Northwest Power and Conservation Committee
Resource Adequacy Advisory Committee Steering and Technical
April 27, 2021

Richard Devlin, NWPCC, began the RAAC Steering/Technical committee meeting at 1:30. Chad Madron, NWPCC, explained how to best interact with the Go-to-Webinar platform.

Power Plan Adequacy Assessment Preview
John Fazio, NWPCC
Fazio briefed the committee on the resource adequacy assessment that will go into the 2021 Power Plan. Fazio explained how the redeveloped adequacy model (GENESYS) provides a more detailed look into the system, the use of forward-looking Climate Change data and what goes into a Resource Adequacy assessment. Fazio presented results that showed an adequacy need of 1600 MW by 2023 followed by minimal resource needs throughout the planning horizon. Fazio acknowledged that there are risks that the analysis does not fully capture including the inherent uncertainty of the projected WECC buildout and the possibility of accelerated loads due to electrification.

Nicholas Garcia, WPUDA, asked if the 1600MW need identified on [Slide 6] is needed in any specific area to accommodate for transmission limitations or if they could work anywhere in the region. John Ollis, NWPCC, said it should be treated as a regional adequacy need, noting that it is specifically for winter. Ollis added that east/west side tests are inconclusive so far.

Fred Heutte, NW Energy Coalition, noted that [Slide 5] showed resources by category and wondered if certain projects from PGE and PacifiCorp are included. Fazio was not sure but pointed to files that contained the resources.

Heutte then addressed resources not yet in operation or fully committed, saying some utilities have moved beyond the IRPs Gillian Charles, NPWCC, used to gather data. He asked if there will be a look at these projected new utility resource. Fazio said they would.

Tom Kaiserski, Montana Dept of Commerce, asked if the 1600MW is above and beyond what is known to be coming on line. Fazio said if they are planned, sited and licensed they are in the study. Kaiserski added that PacifiCorp is just finishing up at 240MW project in Montana.

Garcia asked if the 1.7% on [Slide 7] is inclusive or exclusive of the 1600MW need. Fazio said the 1600MW is based on 2023 so it is not.

Tomás Morrissey, PNUCC, asked about the market price difference between 2023 and 2025 that is causing this effect. Ollis said it is not a simple answer as it's based on some seasonality. Ollis pointed to the fact that winter 2023 prices are low during the day and high during the ramps but not high enough in all hours to trigger a unit commitment. He added that in 2025 the mid-day prices rise enough to trigger more unit commitment.

Morrissey confirmed that mid-day solar prices are going up. Ollis confirmed, adding that the load is also rising. Ollis added that this will be covered in a few slides.

Rob Petty, BPA, was curious about how much of this effect is driven by price versus other factors. Ollis said he is still trying to break that apart but he suspects that sometimes it is prices and other times it's due to limitations on the hydro system. Fazio noted a study that added more reserves to 2023 when the LOLP dropped from 32% to 9%.

Spencer Gray, NIPPC, wondered if the new model's change of pricing leads to a change in in-region IPPs, out-of-region IPPs or both. Ollis said the new model treats the external market as supply bins and doesn't do unit commitments. Ollis added that it does change the thermal fleet in 2023 and moved to [Slide: Higher Thermal Unit Commitment in 2027….] to illustrate his point.

Gray asked if the model has a point where it says prices are high enough that off takers will sign longer term contracts or if IPP availability is purely on a short-term, merchant basis. Ollis answered that all availability is based on week, day and hour ahead.

Ben Fitch-Fleischmann, Northwestern, confirmed that the model is predicting shortages caused by low prices. Fazio said yes, in a way, adding that the new model has forecast error. Fitch-Fleischmann summarized that while we would expect to see scarcity pricing during scarcity events there is so much variability in combination with forecast error that we see the opposite of scarcity pricing creating scarcity events. Fazio said sort of, pointing to a sensitivity that added more thermal reserves and didn't create the same conditions.

Ollis added that the region is now seeing CA's problems and our hydro flexibility is not enough at all times.

Craig Patterson, independent, said he does not hear anything about the fallout from COVID-19, noting that this has shifted residential use from the traditional morning/evening pattern. He also pointed to businesses going out of business due to the pandemic. Patterson then spoke of the trend of customers moving to pre-paid accounts because of the economy, calling the issues critically important moving forward.

Fazio said the Council is looking at the effects of COVID on load but these studies use downscaled general circulation model climate change analysis. He said the RPM looks at a wide range of load conditions. Fazio then pointed to uncertainty due to electrification that may increase load.

Garcia acknowledged that the models capture WA's CETA requirement of most coal going away by 2025 but wondered about the more recent Cap and Trade bill which would raise dispatch costs for thermal plants. He asked if increased dispatch costs would increase prices enough to influence unit commitment in 2025. Ollis said including a cost of carbon reduces adequacy issues early on but does bring up more issues later. He offered to follow up more offline. Garcia was not surprised by that answer, adding that there is a lot of public policy coming that could affect unit commitment and construction decisions. Because of this, Garcia strongly supported running a scenario around how policy decisions affect reliability.

Devlin commented that the Council is following the economic impacts of COVID-19 very closely but thought that intense electrification would have an impact later in the Plan horizon.

Jim Waddell, independent, noted that 2023 is only 17 months away which makes it seem like existing thermal plants are presently stranded assets. He said that there are over 10,000MW of wind, solar and battery in the BPA interconnection queue, thinking that this would be a signal to bring these resources on sooner. Waddell called this a circular argument saying if these resources are not viable in 2023 then they are not viable now.

Fazio answered that he would not use the word viable, noting that there is price uncertainty. He said this depends on the value of adequacy and there will be a presentation in the SAAC that explores the value of lost load. Fazio said these plants could be very viable in the short term if adequacy is important and cost of curtailment is high.

Aliza Selig, SCL, asked in the question pane if the lack of natural gas commitment is because of a lack of coordinated, day-ahead commitment or if a longer-term commitment is needed. Staff answered that, for the most part, unit commitment would probably be at least in part, dealt with by more coordination on a day-ahead basis. Staff was not as certain in the case of the coal units.

Anthony Jones, RME, wrote in the question pane that the statement, "Sometimes, when a shortfall event is not expected, the market price signal is too low to commit a unit" seems unlikely, at least related to weather induced load events. He wrote that this sounds like a transmission failure, not a price related load /generation failure. Fazio said his quote is an attempt to simplify what is going on in the new model, adding that the new model doesn’t look at forced outages on transmission. He said it does see potential congestion problems that would lead to higher prices.

Ollis thought that Jones was correct that in some cases this can be associated with congestion adding that it could also be caused by forecast error for renewables in a certain location. He said in general this happens when the prices are so low that the available units are simple cycle and hydro which might have more uncertainty. Ollis offered to dig in further and follow up via email.

Garcia was curious about the future flexibility of the hydro system and wondered what a 1000MW loss of borrowed hydro would do to the LOLP [Slide 36.] Fazio said he did not study that scenario in the classic GENESYS but thought the LOLP would go up quite a bit. Fazio also said that the availability of 1000MW of borrowed hydro seemed reasonable to river operators.

Garcia pointed to questions about the lower Snake River dams, saying if they went away, it would cause a 1000MW loss of hydro and all associated flexibility. Fazio said they don't provide much flexibly during the summer. Garcia asked about the winter. Fazio said it would make a difference in the winter but the classic model is not showing many winter events.

Ollis commented that the new GENESYS incorporates Fish and Wildlife constraints. He added that the new GENESYS models some reservoirs explicitly while the classic model treated them as "run of river." Ollis said this change is where some of the additional flexibility is coming from.

Jones wrote in the question pane that Hydro "flexibility" is, realistically, limited to a very few dams: Grand Coulee, Hells Canyon, and a couple others. He asked if this flexibility is limited to the small subset of dams that can perform in that manner. Fazio did not think that was necessarily true and if a reservoir has storage, it would be economic to use that flexibility. Ollis agreed saying there is a spectrum and more flexibility has been revealed by the new model.

Jones said it is also nuanced to broadly assume flexibility when there are a lot of constraints on flow, irrigation, navigation and more. Fazio said all hourly and monthly non-power constraints that the Council could obtain are accounted for, so none of this affects navigation. Fazio added that stakeholders have provided this information.

Jones agreed that this is a tough issue, noting that 15-20 BPA dams in SW Idaho are empty all winter. Fazio said that those are probably not counted on for flexibility. Ollis added that the majority of the dams do not have flexibility especially the smaller ones that just pass the water.

Waddell asked about the effect of adding borrowed hydro in 2023 in the question pane. Fazio said he has not done that study, adding that the new model does not have borrowed hydro. Fazio guessed that if he did the LOLP would drop to 6%.

Gray asked in the question pane how the Power Plan will spotlight the sensitivity of the LOLP results on the model choice and the input assumptions, for example in the classic GENESYS, the number of hours of market availably and the amount of borrowed hydro. Fazio answered that the new GENESYS will be used as it's a more accurate representation and in the new model the number of hours of import is determined dynamically depending on market price and the new model does not model borrowed hydro, it simply models all hourly hydro operating constraints. He said the important parameter being used for the plan is the Adequacy Reserve Margin, which is similar to a planning reserve margin. Fazio said the ARM is fed to the RPM along with a capacity contribution so there doesn't need to be a choice about hours of import.

Aliza Seelig, SCL, asked, have you produced magnitude and duration statistics in addition to the LOLP for the current base study and sensitives, in the question pane. She also asked if these and monthly statistics are still valuable. Fazio did not have them available for this presentation but added that shortfall event statistics are available and will be examined. He said the Council recognizes the lumpiness of the LOLP metric and will likely consider amending its adequacy standard to include the metrics that set limits on event magnitude and duration. Seelig asked if these statistics will be described in the Plan even if they are not used. Fazio was not sure but added that, if possible, they would be. [Note from Fazio: Due to the time and cost of running the redeveloped GENESYS model, the lowest number of simulations were run that still provided robust results. However, because of that, there are not as many shortfall events to extract statistics from.]

Morrissey pointed to the line "New model with no WECC buildout" with its 2025 2.2% LOLP as compared to new GENESYS 2023 run with 32% LOLP. He asked if this is due to unit commitment issue. Fazio clarified that the 32% and 1.7% are based on the baseline WECC buildout and was surprised that the "no WECC buildout" was only 2.2% thus suggesting that it is unit commitment and not WECC buildout that is a bigger driver for the LOLP.

Morrissey said the bigger curiosity was dropping from 32% to 2.2%. Ollis agreed that unit commitment was an issue as higher prices support thermal unit commitment. Ollis added that Site C in Canada was included in the no WECC buildout.

Morrissey said that he was trying to figure out what is driving adequacy in this model saying he is shifting his thinking from the WECC buildout to unit commitment issues. Ollis said the higher reserves example reveals to him that unit commitment is responsible for 2/3rds of the issue or maybe more. Ollis said more tests are being conducted and more information will be revealed in the SAAC.

Elain Hart, Moment Energy Insights, asked if market conditions from AURORA represents corresponding weather conditions to the conditions being experienced in the PNW in GENESYS in the question pane. As example, she asked does the new model capture the constraints/risks that could arise due to something like a heat wave that covers a large portion of the West. Fazio did not think so, adding that there are no climate change temperatures for the rest of the WECC. Ollis agreed that we don't have that information which is why there is a market reliance limit.

Petty thanked the presenters for their work and the committee for the lively discussion. Devlin thanked everyone for attending and adjourned the meeting at 3:30.

Attendees via Go-to-Webinar

John Fazio	NWPCC
Dan Hua	NWPCC
John Ollis	NWPCC
Chad Madron	NWPCC
Richard Devlin	NWPCC
Rob Petty	BPA
Rob Diffely	BPA
Daniel Bedbury	Clark PUD
Dhruv Bhatnagar	PNNL

Leann Bleakney	NWPCC
Frank Brown	BPA
Aaron Bush	PPC
Pat Byrne	BPA
John Chatburn	Idaho OER
Zhi Chen	PGE
Rachel Clark	Tacoma Power
John Cornwell	ODOE
Travis Douville	PNNL
Ryan Egerdahl	BPA
Ben Fitch-Fleischmann	Northwestern
Villamor Gamponia	SCL
Nicolas Garcia	WPUDA
Jacob Goodspeed	PacifiCorp
Andrea Goodwin	NPWCC
Sharon Grace	The E2
Spencer Gray	NIPPC
Elain Hart	Moment Energy Insights
Bill Henry	
Fred Heutte	NW Energy Coalition
Steve Johnson	WA UTC
Anthony Jones	RME
Tom Kaiserski	Montana
Shay LaBray	PacifiCorp
Shirley Lindstrom	NWPCC
Douglas Logan	
John Lyons	Avista
Ian McGetrick	Idaho Power
Shauna McReynolds	PNUCC
Tomás Morrissey	PNUCC
Heather Nicholson	independent
Elizabeth Osborne	NWPCC
Pat Oshie	NWPCC
Craig Patterson	independent
Will Price	EWEB
Kristine Raper	Idaho PUC
Sashwat Roy	Renewable NW
Bill Saporito	Umatilla Electric
Paul Schulz	Montana
Aliza Seelig	SCL
John Shurts	NWPCC
Jamie Starnatson	Montana
Ben Ulrich	EWEB
James Vanden Bos	BPA

Jim Waddell	independent
Marissa Warren	Idaho OER
Seth Wiggins	PGE
Brian Dekiep	NWPCC
Jeffery Allen	NWPCC
Max Greene	Renewable NW
Thomas Haymaker	Clark PUD
Scott Levy	Bluefish
Adam Schulz	ODOE
Jim Yost	NWPCC
David Young	EPRI
Kate von Reis Baron	PGE