Northwest Power and Conservation Council
Reserves in Power Planning
November 1, 2023

John Ollis, NWPCC, began the meeting at 9:30am by calling for introductions and reviewing the agenda. Chad Madron, NWPCC, explained how to best engage with the Go-to-Webinar platform.

Reserves in the 2021 Power Plan: Review of the Plan Recommendation
Fred Heutte, NW Energy Coalition, offered that his view on outages has changed a bit, saying it is more nuanced than he believed [Slide 6]. He said this changes the outlook on the need for reserves, including the fact that reserves can have outages. Heutte thought this would be a growing issue that will require more thinking. Ollis thanked him for the point.

Nicolas Garcia, WPUDA, noted that the region has been blessed with a transmission surplus for 40 years that eased issues with reserves. He predicted this would not be the case going forward and asked for caution around reserve assumptions. Ollis thanked him saying this will be discussed in further detail.

James Adcock, independent, said transmission also touches asymmetrical trading rules with other entities like California. He pointed to the BPA/California interties that could supply 8 gigs of reserves to CA but only allow 3 gigs coming back. Ollis thanked him, adding this will also be addressed.

Garcia approved of using the probabilistic method [Slide 9] but express curiosity about how that translates into actual operations. He imagined a scenario where reserves vary around 5% but sometimes reach 7-8%. Garcia asked how operators could implement the Plan and know to hold enough in reserve.

Ollis clarified that the 5% LOLP is for adequacy but agreed the reserve needs to change over time. He referenced past work that tried to model reserve needs based on the EIM or other data sets and found that output did not respond to that much nuance. Ollis said day-to-day operations, however, could have a more nuanced view, providing there is transparency. He added that the EIM does have good transparency, but other data sets may not.

Adcock insisted that utilities and organizations in general hold the responsibility to maintain stables systems, even if the reserves have not been met. Ollis agreed, saying the Council plans to the level of adequacy which is beyond emergency operations. He pointed Adcock to Resource Adequacy work.

Aliza Seelig, PNUCC, asked if operations outlined on [Slide 11] were happening in the GENESYS model. Ollis answered yes, GENESYS looks at all the operations, as opposed to past Plans that also included the Regional Portfolio Model.

Allison Campbell, PNNL, asked if staff looked at increasing reserves both up and down. Ollis moved to [Slide 12]to explain that adequacy issues when balancing down is mainly an economic issue. Ollis said the main issue was the underutilization of thermal units during shortfall.

John Crider, EWEB, asked if batteries were considered, noting that their duration is getting longer and could play a role in reserves. Ollis thought batteries could play a role, referencing testing four-hour lithium batteries and pump storage, but cautioned that there is probably no single answer. He added that hydro masks some of the short-term signal.

Scott Levy, Bluefish, referenced Ollis' comment about the difficulty with getting thermal to commit and wondered if low prices were the issue. Ollis agreed, saying prices were low and supply was sufficient. He continued, saying some thermal units take time to get up and running which presents challenges.

Levy then recalled forecasted wind that didn't show up. Ollis said that kind of forecast error can be delt with in different ways, depending on when it shows up.

Garcia confirmed that the last set of columns on [Slide 14] implements the resource strategy and ups the balancing reserves. Ollis confirmed.

Poll and Discussion

Adcock rhetorically asked why California can expect 8GW from the Pacific Northwest but can only send 3GW north. He acknowledged the limitations of the south to north intertie but was still (rhetorically) curious.

Heutte said the DC intertie is limited to 1000MW from south to north and requires upgrades to fix that. He said this should be done even if the operators are not interested. Heutte then pointed to complicated rules that might make it difficult to count on the power for reserves.

Ollis thought that people are relying a bit more on CA in the past but said it's hard to figure out where that power is going. He said both Adcock's and Heutte's points were valid.

Discussion Lead by Ryan Roy, Western Power Pool

Ollis asked if Nevada Power is included in the Northwest. Roy said they are in the desert Southwest and listed utilities for the both the Pacific Northwest and the desert Southwest.

Seelig asked about the operating program's prescheduled day, saying participants could bring in a resource that wasn't in their forward showing as deliverable. She said they could have gone to market before if they were having excessive forced outages. Seelig confirmed that it's not that there is no market but there are restrictions, and the participant has to show that.

Roy said the forward showing comes seven months ahead of the binding season and it should show sufficient capacity and transmission check. He said there is no checking after that, but there is no requirement to use the program.

Seelig confirmed that in the preschedule day no one has to show what they purchased, and the utility can say they are not relying on the program. She said as long as all goes well there will be no penalty.

Roy said if you don't pass the forward showing there is a deficiency. He said the WPP runs calculations seven days in advance and sends two different signals. The first, Roy said, is information so people have an indication that there may be a shortfall and can modify behavior. The second, he said, is applying a non-deliver charge to a surplus entity that raises their hand but doesn't deliver.

Garcia asked how hydro fits into this as you look at a 10-year average with a six-month forward showing. He said hydro can vary tremendously over a six-month period, meaning you could be surplus at the six-month showing and deficit going in to the seventh day. Garcia asked if you must still provide power to another.

Roy answered yes, but with the nuance that the model is deterministic with 10 hydro water years, interchange adjusted load, and assumptions about what can leave the footprint. He said the model gives hydro resources the benefit of water storage, and average performance by month. Roy pointed to putting perfect QCC in modeling hydro, which is very different from probabilistic modeling, saying how difficult it is to model cascading hydro and operator performance. Finally, he added that people can walk the QCC back if needed.

Garcia asked if that has to be at the six-month period. Roy answered that it's at the two-year period when they look at loss of load. Roy agreed that this is an area of concern.

Heutte commented that cascading hydro is important for profiling hydro operations and our future when looking at the grid and flexibility resources. He said the analytical response to looking at storage and demand response/flexible demand is an important and growing topic and was interested in everyone's response.

Roy called that a good point, saying his model doesn't price arbitrage short-term storage, and other assumptions. He said, from the WRAP perspective, there were a lot of conversations on how to model the hydro system to reflect potential energy limitation. Roy said there was interest in collaboration around a regional resource adequacy program that has been deferred. Roy said he remains interested in that and it may be revised.

Heutte added that the Columbia River Treaty may change things and may be needed to grapple with.

Reserves in Long Term WECC Regional planning
Allison Campbell and Nader Samaan, PNNL

Heutte asked about PAC's late morning anomaly on the Reg up [Slide 46]. Samaan answered that the forecast is in Mountain time, so the hours are shifted by one. He said they see a significant change in solar ramp at this time with units that catch up or catch down. Samaan said solar diversity also plays a role, meaning you will need reserves for cloudy days. He admitted that this approach is conservative.

Heutte called the different solar performance profiles an interesting anomaly.

Ollis said the greatest periods of forecast error in Council work comes during the ramp because of uncertainty around timing. He was encouraged that the PNNL work found the same thing.

Heutte then asked how the Reserve Contribution Factors are determined [Slide 48]. Samaan answered that they came from discussion with stakeholders. Heutte approved of that method.

Heutte then asked how solar hybrid units are handled now that the IRA separated out storage credits. Samaan answered that PNNL is now building cases for another study with significantly more solar and wind storage. He said they changed how co-located projects could charge but stand alone could optimize as needed.

Garcia noted that this was on the generation side and was curious about how things like EVs or regulation would be handled. Campbell agreed that this would require thought as reserve requirements are extremely sensitive to load forecast error. She said load forecasts are modeled on historically observed forecast errors and does not capture forecast error due to electrification of transportation. Campbell called for more funding and collaboration to produce improved data sets.

Morrissey noted data-related challenges and asked if data could be shared. Campbell thought they were probably shareable back to the member entities as they already have access to the hourly data set. She offered to check and report back.

Eric Graessley, BPA, asked: I think I heard that load errors are simulated with 1 lag autocorrelation. Do you model any correlations across BAs or between loads and wind/solar in an area, in the question pane. Campbell answered that they model utility scale solar as a unique power plant. She said this means they produce forecasts which may add or cancel at the BA-level. Campbell moved to [Slide 36] to say they allow autocorrelation for utility scale generation but do not incorporate cross correlation between BAs. She mentioned wanting to incorporate cross correlation between powerplants in the same BA but lamented the lack of funding.

Adcock noted that studies show EV owners are well-motivated by cost considerations, meaning utilities could use Time of Use programs or something similar to solve this issue.

Patricia Levi, Form Energy, referenced the uncertainty analysis that looked at capacity, ramp rate, and ramp duration and wondered how the rise of energy-limited resources, uncertainties and operation challenges will be incorporated into battery storage. Campbell clarified that the question is how battery storage might introduce uncertainty. Levi confirmed, saying system operators are struggling on how to dispatch short-duration battery storage so it is available when needed [Slide 16].

Campbell said capacity, ramp rate, duration, and the energy is an integral between 0 and the curve. Levy offered to reach out offline for more information.

LUNCH

2023 IRP Overview
Jared Hansen, Idaho Power

Ollis asked a question about Boardman to Hemingway and Gateway[Slide 2023 IRP Resources]. Hansen answered B2H will happen in July while Gateway West will have three separate phases.

Garcia noted the 550 MW of acquisition slated for next year and asked if Idaho Power has started the process yet. Hansen assured him that Idaho Power issued RFPs a few years ago to acquire this resource with more RFPs to come.

Amy Pryse-Phillips, BC Hydro, was curious about the 100-hour storage on [Slide: Regulation Reserves] She thought batteries over a four-hour duration were not very economical yet. Hansen said Idaho Power is a summer peaking utility, but they are seeing increasing winter peak risks hours. He said winter will continue to be a focus in the 20-year outlook. Hansen then said the short duration storage, coupled with solar, works very well to curb summer peak. He said the 100-hour storage is modeled similarly to an iron oxide battery, which is economical as the utility transitions away from natural gas/coal units.

Graessley asked about the 100-hour storage, wondering if Aurora storage logic was used for modeling dispatch, and were you generally satisfied with how it performed, in the question pane. Ian Mcgetrick, Idaho Power, reported that they used Aurora logic for four- and eight-hour batteries but used price arbitrage logic for the 100-hour unit. He said this method made more sense.

Garcia confirmed that solar is valued at the REC [Slide: IPC Renewable Curtailments]. He asked if that was the REC or REC plus wholesale energy. Hansen confirmed that the model curtails solar at a cost point set to the equivalent of a REC.

Campbell asked if future REC prices were incorporated as they could go down [Slide: WECC Renewable Curtailment]. Mcgetrick answered that they had a REC price forecast that was not linear but remained fairly high over the planning period.

Ollis noted that the Council uses clean policy tags and asked if Idaho Power did something similar. Hansen said the tags were not performing as expected so they manually marked every resource.

Ollis then touched on the idea of renewable portfolio standards and emission policy where the compliance mechanism may be somewhat unknown. He asked about pricing or bid ask adjustments around those. Hansen did not recall using tags in that way, saying they constrained emission in general.

Questions

Adcock approved of looking at iron oxide batteries and moderate renewables overbuild and finding them cost effective. He said greenhouse gas emissions are a real cost to human society and should be considered in the model. Adcock added that any state or federal regulatory costs that are put on the utility are also real and should be added to the modeling.

Hansen said carbon price adders are modeled at Idaho Power but wasn't sure about other utilities.

Ollis referenced the table on [Slide: Regulation Reserve Requirements] asking how the reserve requirements were calculated as percentages. Hansen explained that they came up during an integration study from 2020/2021, and it's percentage of load as a base, and then percentage of wind or solar as a base. Mcgetrick added that it is percentage of forecast not nameplate.

Ollis asked if this is the same for all the wind and solar or just a sample mix that makes sense. He wondered how a wind plant in Wyoming might change versus a wind plant in Idaho. Hansen said that was contemplated but aggregation was chosen for simplicity. He agreed that wind in Idaho is different than Wyoming and would be broken out, as opposed to solar.

Seelig asked if the table shows how much regulation the portfolio would have to hold each month for capacity expansion or for production cost modeling. Hansen said the capacity expansion produces a mini production cost run. He said it looks at how much wind is produced and takes a percentage of that and ensures that the regulation reserves are available in the model. He added that after the Aurora run, they also run it through their own tool to confirm they are meeting reliability requirements.

BREAK

Planning Reserves
Aditya Jayam Prabhakar, CAISO

Ollis asked about the [Slide: Percent of resources meeting 3-hour ramps in March 2023…] wondering about the net interchange. He asked how much net interchange CAISO plans for and if it will be constant. Jayam Prabhakar moved to the graph on [Slide 6] to explain that the key takeaway around weather-dependent variable energy resources is that the concept of micro grid does not work. He said you need a larger battery, and the grid is a good battery but there needs to be more interconnection and ties.

Ollis agreed, asking about markets. He wondered how much thermal commitments are assumed to be outside the region. Jayam Prabhakar explained that they use a ball and stick approach where the rest of the WECC has one intertie. He said they are exploring the idea of modeling transmission ties with more granularity.

Pryse-Phillips asked how the capacity contribution of batteries was determined, particularly with ELCC declining as more batteries are added. Jayam Prabhakar noted that they use a process similar to the CPUC and explained it.

Reserves: Regional Implementation Versus Plan Analysis

Seelig noted that utilities are increasing their number of tools and coordinating more because of uncertainty [Slido slide]. She added that more enhanced coordination is still needed. Seelig wondered how well the utilities have been tracking when she asks them to frame reserves held in the past versus reserved used. She also wondered if the utilities noticed any change from past to present.

Seelig continued, noting that CAISO has a lot of historical data which could yield information. She said the Council is saying we need a lot of reserves, but she wondered if we are using them. She wondered what was used to recalibrate the model.

Ollis moved to [Slide 3] which illustrates what is held in the EIM up to 2022. He cautioned that there is less than 18 months of data with all of the NW entities participating. He revealed that the initial Plan requirements were not that far off. Ollis said without adding renewables in the next few years the model shows they are not sufficient as soon as 2027.

Ollis thought unities have a better handle on this and suggested people come to the SAAC. Seelig asked the utilities how this can be tracked, and if they see something change over time in their operations. Hansen said this is why Idaho Power is using their own tool, calling this a good question. Seelig wondered if Northwest Power Pool had some useful data analysis about using reserves over time.

Ollis noted that time for the last Power Plan was too abbreviated to nail a number for each utility or the region. He said testing showed you could get similar results with shaping, but had not time to refine that observation. Ollis said he was pleased that other utilities also found that increased reserve requirements have a shape. He agreed that costs increase with more reserves so finding a really good estimate will lower costs.

Adcock lamented not seeing the large-scale transmission planning he expected on [Slide 9]. He wondered if the Council could encourage BPA to think about it. Seelig pointed to multiple efforts around this, listing the Western Transmission Expansion Coalition, the Western Pathways Initiative, WSTI, and more as involved parties. She said they are the starting phase but understand that this, and permitting reform, has to happen quickly. Seelig called this a challenging issue but noted that the utilities are at the table and talking.

Ollis added that the Council is involved in the WTEC technical committee, emphasizing that staff are not transmission planers but are trying to understand locational value as transmission is a vital issue.

Adcock said he hears utilities say, “well the transmission isn’t there, so we need to build a gas turbine.” Adcock said this is not the right answer and hoped to get a better one soon.

Heutte added more information, pointing to two big initiatives: the Western Power Pool Initiative and the WSTI at the Western Interstate Energy Board. He predicted they would intertwine and has been pushing for using the Council’s wind integration forum as a model. He called this a major opportunity to coordinate more between Power and Transmission planning and hoped the Council would get deeply involved.

Ollis asked if anyone is nervous about reserves as opinions on [Slide Slido] show it will be three to five years before the WECC coalesces on the structure of a day-ahead market. Heutte said it’s stressful but was confident in the technology, tools, data, and analytic power to manage it. Ollis agreed but said three to five years feels like a real risk. He added that going to the markets is an option, but that level of reliance is new to the region.

Heutte noted that day-ahead markets are being developed alongside the WRAP. He said the reserve requirements are not changing as every BA has those responsibilities but the day ahead and WRAP give you more tools. He cautioned that they will not tell the BA what to do. Heutte pointed to https://gridlab.org/wrap-report for information about timing between the WRAP and the IRP process.

Heutte admitted that NW Energy Coalition was nervous about 2021 Plan results around EE [Slide 11] but is more heartened now. He felt the same about DR. Heutte said the load side was not getting enough attention but stated that if you reduce load, you reduce the need for reserves. He stressed that the reduction should focus on big gains around the peak.

Ollis pointed to RTF analysis around EE and reserves.

Adcock asked about TOU along with EE. Ollis said that wasn’t tested but saw value for TOU and dynamic voltage reduction and tradeoffs were considered. He couldn’t remember the potential increase but thought it was dependent on the sectors. Adcock said that even 10 years ago it’s been proven that TOU is effective with managing EV loads. Ollis said he will follow up.

Ollis thanked the room for their participation and ended the meeting at 3:30.

Attendees in person and via Go-to-Webinar

John Ollis	NWPCC	Dor Hirsch Bar Gai	NWPCC

Jennifer Light	NWPCC
Annika Roberts	NWPCC
Dan Hua	NWPCC
Chad Madron	NWPCC
Aliza Seelig	PNUCC
Nicolas Garcia	WPUDA
Allison Campbell	PNNL
Tomás Morrissey	NWPCC
Jarod Hansen	Idaho Power
Nihit Shah	PGE
Sudesha Pal	OPUC
Ryan Roy	Western Planning Pool
Aditya Jayam Prabhakar	CA ISO
Nader Samaan	PNNL
James Adcock	Independent
Brittany Andrus	WECC
Leanne Bleakney	NWPCC
Mike Babineaux	Northwestern
Ryan Bain	OR PUC
Edith Bayer	ODOE
Ian Bledsoe	Clatskanie PUD
Jaden Boehme	BPA
Greg Brunkhorst	Tacoma Power
Pat Byrne	BPS
Jennifer Coulson	PSE
John Crider	EWEB
Robert Diffely	BPA
Dylan DSouza	NWPCC
Mike Dalton	Montana
Curtis Dlouhy	OR PUC
James Gall	Avista
Eric Graessley	BPA
Joshua Haver	Idaho PUC
Fred Heutte	NW Energy Coalition
Julie Jent	OR PUC
Becky Keating	Chelan PUD
Anna Kim	OR PUC
Jeff Kugel	PNGC
Patricia Levi	Form Energy
Scott Levy	Blue Fish
John Lyons	Avista
Ian Mcgetrick	Idaho Power
Bryan Neff	CA
Heather Nicholson	Orcas P&L
Joel Nightingale	WA UTC
Elizabeth Osborne	NWPCC
Craig Patterson	independent
Damon Pellicori	Northwestern
Amy Pryse-Phillips	BC Hydro
Erin Riley	BPA
Steve Schmitt	Northwestern
Paul Schulz	Montana
John Shurts	NWPCC
Tyler Tobin	PSE
Andres Valdepena Delgado	Idaho Power
Hanna Wahl	PSE
Seth Wiggins	PGE
Thomas Chisholm	ind
Brian Dekiep	NWPCC
Brian Dombeck	BPA
Malcom Ainspan	NRG
Meg Anderson	PGE
Steven Galloway	Montana
Aditya Jayam Prabhakar	CA ISO
Rose Pileggi	OR PUC
Blake Scherer	Benton PUD
Mark Thompson	Form Energy
Ben Ulrich	EWEB