<u>Avista 2023 Electric IRP Meeting Notes for TAC 1 on December 8, 2021</u>

Participants: Andres Alvarez, Creative Renewable Solutions; Andrew Artsinger, Tyr Energy; John Barber, Customer; Shay Bauman, PCU; Shawn Bonfield, Avista; Joni Bosh, NWEC; Tamara Bradley, Avista; Annette Brandon, Avista; Michael Brutocao, Avista; Kevin Calhoon, Tyr Energy; Terri Carlock, IPUC; Travis Culbertson, IPUC; Corey Dahl, PCU; Michael Eldred, IPUC; Ryan Finesilver, Avista; Damon Fisher, Avista; Grant Forsyth, Avista; James Gall, Avista; Amanda Ghering, Avista; John Gross, Avista; Josh Haver, IPUC; Lori Hermanson, Avista; Joanna Huang, UTC; Fred Huette, NWEC; Clint Kalich, Avista; Rick Keller, IPUC; Kevin Keyt, IPUC; Scott Kinney, Avista; Mike Louis, IPUC; John Lyons, Avista; Stuart McCausland, Tyr Energy; Jaime Majure, Avista; Heather Moline, UTC; Mike Neher; Elizabeth Osborne, NWPCC; Tom Pardee, Avista; Jennifer Snyder, UTC; Darrell Soyars, Avista; Dean Spratt, Avista; Art Swannack, Whitman County Commission; Gavin Tenold; David Thompson, Avista; Dave Van Hersett, Customer; Katie Ware, Renewable Northwest; Marissa Warren, Idaho Office of Energy; Amy Wheeless, NWEC; Richard Wilson, Tollhouse Energy; Jim Woodward, UTC; Yao Yin, IPUC; and one unidentified caller.

Introductions, John Lyons

Heather Moline: Have you considered how to get these meetings out to a larger group?

John Lyons: This is a technical group by membership. All that it takes to join is a request to be added but it typically includes folks more deeply involved that have a technical background.

2021 Action Item Review, John Lyons

No notes beyond slide deck.

Summer 2021 Heat Event – Resource Adequacy, James Gall

Fred Huette: I'd never heard of CEATI but looks like they've been around for a while. Has Avista been involved with them before?

Scott Kinney: Our hydro engineering group has been involved with this group for at least a decade.

David Thompson: We've been involved as a member for 15 years for asset management and other areas. It's a research sharing organization (regional). CEATI is similar to EPRI. A lot of the research is done through third party researchers whereas EPRI does a lot of the research/analysis in-house.

Art Swannack: My only comment on valley temperatures versus the airport is to remember there wasn't a lot of people in the Spokane Valley until the 1970s. A lot of that area was orchards/fields. Cold air sinks so may not have been warmer in the valley. Would needs lots of data to verify.

Clint Kalich: Thanks Art for the comment. I believe the point of measurement in the 1960s was the Spokane Airport west of Spokane. But if still the point of measurement was Felts Field, it could be as you suggest. Does anyone know when the Spokane Airport was the point of record? I'm thinking it was pre-60s. [Airport change was 1947].

Fred Huette: Was there enough load loss to make enough difference to push the peak load to Wednesday?

James Gall: Wednesday very few customers out [context: at the same time]. Not enough out on Tuesday to push the load up. David might be able to add some context in his presentation.

Scott Kinney: We made appeals to customers to conserve. I don't think we did this on Wednesday with temperatures declining. And we had a large industrial curtail that helped as well.

Yao Yin: In terms of planning for new resources is the net peak or the absolute peak hour that we care about?

James Gall: Good question. I see that type of planning in California at least for solar. Plan for peak net of solar. What really should be done for planning is to plan for a peak and then LOLP randomized based on likely production curves. In reality, it nets those peaks off. Both should be done for planning. Customer solar should be netted out as well.

Yao Yin: For peak data that we're seeing, the orange line is non-customer solar.

James Gall: Correct.

Yao Yin: Is it possible that if the peak is met, the net peak is not met?

James Gall: I think what can happen is that there's so much solar that the peak gets shifted to another hour and you didn't plan for that. That's something you need to look for. We do a test to make sure the amount of solar from the customer's side doesn't shift our peak. I don't currently see a risk of that on our customer side unless solar penetration is over the 200-300 MW range. In the future, we could see that peak shift, but it should be accounted for in the ELCC calculation if it's done accurately. ELCC would measure each resource's ability to meet sustained peak. We'll talk about this more later today.

Fred Huette: What data do you have on residential AC (air conditioning) penetration? There's been a series of heat waves in Portland, and beginning in Seattle, so we're seeing changes in behavior.

James Gall: Avista contracted with Bidgely who takes AMI data to estimate several end-uses including AC. Something that we could look at in the future.

Jennifer Snyder: NEEA is conducting a multi-family building stock assessment that UTC Staff encourages Avista to participate in.

Lori Hermanson: Thanks Jennifer. We have typically participated in these building stock assessments in the past. Our EE group leads these efforts as opposed to our planning group.

Gavin Tenold: Why not a 10-year average?

James Gall: Regarding the 10-year average, that is definitely an option, as well as using forecasted temperatures. We will continue to monitor. I will defer to Grant Forsyth if he has any other concerns with a short-term view

Summer 2021 Heat Event – Feeder Outages, David Thompson

Art Swannack: Any indication of increased business use of AC due to heat safety rules from L&I?

John Lyons: Art, that is an area where we don't have good data on – commercial and industrial AC use.

Fred Huette: Never heard of a mobile substation, can you describe this?

David Thompson: It is a trailer-based transformer, circuit breaker and other components. We have two trailers available for service at the moment. Can be transported in and connected to provide enhancement. Connected overnight. We require a 4-hour outage before dispatch and there may be some staging.

John Gross: General rule of thumb is about 24 hours from being notified and mobilized and connected. Even 24 hours would be quick. If feeders have capacity, we'd use those. Typically, in these heat events we don't have feeder capacity and that's why we bring in these mobile options.

Rick Keller: When you balance the feeder, is that a manual or automated process?

David Thompson: It is a manual process to identify where the imbalance is and to connect that to a different feeder.

Rick Keller: On slide 7, can you provide more detail around the cooling non function?

David Thompson: The fans have several cooling alarms or levels of alarms. There are 16 fans and they ended up replacing four. The problem was rectified within a short period of time.

Rick Keller: If you see a trend where you will experience high temperatures, will you review fans to ensure they're operational.

David Thompson: We cover lessons learned at the end.

Rick Keller: Is there a long-term impact to the transformers?

David Thompson: Operational concerns of operating in high temperatures and its impacts to the health of the equipment. These steps we're putting in place are to protect the equipment from failure or degradation. Still safe operating conditions based on the manufacturing information, but we still note it for a health index of the assets. The ideas of alarms and dropping of load is to protect the equipment.

Art Swannack: Are you looking at higher quality equipment design (bushings, etc.) to decrease future problems?

David Thompson: Always looking at best available equipment. This information is captured from asset management equipment health.

John Gross: Of the breakers that had bushing issues, newer equipment performed better.

Fred Huette: Do you have an estimate of the loss of load for outages mentioned on slide 16?
David Thompson: We do not.

Fred Huette: The main reason I'm wondering, is there really a significant change in peak load. Realize it's not easy to project.

David Thompson: It'd take some projections because this occurred while loads were increasing.

Fred Huette: Thank you for making this presentation. We're learning important lessons. Gas plants don't perform well in high heat.

Gavin Tenold: What is the average age of your substation transformers?

David Thompson: I will look that up and put the answer in the chat.

Fred Huette: If you could also give a rough estimate of expected life of that? I think what we're seeing here is that the equipment is generally older than the average life.

David Thompson: I'm pretty sure that that is where ours will fall, but I'll get those numbers and post them in the chat.

David Thompson: (in chat) Going back to the transformer age question: Typical manufacturer specifications stipulate a 30-year life based on nominal loading. That spec is generally reduced to 20 years if operated at full nameplate capacity 24/7. Avista's approximate population age is 38 years with a range of about 80 years.

NW Power Pool Resource Adequacy Program, Scott Kinney

Mike Louis: Please provide an example of conditional firm transmission referenced on slide 9.

Scott Kinney: Close to firm but not quite so it allows for curtailment. Firm, you can only curtail due to reliability. A little bit less reliable product that you can buy.

Joni Bosh: What documents will be used to create financial settlements – e-tags?

Scott Kinney: Will utilize e-tags on a delivery basis. On a day-ahead hold back, the operator will have record on that to determine payment.

Joni Bosh: Can the nominating committee nominate non-utility reps to the Board of Directors?

Scott Kinney: Yes, it is an independent board so it could. They'll be some structure and requirements.

Resource Adequacy Program Impact to IRP, Michael Brutocao

Yao Yin: Could you explain why this operating reserve credit is not included?

James Gall: The operating reserve credit is hydro capacity capable of delivering reserves that we have not included as firm energy on the resource contribution. Since the new planning margin captures operating reserves and the QCC captures the unit's capability to provide energy, including this additional value would be double counting the available capacity.

Michael Eldred: What caused the planning margin difference between the 2021 method to the RAP? The 7% to the 12%.

James Gall: When looking at the regional footprint, there's a summer and winter contingency of participating utilities.

Scott Kinney: That's exactly right. We're more of a winter peaking, but when looking at the region as a whole, we're more dual peaking.

James Gall: I'd argue this is similar in total. The big savings is in the winter and that step change is helped by the diversity of the region and driving the biggest benefit for Avista as far as the amount of capacity we'll have to acquire.

Michael Eldred: On the QCC, is that capacity credit for this new RAP service territory?

James Gall: It's Avista system specific.

James Gall: Peak credit in previous methodology and it was Avista only. In this case, the QCC will be calculated for each resource in the system based on methodology for the various zones/type.

Michael Brutocao: These are the values the RAP can count on.

Scott Kinney: RAP methodology we've agreed to based on Avista resources.

James Gall: Newer resources, such as storage, we're still trying to figure these out.

Scott Kinney: The program operator will be monitoring and making those changes on a continuous basis, every other year or maybe annually.

Joni Bosh: On the draft, this slide had less detail.

Michael Brutocao: It was a poor example of me trying to explain how these values were calculated.

James Gall: We updated that it was storage hydro resources and other types of resources. **Scott Kinney:** We do have Mid-C contracts – the PUDs will have their own QCC values and based on our percentages. We'll apply that to these values.

Mike Louis: Is that the L&R?

James Gall: Yes, from the last IRP adjusted for the RAP. Does not include changes to the load forecast that we provided to the IPUC since the last IRP.

IRP Resource Adequacy/Resiliency Planning, James Gall

James Gall: Credit to DER? Should we plan to no more than a 3-hour outage? What belongs in the IRP? Should we pay extra for resources that can provide a certain amount of resiliency?

Mike Louis: Special cause variation – response time, can build yourself out of those situations because it's too costly. Common cause – occurs frequently and things you can build for. I think that's helpful in evaluating this.

Jennifer Snyder: I'd love to hear from Avista customers on this.

Annette Brandon: Jennifer, we have a team set up that is already working with customers on customer resiliency. In the context of the CEIP we also plan on discussing with the EAG again in the context of our CBIs.

Mike Louis: Can probably deal with a certain amount of special causes, but I don't think you can build yourself out of these situations.

Gavin Tenold: Is the CETA reference to 1 hour planning available? Where is this cited in the statute?

James Gall: I don't recall there being a 1-hour reference. The rules don't yet say you have to do 1-hour planning. There was a workshop about what it means to plan the system to meet its load. One option is that we'd have to show from a modeling view that we're capable of providing this on an hourly basis. This is still being refined but one option that the Commission has set out there so far.

Shawn Bonfield: The draft rule is not finalized or adopted. Regarding the draft CETA rules discussed, here is a link to the WUTC docket where they are working on the rules: https://www.utc.wa.gov/casedocket/2021/210183/docsets. If you scroll down to November 10th, you will see a Notice of Opportunity to Comment along with the proposed draft rules being considered.

Joni Bosh (in chat):

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Proposed rule: WAC 480-100-650 Reporting and compliance.
(1) Resource acquisition and compliance. Using electricity for compliance under R
CW 19.405.040(1) and RCW 19.405.050(1) means that a utility:
(a) has acquired renewable and nonemitting resources to meet
its retail electric load, and
(b) can demonstrate compliance as required in subsection (2)
of this section.
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Mike Louis: How do we measure resiliency performance?

James Gall: Metric for distribution.

Scott Kinney: They monitor some other industry metrics but beyond those IEEE metrics, I'm not sure.

Heather Moline: The ability of the bulk power system to meet capacity (resiliency always a response to a very specific event – fire, etc). We're used to thinking of power supply as the average customers versus those having a harder time. I think we should consider resiliency as a local phenomenon.

Michael Eldred: Using Plexos for risk assessment - can you explain this further?

James Gall: Plexos is a power supply model that dispatches resources to load. We'd run that model stochastically – vary load each hour and generation potential, and randomize inputs impacting generation. The result would be the amount of hours and MWh above load, this would measure the market risk we have in extreme hours even though we would be resource compliant. This test would also validate if we need additional transmission, or if we should acquire additional generation to lessen this market risk.

TAC Survey Results and Discussion, Lori Hermanson

Lori Hermanson (Slide 3): 53% no to two TAC tracks.

Lori Hermanson (Slide 4): 50% in both tracks and 38% in technical only track, so 85% total. Based on this we will continue the single-track TAC path we have been using.

Lori Hermanson (Slide 5): 69% prefer about 8 meetings of no more than 3 to 4 hours. You'll notice that the Work Plan later has 8 meetings of about 4 hours with lunch.

Lori Hermanson (Slide 6): More data, document and chapters provided. Are there more topics or areas? Couple: resource adequacy, reliability, climate change, and T&D. These items are included in one agenda item or another so many are already discussed, such as DER today.

Lori Hermanson (Slide 7): Additional data about right. One person asked for an additional chart for each strategy, updated climate modeling, hydro area studies and will be included. Regional western effort for resource adequacy will change IRP process to match it. To comply with Washington law – focus on low cost. Modernize with WISDOM-P. We are evaluating more models all the time. Energy Exemplar's Aurora and Plexos enhancements to DER, storage, etc. Draft info in 2022. Utilize existing biomass – upgrade for KFGS and responses to IRP.

Lori Hermanson (Slide 8): Last TAC was different with an after-hours TAC meeting geared towards customers. Several hundred RSVPed and over 100 participated. The top two ideas for improvement included better utilizing the IRP web site and informational invitation. Newspaper articles and input from actual customers rather than from outside the service territory.

Lori Hermanson (Slide 9): 2021 process – detailed, appreciated the difficulty involved with two states. Increased transparency and breaking down technical/complex issues. Remote meetings and format.

Lori Hermanson (slide 10): Improvements. Maybe summarize them. Energy Exemplar's database – whole new section of available storage options with costs.

Gavin Tenold (chat): Would we be able to get some data, and details on Exemplar's updates as they relate to how Avista plans to consider DERs?

Lori Hermanson: Yes, we'll be presenting on resources that we'll be evaluating. It'll be covered in a future TAC meeting.

Gavin Tenold (chat): Thank you, it would be nice to learn in some detail about the tool's updates to DER planning.

Washington State Customer Benefit Indicators, Annette Brandon and James Gall

Heather Moline: Of all the renewable energy, about 10% is in those named communities.

James Gall: 10% of retail sales was met by non-emitting or renewable resources in named communities. You'll see this percentage grow because we started this in 2016, but didn't include the cumulative impact of energy efficiency already online so this is understated.

Joni Bosh: Cumulative number?

James Gall: Cumulative for energy efficiency since it's still online, but not for generation – it's the production for that year.

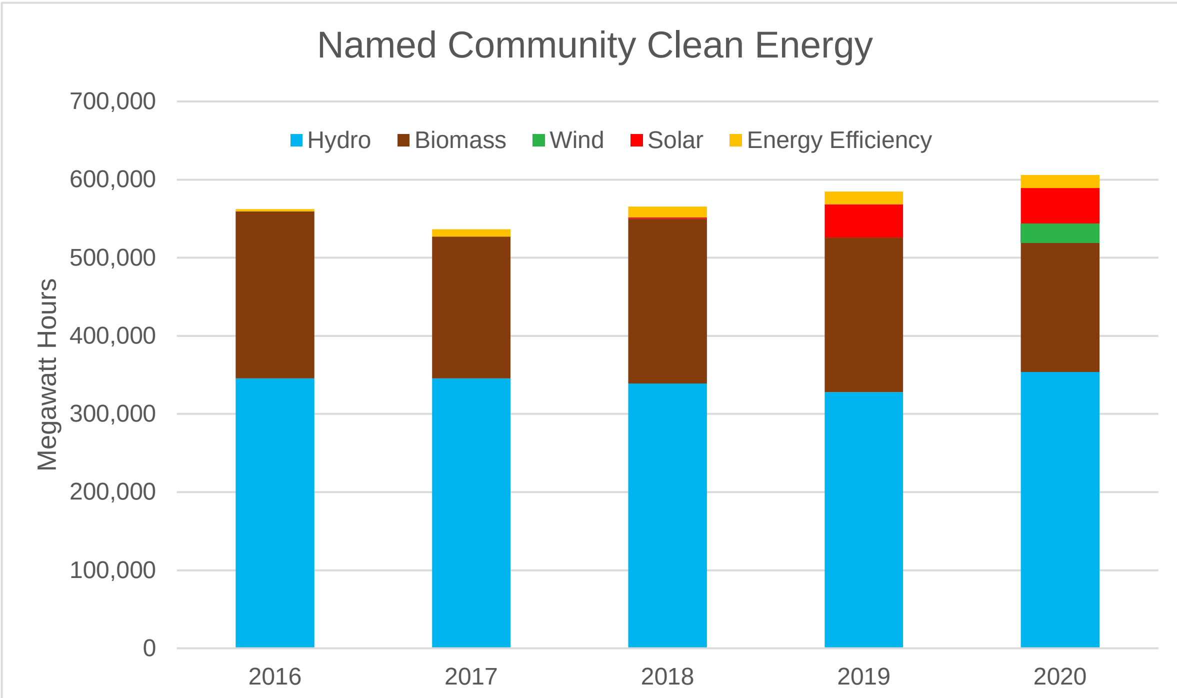
Joni Bosh: Drop from 2016 to 2017?

James Gall: I think it was hydro conditions. I'll look it up and validate that [Results show it was less generation from Kettle Falls].

Joni Bosh: Located in named communities – is it mostly hydro?

James Gall: Hydro, biomass, wind in named communities; maybe that's an enhancement we can make. The chart below includes the requested data from the question in the meeting of generation types in named communities.

Annette Brandon: Rattlesnake Wind was only online for half of December so this will go up in 2021.



Joni Bosh: If these are located in Washington, are they dedicated to Avista customers?

James Gall: Yes, we're using them for our load but if there's excess, we sell it. Our system is energy long so a portion will be sold to another entity.

Annette Brandon: If it's close to our house, we're more secure based on customer feedback – easy for them to understand and for us to measure improvements

Joni Bosh: The rules for your CEIP are CBI values or indications that it wasn't applicable to that resource selection. You may need to include a narrative about how affordability was impacted by this resource selection. I think the "why" is the most important. Narrative on how the CBIs relate to that choice rather than check, check, check. I think this should be applied to all resources not just energy efficiency.

Heather Moline: We noticed nothing about DERs (distributed energy resources) beyond energy efficiency.

James Gall: Modeling local solar doesn't do much in our service territory. Implicit opportunity cost conversation could be done if you can't quantify the impact.

2023 Draft IRP Workplan, John Lyons

Michael Eldred: Portfolio optimization, will it be the same as the last methodology as the last?
James Gall: Yes, unless there's a new cost allocation methodology developed first.