Northwest Power and Conservation Council
Demand Response Advisory Committee
September 14, 2017

Tina Jayaweera, NPCC, started the meeting at 9 by reviewing the agenda. Chad Madron, NPCC, explained the new audio-visual equipment to the Committee.

Lee Hall, BPA, updated the DRAC on the DR Potential study presented at the June 7th meeting. He noted that the South of Allston to be reviewed is a North and South and Southeast issue (into central Oregon, the Gorge, and Clark County). He added that BPA's transmission planners are reporting DR-capable loads in the Tri-Cities, the Olympic Peninsula and central Oregon.

Hall addressed optimizing multiple cost curves by adding an extreme weather cost curve. He spoke of interviews with utilities, market players, stakeholders and internal groups to generate a report. Hossein Haeri, Cadmus, added that end use customers were contacted too.

Bryce Yonker, Smart Grid NW, spoke about the NW Demand Response & Energy Storage Summit, held on September 27 and 28.

Demand Response
Request for Proposal Results and Lessons Learned
Elaine Markham, PSE
Fred Heutte, NW Energy Coalition, asked if PSE aimed to acquire the full complement of programs from a single vendor or multiple vendors [Slide 6.] Markham answered that they left the door open for multiple vendors. Heutte asked if she anticipated seeing an aggregator. Markham answered yes.

Tom Eckhart, UCONS LLC, asked how the 58% ELCC was derived [Slide 8.] Markham answered that the integrated resource planning team looked for changes in the number of lost load events before and after the DR resource.

Heutte asked why the chart has two columns labeled 24. Markham explained that the last column represented 24 hours between events while the second-to-last-column represented hours lapsed after last event. Heutte expressed surprise that ELCC was used in the first place.

Bill Henry, EQL Energy, asked about a requirement for a number of consecutive days. Markham stated that there is analysis that requires events on no more than two consecutive days and PSE IRP analysts found that four consecutive days would meet their full resource needs.

Heutte confirmed that PSE is winter peaking only but the peak could happen in the morning and/or the evening. Markham confirmed.

Josh Keeling, PGE, asked if the ELCC did a dispatch model with the DR resources or if it was done after the fact. Markham did not know. Keeling asked why a one-hour notification was required. Markham answered that that the goal was for a firm, supply-side resource. Keeling pointed to California's firm, day-ahead resources. Markham stated that they will look day ahead for the 2019 IRP. Keeling mused that an hour-ahead requirement was hard to meet, even for a thermostat.

Jason Salmi Klotz, Oregon PUC, asked Heutte why he was skeptical about using ELCC. Heutte wondered if DR is the same thing as a wind or solar generating resource. Markham added that PSE's morning and evening peak will cause issues no matter which availability factor was used. Heutte stated that using ELCC might be fine but wondered how to compare a resource that doesn't look like other resources.

Riley Peck, ICNU/Davison Van Cleve, PC, asked if the one, four-hour event was for all classes. Markham answered yes. Peck countered that a commercial or industrial customer might be willing to go to a four-day event if you create economic value. Markham agreed.

Ken Nichols, EQL Energy, mentioned that BC Hydro looked for three days, noting that the third day had the greatest need. There were nods of agreement in the room. Markham stated that there was an assumption that a commercial/industrial customer would respond for four days, noting that 98% of events were covered by the third day.

Robert King, Whisker Labs Connected Savings, stated that limiting events to two days limits the benefit. Keeling agreed that it is hard to set thresholds and gradients.

Haeri asked how PSE decided on 70 and 51 MW targets. Markham answered that they are from their 2015 IRP resource potential assessment.

Henry suggested being clear about these issues up front before putting out an RFP. Markham agreed, stating that this analysis was not available before putting out the RFP.

Ollis stated that PSE is providing more deferral benefit than the Council provided in the Seventh Plan [Slide 9.]

King addressed cost [Slide 11] saying that consumer-bought thermostats and equipment installation are mostly vacuumed out. Markham stated these were not requirements but a bring-your-own-device bid was also not cost effective and many bidders proposed direct install. Keeling added that most of the electric heating load is zonal, which explains the need for direct install.

Eckhart asked if cost-effectiveness was open and known for this RFP [Slide 12.] Markham stated that they responded with their avoided capacity cost in the questionnaire and it lowered from $190 to $64.

Eckhart referenced BPA's longer-term market approach for avoided costs versus a current market approach. Hall explained that there is a price premium on one-to-two-year demonstration projects. Markham agreed, noting that longer-term deals were offered for less cost.

King suggested considering a pilot that takes advantage of existing stock and grows organically. Markham stated that may be an option going forward.

Peck asked if PSE considered working with large, commercial/industrial clients directly to bring costs down. Markham answered no, noting that PSE's large C/I customers are either buying their electricity at retail (retail wheeling) or already on an interruptible schedule. She added that PSE would need outside help getting 120 MW by 2021.

Nichols asked if PSE would consider going back to vendors with new avoided costs. Markham stated that they plan to work through cost effectiveness/cost recovery issues and go out again as their 2017 draft IRP shows them needing 103 MW of DR by 2023. Nichols referenced the operational expenditures (OPEX), wondering if PSE fears that they will not be able to recover their non-vendor costs. Markham stated that they do not want their DR budget in their OPEX budget.

Graham Horn, ENBALA Power Networks, thanked PSE for a good RFP and suggested considering a hybrid RFP next time where PSE is the aggregator.

Hall voiced interest in WA UTC's developing cost-effectiveness model noting its potential regional benefits.

Henry pointed to FERC requirements for a balanced day-ahead schedule for a firm resource and the need for a standardized, non-derated product to compare to avoided capacity costs in their next IRP.

BREAK

DR Barriers

Concern with B/C approach: Seventh Plan Experience
Eckhart asked if the transmission side had the same adequacy problems as the power supply side. Ollis did not know. Hall said that it does and explained the issues. Eckhart pointed to California's similar problems and their use of DR as a tool to avoid building transmission resources. Ollis noted the organized markets benefit of locational marginal pricing. Keeling added that a way to come up with a good price is to have a market for it.

Tomas Morrissey, PNUCC, pointed to the DR benefit found in the Seventh Plan. Ollis stated that was a transmission deferral credit and not a distribution credit.

Debora Reynolds, WA UTC, spoke of DR as more of a peak-need resource. Ollis agreed, calling DR an insurance product. Reynolds mused over the connection to the difference in line loss and the value of peak deferral. Jayaweera explained how the process works for EE. Ollis said that utilities are better equipped to dig into transmission issues.

King agreed with the graph but stated that if DR has less value the market is probably over procured. Ollis explained how the Northwest Loss of Load Probability is calculated with 80 hydro years which is different than the rest of the country. King agreed, then suggested that planning DR into the Resource Adequacy earlier might be part of the solution. Heutte noted that Bonneville is mostly hydro and doesn't have a planning reserve.

Rob Pratt, PNNL, observed from a customer perspective that a risk portfolio resource used once every 10 years will never be recovered. He said this has implications for bring-your-own-device programs. Ollis noted that the RPM might not have the right fidelity to determine the corrected dispatch, calling it a planning versus operations issue. There were nods of agreement in the room.

Haeri asked about IRPs treating DR as a selectable capacity resource versus insurance and the need to worry about a contingency reserve benefit. Ollis conceded that DR doesn't look like a true insurance product but more closely resembles insurance than a combined cycle gas plant. Haeri stated that DR used only as a contingency reserve can't be included in a resource portfolio as it would change the benefit/cost calculations. Ollis stated that you would have something that co-optimizes between energy dispatch and reserves. Ollis admitted that not many Portfolio Models do this.

Mark Osborn, Cadmus, stated that he was troubled by utilities looking at DR and developing a non-wires alternative at the distribution feeder level. He suggested exploring a DR strategy to take advantage of market niches, stating that a Portfolio approach could help identify those niches. Keeling referenced PGE's C&I program that treated DR like a gas plant. This, he said, lead to more productive conversations with their trading floor.

Markham spoke about DR moving from EE to power supply which has kept traders engaged and excited. This suggested to Ollis that organizations may asses risk with internal conversations instead of a Portfolio model. Keeling noted that the lack of market creates a chicken/egg problem compounded by a heavily-regulated RFP process.

Nichols shared California's approach of breaking DR into a load modifying resource for IOUs and a dispatchable resource for the ISO. He suggested giving a target to utilities that would use DR as a load modifying resource and let them figure out cost effectiveness.

Combine Simplicity with Risk Evaluation

Morrissey asked if reliability would ultimately be calculated by Portfolio NPV. Ollis asked what the value of adequacy is and suggested seeing how DR works in that structure. Morrissey countered that no utility plans without an adequacy standard. Ollis agreed, calling it a harder analysis than other options.

Hall elaborated, noting that avoided generation and energy falls into power operation while deferred T&D and reliability fall into the transmission side. He stated that deferred T&D is locational and not easy to quantify. Jayaweera agreed, pointing to an upcoming blueprint for a methodology for utilities to determine an *a priori* estimate.

Ben Kujala, NPCC, referenced EE experience in using these values, saying they are neither perfect nor biased. He stated the art comes in slicing the information for planning verses actual implementation. He agreed that methods for calculating avoided generation, energy and deferred T&D can be refined, and reliability standards are being re-evaluated, calling this the real issue.

Keeling agreed that there is a lack of understanding about capacity, particularly as needs become more nuanced. Kujala called the gap in methods a significant barrier to DR.

King suggested that knowing the value of the California balancing market might be helpful. Keeling added that looking at storage would add value as it examines services over avoided costs. Nichols agreed, reiterating that separating DR into a load modifying resource and a dispatchable resource could be key.

LUNCH

National Standard Practice Manual
RESOURCE VALUE TEST FRAMEWORK
Deborah Reynolds, WA UTC

Appendix B (three slides)
David Lowrey, ITRON, asked if there is a cost to jobs and economic development to go with the benefit. Reynolds answered yes, pointing to the manual's assumption of using net benefits, which mirrors the regulatory perspective of matching principal.

Eckhart asked if this is being considered for all three of Washington's IOUs. Reynolds said this is new, stressing that the Council-modified total resource cost test is a resource value test which incorporates all of the requirements of the NW Power Act.

Doug Dickson, Snohomish PUD, stated that while utilities know they can count things like Non-Energy Benefits, staff is often hesitant to do so and asked if this test will change things. Reynolds said it's a policy decision made by the board or commission you're in front of, but we will watch closely.

Osborn asked why there are no utility measure costs for distributed generation and storage. Reynolds explained that measure costs are for money you paid to someone but will check and get back to him.

Eckhart asked if California's Standard Practice Model tests have been compared to this. Reynolds was not sure, calling this a good picture of the utility cost test but the other depends heavily on state policies.

Combine Simplicity with Risk Evaluation
Morrissey asked if the reliability benefit is captured by the avoided generation benefit, noting in the Northwest resources are being built for reliability and not economics. Quentin Nesbitt, Idaho Power, agreed, saying the PUC uses avoided generation as the proxy.

PNDRP Paper on DR Costs
Haeri noted that reliability conversations are usually from a utility-system perspective and asked about the end customer, referencing PJM's look at the value of unserved energy. Ollis called this a good point that may be discussed further at the RAAC. Morrissey stated that he views the value of lost load as another reliability metric to possibly build towards.

Jayaweera asked the public utilities in the room report on attempts to make DR cost effective.

Ahlmahz Negash, Tacoma Power, stated that a customer wants to participate in a DR program to stay competitive, but their trading table can't find any benefits except for load shaping.

Zeecha Van Hoose, Clark PUD, reported similar findings, noting that the BPA pilot didn't work for them. She stated that their strategy is keeping communication open but not taking action at the utility level as they see no value on the distribution system or rate contract benefits. She expressed future interest in the Idaho model of running a DR program yearly to keep in practice.

Dickson admitted to not doing much more than the BPA pilot.

Hall noted that large industrial customers see their competitors taking advantage of DR programs and are asking for the same. Hall addressed the equity issue of benefiting one customer at the expense of others and the time lag created by introducing new products to the trading floor. Hall also addressed customer fatigue.

Keeling noted that PGE has the opposite problem of needing capacity and having nowhere to get it as large customers already have direct access. He called this a market or marketing problem and encouraged trading desks to sell excess capacity. Cara Ford, BPA, countered that Keeling is assuming that we have a lack of capacity to sell, stating that they do have capacity to sell but BPA can't sell it.

Morrissey explained that certain publics can't resell BPA power, but didn't know the rules around their own power plants.

King asked Van Hoose to explain contractual barriers between Clark and BPA. Van Hoose clarified that it is not a barrier but contracts and pricing mean we don't have a large demand charge so there is no benefit to shaving it.

Dickson pointed to Avista's work on finding the value of capacity and creating a calculator. James Gall, Avista, said the calculator is trying to find the value of all distributed energy resources but didn't know how applicable the values would be other utilities.

Haeri stated that PSE and PGE are both capacity constrained in the future, yet their IRP model isn't taking DR. Markham and Keeling both stated that their IRP is taking DR. Haeri asked what is wrong with the bids. Markham explained that in 2015 they didn't use the ELCC at all so had no deration and the avoided cost of capacity came down by more than a third. Haeri suggested PSE take the bids and resell the capacity to PGE. Keeling felt that there would have to be market adjustments before selling DR capacity.

Ollis noted that the concept of DR opening up other parts of the portfolio to sale has been discussed, but stated that the public's rate structure might not allow it. King asked if BPA looked at changing the rate structure to incent behavior. Hall explained regional dialog contracts that have been in place since 2009 and go until 2028. He noted that they approach utilities by saying they can affect their demand charges and contribute to an overall solution within the BA.

King stated that the only option left is BPA providing additional direct incentives to reflect the marginal value. Hall pointed to finding a need in the IRP for energy and/or capacity and then cost testing what's available, stating that they are getting more sophisticated at looking at demand-side resources.

Pratt mused that a coalition of the willing made up of the BPA and the publics could use the resource and monetize it on behalf of the group. Ollis asked if there was a way for BPA's portfolio to do a transfer. Hall stated that they did a pilot with Energy Northwest, EnerNOC and allowed a utility to function as an aggregator but it still comes down to cost effectiveness and its effect on the resource plan.

Van Hoose stated that the coalition of the willing has to be the end-users who will experience interruptions of service. Keeling added that the most promising customers in his service area buy energy from retailers who are also not selling capacity.

Heutte stated that water heaters are a big, inexpensive potential DR and storage source that may come on line in five years. He stated that there is a strong tendency to reach for a peaker for adequacy and urged the room to think about water heaters in the future. Markham noted that water heaters and space heaters were part of their RFP's technical potential assessment.

Reynolds stated that the hydro system is a public good and you can't ask people to pay more for it. She acknowledged that the region is overbuilt and credited it for our economic development. She hoped that we can live within the system we have and that we may need a shift in thinking about demand charges and rates.

King stated that he didn't know the background but heard that the option to rates is incenting the recognized marginal value and planning for DR. Nichols stated that in a carbon reduction future, hydro is a valuable asset and DR could provide more value.

BREAK (While Woody Guthrie's "Roll on Columbia" played.)

Update on Developing Ex Ante Estimates for DR
Jennifer Light, NPCC RTF Chair/Manager
Gregory Brown, RTF CAT
Eckhart asked what role Bonneville is playing in this work [Slide 4.] Jennifer Light, RTF Chair/Manager, stated that Bonneville is conducting their DR Potential Assessment and the RTF will leverage their thinking along with other potential assessment work.

Keeling agreed that this process made sense and suggested cross-referencing with other potential assessment work. Morrissey noted that the RAAC looks at what kind of events trigger DR and might have useful data.

Role of the Aggregator
Osborne voiced concern with aggregators like NEST, saying that it is a popular product that utilities are building their DR programs around. He wondered what would happen if NEST goes bankrupt. He suggested that utilities enforce standards and not rely on platforms that might lead to stranded assets. Osborne then called aggregators a wonderful asset to a utility.

Van Hoose stated that brand-specific providers come between the utility and their customers, noting that Clark takes pride in being a publicly-owned utility that serves their public. She stated that Clark also shies away from influencing commerce by selecting a specific technology. Van Hoose mentioned that aggregators provide good interfaces, but as they are proprietary, assets become stranded when a program ends.

Hall assured the room that BPA conducts financial tests before hiring an aggregator. He then pointed to BPA's limited staff and an aggregator's ability to see a DR program through its entire lifecycle. Hall stated that determining who gets the value of DR: the end user, the intermediate utility or the aggregator, is a barrier.

Keeling spoke of PGE's nuanced view of aggregators, noting that they are sometimes the aggregator. He stated that the company has been burned by aggregator bankruptcies and sales in the past but called NEST a special case as they have half the market. He stated that commercial aggregators absorb the risk but there's a tradeoff of losing the acquisition.

Peck noted that customers want to do this but cost effectiveness tops the list of barriers. He stated that removing the aggregator's margins would help remove this.

Heutte noted that large companies like NEST will probably not go away, but dealing with large companies is not always a great experience. He stated that there's a risk with dealing with younger companies in an emerging market.

Keeling referenced the idea of a third-party coming aggregator between the utility and their customer, stating that he sees NEST as partner and not an intermediary. Van Hoose countered that she did not have a lot of leverage with her local aggregator.

King stated that residential customers are already transitioning to Smart, Internet-of-Things technology and this is an opportunity to shape its impact on the system and how it is woven into the utility. He noted that Whisker is product neutral, allowing customer choice and market innovation. King admitted that there is risk that the platform company might go away, but a dashboard can be replaced by a competitor. King concluded by saying an induvial utility can't do this work cost effectively but a national aggregator can.

Markham noted that PSE was sensitive to an aggregator coming between the utility and their customers, so their RFP stated that PSE owns the relationship. She said she was impressed with the C&I aggregators' responses. She agreed that for residential, utilities must go where the customers are and partner with vendors.

Horn commented that there are different views of what an aggregator is and suggested that the utility maintains the brand value. He concluded by saying a utility can mitigate risk by rolling out an ecosystem of services provided by many suppliers.

Heutte asked who the customer calls if there is an issue: NEST or PGE. He then stated that NEST's national Rush Hour Rewards program is marketed for summer use and PGE had to work to get them to market for winter. Heutte stated this speaks to ramp rates, which have not been addressed and suggested speaking to the rest of the country to get to the Council's 600 MW target.

Hall stated that the DRAC website has the 2016 benchmarking effort. He stated that BPA always encouraged utilities to approach C&I customers on their own and finds value in having the utility design a program and choose an aggregator going forward. He stated that an aggregator like Energy Northwest gets a diversity of assets that are oversubscribed which might be hard to get with direct engagement.

Hall noted that the residential space is more complicated and expensive, but Energy Northwest had 500 electric water heaters under direct load control as part of their total. He gave a shout out to Milton-Freewater and other smaller utilities that are showing courage and innovation on this front.

Henry addressed risk, noting that a utility might shoulder the risk while an aggregator provides the technical services. He suggested that PSE's next RFP specifically identify how that will work. Keeling added that PGE has split the risk between PGE, the vendor, and the customer.

Heutte added that cyber security is a big factor in the DR space, calling the intersection of the Internet of Things with today's grid potentially combustible. He admired NEST's security, noting that other aggregators should provide this.

BREAK

Nichols addressed the aggregator discussion, saying that programs that work through technology go through vendors that have global reach. He thought that it would be hard for utilities to duplicate. He stated that utilities are selling reliability and his view of the future includes utilities working on Demand Response Management Systems (DRMS) with different vendors.

Osborn stated that funding DRMS internally is a tough nut for utilities to crack. Nichols said that you need cost effectiveness, value and resource to justify the spend. Hall stated that cybersecurity, interconnection and integration also play a role. He explained that BPA tested two DRMS systems outside the firewall.

DR Template

Hall asked for an explanation of the difference between "historical DR we can count on" and "future plans for DR." Ollis explained that "historical" means currently operating programs. Jayaweera added that the load forecast for adequacy is an econometric one that projects out, so it would be good to know if a historical DR program will not be continued

King asked if research pilots count. Ollis answered not yet.

Hall asked about the definition of the enablement costs and implementation costs. Ollis explained that enablement costs are the fixed capital costs while the implementation costs are the ongoing program costs. Peck asked if we're talking about fixed and operating costs. Ollis said yes but this is the usual terminology.

Hall asked if pilots and commercial demonstrations should go on the chart. Jayaweera said they should go on the historic tab. Hall stated that these kinds of projects will have a price premium that is not reflective of the future. Jayaweera suggested adding that context to the notes column.

Negash asked for guidance on their planned pilot as she was not sure if it would continue. Jayaweera said to put that in planned and note that it's a pilot. Hall confirmed that commercialized means that the program will be repeated year after year. Ollis confirmed.

Henry asked about units of cost. Jayaweera said they want dollars.

Heutte asked about the average duration of events versus maximum and if notification protocol is 10-minute, hour-ahead and day-ahead. Ollis said yes about the notification protocol. For average duration versus maximum, Ollis said it would be a good point to have but tricky to model. Heutte stated that it would be useful to know the average of how much was actually used during the maximum duration. Ollis agreed to add it.

Henry asked for the baseline methodology. Jayaweera pointed him to the historic tab.

Jayaweera concluded by saying they will incorporate Heutte's comment and send the template out with the hope of getting some information back by the end of the year. She noted that the next DRAC meeting is on December 6, 2017 and Hall will discuss BPA's potential study and Jeff Harris, NEEA, will hopefully attend to give an update on the CTA 2045 work.

Jayaweera ended the meeting at 3:45.

Attendees on Site

Tina Jayaweera	NPCC
John Ollis	NPCC
Riley Peck	ICNU/Davison Van Cleve, PC
Doug Dickson	Snohomish PUD
Fred Heutte	NW Energy Coalition
Mark Osborn	Cadmus
Deborah Reynolds	WA UTC
Lee Hall	BPA
Hossein Haeri	Cadmus
Tomas Morrissey	PNUCC
Zeecha Van Hoose	Clark PUD
Bryce Yonker	Smart Grid NW
Rob Pratt	PNNL
Elaine Markham	PSE
Robert King	Whisker Labs Connected Savings
Tom Eckhart	UCONS, LLC
Graham Horn	ENBALA Power Networks
Ahlmahz Negash	Tacoma Power
Bill Henry	EQL Energy
Josh Keeling	PGE
Lois Gordon	ASWB Engineering
David Lowrey	ITRON
Phil Jones	Phil Jones Associates

Attendees via Webinar

Adam Schultz	Oregon Department of Energy
Bo Downen	Public Power Council

Wade Carey	BPA
Elizabeth Osborne	NPCC
Erin Keys	Itron/Comverge
Cara Ford	BPA
Frank Brown	BPA
Greg Brown	RTF CAT
Hanna Lee	Cadmus
James Gall	Avista
Jason Salmi Klotz	Oregon PUC
John Steigers	Energy Northwest
Judi Hertz	NPCC
Karen Horkitz	Cadmus
Kiley Faherty	Puget Sound Energy
Kyla Maki	Montana Department of Environmental Quality
Mary Anne Piette	LBNL
Jessica Mitchell	Snohomish PUD
Eli Morris	Pacific Power
Teague Douglas	CLEAResult