Northwest Power and Conservation Council
Demand Response Advisory Committee
September 20, 2018

Tina Jayaweera, NWPCC, began the meeting at 9:30 with a round of introductions, a review of the agenda and a welcome to new Committee members. Jennifer Light, NWPCC, discussed the Regional Technical Forum's work plan for 2019, noting that 5% of the RTF's budget is allocated toward examining some DR technologies to determine the per unit capacity savings and technology costs. She asked that any interested parties join the RTF subcommittees to further discuss the work.

Jayaweera noted that the June 2018 minutes were only recently posted. David Nightingale, WA UTC, mentioned that Tony Usibelli, WA Dept of Commerce, was listed as working at the WA UTC in the March 2018 minutes. The minutes were changed.

DR Barriers Mitigation
Lee Hall, BPA

Nightingale asked if the idea of stacking benefits befuddles decision makers [Slide 9.] Hall answered no, but there is tension about who gets first use. He continued, stated that stacked benefits get at how DR and DER are valued in an IRP as it could be only capacity, energy or reliability. He added that the value could be to transmission, power, or customers. Lee concluded by saying that DR and DER needs to be paid for and we must be mindful of the rate impact of a new program.

Nightingale suggested that an organized market might make valuing DR easier and asked if anyone in the NW is talking about that. Hall said BPA has identified other locations where DR has been successful and agreed that at a marketplace would ease the process, but said cost effectiveness is the ultimate driving force.

Nightingale pointed to the conundrum of valuing something that doesn't yet have a marketplace in which to find value. Lee offered to continue the conversation offline, but remained optimistic pointing to different IRPs from the NW region and beyond.

Jayaweera asked if anyone from CA EIM could speak to how the market could enable DR. Quentin Nesbitt, Idaho Power, stated that the EIM has not yet had an effect on DR dispatching. He also stated that it be hard to recruit customers with that concept in mind.

Jason Salmi Klotz, PGE, pointed to rules that would make it difficult for DR to make it into the EIM. Jayaweera reframed the question, asking about providing DR for customers and then opening up the supply for bidding. Salmi Klotz confirmed that EIM is for balancing then pointed to PGE's Decarbonization study which presented the case for flexible load. Salmi Klotz called that a future state that PGE is moving towards.

Fred Heutte, NW Energy Coalition, stated that EIM is an ancillary service that treats these products differently than power markets. He continued, saying he thought DR could help meet the ISO's efficiency test, which determines what resources are available to the EIM.

Carl Linvill, RAP, stated that the intention is to make this as easy as possible demonstrated by CAISO's work. He addressed earlier statements, agreeing that this has to make economic sense to the bidders, and pointed to the strong commitment by those working to create the platform.

Jayaweera asked for discussion about the recent contract between BPA and PGE [Slide 10.] Hall admitted to not knowing all the details but called it common contract and a positive step forward.

Heutte moved back to [Slide 9] to talk about five-year capacity contracts asking if DR could help BPA offer these kinds of contracts by providing more range for an operating system. He stated that this is not captured by a traditional cost/benefit test. Hall said BPA is thinking about this but there are some statutory legal requirements in the Power Act that must be addressed.

Heutte then moved back to [Slide 10] asking if anyone is thinking about how DR and AMI can be combined to provide a better control environment to the utility. Hall answered yes, referencing the early adoption of AMI to take advantage of Federal funding. Hall suspected that AMI deployment has dropped since then because of the price but stated that in some cases, like CTA-2045, deployment doesn't need AMI.

Usibelli asked about BPA's perspective on customers who may want more control over the resources they are served with in the energy space and beyond, referencing the Internet of Things [Slide 17.] Lee moved back to End User Interest on [Slide 8], noting that industrial customers are interested in an economically driven DR program. Hall pointed to the desire to lightly impact customers, noting a 5% attrition rate.

Nicholas Garcia, WPUDA, stated that some utilities that don't need DR might want to sell it to other utilities or Bonneville. Hall stated that this has been considered, pointing to success with non-profit aggregator Energy NW.

Salmi Klotz mentioned California's DRAM where entities bid in and then MW are bid out into the wholesale market. He noted the regional barriers and then asked if that could be a consideration here. He suggested taking the topic up in December.

Heutte commented that the control operators' needs matters and different regions, like South of Allston, have different needs. Hall pointed to BPA's 24 load areas and multiple cut plains and didn't want to say that DR is the answer to everything.

Linvill stated that Adam Schultz, ODOE, would be a good resource on the DRAM.

BREAK

Enabling Technologies for DR
Debyani Ghosh, Navigant
Bryce Yonker, Smart Grid Northwest.

Jayaweera stated that the DR Market Snapshot Report co-written by Navigant [Slide 5] is available on the Council website.

Heutte asked for a description of the differences between DERMS, DRMS and DROMS [Slide 8.] Ghosh answered that DROMS stands for Demand Response Optimization and Management, a marketing term for DERMS. Yonker said the industry is moving away from DRMS to avoid multiple platforms for different programs. He stated that most DERMS are deployed for one or two use cases, despite being multi-functional. Heutte urged getting more input on this.

Hall noted that [Slide 9] is from 2015 and things have moved ahead but called it ground breaking and still relevant. Jayaweera confirmed that 31% of all customers across different rate classes have smart meters. Yonker confirmed, adding that PacifiCorp, SCL, Avista, and Tacoma are on track to bring the number up to 52%, noting that each state is different.

Nightingale noted that Avista is in the process. Ryan Finesilver, Avista, agreed.

Yonker asked if different products would have to be deployed for the different service types: Shed, Shape, Shift, and Shimmy [Slide 11.] Ghosh answered no, there are areas that overlap.

Salmi Klotz asked why AC can't deliver shimmy [Slide 13.] Ghosh answered that the compressor on a residential AC unit can't handle the run time but there is testing on new technology. Nick Bengtson, CLEAResult, agreed.

Salmi Klotz referenced 2009 LBNL work that focused on residential ACs and balancing services. Ghosh asked if it was spin or non-spin. Salmi Klotz didn't remember. Ghosh called it an interesting question but the potential study did not classify them as a Shimmy contributor.

Salmi Klotz noted that [Slide 12] has Shimmy with minutes and hours and wondered if residential AC was disqualified because it couldn't do seconds. Ghosh responded that this was the parameter for the California study for regulation.

Heutte referenced data centers, noting that they could provide Shimmy. Yonker said they don't want to. Heutte insisted that as they are distributed, they could shift the CPU work around the world. Hall referenced his work in the sector, noting there is an opportunity, but large data centers are averse to providing their loads to anyone.

Usibelli addressed the second bullet on [Slide 15] asking if it is because a lot of retrofit doesn't use the latest technology. Ghosh agreed. John Ollis, NWPCC, wondered if lighting could Shift if you set the lighting in the middle of an acceptable range and move the levels up and down. Ghosh stated that Shift refers to the time of day and you can't pre-light for the dark. Jayaweera explained that the question is about shifting between acceptable light levels within a given hour. Ghosh stated that that is not Shifting as defined.

Heutte talked about the definition of storage and stated the real issue is what the grid sees as INCs and DECs, so the Shift of energy might not need actual storage. He likened the issue to water heaters and pointed to the difficulties of sorting issues out from a regulatory point of view.

Linvill asked what services OhmConnect provides to CAISO [Slide 20.] Yonker did not know. Ghosh called them the largest contractor under DRAM for residential DR.

Hall noted that in the public and IOU sector each of these areas have been explored through pilots and demonstrations in the NW and found much success. He then stated that these are great, but asked how much these will cost and to what purpose.

Yonker stated that what enabling technologies look like at pilot scale versus commercial scale is a different conversation.

LUNCH

How the RPM Works
John Ollis, NWPCC

Nightingale asked for an explanation of a six-moth lead time [Slide 3.] Ollis explained you need six months to achieve capacity reductions.

Hall noted that sunk or implementation costs are still costs [Slide 3] and a utility will want to minimize the uncertainty. Because of this, he says, we don't want to embark on a program where conditions change after 6-12 months and find we don't need the program because we still have to recover those costs. Ollis stated that model doesn't minimize these costs and options that you don't use are still a cost.

Linvill asked if differences between running a program through a third party versus internal utility program building approach was investigated. Ollis answered yes, pointing to the binning of DR which lead to an "average-ish" lead time. Ollis noted that the Seventh Plan RPM is quarterly so the six-month lead time for DR is two quarters while gas is 2.5 years, wind is 1.5 and EE is instant.

Salmi Klotz asked why EE is instant. Ollis pointed to the acquisition strategy. Jayaweera noted the 30 years of EE infrastructure. Salmi Klotz stated that as an IOU with a third-party EE arm, he believed the two could be related in programmatic structure and delivery. Ollis stated that some parties believed that DR could be instantaneous and other thought it would take longer. Salmi Klotz agreed that than six months seemed about right. Ollis pointed out that model only sees DR in 10 MW chunks.

Hall cautioned against false precision and noted that the planning process often yields a single number. He looked at assumptions, sensitives and how much can realistically be acquired, noting the huge error bands around results.

Nightingale confirmed that DR has ramp rates similar to conservation but you don't start the ramp until six months out. Ollis answered yes.

Heutte dissented mildly about agent-based modeling pointing to other approaches at Iowa State and hoped for expansion in the future. Ollis agreed that it's a broader term and in this case the agent is a resource planner.

Linvill asked if [Slide 4] represents the starting point or a derived resource [Slide 4.] Ollis answered that this represents a sample strategy and offered to talk more offline. Hall inquired about the differences with EE. Ollis answered that these resources are dispatchable and EE is not. Ollis added that there might be changes for the Eighth Plan. Hall asked if this is an energy or capacity model. Ollis answered that this is a capital expansion model that knows something about energy, capacity adequacy requirements and if resources are economic.

Hall asked if for the EE, the T&D credit drove into negative cost territory [Slide 10.] Jayaweera said yes in some cases, and then referenced a 7th Plan scenario that ran without the T&D levelized costs that didn't change results much.

Garcia stated that the transmission system is not the same throughout the region and asked how differences were accounted for. Ollis answered that credits were applied on the advice of Advisory Committees and this time there will be more exploration of the topic. Jayaweera noted that a T&D deferral presentation will be given next. Garcia stated that some utilities have both an adequate supply and capacity and asked how DR is valued given this fact. Ollis said this is an ongoing topic with the development of the Eighth Plan.

Jayaweera said that our modeling sees the region as a big, happy family that washes out localized needs and this needs to be considered in our Action Plans.

Salmi Klotz asked for the T&D credit for DR. Ollis answered $26 per kW/year. Hall stated that EE received $57 per kW/year. Jayaweera said $26 and $31 for T and D, respectively. Hall agreed with Garcia that these assets are location and peak dependent but stated that our transmission assets are in general underutilized.

Usibelli asked if the large penalty cost associated with curtailment is internal to the model [Slide 12.] Ollis answered yes, it's a number we enter, noting that the higher the number the more the system builds. Ollis said the system is tested in GENESYS to see if it's overbuilt.

Ghosh asked how DR is characterized in the model in terms of dispatchability [Slide 13] and how the interactions between EE and DR are modeled. Ollis answered that they are looking more closely into the interactions between EE and DR for the Eighth Plan. Ollis then said the dispatch price was high, $110 per MWh to make it a peak capacity resource. He said they assumed between 50-60 hours of DR were available for the year with no event duration. Ollis said they will look to tune and refine that for the Eighth Plan.

Garcia stated that not all DR is the same and treating it as such creates an illusion of how much is available. He then noted that this data is three years old and asked how much has been achieved. Jayaweera stated that the mid-term report will be released in October with another survey due in the winter. She said that the net shows that we are not near 600 MW region wide but we do see utilities seeing the need in a 5-10-year horizon.

Tomás Morrissey, PNUCC, noted that BPA has been improving DR logic in the existing GENESYS model that might be interesting to explore [Slide 15.] Ollis agreed, stating that the existing GENESYS is being enhanced as well as being translated into a more modern platform.

T&D Deferral
Tina Jayaweera, NWPCC

Hall asked if the same T and/or D value will be used for EE and DR [Slide 2.] Jayaweera said that will be discussed.

Hall noted that he never saw the data request on [Slide 4] and suggested sending requests to the correct people. Jayaweera agreed pointing to softness in the timeline.

Hall stated that BPA looks at sustained transmission system costs vs expanded transmission system costs and [Slide 5] addresses load growth or expanded transmission system costs. Jayaweera explained the utilization factor or "Peanut Butter" effect noting that it does exist on the Transmission side. Hall called this a large dial on the model. Ollis agreed, saying anything that effects the capital model is going to be a big dial but acknowledged that some resources don't get this credit. Jayaweera recalled a sensitivity that took away the T&D credit on EE in the 7th Plan which slowed the acquisition but not by much.

Salmi Klotz asked for a recap of the utilization factor concept [Slide 6.] Jayaweera did, noting that the Plan is a regional look and if we didn't include the utilization factor it would imply that every resource provided this deferral value.

Hall asked about the methodology behind the 60%. Morrissey added that the number can vary by utility and is not locked in. Jayaweera explained that it is an imperfect proxy developed by PacifiCorp. She said they created it by taking their average load divided by their average system capacity. She touched on Idaho Power's more refined approach.

Hall stated that BPA is looking very critically at each non-wires situation, comparing capital costs of building out and serving load versus EE, DR, and storage solutions. Ollis encouraged utility resource planning departments to connect with departments that work on non-wires solutions, hoping the NWPCC can leverage off that connection.

Garcia stated that the value of DR for postponing infrastructure development will be bi-modal and felt that averaging sends the wrong signal. Jayaweera stated that there is a planning number and an implementation number. She said she agrees with Garcia, but stated that this is meant as a planning number for the Regional resource plan. Jayaweera noted that PacifiCorp puts this number in their IRP but does “hard core analysis” for their T&D system planning and this is more of a directional indicative.

Ollis added complications with modeling DR at $0 versus $100.

Garcia agreed that the peanut butter approach makes sense for a regional approach but cautioned against saying “Utility A is 2% of the region so they should get 2% of the DR.” Jayaweera stated that the Council wouldn’t do that. Garcia asked that the next Plan acknowledge that specifically.

Nightingale suggested looking across the Cascades as the most likely place that needs quantifying calling it the Big Gorilla. Jayaweera agreed pointing to the work of Mike Starrett, NWPCC. Ollis agreed pointing to the Seventh Plan which modeled west and east resources differently.

Heutte pointed to the WA UTC’s investigation of using the Council’s Resource Adequacy approach or something else. He said his organization feels that it’s a really good starting point but not something to plug and play. He said the same theory holds here, the Plan is looking for a directional approach.

BREAK

Non-Firm Demand Response Case Study
Josh Keeling, PGE
Jim Stewart, Cadmus
Scott Reeves, Cadmus

Morrissey asked how Time of Use rates work, noting that this discussion is about kWh and DR is usually discussed by kW [Slide 8.] Stewart answered that the analysis is on interval consumption data and suggested thinking about it as average kW over a period. Keeling added that there was no demand charge component, just volumetric time of use rates.

Heutte [Slide 15] confirmed that the opt-in option lost 6-8% of customers while the opt-out approach lost 2-3%. Keeling answered yes. Reeves added that these are lower numbers than other programs with no mass marketing push. Keeling noted that the numbers includes a 2% churn rate.

Morrissey asked if the kW saved per customer was a high-price event or averaged [Slide 16.] Stewart answered that it's the average across the seven events. Heutte pointed to the middle rebate and suggested that this is price inelastic. Stewart stated that they tested rebates from $.80-2.25/kWh and did see higher satisfaction with higher rebates.

Salmi Klotz asked for satisfaction rates for opt-out/opt-in [Slide 17.] Stewart stated that that slide is in an appendix and it shows that the satisfaction rate for opt-out were not as high. Keeling added that the study also shows causal impacts on satisfaction.

Keeling explained how PTR payments work [Slide 21.]

Morrissey asked why summer is overperforming [Slide 25.] Reeves speculated that it has to do with customers having less options to save in the summer. Keeling noted that thermostat studies show better satisfaction in the summer as well. Keeling then retold how a Portland snow day nearly broke the model.

Heutte asked if there was any persistence effect in the early group on [Slide 32.] Stewart reported that it was consistent all the way through.

Jayaweera stated that Ontario, which is dual peaking uses TOU rates and asked if they saw winter savings. Stewart didn't know but said the summer savings for the opt-out program is 2.5-3%. Morrissey asked about controlling for gas heat. Stewart noted that there was no reliable data on customer's heating fuel. Jayaweera pointed to AMI data which could be used for VBDD analysis. Keeling agreed.

Jayaweera asked if PGE is considering any further actions [conclusion.] Keeling noted a workshop with staff and stakeholders and a proposal for a full-scale, opt in PTR at $1/kWh program and an opt-in PTR/TOU hybrid with a roll out in April 2019. Nick Bengtson, CLEAResult, spoke about how mass marketing could help opt-out BDR. Keeling agreed.

Hall asked how many MW are expected from this program. Keeling stated that the IRP called for 38 MW and is actually forecasted at 51 MW from 125,000 customers. Hall called these good numbers.

Heutte suggested checking out OhmConnect for customer engagement ideas. He then noted that CA's flex approach has evolved over the years. Keeling agreed, noting that flex only gets called a few times a year.

Jayaweera thanked the room and pointed to the December 13th meeting. She ended the meeting at 4:00 pm.

Attendees

Tina Jayaweera	NWPCC
John Ollis	NWPCC

Carl Linvill	RAP
David Nightingale	WA UTC
Bud Tracy	Consultant to Idaho
Fred Heutte	NW Energy Coalition
Lee Hall	BPA
Bryce Yonker	Smart Grid NW
Tony Usibelli	WA Dept of Commerce
Thomas Familia	Oregon PUC
Sarah Vorpahl	WA State Energy Office
Cassie Koerner	Idaho PUC
Debyani Ghosh	Navigant
Jason Salmi Klotz	PGE
Tomás Morrissey	PNUCC
Jennifer Light	NWPCC
Nick Bengtson	CLEAResult
Josh Keeling	PGE
Jim Stewart	Cadmus
Scott Reeves	Cadmus

Attendees via Webinar

Ryan Finesilver	Avista Corp
Clint Gerkensmeyer	Energy NW
Larry Johnson	??? Engineering
Nathan Kelly	BPA
Ahlmahz Negash	Tacoma Power
Quentin Nesbitt	Idaho Power
Nicolas Garcia	WPUDA
Will Price	EWEB
Teague Douglas	CLEAResult
Brian Dekiep	NWPCC