Northwest Power and Conservation Council
Demand Response Advisory Committee
December 6, 2017

Tina Jayaweera, NWPCC, began the meeting at 9:30 with introductions and a review of the agenda. She thanked Idaho Power and Avista for filling out the data templet and called for more members to contribute. Eli Morris, PacifiCorp, asked for a handout of the latest template version. Chad Madron, NWPCC, offered to post it.

Update on CTA 2045 Work
Jeff Harris, NEEA
Jayaweera asked if there were any Northwest-specific inputs into the water heater/CTA work. Harris answered yes, pointing to NEEA's on going work. Conrad Eustis, PGE, added that the work is in the pilot stage with an additional 200 tanks being installed by five to eight utilities. He stressed that the product is not the embedded 2045 CTA, but an adapter product.

BPA Demand Response Barriers Study
Lee Hall, BPA
Tom Eckhart, UCONNS, LLC, asked if "barriers and challenges" are to implementation or design [Slide 3.] Hall stated that the question will be answered later in the presentation.

There was a question about blank lines representing a question not being asked [Slide 15]. Hall answered yes, because the question was not considered applicable.

Harris asked for an explanation about the difference between curtailment and rate-based in the Managed Account row on [Slide 18.] Hall explained that rate-based means there is already a time-of-use rate in place versus a contract in hand that allows curtailment. Hossein Haeri, Cadmus, added that time-of-use rates cover all price-based DER strategies.

John Steigers, Energy Northwest, asked how the study addressed discussions with utility and industrial asset providers in relation to response time. He pointed to large differences between a 10-minute response to day-ahead. He also wondered about duration, noting that an industrial partner may be comfortable with a 90-minut disruption but not a four-hour one. Haeri agreed, and referenced another study that looks at well-defined products and program options. Tom Brim, BPA, added that the more-detailed study looks at durations and frequency with predictable results.

Jayaweera asked if the more detailed study will be publicly available. Hall answered that the full study will be available after January 1, 2018 and this presentation is a preview of initial findings. Brim added that they are still working through mitigation strategies.

Conrad Eustis, PGE, moved to [Slide 15] and asked if the surveyed residential customers were chosen randomly or if they were already participating in a DR program. Haeri answered that this was a random sample. Eustis commented that NW customers are "horrifically" uninformed about Demand Response which may account for the high percentage who identified the cost of purchasing required equipment as a barrier. He then asked what the customer's perception of cost is. Haeri stated that this illustrates both barriers and perception of barriers.

Eustis asked about the wording of the question. Karen Horkitz, Cadmus, answered that as the customers were a random sample and the question included a description of different DR programs. She used a thermostat program as an example and said the customers were asked to rate the barriers significance.

Eustis asked if an appendix with the actual questions will be included in the report. Both Horkitz and Haeri answered yes.

Eckhart referenced the high level of smart meters in California collecting large amounts of data that are unused. He asked about the Northwest's potential to collect and use smart meter data. Eustis answered that PGE has had smart meters since 2009 and the data are regularly used for distribution analytics. Hall pointed to other AMI examples: granular voltage information and Avista's smart meter uptake.

Haeri noted that the survey does not represent Cadmus's opinions but the perceptions of Bonneville's power customers. He agreed that there is a misperception that AMI is necessary for DR but pointed to solutions like education and dissemination of information.

Harris moved to [Slide 12] calling the perception differences about infrastructure/technology barriers between providers striking. He singled out "back office systems" noting that 50% of BPA experts call this a barrier while service providers do not, and asked for comment. Hall answered that integration (dispatchability, M&V) is half the battle and cost. He noted that service providers he knows agree that is a challenge and acknowledged their hard work to overcome the barrier.

Jane Peters, Research into Action, agreed with Eustis's earlier comment saying that success will depend on how the program is framed and the degree to which the needed program is explained.

Eustis gave an example on how AMI data can be a true barrier and not just a perceived one. He mentioned PGE's changing billing system that will include a peak time rebate noting that this will require 15-minute information for resolution. He stressed that a flexible rate system and price-respondent DR is the biggest component they hope to have online by 2021.

Tony Usibelli, Washington Dept. of Commerce, asked if the survey included information about demand charges, both wholesale and large retail, and their relationship to DR barriers. Hall stated that this was primarily addressed through time-of-use rates. Horkitz acknowledged that the topic came up during interviews and power customers felt the demand charges and overall pricing structure was a barrier.

Steigers moved to [Slide 16] and asked about the distinction between comfort and interruption and quality and interruption. Horkitz answered that comfort was about employee comfort but agreed that there is room for interpretation. She stated that business operations and quality of product are very intertwined. Hall agreed that there are many integrated, intertwined issues which precluded stand-alone solutions.

Ross Holter, Flathead Electric Coop, asked if Voluntary Usage Reduction [Slide 18] was a direct question. Hall answered that 49% of respondents would consider this kind of offering. Holter thanked him and referenced Flathead's water heater program calling marketing, communication and overcoming suspicion about offering, a barrier. Hall thanked him and called small utility programs like his innovative and groundbreaking.

Eustis commented that large, informed customers had less negative comments about barriers and suggested a separate sheet of barriers that would remain in place even after education and communication programs. Hall called that a good idea that got into the hypothesis realm. He hoped that utilities would see the opportunities in this study and places to cost-effectively dig in.

Jayaweera moved to [Slide 12] saying she was surprised at how the lack of established tariffs and contracts for DER did not have a high barrier rating. She asked for some context. Hall called this low in comparison, but 1/3 rated it at a four or five. He acknowledged that rate-making is complex and long and these experts must see a cost-effective need for DR. Haeri noted that BPA rates already include a demand charge and demand penalty but it isn't large enough to induce action.

John Ollis, NWPCC, asked about need, saying it can be framed in many ways. He asked for a comment on how need is seen as a barrier based on BPA assets. Hall answered that the second part of the potential study will inform resource planning and non-wires transmission planners. He stressed that other factors like legal and statutory requirements, place of need, time of day/year, other solutions and more will come into play, yet he still remains hopeful.

BREAK

Rate Design that Support Beneficial DR
Carl Linvill, Regulatory Assistance Project
Josh Keeling, PGE, asked if this suggests no minimum distribution system whatsoever [Slide 5.] Linvill answered yes.

Steigers suggested that the rational behind this is influenced by the substantial, systematic spread between serving peak and non-peak periods. He noted that California is very different than the Pacific Northwest and asked if this is equally valid here. Linvill stated that this is generic work so his initial answer is yes, but remains open to being proven wrong.

Tomás Morrissey, PNUCC, asked if the paper went into quantitative detail about what rates would look like compared to today [Slide 9.] Linvill answered yes saying it will be shown later in the presentation.

Jason R. Salmi Klotz, Oregon PUC, asked how “Transparent Real Time Prices” was defined particularly for the customer [Slide 10.] Linvill admitted that applies to locational marginal prices for the California ISO and said that this does not exist for Oregon today. He noted that the rate design in the paper doesn’t use locational marginal prices but suggests what it would look like for large customers.

Keeling noted that the graph on [Slide 10] comes almost exclusively from summer-peaking utilities.

Harris asked for a clarification between the Rate and Rate with Tech. Linvill used a smart meter as an example. Harris asked if the smart meter had two-way communication. Linvill said the data is four-to five years old, before two-way communication, but included other enabling tech. Keeling called it a mix of in-home displays and programmable thermostats.

Salmi Klotz called attention to a study from Baltimore Gas & Electric on this and found that enabling tech had better response, but still called cost effectiveness into question.

Ollis asked if long-run marginal cost pricing is a way to capture risk mitigation between different time periods and situations, i.e. time of year and snowpack [Slide 15.] Linvill said this is a question for Jim Lazar, RAP, and he will get back to Ollis with an answer.

Morrissey asked how the percentages were gathered for [Slide 17.] Keeling answered that they came from a survey and not AMI data.

A question was asked about **Price Can Influence <u>When</u> EVs Are Charged** slide. The participant wondered if this data was from fleet customers or the system. Linvill was not sure but assumed that the rate was available to any customer. Eli Morris, PacifiCorp, posed that this is residential charging. Keeling stated that this looked like it was from the Idaho National Lab study.

Ollis compared California’s super off-peak pricing, which is connected to daily peak solar production to the Northwest’s seasonal peak energy production in the spring [Slide 30.] Linvill said that would probably result in a seasonal rate. Morrissey said the Northwest would probably benefit from cheaper prices on sunny days due to California and Northwest solar.

Mark Osborn, Cadmus, asked how cost of service principals could apply, particularly with a customer charge. Linvill explained that the process leaves the distribution, transmission and generation system to be largely collected through volumetric rates and divides the share of those rates to be consistent with the customer’s needs. Osborn continued saying larger, metered customers may be cheaper than a group of smaller customers and wondered how that is reflected. Linvill explained that there would not be one non-residential rate, but a number of tailored rates and the general principals of this rate design would go across all of those rates.

Osborn pointed to subsidization on volumetric rates that goes towards customer costs and wondered if this rate design strips them back and puts the customer costs where they are deserved. Linvill said the process started with defining what should be collected through a non-coincident peak demand charge [Slide 5.] He said he would like a price signal correlated with system need for things beyond the dedicated facilitates and most proximate transformer. Osborn asked if that charge recovers all of the billing costs, even those associated with more complex back office things.

Osborn then stated that more complex components, like real-time rates, need more back-office support and wondered if those additional costs go into the volumetric rate or peak-pricing rate. Linvill said it would be legitimate to assign real-time billing costs to the customers that use them but called it unlikely to happen as there are other, more sophisticated approaches.

Ahlmahz Negash, Tacoma Power, called the spread between the low and high rates pretty large and asked what they would be for an all-hydro utility. Linvill answered much smaller.

Harris said [Slide 29] makes a lot of sense and helps make a business case for DR. He asked if there was anything in the structure that would keep them from going to finer, five-minute, granularity. He then asked where ancillary service costs: voltage regulation, frequency regulation, fit in. Linvill said information and the ability to manage it would make more granularity hard but not impossible. Linvill then clarified if ancillary costs are system costs to provide these services. Harris answered yes. Linvill said they would be part of the distribution transmission cost. [Tracking System Costs Into Rate Design Elements.]

Harris pushed that resources and costs attached to reliability concerns may not be part of any of these categories. Linvill countered that it would be part of Generation Capacity costs.

Keeling thanked Linvill for calling out the long- and short-run marginal costs, as it is important in the Northwest. He then asked about the balance between providing incentives through rates versus programs. Linvill pointed to Hall's earlier study that showed customer participation as a barrier that cannot be overcome by pricing and said there will be room for programs as this is a structural change.

Osborn asked if ease of implementing this tariff structure was studied. Linvill answered that there are people that benefit with the status quo so there will be some resistance. He also noted that changes in rate design is never easy but called this a public-interested, objective approach.

Hall pointed to the industry's dynamic nature and BPA's interest in staying out in front of it. He thought this would be appealing to a utility as they look at their distribution systems. He predicted EV charging will have a huge impact on the load curves, which is something else utilities need to think about.

Bud Tracy, Consultant, stated that all costs are borne by the ratepayer and noted that he didn't see the cost for the contribution or extension policy that the consumer initially paid. He then asked if the report will be available. Jayaweera said it will be posted on the DR webpage. Linvill asked for a clarification on which embedded cost Tracy was referencing. Tracy said he was wondering about the cost of extending that service to the ultimate retail customer. Linvill said it was included in the distribution costs, which include recovering the costs of the legacy system and the incremental costs going forward.

Keeling asked what other costs can't go into rates. Linvill felt that ancillary services from customer to the utility didn't belong in the tariff. Keeling asked about a customer that creates a need for ancillary services. Linvill called that a difficult question and suggested that the dividing line be created and communicated transparently.

Ollis added that ancillary services are just another way to utilize an asset, and that utilization requires sizing. He felt that a cost allocation could come from that sizing. Linvill said giving a utility control of something like a water heater should be a rewarded in the tariff. Keeling called that similar to PG&E's tiered rates for controlled versus uncontrolled.

Harris argued that the existing capital return on investment structure rewards the investor-owned utility if they own the asset.

LUNCH
Seventh Plan Action Item Progress Report
Tina Jayaweera, NWPCC
John Ollis, NWPCC
Harris spoke about NEEA's strategic planning workshop [RES 5 Support regional market transformation for demand response.] He said they are considering if DR meets boundary conditions and suggested contacting NEEA board members with opinions.

Hall referenced [BPA 4] suggesting that the arrow should be blue and not red as they finished two major demonstrations and will have a substantial report published by the end of the year (2017). He added that there are report outs for South of Allston that include DR and another round of 2016 benchmarking on the DRAC website. Ollis predicted that it would be blue by the midterm and noted that this is not an official report. Ollis stated that the template is still an issue but thanked Hall for the information and said this is moving in the right direction. Hall added that BPA restarted utility cross-shares, calling it extremely successful.

Ollis asked for a summary of cross-shares. Hall explained that the project, started three to four years ago, encouraged interested utilities to share their DR information among themselves. He stated that BPA facilitates this work and it has been very well received.

Eckhart asked if any of the barriers/challenges/regulatory differences among the states have changed the Council's idea of DR potential. Jayaweera explained that the potential was based on need, not barriers. Eckhart acknowledged that need is one thing and asked about realistic potential. Ollis acknowledged the difference between total potential and technically achievable, but stated that the Seventh Plan revealed a signal that they are now trying to respond to.

Demand Response
Oregon Public Utility Commission
Jason Salmi Klotz, Manager, Climate Change Lead

Zeecha Van Hoose, Clark Public Utilities, asked if there is a plan to incorporate existing energy efficiency outreach as the test beds are developed. Salmi Klotz answered that there are no plans but an understanding that outreach and coordination are probably necessary. He continued, saying if DR is a long-term asset then it probably has the same outreach path as efficiency.

Steigers pointed to a focus on load reduction, or INCs, from the utility perspective and asked if the scope also contemplates DECs, like load increases, as that may have value as well. Salmi Klotz answered that the test bed is in response to PGE's capacity shortfall and balancing wasn't part of the original scope but that doesn't mean there will not be changes in the studies.

Keeling added that the value stream for that doesn't exist today but local issues, like backflow problems may call for load synchs that are enabled through DR. He noted that the DR they are pursuing can do both as they are a form of storage.

Eckhart asked for a reference for California's avoided costs used in the presentation. Salmi Klotz clarified that their DR methodology was used and not their avoided cost filings.

Harris asked if the test bed could be aggregated in horizontal segments by customer type, i.e. computer chip manufacturers, food processors, multi-family housing etc. Salmi Klotz answered that that level of granularity was not discussed yet. He noted the unusual nature of the still nascent work.

Jayaweera wondered what the packaging of energy efficiency and DR would look like and how challenges would be overcome. Salmi Klotz answered that experience shows the less you touch a customer the better off you are, calling it beneficial to coordinate offerings. He used the NEST thermostat, which has DR capabilities, as an example. Jayaweera stated that Ecobee has that too. Jayaweera speculated that there will be other challenges in the future. Salmi Klotz agreed.

Osborn spoke about his history working on test projects, noting that the expansion phase required a rate impact which took about a year to justify. He asked if that hurdle has been planed for in this test bed. Salmi Klotz assured him that his commission would not have endorsed this if they didn't understand that it comes with a rate increase. He noted that a short-term rate impact will hopefully lead to faster uptake and long-term savings.

Tracy applauded coupling energy efficiency and DR, calling it the most effective approach for member-owned utilities as it rewards efforts.

Usibelli asked how the program will verify net changes: historic data from the area, control groups, comparisons with other PGE customers, etc. Salmi Klotz admitted that they are not yet that far in the process but assured him that the goal is transparency through regular reporting and stakeholder meetings, etc.

Steigers noted that PGE is driving this effort and asked if PacifiCorp has any plans. Salmi Klotz stated that PacifiCorp is a different utility with different challenges and strategies. He felt that PGE is more progressive on DER and distributed energy generation, resources and assets and noted PGE's investments in customer information systems and advanced metering. Salmi Klotz also noted that PacifiCorp is not capacity short, so it would be hard to obligate them to make investments in DR.

BREAK

Return on Investment for DSM Resources
John Ollis, NWPCC
Tina Jayaweera, NWPCC

Keeling addressed the first bullet [Slide 7] asking if Idaho Power is allowed to put their DR programs in a rate base and earn a rate of return. Zeke VanHooser, Idaho Power, answered that there are two different mandates for two different states: the energy efficiency rider for Oregon and the Power Cost Adjustment (PCA) in Idaho.

Keeling asked if the PCA is treated like a fuel cost. VanHooser answered yes, it's an operating cost that is trued up every year.

Keeling addressed variable power costs, saying if you oversubscribe a program and under forecast DR enrollment you actually eat into shareholder revenue. Ollis agreed that there are different decoupling environments in each state.

Conservation and Return on Investment
David Nightingale, WA UTC

Elain Markham, PSE, addressed the last slide [NONETHELESS, INCENTIVE PAYMENTS ARE AVAILABLE TO INVESTOR-OWNED ELECTRIC UTILITIES UNDER 80.28 RCT.] saying that she doesn't see a clear path of what to propose for cost recovery but incentives will be of great interest. She noted that PSE is working hard on bringing DR to full scale and the different opportunities for cost recovery in anticipation for a 2018 DR RFP.
Kyla Maki, Montana DEQ discussed [Questions for Panel Slide 6.]
Jason Salmi Klotz, Oregon PUC, discussed Oregon's perspective and the history of ETO

Jayaweera asked Morris to speak to PacifiCorp's cost recovery for DR programs in Utah. Morris explained that DR is treated like EE for cost recovery in Utah. He noted that the passage of the Sustainable Transportation and Energy Plan changed how the costs are amortized, noting that they now get a rate of return.

Keeling stated that you can't ignore, or forget, the rate and cost-recovery changes that made energy efficiency happen. He referenced Linvill's earlier presentation about volumetric rates, calling it important and pointed to the interplay between rates, programs, policy and business model. Keeling stated that this was not fully optimized for energy efficiency and hoped that it could be moved forward for DR.

Ollis asked Hall for a BPA perspective. Hall stated that Bonneville does not have a Return on Investment but still needs revenue for bond and credit ratings. He pointed to tiered rates and concluded by saying BPA is a cost-based organization that drives towards a level of reserves for cash flow and debt management. He felt the best-case scenario is DR that is no worse than revenue neutral.

Osborn stated that PGE's dispatchable standby generation program was considered DR and he felt it was treated unfairly as compared to the big generators. He explained that the paralleling switch gear that allowed the generator to interconnect with the grid was treated like a regulatory asset and was amortized over 10 years. He noted the commutations equipment were treated like full-blown assets that earned a rate of return. Osborn felt that it was unfair that they couldn't earn any return from the expensive switch gear. He asked the regulators to consider fairness issues like this as they think about recovery mechanisms.

Salmi Klotz referenced SB 978 that requires the Public Utility Commission to look into the regulatory paradigm and what changes could or could not be made. He noted the Commission opened a stakeholder process and predicted the discussion will grow louder in the upcoming months.

Keeling commented that risk is quantified in the cost/benefit calculation for conservation. He was not sure who is bearing the risk and we should think about who should be compensated for the risk. Harris acknowledged that EE talks about uncertainty and tries to quantify risk. He agreed that a challenge for Demand Management Resources is understanding that it may only be activated once in a long while and the hydro system makes assessing risk challenging.

Ollis added that the signal for DR broadly came from risk exploration in the Seventh Power Plan. He noted that some find it "cost effective," while others will not find it easy to justify. Ollis stated that the Northwest still has a huge risk potential, referencing 2001, bad hydro years and moving load. He called DR a cheap type of insurance and admitted that it is a challenging question.

Osborn recalled working on BPA's storage study and found that value stacking generated interesting discussions. He noted that one BPA reviewer suggested broadening the value stacking concept and present it in terms of all Demand Response. He stated that if we design it right all the value streams of various DR programs and equipment can be advantaged. He suggested the DRAC take that approach. Jayaweera referenced the Council's whitepaper on storage that could be taken to a broader forum discussion that crosscuts Advisory Committees.

Hall referenced a slide in his early presentation that said, "all of these things are integrated." He cautioned that stacking values impacts the customer and industrial customers may experience fatigue. He stressed looking at the total picture, finding the loads to meet particular needs, recruiting and aggregating those loads, designing the right product and keeping it revenue neutral for the utility.

Ollis agreed with Hall, noting the Seventh Plan got rid of much of the value stacking. Keeling asked for consistency in valuing the core benefits. He recalled PGE's analysis of DR versus storage noting the value of things influences the structure of programs and contracts. He called this backwards, saying if he could tell his customers he'd call on them once every four years he would have a lot more customers. He called value stacking cool, but admitted that he would be satisfied knowing what the capacity is worth.

Jayaweera concluded by discussing the next meetings in March and June 2018. She shared some topics on the March agenda. She thanked the participants and ended the meeting at 4:00.

Attendees on Site

Tina Jayaweera	NWPCC
John Ollis	NWPCC
Eli Morris	PacifiCorp
Hossein Haeri	Cadmus
Karen Horkitz	Cadmus
John Steigers	Energy Northwest
Tom Eckhart	UCONS, LLC
Bud Tracy	Consultant
Carl Linvill	RAP
Mark Osborn	Cadmus
Jason R. Salmi Klotz	Oregon PUC
Ahlmahz Negash	Tacoma Power
Adam Schultz	ODOE
Lee Hall	BPA
Tom Brim	BPA (ret)
Tomás Morrissey	PNUCC
Jennifer Light	NWPCC
Larry Voss	North Pacific Paper
Janice Bowman	Embertec
Bill Henry	EQL

Gregg Hardy	Pacific Crest Labs
Jeff Harris	NEEA
Conrad Eustis	PGE
Josh Keeling	PGE
Riley Peck	ICNU
Stan Price	NEEC

Attendees via Go-to-Meeting

Allegra Hodges	BPA
Douglas Ballou	BPA
Ben Kujala	NWPCC
Brian Dekiep	NWPCC
Danielle Walker	BPA
Thomas Brim	BPA
Wade Carey	Central Lincoln
Cindy Wright	Seattle City Light
David Lowery	Itron
Elaine Markham	Puget Sound Energy
Suzanne Frew	Snohomish PUD
Gwen Resendes	BPA
James Gall	Avista
Jane Peters	Research into Action
Jasmine Vasavada	Washing Department of Commerce
Nathan Kelly	BPA
Kyla Maki	Montana DEQ
Mary Ann Piette	LBNL
Melanie Smith	BPA
Davide Nightingale	WA UTC
Robert Pratt	PNNL
Ross Holter	Flathead Electric Coop
Kelly Strand	Snohomish PUD
Ted Light	EES Consulting
Tony Usibelli	Washington Dept of Commerce
Zeecha Van Hoose	Clark PUD
Zeke VanHooser	Idaho Power