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

Minutes for Systems Analysis Advisory Committee
April 22, 2026

John Ollis, NWPCC, began the meeting at 9:00. Chad Madron, NWPCC, explained the best way to interact with the Zoom Webinar platform. Ollis called for introductions, both in the room and online.

OptGen Methodology Updates

Fred Heutte, NW Energy Coalition, asked what "seemed extraneous" on [Slide 3] means. Ollis answered that he will cover that later in the presentation, previewing that he should have probably said redundant.

Dan Kirschner, DSK Advisors, asked if storage is on-site or underground/LNG storage [Slide 9]. Tomás Morrissey, NWPCC, said this storage is on-site for new builds. Kirschner confirmed that existing storage would be Jackson Prairie and Mist while new storage is on-site. Morrissey answered yes.

Heutte asked if there are any dual fuel gas plants right now. Morrissey thought so. Heutte asked specifically about combined cycles. Morrissey answered no.

Heutte asked about the basis for the 1.6 million/day MMBtu found on the third point of the slide. Morrissey answered that it was the staff estimate for the highest use day in Jan 2024. Morrissey admitted that staff used a lot of assumptions in that estimate.

Heutte asked about the total available NW supply. Kirschner answered that it is a little over 4. Heutte wondered how much of that would go into residential/commercial/direct use versus industrial and power.

Morrissey said the 1.6 number is above what is subscribed to the electric power side. Morrissey reminded the room that this is a spreadsheet analysis. Heutte thought the Council should think about a model. Ollis said current technology has that capability but there are questions around data, sourcing, and staff time.

Kirschner referenced analysis of the cold snap weekend in 2024 which found 220,000 deca therms for one hour. Ollis asked for any data stakeholders can share. Kirschner said this is for OR and WA only and offered to share the information.

Aliza Selig, PNUCC, confirmed that the limit in 2032 is capped because the existing system has only so many fuel tanks available [Slide 11]. Morrissey said that's the staff's assumption of how many gas plants can be built with a firm fuel supply. Selig asked if Morrissey is talking about LNG. Morrissey said they didn't get into that much detail. Kirschner confirmed that storage gets built up to 2032 and after that there are assumptions about pipeline expansions.

Selig asked, aside from LNG, why a fuel tank would limit build out. Morrissey said the concept is getting to peak capacity versus and energy question. He explained that storage has two to three days of fuel that gets filled once a month and more plants would rely on storage.

Selig still thought that simple cycles would be available to add in the near term as opposed to combined cycles and thought the two technologies could be split out. Morrissey said it's the total, the model prefers simple cycles, and the cap is for both technologies.

Sibyl Geiselman, Pub Gen Pool, asked for more information about the 10GW cap in 2046, saying she thought pipe expansion would be easier than transmission expansion. Morrissey said staff didn't run a sensitivity without the cap, adding that in 2046 of some studies do brush up against the cap. Ollis added that there a few looks at transmission along the way with the cap in effect. Ollis also pointed to emerging technologies that may offer a tradeoff.

Heutte said the 9th Plan should start with need which gets back to gas terminology. Heutte said there are two modes of machines and 3000MW of new gas builds mean simple cycle/peaking which has value for 1% of the year.

Heutte said the issue is speed to power which led to problems in January 2024. Heutte suggested looking at need and risk while listing the challenges of adding gas plants.

Kirschner wondered how to inform the Council members in a way that allows them to think about policy. He asked, "if not this then what?" from a planning perspective.

Heutte said we need to look at other aspects of the Plan, pointing to issues with programmatic DR. He said a regional DR approach and lots of work would yield good results, but hard to specify, as an example. He also pointed to import limits. Heutte said we should try to avoid the easy play of adding more gas. Ollis said staff are aware of tradeoffs and try to do the best they can especially with all kinds of fuel accounting.

Scott Levy, Bluefish, thought that the January 2024 issue was solved by imports from the desert SW, which showed removing the winter import cap is the obvious other solution.

Sophie Major, WA UTC, asked about other policy or emission constraints on the gas buildout. Morrissey and Ollis listed the constraints staff entered into the model. Major asked if the model was putting out unrealistic gas buildouts with the constraints but without the cap. Morrissey said it did in some scenarios.

Selig confirmed that the model builds too much in the near term, but the 10GW constraint does not hit until the end. She thought the ramping is building too much and not the model. Morrissey said staff are seeing numbers in 2032 that felt higher than the existing system/storage could support. Selig thought constraints should be limited to near term and not long term.

Heutte referenced a 2016-17 study, asking the Council to talk to the CEC and see what they learned about assessing potential and risk on the gas/electric interface.

Levy hoped that the model allowed for storage to recharge using sources from outside the region, adding that BPA is hesitant to do that [Slide 21]. Ollis said yes, there is no limit like that on storage.

Nolan Kelly, BPA, pointed to EE as a contributing factor for annual energy, peak needs, and planning reserve margin. He asked for more information on EE in the planning reserve margin and annual energy. Ollis said EE and DR reduces the reserve margin because EE and DR reduce load.

Heutte confirmed that the time interval on [Slide 25] is day not month. He then noted that GENESYS looks at a range of shapes on a daily basis while OptGen looks at an average per season. Ollis confirmed this.

Heutte expressed discomfort with the term Planning Reserve Margin, saying it means different things to different people and requires constant explanation [Slide 29]. Ollis agreed.

Kirschner called this slide a place where gas and the grid "pass in the night." He asked if there is a way to drive things closer together, saying it would help coordinate planning. Ollis said the same could be said about Reserves. Kirschner called for the Council to define the differences in the documents, saying it would be helpful. Ollis agreed that understanding the coordination between the electric and gas systems would be good.

Levy thought, given the state of a lawsuit, the RCBA, MOP Op, and BiOp, would be gone. Ollis said some of this is inertia and some runs happened in August 2025.

John Crider, EWEB, wondered why summer PRMs are bigger than winter. Ollis said winter loads are naturally higher in the NW and we want to be less reliant on the WECC during the summer when the rest of the area is peaking. Dor Hirsh Bar Gai, NWPCC, said it goes back to the shortfall record driving the peak margins.

Selig confirmed that this is satisfying the peak and frequency metrics. Hirsh Bar Gai said yes.

Selig asked if the balancing up reserve is shown [Slide 33]. Hirsh Bar Gai answered no. Ollis said it's around 2000-3000MW a season and explained the process.

Heutte thought it might be good to call PRM peak reserve margin. He then called it interesting how the PRMs vary between summer and winter. Heutte addressed transfer limits, saying he is pounding the table as the world is completely different now, noting how much flows north today.

Heutte asked how to bring this issue forward. Hirsh Bar Gai said this has been a topic for the Resource Adequacy Advisory Committee for years. Hirsh Bar Gai said opinions have been mixed, even at the most recent meeting. He added that this event is an emergency measure that is not planned for.

Ollis said he is sympathetic to this, pointing to others who are concerned with market reliance limits. Ollis pointed to a difference between transferring and importing, saying this committee can direct staff to talk to the Council.

Morrissey moved to [Slide 32] to say market column is the TC limit in the model.

Heutte understood the difference between net and sink, calling on transmission planners to help explain that to the Council. He then discussed firm, asking what that means during high stress periods for the WECC while pointing to March of this year. Heutte ended by saying the transfer limits are too low. Ollis said he can pass this perennial concern along.

BREAK

Kari Hay, BPA, asked about the average seasonal peak load value, wondering what the average is over. Morrissey explained how GENESYS finds the highest peak hour per year. Ollis explained the philosophy behind the methodology.

Hay asked where the need comes from. Hirsh Bar Gai said he can provide that offline.

Levy suggested running a sensitivity where there is a natural gas need as a way to show the bounds of the transfer limit.

Huette said that 6% is the required NERC load in resource [Slide 35].

Selig asked if the OptGen typical peak day load comes from a particular load forecast [Slide 37]. Hirsh Bar Gai said both GENESYS and OptGen are using the high growth trajectory for the five runs. He added that need do differ.

Selig thought she needed to better understand how that need is calculated. Hirsh Bar Gai explained the process.

Heutte said Spring is tricky especially in March and it would not be possible to represent every case. He said staff should focus on low hydro. Ollis said that both GENESYS and OptGen include the seasonality of hydro and thermal maintenance.

Heutte asked if OptGen looks at things project-by-project. Ollis said yes, within the Northwest.

Eric Graessley, BPA, asked if the OptGen typical day load is the peak. Ollis answered yes.

Kirschner asked how staff arrived at the original constraints on [Slide 41]. Ollis said staff looked at the maximum number of resources brought in the last five years. Kirschner said the Council should know staff started here and couldn't get to adequacy. Ollis agreed.

Heutte called the limits on [Slide 42] too low, pointing to PGE's RFP which has 2000MW of batteries in 2029. He pointed to new domestic battery manufacturing that will eliminate constraints. Ollis said most sensitives do not have a limitation.

Heutte didn't think this was binding in the grand scheme. Ollis assured him that the planned resources include PGE's plan.

LUNCH

Draft Resource Strategy Analysis Methodology and Results

Kirschner noted that Oregon's Climate Protection Plan was ruled invalid in 2025 and then reconstituted [Slide 7]. Kirschner asked if it is included or not. Morrissey said he would have to double check, saying it probably impacts the load forecast more than the electric side.

Jake Kennedy, NWPCC, said in some scenarios OR and WA ramp up the HVAC electrification scenarios. Kirschner said he was satisfied with the answer and required no additional follow up.

Geiselman asked for more information about how emission reduction policy/goals are treated. Ollis explained that clean targets are shows as a region-wide goal, adding that CETA and HB2021 are treated slightly differently from each other. Morrissey dove in a bit deeper.

Geiselman confirmed that there's no binding emission reduction trajectory as a constraint, which allows thermals, and emissions, to be outsourced elsewhere. Ollis said yes.

Heutte called [Slide 8] a good range, saying it's important to look at the high and low ranges and see what that does to the resource mix.

Kirschner wondered why there are increases in every case from 2040 on. Morrisey said that came from the results from the gas survey. Kirschner agreed the jaws look pretty good, saying he might move the upper jaw more towards the middle.

Heutte was tantalized by the international scene, wondering what happens after 2030. Heutte said he's hearing that Asian and European demand for gas may go down as they move to renewables.

Heutte said the range of uncertainty in the demand forecast should be the story of the 9th Plan [Slide 12]. Steve Simmons, NWPCC, said past Plans based the trajectory on economic signals and that has changed with the introduction of data centers, electrification, and EVs.

Kirschner confirmed that staff tested two scenarios with 13 sensitivities [Slide 21]. Ollis said yes.

Geiselman confirmed that the resource adequacy or production cost modeling market view doesn't represent the two market/two RA future that is laid out here [Slide 22]. Ollis said that is kind of close, saying there is no clean break between the two markets. Ollis said they've tried to represent a few things but admitted that this a tricky situation that will require consistent work.

Huette asked if staff have been in contact with the Renewable Hydrogen Alliance. Morrissey confirmed this.

Heutte thought other things would drive rooftop solar forward [Slide 24]. Ollis assured him that there is assumed rooftop solar in the demand forecast and this represents installations over and above that.

Heutte then jumped to the promise of geothermal, admitting that it is hard to pin down. He said advanced geothermal is going to happen, mentioning Fervo and new contracts in the last year. Heutte said this makes staff estimates conservative and suggested talking about how to push it forward. Ollis thanked him, saying staff used small, modular nukes as a placeholder for clean baseload.

Heutte argued for a low and high value for this. Ollis said there already is one. Heutte said nuclear fuel is very expensive while geothermal is much less so.

Crider asked how ELCCs are treated in the future [Slide 26]. Ollis said staff didn't use ELCCs, explaining how the methodology was designed. Crider asked how the cumulative buildout of a particular resource is captured en masse.

Ollis moved to [Slide 106] to explain further.

Heutte reiterated that the more storage the lower the ELCC but admitted that there are limitations. He listed these limitations and said he approved of taking a different path.

Major addressed ELCC, saying a lot of WA utilities are using the ELCC approach [Slide 27]. She said WA UTC staff look to the Plan for context and to cross reference their work. Major wondered if there could be some interpretive support after the Plan is written.

Ollis said footprint matters for ELCC before diving into some high-level findings. He offered to help find connections after the Plan work was complete.

Geiselman asked for more information about how a typical day approach would cover events like a wind drought during a cold snap. Ollis explained how the typical day approach works and how the dynamic probabilistic reserve offers protection. Morrissey added that staff backchecked this in GENESYS for accuracy and it checked out well until 2031. Hirsh Bar Gai offered to share the metrics in the chat.

Mary Kulas, Consultant for PPC, pointed to transmission+ versus transmission max on [Slide 28], asking if staff considered the initial resource assumptions inside the region. She said

transmission max doesn't change until after 2033, adding that she expected to see a similar buildout. Ollis said it relates to the market study

Heutte called for more detail about gas in the charts on [Slide 29]. Morrissey moved to [Slide 86] to show gas. Heutte argued against too many peakers, saying they would be expensive. Morrissey answered that they would have to arrive with a fuel tank.

Crider pointed to delayed battery/delayed demand side where the recips are chosen. He asked if it's because of availability. Morrissy was not sure, saying staff has to dig in more.

Jen Light, NWPCC, added that the flatness you see on [Slide 84] could be because this is the one sensitivity that butts up against binding clean policies.

Hay pointed to the federal policy box on the right, asking which policy that is. Ollis said the non-dotted orange boxes are under the current administration while the other is 2024 Fed policy.

Heutte again asked for geothermal, pointing to PGE's work that looked at pre-post 2024 Federal policy. Ollis agreed that staff took a blunter look. Heutte said even without the IRA credits the increase of cost for solar/wind is less than the increase in gas.

Geiselman noted that staff said the model was running out of resource options for reliability [Slide 42]. She asked if these were still reliable portfolios, wondering if it is over constrained as the model keeps picking the same resources. Ollis said staff didn't test for adequacy every year but reported that the reserve margin did well except for 2028, saying there is a message there. Geiselman thought this made sense, saying she didn't realize this is on the front end.

Heutte said there is strong confidence in the Council's approach [Slide 39]. He said this Plan should be a clarion call to the region to max out EE because it provides so many additional benefits.

Heutte said he was in favor of DVR/CVR but said there is 3000MW of programmatic DR and the model is not picking much of it [Slide 46]. He asked about the model blocking this resource. Ollis explained that DR cannot provide the reserve value that the model gets out of storage. Heutte asked if this is a modeling artifact. Ollis said that is unclear.

Heutte wondered if DR is a load modifier, reserve, or a little of both. Morrissey mentioned that DR helps reserves in the same way EE does. Ollis explained how the typical day arbitrage might affect things too.

Heutte hoped the Council would move to both storage and DR, again pointing to PGE work. Ollis admitted there is not clean way to model DR in this model, but said staff will continue to explore.

BREAK

Heutte confirmed that long-duration storage was Form Energy batteries [Slide 64] which he called a slow battery. He wondered why the model was not picking pump storage. Ollis said the model does pick hydrogen later on, saying both are modeled as pump storage.

Heutte then asked if peak value of hybrid storage is additive [Slide 67]. Ollis said the nameplate of the inverter is listed for hybrid, so they are not stacked.

Selig addressed price volatility, wondering about costs out of the model and the model optimization of 10 futures and gas volatility. She asked if the volatility was caused by the choices for the day and if MPVs were an average. Ollis revealed that staff are working on isolating costs now. Selig was curious about fixed cost, variable cost, and the market. Ollis said staff are seeing a range that is similar to AURORA WECC-wide. He acknowledged that some price volatility would be dampened by the dynamic probabilistic reserve.

Geiselman asked if staff think the typical day approach is incentivizing the model to favor hybrids, causing stand-alone storage to miss out. She asked for more information on cost parameters that might be causing this. Ollis said stand-alone storage and DR may not be well explored, adding that hybrids are probably being chosen because they solve two different problems.

Heutte pointed to California storage, saying they are used a lot [Slide 63]. He said hydro sets the NW apart, along with IOUs not having access to that flexibility, and two markets about to come online. Heutte said the model picking for reserves and not dispatch makes sense.

Selig asked if the OptGen buildout on [Slide 78] would be the same as the WECC AURORA buildout. Ollis was not sure, saying staff looked at total amounts. He said AURORA's treatment of storage is not as nuanced.

Heutte pointed to a new MT connectivity study which shows buildout potential. Ollis said that the Transmission Max scenario has more connectivity.

Kulas addressed Transmission Max, saying AURORA is building because it sees that there will be max transmission in the future. She said the model in 2032 would make more sense for Transmission Max and Transmission+ to have the same build and wondered why. Ollis agreed, saying there is a connection in the 20-year study.

Geiselman noted that the model didn't pick up all planned renewables in the early years and how there was discussion on maxing out near-term conservation. She asked how this could be true. Ollis said most planned resources, including renewables, were picked up in 2028 but didn't always get built. He said the model was solving the planning reserve margin instead of the firm energy problem.

Geiselman asked about build limits by resource types versus planned. Ollis said there were not a lot except for natural gas. Morrissey pointed to total resource limits in early years.

Heutte was happy to see geothermal but questioned the 2034 beginning date. Ollis said that came from the GRAC. Light said the seven-year lead time was for identifying and building out the site. Heutte offered to send reports.

Ollis ended the meeting at 4:00pm.

Attendees In Person and via Zoom Webinar

John Ollis	NWPCC
Tomás Morrissey	NWPCC
Dor Hirsh Bar Gai	NWPCC
Jennifer Light	NWPCC
Jake Kennedy	NWPCC
Fred Heutte	NW Energy Coalition
Aliza Seelig	PNUCC
Dan Kirschner	DSK Advisors
Jess Kincaid	PNNL
Kari Hay	BPA
Eric Graessley	BPA
Rachel Gardner-Clark	Tacoma Power
Verene Martin	Seattle City Light
Alexandra Karpoff	Puget Sound Energy
John Crider	EWEB
Rebecca Klein	Seattle City Light
John Purvis	Clallam PUD
Ryan Bottem	Public Generating Pool
Kaitryn Olson	Puget Sound Energy
Ian McGetrick	Idaho Power
Marty Kulas	Consultant for PPC
Leann Bleakney	NWPCC
Michael Cocks	BPA
Ted Drennan	OR PUC
Brian Dekiep	NWPCC
Sophie Major	WA UTC
Taylor Toews	NW Natural
Steven Simmons	NPWCC
Jared Hansen	Idaho Power
Sibyl Geiselman	Public Generating Pool
Elizabeth Osborne	NWPCC
Christian Douglass	NWPCC
Nathaniel Clayville	NWPCC
John Lyons	Avista Corp
Mary Rudolph-Knobbe	NW Natural
Jason Sierman	ODOE
Connor Lennon	Tacoma Power
Kevin Smit	NWPCC
Brittany Andrus	WECC
Scott Levy	Bluefish
Nolan Kelly	BPA
Hanna Lee	BPA
Sanjeev Joshi	CRITFC
Joe Walderman	NWPCC
Mike Swirsky	CRITFC
Andrea Talty	Puget Sound Energy