Northwest Power and Conservation Council
Demand Response Advisory Committee
June 7, 2017

Tina Jayaweera, NPCC, began the meeting at 9:00 am by calling for introductions, reviewing the agenda and accepting the minutes from the March DRAC meeting.

Bryce Yonker, Smart Grid NW, announced that there is great interest in the NW Demand Response & Energy Storage Summit, September 27 and 28 2017 and encouraged DRAC members to participate.

Jayaweera addressed dropping PNDRP as it is redundant to the DRAC and the Summit. She welcomed comments on the decision.

Update from BPA Distributed Energy Resources Potential Study
Lee Hall, BPA
Hall presented [Slides 1-8] and asked for questions.

Josh Keeling, PGE, praised the study and asked if there is any economic screening. Hall explained that there is a cost/supply curve that looks at all segments: residential, commercial, agricultural and industrial. He noted the different products, 10-minute and day ahead, as well. Hall cautioned that it applies to BPA customer utilities but suggested that they could apply to other utilities as well.

Robert King, Whisker Labs, confirmed if these were multiple cost curves for different products. Hall answered that that is the intent but Bonneville is still looking into how to accomplish this.

Keeling asked for clarification, wondering if there will be technical potential, economic potential and achievable potential curves. Hall answered yes, saying it would be used by the Council and BPA internal planning groups.

Riley Peck, Davison Van Cleve, P.C., representing Industrial Customers of Northwest Utilities (ICNU), asked about incentives for end-use customers and how this work informs BPA's understanding of incentives going forward. Hall pointed to two customer benefits: 1. Customers will have their voice heard and can better assess potential internally and barriers and 2. This information will be publicly shared. Hall reports strong enthusiasm for participation

Peck clarified that there isn't a financial incentive for program participation at this stage. Hall stated that he's asking for an hour or two of time for interviews. He stated most information will be about barriers but there will be some about potential.

Rob Pratt, PNNL, asked why BPA used an East West split when the "South of Allston" issue is better served by dividing North/South. Hall answered that this was the priority when gathering information and will be helpful in the end.

Jeff Harris, NEEA, asked if there is categorizing of the different durations of products. Hall answered that historically they've gone to a three-hour event but could look at one-hour and 10-minute events too. Harris then asked about the baseline for the supply curve development. Hall was not sure what Harris meant by baseline but stated that he is looking at what is out there and has historically proven useful to avoid overestimation.

Fred Heutte, NW Energy Coalition, expressed hope that thermal storage is included in the primary DR category. Hall was reluctant to call that primary, but pointed to categories framed around sectors that included electric and heat pump water heaters. Heutte then asked about cold storage. Hall answered that there have been good experiences around cold storage demonstrations.

Tom Eckhart, UCONS, LLC, asked if this is a pure phone survey. Hall answered no, noting that the BPA is providing the best inputs they have and will include as many face-to-face meetings as possible.

Keeling moved back to economic screening asking if the South of Allston leg will be looked at specifically as an avoided transmission cost as the Council takes a "peanut butter" approach. Hall clarified that this is the cost of the asset not an avoided cost. He pointed to separate BPA work that looks at the valuation of DER. Keeling asked if this is a supply curve without an avoided cost assessment. Hossein Haeri, Cadmus, said this will be a conventional supply curve, with every point defined and every variation detailed, and will reveal the quantity of the resource in MW and per unit cost. Hall again stressed that this is not an economic evaluation. Keeling echoed the importance of segmenting North to South instead of East to West. Haeri noted that there will be no screening and everything will be on the supply curve.

Bud Tracy, Consultant (Idaho), approved of the idea but voiced concern about the lack of economic analysis. Hall clarified that these are robust cost curves for the asset but does not compare the resources to alternatives. Hall said this is a DER potential study, calling it sophisticated input for deciding between building transmission or buying a resource.

King asked if the cost curve is the cost to the utility to acquire some quantity of the asset. Hall answered that this is the cost of delivering the asset to the user. King asked about homeowner investment. Hall stated that embedded program costs would be paid to the owner. Haeri stated that typically in DR the only relevant cost is to the program administrator and participant cost is often unknown.

Keeling countered that DR incentives make a huge difference between a TRC and utility cost. Haeri agreed that may be the case but pointed to third-party curtailment contracts saying that most of the time the program administrator doesn't know the incentive amount.

Bill Henry, EQL Energy, asked about the amount of top/down versus bottom/up information that will be in the inputs. Hall stated that it is coming from both points.

Mary Anne Piette, LBNL, asked if BPA is considering both manual and automated DR as well as first costs and operating costs. Hall answered yes to both as they are looking at all types of DR and DER in general, stressing that they are getting at the total cost of the asset.

Hall thanked his team, naming Lakin Garth, Cadmus in particular, noting the accelerated schedule.

Embedding Demand Management Functionality: Getting to Scale in the Northwest
Jeff Harris, NEEA

David Nightingale, WA-UTC, asked for an explanation of a tempering valve [Slide 5.] Harris explained that a tempering valve, a common device found in plumbing supply houses, allows the tank to store water at a higher temperature while delivering water for household use at a safe temperature. Harris explained that this device allows you build bigger thermal batteries.

Edward Louie, OSU Energy Policy, noted that General Electric has discontinued the production of Heat Pump Water Heaters (HPWH) due to inadequate demand. Harris moved to [Slide 7] to explain the scale needed. King pointed to the significant upfront cost. Harris agreed, noting that GE left the market as the three largest water heater manufacturers, who own 95% of the market, are now making HPWH [Slide 8.]

Eckhart agreed with Harris' capital cost estimate but stated that installation costs are higher because of ducting. Keeling agreed that installing these in a multi-family setting will be tough. Harris agreed that this will cost more but pointed to the large amount of single-family opportunities available.

Heutte pointed to different operational characteristics between a HPWH and an electrical resistance water heater. He cautioned against counting all of the HPWH as some go to electrical resistance mode. Harris agreed, but gestured to the opportunity for a flexible, off-grid thermal battery that could be scheduled for day-ahead use.

Heutte asked about the size of the 50-gallon-or-more market. Harris didn't know but pointed to a bump in sales in the 66- and 80-gallon size.

Jayaweera stated that the last RBSA, which came out before the Federal Standard, found that 88% of tanks are less than 55 gallons for single family homes. Heutte noted the Effective Useful Life is 10 to 15 years which means a 6-10% turnover every year. Harris agreed calling it a big lift as our region has to agree on the specifications for demand management. Harris noted that this has been successful in the past for energy efficiency specifications.

Harris asked for interested parties to put their name on a sign-up sheet passed around the room to discuss next steps [Slide 11.]

Tracy, apologized for being, “the skunk at the church social,” stating that success is predicated by how much consumers are willing to pay for this technology. He stated that without giving consumers some benefit this will not work. Harris did not disagree. He acknowledged that HPWH delivers savings every year but noted that there has to be a commercial agreement before the end user allows a utility to manipulate it. Tracy agreed, then pointed to possible limited participation due to variations in water quality and urged Harris to include that in his assessments.

Louie pointed to big capital cost differences to the consumer that can run 2.2x higher than the cost of a typical electric resistance water heater. He acknowledged major rebates and incentives already in place but wondered how sustainable these are pointing to some anger by the cross-subsidy between rate payers. Harris agreed that there is an increased capital cost but stressed that at scale it shouldn’t be more than $500 or less. He noted that some manufacturers are adding shifts to build these products and it should not cost more than a room air conditioner.

Eckhart asked about the status of GE. Harris answered that Bradford White bought the manufacturing assets, is honoring the warrantee and continues to manufacture the unit in the US.

Keeling suggested that we may be overestimating the capacity benefits as a real peak load shape is different than the average load shape used and a HPWH can look like a resistance unit on a cold winter morning. Keeling then cautioned the room to consider the EE impacts if these units are leaned on for storage. Harris agreed, but noted that in Tier 3 models the electric element hardly ever turns on and offers different capabilities for grid management.

Nightingale asked if the BPA/PGE units had a tempering valve. Hall answered that they were normal, off-the-shelf technology and pointed to past mixing valve pilots that caused concern because they required 100% perfect operation. Nightingale asked if the tempering valve would increase heat loss rate and diminish savings. Hall answered yes but it’s small. Keeling agreed.

Quentin Nesbitt, Idaho Power, asked if it is approximately $20 to add controls to a HPWH would it not be similar cost to add control to a standard water heater. Harris answered that it’s a different bundle that would cost in the $100s.

Heutte added that customer acceptance may be a market barrier. He then pointed to three value streams HPs deliver: energy efficiency, DR and other grid services like frequency response. He called this last stream a potentially big impact that has not yet been monetized. Heutte then stated that a new gas peaker is about $125/kW-yr while HPWH are about 20-25% of that, meaning DR could drive the business case for significant scaling.

Piette called the CTA 2045 a neutral dongle interface but said deciding what signal to send to that platform and the logic needed to respond to that signal the real work. Keeling agreed, noting that the connectivity of a water heater is harder than that of a thermostat. Harris agreed and noted that this doesn't address the utility, grid-side communications mode. Harris recalled that the BPA/PGE study used FM radio signals but CTA 2045 is neutral and can use many approaches but manufacturers are concerned with the command structure.

BREAK

DR Barriers

Haeri asked if the group will cover market and economic barriers today. Jayaweera answered that DR Valuation [Slide 2] will cover much of the economic barriers while many market barriers will be covered when talking about Intra- and Inter Agency coordination and Regulatory Requirements.

Keeling stated that [Slide 2] looks like a vertically integrated utility's view of DR and asked about facets like liquidity. John Ollis, NPCC, stated that these classifications are more cross cutting than March's and suggested thinking about it as prep work as the units are intertwined and lead into DR Valuation. He asked the room to add more barriers as the discussion progressed.

Haeri voiced surprise that these classifications relate to valuation as barriers, in his mind, relate to quantity of DR. For example, he pointed to Consumer Acceptance which doesn't change the value but impacts quantity. Ollis agreed but cautioned against getting too far into the weeds.

Pratt asked if Operations Platform under Data Handling is a home energy management system. Jayaweera answered that she was envisioning something on the grid that the utility would connect to but it could be more. Pratt submitted that there may or may not be an associated supervisory platform that potentially runs multiple systems in a business or home. Jayaweera agreed and stated that a utility's AMI system could be part of the data handling perspective and addresses Harris's earlier comments [Slide 3].

Hall called this a multifaceted and complex issue pointing to different sectors with different platforms and protocols for signaling. He then said there are platforms and aggregators on the market who do this already. Hall asked what the result of this discussion should be. Jayaweera agreed that that is the question and stated that it will take manufacturing standards to reach HPWHs, Nest Thermostats and building energy management system which is a barrier.

Hall said there is a difference between barriers and gaps and the residential sphere is dealing with gaps. He admitted the solutions have costs and value to the operator and wondered how time of use played into the equation.

Piette stated that interoperability is important as there are many different architectures for communication and logic layers greatly matter. She spoke of her work with OpenADR signaling and the importance of pointing out the pros and cons of other standards. Piette insisted that there doesn't have to be just one but vendors need to know what their investment in interoperability will look like.

Peck expanded on Hall's comments noting that in the agriculture and industrial segments the communications standards are a phone call or text message. Jayaweera asked Nesbitt for his opinion on communication barriers for irrigation. Nesbitt stated that they use devices on panel that allow communication with the actual pump. He admitted that there are cell phone coverage issues, their AMI is not deployed everywhere and other DR communication issues in general.

King stated that he doesn't know if communication protocols are a barrier but noted that water heater manufacturers do it differently than thermostat manufacturers, so he supported OpenADR. King then stated that homes without Wi-Fi are the biggest barrier.

Hall addressed measurement and verification, noting that verifying large-loads-performance during an event is a challenge. King stated that residential loads require a random control test to do M&V well.

Haeri echoed Peck's earlier comment saying third-party aggregators deploy about 50-60% of DR where communications involve an email. He noted that there are communication barriers between the third-party aggregators and the end-user customers which is a barrier to automated DR. He suggested separating communication as a barrier by these areas.

Heutte stated that OpenADR is a barrier because it's an emerging "situation." He admitted that a lot of DR is deployed with a simple phone call or email and will continue but there is an increasing, diverse set of resources that are monitored electronically. He suggested that this will be a long-standing challenge and we should remain targeted.

Keeling countered that industrial customers with large loads, like waste water treatment plants, have communications issue too. He noted that residential presents a bigger issue due to fixed cost, noting that customers don't buy a Nest to participate in DR. He concluded by saying in AMI the utility is the customer but for DR we are not.

Jayaweera asked if, aside from the NEEA work, there are any activities the region should embark on. Keeling stated that we have to be a part of the conversation around OpenADR. Piette noted three architectures that use OpenADR and as a member of the OpenADR Alliance board she welcomed Northwest input.

Keeling touched on what the DR Summit will discuss. Hall called it a vibrant market that will include battery management, building management and the integration points. Hall pointed to the amount of data AMI generates along with privacy and cyber security issues, noting that BPA will not integrate it inside their firewall. Keeling agreed, noting that architecture is the biggest problem and figuring out where vendors are OpenADR compliant is an issue.

Jayaweera asked what next steps should be. Keeling stated that SmartGrid NW is getting parties in the room to solve the problem consistently and at scale.

King asked if there would only be incentives for equipment that uses certain standards. Hall pointed to contractual RFPs that require OpenADR. Keeling countered that there is no leverage with retail products like Nest. Piette noted that Nest said they would use OpenADR if enough people ask for it.

Heutte addressed security, saying it touches on both consumer and industry acceptance. He noted 30,000 home tv cameras took down a large chunk of the internet last year and devices connected to substations are a pathway of contagion for attacks on the grid. He admitted that this could become a showstopper and hoped to find ways through it. Hall stated that in the future there will be a way to integrate these technologies in the system but first they have to get through NERC standards first.

Industrial Customers of Northwest Utilities: Perspectives on Demand Response.
Riley Peck, Davison Van Cleve, P.C.

Graham Bailey, Norpac Paper, stated he had his first three-hour event for their first DR program and it was successful but pointed to frustrations like startup costs and training [Slide 5.]

Haeri noted that everyone wants to improve economic efficiency, but aggregators [Slide 7] bring value to the table by possibly offering lower costs than the utility. Peck agreed and said he would come back to the topic when he discusses tailoring programs to individual needs.

Bailey added that in his case an aggregator (Energy NW) brought the program to him not the local utility. He then asked why there is no visibility and why we need aggregators in the long term. Peck insisted that he didn't mean to step on anyone's toes and the DRAC's goals are to make the barriers to DR understood. He said for industrial customers with very large loads we perhaps should have an ongoing conversation about direct integration to maximize incentive. Keeling noted that some utilities have these programs.

Nesbitt stated that he takes out the middleman in his programs as they had long-standing relationships with the customer. He said this works well with small customers as well as large ones.

Heutte voiced support for a direct relationship between load and utility but noted that BPA doesn't have a direct relationship with its end-use customers [Slide 8] which is significant for the South of Allston issue.

Keeling asked how many survey participants were direct access customers as PGE has transmission distribution customers that don't also purchase power. Peck did not know and offered to get back to him.

Hall mentioned a pilot that tested incentives, communication devices and customer fatigue and stressed that industrial customers are utility customers first. He stated that a change in load profile matters to the utility. Hall concluded by saying sometimes they work through the utility and other times the utility allows them to work directly with the customer, but their first responsibility is to the utility.

Bailey voiced concern with the lack of transparency needed to get involved with DR. He praised Energy NW's role in aggregating but wondered why he couldn't work with Cowlitz PUD directly going forward.

Zeecha Van Hoose, Clark Public Utilities, said Clark wants to help both customers and Bonneville with load balancing but have no pricing signals in their rate schedule to provide direct service.

Haeri clarified that he is not advocating for aggregators and it is preferable for utilities to have a direct relationship with the customer, however he noted that because they are engaged by RFP, aggregators take away cost uncertainty which provides value.

Eckhart noted that some utilities may have a day or more notice before a DR event and wondered if that would lessen industrial impact [Slide 10]. Peck presumed so but pointed to industrial customers that can work with five- to 10-minute notice.

Henry wanted to tee up the topic of interagency coordination needed when the DR potential is in one utility and the demand for capacity is in another.

Bobby Castaneda, CLEAReasult, stressed that the value of DR to industrial customers transcends dollars made or lost and includes branding, corporate objectives and environmental responsibilities. Peck agreed but called the base cost and benefit the primary driver, speculating that it would be difficult to persuade large loads to take a cut based on soft benefits. Castaneda agreed, pointing to impact on demand charges. Peck acknowledged that should also be part of the conversation.

LUNCH

Barriers to Deal with First [Slide 6]

Eckhart asked regulators in the room how they collaborate between states given that the Seventh Power Plan puts priority on the process yet each state has its own regulatory priorities. Nightingale noted a recent meeting between state regulators. Ollis added that it was robust conversation but admitted that it will be tricky. Nightingale stated that they spoke about distributed energy resources, which includes DR, calling the situation a large puzzle. He was optimistic that the Northwest states could come to some common understandings.

Eckhart noted that some industrial customers have facilities in multiple states which may complicate the process. Nightingale suggested monitoring PSE, calling it a bellwether. He then said he sensed much interest in any least-cost resource, theorizing that DR would fit into the same bucket. He then pointed to a revised IRP rule that will include distributed resource planning and offered to talk off-line.

Ollis asked how to reconcile DR's prudency with its adequacy emergency uses. Nightingale pointed to the stacked benefit potential, which is not as concrete as a power plant but cheaper. He admitted that it would be more difficult to show prudency with emergency-only DR but called it just one piece of the stack. Nightingale then speculated that smart HPWHs, that are engaged once a week or so, would be easier to quantify with a cost/benefit ratio.

Ollis pointed to Plan findings that showed DR is an inexpensive way to mitigate hydro and load risk problems. Nightingale agreed that emergency products have value and asked for more input as he is writing the DER section of the new IRP rule.

Nesbitt pointed to Idaho Power's early DR struggles, commenting that a return on investment makes DR easier to get, particularly for an IOU. He noted direct pressure from the Idaho commission motivated him to get DR when needed. When things changed, he stated, the IRP reflected that putting them at risk of prudency. He stated that his planning IRP is extreme (a 1-in-20-year load scenario with a 1-in-10-year water scenario) to avoid building a peaker. Nesbitt concluded that they were told to keep the resource in 2013 and made a commitment to use it three times a season.

Ahlmaz Negash, Tacoma Power, asked if Nightingale is proposing a DER plan that is separate from the IRP or a modification of IRP rules. Both, answered Nightingale outlining it further. He expected to have something by late next year. Negash asked if it will be descriptive. Nightingale answered that it will be descriptive but not necessarily proscriptive and pointed to a generous comment opportunity.

Henry asked what the system capacity requirements are, like duration of response, which can inform the best resource choice. He suggested a list of DR products. Jayaweera said this will come up during discussions on *ex ante* estimates as they are dependent on DR product definition.

Nightingale commented that if DR is a lower priced capacity option it should be on the table to shave daily peaks. Ollis strongly agreed, saying it's tricky to know if DR is economic and asked Hall his opinion. Hall pointed to issues in what you can and cannot call a resource and arbitrage but said DR stands on solid ground when it comes to reliability. Hall noted that hydro's flexibility has provided leeway in the past but is now squeezed. He said breaking the code between agencies and balancing authorities is full of challenges and opportunities.

DR Valuation [Slide 10]

Henry commented that elsewhere, organized markets provide a clear capacity requirement, which is not the case in the Northwest and suggested crossing it off the list. He did say that if EIM participants had to identify their peak capacity source it might make DR more valuable. He then addressed transferring between utilities or BAs, saying he thought you can transact DR using WSPP Schedule C. Ollis agreed that WSPP allowed the exchange of similarly-shaped products but pointed to challenges within the organization that might put up barriers.

John Steigers, Energy Northwest, interjected that hour-ahead and day-ahead products can probably be accommodated BA to BA but in-hour, fast products cannot within the rules. He asked if the region needs or wants fast products locked within one particular BA.

King stressed the importance of knowing a defined need and stated that markets allow DR to bid against other products to some extent. He cautioned that markets sometimes make it hard on themselves by defining products as 12-month, 24-hour product which excludes DR. King called a forward capacity market a mixed blessing as much can happen three to four years out while there's no incentive to reduce capacity in that first planning year. He stated that a vertically integrated environment is more flexible. He concluded that as a market participant he likes a predictable, ongoing, real-time market over future bids.

Nightingale noted that PSE's IRP is looking for long-term resource that ramps up to 2021 as opposed to an emergency resource. Kiley Faherty, Puget Sound Energy, agreed.

DR Definition

Hall offered that reliability is an important need that often can't be monetized [Slide 3]. Tracy stated that we must know for whom DR is cost effective. Peck stated that for it to work DR has to be cost effective for the utility and the utility customer along with other stakeholders. Tracy speculated that those would be different numbers. Peck agreed.

Mike Hoffman, PNNL, observed that unless you have a market there may be a variety of decisions.

Steigers countered that it only has to be cost effective to the entity paying for it. The end user, he said defines what they need and what it's worth and everything flows from that point. Steigers called it nonsensical to think anyone else would set the price, even if there is a top-down regulatory mandate.

Eckhart stated that energy is an open market and suspected the same will happen for DR, with different prices.

Nightingale responded to Steiger's comment, saying that small, individual customers don't have price power so it could create a monopoly situation. He stated that WA doesn't have a DR mandate like OR or CA but they are looking for least-cost solutions.

Nightingale expressed his views on the second sentence of the Proposed Definition [Slide 4] calling it more about context than definition. King argued that the second sentence should remain, pointing to past judgements about the importance of third-party-driven service. There was back and forth wordsmithing between Nightingale and King.

Peck agreed with Nightingale's point that the technical definition of DR doesn't include an incentive structure but practically speaking financial incentives are a critical part of a policy definition and advocated leaving it in. Nightingale restated that cost effectiveness has nothing to do with the definition and there's a difference between the business case and what DR is.

Peck voiced support for the first definition [Slide 4] as it doesn't mention cost effectiveness but recognizes an agreement between parties that could potentially be financial.

Heutte noted that the DRAC has been talking about this for a year and this sounds like it was written by committee. He suggested leaving [Slide 4] as a directional definition and coming back to it in a year. He then asked if "potentially financial" is an exchange of money or value.

King suggested adding the word "voluntary." Ollis discussed the history of the Proposed Definition.

Tracy restated that the DRAC has walked around the "cost effective for who" question, noting that if DR is a resource the original Act says it must be cost effective. Ollis agreed, noting the careful wording around DR as a resource or a reserve in the Seventh Power Plan. Ollis noted that DR does provide value for the region.

Frank Brown, BPA, noted that the Plan counts TOU as DR and asked if the Proposed Definition allows that. Ollis recalled that non-firm DR was not included as potential in the Plan but TOU would be because it's an agreement. Brown then said timeclocks set to the same commands all year can be a very effective, low-cost DR measure, asking if "non-persistent" exclude such measures. Ollis stated that the concept behind non-persistent could be repetitive. King suggested "limited duration" as alternative language. Negash also wondered about the exclusion of TOU rates and didn't agree with Ollis' explanation that "by an agreement" covered it.

Heutte pointed to CA's efforts to include TOU rates by 2019, again stating that this definition should be neither perfect nor permanent. Brown preferred "limited duration" over "non-persistent" calling it a stretch to count TOU rates as an agreement.

Nightingale suggested beefing up the alternate definition [Slide 5]. Steigers suggested some changes: remove "temporary" add the word "intentional" and the change is "within a prior agreement" which would encompass TOU.

Jayaweera did not agree that normal means historical and future as EE changes historical patterns and becomes the new normal. Steigers stated that it's a change from what's going on right then. Ollis made changes to the slide.

Van Hoose suggested the word "transactive." Hoffman countered that "transactive" might not be well defined.

Steigers addressed cost effectiveness, saying the principal is encompassed in this definition with the word “agreement” [Slide 5.]

Peck noted that, as this definition is intended to inform the next Plan, it would be wrong headed to leave out policy reasons that customers would consider when engaging DR. He acknowledged that you could have DR without a financial transaction, but you have to give customers something in this definition if you’re trying to encourage widespread adoption.

Keeling noted comments about pursuing opt outs for TOU rates and strongly suggested the definition include something about them.

King suggested more wordage.

Bo Downen, Public Power Council, suggested making it clear that this is a working definition. Keeling suggested using “load shape” instead of “energy usage.”

Ollis added “or tariff” to [Slide 4.]

Eli Morris, PacifiCorp, agreed that the second definition doesn’t have the TOU piece.

Downen wrote via Chat, “It seems that the discussion around resource/reserve is critical in defining DR, or at least an acknowledgement that it sometimes operates as both. If we are attempting a "definition" a partial one that passes as the DRAC's official definition could create problems in the future. If not a perfect or permanent definition, why not make it clear that this is the working definition.” Ollis stated he was hoping for buyoff on this and suggested tabling the topic for now.

BREAK

Ollis presented a hybrid definition [Slide 6]. Heutte said this definition misses the intentionality piece and again suggested calling this a working definition and coming back to it. Steigers agreed that this document is close enough for a working definition.

Regional DR Ex Ante Savings
Jennifer Light RTF Manager/Chair
Greg Brown, RTF CAT

Eckhart asked if the RTF put out a paper with ex ante assumptions [Slide 2]. Jennifer Light, RTF manager/chair, stated that the RTF has done nothing with DR yet but there are DR supply curves for the Seventh Plan that could be built on for the Eighth.

King asked if [Slide 4] is to be applied to everyone noting a 16% difference between competing companies on the east coast which downgraded everyone else. Brown agreed and said it will be discussed in a few slides.

David Lowrey, Comverge, asked if [Slide 5] represents a 24-hour period. Brown answered no, this is a per-participant estimate focused on a per-hour with a focus on duration. Lowrey referenced an issue in CA that averages savings from 1 to 6 pm, noting that not all programs fit within that timeframe and are de-rated. Brown agreed that duration, time of day and time of year should be in the parameters.

Hall commented that this looks like a large sensitivity analysis. Brown agreed noting that a large data set would be needed.

Louie asked, via chat, is it savings or load shifting. If you don't heat now generally you have to heat later. Brown said this gets to the net energy point [Slide 4] and there is interest in exploring that too.

Tracy stressed to remember two time zones when looking at hourly data. Keeling wondered if there would be a strawman as the table would likely be huge.

King noted that differences in weather will keep some studies from being helpful [Slide 6]. Brown agreed, saying ongoing data collection strategies would help tailor the data to the region.

Louis chatted that Ecobee and perhaps Nest gives users the chance to donate their data and wondered if it was available [Slide 7.] He wondered if it would have to be time synched with energy consumption data. Keeling strongly cautioned against using thermostat data on its own for heating as it can be off. Brown said he hasn't yet reached out to manufactures.

King offered to share curves of what's available by temperature [Slide 8.] Brown thanked him calling that helpful. Lowrey noted that temperature setbacks and cycling are always in play. Brown agreed.

King wondered if this is looking at individual customer response as aggregators often influence persistence and duration. Brown agreed noting the desire to incorporate gathered data into quantified measure parameters. King voiced concern about projecting a number that another entity can use after his company spent millions of dollars on algorithms and processes. Brown called the point fair.

Jayaweera wrapped up the meeting asking if a meeting in early September and December works. There were thumbs up of approval. Jayaweera offered to send out Doodle polls and suggested agenda topics like the template, barriers, the PGE/BPA pilot, working with a BA versus an aggregator and defining different DR products.

Jayaweera ended the meeting at 4.

Attendees on Site

Tina Jayaweera	NPCC
John Ollis	NPCC
Jeff Harris	NEEA
Rob Pratt	PNNL
Riley Peck	Davison Van Cleve, P.C.
Robert J. King	Whisker Labs
Tom Eckhart	UCONS, LLC
Bryce Yonker	Smart Grid NW
Bud Tracy	Consultant (Idaho)
John Steigers	Energy Northwest
David Nightingale	WA-UTC
Fred Heutte	NW Energy Coalition
Bill Henry	EQL Energy
Adam Schultz	ODOE
Lee Hall	BPA
Hossein Haeri	Cadmus
Shauna McReynolds	PNUCC
Josh Keeling	PGE
Ahlmaz Negash	Tacoma Power
Mike Hoffman	PNNL
David Lowrey	Comverge
Susan Frisch	Snohomish
Greg Brown	RTF CAT

Attendees via Webinar

Graham Bailey	Norpac Paper
Bo Downen	Public Power Council
Bobby Castaneda	CLEAReasult
Edward Louie	OSU Energy Policy
Elizabeth Osborne	NPCC
Frank Brown	BPA
James Gall	Avista
Kevin O'Meara	Public Power Council
Kiley Faherty	Puget Sound Energy
Kyla Maki	Montana Department of Environmental Quality
Lakin Garth	Cadmus
Mary Ann Piette	LBNL
Megan Stratman	NRU-NW
Eli Morris	PacifiCorp
Quentin Nesbitt	Idaho Power
Will Price	EWEB

Rob Diffely	BPA
Doug Sansom	NRG
Stuart Schare	Navigant
Tony Usibelli	WA-Commerce
Trent Hardman	
Wade Carey	BPA
Zeecha Van Hoose	Clark Public Utilities