Northwest Power & Conservation Council
Conservation Resources Advisory Committee
September 24, 2024

Kevin Smit, NWPCC, began the meeting at 9:00am. Christian Douglass, NWPCC, called for introductions. Smit reviewed the agenda, emphasizing that he would be asking the committee for direction at several points.

Northwest Council Utility Admin Cost Project Findings
Noah Lieb, Apex Analytics

Jim Lazar, Electricity Brain Trust, asked Do we have the scatter of these results? Can we identify best practices from those of the lower-cost utilities? in the question panel [Slide 14]. Noah Lieb, Apex Analytics, answered no, as they don't have program-level resolution to understand if one portfolio is more heavily driven by behavioral spending versus another portfolio driven by direct install kits or income qualified programs. He said there is more on this in the upcoming recommendations slide.

Bonnie Watson, BPA, asked How do these results compare to previous 2021 Power Plan assumptions, in the question panel. Douglass did not think they had a $/kWh metric in that Plan as they were still using 20% of incremental cost.

Nicholas Garcia, WPUDA, said he understood why Lieb's methodology used weighted averages, but wondered about size as a smaller utility would have to spread costs over fewer customers. He asked if Lieb looked at the data on a size basis. Lieb answered yes, saying that slide is coming up later in the presentation.

Watson asked if Ag was intentionally excluded from the scope of this analysis, in the question pane [Slide 17]. Lieb answered that they don't have Ag in the 861 data, so this was an effort to keep things contained. Douglass thought it might be included in industrial. Lieb said they talk about consistency in reporting in the additional slides, calling it a fruit salad of portfolio data.

Lazar was surprised by the industrial first cost of $1.3 Billion compared to residential, asking what is going on [Slide 21]. Lieb was not sure, saying this is data out of ProCost, adding that it might have to do with the units.

Lazar did not think this was plausible. Lieb agreed, cautioning the room not to place too much emphasis on the slide as the data comes from a weak foundation. Douglass agreed that unitization might be the cause as residential has small units ($/sq. ft) while industrial measures are top-down where savings are a percent of total industrial load. He thought the percentages were still valid.

Rich Arneson, Tacoma Power, wrote, the residential 7% value is surprising. Can you describe what is going on with the data… kinds of programs etc.., in the question pane. Lieb said this slide is not something that was used or leaned on and regretted including it.

Smit said he and Douglass could dig into what's going on with the ProCost tools to better answer the questions. Lieb recalled an email exchange where this was discussed, saying he would find it.

Arneson wrote, One other thought. Administrative costs tend to be hard to reduce. Meanwhile utilities have been working through their potential and now the potentials are smaller, and the conservation acquisitions are smaller. I am thinking that somewhat sticky administrative cost applied over a smaller total savings means pressure on the programs to be cost effective, in the question pane**.**

Garcia referenced utility size saying ten of the utilities he works with have fewer than 20,000 customers [Slide 22]. He said this makes conversations about conservation challenging as they have very few customers to spread the admin costs over. Garcia understood why some utilities were at 83% or 43% but could also see far less. He asked if there was any way to look at a fundamental difference in costs depending on utility size, thinking there would be.

Lieb said the individual utility data did not make clear size delineations, saying some larger portfolios ended up on the left side of the axis while some smaller ones ended up on the right.

Lieb added that applying an admin cost for portfolio planning is done on a measure specific level, making it impossible to identify if that individual measure is going to a small or large portfolio. He said they must make blanket assumptions for the region, calling it the most reasonably accurate assumption they can make. Lieb did not think they had the underlying data to differentiate in another way.

Smit said the new models might be able to do this if the data was available but was not yet sure. He asked the room to remember that this is a planning assumption to broadly account for admin costs and this might be better than assuming a blanket 20% adder.

Lieb envisioned using customer sectors off of the 861 to tier utilities by size. He offered to do that and report back.

Garcia appreciated that, suggesting that Lieb ask a few utilities if the presented costs look reasonable. Lieb said he has a slide on this coming up.

Jeff Harris, NEEA, said he didn't know many utilities that are paying 100% incremental costs for a measure within a program outside of direct install. He said most are paying some portion of incremental capital costs and wondered if Lieb looked at the percentage of program costs versus percentage of total incremental costs.

Lieb answered that they looked at portfolios and bundled the costs from top to bottom, saying it becomes a circular argument. He said you have to allocate portfolio costs if you're doing a measure level, or sector level exploration, and decide how to distribute.

Harris understood, saying this exercise is about understand the utility investment required to acquire the resource. He wondered if this is the right exercise, acknowledging that this is how the Council always operated but thought it might not be the right metric for the real world. He said, for example, it would look like 100% admin costs if a utility could get the same or better results through marketing alone. Lieb said the point of this is to come up with the "least worst" option as there is no perfect choice.

Jennifer Snyder, WA UTC, said large IOU in WA expects admin costs to go up as the low-hanging fruit has been harvested and they are now trying to get harder-to-reach customers. She this makes it more complicated as more admin is needed pointing to equity reasons as well.

Lazar said total measure cost is the relevant denominator, whether paid by the customer, utility, or third-party grant. He said the admin cost as a proportion of the total measure costs seems relevant while the admin costs as a proportion of the utility-only cost doesn't.

Aquila Velonis, Cadmus Group, said he has also struggled with characterizing admin costs. He commented that using a percent of incremental costs may be good for energy efficiency but more challenging when talking about building electrification. Lieb said that is also coming up later in the presentation.

RECOMMENDATIONS [Slide 30]

Lazar was comfortable with recommendation 1 but voiced concern that they were measuring the wrong thing. He noted that his local utility has been helping customers fill out state and federal grant paperwork, saying this involves a lot of admin costs but eliminates program expenses. He thought the two are fungible when there are federal and state incentives, predicting that we may see more of that in other areas.

Harris agreed with Lazar, appreciating the differentiation across the sectors. He said that industrial has the most custom measures and program approaches which don't have the same admin costs but do have other costs. Harris noted that as these are first year kWh savings, making effective useful life an important factor.

Lieb said first year and lifetime were initially included but it created a noisy analysis due to lifetime information lacking in some data sources.

Quentin Nesbitt, Idaho Power, asked how far the numbers in recommendation 1 are from the 20% adder. Lieb said they tried to do that through BPA Beets data, and it was almost perfectly aligned with the residential number. He said applying outside the region found a higher percentage of incremental costs closer to 33%. Lieb thought this was due to not having the right data because of custom measures without incremental costs.

Nesbitt asked why custom measures are 0. Lieb said the data didn't include incremental costs for custom, only UES.

Peter Kernan, OR PUC, saw the benefits of a sector approach but was concerned that both this new approach, and the old 20% adder, are too punitive to overall cost effectiveness. He said, as the overseer of Energy Trust of Oregon, they can look at the overall structure and include a performance measure where admin costs must be 6.5% of overall expenditure structure, adding that Energy Trust comes in below.

Kernan thought that applying this at the measure level could be screening out valuable energy efficiency too early in the process.

Harris wrote Could you take another approach where the admin costs are not applied at the measure level at all but are applied in the system planning model at the resource level? This would be more realistic for how utilities think about their admin costs to deliver a portfolio of EE programs, in the question pane.

Harris said the admin would be applied to the block of resource chosen by the system planning model. He said that number could be better compared to overall portfolio spending, getting it closer to how admin is accounted for by regional utilities and energy efficiency program administrators.

Watson loved and supported Harris's recommendation, saying looking at energy efficiency as a block of a resource allows more flexibility within the portfolio.

Nesbitt said when Idaho Power looks at measure cost effectiveness, they include an estimated admin cost and track by program, not measure. He thought doing this at a portfolio level at the front end would include non-cost-effective measures and then ask that they be subsidized by other measures.

Velonis wrote, if the option 1 is chosen, is the intent to evaluate the $/kWh every Power Plan as cost to implement will change over time, in the question pane.

Kernan wrote, Agree with Jeff--I think this approach could lead to more cumulative and cost-effective EE for the region, in the question pane.

Harris wrote, One other thought: As noted, real-world program administration requires some stability year-to-year, it does not ramp up and down with incremental costs or even program throughput. That makes it subject to variations in yearly accomplishments and or changes in portfolio structure that would affect the total incentives paid out in any given year; e.g. Covid impacts in 2021-2023. So, what we really need is a representation of the long-term average costs required to run EE programs over the 20-year planning horizon. These long-term averages would probably have a fixed cost and a variable cost element but would be spread across the entire EE portfolio, in the question pane.

Douglass thanked the CRAC, saying there will be follow ups and more information to come.

BREAK

Line Losses for the Ninth Power Plan
Christian Douglass, NWPCC

Lazar added that marginal losses can reach 20% or more at system peak [Slide 4]. He asked to talk about the capacity value of energy efficiency later in the day. Douglass called this an important point.

Nesbitt asked if marginal losses are similar to peak losses. Lazar said no, explaining the math behind different losses. He said at a lightly loaded hour where system losses are 5%, marginal losses would be substantially higher and at peak where system losses are 10% marginal losses can approach 20%.

Douglass says he thinks of resistive losses as having a quadratic relationship with load, so saving those losses off the top has more value than saving average losses.

Arneson confirmed that this is about the load losses component and not the no-load losses component. Douglass said this is about average line losses represented by the blue line on the graph.

Lazar insisted that the losses on [Slide 9] do not vary by sector but by voltage level. Douglass thanked him. Lazar then noted that the PGE data on the graph is presented inconsistently. Douglass agreed, explaining how PGE reported the information.

Lazar continued, saying all of the utilities are relatively large and mostly urban while rural utilities have a lot more wire per kWh. He said this leads to higher resistive losses. Douglass said that makes sense, explaining other theories.

Lazar maintained that each of the represented utilities have done cost-to-service studies which includes a loss study. He said that means there's more data available to review. Douglass was pleased by that information, saying he will be asking for more data.

Arneson wrote Tacoma has been using hourly line loss values in its CPAs. Result is "average" losses can vary significantly depending on the measure or industry, in the question pane. Lazar called that good stuff as some conservation measures will save energy at peak hours when both line losses and capacity value are high.

Harris wrote The EIA 861 T&D data has a number of challenges; not the least of which is that it is not always complete. The NW Utility data is likely to be more accurate for this purpose, in the question pane. Douglass said he has received the same comment from another CRAC member and asked the body to weigh in.

Nesbitt said Idaho Power data is an average, noting that they are both a rural and urban utility. He added that AMI has improved their data over the years creating a more accurate studies. Nesbitt said examining more detailed metered data shows line losses have dropped.

Douglass asked if he has separated transmission losses versus distribution losses. Nesbitt answered yes.

Lazar asserted that there is a big difference between east and west on [Slide 10]. Douglass thanked him.

Lazar inserted that there will be data from large utilities like Clark, Snohomish, and Seattle but he often uses borrowed data for smaller utilities [Slide 11]. Garcia said he will ask around for some resources. Douglass thanked him.

Lazar admitted that it is possible that line losses have dropped a lot, talking about work he has seen at Burbank Water & Power as an example.

Lazar addressed EIA data, saying it lacks two important factors: company use and divergence. Because of this he was skeptical of using EIA data.

Harris put an exclamation point on Lazar's point, saying the region has better, more robust regional data that's already being applied to regulatory uses.

Nesbitt said it makes sense to use Northwest data as we are a Northwest organization.

Smit thanked the CRAC for their input, adding that he is not seeing line losses decreasing compared to past Plans, saying it's on par or actually higher. Lazar interjected his observation that the region is exchanging more power with California than ever before. He called this a good thing but thought that moving power around in this new way might offset other efficiencies. Smit agreed.

Distributed Solar in the Pacific Northwest
Approach for the Ninth Power Plan
Kevin Smit, NWPCC, Joe Walderman, NWPCC

Nesbitt asked if EIA was the data source for the information on [Slide 6]. Smit said yes.

Lazar wrote, Will the character of distributed solar in the PNW shift like it has in Hawaii and California, away from Residential, more to Commercial, in response to NEM revisions? I wrote a pieces on this https://energycentral.com/c/um/california-will-follow-hawaii-and-see-shift-solar-most-will-now-go-commercial in the question pane [Slide 10]. He added that commercial customers receive retail benefits, saying that Hawaii used to have 2/3rd residential installations but now see 2/3rd commercial installations as the customer leases the roof.

Smit said that was a recent topic of discussion and staff will continue to think about it.

Lazar said community solar injects more power into the distribution system at distribution voltage level which could cause a significant change in line losses [Slide 14]. He noted Hawaii's dramatic change in line losses because of this.

Harris noted that the Council is moving to an hourly planning model, asking if they also plan to move to an hourly D&D loss model. He said the congestion periods in the Northwest could be different than the rest of the country. Smit said he will look into this.

Lazar said the $2.2/per watt is for large systems like the 30kW Walmart systems [Slide 15]. Lazar predicted that this would be where much of the growth will be but wasn't sure if it was the right number for right now. Smit agreed, saying these are national data points.

Harris suggested reaching out to Energy Trust of Oregon, saying there may be an intermediate block of costs for small to medium business. He noted there are a lot of small buildings and relatively few larger structures and we want to reflect what Energy Trust is doing with small to medium customers. Lazar said 30kW is a Wallgreen's roof while $2.2 per wat is a Walmart sized roof.

Adam Shick, Energy Trust of Oregon, said he will check.

Angela Long, Rockcress Consulting, said they worked extensively with Energy Trust for the residential sector and plan to do the same for commercial.

Lazar asked if the purpose of [Slide 18] is to figure out how much solar is coming or to determine the cost effectiveness to figure out where it belongs in the resource acquisition portfolio. Smit said it's mostly the latter as it is really starting to make an impact, but they will do both.

Lazar thought in this case the customer-owned or utility-owned distributed resource is the right pathway. He pointed to southern California's plethora of flat-roofed warehouses that are mostly owned by REITs. Lazar said tenants don't have enough certainty to invest in solar and owners don't have enough certainty in the tenants, but the utility has confidence that the roof will be there long term, adding that this pathway changes the economics.

Harris said if the Plan wants to encourage more rooftop solar as a cost-effective resource, they need to look at hourly grid impacts, saying there are times this could be very valuable in a congested distribution system. He then addressed smart solar inverters and storage, saying they should look at what additional economic benefits they can bring.

Lazar added that inverting DC to AC can produce whatever the grid wants.

Smit said he asks these questions at the end of the presentation. Lazar interjected that adding storage dramatically improves distribution grid benefits. Smit said the Council's new multi-zoned modeling effort will reveal a lot of these benefits.

Lazar asked about the benefit of reducing air conditioning loads thanks to the shading effect of rooftop solar [Slide 21]. Smit said they will look into this, asking for data.

Harris asked if the Council changed their position on seeing state-level incentive as a transfer payment [Slide 27]. He noted the cost reductions from the federal tax incentives were included but wondered about within region. Smit said he had the same question and it will come up internally and with the Council. Smit noted that many of the state incentives come from the federal government and move through the state which may be different.

Harris added that Lazar's suggestion to look at multiple system sizes made sense to him. He also encouraged looking into non-energy/grid benefits for frequency and voltage support along with distribution system deferral of upgrades.

Smit agreed adding that coming up with values presents a challenge.

Lazar pointed to a 380mw system at the Centralia coal mine site. He said the cost of solar came down so much that it made economic sense, which surprised him.

Smit said work will continue and asked for CRAC members to send comments and data.

Harris wrote, Grid values include frequency and voltage support at the local distribution system level which could be valued at the cost of alternative distribution system investments such as capacitor banks for voltage support and local backup generators for frequency support, in the question pane.

Smit ended the meeting at 12:00.

Attendees Via Zoom Webinar

Kevin Smit	NWPCC
Christian Douglass	NWPCC
Noah Lieb	Apex Analytics
Joe Walderman	NWPCC
Leona Haley	Avista Corp
Frank Brown	BPA
Ruby Moore-Bloom	Clean Energy Transition
Sophia Spencer	Nauvoo Solutions
Heather Nicholson	Orcas Power & Light
Andy Cameron	ODOE
Nora Hawkins	WA Dept of Com
Mary Kulas	PPC Consultant
Peter Kernan	OR PUC
Blake Scherer	Benton PUD
Jim McMahon	Better Climate
Louie Pitt	NWPCC
Nolan Brickwood	VNF
Jim Lazar	Electricity Brain Trust
Brian Dekiep	NWPCC
Duncan Ward	Apex Analytics
Haley Ellett	Hood River
Michael Coe	Snohomish PUD
Jennifer Snyder	WA UTC
Aquila Velonis	Cadmus Group
Jennifer Finnigan	Seattle City Light
Adam Shick	Energy Trust of Oregon
Elizabeth Osborne	NWPCC
Jeff Harris	NEEA
Nicolas Garcia	WPUDA
Ashley King	Clark PUD
Bonnie Watson	BPA
Kerry Meade	NEEC
Rich Arneson	Tacoma Power
Eli Morris	Applied Energy Group
Christina Steinhoff	NEEA
Annika Roberts	NWPCC
Margaret Frey	Seattle City Light
Quentin Nesbitt	Idaho Power
Debbie DePetris	Clark PUD
Lauren McCloy	NW Energy
Tomás Morrissey	NWPCC
Angela Long	Rockcress Consulting