Northwest Power & Conservation Council
Systems Analysis Advisory Committee
August 10, 2022

John Ollis, NWPCC, began the meeting at 9:00. Chad Madron, NWPCC, reviewed how to best interact with the Go-to-Webinar platform.

Discussion on 2022 Market Study Methodology Revisions and Results (Part 1)

Nicholas Garcia, WPUDA, stated that he thought coal-to-gas conversions meant replacing boilers with turbines [Slide 3]. Ollis agreed that he was under the same assumption but learned that there a few different approaches that could yield better heat rates.

Garcia hoped that operating characteristics of gas with a boiler versus gas with a turbine would be accounted for. Ollis said they are not and explained his method which includes updating gas prices and capacity while leaving heat rates the same.

Garcia cautioned that ramp rates need to be set up appropriately. Ollis said fleet flexibility is important and this a large part of the fleet in Alberta. He said his main concern is getting price right but made a note to look at flexibility too.

Aliza Seelig, PNUCC, asked "How does the REC bid adder relate to the other requirements such as the WA climate commitment act representation in the model" in the question pane [Slide 6]. Ollis answered that the REC adder is specifically related to the overall WECC RPS and clean requirements and not for individual states. He agreed they used to be represented on a state-by-state basis, but found it difficult, so it was simplified to an overall approach.

Seelig understood the simplified approach and asked how much it's affecting power prices, noting its important to the Resource Adequacy modeling. Ollis said there is a lot of uncertainty, and more work could be done to understand the difference between modeling WECC-wide versus state-by-state. He added that the state-by-state analysis yielded odd results.

Seelig asked what "odd results" mean. Ollis said they looked unreasonable and Council assumptions were driving results. Ollis added that they don't include the Aurora build out for inside the region. Seelig confirmed that Aurora creates supply stacks outside the region to determine when imports are available. She then asked about when the region exports.

Ollis said GENESYS allows NW exports as long as there are reserves. He said in practice the hurdle rate of wheeling costs keeps resources in the region unless there is a strong economic signal. Ollis added that if there is inexpensive power in the middle of the day the NW will import and use/export hydro later in the day. Ollis added that this changes in the summer when a lot of the WECC is peaking at different times of day.

Seelig said the Aurora runs and some demand shapes would be major inputs in the Adequacy work and suggested finding a diversity of scenarios to understand impacts. Ollis strongly agreed.

Seelig explored how Aurora works in and out of the region and confirmed that this looks at how other region's builds affect NW adequacy. Ollis pointed to the market reliance limit which limits influence up to a point. He said imports add up and notes there are mid-day imports in some places that really changes how the hydro system works. Ollis said the goal was discovering what investments meet the adequacy of today.

Garcia noted that Aurora has a build out based on its needs and transmission constraints. He then asked if GENESYS could deliver resources that are constrained by transmission. Ollis clarified that the redeveloped GENESYS has similar transmission constraints. He then observed that there are still localized challenges based on transmission limitations. Ollis said this might be a model optimization issue but assured Garcia that any outage is treated as a regional event

Garcia asked what happens if there is an outage in eastern Oregon but nowhere else. He wondered if that event is diluted because you're looking at the entire region or can you say that area needs to build resources.

Ollis said there are some localized situations and maybe those areas should look at solutions, but there are other situations where the whole region is short. He conceded that GENESYS might not understand the power flow well enough but that was not the goal of the model.

Garcia said he is concerned about the Puget Sound region of WA and wondered if you could get power to this area because of internal constraints. Ollis said he will very much "enjoy" the zonal conversation later in the day and the scenario about adding more transmission.

Seelig wrote in the question pane that she is curious based on Garcia's question. She wondered if we need to understand power flow for import supply stacks for the interconnected regions. Ollis answered that GENESYS is not a power flow model but does consider things like reactants and some line constraints. He then talked about the challenges around developing another model.

Seelig thought she might be conflating the two models. Ollis confirmed that both models use the same physical transmission limits along with a net import limit. He said there could be a lot of power flowing through the region, but the NW can only rely on that limit of net imports.

Blake Scherer, Benton PUD, clarified that offshore wind will not be available to 2032 and wondered about SMRs [Slide 7]. He also asked for clarity around where offshore wind is being picked up. Scherer then asked how the timing affects the resource adequacy study.

Ollis said that only the offshore wind in CA was picked up adding that the resource was available in OR but not chosen. He thought it might get picked up in another iteration adding that CA and OR are in two different reserve sharing groups.

Ollis said this could change the supply for 2027 which would play into adequacy. Scherer asked what year the adequacy study is for. Ollis answered that they are talking about 2027 or 2028.

Garcia said he heard CA may require behind the meter storage to go with behind the meter generation and asked if this is true [Slide 9]. Ollis did not know but said the behind the meter storage does go up.

BREAK

Rob Diffely, BPA, asked if the graph on [Slide 12] represents the net peak loads. Ollis answered yes to the best of his knowledge. Diffely then asked about the assumption around electrification behind these loads. Ollis said the assumption comes from their baseline forecast, adding that there is an electrification/higher demand scenario that will be explored.

Dave LeVee, Powercast, said he is working on demand response actions and activities and thought that says a lot about the demand shifts and reserve margins on [Slide 14]. He said a lot is driven by price signals and utility actions. He called peak requirements and reserves a moving target and suggested incorporating timing that shifts loads. Ollis thanked him and said this is consistent with what was seen in the Plan.

Garcia was concerned that a lot thermal held in reserve might actually disappear if public policy makes them too expensive to retain [Slide 15]. Ollis agreed and pointed to Aurora's economic retirement logic adding that they don't use it because it tends to replace large swaths of the system. He said they could look at economic retirements and putting in a patchwork of carbon prices doesn't help.

Levee asked if the data for the model has increasing amounts of DR that assumes customers can shed load based on price [Slide 16]. He said there are backdoor ways to change load behavior in Aurora. Ollis said there are some assumed levels of DR and some of that is in the peak load forecast, but he doesn't have a way to increase above and beyond utility forecasts.

Ollis said they do look at added utility-scale storage as a highlighted area where DR might find a place as the price signal is there. Levee said this isn't changing over time but remains static. Ollis said it does change over time in some places. Levee said that's more in the load forecast and not necessarily in the data that goes into Aurora. Ollis agreed.

Ollis ended the meeting at 12:00, asking for more thoughts and suggestions about scenarios be sent to him.

Craig Patterson, independent, wrote, “How does your modeling address the economic effects of radically different rates? So, when high priced utilities compete with low priced utilities, how do you insure the low priced utilities will get the energy?” in the question pane. A staff member answered: “That level of granularity is outside the scope of this study” in the pane.

Attendees via Go-to-Webinar
John Ollis, NWPCC
Leann Bleakney, NWPCC
Glenn Blackmon, WA Dept of Commerce
Rachel Clark, Tacoma Power
John Crider, EWEB
Enoch Dahi, NW NRU
Rob Diffely, BPA
Ted Drennan, Oreogn PUC
Ryan Fulleman, Tacoma Power
Nicolas Garcia, WPUDA
Ellyn Groves, NW NRU
Lee Hall, BPA
Jared Hansen, Idaho Power
Massoud Jourabchi, NWPCC
David LeVee, Powercast
Jennifer Light, NWPCC
Ian Mcgetrick, Idaho Power
Heather Nicholson, independent
Kevin Nordt, GC PUD
Elizabeth Osborne, NWPCC
Craig Patterson, independent
Damon Pellicori, Northwestern
Sashwat Roy, Renewable NW
Blake Scherer, Benton PUD
Steve Schmitt, Northwestern
Aliza Seelig, PNUCC
Jaime Stamatson, MT
Danielle Szigeti, Tacoma Power
Tyler Tobin, PSE
Ahlmahz Negash, Tacoma Power
Frank Brown, BPA
Brian Dekiep, NWPCC
Lori Hermanson, Avista
Ben Kropeinicki, Avista
Michael Linn, Portland PCC
Joel Nightingale, WA UTC
Paul Nissley, Seattle City Light
Kathi Scanlan, WA UTC

Landon Snyder, Snohomish
Kelli Schermerhorn, Northwestern