Northwest **Power** and **Conservation** Council

# Minutes for Systems Analysis/Resource Adequacy Advisory Committee
# October 1, 2025

Dor Hirsh Bar Gai, NWPCC, began the meeting at 9:00 by taking attendance. Chad Madron, NWPCC, explained the best way to interact with the Zoom Webinar platform. Hirsh Bar Gai then welcomed the combined committee to the start of the 2026 water year to emphasize how important hydro is to the region.

## Deriving Reserve Margins from Needs Assessment Results

Phillip Popoff, Puget Sound Energy, confirmed that staff are planning on using the resource adequacy framework to develop a variety of reserve margins that can then represent different resource adequacy requirements in the portfolio model [Slide 19]. John Ollis, NWPCC, confirmed that that is the strategy.

Popoff continued, saying because there are multiple metrics to manage staff needs a diversity of reserves. Ollis agreed, explaining further.

Popoff said the idea of saturation is still important. Ollis confirmed and expanded on the idea. Popoff then moved to [Slide 18] confirming that staff is not asking the model to develop a lot of reserve margins but instead how the portfolio model will act on the reserve margins. Ollis again agreed.

Sean Ford, PPC, confirmed that [Slide 20] is an energy model with hourly forecast errors. Ollis said the adequacy model is an hourly model with three different time stages and a true up to capture the concept of forecast error. Ollis said the capital expansion model is hourly from the perspective of sampling particular days to get an idea of what's happening in each season.

Nicholas Garcia, WPUDA, was confused about staff dividing the region into subregions. Garcia asked if staff is developing curves for each subregion. Ollis moved to [Slide 16] to talk about subregional loads and resources, saying reserves are held on a regional perspective. Ollis summarized that the reserve margin is contained on a pool basis, so staff is not solving for the adequacy of a specific zone but for the region.

Carla Essenberg, BPA, asked what ARM stands for [Slide 24]. Hirsh Bar Gai said it stands for Adequacy Reserve Margin. Ford asked about the hourly granularity within the month of the ARM. Hirsh Bar Gai assured him that would be covered and discussed later in the presentation.

Essenberg said she was having trouble connecting [Slide 17] with this ARM Methodology. Hirsh Bar Gai explained. Ollis explained further, saying one of the components of the ARM is the Planning Reserve Risk.

Garcia asked about the duration metric, presuming that outages are concentrated in the summer or winter [Slide 25]. He questioned using an annual average number to reflect the ability to reduce the duration of an outage, as a good portion of that average occurs at an unexpected time for outages. Hirsh Bar Gai called this a good concern saying it is part of the fourth step of the process and will be covered in depth later in the day.

Essenberg asked how [Slide 28] helps the committee get to a monthly perspective. Hirsh Bar Gai said this slide represents step 2 ¾ and the next slide should make things clearer. Essenberg asked about the temporal scale of the slide, wondering if it is monthly, a single month, a whole year, or something else. Hirsh Bar Gai said this slide represents all hourly-level events through a whole study.

Aliza Seelig, PNUCC, confirmed that staff found that 1100MW were needed to get rid of durations that are greater than eight hours. Hirsh Bar Gai confirmed that 1100MW is the implied need to satisfy the VaR Duration in the described example.

Ford asked for a reminder about capacity metrics, wondering if the model is designed to not violate any of the six different metrics. Hirsh Bar Gai said not quite, explaining that Genesys co-optimizes several aspects but not to these adequacy metrics. Hirsh Bar Gai said the shortfall record is an outcome given the conditions and simulations Genesys tests.

Ford confirmed that the shortfalls are iterated back through the models as reserve margins. Ollis explained the concepts further.

Seelig confirmed that the eight-hour threshold was based on 39 out of 40 years. Hirsh Bar Gai said no, the eight hours are part of a different question about the duration length that we want to protect against. Hirsh Bar Gai said the 39 out of 40 years is how often we allow the event to happen.

Seelig said she's hearing staff is looking for the eight hours and for it not to happen more than once in 40 years. Hirsh Bar Gai framed it as incrementing resources and testing remaining shortfalls until the 97.5$^{th}$ percentile value is at eight hours.

Garcia asked about the types of resources added saying they will have different impacts. He wondered how staff decided on resource attributions. Hirsh Bar Gai said that connects to what OptGen does. Hirsh Bar Gai said staff define the resources and OptGen decides the optimal solution. Ollis wanted to highlight this question saying this is an opportunity to match resources to needs.

Essenberg moved back to [Slide 27] asking what staff meant by assuming the highest value for each. She said there are two different criteria, wondering if this is two different checks to figure

out how short the region is for capacity and energy and then you grab the maximum for the capacity. Hirsh Bar Gai said yes, moving to [Slide 29] to explain further.

Essenberg confirmed that [Slide 30] is the capacity/peak needs from before while the next column is the load. Hirsh Bar Gai said yes, calling it the output of monthly analysis.

Ford asked if this represents peak need/hourly peak deficit and not the VaR number. Hirsh Bar Gai said this is monthly, saying a heat map for hours is coming.

Frank Brown, BPA, asked why a MW need is divided into an aMW energy amount. Hirsh Bar Gai said it's a way to connect the signal from an average load perspective. Ollis added that this is a reserve margin that is evaluated above typical day in OptGen.

Garcia suggested footnoting the need definition that Ollis just explained.

Essenberg wondered where the probabilistic reserve requirement fits into this work. Ollis said the dynamic probabilistic reserve is not calculated in Genesys but calculated endogenously in OptGen.

Ford said that WRAP is p50 peak plus the planning reserve margin. He asked about the percent above load numbers wondering if they are percent above the load in each hour or more of a load factor. Ollis said it's more percent above the average load at any given hour in the month.

Essenberg confirmed that the shown example is for peak need/capacity and wondered if staff will talk about energy. Hirsh Bar Gai said staff is looking for a monthly percent and will talk about energy later.

BREAK

Popoff asked if [Slide 34] represents a specific hydro scenario or all hydro scenarios. Hirsh Bar Gai answered that this is 90 climate-projected load and stream flows and associated with the 2020 spill regime.

Garcia confirmed that it's 7000 shortfalls over 90 different scenarios. Hirsh Bar Gai answered yes. Garcia said that could be annualized as 4000 divided by 90. Hirsh Bar Gai confirmed the LOLEV is very high.

Popoff confirmed that this is number of shortfalls with no description of shortfalls. Hirsh Bar Gai said yes, adding that the vast majority of shortfalls are one hour long.

Essenberg clarified that [Slide 34] does not include resources that are presently under development. Hirsh Bar Gai thought if construction has started the resource is included. Ollis offered to follow up.

Ryan Egerdahl, BPA, asked about transmission assumptions for the coming resources. Hirsh Bar Gai said there is a Transmission Plus scenario to test this.

Seelig asked to see the resources that are in the database. Hirsh Bar Gai said it is available. Seelig asked if PGE's new batteries are included in that list. Ollis thought so. Jennifer Light, NWPCC, said the online database is being worked on now.

Popoff asked if you get the LOLP by dividing the shortfalls by simulations. Hirsh Bar Gai said LOLP is a bit different but agreed that that is the method for getting the LOLEV.

Graessly wrote: As a reminder, is 'shortfall' only when load cannot be met without emergency measures, or can shortfalls happen due to some reserve category violation, but load still met? In the question pane. Ollis wrote: Both reserves and load obligations must be met or there is a shortfall. So, if a reserve cannot be met but load can be, there would still be a shortfall in the reply pane.

Popoff thought the spring market reliance limits were fine [Slide 35] and using unspecified market makes him nervous.

Essenberg asked what the market reliance assumption was based on. Hirsh Bar Gai explained the reasoning. Ollis added that our region can define market reliance as we want, and quite granularly but this is simpler.

Popoff approved of keeping the market reliance conservative as it allows utilities to make decisions based on individual comfort levels.

Garcia worried about zonal resource adequacy more than the regional, asking if there are shortfalls simulated by zones. Hirsh Bar Gai confirmed that the shown output is regional, adding that there are limitations to saying what shortfall is attached to a specific BA. Hirsh Bar Gai said staff lack proprietary data to be that granular, but Genesys has the granularity to deal with transmission.

Garcia said it would be useful to sectionalize the shortfalls between areas that are within the transmission constraint bubbles. He said he was worried that the graphic on [Slide 35] could be misleading if that import power couldn't get across the Cascades. Hirsh Bar Gai said this is implied that market and transmission are available.

Garcia appreciated that staff recognized the potential issue but was still not convinced that the inferred assumptions are accurate. He recommended a note to explain the base assumption about availability. Ollis said limitations are represented in Genesys, but results are not subregional because of proprietary contractual set ups.

Ford asked if there is a general story about what is happening in the model for the one-hour events portrayed on [Slide 36]. Hirsh Bar Gai said Genesys is a multi-stage model, with week,

day, and hour ahead. He said the week and hour ahead has the forecast error and there might be a challenging hour that can trigger a deficit.

Essenberg wrote: What reserve obligations is the model assuming? In the question pane. Ollis said the 2021 Plan asked the region to hold a larger number of reserves but did not have a way to dynamically solve for reserves leading to a lot of guess and check. Ollis said this study holds less because the dynamic probabilistic reserve is a side calculation, allowing staff to calculate for the existing system.

Essenberg clarified that a shortfall is defined as if we are not able to meet load plus the 1-3000MW reserve. Ollis answered yes, reserves are a hard constraint while serving load is a soft constraint.

LUNCH

John Fazio, Grid Lab, wrote: So, if all reserves and load obligations must be met or there is a shortfall, then reserves are essentially a hard constraint. Is that right? And, if so, then capacity needed for adequacy ensures that reserves are met. So, when calculating the ARM, is it double counting to add the 6% contingency reserves? In other words, if the ARM is calculated only using the needed capacity for adequacy, wouldn't that ensure that contingency reserves are met? In the question pane [Slide 42]. Ollis responded with: We are going to check any of the balancing reserves and the contingency reserves are double counted. The proposed methodology is how we are thinking about it now, but we had a similar concern.

Essenberg asked if staff add the same margin to every month or if the margin differs from month to month [Slide 48]. Hirsh Bar Gai said the margin can change monthly or hourly within a month, or other ways. Essenberg asked if that happens in OptGen. Hirsh Bar Gai said yes, staff are considering how much to vary it now.

Fazio was pleased that options on [Slide 51] could be tested. He then stated that the last Plan used quarter ARMs. Ollis agreed. Fazio then asked if it matters, wondering if hourly is too detailed. Ollis thought that the largest percent margin will drive the others, but the variety of resource options doesn't guarantee that, and staff are trying for fidelity.

Fazio asked if the numbers on [Slide 52] include the 6% contingency. Hirsh Bar Gai answered yes. Fazio then asked if staff use an ELCC when counting the resources or if OptGen is different. Ollis answered that OptGen is different, and the region benefits from not using the ELCC.

Ford confirmed that [Slide 53] are the percentages above the average energy by hour. Ford was fine with that monthly approach but thought a higher percentage in low energy hours might not work in a higher energy hour.

Seelig called the presentation a lot to take. She confirmed that [Slide 61] is one hydro sensitivity with a BIOP. She asked if staff is proposing using the peak and energy ARMs derived from this and

the mixed bag load forecast consistently across the scenarios. Ollis said the percentages would be consistent in every demand future in this sensitivity run through OptGen.

Seelig asked if there are six different demand futures. Ollis said there are five different trajectories and multiple climate change models totaling 15. Seelig asked if staff would use different hydro sensitivities. Ollis said that is the plan, explaining further.

OptGen Methodology Updates

Rebecca Klein, Seattle City Light, clarified that each of the days represented on [Slide 5] is taking an average of demand which mutes days with higher-than-usual demand. Ollis said yes. Klein said this made sense to her.

Seelig asked if the two typical days are chronological, if it matters, and if a multi-day event is captured in the reserve margins. Ollis said staff normally do not want to decouple the days because of concern around duration but we can if they are captured in the reserve margin.

Seelig confirmed that having weekday/weekend represents the financial value and the model extrapolates. Ollis confirmed that the model expands to 8760.

Essenberg asked how the model represents variable energy resources. Ollis said they use two ways: expected availability generation and implied number of balancing reserves based on existing generation.

Egerdahl brought up extreme weather where the expected generation from renewables would be different as renewables do not generate as much. Ollis agreed but said staff is accounting for that by looking at year-to-year uncertainty.

Alexander Karpoff, PSE, wrote: How much runtime do you save by moving from sampling 8760 to 576 hours? Sorry if I missed you saying this! In the question pane. Ollis was not sure but thought it was close to an order of magnitude.

Klein wrote: Are you able to account for holidays? For example, if there was a holiday on Friday, could the weekday be an average of Monday-Thursday and the weekend an average of Friday-Sunday? in the question pane. Ollis said this gets tricky and staff considered this approach. Ollis said holidays are captured as uncertainty as the holidays move around over the years. He said staff is willing to explore this more.

Klein asked how batteries are handled in the reserves [Slide 7]. Ollis said short duration batteries start at one level and must end at another. He added that the batteries start at about 10% and must complete its storage economics in 24 hours. Ollis said longer duration resources are treated differently.

Brown said DR can be credited as a resource in WRAP and wondered if "relevant reserve sharing pool" meant WRAP which takes DR. Ollis answered that it depends on the

DR resource and explained proposed DR modeling ideas.

Seelig asked what transmission max means [Slide 12]. Ollis said it's an optimistic view of what might be built for the transmission risk sensitivity.

Ollis ended the meeting at 3:00.

Attendees via Zoom Webinar

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| Jennifer Light | NWPCC |
| Dor Hirsh Bar Gai | NWPCC |
| John Ollis | NWPCC |
| Jake Kennedy | NWPCC |
| Tomás Morrissey | NWPCC |
| Daniel Hua | NWPCC |
| Paul Barrager | WA UTC |
| Aliza Seelig | PNUCC |
| Mary Kulas | consultant for PPC |
| Ian McGetrick | Idaho Power |
| Sophie Major | WA UTC |
| Adela Arguello | BPA |
| Esther Neuls | BPA |
| Frank Brown | BPA |
| Rebecca Klein | Seattle City Light |
| John Purvis | Clallam PUD |
| Sibyl Geiselman | Public Gen Pool |
| Kaitryn Olson | Puget Sound Energy |
| Alexandra Karpoff | Puget Sound Energy |
| Steve Andersen | Clark PUD |
| John Rothlin | Avista Corp |
| Heather Nicholson | Orcas Power & Light |
| Elizabeth Hossner | Puget Sound Energy |
| Sofya Atitsogbe | WA UTC |
| Andrea Talty | Puget Sound Energy |
| Mike Hermanson | Avista Corp |
| Andres V Delgado | Idaho Power |
| John Fazio | Grid Lab |
| John Crider | EWEB |
| David Clement | NEEA |
| Heather Moline | WA UTC |
| Pat Byrne | BPA |
| Carla Essenberg | BPA |
| John Lyons | Avista Corp |
| Eric Graessley | BPA |
| Ryan Egerdahl | BPA |
| Ben Ulrich | EWEB |
| Kevin Smit | NWPCC |
| Jared Hansen | Idaho Power |
| Ryan Bottem | Public Gen Pool |
| Phillip Popoff | Puget Sound Energy |
| Leann Bleakney | NWPCC |
| Doug Logan | independent |
| Jaime Stamatson | Montana |
| Peter Jensen | NWPCC |
| Mike Swirsky | Critfc |
| Sean Ford | PPC |
| Nicolas Garcia | WPUDA |
| Devin Mounts | PGE |
| Sanjeev Joshi | Critfc |
| Nelson Lee | Puget Sound Energy |
| Kym Buzdygon | NWPCC |
| Blake Scherer | Benton PUD |
| Brian Dekiep | NWPCC |
| Ryan Swartz | Energy Exemplar |
| Lauren Slawsky | PGE |
| Melissa Skelton | CAISO |
| Landon Snyder | Snohomish PUD |