Participants:

John Barber, Customer; Shawn Bonfield, Avista; Tamara Bradley, Avista; Molly Brewer, Washington UTC; Terrence Browne, Avista; Michael Brutocao, Avista; Logan Callen, City of Spokane; Katie Chamberlain, Renewable Northwest; Josie Cummings, Avista; Corey Dahl, Public Counsel; Kelly Dengel, Avista; Joshua Dennis, Washington UTC; Mike Dillon, Avista; Chris Drake, Avista; Michael Eldred, IPUC; Ryan Finesilver, Avista; Damon Fisher, Avista; Grant Forsyth, Avista; James Gall, Avista; Amanda Ghering, Avista; John Gross, Avista; Leona Haley, Avista; Lori Hermanson, Avista; Mike Hermanson, Avista; Jackson Parthasarathy, Grid United; Mary Kulas, White Gull Analytics?; Mike Louis, IPUC; John Lyons, Avista; Patrick Maher, Avista; Heather Moline, Washington UTC; Thomas Morrissey, NWPCC; Tom Pardee, Avista; Lloyd Reed; John Robbins, Wartsilla Energy Solutions; John Rothlin, Avista; Jennifer Snyder, Washington UTC; Dean Spratt, Avista; Lisa Stites, Grant County PUD; Brandon Taylor; Tyler Tobin, Puget Sound Energy; Yao Yin, IPUC

Introduction, John Lyons

John Lyons: I'm John Lyons with Avista's Resource Planning Group. Welcome to our third Technical Advisory Committee meeting today. We'll do a brief introduction, then we'll get into a review of the January cold weather event, then the wholesale natural gas and electric price forecast, and then we'll end with the discussion on portfolio and market scenario options that we're planning on looking at. We had some discussion here early on in this 2025 TAC process and a lot of the feedback that we got was that it's an awful lot of information that we're going through and members would like some time to process it and work that out in their mind. The thought was if we have more frequent TAC meetings that are shorter, that will keep people more involved with the process, but also, we will try to focus on just one or two key items.

John Lyons: We also, if you'll notice when I send out the email with the slide deck, we're trying to put on the key questions we're going to be asking you so you can start thinking ahead of time the ideas we would like to discuss. We will still take comments afterwards, if those come to you later. Also want to do a quick reminder, we have our DPAG [Distribution Planning Advisory Group] meeting next week that's on the 27th and that's going to be on EVs and solar in particular. If you're interested in those topics, be sure to call into that. If you're not on the DPAG, you can contact me, and I'll get you in touch with that.

John Lyons: Also, a lot of the data that we're starting to share is already out on the Teams site for the IRP. One thing we are asking if you go out to the Teams site, let us know if you're having problems pulling that data because we did receive a notice that there are some potential security issues and they might be locking some of that up, but so far it looks like people can still access it, but if they're not able to, please let us know.

And then we would just go back to posting that on the website and after that part of the today's agenda, we do have the remaining TAC meeting.

John Lyons: Starting April 9th, will be every two weeks, with the exception of the Fourth of July weekend, and got those on there. They're also posted on the website, and you can see the topic. Next time we have future climate analysis and the economic forecast and the five-year load forecast. We also have the technical modeling workshop on June 25th. That is the only one that I haven't sent the meeting notice out yet, because I didn't want to hit everyone with too many meeting notices all at once. I'll be sending that out soon. August 13th will be the last TAC meeting for this series, this every other week schedule. We will release the draft IRP September 2nd and the final IRP January of 2025.

John Lyons: And then we also will have a couple of public sessions where we'll have a recorded presentation and then we'll have a daytime and an evening time period for comment. That's all I've got for the introduction, unless there's any questions. Hearing none James, do you want to take it over and start sharing the load event presentation?

<u>Review of January Cold Weather Event, James Gall</u>

James Gall: Do you see my slide?

John Lyons: I do.

James Gall: OK. We're in good shape then.

John Lyons: Hopefully someone outside of Avista can see that as well.

James Gall: Hopefully. Usually that's the case. Good morning everybody. The MLK weekend weather event. I'd say it's kind of the canary in the coal mine event for the region. The reason why I say that is I think that's the closest our system in between Avista and the region has been from not meeting loads. Actually, Avista did have to curtail some loads which I'll get to in a little bit. But it shows the dire need of resource adequacy in the Northwest. We'll go through some Avista's experiences.

James Gall: We had some very unique experiences during that event compared to the region Feel free to stop me as I go through this. If there's a question that comes up, there's your hand. I'll probably see that, or Lori or John might see it as well, and we can pause. Or go ahead and put it in the chat and that works as well. I'll getting started.

James Gall: This is just to give you an idea of the temperatures that we experienced on January 13th. These are the low temperatures. Spokane, which we typically plan for, we were minus 10 at the airport as a low. Our high was minus four, maybe minus two. Parts of our service territory got in the minus 20s, minus 28 down in Lewiston, or Sandpoint area minus 17. We saw extreme temperatures during this event, and this was, I would say, very similar to an event we had a year ago on December 22, 2022. We saw almost identical low temperatures and very close to the same high temperature. So, we saw two of these events in the winter in a row, but we actually saw different outcomes in load and also in performance.

James Gall: We'll get to the performance of the gas system in a minute. This chart represents our loads and resources, and this is what we're trying to balance. If you want to relate this to an IRP, this is the best illustration because the IRP is trying to plan our system to meet this type of an event and the black line on this chart represents what our actual load was. During this event, we had our highest load on the 13th, which is a Saturday, which is typically uncommon. But right here in our 18, in this black, dotted line represents what the load would have been if we did not have to curtail some of our industrial customers. One was voluntary, one was involuntary, and what I mean by involuntary, we had a natural gas issue on the GTN pipeline. Upstream of us there were some mechanical problems on a compressor station and that reduced the pressure for the Spokane area. In response to that, two of our natural gas facilities had to curtail, and a substantial amount of industrial customers also had to curtail. And when that happened, one of our industrial customers on the electric side has both gas and electric service had to reduce their loading. I see a hand up by Molly. You have a question?

Molly Brewer (UTC): Yeah, there's the question is, is curtailing like load shedding or what exactly is curtailing?

James Gall: Yeah. Think of his load shedding.

Molly Brewer (UTC): OK.

James Gall: Essentially asking that customer to reduce their demand. One of our industrial customers, we have an agreement to reduce demand and there's a compensation package for that and other customers. If there is a reliability event, there are some agreements to reduce demand in those circumstances. Those are very rare, and this is a very rare event.

Molly Brewer (UTC): OK. Thank you.

James Gall: From that point of view, the red line that's dotted on top represents how much capacity we actually have to hold on our system. Even though our load may have been at the level you see here, we actually have to reserve capacity on our system for that higher amount to meet two critical things. One is operating reserves. Those are reserves that we're required to hold by WECC, 3% of our load amount and 3% of our online generation. Those reserves are required to keep our system stable in the event a unit trips. For example, when we had to bring units down here in the early part of the day on Friday, something has to respond to that unit going down. That's why we hold these reserves and that's required by every generator and load serving entity in the Western Interconnect. The other component of capacity we have to hold is something that is newer to Avista and that is EIM flex ramp. When we participate in the EIM, we actually have to hold capacity on our system to participate in the market. Before EIM, we ran our system as we saw fit. We wanted to hold reserves for our needs, but now we actually have a mandated amount of reserves we have to carry. These two things add up to maybe a couple hundred megawatts between the two that we have to carry in reserve.

James Gall: I'm moving to the resource side. On the bottom we have our Kettle Falls in our qualifying facilities, and black - Colstrip and brown - our natural gas, and yellow – wind, solar is the green, and hydro is in the blue section. How this chart works is if you see colored area below the black line where purchasing power on the market and if we are the color is above the block line we're selling. You can see here, during our peak event when we lost our generation, we had a substantial purchase. When we plan our system and IRP we do expect to rely on the market to a certain amount. It's about 330 megawatts in our planning and we also intend to serve all of our loads. If from an IRP planning type of event, when we model those, we're trying to see what is the probability of a loss of load event? That is a circumstance where you can't serve all of your load with your generation or up to 330 megawatts from the market. This event actually qualifies. This would be a loss of load event in our planning process methodology.

James Gall: This is actually pretty concerning from a reliability point of view because it's starting to show maybe we do not have enough capacity. Going into this event, last IRP, we thought we had quite a bit more capacity than, or I should say we were capacity long I think to about 2035, but there's a few things that have changed since then. One is we are seeing substantially higher loads for this load level for the given temperature. Given that we had the same temperature last winter was around, I believe 70 or 80 megawatts higher at that peak hour, and that doesn't even include some of the load shedding we had to do. So, there has been some load growth, also this EIM flex ramp that we're required to hold that is something we've not really planned for. In the past, we've planned for a lower amount of flexibility. We're going to see in this next IRP, because of this event and we have real data to the look at, we need to start planning for these types of events and if a future occurs like we're we know in 2026, this brown, bar down here, Colstrip is not going to be available to us. How do we serve these events?

James Gall: We call them sustained peaking events and without a stable resource it's going to be difficult in the future to have a reliable system. One analysis I looked at after this event because again this is a low hydro event, high load event with some resource outages that if we even had 10 times as much wind which would be around 1,600 megawatts more of wind and 100 times more solar, say 2,000 megawatts of solar. That's the future we're tracking towards. How do we serve this event with those resources? And really, at the end of the day, it comes down to we need storage assets, but the amount of storage we need is so massive, the service of and I don't know how that's going to occur at least in the next decade. Just to give you an illustration, if the common battery of today is four hours, if we had four-hour battery and the renewable resources I mentioned earlier, we would need 14,000 megawatts of batteries. Now that's more than is on the Western system right now and that's just to serve our load. Long duration batteries is probably where we need to go. If we had 50-hour batteries, we would only need around 1,200 megawatts. But the challenge with that is at 1,200 megawatts at the 50-hour battery, even if we perfectly timed our dispatch, we would have nothing left at the end of this week to serve the next week.

James Gall: The key to have a future, a reliable future with no natural gas or no coal, we're going to need some extremely long duration energy storage facilities. I see a hand up. Actually, I see two hands up. I don't know who is first. Kelly, go ahead and go first.

Kelly Dengel: Yeah, James, thanks. This is Kelly, from Avista. This is just painting the picture of the electric customers and you're not really showing the picture of what the gas customers experienced, right? So just where?

James Gall: That's next line. Yep.

Kelly Dengel: OK, because then this pictures only compounded when you include the gas customers that were affected by outages or the shortage of resources as well. That's all I wanted to say.

James Gall: I'll get into that a little bit. I don't have the amount that had to be curtailed on the industrial side. Our firm customers were not curtailed, but I'll illustrate a little bit of how much equivalent electric load there is on the gas system. I can't see who had the other hand up but go ahead.

Jackson Parthasarathy: Jackson, with Grid United. Nice to meet you. Due to the kind of regional nature of this weather where you have this extreme event that's impacting the whole Pacific Northwest all at the same time creates large hurdles for resource adequacy as you're pointing out here. How do you think about, I guess to take a step back, you were talking about batteries as well and the resource build out of batteries that you might need in order to be able to serve load in such events where gas pressure drops, and gas plants leave the system. Do you think about interregional transmission, and I mean particularly one of our projects proposes to connect Colstrip with SPP and MISO and the ability to import resources from outside of the region. If you could talk a little bit about that.

James Gall: Sure. Actually, that's going to be one of my topics coming up on a couple slides.

Jackson Parthasarathy: OK.

James Gall: But you know transmission is, I'll put it this way, it's an option to help with resource adequacy if you can contract for a resource on the other side and there's been some historical examples of transmission is not a necessarily reliable resource and it can be, if you have differing weather patterns. But if you all have a similar event at the same time, it makes it a challenge to rely on the transmission. The one event that comes back to me was a summer event. I think it was in 2006 or 2007 and the whole West was hot and we could not send power to California or vice versa just because we both had severe events. But if we had contracted resources that we could depend on and we had pretty solid evidence that there is a diversity of resources over there, we might be able to argue there's a capacity value there. But again, do we have a secured asset over there and how much can we really rely on the market? Because even if you go into eastern Montana, which is not far from where you're talking about the wind facilities over there, they were frozen up. They could not produce energy. Is that going to be a similar circumstance in South Dakota, North Dakota? I don't know. It's a good question. I don't have the answer, but it definitely gives you options, I'll put it that way.

Jackson Parthasarathy: Thank you.

James Gall: All right. Just to wrap things up here. Assuming we did not have the loss of gas pressure, would this have been an IRP type of loss of load event. It probably would not have been, we would have been in our planning criteria although we did have higher loads, lower hydro production. Basically, what we're finding in resource planning when we do these analyses, we know it's going to be an event like this where you have high loads or slightly above high loads, low water, and then low renewable production and a unit trips. That's the remedy for having resource adequacy issues and those all compounded together. And this event from a price point of view, when we had to go out and buy replacement power almost this whole week was near $1,000 a megawatt hour at the first cap. This is an expensive event when you don't have resources available and that $1,000 represents the need of the region. And I got a slide a little bit later on that, but also the transmission system to California was on. There's two lines that connect the northwest to California. One of those was down on maintenance and that also made it difficult to move power around. So, there's another example. Can you rely on transmission and that case the PCDC intertie was not available at the time. OK.

James Gall: Into gas really quick. I just want to illustrate the amount of load that's on the gas system versus electric system on these days. As I mentioned earlier, this event compared to last winter was about the same load, but we did have to curtail some generation or some load on this event, that's that red bar there. What we did is convert the electric load to Btus, so we could compare those to the gas load, and this is our firm gas load in Washington and Idaho. You can see our gas load is almost three times as much as our electric load on these winter days. And we also set a winter peak load event for the gas system, but like Kelly had mentioned earlier, if you look at our gas system and you think of a future of we want to move people from the gas system to the electric system. Our loads would be substantially higher. How do we manage that?

James Gall: We've shown that in many scenarios in the last couple IRPs, but the 315 mmBtus use, or thousands of mmBtus, wouldn't quite be that much on the electric side. Electric system is a little bit more efficient, but still maybe 2/3 of that would be electric load and it's just a good illustration of the challenges of electrification of buildings, of the quantity of megawatts of just generation you need, but also how do you deliver that to load.

James Gall: It's a substantial challenge that the region would have if we electrify, and you compare that to our highest summer day. So, on our summer day, which was the Heat Dome event June 30th, 2021, highest peak hour we've ever seen and the amount of load that day though was still less than these events because most of that load was concentrated in the evening where the loads that you have in a winter event are all day long.

James Gall: And just to kind of give you an idea that event was like a 1-in-100 event. Some people may argue these winter event temperatures are not unheard of in Spokane. It was still not colder than our 2008 event, which isn't too long ago. Cold events are often. But when you don't get one, our winter loads don't look very high. But when you get a load event in the winter, it illustrates substantially higher loads. If we didn't have to curtail generation and two customers, our load would have been substantially higher than the most extreme event we've ever seen in Spokane.

James Gall: Just to wrap this up quick, from the regional perspective, this is a similar L&R chart on the bottom left and the pink area is my biggest concern. That's the amount of imports the region had to bring in, this here from the Power Council. The Power Council, I believe plans for around 1,500 megawatts of imports. The region was substantially short, did not have enough generation within its own system to meet pretty much most of the loads from late Friday into later in the week. This is really showing a resource adequacy problem in the Northwest during these events. You can see that in market prices, and also how much units are running, or peaking units are being dispatched more than they have been in decades because there's just not enough energy in the system to continue to meet demand. Demands are growing and we're not building dispatchable generation, so we're starting to see more and more reliance on our natural gas units. And as coal goes away because of lack of reliable generation and then moving to the right is the flow of those imports come from, a lot of those come through California. But my understanding is most of those flows really came from the southwest via California. We also did get some energy from Canada and especially Avista. We did rely on Powerex quite a bit. While our units did trip, so we appreciate their support, but I see Kelly, you have a hand up.

Kelly Dengel: Yeah. James, on the left with the resource stack, I see a tiny little bit of nuclear. Can you explain where that's coming from?

James Gall: Yeah, that's the Columbia Generating Station outside of the Tri Cities, it's around 1,100 MW.

Kelly Dengel: OK. Thank you.

James Gall: You're welcome. OK. Just to wrap things up. Since this is a canary in the coal mine event, what are things that we should be doing in resource planning to make sure we have an adequate system? I have three things in red that we are, I would say mostly going to do, or I should say highly considering. And then there's some other items that maybe we should consider. The first one is, obviously, we're going to update our load forecast with the data from this event. We're working on that this week. Grant has got that nearly wrapped up, but what that will do is show a higher load forecast for winter events in our next IRP, which means we'll have to acquire capacity resources sooner than later. Another thing we're doing is we're including the EIM uncertainty flex ramp in our resource planning. When we do our loss of load probability analysis, we'll include that capacity requirement at the levels we are seeing the EIM asking us to hold. We've always included a requirement for this, but the amounts we're being asked to hold are much higher than we anticipated when we did our last round of analysis.

James Gall: The third item is something that is, I think, a key for reliability. It's, I'd say less static. We call it the single largest contingency. What we mean by that is we should be carrying capacity above our or should say we should have a planning margin higher than our single largest contingency resource, which what that means essentially is if that largest contingency resource tripped, we would have at least enough capacity to cover the expected peak load from our other resources. Since Avista actually has probably the largest single contingency resource compared to its load of any of the control areas, that would essentially make us a little bit longer and likely the summer months is what we're expecting. That change would likely push us into a shorter position this summer as our Coyote Springs facilities is our largest single contingency unit.

James Gall: The fourth item has to do with low hydro years. The region used to always plan for low hydro, but when we started moving to loss of load probability type analysis, low hydro got moved to median hydro. When we got our QCC values for example, that's qualifying capacity credit in our regional resource adequacy program, they typically assume you know more of an average hydro or meeting hydro event, and should we be assuming a low hydro event which means lowering the expectation of our storage hydro units. And I think that has a lot to do with the regional response. We just did not get as much out of our hydro system as maybe we had hoped for from a regional perspective. At least that's my opinion.

James Gall: The next one, should we be looking at something different than 5% loss of load probability? Essentially, when you plan for resource adequacy, a 5% loss of load probably means that you're going to have a loss of load one out of every 20 years and that's kind of what we got here. Is that the right level of planning? Should we be planning for a more reliable system? And I think that might be a question for, even the tag here, is 5% too modest? Should we be more conservative and plan for something a little bit tighter? One percent, 2%? What's an acceptable outage when you're having an extreme cold event? I know there are consequences of losing load, especially when it starts affecting residential customers.

James Gall: Another thing is how much can we depend on the market which is the second to last bullet. We've always assumed around 330 megawatts. We were able to lean on the market for that amount for a short amount of time. That was definitely not something we could have done sustained. As you can see in that week, because the whole region was looking for the market. That goes back to even the transmission as well. We had more transmission. Can we rely somewhat on the market at a higher level and I say those are still questionable. The last one, is doing loss of load probability analysis or looking at statistics, a right way to do resource adequacy planning? Should we rather be looking at event planning where we have a low water year event, we have a low renewable output event with higher-than-average loads? Should we be planning for those events rather than a statistical probability of an event? It starts to make some sense to me to start looking at that. We'll be studying what that looks like in this IRP process, but that's all I have. Are there any questions, comments? Katie, go ahead.

Katie Chamberlain: Hi. I think you may have explained this at the beginning and I'm sorry if I missed it but could you just reiterate what happened with gas on your system? I think on the 13th.

James Gall: Yeah. The late the day before. GTN is a pipeline that we use to buy gas from for our local distribution customers and to supply our natural gas turbines. They had a compressor station issue in Alberta, and they were not able to deliver as much gas as we had requested. So, we had to bring down two of our facilities and then also some of the natural gas transport customers who buy gas on that system in our area also had to reduce their gas usage.

Katie Chamberlain: Got it. Thanks.

James Gall: Yeah. Any other questions? If not, I think I'm going to turn it over to Tom.

<u>Wholesale Natural Gas Price Forecast, Tom Pardee and Michael Brutocao</u>

James Gall: Tom, if you're got your slides ready to go.

Tom Pardee: I do.

James Gall: Yeah, it's all yours.

Tom Pardee: OK. I'll get my ducks in a row here. Share this screen. Pop this up. Hopefully it goes to the right screen. Hey, can everybody see that? OK.

James Gall: We see your North American supply slide, OK.

Tom Pardee: Tom Pardee, I'm the natural gas planning manager in James' Group, in the Integrated Resource Planning Group. One more real quick thing so I can see. OK, so I'm going to go over a fundamental forecast from Wood Mackenzie. These slides will give you an idea of what they're expecting as far as demand and supply within the region and nationally.

Tom Pardee: This slide here is a lower 48, just the continental lower 48 in the United States. What you can see here is the different breakouts for the demand between residential exports, Mexico LNG industrial and where I would point to, there's a couple interesting things in here. So, #1 this plot, the demand essentially is leveling out for natural gas within the mid-2030s time range and then it starts to decrease and I'll go into why that is. And then I'll also show the Pacific Northwest in our mountain regions.

Tom Pardee: Another interesting thing here is they expect blue hydrogen to come on more. Blue hydrogen would help serve this load demand or the fuel demand. Blue

Hydrogen is using natural gas to create the hydrogen, you split it, and then you capture the carbon, and you store it. That's what blue hydrogen is. You can see that little blue sliver here, and if you can see my mouse there it is. By the 2050-time frame, there's I'd say, a more sizable market for blue hydrogen in these expectations. Net Mexican exports. This is exports from the United States and go to the generation plants in Mexico. There's some pipelines and interties that export it down there and they have quite a large load demand with air conditioning and otherwise, that feeds their generation plants. The sizable piece to this is the LNG exports, and for those that follow the market it's comes as no surprise, I believe there's 12 BCF a day of LNG exports is waiting to be built and that's on top of roughly the same amount as of today. And so, LNG exports is really what's driving this demand.

Tom Pardee: Finally, what I'll point out in here, because the other ones are mostly the same. I'll point out here the power demand. You can see power is green and over time it's shifting to a lower demand within the power sector and it's actually more substantial within our region. And like James, please interrupt me whenever there's questions. In order to fill this demand, there's a North American supply. On the chart on the left, this is telling you the region where supply is coming from. Rockies is one region that we get our gas from, and you can see over time that starts to decrease. The Gulf Coast is looking for an increase. Permian is in Texas. Fort Worth, of course, in Texas as well. But then you have northeast. Northeast is really Marcellus and Utica range. That's a lot of the high production, fracked gas and that looks like it's mostly going to stay the same, maybe grow a little bit. The other portion that we get our gas from is called WCSB, Western Canadian Sedimentary Basin. That's essentially any gas that we get from Western Canada and then they have a very small amount that comes from eastern Canada and feeds the East Coast of the state. One interesting thing here is if you look at the supply growth, and we're right in this region, if you look at that and then you compare that to the rig count, the rig counts are looking to increase by 2027 and then they slowly decrease. Actually, not really slowly in this depiction. A lot of gas gathering and production relies on efficiencies within the drilling process itself. This tells me that they're expecting higher production rates from lower rig counts. In other words, each well drilled is producing more and more gas, so you don't need as many rigs either oil in the large. Let me step back, an oil rig is essentially what you're doing. You're drilling for oil now in any process. That's why oil rigs are in here. There's going to be a byproduct of methane and some other a liquids, but they're primarily drilling and looking for oil within this lighter blue of the chart. But again, there is this side product or that extra product that they're not looking for specifically that adds to the economics. Because of that, the supply is going up because it's more efficient as the rigs are driving down. This is a look at the natural gas share of this. This is total energy.

Tom Pardee: The other was in just gas, so this is a look at total energy by fuel. Some things I'd point out here is that in the United States, you can see that gas is roughly staying the same, oil is decreasing overtime over this horizon from 2023 to 2050. And then you have a removal, mostly in coal, by 2050 there's not much energy coming from coal. Nuclear is staying roughly the same, but the other renewables are what you're driving that delta from, oil or gas, as far as an energy component to renewables. Canada in this case is looking at load growth in gas and they have a new LNG facility up there, LNG Canada. That's going to drive some of their demand. But overall, their trajectory for oil looks much the same and they have a lot of drilling and oil in Canada as well. You can see the overall energy demand of oil is expected to go down as well.

Tom Pardee: I believe this is my final slide. When we step back and look at from the US and then realize that policies are much different as compared to the US, we have the Pacific demand on the left and then mountain demand on the right. I pulled in mountain because of how they break it out. Idaho wasn't included in Pacific, as you can see. It's Washington, Oregon and California. Mountain includes Idaho, but there's a bunch of other states in there, the mountain regions. I'll start with the chart on the left, the Pacific region. Here again you can see blue hydrogen coming into their expectations here in the near term and then increasing to what is roughly a BCF a day by the long term by 2050. But the power demand in this chart is really what drives the reduction in demand in the Pacific region. By 2025, they're expecting power demand or power produced from gas to decrease by quite a bit. And then it slowly trickles down to maybe 750,000 MMBTU per day. I'll keep going. Residential demand in their expectations is staying roughly the same commercial, the same in industrial. It looks like it's going down and my expectation is this blue hydrogen is replacing this. This industrial load is now moving over to the mountain region, you see much the same depiction of the Pacific. In reality, what's driving the reduction here is the power, the lack of demand or decreasing demand in the power generation. The other is for byproducts and let me see. Pacific demand declines from 7 more moderate build out. In this piece, it's going towards other processes, chemical processes and things like that. In both cases, what you're seeing is an expectation from a fundamentals forecaster of reducing demand in both of these regions and I would say mostly because of the lack of power generation that's expected in the regions.

James Gall: Heather. Go ahead, you have your question?

Tom Pardee: Yeah.

Heather Moline (UTC): Yeah. Heather from (UTC), Tom. When were these demand forecasts from Wood Mackenzie created?

Tom Pardee: They only release theirs once a year, and unfortunately this was from March of 2023. We would just be on their new one. This is from their 2023 case, long term case.

Heather Moline (UTC): Thanks.

Tom Pardee: Yep. Any other questions?

James Gall: Kelly.

Kelly Dengel: Yes, any of these decreases in demand take into effect policy changes for the gas industry.

Tom Pardee: Yeah, I'd say both of them do. The decrease in power generation is definitely driving that from a policy change. And then also the increase in blue hydrogen expectation in the Pacific region, but also within the mountain regions as well. Any other questions? OK.

James Gall: Alright, I apologize. I probably didn't set up Tom's presentation too much, but I'll try to do that a little bit for the next two presentations and we're going to get into the natural gas and electric price forecast.

James Gall: These two price forecasts are extremely important for an IRP process. One, the gas forecast that Michael Brutocao is going to go through next is an input into our Aurora model that really helps drive what electric prices will be in the future or at least is one of the major components. We'll start with the gas forecast and then we'll get into the electric price forecast with Lori's presentation. Michael, if you're ready.

Michael Brutocao: I am trying to share my. Ah, there we go. Hopefully you can see this.

James Gall: We can see it.

Michael Brutocao: OK, I don't know if you see yourself on there also. Yeah. Thank you, James. Like James mentioned, I'll be covering our natural gas prices. Our forecast. When we generate our natural gas prices for the IRP, we first start by coming up with the expected price forecast. These are monthly prices and the first year you can see here, on the far left, 2026 is fully following what the forward market prices are on the NYMEX. The reason we do this is there's a high volume of trades at Henry Hub and these prices are very informed as we move out through time. The volume of trades decreases and eventually there aren't any trades going on and there's no information as to what prices may be out say 2040, mid 2030s. We bring in three different forecasts from various market consultants and the EIA's annual times three years and then eventually moves into purely forecasted prices.

Michael Brutocao: At the levelized price you can see is about $5 over this time and one reason we use three different price forecasts is that one may be biased upwards, one may be biased downwards for various reasons. Averaging these three or blending them in together decreases or offsets those potential biases. So, this is the expected price forecast, but not necessarily what we anticipate. Prices are going to be with 100% certainty. To address that uncertainty, we use a process called stochastics. How we run 300 stochastic price forecasts, you could think of each one of those as a different, back to this previous slide, as a different line. It may be higher, may be lower, in different months, but it varies from our expected price. These 300 draws all start from that expected price forecast. And then they move away back towards down. They differ over time, and that difference comes from two different inputs. The standard deviation of errors and the autocorrelation factor, so standard deviation of errors is essentially looking back at historic prices and what the market volatility has been.

Michael Brutocao: That allows us to draw around that expected price and you see overtime as these blue lines, the mean and max does start to widen. It's the jaws of our price forecast and the reason for doing that is that the further you get away from today, the less certainty there is around what prices may be. There's less information and it's more likely that prices are going to be further away from what you may expect, and the autocorrelation factor in this when it's drawing.

Michael Brutocao: Actually, let me let me back up here and just explain what one stochastic draw may do. You start with your expected price. Say it's $4 and based on historic markets, when you're in that first month that distribution around where that price might move in one month is much tighter than what a price might move from five months out or a year out. And so, we take a draw around $4 and we draw $5, we then start the next period recognizing that last month, even though we expected it to be $4, we drew up here at $5. That's where this autocorrelation piece comes in. It says we're going to, instead of now drawing from $4.05 like our expected price says, we're now going to draw from say, $5 or $4.98 and draw from there. That's what also allows this base to deviate from our expected case and the stochastics are a good way of measuring and addressing that kind of risk, of the risk around us not having the exact correct price forecast in our expected case.

James Gall: Michael, Molly has a hand up with a question.

Michael Brutocao: Oh yeah.

Molly Brewer (UTC): Yes, just wanted to know how is this taking in their houses measuring price effect of the Climate Commitment Act?

Michael Brutocao: So that that affect I.

James Gall: I can take that one, Michael. The Climate Commitment Act, it's a single state and that's affected on the retail side, not the wholesale side. The only way there'd be an effect is if there is a lessening demand of natural gas on our system that slightly affects national pricing or regional pricing. I'd say there's no direct or at least a very minor direct correlation between CCA and a long-term price forecast of the country.

Molly Brewer (UTC): OK. What about? Well, I guess you can't. I don't know how you would predict this. If there were something like CCA nationally or in many other regions over the next decade is that somehow, does that factor into this?

James Gall: Yeah, we do have a low price and a high price natural gas scenario price case. We'll run that through our Aurora model, so we can model those cases, or we would have a high carbon price case. I'd say it's outside of maybe this part of the price forecast, it would be more on the Aurora side.

Molly Brewer (UTC): OK. Thank you.

James Gall: Yep.

Michael Brutocao: All right. This is our last slide. To move those prices to our more local gas basins where we're purchasing gas from, we apply a basis differential that comes from our consultant too, basis differential forecast. That's the delta, the price difference between Henry Hub and say AECO, Maline, Sumas, Stanfield and this is just the expected case here. This would then be applied to every one of those 300 stochastic price draws we're running the model. This will also vary as you saw back here. It'll have that same general relationship. And I'll move it to Lori unless there are other questions.

James Gall: Josh has his hand up.

Michael Brutocao: OK.

Joshua Dennis (UTC): Howdy. So, my question is that those month to months are extrapolated to years in the forecast.

Michael Brutocao: Are they're all, they're all monthly.

Joshua Dennis (UTC): OK.

Michael Brutocao: Prices. I'm sorry, were you referencing this this past slide having kind of a inter linear?

Joshua Dennis (UTC): I think it was the slide before this one. Yeah. Wait.

Michael Brutocao: I'm sorry, OK?

Joshua Dennis (UTC): OK. Excuse me? I thought I heard that it was taken on a monthly and then extrapolated to a yearly. So that's my mistake. Thank you.

James Gall: Yeah. All when we.

Michael Brutocao: There is one yearly.

James Gall: Go ahead, Michael. Sorry.

Michael Brutocao: Well, I was just going to say this Annual Energy Outlook 2023 price forecast. But those are annual prices that they provide, and those are broken down to monthly prices. But everything else is purely monthly. Yes.

James Gall: Yeah, just going to add on our Teams site, the monthly price forecast is out there in a spreadsheet. So, if you're interested in looking at what our forecast is, it's that black line on this chart and you can go out and see that along with the pricing that Lori's going to present here.

James Gall: Next, on the electric side. Oh, there's any other gas questions.

<u>Wholesale Electric Price Forecast, Lori Hermanson</u>

James Gall: We'll move to electric. And we got about 30 minutes for the rest of the day. So, I think we should have plenty of time.

Lori Hermanson: OK, let me share my screen real quick. Can you see that in presentation mode? Yep.

James Gall: Now we see the other one. Sorry.

Lori Hermanson: Oh, sorry, on the screen.

James Gall: Yep. We lost your camera like we lost Michaels, but.

Lori Hermanson: How's that?

James Gall: That's much better.

Lori Hermanson: OK, so I'm Lori Hermanson. I'm the Senior Resource Analyst in the Resource Planning group, and I'll be covering the electric price forecast. The whole purpose of the price forecast is to estimate the market value of resources that end up in our IRP and estimate how those dispatchable resources dispatch the price, informs our avoided cost, which we use for our PURPAs and QF. And then finally, it could change the resource selection if resource production is counter to the needs of the wholesale market. For example, if there's a lot of renewables that have been built or forecast to be to be built in a different region than maybe less of those resources would be selected for our area.

Lori Hermanson: We use Aurora, which is a third-party software. It's owned and developed by Energy Exemplar. It's an electric market fundamentals production cost model. It simulates the dispatch of generation to meet load and we put in all the loads across all the WECC. We have all the resources we put in constraints, which could be things like transmission constraints, but it could also be policy constraints, state or federal. And then from all of that, we get the outputs which are our electric market prices. You have a general indication of what the regional energy stack is, what the transmission usage is, the greenhouse gas emissions, as well as the cost. What the margins are for the power plants, the generation levels, and the fuel costs. Finally, we're able to determine our variable power supply cost.

Lori Hermanson: Before we go deeper into the price forecast, let's look at the history of the Mid-C prices. Back in the late 1990s, there was good hydro and we had cheap natural gas prices. In 2000, 2001, we had the energy crisis that we all remember, and we saw prices above $100 a megawatt hour. After that, we resumed briefly our kind of normal conditions and then the natural gas market tightened as we had more demand and less supply, and we saw prices approximately double from what we were used to in 2009. And, for the next decade there were shale developments. And so, there was more supply available, and we saw prices dropping back down to what we'd formally had in the late 1990s and as we come into the recent years, we're starting to see more upward price pressure. This could be contributed to a few things, such as carbon policies in California impacting us, but largely this is indicating what James was touching on earlier in his presentation. It's a reliability issue and resource adequacy and because of these shortages of supply, you're starting to see the prices spike in 2022 and 2023, but then also predicted in our forwards for the next couple of years.

Lori Hermanson: Our 2020 fuel mix both for the Northwest and the WECC, this is based on EIA on their 2023 preliminary results. They usually update their 2023 results mid-year and so I only had access to preliminary results but our energy, or I should say our greenhouse gas emissions, compares better than against the WECC. We have 69% greenhouse gas emission free whereas the rest of the WECC is 47%. Largely this is no surprise. It's due to our high hydro base. We have a 50% hydro footprint while the rest of the WECC has about 20%. Our coal and natural gas footprints are lower compared to the WECC. Our wind and is on par and our solar is considerably less than other areas of the South. Compared to the rest of the WECC where they have 10% solar.

Lori Hermanson: Here are some other market indicators that are giving us some highlights that maybe the market is tightening. This chart on the top left-hand corner is daily natural gas compared to on peak electric prices. We show this because natural gas in the past has been the biggest contributor to power prices. Here we're seeing that even though we see spikes in gas prices here and there. Basically, the cost of, or the comparison is increasing. You're seeing some outliers here compared to most of the history and this could be driven by some of the carbon policies, like in California's carbon pricing. Washington implemented carbon pricing in 2023, but a larger contributor to this is our resource adequacy issues.

Lori Hermanson: The chart on the right is the spark spread. This is a comparison between the mid-C prices and the Stanfield prices. Historically from 2003 to late 2018/2019 and it's been fairly stable. Now we're starting to see some spikes especially in 2021 and 2022 and nearly doubling and 2023.

Lori Hermanson: This chart indicates the profitability of a combined cycle, which in the past, has been the marginal resource. But lately, especially in 2023, that marginal resource has been more of a peaker. Again, this is indicating resource adequacy issues and that there could be reliability issues. The chart on the bottom left-hand corner that shows the implied market heat rate, which is similar to the spark spread chart, but it compares the heat rate equivalent to price of power and gas. In the past you can see it's been stable around a heat rate of 8,000, whereas in more recent years we're seeing more spikes. And in 2023, it almost doubled what we've been seeing historically. Again, the impact from California and other carbon pricing could have some effect here, but again, reliability and resource adequacy issues are being indicated by what we're seeing in the market. And then oh, sorry.

James Gall: Hey Lori, we have a hand up. Heather has got her hand up.

Heather Moline (UTC): Thank you, Lori. Going back to spark spread, two questions. So first is I don't actually know what Stanfield times 7 means.

Lori Hermanson: Stanfield is one of the natural gas hubs. The Stanfield price times 7 subtracted from the mid-C price is what this this spark spread is.

James Gall: Yeah. Can I add a few things there, Lori?

Lori Hermanson: Sure.

James Gall: Other than a combined cycle which is, I'd say the main backstop of the gas resource is going to 7,000 heat rate. The cost to run a combined cycle would be the Stanfield price times 7 for the heat rate. This is showing the profitability of that facility and what happens is if the power price, your mid-C price minus think of it as your fuel cost gets too extreme. The value proposition of a combined cycle combustion turbine is increasing. This is showing is that these turbines, these combined cycle turbines, are vastly in the money, meaning that prices are so high, they're running nonstop, producing power. That is a good indicator of not enough generation in the Northwest to supply the demand, but also now that we have CCA in Washington, at least in 2023. Some of that is contributed to that, which would be a profit reduction, if you're selling into the Washington area. I think at the end of the day, all of these slides are showing the Northwest is capacity constrained and fuel constrained by high price spikes by being deeper in the resource stack and also seen in that last one that Lori's going to get to because volatility of market pricing.

Heather Moline (UTC): OK. Yeah, there's some details there I'm not tracking, but I'm not going to nitpick. Thank you.

James Gall: Yep. Yeah.

Heather Moline (UTC): Just the one thing I think the slides that were sent out, say, Stanfield times 7 minus, mid-C and so I just want to double check that it's actually mid-C minus Stanfield times 7.

Lori Hermanson: Yeah, we caught that after we'd sent those out. This is the corrected version, and we always send out the final slides after the presentation. Thanks for pointing that out.

Heather Moline (UTC): OK. Thanks.

Lori Hermanson: As James mentioned on that last chart on the bottom right-hand corner. That is just showing the standard deviation of the mid-C price. As you can see earlier on, there wasn't much, there was a lower standard deviation, and so there wasn't much volatility. But in the more recent years, you're seeing more volatility, again indicating that there's some reliability, maybe lack of resources available. This is a chart from 1999 to 2022. Again, my source was EIA and it's the greenhouse gas emissions. They only have data available through 2022, but you can see that compared to 1990 we are slightly lower than 1990. The states that have the largest decrease in greenhouse gas emissions are New Mexico, California and Wyoming, the top three. Overall, our process for the price forecast, we start with the vendor database we purchase from Energy Exemplar. It's utilized within Aurora. We're using the 2023 North American database, which came available towards the end of 2023. In addition to that, we add additional inputs such as our 30-year Hydro, which includes climate futures. The natural gas prices that Michael had presented earlier, we put those into the price forecast. We add in regional loads from our consultants, regional loads including energy efficiency and hydrogen production. We add in our own forecast of EVs, net metering, our loads and resources, and any specific operational detail in regards to our generation resources. After that we do a capacity expansion.

Lori Hermanson: We run a capacity expansion model, which is where we put in generic resources and the model, based on the planning margins and the loads and everything, it indicates whether or not it's short or long and it will pull from the generic resources and select which ones need to be built. Then we'll run a deterministic study which we end up with some draft electric prices which I'm presenting today. After that we will run stochastics. The purpose of that is to test resource adequacy. We vary things like renewable load shapes, gas prices, carbon prices, other fuel prices. We vary all those along with hydro and climate futures, and end up with 300 different electric price forecasts.

Lori Hermanson: And then based on that, we look at the level of times that we're short on serving loads and if we need to, we will rerun another capacity expansion model that will build additional resources if necessary. Finally, based on all of that, we'll rerun a deterministic and stochastic run and those will be our final price forecasts. Based on those, we run various scenarios which James will present later today. That's our whole process. Currently we're at Step 5.

Lori Hermanson: I'm presenting today, the preliminary electric prices that came out of this preliminary deterministic study. Now we're testing our stochastic study and I'm doing some small sampling of runs. We'll be launching a full study soon. As I mentioned, one of the inputs is the load forecast. We get our regional load forecast from IHS, which is one of the consulting services. We subscribe to their forecast it includes energy efficiency and hydro production. We add to the load forecast net metering both annually and hourly as well as the electric vehicle forecast. From that we get a forecast of our loads from our planning horizon 2026 to 2045. You can see that the future looks different from today as it's definitely growing. The inputs are carbon pricing assumptions.

Lori Hermanson: We use consultant’s carbon pricing, which rises to about $85.32. We are assuming that there's no national carbon tax. I think last IRP, we assumed that there was in some areas, or we did make that assumption. We're assuming no national carbon price. We're modeling both CCA and that we join California and Quebec as a joint market. That should bring the prices down somewhat. We also assumed that any regions importing into California or Washington incur a carbon adder, a carbon price adder for transferring power into those regions. We are also assuming that, for example, some of the larger generation in Washington. I'm going to forget the actual ones. I think it's Grays Harbor and James, can you remember the other ones that we added carbon pricing to in 2025? Can you remember some?

James Gall: Yes, that's up in Chehalis have a direct price in 2025, Yep.

Lori Hermanson: And then for all the other carbon emitting resources, we added carbon cost to the dispatch starting in 2031. And then as I mentioned, when we do stochastics, this is one of the things that we will vary are the carbon prices options. Based on what you're seeing here, there's a flooring and a ceiling and the prices will vary between there and will take 300 random draws of that contributes to our price forecast. Did you have something to?

James Gall: Lori, Molly had her hand up.

Lori Hermanson: Oh, OK.

Molly Brewer (UTC): Yeah. And maybe this is James or Lori, I don't know. But is this where you're incorporating the social cost of greenhouse gases that we've been talking about, James, the one that the Commission puts out an order to update it cost?

James Gall: What will happen is this is the price that our model will see for dispatching units or selling into the market. And then when we do our capacity expansion study to select resources, that selection process for both energy efficiency and other resources, then that price will be included. So, if a Resource had a CCA price attached to it, it would take the difference, we'd add the social cost of carbon to this value. Yeah, this is what the model sees as a dispatch and then social costs will be in the resource selection side of it.

Molly Brewer (UTC): OK. Thank you for that clarification.

Lori Hermanson: OK. As I mentioned earlier, we put some generic resources into the model that it can select if certain regions are short in order to meet their demand and planning margins. Based on the new resources selected, this is our new resource forecast for the planning horizon, just some excerpts of certain years. But this is very similar to the level we had in the last IRP. The mix is changing slightly, but you're seeing more wind and more nuclear and things like that. This is the resource type history and forecast of the WECC as well as the significant changes by resource type. You can see how it's contrasting against history. You're seeing increases in solar and wind, decreases in natural gas, and those are the largest contributors to the changes for the forecast.

Lori Hermanson: Here's a similar look, but for the Northwest and you're seeing changes in the resource types, increases of solar and wind and decreases in gas and coal. And far as the WECC greenhouse gas forecast, compared to history, you're seeing a large decrease over time. Since 1990, we're seeing a decrease of 135 million metric tons. And then in the forecast from 2026 until 2045, you're seeing another decrease of 129 million metric tons. And at the end of the day, this is the result of the price forecast. It's basically mid-C prices.

Lori Hermanson: We created slightly different zones in Aurora this time compared to last time. Formerly, we had an Oregon, Washington, northern Idaho Zone, but with the CCA going into effect this time we broke it out a little bit differently. We have Washington with and without CCA. And then Avista, which is Eastern Washington, northern Idaho, trying to model based on different resources that could be selling into our market with or without CCA. At the end of the day, the levelized prices are around $48 [per MWh] with CCA around $45 without CCA, and about $42 for our Avista zone and contrasting that with our last IRP, I think our levelized prices were about $35. This price forecast includes quite a bit of expected additional resources in those early years between now and 2030. That's a lot of resources to get built and online and permitted. If those don't come to fruition, these prices would likely be much higher.

James Gall: Lori, I want to add one thing to that last slide and address the prices falling like you mentioned from all these new resources coming online at least projected to be coming online and then the price is bumped back up you can see in 2031. This has to do with our assumption on how allowances will be distributed by the CCA in the future. The law allows for a change in 2031 of how allowances are distributed to utilities and we're assuming at that point in time the projects in the State of Washington would have to include some type of price, the CCA price in its dispatch. The big change there is that assumption that any generator in the State of Washington would have a carbon price in its dispatch versus before that it's just plants that don't have free allowances or importing into the state. So that's the cost of the big change.

Lori Hermanson: Thanks James.

James Gall: Yep.

Heather Moline (UTC): Sorry. Can you repeat, Lori, the kinds of new resources you're talking about?

Lori Hermanson: The kinds of new resources let me hop back here. Whoops, sorry. These are the new resources that were selected from this deterministic run, and this is excerpts over time, 2030 through 2045. Most of the resources being selected are solar and wind, some storage. Those are the big contributors. See a little bit of offshore wind over time, but again are based on generic resources. What we actually acquire could be very different because if we go short, or if we're predicted to be short, we would issue an RFP and the people that submit for an RFP could be very different types of resources or mixes than what we're showing here. We put in generic resources and this is what's being selected.

James Gall: And this is selected for the West region, not Avista.

Lori Hermanson: Yes.

James Gall: Just to be clear, this is California, this is Arizona, Wyoming, Colorado, Washington, Oregon. This is not Avista's preferred mix. This is what would likely serve the greater region. Just to be clear.

Heather Moline (UTC): Thanks.

James Gall: Yeah.

Lori Hermanson: Oops, sorry I went too far. OK, this is basically the same price we just showed, but by season, and this these shapes are very similar to what you saw in the last IRP. A lot of it makes sense. Spring you see it suppressed because of runoffs and all of them you see prices suppressed in the middle of the day. That's because solar comes up. Then you see these evening peaks as solar drops off and people are coming home from work and plugging in their EVs or that sort of thing. These are very similar to what we saw in the last IRP.

Lori Hermanson: Finally, well, I guess I have one more slide after this, but this is comparing the prices that we showed earlier in the flat delivery without CCA, the flat delivery with CCA, and the Avista prices for those zones compared to a couple of our consultant's prices. I think one of the consultant's price forecast was done in December and I think the other one was done in July. This is just to compare results. Finally, these are all of our IRPs since 2005, the black line is actual prices.

Lori Hermanson: This dotted black line is our draft electric price forecast for this IRP and all these other, I mean basically at the end of the day, shows that a price forecast is very difficult to predict what the mid-C prices are going to be. Of all these IRP that we've done, there's six points in time, not six forecasts, but six points in time where we actually got it right. It's just added context here, but it's difficult to forecast and it's based on all these inputs that are best informed to help determine what the prices are going to be. But at the end of the day, they're likely not right. That's why we do these price sensitivities and scenarios that James will be presenting next. That's everything I have. What's left in the process? We're going to connect our stochastic studies. We'll finalize our deterministic and stochastic case based on if we need another capital expansion run. Finally, we'll run scenarios and that's all I have for today. Are there any other questions?

James Gall: Looks like Heather has got a question.

Heather Moline (UTC): Yep, I'm back. Thank you, Lori. I don't know if this is for Lori actually. Do the slides on lower 48 demand for gas North American supply for gas, regional demand for gas Pacific versus mountain, those don't get used in the IRP. Right.

James Gall: Correct. They're context of what the national forecasters are assuming, which basically are used to help develop those natural gas price forecasts.

Heather Moline (UTC): Yeah. OK.

James Gall: They run a model. These consultants, they run a national model for demand of natural gas and that develops a price, and that price then is input into our Aurora model.

Heather Moline (UTC): Got it. That was going to be my next question. Is the thing that they're relevant for is that price forecast and you just answered that. Thanks.

James Gall: If the future was we're going to build a bunch more gas turbines, then maybe that would drop pricing. And for natural gas, if there was so much more demand than there was supply as an example, so.

Tom Pardee: Hey, Heather, if I can add more context to that. Think of that as just one of those forecasts that we use too. As Lori showed on the slides for price forecasting, those are all we have, different forecasts from different entities like the EIA or a few consultants in a forward price. We don't know what the price is going to be, but the law of averages basically states the more you have, the better it's going to be. But this is just one point out of the four points I believe that we used for the single price forecast. It's really just to give context. If I were to show you our other consultant, it's mostly the same and just came out more recently. It's just really contexts around, overall that they are expecting less gas use in our area. That's kind of the one to one of why prices are doing what they are.

Heather Moline (UTC): OK. Thanks.

James Gall: OK. Molly had a question. Go ahead Molly.

Molly Brewer (UTC): Yeah, this is going way back to that set of questions earlier for resource adequacy from that cold event. How are we meant to go about answering those questions. I just have follow up questions on them like how would we know if 1% or 5% probability is more reasonable things like that?

James Gall: I think the expectation of reliability needs to be somewhat directed by the Commission and that's my opinion. The utility is responsible for being able to provide a reliable service. I think there's a level of expectation of what that is now. I think there's also a level of expectation you're not going to overbuild your system. We've always looked at what's the industry standard for reliability, but it seems to me that consumer expectations are changing. Of what they expect. So, I think it's a broader question of what is appropriate for resource adequacy. I mean another example, WRAP set a standard, but is that standard the right standard of what our customers want? I don't know if there's an answer to that without having regulatory bodies or legislature saying this is what we expect. Otherwise, we're going to propose something and it's whether or not the Commission agrees with what we propose. I don't know.

Molly Brewer (UTC): Yeah.

James Gall: If that's helpful or not, but Yep.

Molly Brewer (UTC): No, I mean that is because I just don't know. What's the standard we're using to answer these questions?

James Gall: Yeah, there is no right answer, unfortunately.

Molly Brewer (UTC): That helps me understand the context of asking those questions.

James Gall: Yeah. Whether or not we use an example day as a resource adequacy standard. I think it's good practice to show that and it helps policymakers understand what they're getting into. If we build a bunch of four-hour batteries and rely on wind and solar and we have an event like this, you can see we can't serve it. That is a good indication why we need to look for longer duration storage or rely on natural gas. These are good examples to show to understand what the results are of decisions that get made in these planning processes. Unless there's any other questions, we were going to wrap up by 10.

Portfolio and Market Scenarios Options, James Gall

James Gall: I think we did reserve another 30 minutes on everybody's calendars for this meeting because we weren't quite sure on the time, but I'm not going to take that 30 minutes because the scenario section was really just to go over what we're thinking and let you all chew on that for a while, because we're going to actually cover scenarios in more detail at a future meeting. And let me look up when that is, John had shown that earlier, but I need to look it up again.

James Gall: We're going to cover the final scenarios at least the list and descriptions in TAC 7, but the document we sent out is a description of what we're thinking right now and how this works. We have 19 scenarios right now, or 18 if you don't include the expected case, and then under sensitivity this refers to what price forecast we would be using. That's that Aurora price forecast that we will be studying with each of these portfolio scenarios. Then we have an LOLP study. This represents which of these portfolios will undergo our reliability test to look at what's 5% loss of load probability or 1% if we ended up going there in the future. This is our list. We also have a description of each of the scenarios here.

James Gall: What we'd like the TAC members to do if you want to see something else besides these, you want to add, please let us know. Or if you don't think that one of these scenarios is useful, that's also feedback. But I'm trying to figure out when we wanted feedback. John, I don't know if you remember. I was looking at our Work Plan when we needed to get feedback from everybody on the scenario list. If you had that in your memory or not?

John Lyons: Not off the top of my head. I'm looking really quick.

James Gall: OK, I think I'm there. It is March now that would be today. We have got to push that out.

John Lyons: OK.

James Gall: Our Work Plan had it today, but if you have comments maybe next 30 days for the scenario list, provide those to us. If you want to see something different. Or in addition to these, we had some proposed ones that are on here as well, if that's something you're interested in. We cover what some of the information is on what the targets are on the bottom of what some of these scenarios are.

James Gall: So, with that, are there any questions, thoughts that people have? OK. Alright, so hopefully everybody likes the new TAC schedule of every two weeks. That's what we're going to be moving to going forward and the next couple TAC meetings are really going to concentrate on our load forecast, which I kind of given a clue earlier on. It will be a higher load forecast than we've seen in the past and we'll then go forth and figure out what our availability is for energy efficiency, what resource options we have, what our net position is over the next couple of months. By early summer, we should have some resource selection and show you what types of resources are going to be needed and when. It'll be for our team at least a very strenuous next probably three months, lots of work to get done. It's crunch times for us.

James Gall: If there's no other questions or comments, I guess we'll call it a day.

Heather Moline (UTC): Sorry, James.

James Gall: Yep.

Heather Moline (UTC): Heather here. That list of scenarios, where does that live? Or is it at the end of the presentation?

James Gall: Yeah, it is at the end of presentation we emailed out. We'll also post that to the website today or tomorrow. It's also out on the Teams site as well.

Heather Moline (UTC): Thank you.

James Gall: OK, have a great day everybody. We'll see you next week at the DPAG meeting, hopefully. Bye, bye.