Western Resource Adequacy Program

RAPC Meeting

February 10, 2022; 10-11:30am

Participant	Name	Participant	Name
APS	Brian Cole	NorthWestern	Joe Stimatz
Avangrid	Stewart Rossman	NV Energy	David Rubin
Avista	Scott Kinney – arrived 11:01	PacifiCorp	Mike Wilding
Basin Electric	Garrett Schilling	PGE	Sarah Edmonds
Black Hills	Eric Scherr	Powerex	Mark Holman
BPA	Suzanne Cooper	PSE	Paul Wetherbee
Calpine	Bill Goddard	SRP	Barbara Cenalmor
Chelan	Robb Davis – left 10:37	Seattle	Aliza Seelig
Clatskanie	Paul Dockery	Shell	Ian White – left 11:10
Douglas		SnoPUD	Jeff Kallstrom
EWEB	Matt Schroettnig	Tacoma	Ray Johnson
Grant	Rich Flanigan	TEA	Ed Mount
Idaho	Ben Brandt	TID	Dan Severson

Objectives

1. Provide the RAPC with updates on project progress.
2. Seek RAPC input on progress and any administrative actions

Meeting Agenda

Call to Order	
10:00	1. Attendance 2. Agenda Overview 3. Approve Minutes from last meeting *Minutes unanimously approved at 10:08*
PA/PO Report	
10:08	1. Budget Request *Budget request for funds to support NWPP contracting for administrative support unanimously approved at 10:18*
External Affairs	
10:18	1. Materials from Gov webinar posted, including stakeholder comment matrix

	2. Transmission FAQ *Transmission FAQ unanimously approved for posting to website at 10:25*
	3. CAISO coordination *If other participants are interested in getting involved, get in touch with Gregg*
Ongoing Business	
10:30	1. Interim RA proposed change *Updates to the program's timing approved unanimously at 10:40 (Interim RA Participants only)*
	2. Meeting with Executives – Feb 18 10-11:30am
New Business	
10:42	3. CONE Proposal *Proposal as edited unanimously approved at 11:12*
	4. Load Forecasting Proposal *Proposal unanimously approved at 11:14*
	5. Guide for Grandfathering Contracts and Agreements Proposal *Motion to table – task force will update the language and put on RAOC agenda for 2/15*
	6. Settlement Pricing Proposal *Proposal as edited (removing credit section for further consideration) unanimously approved at 11:19*
Upcoming	
11:25	1. Recommendations from RAOC on Punchlist items (Transmission demonstration requirements, 2nd hub, etc.)
Adjourned ***at 11:36***	

Current 3A Participants: APS, Avangrid; Avista; Basin Electric*; Black Hills; BPA; Calpine; Chelan; Clatskanie*; Douglas; EWEB*; Grant*; Idaho Power; NorthWestern; NV Energy; PacifiCorp; PGE; Powerex; PSE; SRP; SCL; Shell; SnoPUD; Tacoma Power; TEA; TID

*opted out of OC/work group participation

Frequently Asked Questions

On Transmission in the 2B Detailed Design

Transmission Deliverability Key Principles

a) Encourage procurement of firm transmission service sufficient to demonstrate deliverability of resources to load, while recognizing the need for flexibility where necessary or appropriate.

b) Enhance overall visibility with respect to deliverability (from generator to load) for resources used for program compliance, supporting situational awareness and regional planning.

c) Support and enhance reliability across the region without supplanting existing responsibilities of Balancing Authorities, LREs/LSEs, and TSPs, and others.

d) Rely on existing OATT frameworks to facilitate transmission-related requirements for demonstration of resource adequacy and sharing of diversity across the NWPP footprint.

e) Respect program Participants' OATT rights and responsibilities and Participants' other legal obligations, including contractual commitments and statutory requirements.

f) 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.

Transmission Deliverability Frequently Asked Questions

1) **Will the Western Resource Adequacy Program (WRAP) require demonstration of firm transmission to assure deliverability of resources load?**

   Yes - The WRAP will require Participants to demonstrate they have firm transmission service to serve their load.

2) **Once a Participant demonstrates they have firm transmission service does that then mean they are required to utilize it in all circumstances to serve load?**

   No – Though the firm transmission requirement will ensure that RA generation resource output will be deliverable to load during stressed conditions, it is not intended to prevent economic displacement activities when conditions make it safe to purchase energy from other sources, on other transmission paths. The firm transmission requirement is not intended to prevent efficient trading activities, or the use of other transmission products; rather the requirement is intended to help ensure that the generation set aside to meet RA requirements will be able to serve load when no other economic and reliable options are available.

3) **What is the Forward Showing (FS) transmission service requirement?**

At the FS deadline, Participants are required to demonstrate that 75% of their FS obligation (P50 + PRM) is supported by firm transmission rights or firm transmission rights that fall into the conditional (Vulnerable) window (or, as applicable, 6NN transmission rights at the TSP's discretion) from identified generation resources to the load being served other than for defined exceptions.

4) **Is there a penalty for not meeting the FS transmission service requirement?**

   Yes – Not meeting the FS transmission service requirement is considered a failure to meet the WRAP's FS requirements and the Participant would be subject to the WRAP's Cost of New Entry (CONE)-based penalty structure.

5) **Will the Program Operator (PO) or Program Administrator (PA) change the FS transmission service requirement after the FS deadline and prior to the Operating Day?**

   No – The PO or PA will not change the FS transmission service requirement once compliance has been demonstrated in the FS.

6) **Is there additional transmission service requirement in the Operations Time Horizon?**

   Yes - In the operational time horizon if PO forecasts a sharing event (i.e., one or more Participant is forecasted to be deficit), Participants will be required to able to demonstrate that they have 100% firm transmission rights or firm transmission rights that fall into the conditional window (or as applicable, 6NN transmission rights at the TSP's discretion) to meet their expected load + any contingency + forecasted sharing allocation. Exception rules might apply if there was no firm transmission available from FS timeline to operational timeline.

7) **What happens if a Participant cannot procure firm transmission service to meet the FS transmission service requirement or as needed in the operational time horizon?**

   Participants will be required to use due diligence in the program. If sufficient firm transmission rights for FS period of 7 months in advance and from the FS window to the Operational time horizon do not exist, the Participant may be approved for exceptions, if they have made every good faith effort to procure transmission for the FS window.

8) **Would the existing transmission agreements between transmission customers and TSPs be changed under this WRAP?**

No - The current design would not change the existing transmission contracts and obligations between TSPs and their customers.

9) Are TSPs participating entities in the WRAP?

No - The WRAP current design is expected to provide the opportunity for transmission providers to work closely with the PO, on a voluntary basis, to further assess the state of the transmission system after FS. These assessments will use current forecasted load and current forecasted resources to be dispatched.

10) Do you expect the WRAP to inform regional planning and improve situational awareness?

Yes - The current WRAP design is expected to provide enhanced information on transmission limitations in the context of Western resource adequacy. This information may be used by individual entities as well as transmission planning organizations and efforts. . It is also expected to facilitate additional situational awareness with respect to resources availability and associated transmission needed for service to load in the operational planning horizon (7 months in advance of the season). Finally, the WRAP is complementary to other transmission related efforts and activities and in no way replaces those efforts and activities.

11) Will the program design elements that address transmission deliverability issues remain static or could they change as the program evolves?

No - After further experience with this program, NWPP RA Program Participants may explore design improvements related to transmission congestion and its possible impacts to resource adequacy so that the risk of transmission congestion impacting reliability is evaluated on an ongoing basis, including an assessment of the cost/benefits of such design enhancements.

12) How did the WRAP decide on the 75% threshold?

The WRAP considers the 75% threshold as a "goldilocks" number - we are attempting to balance the different objectives and needs of the program. While the goal of the WRAP is increased reliability, we recognize that we don't want to over-prescribe requirements that could lead to unnecessarily large costs. We have left the possibility for appeals and exceptions from the PO/PA, which a task force is currently considering.

Western Resource Adequacy Program
CONE Penalty Task Force – Proposal

Prepared by CONE Penalty Task Force:

Shawn Smith – Chelan PUD	Joe Stimatz – Northwestern Energy
Zach Kanner - PacifiCorp	Villamor Gamponia – Puget Sound Energy
Steve Bellcoff - BPA	Dan O'Hearn - Powerex
Ben Brandt – Idaho Power	Emeka Anyanwu, Aliza Seelig – Seattle City Light
Jeff Johnson – Douglas PUD	Ray Johnson – Tacoma Power
Charles Hendrix, Alex Crawford – SPP	Rebecca Sexton, Ryan Roy - WPP

Background

The CONE (Cost of New Entry) penalty is intended to strongly motivate Participants to comply with program metrics in the forward showing time horizon. If a Participant fails to meet their forward showing capacity or transmission requirements after the cure period, the forward showing program will assess some multiple of a CONE. 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.

Implementation of the CONE charge will be considered in a larger conversation about how to transition into the full, binding RA program; the transition plan will be considered in a separate space and is not scoped within this task force.

Task Force Objectives

1. Propose an approach to CONE calculation for consideration
2. Finalize a framework for calculating CONE and applying penalties to be included in FERC filing

What is Being Approved? - Calculation and Application of CONE

This proposal is limited to the calculation and application of the CONE **NOT** on the timeline for which it will be implemented in association with a failure in the Forward Showing (implementation of the first binding season). This is the long-term solution for the calculation of the penalty and what will be included in the Tariff as the Forward Showing deficiency penalty.

It is the strong desire of WRAP participants that the program only adopt the CONE penalty when:

» participants can secure supply in a competitive environment to pass the Forward Showing
» there are mechanisms to ensure adequate liquidity and ability to contract for capacity in the 8-10 month ahead timeframe
» there has been an assessment of capacity availability prior to the binding season to ensure that all participants can procure enough capacity to pass the Forward Showing

The program must be workable for all participants and as such is not intended to set up any participant for failure during the initial binding seasons. The CONE penalty is designed to incentivize new build when there isn't sufficient capacity in the market.

Proposed Approach

CONE Value

Below are inputs to the CONE calculation, which results in an Annual CONE of **$91.81 per kW-Year.** The CONE value will be re-evaluated on a yearly basis to ensure that it is still an accurate proxy for the cost of replacement capacity.

Capital Costs	O&M Costs	Financial

• EPC - $713/kW (2020 EIA cost)
• Other capital costs
  • Contingency – 3%
  • Land - $1.5M
  • Legal – $1.25M
  • Development costs - $1.5M
  • Mobilization and related engineering and inspection – $1.75M
	• $7/kW (2020 EIA cost)	• 50/50 debt/equity ratio
		• 20 year project/finance life
		• Cost of debt – 5.25% (Prime rate plus 2%)
		• Effective tax rate – 27% (Federal plus state)
		• After tax return on equity – 13%
		• DSCR – 1.5
		• 3 year average inflation rate – 2.48%

Penalty Mechanics Overview

The proposal contemplates a "Forward Showing Year" or "FS Year". The FS Year is a grouping of a winter and summer forward showing season - e.g. summer 2024 + winter 24-25. The penalty is based principally on the largest monthly failure for the forward showing year * annual CONE * CONE factor. Additional monthly failures are incrementally penalized, but at a monthly rate. The intent is to remove any incentive for additional failures after an initial failure.

If a deficient participant pays the CONE charge, that Participant is considered to have met Forward Showing Capacity Requirement; they are able to participate in the Operations Program (appropriate impacts to their participation in the Operations Program will be further considered in a separate venue).

Detailed Mechanics: FS Year Season 1

1. Identify the maximum monthly deficit from the first (summer) season within a forward showing year (Max Summer Deficit)
2. Determine the "first stage" penalty as follows:
    a. $\boldsymbol{Max\ Summer\ Deficit} * (\boldsymbol{Annual\ CONE} * \mathbf{1000}) * \boldsymbol{Summer\ Season\ Annual\ CONE\ Factor}$
3. The Seasonal CONE Factor scales depending on the programs aggregate deficit for the summer forward showing. The Summer Season Annual CONE Factor can vary from 125% to 200%.
4. Incremental monthly failures within the first season are penalized at a $-kW month rate consistent with the Annual CONE * a CONE factor of 200%.

5. The penalty is charged immediately after failure to cure capacity deficits by the end of the summer forward showing cure period.

Detailed Mechanics: FS Year Season 2

1. Identify the maximum monthly deficit from the second (winter) season within a forward showing year (Max Winter Deficit)
2. Determine the "second stage" penalty as follows:
    a. $\boldsymbol{Maximum\ of\ (Max\ Winter\ Deficit - Max\ Summer\ Deficit, 0) * (Annual\ CONE * 1000) * Winter\ Season\ Annual\ CONE\ Factor}$
    b. If the winter maximum monthly failure is less than the summer maximum monthly failure, then each failure within the season are penalized at a $-kW month rate consistent with the Annual CONE * a CONE factor of 200%.
3. The Winter Season CONE Factor scales depending on the programs aggregate deficit for the winter forward showing. The Winter Season Annual CONE Factor can vary from 125% to 200%.
4. Incremental monthly failures within the second season are penalized at a $-kw month rate consistent with the Annual CONE * a cone factor of 200%. This includes any portion of a month that ends up being the highest failure in the FS Year that was equal to the Max Summer Deficit.
5. The penalty is charged immediately after failure to cure capacity deficits by the end of the winter forward showing cure period.

Note that the attached excel file provides a practical application that may assist in understanding.

CONE Factor Scaling

The seasonal annual CONE factors are calculated as follows:

Summer Season Annual CONE Factor:

$$\boldsymbol{Summer\%Deficit = Summer\ Program\ Aggregate\ Deficit \div Summer\ Program\ P50\ Load}$$

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

Winter Season Annual CONE Factor:

$$\boldsymbol{Winter\%Deficit = Winter\ Program\ Aggregate\ Deficit \div Winter\ Program\ P50\ Load}$$

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

If there is a Summer or Winter Program Deficit in a FS Year, the Summer and Winter Annual Seasonal CONE Factor in the subsequent increases to 200%.

Penalty Revenue Redistribution

On the occasion that a CONE penalty is levied against and paid by a deficient Participant, funds collected would be allocated back to Participants who passed the FS with sufficient resources based on their percentage share of the footprint's total P50 load.

Example

Assume a Participant fails to show sufficient capacity in the summer showing and fails to cure the deficiencies as shown in Figure 1.

Figure 1: Utility with Failures in the Summer FS.

	Month	RA Position
FS Y1	Jun	-20
	Jul	-40
	Aug	-10
	Sep	-30
	Oct	
	Nov	?
	Dec	?
	Jan	?
	Feb	?
	Mar	?

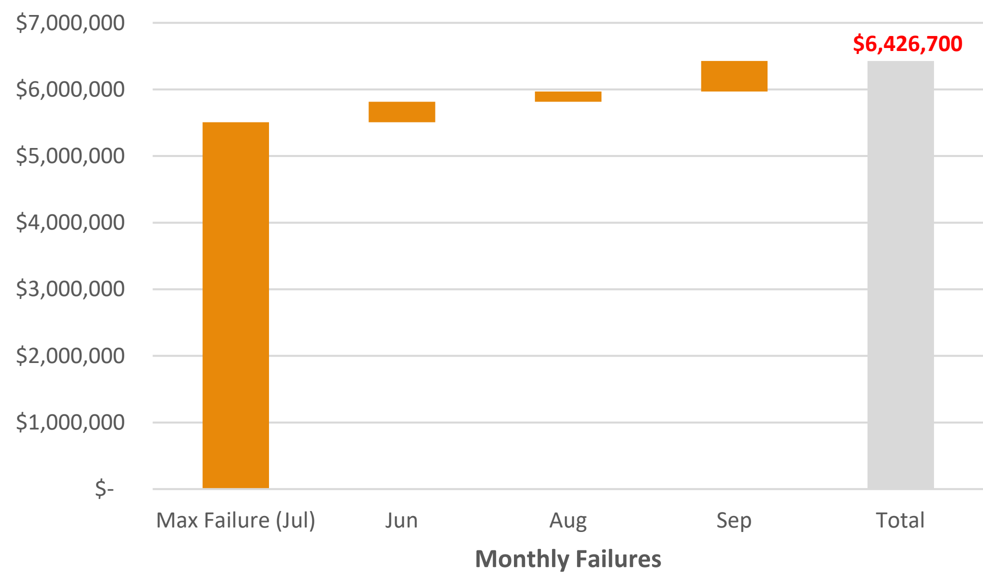
Additionally, assume that the footprint had aggregate failures in the summer showing of 1,200 MW resulting in the following seasonal CONE factor:

Figure 2:Summer Annual CONE Factor

		% Deficit	**Summer Annual CONE Factor**
Total Program P50 Load	67,500		
Summer Seasonal Deficit (sum of the highest deficit month for each deficit entity)	1,200	1.78%	150%

The "stage 1" summer penalty would be calculated as shown in Figure 3:

Figure 3: Summer "Stage 1" Penalty



After the entity pays the summer "stage 1" failure penalty, assume it also fails to show sufficient capacity in the winter showing and fails to cure the deficiencies as shown in Figure 4.

Figure 4: Utility with Failures in the Summer & Winter FS.

	Month	RA Position
FS Y1	Jun	-20
	Jul	-40
	Aug	-10
	Sep	-30
	Oct	
	Nov	30
	Dec	20
	Jan	-50
	Feb	-10
	Mar	10

Additionally, assume that the footprint had aggregate failures in the winter showing of 1,200 MW resulting in the following seasonal CONE factor:

Figure 5: Winter Annual CONE Factor

		% Deficit	Winter Annual CONE Factor
Winter Seasonal Deficit (sum of the highest deficit month for each deficit entity)	1,200	1.78%	150%

The "stage 2" winter penalty would be calculated as shown in *Figure 6* below.

Figure 6: Winter "Stage 2" Penalty

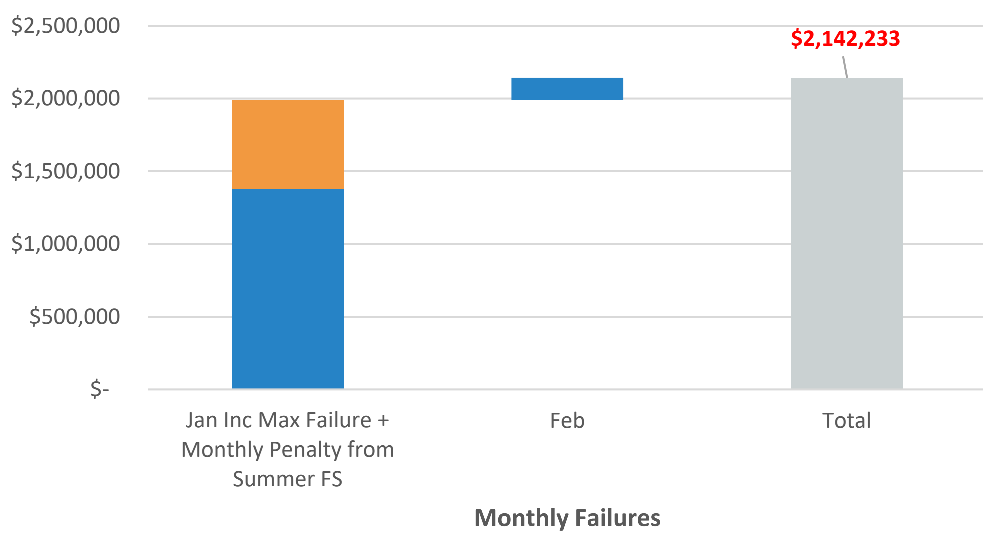
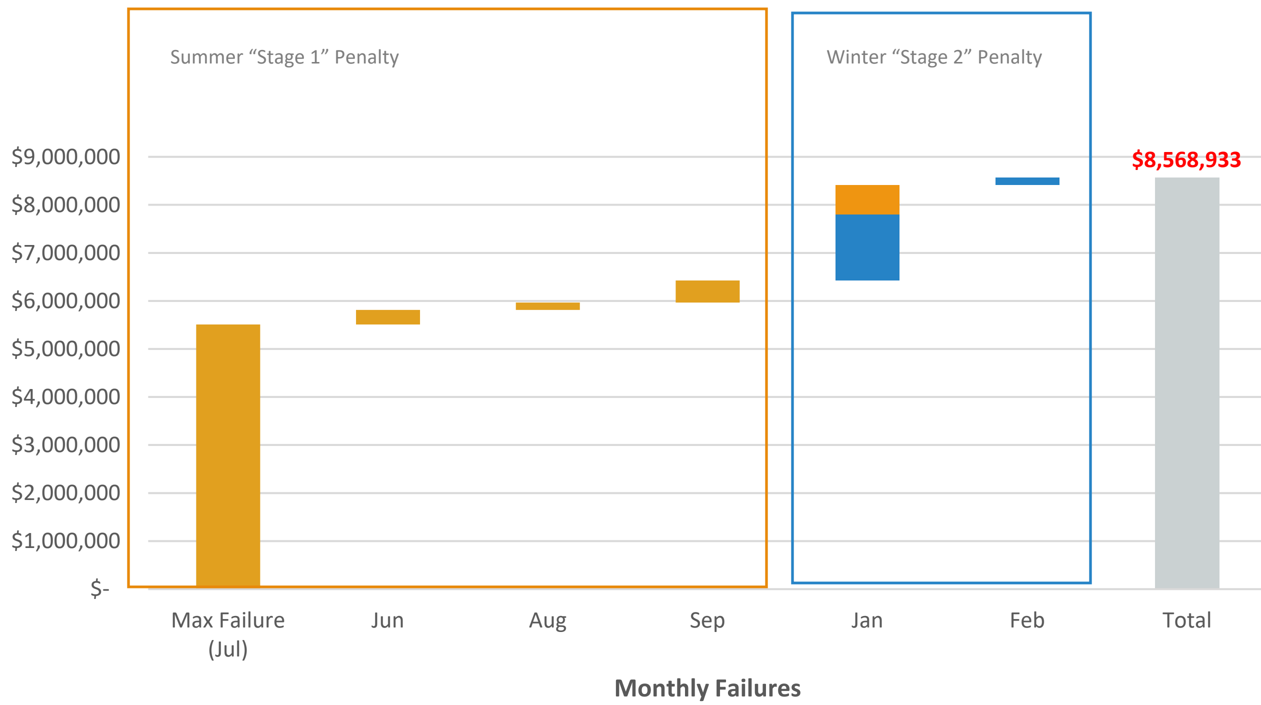


Figure 7 shows the aggregate forward showing penalty.

Figure 7: FS Year Penalty



Post Forward-Showing Application of CONE for Disqualified Capacity and Error

Participants were concerned about the impact to Capacity prices for those entities procuring capacity after the FS but prior to the end of the cure period. If a WRAP Participant is procuring RA quality capacity during this period, it may indicate something about their RA position and may result in the price of capacity being set at or very near the CONE. This concern is valid especially for those entities who turned in a FS workbook that they believed was compliant through attestation but were later notified by the Program Operator they were deficient due to capacity being disqualified or through error. If a Participant submits a FS workbook that they believe is accurate and meets the FS requirements through attestation and is later found to be deficient the CONE will be scaled according to the following methodology.

1. If the Participant is the only Participant that is deficit in the program, their deficiency is less than or equal to 1% of their FS compliance requirement (P50 + planning reserve margin (PRM)) and they cannot cure the deficiency the CONE factor for the purposes of the above methodology will be set to 50%.

2. If there are two Participants that are deficit, their deficiency is less than or equal to 1% of their FS compliance requirement (P50 + PRM) and they cannot cure the deficiency the CONE factor for the purposes of the above methodology will be set to 75%.
3. If there are more than two Participants that are deficient the standard methodology will apply.

It is very important to note that the scaling of the CONE applies only to those Participants that attested to submitting a workbook that met the FS compliance requirement (P50 + PRM). This will only be applied in the event that capacity was subsequently disqualified or there was an error in the FS workbook.

Alternatives

In addition to the approach outlined above, the Task Force evaluated two alternatives.

1. The first alternative was to apply the annual CONE value based on a half-year equivalent. The seasonal penalty would be calculated as (assuming a CONE factor of 125%):

   CONE x 125% x MW x ½

   The Task Force felt that a ½ CONE was not adequate to incentivize compliance with the FS so this alternative was not pursued.

2. The second alternative was to calculate the penalty in the first season as (assuming a CONE factor of 125%):

   $$\boldsymbol{CONE\ x\ 125\%\ x\ MW}$$

   The penalty in the second season would be calculated as:

   $$\boldsymbol{(CONE\ x\ 50\%\ x\ Season\ 1\ MW\ Deficiency) + (CONE\ x\ 125\%\ x\ Additional\ Deficiency\ Above\ Season\ 1)}$$

   This alternative was not selected but the use of an incremental charge was incorporated into the proposed approach.

Western Resource Adequacy Program
Load Forecast (Step 2) Task Force – Proposal

Prepared by Load Forecast Task Force:

Garrison Marr - Snohomish	Ruth Burris – PGE
Tyler Moore - APS	Ray Johnson, Ryan Fulleman – Tacoma
Jon Cook, Tom Cooper, Harry Sauthoff – SRP	Steve Bellcoff – BPA
Mark Holman, Mike Goodenough, Dan O'Hearn - PWX	Becky Keating - Chelan
Emeka Anyanwu, John Rudolph - SCL	Lorin Molander – PSE
Charles Hendrix, Alex Crawford – SPP	Rebecca Sexton, Ryan Roy - WPP

Background

Load forecasting is a critical aspect of setting the WRAP Forward Showing (FS) metrics appropriately. The load forecasting methodology (specifically load growth expectations) must be objectively and consistently applied to ensure program rigor, fairness, and reliability.

It is critical that all quantified elements of the WRAP are consistently and objectively determined. Most elements, such as the reliability objective (1-in-10 LOLE), the associated PRM, and the Qualifying Capacity Contributions, are objectively determined. The one outstanding exception was the load forecast, which per that Phase 2B Detailed Design, was proposed to be determined and submitted by each Participant, based on their own load forecasting methodology and drivers. The purpose of this methodology is to develop a fair and objective way of establishing the load term (P50) in the compliance metric and reliably identify load inputs for the LOLE and ELCC studies. Note that this is not a replacement for existing IRP or infrastructure planning processes. The WRAP FS utilizes a 2-year ahead forecast to support the modeling timeline for the binding season. This is a much shorter timeframe than is addressed in resource and infrastructure planning processes.

Allowing entities to submit a subjectively derived load forecast, creates two potential problems for the program: 1) A significant gaming opportunity given the incentive to submit a an artificially low forecast which could benefit a Participant in both the FS and operations program and 2) stakeholders provided numerous comments on the load forecasting proposal from Phase 2B. These comments included a strong interest in either centralized load forecasting or an objective methodology that considers stakeholder areas of concern such as climate change. If not resolved this gap could open the program up for criticism from Participants, program stakeholders, and potential interveners in the FERC filing process.

This task force focused on the process used to establish the P50 load that Participants will use in their compliance metric in the non-binding forward showings (Winter 2022-2023 and Summer 2023) during Phase 3A.

When the Program Review Committee (PRC) is established in Spring of 2022, it will further consider how to refine the assumptions used to establish inputs into the LOLE study for use in determining the regional capacity needs for future binding seasons and any true ups, if they occur.

Proposed Approach: Non-Binding FS

For the purposes of the initial LOLE study and non-binding FS the group elected to prioritize a methodology that is objective, that will not materially impact the results of the study and provides a fair allocation of the program's capacity requirement given the current schedule and lack of an established PRC.

For LOLE Study:

The Task Force settled on the following methodology to establish a load forecast for the LOLE study.

- Start with the median of each year's peak load by season for the last five years (this was based on the 2016-2020 data provided in the FS data request) and apply a program-wide growth rate of 1.1% to all participating LREs
- 1.1% was identified by an informal survey of published load growth and demand projections from ten participating LREs as well as publicly available load forecast information from the Northwest Power and Conservation Council and other groups. Values ranged from –0.6% to +4.5 load growth.
- Note that the LOLE study will vary the load based on historical information; small changes to the load forecast utilized will have minimal impact on the actual PRM output from the modeling exercise.
- This load forecast, used for modeling (LOLE study and resulting PRM), will not limit or indicate the load to be used for the non-binding or binding showing (for any individual LREs P50 + PRM compliance metric).

For Allocation / Participant FS Requirement Metric (P50):

The Task force proposed using the following as the basis for the compliance metric / allocation of program capacity requirement (P50) in the non-binding FS. This is:

- Start with the median of each year's peak load by season for the last five years (this was based on the 2016-2020 data provided in the FS data request)
- At this time a load growth factor will not be included
- Allow Participants to modify the base load to account for known load to be added and any existing load that will be removed in the forecast window.
- The Participant must provide the median value as well as a narrative describing the load to be added or removed. The formal process and any documentation needed for verification is yet to be defined. Given the aggressive modeling timeline and significant Program Administrator (PA) / Program Operator (PO) workload this could be something as minimal as a very short, signed

statement of the accuracy of the offsets to load by the WRAP Participant committee member. A more formal process will be established for the binding program as described below.

Proposed Approach: Binding Program

For the binding program the WRAP is proposing a program-developed framework that could be utilized by each Participant to establish their P50 / binding FS capacity requirement and form the basis for the aggregate load forecast used in the FS modeling. It is important to note the details of this framework will be developed by the PRC. The narrative below is intended to serve two purposes: 1) provide the RAPC with enough context and background to be comfortable adopting the recommendation for the non-binding showing and to delegate the establishment of a more formal load forecasting methodology to the PRC for the binding phase 2) provide the PRC with background information related to the load task force work that might be useful as they address the load forecasting issue.

For the binding showing the task force thought that one viable approach would be establishing a growth rate or set of growth rates that could be added to the Participant base load (median of last 5 years) and adopted by any Participant as their binding forecast (potential considerations listed below). This would be coupled with the option to provide an entity specific growth rate through a negotiated process.

Base Load + Program Established Growth Rate:

This methodology would retain the approach from the non-binding seasons for calculating the base load which is to utilize the median of the previous five years, normalized to any additions or removals of load in the historical record and with the inclusion of additions and removals of load in the forecast window.

The task force proposed allowing the PRC (with stakeholder input) to establish a base program-wide growth rate that could then be regionalized to account for geographic differences, entity type, customer makeup, weather and other key factors that might cause Participants to have like growth rates. The exact methodology for developing the growth rate or rates would be developed by the PRC and follow the approval process defined in the governance document. This rate would be a safe-harbor growth rate that could be adopted by any Participant, and it would not require any PO intervention or validation.

This approach ensures that the growth rate is objectively established, accounts for the potential differences that may exist between Participants and is informed by input from stakeholders. (Note that this is not a replacement for the load forecast used in existing IRP or infrastructure planning processes)

Base Load + Participant Alternative Growth Rate:

If a Participant believes that using the program developed growth rate is not an accurate proxy of their anticipated load growth, they could negotiate an alternative growth rate with and independent entity. Possible alternatives include the PA, PO, or the Independent Evaluator (This could expand the currently anticipated scope of the Independent Evaluator beyond after-the-fact review and analysis)

The task force thought it was important that the independent entity make the evaluation of the alternative growth rate against a set of principles developed by the PRC and stakeholders. These might include things like

- Objective, robust and have a data driven basis for calculation
- Includes weather adjusted input data
- Includes factors that are relevant to determining peak load (economic growth, climate etc.)
- There was a strong desire that the alternative negotiation process be executed only:

1) in circumstances that it is absolutely necessary, and would therefore not be permitted unless the proposed growth rate was more than "x%" different from the program's default growth rate for the applicable area; and

2) if it resulted in incremental program costs (e.g., for the independent entity making the evaluation) then those costs may have to be covered by the requesting Participant.

Additional Considerations

- The basis for the load utilized in the LOLE / PRM studies will be the sum of the values submitted by Participants (Base Load + Growth Rate). This ensures alignment between the Participant forecasts and modeling inputs.
- Additions and removals are intended to be separate and distinct from the load growth factor. Load growth is intended to consider things like population change, economic factors, electrification, change in usage patterns due to climate change, demand destruction if applicable etc. The process for adding and removing load is intended to capture very sizable one-time changes such as the introduction of a large load industrial customer, change in contracts, an entity leaving a BAA etc.
- If there are additions and removals of load after the LOLE / PRM modeling but before the Forward Showing these can be reflected in the allocation of the regional capacity requirement. If a Participant has added loads (large industrial customer, additional contracted load as an ESS or third-party supplier) they would submit this in their FS workbook and will have a slightly higher capacity requirement than the original forecast. If a Participant has removed loads, they would submit this in their FS workbook and will have a slightly lower capacity requirement than the original forecast. It is critical that load not be understated in the FS and as such any load change greater than 10 MWs with a higher than 50% probability occurring after the LOLE / PRM modeling

must be provided in the FS workbook. This will not be actively monitored for compliance, but it is important to remember that the FS workbook is attested to by a senior officer.

- If there are load changes after the forward showing these will be absorbed by the Operations Program. A Participant that sees a significant addition in load may see a negative sharing calculation result more frequently. A Participant that sees significant load removed may see a positive sharing calculation result and additional holdback / delivery more frequently (will be adequately compensated through the settlement proposal). These will be trued up at the next Forward Showing.

Western Resource Adequacy Program
Settlement and Pricing Proposal – Proposal

Prepared by Settlements and Delivery Failure Task Force:

Barbara Cenalmor – SRP	Ryan Atkins - NVE
Zach Kanner - PacifiCorp	Phil Haines, Sachi Begur – Puget Sound Energy
Ian White, Chris Nichol, Bo Tully, Hilary Bell, Doug Meeuwsen – Shell	Dan O'Hearn, Mike Goodenough, Derek Russell - Powerex
Ben Brandt – Idaho Power	Cory Anderson – Seattle City Light
Jeff Johnson – Douglas PUD	Ray Johnson – Tacoma Power
Deb Malin, Eddie Elizeh, Rahul Kukreti - BPA	Mike Bradshaw, Janet Jaspers – Chelan
Tyler Moore - APS	
Charles Hendrix, Alex Crawford – SPP	Rebecca Sexton, Ryan Roy - WPP

Background

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.

Proposal Topics

1. Applicable indices
2. Settlement pricing for holdback and delivery
3. Calculation and posting of settlement quantities and prices
4. Participant charge for non-delivery of holdback

Applicable Indices

A key component of the settlement and pricing methodology is having prices that are reflective of the market value of energy in both day-ahead and real-time and are applicable to specific areas in the broad geographic footprint of the WRAP. To support the development of the settlement and pricing approach, the WRAP has selected the following indices and market-based prices to serve as the representation of day-ahead and real-time energy values.

For those entities participating in the Northwest region the following prices will be utilized:

» **Day-ahead Price:** Ice Day-Ahead (DA) Mid C Index
» **Realtime Price:** Powerdex Realtime Index

For those entities participating in the Eastern and Southwest Regions the following prices will be utilized:

» **Day-ahead Price**: Ice DA Palo Verde Index
» **Realtime Price:** Average of the 4 fifteen-minute (FMM) market results for the Palo Verde intertie in the CAISO market (FMM Scheduling Point / Tie Combination LMP; Node: PALOVRDE_ASR-APND; Tie: PVWEST)

Holdback and Delivery Settlement Pricing

Settlement Price Calculation

The proposed settlement price is based on the CAISO methodology for implementing FERC Order 831. This methodology has the benefit of having been developed with significant stakeholder input during the CAISO's 831 implementation and was ultimately accepted by FERC. The Settlement Price is shaped using a shaping factor that reflects changes in energy/capacity value from hour to hour and is based on locational indices at Mid C and Palo Verde (PV).

The settlement price is based on a regional index price, shaped hourly, plus a 10% adder. The adder is intended to help ensure the price is set at a level that incentivizes use of the bilateral market to prior to accessing pooled capacity if possible.

If the settlement price does not adequately reflect the foregone opportunity cost of the entity providing holdback, as measured by selling the heavy load block at the applicable locational index (Mid C or PV), then a make whole payment will be triggered, payable from the receiving entity.

Definition: Total Settlement Price

$$\textbf{Total Settlement Price} = \textbf{MAX}(\textbf{MIN}(\$\textbf{2000}, \textbf{Hourly Shaping Factor} \times \textbf{Applicable Index Price} \times \textbf{110\%}), \textbf{0})$$

Where:

– **The $\textbf{Hourly Shaping Factor}$ 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.**

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

– **The $\textbf{Applicable Index Price}$ is the day ahead 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.**

- **For Sundays a 1x16 index is used if available and the holdback occurs during HE7-HE22, otherwise the applicable light load index is used**

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
$\textbf{Energy Declined Settlement Price} = \textbf{lesser of} \begin{cases} \textbf{\textit{Applicable Powerdex (or similar) hourly index, or the}} \\ \textbf{\textit{Settlement Price}} \times \textbf{80\%} \end{cases}$
80% factor ensures that sellers will receive at least 20% for carrying holdback regardless of energy deployment.
Definition: Holdback Settlement Price
$\textbf{Holdback Settlement Price} = \textbf{Total Settlement Price} - \textbf{Energy Declined Settlement Price}$
Final Settlement For Any Applicable Hour
$\textbf{Final Settlement (for any applicable hour)} = (\textbf{Holdback Settlement Price} \times \textbf{Holdback MW Requested}) + (\textbf{Energy Settlement Price} \times \textbf{Operational Energy MWh Dispatched})$

Make Whole Payment

The Make Whole Payment is triggered in the event that the settlement revenue and the estimated value of the non-dispatched energy is less than what the selling entity would have received had they sold a day-ahead block of energy instead.

Definition: Make Whole Payment

$$\begin{aligned}\textbf{Make Whole Payment (when applicable)} \\ &= \boldsymbol{\mathit{Possible\ Block\ Sale\ Revenue}} \\ &- \boldsymbol{\mathit{Final\ Settlement\ Revenue}} \\ &- \boldsymbol{\mathit{Realtime\ value\ of\ declined\ energy}} \\ &- \boldsymbol{\mathit{Realtime\ value\ of\ unheld\ energy}}\end{aligned}$$
Ensures that the seller is no worse off than had they sold the energy as a block in day-ahead. The MW amount associated with the Possible Block Sale Revenue is the maximum amount requested for the hours in the block.
Definition: Realtime value of declined energy
$$\begin{aligned}\textbf{Realtime value of declined energy} \\ &= \textbf{Energy Declined} \\ &\times \textbf{Energy Declined Settlement Price}\end{aligned}$$
Declined energy is only applicable to those hours where there was positive holdback.
Definition: Realtime value of unheld energy
$$\begin{aligned}&\textbf{Realtime value of unheld energy} \\ &= (\textbf{Maximum holdback MW in block} \\ &- \textbf{Holdback MW Requested}) \\ &\times \textbf{Applicable Powerdex (or similar)hourly index}\end{aligned}$$
This represents the value that is realized by marketing unheld energy at the applicable real-time index.

Calculation and Posting of Settlement Quantities and Prices

The Program Administrator (PA) will have responsibility for calculating and posting settlement quantities and prices based on Program Operator (PO) calculated delivery and holdback. The process by which any non-delivery or additional energy that is delivered voluntarily is communicated from the Participants to the PA and PO has not yet been developed.

Participant Charge for Non-delivery of Holdback

The WRAP will have a robust framework in which non-delivery events are evaluated and may be waived if they meet a set of program-defined criteria. If a Participant is requested to deliver holdback and fails to do so without a valid waiver / exemption they will be subject to a non-delivery charge. An instance of non-delivery is defined as failure to deliver required holdback on one or more hours on any operating day, where a day is defined as the time beginning at 00:00 and ending at 24:00 PPT.

The hourly non-delivery charge is calculated as:

$$\textbf{Maximum of (applicable day ahead and realtime price on hour of non} \\ \textbf{− delivery) x penalty factor}$$

and is charged for every MWh of a non-waived delivery failure.

The penalty factor scales based on number of non-delivery instances in both seasons of the year and whether the energy that wasn't delivered was able to be served by someone else in the program. The penalties are intended to be high enough that non-delivery is not an economic option. The relatively high penalty factors are believed to be just and reasonable because the program will have a robust waiver of delivery failure process and non-delivery may lead to a load shedding event for the deficit entity.

Definition: Penalty for NON-WAIVED Delivery Failures in year (multiple failures in the same day constitute 1 delivery failure when calculating the penalty factor)	
If a Participant fails to provide energy and that deficit is entirely covered by other Participants of the WRAP, the penalties are as follows:	
First day with non-waived delivery failure(s)	5 times the index price of the default centroid for the undelivered megawatt hours (MWhs)
Second day with non-waived delivery failure(s)	10 times the index price of the default centroid for the undelivered MWhs
Third day or more with non-waived delivery failure(s)	20 times the index price of the default centroid for the undelivered MWhs and be cause for review for expulsion by the Delivery Failure Review Committee
If a Participant fails to provide energy and that deficit is not entirely covered by other Participants of the WRAP, the penalties are as follows:	
First day with non-waived delivery failure(s)	25 times the index price of the default centroid for the undelivered MWhs
Second day with non-waived delivery failure(s)	50 times the index price of the default centroid for the undelivered MWhs and be cause for review for expulsion by the Delivery Failure Review Committee

Participant Maximum Accumulated Non-Delivery Charge

Because the potential impact of non-delivery is load shedding the above multipliers are intended to provide a significant incentive to deliver holdback energy as requested. However, they are not intended to compound in such a way that the Participant Charge for Non-Delivery becomes punitive. To protect against over penalization the total amount of accumulated non-delivery charges for an individual Participant will be capped at the CONE equivalent non-delivery charge ceiling. This ceiling resets at the end of every second season and is calculated using the following methodology (on a per-Participant basis).

1. At the end of month one in the first season of the year, the maximum hourly non-delivery amount for that month is utilized to calculate a value equivalent to the CONE penalty. Meaning the hourly amount will be treated in the same way as a deficiency in that same amount for that month in the forward showing. The resulting equivalent CONE penalty is calculated as:

   $$\boldsymbol{maximum\ hourly\ non-delivery\ for\ month\ x\ CONE\ x\ CONE\ Factor\ from\ FS\ x\ 1000}$$

2. At the end of month two in the first season of the year, the maximum hourly non-delivery amount for that month is utilized to calculate a value equivalent CONE penalty. If the maximum hourly non-delivery amount in the current month is higher than all previous months in the current year the equivalent CONE is calculated as

   $$\boldsymbol{maximum\ hourly\ non-delivery\ for\ month\ x\ CONE\ x\ CONE\ Factor\ from\ FS\ x\ 1000}$$

   and all previous month's values are recalculated using the monthly incremental penalty of

   $$\boldsymbol{maximum\ hourly\ non-delivery\ for\ month\ x\ 15.302\ x\ 1000}$$

   If the maximum hourly non-delivery amount in the current month is lower than the previous highest value in the current year, the equivalent CONE value is calculated as

   $$\boldsymbol{maximum\ hourly\ non-delivery\ for\ month\ x\ 15.302\ x\ 1000}$$

3. This calculation would continue for each month of both seasons in the year and the monthly result would be added to all previous months. This accumulated value is the CONE equivalent non-delivery charge ceiling. If at any time the accumulated non-delivery charge for a given Participant is greater than or equal to the CONE equivalent non-delivery charge ceiling that Participant will no longer be subject to non-delivery penalties.

Any non-delivery charge collected by the PA where the deficit was met by other Participants of the WRAP will be used to reduce program administration costs. Any non-delivery charge collected by the PA where the deficit was not met by other Participants of the WRAP will be collected by the PA and passed through to the entity that had unserved deficit.

Delivery Failure Review Committee

The Delivery Failure Review Committee's responsibility is to make recommendations to the NWPP Board of Directors about standing in the WRAP and continued participation for those Participants that have incurred top tier penalties (20x if the deficit can be served, 50x if it cannot be served). This committee will not be responsible for granting waivers. The wavier request and review process will be managed by the PO.