Demand Response Advisory Committee
Northwest Power and Conservation Council
October 30, 2019

Tina Jayaweera, NWPCC, began the meeting at 9:30 with a call for introductions and a review of the agenda.

Space Heating DLC Spreadsheet

Lee Hall, BPA, asked if the BPA numbers came from the Cadmus study. Jayaweera answered yes, adding that she tried to check them against the update.

Ahlmaz Negash, Tacoma Power, asked if the set-up costs are the same regardless of program size. Jayaweera answered yes.

Suzanne Frew, Snohomish PUD, felt that $20 was too low to incent a commercial customer for the entire heating season. Negash agreed that $20 is low to incent a small commercial customer but was ok if it was part of a bigger package.

Quentin Nesbitt, Idaho Power, felt the $20 is more related to the kW they could get from commercial customers as compared to a residential system. He agreed that $20 seemed low. Jayaweera agreed that savings are higher on the commercial side and changed the number to $40 for the thermostat program.

Jayaweera asked about including a one-time incentive for participating in a Bring-Your-Own-Thermostat program. Frew said it's typical to have a one-time incentive along with an annual incentive for a BYOT program, but wasn't sure about a switch program.

Jayaweera asked Eli Morris, AEG, if he recalled how PacifiCorp determined eligibility. Morris did not remember. Frank Brown, BPA, explained how he followed the CBSA to split out building types.

Jayaweera said that this is for small commercial and wondered if she should create a spreadsheet for medium commercial. Brown said the CBSA shows almost as much floor space and load in small commercial as in medium commercial, making medium commercial as important. Jayaweera asked if a BYOT applies to medium commercial. Brown answered no as medium commercial usually has a single building management system.

Jayaweera said it sounds like she should add a medium commercial switch program and cautioned the group that she will ask how everything overlaps when it comes to demand curtailment.

Brown said the 2.5 kW Peak Load Impact number came from the metered Milton Freewater program but didn't know where the 1.87 kW came from. Jayaweera said the metered data is very valuable as there are very little data available.

Brown called the 3% too low and discussed good results when working with retail chain small commercial like a Starbucks or a MiniMart. He added that Cadmus's benchmarking work found between 5-18% penetration which averaged to 10%.

Hall called the difference between 3% and 10% significant but did not advocate for splitting the difference. He said even a somewhat aggressive program can get to 10% participation. Jayaweera was fine switching the number to 10% but cautioned that she didn't think there are a lot of space heating DLC commercial programs out there.

Jayaweera discussed her difficulties in gathering Peak Load Impact and Program Participation numbers, particularly for the thermostat program. She said her options are using the same number or ratioing the difference. Negash asked about the ratio. Jayaweera thought it was about half the impact on the residential side.

Frew called the ratio conservative but was okay with it. She did not support using 4kW because it would be higher than a switch program.

Frew addressed participation asking if it's for customers that already have the technology. Jayaweera answered yes, this is for small commercial that already have the technology connected. Jayaweera added that she wasn't sure what the CBSA will reveal, saying it might be a SWAG. Negash suggested treating it like residential unless it's ridiculously high.

Cooling DLC Spreadsheet

Brown brought up a complexity with multi-season DR products, saying because of the layout of the data request, he put all of the costs in both seasons. He said this means the equipment and marketing costs should be cut in half. He said this will require thinking deeply about the small commercial numbers and how the RPM will treat them.

Jayaweera thanked him and explained the Seventh Plan bundling process. She agreed that the equipment may not need to be doubled as one appliance can do both heating and cooling. She asked if she should add an assumption about how many customers participate in both heating and cooling. Brown did not have an answer but called for caution when binning all of these DR products to avoid double counting. Jayaweera agreed, calling cooling/heating DLC and irrigation exceptions.

Brown thought a simplifying assumption of one building participating in both seasons was appropriate given that small commercial is a small sector.

Frew confirmed that the model will pick up on potential in the winter or the summer. Jayaweera answered that the model picks up on need for potential. Frew said there is customer choice and utility choice as far as duel season DR programs.

BREAK

Jayaweera presented the changes she made to the space heating/cooling DLC spreadsheets. There were no objections or concerns.

DR Products: RTF Analysis on Irrigation Pump Controls, Lighting Controls and Refrigeration Controls.

Irrigation Pump Controls Spreadsheet
Brown clarified that the BPA analysis is split into large and small farms and not pumps stressing that they are quite different in costs and load reduction as per the Department of Agriculture Irrigation Census.

Fred Heutte, NW Energy Coalition, asked how a farm is determined to be large or small. Brown said it's acreage, 2000 acres for a large farm, less than 2000 for a small farm. Brown added that the industrial farms run their acreage very differently with modern, centralized control centers.

Heutte asked if a center pivot irrigation installation is strictly used in large farm. Hall said maybe not. Heutte said the analysis should reflect the significant differences between large and small farms as they have implications for automated dispatch. Hall added that there's also implications around overall costs, likening large farms to large industrial loads.

Jayaweera asked how to break out loads between large and small farms. Brown said he'd have to go back to the Cadmus study but guessed that 50% of the total acreage was small farms and 50% large. He added that these numbers are for farms in the BPA service area including federally powered irrigation districts.

Jayaweera said she was asking about peak impact and didn't know if it could be broken out by load. She offered to come back to it.

Heutte asked why the PacifiCorp number is such an outlier. Jayaweera said they include set-up costs.

Brown said there are no equipment costs for their large farms pilots as everything is already automated, in place and just needs software.

Nesbitt added that they need more software on their end to manage a large site that doesn't take on equipment. He said if they choose to use Idaho Power equipment, they spend more than $800 per site. He said instead of differentiating by farm size he would differentiate by amount of horsepower on site.

Heutte said it will not be easy to make a distinction based on how much consistent data will be available.

Nesbitt said he used to differentiate at 1000hp.

Heutte wondered if there was a rough estimate of total potential resource. Nesbitt estimated it at 20% of his total program. Heutte said that 20% is important because they are large players and easier to work with. Nesbitt added a caveat: when they started their program and needed sites to turn off, no larger sites participated. He said he had to go back and talk about rules that would allow these large farms to participate. Heutte said a binary, on/off approach will not work with large farms. Nesbitt agreed.

Heutte called timing a significant issue for Idaho Power, where the peak irrigation season is mid-June but the regional system needs are later in the summer when hydro is low. Nesbitt said Idaho Power's max potential load would happen in early July if temperatures are extreme, i.e. 105F.

Brown clarified that many of their successful pilots were targeted to large farms that had water storage, so they could fill them at night.

Nesbitt spoke about total potential in Idaho, and how they got participation over a broad base of customers even without storage. He said this could be harder for a utility with farms that only has canal systems with small pump for fear of wash out.

Jayaweera said this discussion mostly relates to eligibility which will come up later. She then asked about equipment costs. Nesbitt asked where software belongs: equipment, O&M or setup. Jayaweera said it could go in a variety of buckets but O&M costs repeat every year, setup is the cost to stand up a program so equipment might be a better fit.

Nesbitt said it's hard to pay different customers in the same class different amounts, so the $10/$19 is not a reality. He said they pay by KW. Nesbitt agreed that costs to Idaho Power are less for large farms. He continued saying, for set up, there are more software costs for large farms and more field costs for small.

Jayaweera reiterated that equipment costs for large farms should be lower. Nesbitt was okay with $200/$800 but thought you could drop further on O&M.

Brown couldn't remember where the $10 O&M cost came from, saying he's hung up on the participant because BPA followed the Irrigation Census method of differentiating by acre and farm. He asked if "participant" is the farm, or the family that owns a few farms, or the company that owns 10 farms across three valleys.

Jayaweera said the best data she has is the number of farms asking if that is appropriate. Brown offered "per pump" as another metric option. Nesbitt said then you have to figure out average pump size. Nesbit said Idaho Power's numbers are not that high for the small and really low for the large.

Jayaweera told Nesbitt that the RTF generated the $800 based on his per-site numbers. She asked if she could use farm as a proxy for site. Nesbitt waffled. Jayaweera said she will use the USDA survey. Nesbitt said that is an owner-basis and would be different than the $200/$800.

Jayaweera asked if per KW is better. Nesbitt said it might be and for his utility it would equal $5 per KW for small and almost 0 for large farms.

Heutte wondered if per acre might be a better proxy because of state-level data. Nesbitt commented that acreage is problematic because there might be a mix of pumps with different lifts and different HP.

Brown said he was amused and surprised that there is so much struggle characterizing one of the largest summer loads.

Nesbitt said he was fine with the setup cost, O&M on a per KW basis, equipment and marketing but said incentives need to be on a per KW basis. Brown said Idaho Power's annual report is BPA's default because it is complete, clear and detailed.

Nesbitt said Idaho Power uses $1 per KW for small O&M and $0 large. Jayaweera asked what the marketing spend is. Nesbitt said it's really small, less than $1. Brown said BPA includes marketing in the annual O&M. Jayaweera proposed $30 per participant. Brown said that number is much too high as large farms have almost $0 marketing costs. Nesbitt countered that $30 might be low when rolling out the program.

Heutte recalled presentations that said rolling out a program requires a lot of driving, talking and hand holding.

Nesbitt said he was fine using $50 for both. Brown appreciated Nesbitt's experience but still thought it was too high and could keep DR from being picked by the model. Jayaweera pointed to other lower costs. Nesbitt said if participant was defined as site versus farmer, he could see using a lower number as Idaho has a lot of sites but not a lot of farmers.

Nesbitt approved of dropping the number to $20 if it's a per site basis.

Hall echoed Brown's concern of not trying to pick numbers based on what will be picked by the model but also didn't want to hold a finger to the wind. He said we need to be careful as this will impact the resource. Jayaweera said we will come back in February to look at levelized costs and if something seems out of whack it can be reexamined. Hall suggested looking at Nesbitt's work for the PUC versus the Cadmus study, stressing that they defer to real world, regional numbers.

Nesbitt said if he looked at the numbers from a potential study perspective the place to be the most wrong is at equipment cost per KW. Jayaweera added a note that said, "per site vs per kW depends on lift. "

Jayaweera noted that the $41 for BPA small farms came from an LBNL study of California. She said she will bring this back as levelized costs giving the DRAC the opportunity for another check.

Jayaweera moved on to incentives.

Nesbitt stressed that incentives have to be on a kW basis. He noted that while Idaho Power uses a combination of demand and energy payment, there are other acceptable ways. He did say that it would be easier to use demand only, which would add up to between $16-20 for Idaho Power.

Jayaweera brought up the issue of accounting for dispatch and asked Nesbitt how he came up with the numbers. Nesbit, admitted that it's complicated, saying when the program started, he was told the maximum incentive would have to equal a simple-cycle peaker and went backward from there. His goal was to maximize participation while remaining cost effective even if the program only lasted one year.

He explained the problem with paying by demand and how he divided the payments into demand and energy. He said over time he grew to like the energy payment as it better incents the higher load-factor customers.

Negash said Tacoma Power is in the middle of developing a DR rate and wanted to use kW but didn't want to over-incentivize the utility and burden the customer. She thought an energy payment would prevent that. She explained that Tacoma started with a total DR value in kW, then broke that value into kW and dispatch incentive. She said the dispatch incentive is high enough to discourage the utility from overcalling on customers.

Nesbitt said Negash's method sounds like a fixed and variable approach. He said Idaho Power has a $16 per kW fixed component and the variable can get you up to $24 if there are enough events. He said it's important to the design to have a fixed and variable.

John Ollis, NWPCC, was cool with that approach, calling for an idea around dispatch costs, which could be associated with the variable incentive. He recalled the $110 per MW/hour was deemed high and hand-wavy.

Nesbitt said Idaho Power uses two different rates for a per kW/h which averages to $180 per MW/h. He said the goal was finding a number that's higher than market price. Negash said she used $150.

Ollis said that might be reasonable but DR would never dispatch if he put those numbers in the Seventh Plan. Ollis said the 2021 Plan might be more volatile because of the addition of renewables but his gut feel told him DR wouldn't dispatch much with this incentive. He said it could be put in as a proxy and tweaked later.

Nesbitt agreed that Idaho Power uses DR for adequacy and not energy and wanted a price that wouldn't dispatch a lot. He noted that they do run the program a minimum of three times a year. Ollis doubted that the model will have that level of fidelity, but might have a way to understand the minimum. Nesbitt agreed that it's hard.

LUNCH

Non-Residential Lighting Controls

Heutte recently read that LED street lights can be dispatched which may be a significant for winter evenings [Slide 11.] Jayaweera was aware of the technology and possible safety issues. Heutte thought it could also be used for parking lots. Jayaweera thought this could come up again after BPA finishes an outdoor lighting stock assessment.

Heutte asked why there are differences in cost on [Slide 14.] Jayaweera didn't know but thought it had to do with integrating to different building systems.

Lighting Controls Spreadsheet

Brown stated that BPA's Cadmus potential assessment for the entire commercial building sector was separate from the commercial demand curtailment which was assumed to only contain changes to space conditioning. Jayaweera asked why demand curtailment was only assumed for space conditioning. Brown did not know.

Jayaweera suggested keeping them distinct for now as most utilities have generic demand control curtailment programs.

Brown addressed incentives, calling it a complicated as the product design assumed the DR product was integrated with an EE control program. He said the EE part provided the usual BPA incentive so no further incentive was justified. He added that there was an incremental cost around fixtures.

Jayaweera agreed that there would be incremental equipment costs for EE but wasn't sure about the incentive piece as it can be utility-specific. She asked if the EE incentive was comprehensive enough.

Frew said if you want reliable, year-after-year participation you have to provide an incentive. Brown countered that PG&E does not incent the continued use of DR-enabled lighting system, but provides a generous, upfront EE incentive. Brown stated that the utility doesn't call events but will dim lights during a peak period and customers don't notice. Brown said they give the building owner enough incentive upfront to justify this and it is in the incentive contract.

Jayaweera wondered why newer lighting systems wouldn't run a less-than-100% levels to start as their high-end trim better allows it. Brown didn't know, calling it a "murky measure" that Cadmus modeled their program on.
Heutte thought that every new load on the system should be managed by the system, and combining EE incentive with DR made sense, but agreed that the approach will make it more complicated to attribute costs. He was fine with the number the analyst provided.

Negash confirmed that the incentive is $10 for a whole year. Jayaweera confirmed and agreed to use it as a place holder and keep looking. Brown called $10 high. Jayaweera agreed and offered $5.

Ollis said anecdotally these programs require less incentive as customers don't lose a lot of utility.

Jayaweera asked about the 20% eligibility. Brown said that was based on the PG&E program that identified that 20% of their EE program participants installed DR enabled fixtures.

Refrigeration Controls Spreadsheet
Frew thought there should be some marketing costs as you have to reach out to customers individually. Jayaweera thought the Seventh Plan might have wrapped them in O&M costs. Frew countered that this should be consistent with other measures.

Brown said refrigeration control was a major part of the industrial demand curtailment product.

Demand Curtailment Assumptions Spreadsheet

Heutte wasn't sure how to settle incentive payment as there's not a lot of examples to work with. He suggested staying with what you have.

Negash said you can justify not having a variable incentive if the DR doesn't have much impact or inconvenience but she would have fixed and variable for consistency. Jayaweera asked what numbers to use. Negash said to keep them the same for all of them.

Heutte was still not clear. Jayaweera agreed, but felt more in line with Negash's idea of variable. Heutte said it might be useful to ask for more input from IRP planners, commissions and so on. He said consistency matters but wanted more discussion around a backstop.

Heutte added that the marginal value to each utility may be different. Ollis said any result from the RPM will be reflective of a regional value; any DR program will be catered to individual utilities with its own situation, T&D value and value to the utility. He said the RPM would not be strong for this but DR could still be acquired for adequacy. He said they could analyze an individual DR program in one of the more granular models and add narrative for things that can't be modeled well.

Heutte said the NW Power Pool is working on a resource adequacy product and he will be pushing hard for flexible demand/DR to play a role in that product. He said this could lead to a composite value for the region. He acknowledged the difficulty in this process but felt that it is wrong to not put any value on the metrics.

Jayaweera said she would reach out to other experts.

Brown said just because the metrics are displayed as $/kW year doesn't mean they always assume a single capacity charge method of payment. He said sometimes they assume a variable component and energy charge. He said this means they make assumptions: number of event's per season, hours per event, kW per event and come up with an energy payment that is converted into the capacity charge. He suggested converting the payment using BPA math and adding it to make the modeling less complicated.

Ollis called that a great suggestion and could be done but it would mean treating DR inconsistently with other dispatchable resources. He said if we see high electricity prices, over $150 MW/h, then DR would dispatch. Ollis said having a variable incentive better fits the models, which is not satisfying but the way forward for the 2021 Plan. Brown said that made sense.

Jayaweera moved to Peak Load Impact.

Nesbitt called 52% high and couldn't imagine an industrial site reducing 52% of load. Jayaweera said this is commercial. Nesbitt still thought is was high but wanted to think about it.

Heutte said Industrial has 52% and thought that there're facilities with large machines that could offer a big reduction but questioned if commercial could with lighting and HVAC.

Brown said it's 52% of the load that eligible to participate in a DR event. He said he multiples the 52% by the 25% to get the expected peak reduction. Nesbitt said he interpreted that differently, thinking that the percent eligible segment was the total commercial segment and what percent was going to participate. He said the peak load impact was a percent of a site load. Jayaweera agreed with Nesbitt that 25% of all commercial loads participating and of those that are participating half of that load is reduced.

Jayaweera asked about eligibility wondering if load class eligibility is what Brown was talking about. Brown thought something was missing as he didn't think a participant would drop 52% of load but 52% of loads that were eligible.

Nesbitt said it's 20-30% of a facility load i.e. a Target, Walmart or Lowes. He said those customers are good at their nominations but might nominate a bit more at times. He said he gets 90-100% from what the whole sector nominated. Jayaweera confirmed that 95% is correct for event participation. Nesbitt answered yes, as percent of nominated load and not percent of participants.

Jayaweera dropped Peak Load Impact to 25% and asked Brown to investigate missing information.

Nesbitt said 25% program participation is a good goal and explained why. He said it's more like 1-2% despite having a program since 2009 with lots of marketing and good incentives. Jayaweera dropped the number to 5% and called for more information.

Jayaweera moved to Demand Curtailment Industrial. Nesbitt said he sees more variability in event participation from large industrial because they are very process oriented. Jayaweera asked how much notice he gives customers. Nesbitt answered two hours. Jayaweera dropped event participation to acknowledge that fact.

Heutte recalled the McMinnville Steel Mill responded most of the time. Hall pointed to the broad spectrum of pilots that saw participation grow over the years due to better communication. He noted that participation ran from the mid 80% to the mid 90%.

Nesbitt said the participants are engaged but the level of load reduction is variable. Hall added that aggregators oversubscribe by 25-50% because not everyone can respond. Nesbitt called that a good point.

Stand-alone DLC or Part of Larger Program
Jayaweera said she will continue keeping them separate. Heutte worried about double counting. He wondered how this is assessed in the east. Jayaweera reported seeing all-in programs.

Nesbitt agreed. Jayaweera said it doesn't matter how refrigeration warehouse is modeled as it could be carved out. She said breaking it out into two products has benefits but the RPM can't model them separately.

Jayaweera proposed keeping refrigerated warehouses separate but to pull the lighting in too. Nesbitt agreed. Brown did not approve of keeping refrigeration products separate from industrial. Brown said 1/3 of the industrial loads are paper and pulp mills and asked why they are not separated out. Jayaweera countered that refrigerated warehouses were separated out because good EE information exists. Brown was not convinced, calling it odd to separate out one part of the industrial sector. Brown did think rolling lighting into commercial and public buildings demand curtailment programs a smart idea.

Jayaweera said she was fine with rolling it all in together. Nesbitt agreed, saying if there was amazing data there might be a reason to separate it out.

BREAK

Irrigation Eligibility

Brown discussed why the eligibility numbers are differentiated between large and small. He noted that there were two adjustments, one for crop types and one for farms with a 150 HP pump. Jayaweera said the report talks about 100 HP cumulative. Brown agreed.

Nesbitt asked if it is by site or farm. Brown answered that it's a farm.

Nesbitt addressed customer saturation saying it's around 13%. He added that there are between 18,000 and 19,000 irrigation sites that range between 0HP and 1000s HP. He said participation is higher because in the beginning people had to pay to get in. Nesbitt said the average is close to 200HP, adding that there is better participation in the larger pump sizes.

Brown agreed that 13% for the small and 19% for the large made sense.

Nesbitt asked what is considered eligible when you do a study for the region, the whole irrigation load or just part of it. He thought you would look at the whole load and participation is what you got.

Jayaweera asked Brown if he started the program at 100 cumulative HP because anything less would not be worth it. Brown answered yes. Nesbitt wasn't sure how to evaluate if a farm has 100 HP. Brown said they used the USDA irrigated agriculture census.

Heutte wondered if a good rule of thumb is for every 100 HP you get 85 kW. Hall answered yes. Heutte thought a utility would have good demand figures.

Jayaweera said she would ask Cadmus about the 100 HP but she thought the numbers looked reasonable overall. She asked why BPA had less participation on the west side. Brown answered that there is almost no irrigated agriculture west of the Cascades. Jayaweera said this number is of eligible customers. Brown thought it had to do with crop type.

Nesbitt thought it was related to lift and small amount of HP. Brown added that only 1% of irrigated acreage is west of the Cascades. Hall recalled moving all of that 1% of irrigation pipe himself when working at farms in the past.

Jayaweera moved to Peak Load Impact.

Heutte asked about irrigation timetables. Nesbitt said it's 24-hours a day during the heavy grow time unless it rains or gets cool. He said it would be unusual to turn off during the hottest parts of the day and the only time it gets shut off is when something is wrong with the pivot or they are cutting hay.

Heutte called this an inelastic load. He wondered how much of this can be counted on during a one-in-ten-year peak. Nesbitt agreed that this could be an issue, adding that they limit their program to no more than 15 hours a week acknowledging that the rule is risky from a resource adequacy perspective.

Heutte said the worst case of a long, hot summer following a dry spring worries him from a resource adequacy perspective. Nesbitt agreed with his worry.

Jayaweera said she had 50 hours for a lot of the products. Nesbitt said his programs are 60 max per season, 15 per week.

Jayaweera asked if they can model a weekly limit. Ollis said it can be reflected in GENESYS but the RPM can reflect the "spirit" of it.

Hall said BPA products are modeled as 40 hours products. Jayaweera asked Nesbitt if he ever ran the full 60 hours. Nesbitt answered no, the most for irrigation was five, four-hour events.

Ollis recalled that they used between 40 and 60 hours for the Seventh Plan and didn't think that was a big part of the result.

Jayaweera stated that the peak load impacts are meant to represent the maximum. Nesbitt clarified that HPx80%=kW but found that not all customers run at 100% when they are turned off. He said that maybe 80% are on at peak time, admitting that statement is counter to what he said before about them all being on 24/7.

Jayaweera called BPA's 75% comparable. Nesbitt said he would be comfortable with either of those numbers cautioning that there's a seasonal component as well. Jayaweera said that there will be an 8760-irrigation load profile that will come into play.

The room was comfortable with the 80%.

Jayaweera moved to percent transfer. Brown said that number came from the California report that lumps irrigation with industrial.

Nesbitt called this hard for him to figure out as there is a cost to managing around our events.

Jayaweera called this the swaggiest of all of the SWAGs.

Hall commented that this is a relative cost compared to other DR programs. He agreed that it will be hard to figure out but will have to pass the "reasonable" test. He thought the number should hold.

Brown added that there is no underlying study of this and is basically the CA PUC staff estimates.

Jayaweera said she will send an email out asking for more information. There were no public comments. She ended the meeting at 3:30.

Attendees

Tina Jayaweera	NWPCC
John Ollis	NWPCC
Ahlmaz Negash	Tacoma Power
Lee Hall	BPA
Fred Heutte	NW Energy Coalition
Adam Schultz	OR DOE
Suzanne Frew	Snohomish PUD

Attendees via Webinar

Bill Saporito	Umatilla Electric
Blake Scherer	Benton PUD
Clint Gerkensmeyer	Energy NW
David Lowrey	CLEAResult
Eli Morris	Applied Energy Group
Elizabeth Osborne	NWPCC
Frank Brown	BPA
Kyle Frankiewich	WA UTC
L McCarty	
Malcolm Ainspan	NRG
Michael Schmidt	DVC Law
Quentin Nesbitt	Idaho Power
Gurvinder Singh	PSE
Tom Eckhart	UCONS
Brian Dekiep	NWPCC