Northwest Power and Conservation Council
Demand Response Advisory Committee
March 6, 2019

Tina Jayaweera, NWPCC, began the meeting at 9:30 am with introductions and a review of the agenda. She noted that the Regional Technical Forum is exploring how to quantify the impacts of six DR products and is looking for expertise in their DR subcommittee. Jayaweera also pointed to the EE/DR Systems Integration Forum (SIF) taking place on March 27, 2019.

Levelized Cost for DR
Tina Jayaweera, NWPCC
Tom Eckhart, UCONS, LLC, asked if there is a single levelized cost methodology for the entire region. Jayaweera stated that this is the goal and more will be covered in the presentation.

Lee Hall, BPA, asked if equation on [Slide 2] represents the value a product brings to the system or the cost incurred. Jayaweera answered that the cost is the numerator and the denominator is either the energy savings or the capacity impact so it finds a value and that goes into the RPM. Hall said this is really the cost per unit impact and when he thinks of value, he thinks of benefit impact, admitting that this is a nomenclature issue. Jayaweera said this gets at the difference between the KW and KWh.

Quentin Nesbitt, Idaho Power, stated that their cost is what they spent on a program but cost effectiveness requires evaluation of the cost of a program fully utilized to its maximum hours [Slide 3.] He noted that Idaho Power pays a variable rate that goes up significantly for extra hours so potential cost should be included in any calculation. John Ollis, NWPCC, stated that from a systems analysis perspective this would create a mismatch so a range of expected costs would be better. Nesbitt agreed that this made sense, calling DR a hard resource to model. Jayaweera agreed and pointed to a difference between planning assumptions and actual evaluation findings.

Gurvinder Singh, Puget Sound Energy, praised the [Spreadsheet of Direct Quantifiable Resource Costs.] Jayaweera said it's still being refined and was inspired by the SWAG document.

Lee Hall, BPA, asked if batteries will be considered [Slide 6.] Ollis answered yes, the Generating Resources team is looking at utility scale batteries and the Demand Forecast team is looking at current batteries on the system.

Nicolas Garcia, WPUDA, asked how the Council plans to deal with the cost benefit of distribution systems that may vary widely across the system. Jayaweera explained that T&D is included in the list, broken down into existing and new. She stated that the deferred T&D value will be used for EE and DR to reflect the value of deferring investment while a generating cost will be added to resources like Montana wind. Ollis added that there are a number of ways to consider T&D but the main distribution input is a credit.

Eli Morris, PacifiCorp, stated that his company doesn't consider T&D deferral as a non-energy benefit [Slide 7] and asked if there has been a decision made about the seasonal value of T&D. Jayaweera said no, adding that there is a per KW/year value but there is no data to inform seasonal differences. Morris wondered if the system was going to be labeled winter or summer peaking. Jayaweera answered there has not been a decision yet, but it still looks winter peaking. She added that figuring out how to model climate change may change that and for the Seventh Plan they valued summer and winter quarters distinctly in the RPM.

Eckhart agreed that there are seasonal impacts for DR and T&D, but argued that long-term levelized costs get washed out. Jayaweera stated that summer and winter peak have a different calculated levelized cost and the same could be done for DR.

Morris stated to be careful and not value winter EE and summer for DR. Ollis agreed, noting that this might be paving new ground. Jayaweera added that the word resource is being applied to DR, recognizing that the language in the Act isn't clear.

David Nightingale, WA UTC, asked for examples of Non-Energy Benefits offline.

Nesbitt asked if Non-Energy Benefits differ from EE to DR, adding that DR can come with specific T&D requests that don't align with system benefits.

Hall said BPA faces the same issue, pointing to six-hour-a-day problems that force the de-rating of three-hour products. He voiced concern over peanut buttering the modeling which may inflate its value as DR is location specific and only presents a T&D benefit when you use it. Ollis called this valuable but stated that the Council has neither a powerful enough model or detailed enough information to run for each system. He said the goal is to come up with the best estimate for a capital expansion model. Jayaweera said this topic should go on the June 2019 agenda.

Tomás Morrissey, PNUCC, asked if the program characteristics influence the net costs. Ollis though it could potentially have a lower system cost. Morrissey asked if the model differentiates between bins and if it can pick from two bins. Ollis said there is a way the RPM acknowledges this.

Morris stated that costs need to go hand in hand with program design and the number of hours available. There are nods of agreement in the room. Ollis theorized that if there were two identical programs—noting the unlikelihood—the RPM would prefer the one with more hours available.

Nightingale asked how the loss of service value is determined [Slide 10.] Jayaweera pointed to CA which used 50-75% of the incentive. Hall said that's the "what" and not the "how." Jayaweera agreed, and wasn't sure that there is a good "how" but said that the Seventh Plan looked at a range of utility incentives for each product and chose per product the lowest one as a proxy for the loss of service. Ollis pointed to the process which stared out with zero incentives and then moved to this approach, which the Council was comfortable with. Ollis added that he's hoping to do something more consistent this time.

Ahlmahz Negash, Tacoma Power, stated that 0 or 100% makes sense and anything else needs justification beyond loss of service.

John Wellschlager, BPA, said they valued DR downtime by paying a capacity fee and have people bid what they thought the value would be by not taking it when deploying the resource. He said they bid a heat rate and used a representative gas index adding that this system was simple, straight forward and worked well. Ollis likened it to an option contract.

Jayaweera asked how this might apply to residential direct load control product. Wellschlager thought the fair rate would be whatever the index price of energy is at that time. Negash asked what happens if the incentive is less. Wellschlager said it's all a negotiation.

Bob King, Smart Energy Water, asked if we're quantifying the value to the customer or the system. Jayaweera said the customer as they are compensated for not using energy.

Riley Peck, DVC, asked Wellschlager to talk about using the aluminum price index. Wellschlager answered that they didn't explore it because it was too complex adding that money and the threat of penalties encouraged participation. Peck agreed, adding that tying to the energy cost index is an almost perfect representation of the utility cost but may not accurately capture the industrial customer loss revenue. Wellschlager said the customer can negotiate that price noting that he allowed 300% of index in the spring. Peck said this made sense but some customers would prefer a flat rate.

Nesbitt added that sometimes production is not lost but only shifted and you're paying for the inconvenience of that shift.

Hall commented that the program Wellschlager is talking about has not been continued. He was concerned with modeling something that is subject to negotiation. He thought it should be zero or 100% and was leaning toward 100% to reflect the transaction costs incurred by utilities that have to create IRPs.

Ollis added context, saying he thinks of this as a capacity call option, paying a customer a fixed cost, but there could also be a variable cost. He cautioned that taking either zero or 100% might not reflect reality as well as something in the middle. He acknowledged that this is hard.

Morris stated that CA protocol excludes incentives and counts costs the customers which is the opposite of what's represented on [Slide 10.] Jayaweera agreed, saying that in the end it's the same but it's more of a total cost perspective.

Nightingale said there's a transfer of value as you're paying people for not using energy they were going to use. He wasn't sure of the value of figuring out a number between zero and 100% for C&I customers and thought it was more like EE than not.

Singh voiced confusion over getting the value of lost service data, calling it industry and customer specific. He said once you get the number, it was still unclear how they would play out in the programs.

Mark Jerome, CLEAResult, commented that this would vary by DR asset affected. Jayaweera agreed that it would be hard to come up with this value and it would vary by product.

Jim Woodward, WA UTC, said there would have to be a high degree of transparency when valuing by product to avoid furthering favorites. Jayaweera said we could do the same approach as last time or have DRAC input into another approach.

Singh thought that collecting the value of service from the customer view would require a large study.

Nesbitt stated that at least the minimum number would be the value of energy, adding that they were paying for acknowledging that there may be costs above that could be covered with an added margin.

Hall said the decision made in the modeling has an impact on the modeling results which affect policy and guidance in the Power Plan. He asked what the end recommendation in the Plan could be, wondering if bins of products will be executed across the region. Jayaweera said it's up to the Council Members, who may come up with their own recommendation.

Singh agreed that the methodology is correct and a good framework to figure out C&I customers but the challenge is figuring out the values. He thought that it may be revealed that the most cost effective DR may be with residential customers.

Jayaweera asked the room about Nesbitt's proposal to value energy at lost service. Negash said this is not unheard of and it's been proposed to use the wholesale energy price minus the retail rate, noting that the argument didn't succeed.

Zeecha Van Hoose, Clark PUD, noted that the retail or wholesale rate might be different depending on the products. Jayaweera thought the approach might be used as a base and then consider a factor after going through the products. Van Hoose pointed to obtaining that product from the targeted segment.

BREAK

CA Demand Response Auction Mechanism
Aloke Gupta, CA PUC

Eckhart asked if there is a formal relationship between the CAISO and CA PUC on DR [Slide: Demand Response (DR) Portfolio.] Gupta stated that they are two independent regulatory entities with a shared relationship when it comes to DR.

Wellschlager asked about limitations on deployment and accompanying penalties, noting that you can't keep a freezer off for two days. Gupta said the capacity resource adequacy rules say the DR resources are required to be available for dispatch for up to four hours and not more.

Jason Salmi Klotz, PGE, asked if the DR and EE are delivered to the customer together or separately. Gupta said largely separately but there have been multiple attempts to integrate them better and funds were put aside to meet a directive to deliver them more holistically.

Salmi Klotz asked if the utility or a third-party aggregator has the relationship with the customer. Gupta said it depends on the vehicle and more will be discussed further in the presentation. Salmi Klotz asked how much oversight is given to the third party. Gupta called that a moving target, adding that the DRAM and LCR involve contracts which are oversight mechanisms. He said the Commission has taken more interest in doing better oversight for DR, solar and EE. Salmi Klotz asked if there have been any issues between aggregators and their third-party customers. Gupta said not with the C&I DR providers, noting that there are a lot of residential customers but there hasn't been a big problem.

Nesbitt asked if oversight over third-party DR providers include oversight over the baseline. Gupta answered yes, with the market integrated programs CAISO has its own baseline methodologies which will be covered further in the presentation.

Salmi Klotz asked how you counter customer burn out [Slide: DRAM: Reverse Capacity Auction w/Separate Energy Market.] Gupta said that is up to the aggregators as they have the relationship and the motivation to retain customers. Salmi Klotz asked for insight into contracts between DRPs and the customers. Gupta said no, calling it intellectual properties.

Jayaweera asked if the DRP will be paid by the IOU regardless if CAISO accepts (uses) the product or if it has to be accepted by the CAISO before payment. Gupta said the DI is obligated to pay for the capacity. King confirmed that the capacity value has to be perfected by its acceptance as a product in the market. He said if you won in the DRAM but didn't qualify in CAISO you would have to pay back money. Gupta called this mostly right, saying that CAISO doesn't qualify the resource and once PUC assigns RA credit to the DRAM resource then those resources are eligible and have an obligation to be available under penalty.

King said it has to register the resource with CAISO and be prepared. Jayaweera confirmed that CAISO may never dispatch. Gupta agreed.

Jayaweera asked how the IOUs value the MWs to the DRPs. Gupta called it a competitive solicitation that includes a least-cost, best-fit evaluation which generates a ranking. Jayaweera asked how the Commission comes up with a funding amount. Gupta said this is a pilot exercise and more information is on [Slide: DRAM Pilot Procurement & Budgets]

Hall noted that these are short term contracts which result in paying a premium. Gupta agreed that there are price benefits to longer term contracts and the LCR mechanism has contracts that span from five to 20 years. Gupta added that the Commission chose short-term contracts as it is a pilot.

Singh asked if the bids test against an avoided capacity cost or a comparison to an alternate supply side resource. Gupta said this will be covered in the presentation.

Wellschlager asked if deployment is tracked in real time or after the fact. Gupta said more after the fact, explaining the process and saying it will be covered in the presentation.

Frew asked if the one-year contracts were compared to the long-term avoided costs or the avoided costs for the associated year [Slide: Q&A.] Gupta answered that the long-term avoided costs changed year to year and the costs were competitive, dropping quite a bit by the third round.

King pointed to issues DRPs have in securing residential meter data. He recalled that Gupta said CAISO bids were not competitive and stated that PDR at CAISO allows DR to bid at a $1000 cap, which encourages bidding at that cap. Gupta called these good points, noting that accessing data was cumbersome but now looks promising. Gupta addressed the competitiveness of bid prices calling a difficult question to evaluate with no specific guidelines on how to judge competitiveness. He said the question is still being debated.

LUNCH

Jayaweera announced that the appliance standard bill, including CTA-2045 for water heaters, passed the WA house and will go to the full senate. She added that the SB5116 has passed the senate which will require WA utilities to have 100% non-fossil fuel portfolios by 2045.

Demand Response Across BAs and Overview of the PGE Capacity Sale for 2021-2025
John Wellschlager, BPA

Salmi Klotz asked if Avista had to procure extra resources just for the 10-minute resource or for all [Slide 5.] Wellschlager said all BAs have to have resources and we were addressing the impact that our decrementing the resource had on them, so it was just for Ponderay Newsprint's 16 MW. Salmi Klotz confirmed that Avista had day-ahead notice and Ponderay Newsprint only had 10 minutes and asked if Avista still had to procure. Wellschlager said no, not on a MW to MW basis.

Ollis clarified that an imbalance resource needs 15-minute schedules to cover other errors in the system. Wellschlager said yes and BPA's standard says it has to be fully deployed in 10 minutes. Ollis asked if it's possible to notify a day ahead and carry reserves. Wellschlager said

yes. Hall added that this comes at a cost to the BA and the purpose of the pilot was to test a 10-minute notification product.
Nightingale asked if Wellschlager could address Avista's imbalance concerns. Wellschlager answered no.

Ollis recalled that he thinks of DR as an options contract and asked how options contract tags, or DR tags, are insufficient [Slide 6.] Wellschlager stated that he can't fully speak to this but a capacity tag is always there to turn off and on but a DR resource is limited. Ollis stated that options are sometimes also limited call and wondered about their tags. Wellschlager said he believed you could specify, adding that this is beyond his expertise.

King asked if the tagging system is just for the relationship to the transmission across BAs. Wellschlager answered yes, reserving capacity and tracking energy flow.

Ollis wondered if the difficulty lies in scheduling within the hour. Wellschlager answered yes, and the further out the timeframe gets the less problematic it becomes.

Negash confirmed that 10-minute notification DR across BAs is not a good idea [Slide 7.] Wellschlager said he couldn't figure out a way to make it work, due to schedules and the added cost of asking the other BA to carry additional reserves.

Salmi Klotz asked for a definition of cost effective. Wellschlager answered competitive with conventional resources. Salmi Klotz wondered if he used a de-rating system similar to PGE's. Wellschlager said not for the pilot.

Salmi Klotz asked if these were process resources or a backup generator. Wellschlager said all process with the exception of voltage control. Salmi Klotz asked if location values were collected. Wellschlager answered no.

Negash inquired about customer feedback. Wellschlager stated that Ponderay thought the monthly cash infusion was a dream come true and NORPAC did a great job setting up manual controls and would like to do this again.

Morrissey asked how the cost of DR in this program compares to the cost of the next capacity resource. Wellschlager said this was a bit more expensive but in the ballpark.

Hall added that the purpose of the pilot was not to specifically test cost effectiveness but to test operations.

Salmi Klotz asked if there was a potential study about what resources may be available. Wellschlager stated that a request for offers was put out first and Energy NW looked best. He added that they worked with Energy NW to hone and fine tune the offer. Hall added that the Cadmus potential study has information for the future.

Salmi Klotz asked if high-value load pockets were identified. Wellschlager doubted the ability to classify by load types and illustrated his point with a story of two highly-motivated mills, one with high 90% implementation and the other with 60%. Salmi Klotz confirmed that response to an event was the responsibility of the contracted customer. Wellschlager said yes. Salmi Klotz asked if any investment in building management systems were made. Wellschlager said no, the physical dispatching was done by mills turning stuff off.

Graham Horn, Enbala, asked how the amortization period on DR was reconciled with conventional resources. Wellschlager answered that they didn't because of the nominal investment compared to new resources.

Negash asked how hard the development of a DR-specific tag would be. Wellschlager couldn't speak to that as he his not a member of NAESB, but expected that it's likely complex. Hall added that executing an energy tag at BPA was complex, adding that other DR programs that run in ISOs or RTOs don't require tagging while we have 20+ BAs.

Part Two - Overview of the PGE Capacity Sale for 2021-2025
John Wellschlager, BPA
Adam Schultz, ODOE, asked who delivers when a contract is called [Slide 13.] Wellschlager said PGE, calling it a virtual resource for them.

Morrissey asked about the energy parameters associated with the contract. Wellschlager said he couldn't speak to that. Ollis said the options contract he spoke about earlier is what people are preferring to DR and asked about how these contracts can teach us how to incorporate more DR into portfolios. Wellschlager said figuring out how to use DR for multiple purposes will help make it cost effective and workable. He also pointed to the importance of aggregation.

Power Plan Development Process
Tina Jayaweera, NWPCC
Morrissey asked if the test data can be draft [Slide 3.] Jayaweera answered yes, Ollis added that the better the data are, the more informative it will be.

Salmi Klotz asked if EE is supposed to overlap with DR on [Slide 4.] Jayaweera answered that it was not on purpose and suggested coming to the SIF for more.

Nesbitt stated that achievable potential for DR seems like a two-part analysis that is different from EE [Slide 5.] Ollis said the RPM has a signal to come up with a least cost way to address system need. Jayaweera acknowledged that "achievable potential" is an EE term and could be a called "market potential" in the DR realm.

Nesbitt stated that Idaho Power IRPs don't limit EE so if the potential is there it's included. Jayaweera countered that Idaho Power does cost effectiveness a priori and the Council does not. Nesbitt asked if the RPM might not choose low cost DR if the system doesn't need it.

Jayaweera answered yes, because of some of the 800 futures might not have load growth or resource loss. Ollis added that in practice most resources are acquired for adequacy.

King confirmed that load-side, customer-driven resource like solar panels would come under the load forecast. Jayaweera said yes.

Proposed Dispatchable DR Products for the 2021 Plan
Tina Jayaweera, NWPCC

Eckhart asked what forms of Res Water Heating is being explored [Slide 3] asking if it's only HPWH. Jayaweera said that will be discussed in the SIF.

Hall noted that BPA added a manual switch to their potential assessment and the CTA-2045 models will have a 15-year ramp at best. Jayaweera agreed that grid-ready water heaters will ramp slowly.

Morrissey asked if time of day usability will be addressed. Ollis answered yes and is important to both the RPM and GENESYS.

Nightingale asked why Events per Season is limited to five as more events could result in a cheaper resource. Jayaweera answered that there would be cases where the number could be adjusted, as in the instance of a manual timer, but the number is mostly there to address customer fatigue. Nightingale suggested that pinging residents for every event would not be cost effective and asked for more fine tuning. He said smart-enabled technology should be assessed for customer fatigue and program design could play a role.

Jayaweera said many of these points were considered in a past RTF DR subcommittee and all the variables would not be appropriate in a DR supply curve. She called for a prototypical product or action. Nightingale agreed and suggested that a four-hour duration for residential heating is bad design. Jayaweera agreed that program design is important.

Ollis reminded the group that the RPM is not an hourly model. Nightingale offered to work more offline.

Morrissey suggested that the season column be more granular than Winter/Summer as some programs are two months shorter than an entire season.

Woodward asked about the plan to get data for a bottom-up approach. Jayaweera stated that there is good, granular data in the RBSA that is two-years old. She said the CBSA is in the field right now and the plan is to use the most recent data.

Morrissey asked about programs for window-unit AC. King said that Con Ed had a program like that. Ollis called for more detailed penetration data.

Frew said EPRI has ENERGY STAR information. Jayaweera asked to see it.

Hall called out the lack of large industrial loads on [Slide 6.] He said such loads are significant and finds potential in industrial loads for municipalities. Jayaweera said she sees that in Demand Curtailment. Hall said BPA breaks down by sector and offered to talk more offline.

DR Programs in Portfolio Analysis: Binning Strategies
John Ollis, NWPCC
Morrissey said beyond the NPV you also select resources for the ARMS [Slide 3.] Ollis said yes, though explained the ARM and the penalty associated with it impacts the NPV.

Shauna Jensen, PGE, said her company uses bins from the Seventh Plan to inform DR fixed costs [Slide 10] calling them easy and straight forward. She didn't know where to categorize EV DLC and would like to see it mapped into a bin. Jayaweera pointed to a past RTF meeting that yielded information but she couldn't say what the bins for the 2021 plan will look like.

Van Hoose asked what analytical options for the bins are being considered. Ollis said it's hard to consider other ways without knowing the costs and other data. He stated that this is what staff is proposing but could be convinced otherwise.

Morrissey asked how program characteristics come into play. Ollis said programs are clumped together and given an amalgamated look.

Woodward moved back to [Slide 6] and asked about optimization strategies. Ollis said this slide shows different seasonal attributes and are not bundled together but are bundled by price as illustrated on [Slide 7.]

Salmi Klotz said the original DR definition looks like load modifying and asked about battery storage. Jayaweera said storage could be a means by which you achieve DR and utility-scale batteries are in the load forecast. Salmi Klotz stated that some of his large, industrial customers might be interested in batteries and hope to get DR services out of them. Ollis said if that was in the load forecast the DR effect would be in there too and could not be picked by the RPM. Jayaweera pointed to the generic, non-res curtailable program as a possibility.

Hall stated that BPA has 10-15MW batteries that could be called for capacity and calling on batteries has seen some success in the pilot. He admitted that they will have a role in the future and cautioned that care must be taken when modeling them. He did not agree that they could only be treated as load. Jayaweera confirmed if they were utility-owned systems they will be looked at as a unique resource in the next plan.

Jayaweera adjourned the meeting at 3:45.

Attendees

Tina Jayaweera	NWPCC

John Ollis	NWPCC
David Nightingale	WA UTC
Jim Woodward	WA UTC
Tom Eckhart	UCONS, LLC
Tomás Morrissey	PNUCC
Adam Schultz	ODOE
Lee Hall	BPA
Ahlmaz Negash	Tacoma Power
Eli Morris	PacifiCorp
Bob King	Smart Energy Water
Bill Henry	PSU
Jason Salmi Klotz	PGE
John Wellschlager	BPA
Joan Wang	Cadmus

Attendees via Webinar

Dan Patry	Oracle
David Lowrey	CLEAResult
Elizabeth Osborne	NWPCC, Washington
Ryan Finesilver	Avista
Frank Brown	BPA
Clint Gerkensmeyer	Energy Northwest
Gillian Charles	NWPCC
Graham Horn	Enbala
Aloke Gupta	CA PUC
Jennifer Finnigan	SCL
Kerry Meade	Smart Buildings Center
Malcolm Ainspan	NRG
Mark Jerome	CLEAResult
Mary Ann Piette	LBNL
Mike Hoffman	PNNL
Nathan Kelly	BPA
Quentin Nesbitt	Idaho Power
Nick Bengtson	CLEAResult
Nicolas Garcia	WPUDA
Riley Peck	DVC
Sarah Vorpahl	WA Dept of Commerce
Shauna Jensen	PGE
Shirley Lindstrom	NWPCC, Idaho
Gurvinder Singh	PSE
Suzanne Frew	Snohomish PUD
Zeecha Van Hoose	Clark PUD
Will Price	EWEB
Brian Dekiep	NWPCC, Montana