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

Minutes for Demand Response Advisory Committee

April 16, 2025

Joe Walderman, NWPCC, began the meeting at 1:30 on the Go-to-Webinar platform. Kevin Smit, NPWCC, took attendance.

Andrew Grant, Cadmus Group, addressed EV Charging [Slide 5], asking if staff updated savings assumptions to account for lockouts or requiring a percent charge. Grant was unsure if EV charging is equivalent to water heating when it comes to customer impact, arguing that the 10% should have stayed at 25%.

Walderman pointed to a high opt-out rate that justifies the value used. Walderman asked what number Grant suggests. Grant did not have one but wondered if this was considered. Walderman said staff has thought this through.

Quentin Nesbitt, Idaho Power, thought the approach outlined on [Slide 7] seemed logical.

Ted Light, Lighthouse Energy, thought the first approach might result in a more optimal solution to persuade the region to choose one cost effective program over another but mused that the second solution seemed more realistic.

T. Light then said the 5% seemed arbitrary and might be worth testing by looking at participation across different customer groups. Walderman said that made sense, agreeing there is probably overlap between customer groups.

Grant asked if there was any consideration given to DR product interaction with EE. Walderman answered yes, outlining what staff is working on to bring to the DRAC. Grant asked about curtailment impacting end-use loads of EE, acknowledging it’s a hard problem to crack.

Nesbitt said Idaho Power has adjusted their TOU times to 6:00-10:00pm, but programs are available from 3:oo-11:00pm [Slide 8]. Nesbitt said they are trying to target a net peak concept due to Solar’s resource costs.

Leona Haley, Avista Corp, asked “what are the months in each season and what season are you bucketing shoulder months in,” in the question pane. Walderman said they are not completely defined yet but are seeing peak need from Dec-Feb and June-Aug in the summer while staff are still talking about a TOU rate.

Nesbitt shared that Idaho Power's summer season runs from June 15th-Sept 15th. He said TOU for winter runs from Nov-Feb. Walderman said he will continue to work with the modeling/forecasting team to identify needs.

Nicholas Garcia, WPUDA, understood the reasoning behind needing a significant price difference between peak and off-peak to change behavior, but didn't think approval of a 250% price increase was politically possible for elected commissioners. Garcia asked where the numbers came from. Walderman said PGE's is 2.5 to 1 and he is basing the peak load impact and participation numbers off of this to an extent. Walderman also pointed to a review of price-based programs from LBNL that identified these numbers as a middle ground.

Nesbitt said Idaho Power uses a 4x differential adding that it is in no way based on economics. Nesbitt said the only reason they reached that number is because it is only for residential and there is a fixed cost adjustment. He stressed that this is not based on anything that is economical but a creating a big enough incentive for customers. Nesbitt argued against doing this for things like irrigation because it would encourage customers to upsize pumps to take advantage of the program.

Garcia agreed the economic signal is important but argued that understanding the political dynamics is also important.

Haley wrote Avista's pilot is 3-1 in the chat.

Zeecha Van Hoose, Clark PUD, agreed with Garcia that 2.5 is unlikely, calling that politically unlikely in her company's territory.

Frank Brown, BPA, wrote 2.5 is not likely in public utility service areas, at least not until many years of program implementation occurs in the question pane.

Walderman explained that staff is not doing program design but including these numbers as a reference. He said if they are not realistic then other numbers in upcoming slides should be derated a bit.

Van Hoose thought this could be reflected in the adoption/program rate. She thought the overall population for her utility would probably drive numbers down a bit. Walderman suggested continuing this discussion when he reaches the impact assumptions section of the presentation.

T. Light put a link in the question pane to Snohomish PUD's pilot which mentions an on-peak price that is twice the mid-peak price, calling it in the ballpark of the proposed 2.5 ratio.

Jeff Harris, NEEA, wrote I agree with Ted L on participation for TOU; I would also be really careful about absolute rates; California rates are very expensive compared to NW rates; so, participation is likely to be higher in the question pane.

Suzane Frew, Snohomish PUD, added that her utility is revising their TOU rates.

Hayden Reeve, PNNL, wrote some operators are starting to see secondary peaks in TOU rates (especially in regions with high EV charging,) in the question pane.

Nesbitt asked about billing system costs [Slide 9]. Walderman said staff thought they were fully incorporated into the $150,000 one time set up costs. Walderman thought subscription costs could be incorporated into the O&M. Nesbitt recalled acquiring a new billing system in 2001, saying these systems are incredibly expensive, costing in the multi-millions.

Walderman said staff could incorporate this into the eligibility rates adding that it gets hard to include large, utility-wide costs. Nesbitt approved of adding “assuming existing AMI and/or billing capability” to make the presented number make sense.

Nolan Kelly, BPA, asked if this is a good area to use the model’s new zonal capabilities as AMI is not fully deployed throughout the region. Walderman answered that staff do not want to treat the 17 zones as individual utilities but acknowledged that this could be incorporated on a state level. Kelly called the $0 funky when we know that is not the case. Walderman thought staff could create a second DR program that includes the costs.

Smit added there are a couple ways to handle this, listing a few ideas.

Haley pointed to a pilot that took advantage of existing AMI and a meter data management system that still cost over $1 million. Haley listed the expenses that go into creating the pilot, arguing against $150,000. Walderman asked if Haley could share the costs. She said yes.

Frew was not sure where the numbers on [Slide 10] came from but pointed to a staff member in their rate department as the best source. Walderman said the numbers are from a LBNL survey, and agreed to reach out.

T. Light asked if the LBNL numbers were opt in or opt out. Walderman said they are opt in. T. Light said work he did with EIA data showed numbers close 13% for residential, opt-in programs and half of that for commercial. Walderman asked to see the data.

Garcia asked about assumptions for utilities that have AMI but don’t implement TOU rate programs. Garcia thought 100% adoption was highly optimistic. Walderman said this a regional observation where eligibility is the entire population that has AMI while participation rate is the percentage of entities that would enroll.

Smit further clarified calling this potential, which identifies how much is potentially available and should not be arbitrarily limited.

Garcia was unconvinced, saying 100% residential opt in will never happen. Garcia thought it was okay to calculate the theoretical maximum but said that is not based in reality as some utilities choose not to implement a program.

John Ollis, NWPCC, said there may not be a price signal for everyone, but staff is evaluating wholesale prices and cannot get that granular in the modeling. Ollis said if loads go up some publics might want to avoid a demand charge. Ollis then asked how to evaluate future load growth, as TOU would respond to this, and you don't want to limit potential.

Garcia said a utility that is likely to exceed the contracted high-water mark could experience market prices so TOU rates would look attractive. But Garcia wondered about utilities that do not experience this, wondering what the advantages of adopting a TOU program would be for them.

Nesbitt reported TOU programs seeing small reductions in load on the hottest days, saying the four to10 worst possible days should be considered.

Van Hoose said Clark doesn't have AMI, but staff are evaluating it. She thought the utility would move more to the carrot versus the stick approach, meaning opt-in would come with benefits during the peak period. Van Hoose said some options could end up being costly to the utility from a programmatic standpoint as BPA full requirements has a demand charge.

Walderman called this interesting, asking if Clark is more interested in developing a critical peak rebate program, pointing to a critical peak pricing program developed by staff. Van Hoose said critical peak pricing increases prices to shift behavior versus incentivizing. She called this two sides of the same coin, adding that her customers are more used to incentive-based interactions.

Walderman said staff can reassess and suggested holding discussion until they get to the critical peak pricing section of the presentation.

Kelly pointed to the $0 equipment cost for EV TOU [Slide 14] saying you would have to buy chargers or vehicles that could adapt to AMI. Kelly asked if this is considered a total resource cost test or a utility resource cost test as the vehicle owner has to make investments. Walderman said this is a typo and should be $60.

Kelly thought that $60 was a bit low. Walderman said the number came from research that showed the difference between a normal versus networked charger. Kelly called that reasonable.

Nesbitt was not sure if [Slide 18] assumes AMI or a compatible billing system. Walderman said that is an eligibility and has the same assumptions as a TOU rate. Nesbitt reported seeing higher implementation costs due to customer notification.

T. Light pointed to his earlier TOU participation comment, suggesting these numbers should be scaled down as well.

Garcia wondered how to communicate with the customer for a program like this. Garcia said program design will impact peak load reduction, and the costs of early notification would be higher but also result in a higher reduction. Walderman understood, saying most programs represented in these numbers are day-ahead notification.

Kelly said the peak load impact on [Slide 19] is based on a 6 to 1 price ratio while past discussions had a 4 to1 or 3 to1 ratio that people thought was too high. Walderman said this is specifically for critical peak pricing which is higher than TOU. Kelly wondered what DRAC members thought was reasonable.

Van Hoose thought a hefty multiplier was okay here versus TOU as it is event driven.

Brittainy Pond, PSE, asked if real time pricing assumes installing operational system so customers can self-serve. Pond said PSE is using KYZ pulses adding that even that has significant O&M costs. Walderman asked to talk about costs more offline. Pond was happy to share and offered to connect Walderman with PSE's TOU team.

BREAK

Nesbitt noted that the O&M costs on [Slide 24] are expressed as a dollar amount per year. Nesbitt said he saw prices expressed as a vendor fee per device. He said they are similar to a bring-your-own-thermostat program where the vendor retains a lot of control, so the proposed $75,000 might not cover a lot of participants.

Nesbitt continued, saying Idaho Power prices a flat fee plus a per battery cost. Walderman asked for more insight about incorporating both a flat and variable fee wondering which is driving the cost as the technology scales. Nesbitt said he saw $100+ per kW for vendor fees.

Grant said he didn't have NW specific numbers but did have country-wide estimates. He asked if staff considered battery size to scale the incentive. Walderman said kW/hour gets tricky, but kW is something to explore.

T. Light reported that PSE's program is per battery so staff should scale the numbers.

Harris asked about the marketing costs on [Slide 27] as DVR happens behind the scenes while maintaining a minimum voltage. Walderman said it was from BPA recruiting their utilities into their pilot. Walderman agreed that there shouldn't be a marketing cost for other utilities developing their own programs.

Brown wrote There are no marketing costs. The marketing costs should be zero, in the question pane.

Harris then addressed the assumption of what percentage of the benefit should be attributed to DVR versus CVR. Harris noted that he doesn't know of any utility that is practicing DVR that doesn't also have CVR because of equipment costs. Harris supported the 75/25, saying he might go higher but asked for utility input.

Nesbitt said it doesn't really matter, suggesting staff call it CVR/DVR and put a reduction on it.

Ollis said past modeling efforts made a delineation but that might not be the case today. Ollis said this can work as long as there is not a significant difference in equipment costs. Nesbitt offered to put Ollis in touch with an expert from Idaho Power.

Fred Heutte, NW Energy Coalition, recalled that in the recent past BPA's demand charge made DVR a better choice. He said that CVR may have had some implications for overall revenue. Heutte said costs now are probably similar and utilities might run one or the other.

Heutte said for modeling he thinks of both as one thing, but there might be some differences for a labeling/program development point of view. Heutte concluded by saying the 2021 Plan identified this as a significant resource and staff should get on with it.

Nesbitt said Idaho Power has fully implemented DVR and see 1.25% for Peak Load Impact [Slide 28]. Walderman said he might bring the number down to 2%.

Van Hoose agreed with Nesbitt, saying her utility runs CVR in the winter and sees a 1.2 to 1.3% difference. She agreed this varies from utility to utility.

Brown wrote Our public utility customers seem to be favoring CVR these days over DVR in the question pane.

Heutte suggested looking at an urban/suburban versus rural divide where the lines are spread out more. He thought something in between 1.2 and 2.5% is reasonable, saying even a .5% difference adds up.

Harris noted that the equipment for DVR and CVR is the same and most utilities do not let their voltages drop too far because of concerns about customer complaints. Harris said average CVR operations might see 2% or less depending on feeder size. Harris thought that a utility with long feeders like Idaho Power may be willing to operate as a DVR resource when loads get tough.

Harris approved of modeling this as a CVR/DVR resource with variable capacity benefits during peak periods. Harris then pointed to a large study that looked at CVR potential and factors related to different loads and feeders. Smit said he had the report. Harris also noted the large KVAR benefit to CVR adding that it is larger than the energy. Smit said he will double check for that.

Harris called this similar to HPWHs with CTA 2045, saying there is a permanent capacity reduction from a HPWH that can get additional peak benefit from the CTA 2045. Harris wondered if there was a way to categorize these specific resources.

Ollis said that a hybrid-approach functionality is available if staff can make the data align, especially for CVR/DVR.

T. Light pointed to his work with the City of Richland reporting that they continue to implement DVR which allows them to drop voltage 2%, getting a 1% demand drop. Because of this T. Light approved of dropping the proposed numbers a bit.

Heutte again pointed to the 2021Plan identifying this as a big resource even though there is not a lot of field data. Heutte agreed with Harris's suggestion of creating a CVR baseline with incremental value for peak periods where operation modes move to DVR. Heutte said peak values will be important for the 9th Plan.

Smit agreed saying staff is wrestling with this as well and will present more in the next meeting.

T&D Deferral in the Ninth Plan
Tomás Morrissey, NWPCC

Heutte asked what it means that the model does not represent DR as a resource [Slide 4]. Ollis asked for more clarification. Heutte explained that it goes back to the question of if DR is a load modifying resource or some other thing. Heutte said the model doesn't have a "DR handle" so staff put the resource in other categories like storage. Ollis said that is a correct interpretation.

Heutte said this sounds fine as long as it produces an accurate interpretation of what DR can do. Heutte wondered if staff could pull DR out at the end or if the resource becomes intertwined with the other resources. Morrissey said staff could pull it out as each project is labeled.

Heutte saw a problem with heating and cooling [Slide 6] during difficult conditions. Heutte thought the region will learn to adjust but shouldn't count on thermal DR to carry us through.

Nesbitt shared staff's concern about assigning T&D value to DR programs, saying his utility has not. Nesbitt listed reasons for this including the fact that distribution deferral often conflicts with the rest of the system. Because of this Nesbitt sees the generation value as higher.

Cam LeHouillier, Tacoma Power, said this might change in a future with more reliable DR programs, but for now his utility's T&D planning group is not confident enough to change any planning or investment strategies. LeHouillier says his system is overbuilt yet they don't see DR bringing relief yet.

Van Hoose wrote Clark only uses power supply value for our DR… currently in the question pane.

Morrissey asked for people to share more offline if they can. Walderman appreciated the DRAC's time and help, ending the meeting at 4:00.

Attendees via Go-to-Webinar

Barry Richardson	NPWCC	Brian Dekiep	NWPCC
Jennifer Light	NWPCC	Tom Eckhart	UCONS
Joe Walderman	NWPCC	Suzanne Frew	Snohomish PUD
Kevin Smit	NWPCC	Andrew Grant	Cadmus Group
Chad Madron	NWPCC	Leona Haley	Avista Corp
Nicolas Garcia	WPUDA	Jeff Harris	NEEA
Kyle Billeci	PGE	Fred Heutte	NW Energy Coalition
Frank Brown	BPA	Aaron James	NEEA

Mark Jerome	CLEAResult
Kelly Nolan	BPA
Paul Koenig	WA UTC
Cam LeHouillier	Tacoma Power
Ted Light	Lighthouse Energy
Tomás Morrissey	NWPCC
Quentin Nesbitt	Idaho Power
Heather Nicholson	Orcas Power & Light
Austin Oglesby	Avista Corp
John Ollis	NWPCC
Maria Perez	*PNNL*
Brittainy Pond	PSE
John Purvis	Clallam PUD
Hayden Reeve	PNNL
Annika Roberts	NWPCC
Christina Steinhoff	NEEA
Laura Thomas	NWPCC
Zeecha Van Hoose	Clark PUD
Quinn Weber	WA UTC
Mary Kulas	PPC consultant.