and to support more efficient commercial trading and economic use of capacity. It demonstrates the progress the Northwest Power Pool members have made and reveals many of the complex challenges facing the Resource Adequacy Program Development Project (RAPDP). - In addition to considering specific elements of the RA Program design, it is important to keep in sight the broad requirements any Northwest (NW) RA Program must fulfill. A NW RA Program must calculate capacity needs during critical water years and temperatures. It must encompass the full range of historic variations and patterns of the natural stream flow available to the hydroelectric generation systems for generating energy and capacity and the energy available to variable energy resources (VER). The variations in temperature and water years must also be adjusted for the effects of greenhouse gas (GHG) driven climate warming. The SC should include these goals in the phased work schedule of the RAPDP.	- Thank you for your comments.
	Capacity RA Program - Designing a capacity RA-based program is a practical and achievable first step. A successful RA Program must consider the interrelationship	- The SC identified capacity RA as the most urgent need facing the region. Further, though its implementation presents a number of challenges, a capacity adequacy program is the most straightforward to implement.

Stakeholder	Comments	Steering Committee (SC) Response
	between capacity and energy, as well as generation ramping capacity (flexibility). The phased work schedule should include target dates for including energy constraints and flexibility capacity.	- The capacity RA Program will address the needs of the region in the capacity critical hours which are the hours within a day where the delta between forecasted net load and generation is the smallest. Once the capacity program is implemented, the SC will explore whether there are other solutions that could build upon this program, such as an energy adequacy standard. Further, the SC recognizes that there can be challenges associated with prolonged low water conditions in the region, and in Phase 2B will work together to evaluate the impact a low water scenario might have on the hydro storage capacity capability during critical hours to determine if changes to the RA requirements should be made. This topic will be further addressed a SAC technical workshop.
	<u>Greenhouse Gas-Driven Climate Change</u> - The Conceptual Design does not speak directly to GHG climate change. If the effects of climate change are to be incorporated into a region-wide RA Program, it will need to be applied in a consistent manner to all loads and resources.	- The SC agrees that the impacts of a changing climate on loads and resources is an important topic and should be considered in long-term resource planning. The RA Program is being designed for a one year out forward program time horizon. The historical data used in the calculations of certain design elements will be determined during Phase 2B. Further, the SC has identified technology neutrality as a key objective for the RAPDP effort. As states will retain control over resource procurement decisions, the RA Program would supply additional information related to resources' contribution toward a reliable grid. In this way, the program will enable states and participating LSEs to meet greenhouse gas (GHG)- and climate-related portfolio standards while maintaining regional reliability.
	<u>Resource Capacity Accreditation</u> - The methodologies for accreditation are reasonable. However, maintaining resource neutrality includes developing capacity ratings for similar resources in a similar timeframe. Keeping with this principle, battery storage and demand response should be included with the development of an accreditation methodology for Storage Hydro during Phase 2B.	- Thank you for your recommendation. The RA Program is intended to be technology agnostic and the SC acknowledges that evaluation of qualifying capacity contribution in similar timeframes helps signal resource neutrality.

Stakeholder	Comments	Steering Committee (SC) Response
	Planning Reserve Margin - The derivation of the Planning Reserve Margin (PRM) may need further discussion as the RA Program develops. For the RA Program to be effective for all load and resource conditions, the PRM must be calculated using the variation reflected in all of the available historic data with adjustments for the effects of GHG driven climate warming.	- Thank you for your recommendation. The PRM continues to be discussed during Phase 2B.
	Import Capacity - The import capacity requirements in the Conceptual Design are appropriate and necessary. The SC should consider applying those same requirements to the deliverability of resources to local zones inside the footprint of the RA Program.	- Thank you for your recommendation. The SC is considering deliverability of resources related to forward showing and operational time horizons, as well as contract eligibility requirements as part of the Phase 2B scope. Ensuring that transmission availability is considered in the design of both forward showing regional and entity-specific metrics, and in design of operational program logistics will be a priority for the SC in coming months.
	Qualifying Capacity Contribution Methodology - The SC should consider using five years of historic data for thermal resources. Additionally, the SC should examine the benefits of using all available production data for calculating the Effective Load Carrying Capacity (ELCC) for VERs. For instance, it should examine if revisiting the ELCC of a VER as additional historic data is available might increase the accuracy of the ELCC for that resource. For a VER with only 3-6 years of historical production data, the SC should examine if using zonal class information in conjunction with the 3-6 years data might improve the accuracy of the ELCC.	- Thank you for your recommendation. The SC will further consider appropriate timeframes for informing ELCC studies and capacity contributions of all resources in Phase 2B. Availability of data for recent resource additions will be considered, as will the need to balance the desire for as much data as may be available with the burden of collecting/processing additional data and the desire to create consistent and repeatable study parameters. Specifics regarding these studies will be discussed further in Phase 2B.
	Transmission and Deliverability - Much of the diversity in load and resources that could be available to NW entities through a RA Program is located beyond the interties connecting	- Thank you for this comment. The SC will further evaluate transmission deliverability in a technical workshop and will consider these recommendations/comments provided.

Stakeholder	Comments	Steering Committee (SC) Response
	the NW to other portions of the Western Interconnect. The RA Program will need to directly answer what capacity the interties can deliver to the NW. - The RA Program should include zonal modeling on an ongoing basis and require the PA to designate RA requirements for local zones. It should examine internal flow gates and designate RA requirements for local zones as necessary. Finally, the RA Program should also work with its members to determine the need for resources to provide voltage support, inertia, and frequency response.	- Also, we are coordinating with all of the BAs participating in the program (including all of the critical transmission providers) and with the Northern Grid transmission group. We will use the input from these groups in addition to the SC members with transmission to consider transmission constraints etc.

NWPP Resource Adequacy Program Detailed Design

Glossary

JUNE 2021

NORTHWEST PowerPool

Glossary

Advisory Season – Annual periods for which program compliance is not mandatory (deficiency payments will not be applied for non-compliance with FS metrics). Spring (March 16 – May 31) and Fall (September 16 – October 31) seasons will be advisory and non-binding.

Annual Assessments – Studies and analyses performed by the Program Operator on an annual basis that includes the Loss of Load Expectation (LOLE) study that makes a determination of a planning reserve margin (PRM) for Program Participants, Effective Load-Carrying Capability (ELCC) studies that make a determination the of qualified capacity contribution (QCC) of Variable Energy Resources (VERs), and additional QCC studies for all other resource types.

Behind-the-meter generation – Generally, generating resources owned by customers or other third parties that are located beyond the utility metering point.

Binding season – Annual periods for which program compliance is mandatory (penalties will be applied for non-compliance with FS metrics or Operational Program requirements). Summer (June 1 – September 15) and Winter (November 1 – March 15) seasons will be binding.

Capacity Critical Hour (CCH) – Hours where the net regional capacity need is above the 95th percentile (highest capacity need hours).

Capacity Resource – A resource that has been assessed a QCC value and can count toward a Participant's FS capacity requirement.

Capability testing – Tests that verify generator real and reactive power capability that meet, at a minimum, the requirements of NERC standard MOD-025.

Centroid – A central location on the electric grid utilized to transact power to and from in order to provide for a known location to enact RA Program deliveries.

Committee of States (COS) – the group of state or provincial regulators established pursuant to the NWPP bylaws, consisting of one representative from each state of the Participants participating in the RA Program.

Contingency Reserves – The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated Emergency Operating Plan standard).

Cure period – Timeframe for Participants that have had deficiencies identified in the Forward Showing data submittal are allowed to supplement their submittals to meet Program requirements.

Customer resources – see behind-the-meter generation.

Delivery Failure Penalties – Monetary charges to a Resource Adequacy (RA) Participant who fails to deliver during Energy Deployment.

Δ Forced Outages - includes any unplanned reliability outages or unplanned reliability de-rates associated with thermal generation units, storage hydro units and transmission outages impacting firm capacity for the operating day. Does not include economic outages and de-rates.

Δ Run-of-River Performance - comparison of forecasted run-of-river production vs. Qualified Capacity Contribution (QCC) of run-of-river hydro. Includes both over and under performance.

Δ Variable Energy Resource (VER) Performance - comparison of forecasted VER production vs. QCC of VER. Includes both over and under performance of wind and solar plants.

Demand response program – Generally, a program that allows end use customers to reduce their electricity usage during periods of high energy prices.

Energy Deployment – An hourly MW value (MWh) that a RA Participant is assigned to deliver during a Sharing Event in order to assist another deficient Participant.

Energy Deployment Calculation – the Sharing Calculation, when performed at T-120 to identify how much energy should be deployed.

Energy Storage Resource (ESR) – A resource capable of receiving energy from the electric grid (either directly or through energy conversion) and storing it for later injection of electric energy back into the grid.

Extended Day-Ahead Market (EDAM) – The California Independent System Operator's proposed initiative that extends participation in the day-ahead market to the Western Energy Imbalance Market (EIM) entities.

Firm block – Energy that is interruptible only for reasons of Uncontrollable Force or to meet the Seller's public utility or statutory obligations to its customers, provided those obligations are for reliability of service to native load.

Forced outages – Includes any outages or de-rates associated with thermal generation units, storage hydro units and transmission outages impacting firm capacity import that are not planned.

Forced outage rates (EFOR) – Metrics taken from the NERC Generator Availability Data System (GADS) that are used for analyses including the LOLE and QCC studies

Forward showing (FS) capacity requirement – An entity's P50 load plus a planning reserve margin (P50+PRM); the amount of qualified capacity (in MW of QCC value of resources, contracts and/or RA transfers) an entity must demonstrate rights to at the FS deadline.

FS deadline – Date at which FS portfolios are due to the Program Operator for compliance review (7 months in advance of the start of each binding season).

FS portfolio – The set of data submitted by a Participant to show they have met their FS capacity requirement. This workbook will include all resources owned by the Participant, RA capacity contracts, and RA transfers.

FS Program – Portion of the RA Program that deals with forward looking planning aspects of the Program. The FS Program includes the performance of Annual Assessments and the administration of FS submittals.

FS Submittals – Data submittals provided by Program Participants to the PO twice a year (March 31st and October 31st) to demonstrate compliance of FS Program requirements.

Grandfathered agreement – Contractual agreements with effective dates prior to the start of the RA Program.

Holdback Requirement – The hourly MW value that a RA Participant is asked to reserve as capacity for use by the Program during a forecasted Sharing Event. For Participants with a positive Sharing Requirement, that Sharing Requirement will be allocated pro rata by positive Sharing requirement to equal the total of the negative Sharing Requirement MWs from deficient Participants. Holdback Requirement is capped at the Sharing Requirement value.

Hybrid resources – For purposes of the RA Program, resources that contain both an Energy Storage Resource and a second resource type (VER or thermal or other)

Independence – Financial independence from individual RA Program Participants and classes of Participants in order to ensure that any such interests do not contribute to undue discrimination by the NWPP.

Installed Capacity (ICAP) – A MW value based on the seasonal net dependable capacity of a unit. Forced outage rates are not accounted for in an ICAP value.

Load Forecast - Forecasted load for the Operating Day (OD) considering the forecasted weather conditions of the OD.

Load forecast uncertainty (LFU) – In the determination of PRM, the probability of the loads that are experienced will be either higher or lower than forecast.

Load Responsible Entity (LRE) – An LRE is an entity that (i) owns, controls, and/or purchases capacity resources, or is a Federal Power Marketing Agency, and (ii) has the obligation, either through statute, rule, contract, or otherwise, to meet energy or system loads at all hours. Subject to the aforementioned criteria, an LRE may be a load serving entity ("LSE") or either an agent or otherwise designated as responsible for an LSE or multiple LSEs or load service under the RA Program.

Multi-Day Ahead Assessment – A non-binding, forecasting run conducted by the Program Administrator (PO) over the upcoming operational horizon utilized for predicting and communicating possible upcoming Sharing Events. This information is provided to Participants for situational awareness and is non-binding.

Net Contract QCC – Summation of the QCC of a Participant's purchases and sales used in the RA Program

Net Peak Demand – The forecasted Peak Demand less the projected impacts of Demand Response Programs

Nominating Committee (NC) – The committee established by the NWPP bylaws to identify a nominee or nominees for positions on the BOD.

NWPP Storage Hydro QCC Methodology – Customized methodology for determining the QCC of storage hydro projects in the NWPP RA FS Program. The methodology considers each resource's actual output, water in storage, reservoir levels, and project flow constraints. The methodology is fully detailed in Appendix D.

Operating Day (OD) – The day of operations.

Operational (Ops) Program – The Ops Program creates a framework to provide Participants with pre-arranged access to capacity resources in the Program footprint during times when a Participant is experiencing an extreme event.

Operational timeframe – the timeframe that begins at the first holdback assessment and ends at real-time.

P50 – Participant load forecast that has a 50% probability of not being exceeded during the season for which it is applicable.

Participant – Entities participating in the NWPP RA Program (i.e., an LRE that signs the Western Resource Adequacy Agreement (WRAA).

Peak Demand – The highest demand including a) transmission losses for energy, b) the projected impacts of Non-Controllable and Non-Dispatchable Behind-the-Meter Generation, and c) the projected impacts of Non-Controllable and Non-Dispatchable Demand Response Programs measured over a one clock hour period.

Planned outages - Outages or de-rates associated with thermal generation units, storage hydro units and transmission outages impacting firm capacity import that are not mandated for the purposes of reliability, safety of equipment or personnel and are at the discretion of the owner.

Planning Reserve Margin (PRM) – A percentage of dependable capacity needed above the P50 Load Forecast to meet unforeseen increases in demand and other unexpected conditions.

Point of Compliance - The Load Responsible Entity which has a compliance obligation to the RA Program.

Portfolio QCC – Summation of a Participant's QCC from its owned or contracted Resources, its purchase and sales agreements, and its RA transfer purchase/obligations

Program Operator (PO) – The entity providing the knowledge, expertise, staff, systems, and technology to implement the Forward Showing and Operational Programs.

Public Utility – for the purposes of this document, public utility should be understood per the Federal Power Act and FERC jurisdictional implications.

Pumped storage facilities – Hydro facilities that have a storage reservoir located on the upstream side of the facility that may be filled by pumping water from the downstream side.

Pure capacity – Term used in technical analyses that represents a constant generating source that has no outage rate

Qualified Capacity Contribution (QCC) **–** The number of megawatts eligible to be counted towards meeting a Participant's FA capacity requirements.

RA Program footprint – The physically and contractually interconnected power system represented by the generating resources, transmission systems, and load serving facilities of Program Participants.

RA Transfer Agreement – A type of capacity contract where the seller assumes part of the purchaser's FS capacity requirement (RA obligation) – see Section 2.4.2.2 for additional detail on these contracts. Under specific circumstances in the Ops Program, energy from these contracts will be deployed to serve either the needs of the purchaser or of the program (see Section 3.4.4).

Regulator Committee (RC) – The group of state or provincial regulators established pursuant to the NWPP bylaws, consisting of one representative from each state for the area including all Participants participating in the RA Program**.**

Release of Capacity – when a Participant is no longer expected to hold (or use to meet load) the amount of capacity from the FS capacity requirement and can use that capacity as desired.

Resource – Typically, a device capable of providing electric energy to the transmission grid.

Resource Adequacy (RA) – NERC defines it as "the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components. In order to ensure supply always matches demand, electric system operators and planners rely on reserves. There are two principal types of reserves, shorter-term operating reserves and long-term planning reserves."

Resource Adequacy Participant Committee (RAPC) – This committee is comprised of Participants and is responsible for developing and recommending policies, procedures, and system enhancements related to the policies and administration of the RA Program by NWPP.

Resource registration – The process of submitting information to the PO to determine the QCC of your resource and validating that it meets the RA Program requirements.

Resource QCC – Summation of a Participant's QCC from its owned resources.

Run-of-river hydro – Hydro resource with less than one hour of storage, not in coordination with another project.

Safety Margin – A term included in the operational program's determination of the total holdback necessary from the RA footprint when a sharing event is forecasted. The PO will identify this safety margin, based on its understanding of market, weather, outages, uncertainty, etc. This term is distinctly separate from 'uncertainty,' which will be assessed and included for each other forecasted term. Additional detail can be found in Section 3.3.10.

Sharing Calculation – The set of calculations the PO performs to forecast a Sharing Event and assign Holdback Requirement to RA Participants. The PO performs the Sharing Calculation on the preschedule day and any other interim days between the preschedule day and the OD. The same calculation is used for the Multi-Day Ahead Assessment, though the results are not binding.

Sharing Event – When the Sharing Calculation results in at least one RA Participant having a net negative Sharing Requirement, that Participant is calculated as being deficient and a Sharing Event is initiated.

Sharing Event Window – The timeframe of a Sharing Event, starting up to one hour before the first hour in which a RA Participant is calculated as deficient and ending up to one hour after the RA Participant is no longer calculated deficient.

Sharing Requirement – A result of the Sharing Calculation that represents the maximum MW amount a RA Participant may be called on by the PO to provide for a given hour of a Sharing Event. A negative Sharing Requirement indicates that a RA Participant is calculated as being deficient.

Showing resource – A generating asset or contract registered or claimed on an entity's FS portfolio.

Storage hydro – Hydro resource with one hour or greater of storage, not in coordination with another project.

Storage Hydro QCC Workbook – Analysis tool that employs the methodology used for the calculation of QCC for Storage Hydro resources

Summer binding season – June 1 through September 15

Thermal resources – Generating resources, such as those fueled by coal or natural gas, in which heat energy is converted to electricity.

Total RA Transfer – Summation of a Participant's RA transfer contracts.

Transmission Outages - An outage that may impact path limits and may affect the ability of a Participant to import firm contracted capacity.

UCAP – Represents the percentage of ICAP available after a unit's forced outage rate is taken into account.

Uncontrollable Force – An event or circumstance which prevents one party from performing its obligations under one or more transactions, which event or circumstance is not within the reasonable control of, or the result of the negligence of, the claiming party, and which by the exercise of due diligence the claiming party is unable to avoid, cause to be avoided, or overcome. This may include such things as flood, drought, earthquake, storm, fire, lightning, epidemic, war, riot, act of terrorism, civil disturbance or disobedience, labor dispute, material shortage, sabotage, etc.

Unit Commitment Service – A capacity and/or associated scheduled energy transaction or a physically settled option under which the seller has agreed to sell, and the purchaser has agreed to buy from a specified unit(s) for a specified period, in accordance with the WSPP Agreement, including Service Schedule B, and any applicable Confirmation.

Variable Energy Resource (VER) – For the purpose of this Program, typically wind and solar resources.

Western Electricity Coordinating Council (WECC) Prescheduling Calendar – Official Calendar published on wecc.org that specifies the prescheduling day for each operating day in a given calendar year.

Western Energy Imbalance Market (EIM) – The California Independent System Operator's real-time energy imbalance market.

Winter binding season – November 1 through March 15.

Western Resource Adequacy Agreement (WRAA) – Future agreement that Participants sign to join the RA Program.

WSPP Service Schedule B – A schedule to the WSPP Power Agreement (WSPP Agreement) describing additional specific procedures, terms, and conditions for requesting and providing Unit Commitment Service.

WSPP Service Schedule C – A schedule to the WSPP Power Agreement (WSPP Agreement) describing additional specific procedures, terms, and conditions for requesting and providing firm capacity/energy sale or exchange service.