Third Electric Technical Advisory Committee Meeting Notes 3/9/22

Introduction, John Lyons

Gall, James: I think if you can see the screen, I think you're ready to go. I'll just hit the button when you ask me to.

Lyons, John: OK, sounds good. Again, welcome to all of you participating in our third Technical Advisory Committee meeting. We're going to start with the introductory slides. I'll go through that quickly and then get to the presentations. You'll notice on the top, we have started the recording and the transcription. If you don't want to be recorded, you would have to sign off, otherwise, we should be good to go. So next slide, James.

Lyons, John: Meeting guidelines, we're still working remotely, but are heading back towards the office. Hopefully the next meeting, there's a good chance it would be in person. We will still offer the online version for people that would like to participate that way. This is our stakeholder feedback form. Should say forum not form but where we get to answer questions and take comments, we share all the responses with the TAC members that we get from email and other ways. If people give us a call, those will be showing up in the appendix. We are working on developing a form for comments and updating the website. You will notice, if you've gone out there, we have revamped the website to make it a little more user friendly to get around as we start posting all of the data. We are still on Microsoft Teams and will keep adding Microsoft Teams option even once we get back to in person meetings. The presentations I sent it out this morning, the updated set. We will have the set also posted on the website in the next couple of days. Meeting notes are getting posted and they are the transcriptions. I do have to go in and edit them for clarity, and sometimes it picks up some odd things and twists some words around. So, I do have to edit those, and I get them down to a decent size. We are also posting the recordings. We've got that figured out now. There's links on the website for the IRP and that'll be for both the gas and the electric side. And that goes to our YouTube page because they're so large. Next slide please.

Lyons, John: A couple of virtual TAC meeting reminders, I think we're all really good on this, but still good to refresh our memory on that. Please mute your microphones unless you're commenting or asking a question. You can also use the raise hand function or the chat box. Several of us from Avista will be watching the chat box to see if there are questions. If we don't get it to them right away, we're usually waiting for a moment when we can get those slipped in there. But we will get to those. Please respect the pause. It's always a little difficult when you're in an online environment to see what's going on, so we'll give some time for that. Try to state your name before commenting. The transcription is pretty good picking up who it is, but it helps everyone else who's not seeing the transcription live. It is a public advisory meeting, so all the comments and questions are documented and recorded. Next slide.

Lyons, John: IRP, for those of you that are new to the process, it's required every two years in Idaho, and it used to be every two years in Washington. Now it's every four years with an update at two years. Essentially, it's another full IRP. It's a 20-year look into the future. We do have some additional years in these earlier ones to get to 2045 to look at the Clean Energy Transformation Act in Washington. And traditionally, we have gone a little over 20 years to get those end effects. We start with the current and projected load and resource position. Figure out what we have, what we need, and then look at the different resource choices available to us, including conservation and demand response. We've been looking at transmission and distribution and we're going to see more integration on that. And the goal is a set of avoided cost, which is going to let developers and new technologies know what the price point is they're having to go up against and we're actually going to be talking about some preliminary costs today. Then we run market and portfolio scenarios for those uncertain future events, big picture issues that if we have a fundamentally different future, alters the trajectory of the plan. Next slide.

Lyons, John: So, the Technical Advisory Committee meeting. I'll let people go through this on their own or if they need it as a refresher, but this is the public process. We try to go through all the questions, but once you've made a point, you know this isn't one where we can rehash the same thing over and over again. because, we have quite a bit of data that we're trying to get through, but that hasn't really been too much of a problem in our TAC meetings. Some key dates to remember though: October 1, 2022, that is the due date for study requests from TAC members. If there are some small things after that we can get to, we will try to do that, but that's the date you need to get those in so we have plenty of time to finish them before the IRP is wrapped up. External draft will be released on Saint Patrick's Day of next year and then public comments would be due May 12th in 2023. The final IRP would be published on and submitted to both commissions on June 1st, 2023, that is later than what we would normally do, but we have an all-source RFP out right now and we want to give time to complete that RFP and have the new resources put in. Next slide, please, James.

Lyons, John: Here's our ongoing schedule. Our next meeting would be August of 2022 and you can see the dates for the rest of the meetings through March 2023. We are going to be picking dates on those soon, but that's the months and then the agenda for today. After this introduction, Mike will be talking about our existing resource overview. Then James will be handling the resource requirements. That was the presentation we weren't able to get to last time because we had such a good discussion going on the economic and load forecast. Then a break. Then DNV is the consultant we've hired to do the non-energy impact study. That's the first time we've done this sort of study. So, I think we're going to have some pretty good discussion on that. Then we'll have an hour for lunch, and then we'll conclude with the natural gas and wholesale electric price forecasts and adjourn around two. Any other questions before we get going?

Kinney, Scott: Hey, John, this is Scott. Can I just do a quick welcome?

Lyons, John: Ah yes, please, Scott.

Kinney, Scott: Alright. Thanks John. This is Scott Kinney, Director of Energy Supply at Avista and I see a lot of familiar names on our list and a lot of new ones to me. So welcome to our TAC meeting today. You all play an important part in this process and we welcome the feedback and the information that you can provide us in into the process and you'll see with the agenda today that we're really starting to get into some of the key data and information that will be important for the assumptions that we bring into our modeling that will occur later this year. So again, we thank you for your participation today and look forward to the engagement.

Lyons, John: Scott, would you like to say anything about starting live on the EIM?

Kinney, Scott: Thanks, John. We did successfully join the Western Energy Imbalance Market last Wednesday at midnight. We've had about a week now of operating experience in the market and we're getting a better feel for how we participate and how and the benefits that the market can bring us. And we can probably share more of that if people are interested in a future meeting after we get a little bit more operating experience under our belt.

<u>Existing Resource Overview, Mike Hermanson</u>

Lyons, John: OK, excellent, let's move on. James, if you want to quit sharing and Mike if you want to put your existing resources presentation up. Mike Hermanson is our newest team member here. We did introduce him last time and put him on the spot, so now you'll get to hear him talk a little more. So, if you want to take it away, Mike.

Hermanson, Mike: Thanks, John. My name is Mike Hermanson and I'm a power supply analyst here at Avista. I'm going over the existing resources Avista currently utilizes. I've broken them down into four different groups of Avista owned hydro, Avista owned thermal, contracted resources, and customer owned resources.

Hermanson, Mike: We have 8 hydroelectric projects on 2 river systems. Spokane and Clark Fork rivers. This map shows the location of those. Five are considered run of river and three have storage reservoirs. Both of the watersheds that supply these projects are snow dominated, so the hydrograph follows the pattern of high flows in the spring and low flows during the late summer and fall. The Spokane River Project includes six projects that start at Post Falls coming out of Lake Coeur d’Alene and ending at Little Falls, which is right at the beginning of the Spokane Indian Reservation.

Hermanson, Mike: This chart shows the different attributes, so you'll notice that the total nameplate capacity for the project is 189.2. The nameplate capacity is rating by the manufacturer and under certain conditions, more energy can be produced so the maximum capability is 10 megawatts more at 199.4. Actual output, of course, is dependent on the amount of water in the system and varies year to year. Expected generation based on the 80-year hydrologic record is 119.5 average megawatts. Currently there is a project at Post Falls that is slated and that will add 3.8 megawatts of incremental winter capacity and four average megawatts of annual energy.

Hermanson, Mike: The two Clark Fork projects are significantly larger than the Spokane projects with a combined nameplate capacity of 783.2 megawatts and Max capability of 880.5 megawatts and the expected annual energy is 320 average megawatts. Avista owns 7 thermal resources with three different fuel types, coal, natural gas and biomass. The maximum winter capacity is 864 megawatts. And then the summer capacity is 759 megawatts. The winter capacity is larger because natural gas is more efficient at lower temperatures.

Hermanson, Mike: I'm going to kind of go through each one of these. And also you can see here from the map that it's distributed. You know we have one in eastern Montana. Over in Boardman Oregon, Coyote Springs, up northeast Washington Kettle Falls and then three located in the Spokane area: Northeast, Rathdrum and then Boulder Park. Colstrip is a coal generating facility in eastern Montana. It's owned by a group of utilities and Avista owns 15% of units three and four. The Max net capacity is 222 megawatts, that's the 15% share of those two units, but after 2025 energy generated at this facility will not be used to serve Washington customers. Coyote Springs 2 is a natural gas fired combined cycle combustion turbine. Produce 50% more electricity than a single cycle combustion turbine that utilize waste heat from the gas turbine to power a steam turbine. The Max winter capacity of this facility is 317 megawatts and max summer capacity is 286 megawatts. Three facilities that are simple cycle and these are all located in the Spokane area, the largest is Rathdrum at 176 megawatts, winter Max and 126 summer. Boulder Park has six natural gas internal combustion reciprocating engines that generate 24.6 megawatts and then we have Northeast, which is 2 aeroderivative simple cycle combustion turbine units max at 68 megawatts. And in the winter and in the summer 42 megawatts. Northeast is only allowed to operate 100 hours per year based on the air operating permit. The final one of the thermal facilities owned by Avista is the Kettle Falls Generating Station. It utilizes waste wood products from area mills to fuel an open loop steam plant. It's among one of the largest biomass generation plants in North America. The max capacity is 50 megawatts. And there is a 7.5 MW gas combustion turbine at the facility that is also utilized.

Hermanson, Mike: In addition to resources owned by Avista, we have long term power purchase agreements for hydro, natural gas, wind and solar. You can see from this table that the agreements have various terms. Some are significant resources such as the Lancaster Gas Plant Agreement ending in October 2026 and then some go all the way out to 2042. We have contracts with three PUDs with projects on the Columbia River. The total capacity of the projects which Avista has a share of ranges from 840 megawatts to 1,254 megawatts. And those are the total capacities of those facilities. Avista has a share of those. This table shows the shares, and the table shows the current contracted share for each project. We have a total on-peak capability of 231 megawatts. And in 2020, this share was 143.9 average megawatts. There's also a line item, the Canadian Entitlement, which is a portion that is returned to Canada per the terms of the Columbia River Treaty for management of storage water and upstream reservoirs and for coordinated flood control and power generation optimization. The mid-Columbia PUD's contracts change over the next 20 years, and this chart shows peak capability that is currently contracted through 2050. It increases up to a peak in 2028 and then decreases going out into the out years. We currently have contracts for three variable energy resources, two wind projects and one solar. The Palouse Wind Project is a 30-year contract signed in 2011. This project has a capability of 105 megawatts. The output is variable based on the wind and in 2021 the output was 41.2 average megawatts. The Rattlesnake Flat Wind Project is a 20-year contract and has a capability as 160.6 megawatts. Though the project is limited by transmission to 244 megawatts. In 2021, output was 48.3 average megawatts. And finally, we have the Adams-Nielsen Solar Facility. The contract was signed in 2017 with the project entering service at the end of 2018. It has the capability of 19.2 megawatts and in 2021 had an output of 4.95 average megawatts.

Hermanson, Mike: Avista has a number of contracts under the Public Utility Regulatory Policies Act. The PURPA statute, as it's known, requires electric utilities to purchase power from cogeneration facilities with small power production facility and small power production facilities of 80 megawatts or less. As you can see from this table, there's quite a range and power production from a small 20 kW hydro in Northeast Washington all the way up to a 60 MW wood waste facility in Lewiston. ID. The total capability from these projects is 109 megawatts with an estimated annual energy of 73 average megawatts.

Hermanson, Mike: The last resource to cover is customer owned generation. At the end of 2021, there were almost 1,800 customer installed systems. They're primarily rooftop solar but do include some combined wind, combined solar and biogas. The average system is 7.63 kW, so as you can see there was a decreasing trend in system installation that started in 2018, but the renewal of some tax incentives contributed to an increase in 2021. In 2021, we estimated that the customer installed systems provided an estimated 1.21 average megawatts to the system. There's a question about Colstrip. I don't know if someone.

Gall, James: This is James. I can answer that one. Doug is asking a question about Colstrip, I'll just read the question. I assume Colstrip will continue to provide power to Avista customers in Idaho, Oregon, etc. How does this work from an accounting perspective? For example, how is Avista stating that none of the energy produced by Colstrip is not directed to Washington? Does Avista have any future plans to relinquish its ownership in Colstrip? First comment on this is Colstrip serves currently Washington and Idaho customers. We do not have any electric service territory in Oregon. The Washington law does not allow us to deliver coal energy into the State of Washington. If the plant is still operating in 2026, we'd still have to work through how the current

Washington share would be treated if the plant is not shut down. I don't know if Scott Kinney, if you want to add an update.

Kinney, Scott: Sure, James, you did a pretty good job of covering it and of course our integrated resource planning process will help inform the value or the economics around Colstrip as it pertains to serving Idaho customers 2026 and beyond. So as this analysis continues and we do our modeling, it will determine if there is economic value or not. And then if that is the case, then we will start a process to work with the Commissions in Washington and Idaho to talk about the need to potentially allocate specific resources to states which we have not done in the past. We've always used a system approach with an allocation based on our load that we serve in each state, which is 1/3 Idaho and 2/3 Washington. Again, this process will inform our decision going forward with regards to Colstrip and then we'll evaluate what options are best for our customers.

Gall, James: OK. I see Jim. Jim Woodward, your hand is up.

Woodward, Jim (UTC): I think Joni Bosh from NWEC maybe beat me to it. I'm happy to go or if she wants to go either way.

Gall, James: Why don't you go ahead and ask your question? Then we'll get to Joni's question next.

Woodward, Jim (UTC): Sure. I actually have two questions. The first one concerns the Chelan PUD contract, which I think was a few slides back. Just wanted to confirm that this reflects contracts with Chelan through the latest one signed at tail end of December, beginning of this year are those updated numbers on that slide?

Gall, James: They should be, yes.

Woodward, Jim (UTC): OK. Thanks for confirming. And my second question, probably goes more with slide 17 the customer owned generation. Is your team including in these specifics, community solar? Or is this just private individual customer? Was it Rathdrum a couple slides back there, there were a couple projects that evolved project status? They were originally community solar and now they're serving different purposes. Wonder if you could come in on the community solar side of this?

Gall, James: Sure. Avista created one community solar. I don't know if you want to back up one slide where there was the list. The Boulder Park Solar farm in the Spokane Valley is a community solar project that was developed as part of a tax incentive package a few years back. That project was always owned by Avista, but the benefits went to customers who signed up for the program. So that's an investor resource. There's also a project in Rathdrum, Idaho that was used for customers participating in My Clean Energy. Again, that's an Avista owned project that the renewable benefits go to those participating customers. The Adams-Nielsen Solar Facility in Lind, Washington, that is part of the Solar Select project. And in that case the project is owned by a third party that we contract through a PPA to buy the renewable energy on behalf of those customers until that program expires and I think five more years and then it will be an

Avista purchased resource. Other than that, I don't recall that there are any other community solar facilities on our system. So, all of the small solar are our customer owned.

Woodward, Jim (UTC): Thanks, James. And just to clarify the Adams-Nielsen project you mentioned, which I think was a couple slides back. At least right now, is that technically classified as community solar? No, I think it's on your next slide up.

Gall, James: It is a PPA and is owned by a third party, but the output is intended for specific commercial industrial customers through the Solar Select program. That's a seven-year program.

Woodward, Jim (UTC): Thanks for that clarification. Sounds like it has hybrid characteristics. Appreciate that rundown.

Gall, James: Yeah, definitely. OK, I'll start to read off questions and Mike, maybe this next one's about Nine Mile if you want to go back to the Spokane River slide. This is Joni's question, and I don't know if you have the answer. I don't necessarily have the answer top of my head with why Nine Mile’s maximum capability is greater than its name plate. I don't know if anybody on the call from Avista may have an answer. Hearing silence, so we may have to get back to Joni on that answer. So, go ahead.

Hermanson, Mike: Yeah, I don't have an answer.

Kalich, Clint: James, I'll take a stab at it. This is Clint Kalich with Avista. The nameplate capacity is based on system conditions at some measured values, so it's some optimal level of head and so forth. You end up with your maximum capability being affected by a lot of other operational situations. For example, and I can't speak specifically to Nine Mile. If you're operating elevation is reduced or if there are changes, this is a very old facility, so we've changed out some of the hardware. Think of the actual turbine that sits in the turbine bay. They don't necessarily change the sticker that goes on the generator, so maybe the turbines themselves connected to the generator don't have the ability to turn that generator at its full capacity. That's my understanding, especially as you retrofit over time. You literally don't change the generator metal plate that has name plate on it and the technology will change and they won't affect or change the name plate sitting on the generator. So that is not the most specific answer, but it gives the general indication of what the delta can be from.

Gall, James: Thanks, Clint. Next question from Ben Otto. Do we have an update on the arbitration currently underway among the six Colstrip owners?

Gall, James: Scott, I'm going to defer to you if you want to answer that question since I I'm not aware of any updates.

Kinney, Scott: I don't have much of an update either. I just know that both the arbitration and the legal challenges are going through their processes and I'm not aware of the current time frames or dates associated with those efforts.

Gall, James: Next question from Doug. Has anyone challenged Washington State on legality of banning energy imports of Colstrip on the basis of Interstate Commerce rules? I'm not aware of that. I don't know if anybody else from Avista or otherwise are aware of any legal challenges.

Joni Bosh (Guest): This is Joni. The law says the bills of customers cannot have coal in the bill, so it was the same thing Oregon had done a couple years earlier. And so that respects the Interstate Commerce rule part.

Gall, James: Thanks Joni. And I think that's all the questions and I'll turn it over to you Mike to finish up.

Hermanson, Mike: OK. Thanks. Just to summarize everything, this pie chart shows the mix of generation in 2021 generation was 1,336 average megawatts. And this shows the generation by resource type. The largest percentages from hydro, 31% of Avista owned Hydro and then we have 10% from the mid-Columbia Hydro. Then we have natural gas next at 31% and coal at 13%. And to round that out, this chart shows generation and market purchases in comparison to native loads and net sales transaction as you can see here. The generation that we have exceeds our native load, so we are a net exporter of energy and then we have the net sales transactions and market purchases to balance that out. So that is the summary of all the resources that we currently utilize.

Gall, James: Right. Thanks, Mike. I just want to poll the crowd to see if there's any additional questions on Mike's presentation. While you're thinking about that, this is a good overview of our resources because the next presentation is going to compare these resources to the loads we saw forecasted by Grant on the last TAC meeting. You may see some of these resources again today in our discussion on non-energy impacts. If there's any last question? Alright. I'm going to start transitioning to the next slide deck.

Hermanson, Mike: OK. Thanks.

Gall, James: Mike, if you want to release control. Bear with me one moment. I've got to shift things around between screens. I think I just saw a question pop up. Art is asking of the renewable resources do you see any greater production capacity output? As far as renewables, with that are better production or better capacity factors and the Northwest, might be a little bit of a challenge. Palouse (Wind) is pretty efficient compared to other regional resources but going east to Montana is likely to provide better production than locally. Obviously, there's also hydro options that are better renewable resource options in many cases compared to wind and solar. So hope that helps to answer your question, Art. If you have a follow up, go ahead and ask.

Art Swannack Whit Co Comm (Guest): I just was curious if that's what we expect going forward. Whenever you put in wind or solar in our area, you're going to have this low actual generation rate versus what it has for listed capacity.

Gall, James: It will definitely be below. Are you never going to have a 100% wind production? I would expect the capacity factors do improve over time with newer facilities as turbine technology gets better. Same with solar. But you know it's a matter of what percentage of the energy its able to capture from the wind that's available. If you had a wind site that blew all the time obviously you would have a higher capacity factor. It's a combination of the wind available and the turbine's capability of capturing that renewable energy. In Montana you're likely to see around 50% capacity factors. The Northwest it's going to be definitely below 40%. Offshore wind has some potential to have higher capacity factors than what we're seeing on the land. And solar you're looking at less than 25% capacity factor when you have tracking solar compared to the DC rating.

Load & Resource Balance Update, James Gall

Gall, James: OK, so this next presentation is going to try to outline what our resource need is for this IRP subject to a few changes we're going to talk about in this presentation. First, we've had some major L&R (load and resource) changes since our last IRP. We went through the load forecast change on the last TAC meeting. We've also signed an agreement with an industrial customer for 30 megawatts of demand response. That was all part of the Washington rate case settlement and we signed two contracts since the last IRP with Chelan County PUD. Chelan County PUD has two projects that we purchased from Rocky Reach and Rock Island. And just to give you an indication of the size of those projects, which Mike went through already, about 54 average megawatts is about a 5% share. So currently we have a 5% share going through 2030. We signed an additional 5% share from our previous RFP that starts in 2024 and then goes out ten years and that was included in the IRP update last year. And then at the end of December (2021) we signed an additional contract that starts in 2026 for 5% and then increases to 10% in 2031 as the existing slice we have expires. We have a quite a bit of extra renewable energy since the last IRP but also this resource, while it's renewable, provides a capacity resource to meet our peak demand in both winter and summer.

Gall, James: With those changes since the last IRP, this is our resource position. Our first resource shortfall is in August of 2027, 127 megawatts and then also in December or sorry, January 2027, 162 megawatts. We're technically short beginning in November of 2026 when that Lancaster contract expires that Mike had mentioned earlier. With some load growth, we increase those deficits to January shortfall of around 200 megawatts and just under 200 megawatts in August. As you stretch out over time, you may remember in Grant's load forecast, the summer peak load grows faster than winter. We expect a summer deficit by a larger position and the outer time periods starting in 2034 or actually I think it looks like 2033. What this chart tries to show is not only our comparison to loads versus our resources, but we're also trying to take into account what's called a planning reserve margin were using 16% in the winter and 7% in the summer and this is until the Western Resource Adequacy Program (WRAP) finalizes their requirements to participate in that program. Avista is intending to participate in the program. At this time, we expect that the WRAP will lower our resource need for winter planning purposes and slightly lower our positions for the summer planning positions. In the first TAC meeting, we went through a presentation on how those changes might look for this L&R. But until we have further information, we are going to be still planning for our current methodology until that program's information is more publicly available. I'll pause there if there's any questions.

Kinney, Scott: Hey, James, this is Scott. Maybe I'll just add quickly for the schedule of the WRAP. We are currently participating in what's called the non-binding trial this year, 2022, that will help inform and maybe make modifications to the program. And basically we're operating as if we're part of the program, but there's no financial penalties for it and then there will be a FERC filing hopefully in the May time frame of this year and will work through the FERC approval process with the intent to hopefully start a binding program sometime in 2024.

Gall, James: Thank you, Scott. Thanks for jumping in. I was meaning to ask you to do that. Alright, so shifting over to energy, so when we.

Kinney, Scott: Looks like somebody's hand is raised James.

Gall, James: OK. Go ahead.

Katie Ware: Hi, this is Katie Whare from Renewable Northwest.? Stop me if you can't hear me.

Gall, James: We can hear you.

Katie Ware: OK. I think at the previous TAC meeting you mentioned that Avista would be using the methodology for capacity planning that the WRAP has I guess determined to be in the preliminary design at least. And it seems maybe you're taking a shift away from that in this meeting. Do I have that right?

Gall, James: No, we are still planning on using the WRAP. At this point in time we don't have enough information to show our position for it. Until we have that information and a go ahead on the WRAP like Scott had mentioned, we want to continue showing what our position is without the WRAP.

Kinney, Scott: I'll just add I think our intent is like James said is from the resource capacity contribution methodology and calculation. I think we intend to use the WRAP methodology for that because it's been, I think, fairly well vetted and we've got some agreement in the region to go to that standard. But I guess it's a little too early from a commitment to using the benefit of the program from a resource, future resource need, perspective since we haven't got commitment to move into the full binding program.

Gall, James: Thanks Scott. There's another hand up by Mike Louis.

Mike Louis (IPUC): Hi, James. My question is related to the previous question. What is the company's current thinking with regard to the reliability target for the company versus the reliability target that WRAP will use? Just to clarify, would the company be using a different planning reserve margin target or another type of reliability target, will it be customized for Avista system or was the company thinking that they would be adopting the same reliability target that the WRAP uses?

Gall, James: I think the intention is to use the same reliability target the WRAP proposes for our region and from an historical POV. When the WRAP first started being discussed they didn't have a regional perspective, now they do. That makes us quite a bit more comfortable with some of the estimates we're seeing for the planning margin targets and how resources are counted towards meeting those targets. The next question is Avista comfortable with those targets? And I think when we see the final PRM quantities that are really required, I will need to look at the risk and market exposure we have and take that and probably come back to the TAC to see if it's appropriate to continue with the WRAP's proposal or do we need something greater than the WRAP's targets. I think changes that we're going to make in our energy planning should alleviate some of those concerns and we're going to get to some of that discussion on the next slide. Does that answer your question Mike?

Mike Louis (IPUC): My thinking here on this James is that the planning reserve margin is dependent upon the resource mix that you would have within the company system versus what you would have across the region. It seems to me that if you had a loss of load expectation or loss of load hour type of reliability target starting that from that with regards to it being more of a policy question. And then determining what your PRM would be based upon the resource mix within your system. It may be different than what was then the resource mix you would have within the region. And so, the PRM might be different and so I'm looking for some rationale as to why you would want to align those two when you eventually get to answering that question.

Gall, James: Alright. Thanks Mike for the perspective.

Kinney, Scott: James, can I add just a brief piece to this? Mike, we will definitely evaluate the WRAP versus our internal resources and in our thoughts to, as James indicated, try to reduce risk. But one thing that's important the WRAP program will provide when we get to the full binding program is an operational component we will be able to share amongst the participants on a real time basis if actual loads or operating conditions are significantly different than what was planned or estimated. And so that again will help us be able to leverage diversity across a fairly large footprint. Now that includes utilities all the way down to Arizona to help eliminate or reduce risk on the operational front. That's something else that needs to be factored into the evaluation.

Mike Louis (IPUC): I appreciate that. Thank you very much. That's all I've got.

Gall, James: Thank you. All right, I think the next question was from Joni Bosh. Do we have a more specific estimate on what the WRAP impact might be in terms of megawatts needed? We had a preliminary estimate shown in our first TAC meeting. This is a slide from the first TAC meeting that shows the benefit. You can see that January value here. It's a little less than 200 megawatts in this example and then summer is around 50 megawatts of benefit in the outer years. This is a significant benefit, but these are definitely subject to change. We have not seen, at least I have not seen, final PRM requirements yet and final QC values yet for resources. We're expecting to see at least a better benefit in the winter than in the summer. And then I think the next I saw Jim's hand went up next, Jim, ask your question.

Woodward, Jim (UTC): Thanks, James. Just given the discussion around WRAP, it sounds like Avista's overall path forward with WRAP seems to be unchanged, but perhaps your team is waiting to make decision points around certain benefits. I just wanted to clarify, there's been discussion around the planning reserve margin when it comes to a specific resource attributes. I think you use QCC. Oftentimes I use ELCC nomenclature. For those capacity contributions, is the path forward there still to ultimately adopt the WRAP values or is that one of the benefit pieces that Avista is withholding judgment on right now?

Gall, James: Yeah, it is. As long as we're moving forward with the WRAP, we will be adopting the WRAP's QCC value or else.

Woodward, Jim (UTC): OK. Thanks for confirming that.

Gall, James: Yeah. Now if it all falls apart, I hope it doesn't, but then we have to go back and reevaluate. Alright, I see a question from Art. Will we see a snapshot of how the WRAP worked before finalizing the IRP? We did a presentation at the first TAC meeting, Scott led that. And there's some slides out there in that TAC meeting, I'd recommend looking at that. will we do another presentation? we might do that just to give the TAC a little bit more information on the final situation for the WRAP. It's a good suggestion. Mike, your hand went back up. Did you have a follow up question?

Mike Louis (IPUC): Just an additional question. What I heard the first time with regards to the ELCC or the capacity contribution, whatever acronym you want to use, was that you were going to adopt the same methodology, but then I just heard that you were going to use the QCC from the WRAP. Which one is it?

Gall, James: The WRAP uses the term QCC as qualifying capacity credit. And ELCC is effective load carrying capability, but from a renewable variable resource point of view, I think the intention is those two values are the same. So ELCC would be synonymous with the QCC value. The QCC is the official terminology that the WRAP uses for resource contribution and that's what will be used.

Mike Louis: OK, but will you be using the same methodology to develop it, or will you be adopting their values?

Gall, James: They provide values based on data that we submit for each resource type. And they will assign us a QCC value for those resources.

Mike Louis (IPUC): OK. And will that be specific to your system then? Will that QCC value then be determined specific for your system and the capability of the resources within your system?

Gall, James: It's based on our resource's capability to satisfy the regional load. Of the system, not Avista. It's a regional value to meet regional loads because there is this operational sharing agreement like Scott had mentioned. So that in the case we are short you know we can lean on and get power from other utilities that may be long.

Mike Louis (IPUC): Thank you for that. Thank you.

Gall, James: OK. I think we got all the questions, feel free to ask more. I am a little conscious on time just because we didn't make it through the last TAC meeting, and we do have a guest coming in at 10 to discuss the non-energy impact study. Hopefully we can get through the rest in the next 15 to 20 minutes because I'm guessing there's going to be some controversial discussion towards the end. Mike, your hand just went back up this, do you have another question? Or is that from before? OK. Alright so on the system energy position, hat this chart is trying to represent is our position from an energy production capability. This compares your load forecast on average to your expected capability of your resources so that would be for example your average hydro conditions when would be your average wind conditions and natural gas turbine would be how much it could produce in potential outages. We do include a contingency factor to protect our customers against potential for higher loads than average or lower hydro than average.

Gall, James: This analysis shows that we are in a short position from an energy perspective. Beginning in 2027. We have larger deficits both in summer and winter. The reason why the annual deficit is significantly less is we have significant surplus in the in the springtime period. The next slide will show how that distribution works. One thing I do want to mention is we are evaluating changing our contingency metric, it's historically been just around hydro and load, but with the additional renewable energy that we've added to our system over the last several years, we would like to include some of those risk metrics as well, especially as we go forward in the event we add additional wind and solar resources.

Gall, James: This next chart is taking the same information from the previous chart and looking at this from a monthly level. We have three different forecast for two years shown. We'll start with the blue bars representing 2025. You can see in 2025 we are long in each month by at least around 200 megawatts. You can see the length that was mentioned in Q2 from our hydro runoff, but as resources are planned to exit, this assumes Lancaster exiting in 2026 and as well as Colstrip exiting in 2026, you can see the short positions in the Q1, Q3 and Q4 periods, but in the spring period we still have significant length due to hydro runoff. As we add resources in this next plan, we will be looking to fill resource deficits in these periods where we're short? One thing we're still evaluating and seeking input on is should we be satisfying this full deficit. This deficit does include a risk factor, or should there be a market component that we're willing to rely on the market for a portion of fulfilling some of that risk in bad hydro or higher loads, so that's something that we're still evaluating. Previous IRPs did not plan resources for this monthly energy level, so this would be a significant change for this plan by planning to this level. The next part of the presentation is going to discuss some of the proposed changes with CETA in Washington. I'm going to stop there. Katie, you have your hand up.

Katie Ware: Thanks James. So I hear that you're still considering how the market might be able to mitigate some of the risk that you're showing here. You mentioned on a previous slide, but I'm curious whether you're setting aside a certain amount of transmission capacity for market imports or how you're going about that planning. I may have missed you say that in a previous slide.

Gall, James: I didn't mention transmission. This is more about how much generation we want to plan for to handle that contingency risk of poor hydro or wind or higher loads from a transmission perspective. We have access to a significant amount of capacity through BPA to the Mid-C or other parties. It's something that our group not necessarily has spent a lot of time on in the IRP process concerned with access to market. At least in capacity constrained periods. Hopefully that helps.

Katie Ware: Yep, thank you.

Gall, James: Alright, so the next part of the presentation is looking at the Washington CETA plan, proposed planning requirements and their latest draft rules. And I thought it was important to bring this to the TAC before the rules are finalized to get some general understanding of how we think the rules may impact us. Any questions brought up for discussion could be helpful as we work with the WUTC to finalize these rules. I'll walk through what we're trying to analyze, and I have some tables and charts that show what our positions look like. Our understanding of the new requirements for meeting CETA and what this has to do with is how we show that we are compliant with the 80% 2030 carbon neutral target and then the 2045 target. In the current draft rules, there is a planning requirement which we're going to be talking about today. It's designed so that we design our system to deliver renewable energy to load. There's also an operating requirement that is really concentrated on the creation of renewable energy and retaining non-power attributes. That's not something we're going to be talking about today. We're going to be focused on the planning side of this and how we would plan our system to be capable of delivering renewables to load.

Gall, James: There's two compliance mechanisms that we have to watch out for in this planning requirement. The first is we need to have renewable generation equal to or greater than 80% of our retail load as our primary compliance in 2030. I'll go through an example of what primary compliance is. The remaining amount of our retail load needs to be met through an offset using alternative compliance. Alternative compliance, at this moment, could be all unbundled RECs, an energy transformation project or a compliance payment. There's not a lot of information out there yet on energy transformation projects. Compliance payment is likely a last resort option, so most alternative compliance will be met through an unbundled REC or a primary compliance renewable. Right now, in the draft rule, there is discussion of a planning standard time step that's not discussed. It's something that I think still needs to be addressed in the rule. What I mean by this is should we be planning to meet load on hourly basis, should it be a monthly basis maybe it's a monthly on/off peak basis.

Gall, James: But we still need to get a full description of that in the in the rule. Now we're going to be talking about monthly in this example. Risk level is another concern. Do we plan for average conditions? Do we plan for something less than average conditions? The CETA rule has a four-year requirement that we would plan to have renewables over a four-year period. That takes some of the planning risk off the table or at least minimizes it, but we still need to understand the risk level intended by the Commission.

Gall, James: I'm going to show some tables in the next couple slides and this slide outlines some of the assumptions I made in this table’s creation. What we're assuming here is monthly retail load versus generation. We're not talking about hourly yet or even on/off peak by month for illustrative purposes. And what we're assuming here is any renewable generation that exceeds the monthly retail load is going to qualify as alternative compliance. Like I mentioned before, we could look at this from an on/off peak perspective. For this expected case methodology, we're assuming this is median hydro, which is actually called out in the CETA law. It uses expect loads and then historical average wind and solar.

Gall, James: One of the major issues, at least for Avista, is how do we allocate resources between states. We’re using what's called the PT ratio. It’s how we allocate cost for resources and other company expenses between states and that's 65.5% to Washington and the remaining to Idaho. Our existing hydro will be using that ratio for wind, but we assume that Washington could purchase the hourly generation of the wind production from Idaho for a fee. For solar, our current solar facility we mentioned earlier, the Adams-Nielsen Solar project is already allocated to 100% to Washington. And for Kettle Falls, it's similar to our wind in that we assume it's allocated 65% Washington, then a purchase from the remaining share from Idaho. Keep in mind, at that facility only 95% of the generation qualifies too. There's a little bit of gas required for startups and potentially some old growth wood from Canada. Lastly the assumption for the new Chelan contracts, we’re following the same methodology we proposed in our previous IRP and CEIP that it would be allocated using the PT ratio plus the potential for a Washington purchase from Idaho. Joni, your hand is up. Go ahead and ask your question.

Joni Bosh (Guest): Thanks. I'm kind of puzzled by the second point where it says renewable generation exceeding monthly retail load qualifies as alternative compliance. Are you saying that renewable generation, you're just talking about the RECs because alternative compliance is pretty closely defined in statute? Are you talking about the energy itself and is it within that month?

Gall, James: Yep. If we had a monthly planning standard, anytime your renewable energy is exceeding your retail load, it would not be serving customers. It would be theoretically sold off system. We from a planning position would not be able to count that excess generation towards primary compliance. That is our understanding now from an operational point of view. If we retained those RECs that would still qualify, but from a planning point of view, our understanding, and this is a good reason why we're having this discussion, is we would not be able to rely on that resource for primary compliance. And maybe it's best to show this in the next table. So, if I don't quite answer your question or there's still some misunderstanding of what we think is how all this works, please come back and bring that up.

Joni Bosh (Guest): Sure.

Gall, James: OK, this table is 2030. This is a forecast we have each month and on the left we have our sales forecast and average megawatts. And we get to reduce that sales forecast by our PURPA generation from in state Washington and that calculates what is called net retail load. That net retail load is what we're targeting to be 100%, where 80% would need to be met by primary compliance resources. The next block where we have Washington share, the PT ratio share of hydro, wind, solar and biomass. Then we have added to that energy we could exchange with Idaho that we described. That's the wind, biomass and Chelan PUD contracts and that total generation is on the bottom, on average, is 577 megawatts of renewable generation that we could allocate to Washington on a monthly basis. What we can show is on that primary compliance column that shows any time that the renewable generation is less than retail load, it would count towards primary compliance. When the renewable generation exceeds native net load, then that would count towards alternative compliance. We have done that. Right there is the amount of generation that is meeting load and the amount that is exceeding load that would count towards alternative compliance from a planning perspective. In 2030, if all things go as average conditions as planned, we are just under 80% primary compliance and then just over 9% from an alternative compliance. To meet the 2030 law, we would need to add 10% of our retail load for alternative compliance and a little bit more for a primary compliance. So I want to go back to that. Joni, is this making sense of how you envision this planning requirement or do you have any other questions?

Joni Bosh (Guest): I will have questions. I wasn't sure about this chart when I was looking at it yesterday, so that you're talking about over the year you're looking at rather than monthly like on the previous slide.

Gall, James: Yeah, you look at each month to decide whether or not the resource would count towards primary or alternative. But we're still shooting for 80% renewable over the year. Actually, it's really over a four-year period. So, for the four-year period, it had to be 80%. I didn't want to show all four years on the chart, so I left it at one year.

Joni Bosh (Guest): Right.

Gall, James: If we add the next year and 2031 was 81% and then 81 or 80, we hit 80% and would be compliant over that four-year period.

Joni Bosh (Guest): This looks like if, and I'm sort of guessing here, that the hydro, the access to hydro that you have in the spring pretty much gets you to the 80%.

Gall, James: Yeah. So that access to hydro in Q2 since you're limited at 100%, so you're taking the amounts between theoretically 80 and 100 for those months and that can help you offset your shortfalls in the other months.

Joni Bosh (Guest): Right.

Gall, James: It gets you to that 80%, but we're not counting all the generation that's in excess of load doesn't count, but up to the 100% it would count.

Joni Bosh (Guest): And then the excess you're treating as RECs rather than as energy that would be applied to the 20%?

Gall, James: Right.

Joni Bosh (Guest): And so, the average line at the bottom? Is that just something you'd multiply by 12? Is that how you're treating that?

Gall, James: Oh, that is just if you take the amounts each month and multiplied by how many hours in each month, then divide all of those by 8760. That's the average over the course of the year.

Joni Bosh (Guest): Right. OK.

Gall, James: You would do this on a MW hour basis in reality. The problem with just showing MW hours it's harder to relate for a lot of us.

Joni Bosh (Guest): Uh-huh. And these are all average MW hours on this.

Gall, James: Yeah, average megawatts, yes.

Joni Bosh (Guest): Average megawatts. OK, thank you.

Gall, James: Yep.

Joni Bosh (Guest): Yeah, I'll look at this. Thanks.

Gall, James: And you know, the Commission could ask us to do this on an hourly basis. They may ask us to do this on a on/off peak monthly basis from a planning perspective. I think it makes the most sense to keep it at no less than monthly on/off peak. Because when you go down to the hourly basis, you're making a lot of assumptions on how we may deliver power. Where monthly on/off peak, might be more reliable, and then then drilling down to the hourly level. But the Commission is still, I think, wrestling through some of those decisions on how the utility should plan for this. I wanted to go through this as our vision of what this might look like. I don't know when the final rules will be made. I think it's final in maybe June, but there might be a draft coming up shortly.

Gall, James: I also want to keep in mind that while right now we are a little over 10% short on the alternate compliance, there is definitely a REC market available including RECs from our Idaho hydro production that could be available to offset that. Where I think I'm going here is 2030, from an average energy point of view, is pretty much compliant with the CETA law assuming that we were able to get normal conditions and the energy we could transfer from for the wind, biomass and Chelan PUD contracts are able to be transferred to Washington. We're looking pretty good to meet that 2030 law.

Joni Bosh (Guest): Can I have some clarification real quickly before I moved just back on that one, I may have misunderstood. I may have confused myself. So, all of your hydro is in your hydro column, your alternative compliance column then is all RECs.

Gall, James: Sure, go ahead. We're showing here the amount of energy that we produce. That exceeds load, so it's our generation. It creates a REC. We hold that REC, so we're not buying a REC, this is just how much the company allocated to Washington is exceeding its load. Whether you call that a REC or excess renewable generation, it's still from our understanding of how the law works, is that would count towards alternative compliance. Even though we generated it, we retain the REC. It may have been sold off system, but that's our understanding how alternative compliance would work in that situation.

Joni Bosh (Guest): Hey. I'm not sure I agree, but I'm going to look at this and then I'll get a hold of you. Thanks.

Gall, James: OK, that works for me.

Joni Bosh (Guest): Yep.

Gall, James: Of course, that could change in the next month.

Joni Bosh (Guest): Yeah, exactly.

Gall, James: So just to wrap things up, to show the full 20-year look out in the future. The green bars represent how much under this methodology we could count towards primary compliance, which is the amount that's under the monthly retail load. The blue is showing the excess generation by month which would be alternative compliance. The black line represents what the target is for the primary compliance goal, where it's 80% through 2033, then ratchets up by 5% every four years until you had 100% in 2045. One way to look at this is if you compare the green bars to the black line that shows our shortfall for primary compliance and then the shortfall between the top of the graph and the blue represents the shortfall from alternative compliance. I would remind everybody that from an alternative compliance point of view, I think of Avista has RECs or renewable hydro from Idaho that is available that could be sold so long as there is no national or state RPS in Idaho. We may not be planning to build resources to meet alternative compliance needs but the primary compliance is what our modeling will try to solve in our resource strategy. There could be an adjustment for risk as we mentioned before, but right now, our position is looking pretty good to meet the 2030 law, at least on an average point of view. That's the last slide I have. We're at the time I was hoping for, and if there's any questions, go ahead. OK, so I think we're planning on taking a break at this point. We were planning on getting back together at 10:00 for a non-energy impact presentation from DNV. So why don't we go on break and I will see all at 10:00 o'clock.

Non-energy Impact Study, DNV

Gall, James: I just want to do a quick check to see Stephanie if you are online.

Whalley, Stephanie: Yes, I'm here.

Gall, James: OK, I think the plan is that if you can share your screen, if you want to. See if you're able to do that.

Whalley, Stephanie: Sure.

Gall, James: We can always do it as well if something doesn't work out. I'll stop presenting. Alright, I do see it. It seems like it's working, so we'll just give everybody a couple more minutes to come back from break and then we'll introduce you and we will get started.

Whalley, Stephanie: OK, sounds great.

Gall, James: OK, hopefully everybody made it back. I have 10:00 o'clock. I want to introduce DNV to the TAC. A few months ago, we contracted with DNV, specifically with a Stephanie Whalley, who's going to be presenting today, and Shawn Bodmann to conduct a supply side non-energy impact study as one of the to do items out of the last IRP. The UTC Staff recommended as we look at the non-energy impacts to the resources that we look to acquire and own. We've been working with DNV for the last several months putting together what are the costs and benefits to societal cost, at least to our customers and others as well. I want to turn it over to Stephane and if you want to go through your presentation and we welcome questions at any time, or do you want to have them at the end? It's up to you and.

Whalley, Stephanie: That sounds great to me. We can take questions as we go along. And we'll also have a discussion time at the end if there's any larger questions.

Gall, James: OK. And then if you have a message you want to put in chat for a question, I'll try to interrupt stepping in at the appropriate time and read those off. So, with that go ahead and take it away.

Whalley, Stephanie: OK, great. Thanks, James. Good morning everyone. As James said, I'll be presenting on the non-energy impact study that we've been doing with Avista for the last several months. I'll begin with a brief overview of the project and then present the approach we used to gather and apply the non-energy impact values. Following that, I'll show some of the results from this study, the study and then cover some of the gap analysis components where we identified key data gaps that could potentially benefit from additional research. And then finally conclude with a discussion.

Whalley, Stephanie: OK, so what is a supply side non energy impact? It's essentially an externality which is an impact that is not reflected in the cost of a good. And in this case, energy. On this slide, you can see some examples of what is typically included in the cost of energy and then what typically isn't. For many things, the line between what's included in the cost of energy and not, it is pretty clear. For instance, the examples here: jobs, direct economic impacts, fuel costs, those are part of the cost of energy. Whereas things like health impacts due to emissions or fatalities throughout the supply chain likely are not part of the cost. But there are other cases, for instance water use, which we have listed here in both examples where the line can be a little bit less clear. For instance, when water is used to produce electricity the costs of withdrawing the water or processing it. That would be assumed to be part of the cost of energy, but there may be other societal or environmental costs that aren't included into that. The cost that's paid for that water. And a lot of those sort of external costs can be a little bit more challenging to quantify using that water example.

Whalley, Stephanie: The goal of this project was to provide Avista with quantitative dollars per MW hour estimates of non-energy impacts for a variety of generation technologies and scenarios. To do this, we started out with a jurisdictional scan to identify non-energy impacts that might be currently in use by other jurisdictions. The jurisdictional scan didn't turn out very much, so it won't be the focus today, but the key take away and the reason it's worth mentioning is that this is a pretty new approach that we're taking here.

Whalley, Stephanie: The next part of the project was to develop the NEI database. Much of our discussion today and the presentation will focus on how we identified readily available non-energy impact values and monetization approaches. Then after the database development, we moved on to database application, so this is where we're taking that database and then we're applying it to Avista’s scenarios. And then finally, we have the gap analysis where we looked along that whole process as we're developing the database and identified key area metrics that were missing in the data that could benefit from additional research.

Whalley, Stephanie: OK, so next I'm going to discuss the approach that we took specifically for assembling the database and then applying the database to Avista scenarios. Our approach was to identify readily available non-energy impact values and monetization approaches. We primarily used federal regulatory and then some academic publications. While primary research could be more closely tailored to the specific jurisdiction to the specific resources, using secondary research, particularly at this stage of the process, provided a number of benefits as we're starting to quantify and monetize non-energy impacts. This approach cost less than primary research can be conducted, conducted faster and then can also be used to identify and prioritize gaps for additional research.

Whalley, Stephanie: This slide summarizes the database compilation approach we took. The approach involved identifying any values, that the figure to the left, and then also monetizing those values and throughout the whole process we identified any gaps in the data that could benefit from additional research. For some metrics, such as emissions, we were able to use values directly from Avista, but for most other metrics we relied on values from other publications or sources. Whenever possible, we tried to use the same source for all of the different generator technologies we were considering to minimize differences and methodologies across technologies for the same metric.

Whalley, Stephanie: That is the kind of wrapping up the approach component. Uh, we unit found a number of limitations, but also benefits of using secondary research. A couple of things to note, values are not always compatible across regions for a variety of reasons, such as different economic conditions, environmental conditions or concerns. Also, sometimes studies are outdated. Some generator types, for instance, were primarily installed many decades ago, so there is limited information about what the impacts of a new facility might be. Newer technologies sometimes also don't have a lot of good source data because the technologies are developing so quickly, and the studies can rapidly be out of date. And like I had mentioned in the prior slide, we did try to use consistent sources whenever possible to minimize methodology differences, but in some cases that's unavoidable. If not, all technologies are covered in the same source. Some sources had relatively opaque methodologies, so that made it a little bit harder to know exactly what some of the assumptions were. And finally, there were gaps of course in the secondary research and this was the biggest problem when it came to monetization.

Whalley, Stephanie: This slide shows the different metric categories that we considered and then the boxes represent each NEI metric that we looked at. The green shapes are the ones that we were able to monetize and then the blue ones we were typically able to quantify to some level, but we were not able to fully monetize them. For public health, we looked at the impacts of fine particulate matter PM 2.5, sulfur dioxide and then nitrogen oxides. And for the green ones, I'm going to go through them, but we'll talk more in depth about those in the results section. The green ones, the monetized ones, will go into more detail in a little bit. For safety, we looked at direct fatalities from construction and operations. And indirect fatalities from supply chain activities. For energy security, we focused on energy burden, which is the proportion of household income spent on electricity and heating. And we addressed this metric qualitatively by assessing whether a resource is expected to increase or decrease the levelized cost of energy. We did this under the assumption that if there's a higher-level cost of energy, that energy would be more expensive for the end user.

Whalley, Stephanie: For the environment we identified land use for most technologies and were able to identify some values for project phases beyond operations, so in some cases going back to manufacturing, construction and through decommissioning. However, a land use which was difficult to monetize as we'd want to have the value for the externalities component of the land use. In most cases the land use for either purchase or leasing should already be included in the cost of energy. But for certain types of land use, we expect that there is some level of externality. There just wasn't a readily available source.

Gall, James: Hey, Stephanie, we have a hand up on a question from Heather. Heather, would you like to ask your question?

Whalley, Stephanie: Sure.

Moline, Heather (UTC): Awesome. Thanks. This is Heather from Washington UTC. The price of a resource as reflected in the price per MW hour would capture whether a resource has a higher levelized cost, and as such whether a customer would have to pay more for it than another resource. I guess my question is I never thought of adding additional NEIs almost supply side to account for. An increase or decrease in energy burden to me, that's already kind of implicit in a price.

Whalley, Stephanie: Sure. And that's essentially where we ended up, so essentially in the report we discussed that more in terms of how there are these other burdens, but we didn't factor it into the final dollar per MW hour.

Bodmann, Shawn: When we were talking to about this, James - jump in on this, one of the things we talked about was part of the process here right. The IRP process is to take those LCOS for the different sources and do the computations you need to do in order to get them to that you know the cost per MW that a customer would pay.

Gall, James: This is James. And I think the whole concept here is energy burden is a function of cost, utility cost or resource cost. But it has an effect on the customer that needs to be considered and in part of the CETA requirements that we include in the CEIP these customer benefit indicators, energy burden shows up and we have metrics for that. I think this is just connecting the dots between that affordability customer benefit indicator and what we're doing through our resource planning. I did see another hand up and I think it was Joni. Do you have a question or comment?

Joni Bosh: Yeah, I have a shared I think some of the concerns Heather just raised. It seemed to me like energy security rather than being energy burden might be something like how can you depend on your power or how many outages do you have? That kind of stuff of is it a neighborhood more likely to lose their power than other neighborhoods. So, if you could talk about that a little bit because energy burden is just calculated on your income and what you're paying for your bill.

Whalley, Stephanie: Sure, we did explore looking at it in terms of outages and from that perspective, the challenge was we were trying to tie the NEI metrics to specific resources. Whereas a lot of the outage issues and whatnot would require a different level of analysis then we were focusing on here.

Joni Bosh: Sorry. Some of these values, and I have to admit I haven't read the report yet but heard some of these values going to be in some cases positive numbers for some resources and negative numbers for the exact same value for other resources.

Whalley, Stephanie: We were not looking at one resource displacing a different one. We were looking at the impact of each individual one, so economic impacts are generally positive. Whereas, safety, public health, those tend to be negative impacts for everything. Excuse me.

Joni Bosh: OK.

Bodmann, Shawn: A bit more on energy security. This is Sean from DNV. We were looking at a definition of energy security as access to affordable energy and so those reliability statistics is the access part. As Stephanie was saying, that was outside of what we were able to assess when we're talking about a specific generation source. That left the affordability part. That's why we have energy burden here for energy security.

Gall, James: I want to add one more thing on security and a lot of it has to do with reliability. Some of this comes down to the resource choices, or really the transmission or distribution system. If I have a resource that doesn't matter necessarily where it's at, it could be a transmission or distribution issue that is there. The cause of the energy security issue rather than the specific resource, some resources that you may locate on the distribution system may or may not benefit energy security. I don't think it's necessarily a resource specific value. It may be a value of the security that we would apply to certain resources. That's why I went after the discussions with DNV. I think it's something we need to explore after the fact on a resource specific basis, but maybe a locational basis of the resource. Alright, I'll turn it back over to Stephanie.

Gall, James: I don't think there's any more questions yet.

Whalley, Stephanie: I think we stopped with land use, so water use. We identified water use for the operations phase for many technologies as well and we focused on water consumption. That's water that's lost during the process either, evaporation or from other reasons. Like land use, we found it was difficult to monetize this one as the cost for withdrawing the water or utility costs would be assumed to be part of the cost of energy, whereas the sort of externality costs there, so potential. Like tradeoffs for using water for electricity versus something else was more challenging to monetize.

Gall, James: We have a question from Joni on the chat, Stephanie, on water contamination. You have a thought on how that would be evaluated?

Whalley, Stephanie: Are you thinking water contamination where you have to keep the water in a holding pond or water treatment or environmental contamination?

Joni Bosh: Some process that ends up being unusable, let's say.

Whalley, Stephanie: Yes. So that would fall under water consumption because it can't be returned to the environment, that's the portion we focused on. But we didn't find.

Joni Bosh: I would say. I'm sorry. It's not a volume question to me, it's a contamination problem.

Whalley, Stephanie: OK, so in terms of keeping it out of the system? I'm trying to think.

Joni Bosh: Yeah, I mean, if it has to be treated before it can be safely released into a creek or something like that, or if it has to be contained for some reason, or if it goes through a process and ends up contaminated. I'm just curious why it's just water use rather than say, water degradation. Or both.

Whalley, Stephanie: I believe that was actually part of water consumption, because it can't be immediately returned to the environment. But we did not find a good way to monetize that. From what I'm remembering from the specific definition from the source as it was, it could be evaporation, which is what I mentioned, but also if it can't be returned to the system or the environment for contamination reasons.

Gall, James: This is at James I want to add one thing here and with quite a bit of discussion on water issues and if there is a clean-up process or a consumption of water, those are usually embedded into the cost of the resource. There is an impact, but it is one of those impacts that are embedded into the cost of the resource when we're trying to do here is estimate the impacts that are not included in the resource cost and if there is a contamination problem that extends outside the resource cost, that's one issue. We're trying to capture the values that are not already included in the resource cost.

Whalley, Stephanie: And for wildlife impacts, we identified bird fatalities for fossil fuels, nuclear and wind but we were not able to monetize those impacts. And for wildfire, we were unable to find a resource specific wildfire risk value, so we used greenhouse gas emissions as a proxy for climate change impacts. As climate change has increased, the severity can impact the timing of wildfires. We did see some research looking at length of transmission lines and those types of metrics that might be worth further pursuing, but there wasn't anything that was resource specific.

Whalley, Stephanie: OK. And then for economic impacts. Actually, induced jobs really does fall under this induced value add because they work together. But we were looking at the jobs and value-added impact that were above and beyond the direct jobs created by constructing and operating a generator. We'll go into more detail on that and the public health and safety as we move into the results section in a couple slides.

Gall, James: Stephanie, there's another question from Jim Woodward. It's a good time. We can ask that question.

Whalley, Stephanie: Perfect.

Woodward, Jim (UTC): Thanks, James. Hi, Stephanie. Thanks for this presentation so far. I raised my hand when you mentioned, I'm going to admittedly paraphrase you, but wildfire serving as a proxy for climate change. And that that did get me thinking that maybe I missed it, but I haven't seen too much in the way of in the way of looking at climate change, especially in GHG emissions, reflected here and maybe this is what I call a sandbox question because I know on a different set of metrics front customer benefit indicator metrics. This may be outside your specific purview, but at some point NEIs stop and CBIs begin and there may be some overlap but some complementarity as well. I just wondered if you could speak a little bit more to GHG emissions and is that a part of this or is that really outside this quantification focus right here?

Whalley, Stephanie: Sure. Under wildfire, we used greenhouse gas emissions as a more qualitative discussion of which resource types might be more likely to have a higher wildfire risk. It's admittedly a bit of a stretch, but there is some research showing the connection between climate change and wildfires. We didn't use greenhouse gas emissions in other aspects here because James I believe the social cost of carbon goes into another part of your analysis. That's outside of what we did.

Gall, James: That's correct. So, Jim, as you know, we have to include the social cost of carbon in our evaluation for the resource plan for the State of Washington. We didn't want to have DNV spent a lot of time on the carbon side of the non-energy impact since those are already included elsewhere. In the event of wildfire, if that if it looks like that any could potentially be at least proportionally accounted for in that side of things. If there's other non-carbon related wildfire risks such as transmission lines, that might be something that we need to look at in that gap analysis.

Woodward, Jim (UTC): Thanks. That's helpful. Again, just trying to delineate where the focus of one set of indicators stop, there wouldn't begin, so thanks.

Bodmann, Shawn: Speaking to Heather's comment in the chat, so you know that trend, I think the transmission is really the most direct risk for wildfires. If you have a high voltage line going through a wooded area. This study was just looking at the generation. We didn't have any sort of transmission data or scenarios that we could take into account. That piece of wildfire risk is just is just outside of what we were analyzing here.

Whalley, Stephanie: These tables summarized the data coverage by generator type of the NEI metrics that we looked at on the last slide. Most of these, you'll see a check if we have information for that particular resource and any for economic, there's a few that have sort of the squiggly line here and that's because we used a different method to approximate impacts and we weren't able to fully quantify those in the same way, but we'll get into more details on that in the economics results discussion. One of the key things to note here is that the newer generator types such as hydrogen electrolyzers, batteries, non-natural gas generator types tend to have fewer identified values and this falls along the line of earlier discussions where it sometimes takes a while for the secondary resources to catch up with the technologies. Conversely, you can see that the more established technologies do have pretty good coverage for most metrics. So now natural gas. We had liquid air, renewable natural gas, trying to remember what the other ones are off the top my head, I think there's another hydrogen one.

Gall, James: Yeah, this is James here is, think about biofuels, hydrogen, liquid air, RNG. The idea here is using a gas turbine technology, but it's not burning natural gas to create power.

Whalley, Stephanie: All right. Are there any other questions on the approach before the next section? OK. So next I will walk through the results of focusing on the NEI values that we were able to monetize. Public health, safety and economic impacts, and then we'll look at an example of how we applied the database too. The scenarios we're looking at. Starting with public health, we looked at fine particulate matter, sulfur dioxide and nitrogen oxides. These were readily available values. I mean, these are all specifically for the operational impacts. The values we used here you can see are primarily from Avista and in some cases also from EGRID and for the cost component of the calculation, we used EPA's COBRA model to calculate the dollars per ton. The COBRA model produces cost estimates per unit of emissions for every county in the United States, so the model results are primarily dependent on the location of the facility and how those emissions would disperse throughout the United States. It’s important to note, like emissions that go into Canada aren't accounted or into Mexico or not accounted for in the model there's some, dependent on population level. All these other different things that can go into the cost estimation. To the right of this slide, you can see an example of the summary output from COBRA. It provides the change and incidents like increase of various health impacts as well as the monetary impacts of those. And the costs associated with these emissions cover everything from increased mortality through more minor impacts such as increased numbers of restricted activity days. And they are focused on respiratory and cardiovascular impacts.

Gall, James: Stephanie, you have a question from Heather.

Whalley, Stephanie: Sure.

Moline, Heather (UTC): Thanks, Heather from UTC here. I want to make sure I'm understanding the scope of this. When natural gas is extracted from the ground, there may be some public health and emissions impacts there, but we're specifically talking about when electricity is generated from natural gas, so specific to the generation plant and not the very beginning of that process for example.

Whalley, Stephanie: That's right. Yes. This is operations focus because that's where we were able to find the emissions values. Theoretically if, for instance, emissions estimates from a natural gas extraction facility, we could put that into COBRA and get an estimate. But we don't have those values at this point. OK. So, we took the tons per MW hour from the emissions values. And then the dollars per ton from the COBRA models to calculate the monetized health impacts in terms of dollars per MW hour. And you'll notice for some of the impacts, we focus on the dollar per MW hour and then some per MW. But since this is based on electricity generation, we've used MW hours here. This figure shows the monetized health impacts from fine particulate emissions for existing and proposed generator types. As I had mentioned in the prior slide, the COBRA model produces county level impacts for the entire United States. We've summarized those into three categories here. The dark blue bars show the impacts on the county where the resource would be located. He caught the site county here. The light blue summarizes the impacts on Avista's territory. And if the facility would be located within Avista's territory, you'd get the total impact on Avista's territory by summing the dark blue and the light blue bars. And then the green bars are the impact for the rest of the United States. And another note, for hydro, wind, solar, nuclear that don't have operational PM 2.5 emissions, we've collapsed those here into to single row.

Whalley, Stephanie: For existing resources, Colstrip and Kettle Falls have the largest impact on the United States as a whole. Another thing to note is Colstrip, which is in Montana, you can see here has very little. There's tiny little lines of four Avista in the site county so you can see how the location of the resource does impact these results here. Joni, I see you have a question.

Joni Bosh: What's the difference between the proposed and the existing?

Whalley, Stephanie: Thank you. The existing are Avista's current facilities and then the proposed are some of the other potential sites that they had asked us to look at, like Kettle falls, I think that would be a potential expansion of the current facility. Same for Colstrip. And then like some of these other ones, it says northern Idaho, so it's more of a general location and when that's the case, we typically used one of Avista's existing facilities as the location.

Joni Bosh: So, this is over a period of time between or measured at what 2030 or 2045 or what's the time?

Whalley, Stephanie: We used $2021, but this is per MW hour. I mean that's like.

Joni Bosh: I'm not quite sure I'm following Colstrip, for example. So, if you could talk through Colstrip between existing and future Colstrip is out in 2025, out of bills.

Gall, James: This is James I just want to clarify this section. The bottom is if we had it as a resource option to choose between for alternatives to our preferred resource strategy. So, we're selecting resources, these are the values we would assign for a new generator for resource selection. So the Colstrip one on the bottom would represent, not that we're going to go out and build a coal plant, but if we had a coal plant as an option that was located in Colstrip, this would be the NEI for PM 2.5 for that resource.

Joni Bosh: Using current technologies rather than the existing Colstrip technologies?

Gall, James: Using the newer technology, which is why the emissions are lower.

Joni Bosh: OK.

Gall, James: Those are all resource options, so when we do our resource selection, we can include these values in addition to utility costs values to have a more comprehensive cost analysis.

Joni Bosh: OK. Thanks.

Gall, James: I want to add one other thing on Kettle Falls and this one is a debatable issue that we probably still need to wrestle with. Kettle Falls, you can see there is high levels of PM 2.5 at least per MW hour. That resource uses waste products, so the question is, that waste product, would it be burned otherwise or be emitted into the atmosphere in another way. On a net basis while the plant is emitting this amount of PM 2.5 would it have already reached the atmosphere regardless of whether it was burned at our facility? This is one of the plants that we have questions whether or not there should be this value, obviously there is emissions, but would those emissions happen regardless of Avista combusting it in their generator. I see two hands went up, three hands now. I think it went Heather, Jim then Art. Will try to go in that order. So Heather, you want to go first.

Moline, Heather (UTC): OK, sure. Thanks, Heather from UTC. I'm going back to my question from before. I definitely know that there's data about pollution around coal mining facilities, but I don't think that's included here. Not because there isn't data on pollution around coal mining facilities, but because this is specific to where coal is to Colstrip, which is where coal becomes electricity, meaning we're talking specifically at a generation site or later than that on the supply chain. I guess again, just trying to understand the scope of this study, if you could help me there.

Whalley, Stephanie: Sure, we focus specifically on operations, but that's certainly an area that could be worth the additional research because there are studies looking at, as you mentioned, health impacts around mining. But that's not something we included here.

Gall, James: Jim do you want to go next?

Woodward, Jim (UTC): Thanks James. And my question was precipitated by your comment. I was almost going to raise a question around a supply chain. Because that's how I characterized. I guess you could say Avista is based on this study I think current accounting a Kettle Falls. At this point, are you saying that what we're seeing here and what we're seeing in maybe study results assumes that Avista would take ownership of those impacts, whether it's actually occurring at the endpoint or it would occur via alternative scenario versus have decisions based on what we're viewing here already been made to say, and I'm going to speak just as an example like 20% going into Kettle Falls. If let's say 20% of those impacts would have occurred regardless, that's not reflected here. If that makes sense. Is right now the current state sort of airing on the higher side of Avista accounting for everything versus have our carve outs already been made. If that makes sense.

Gall, James: Yeah, this is everything. There's no carve out yet at this time.

Woodward, Jim (UTC): OK, so if anything based on current thinking, these are high end estimates, they could potentially go down?

Gall, James: For the Kettle Falls one, yes.

Woodward, Jim (UTC): OK. Alright. Thanks.

Gall, James: Yeah, we still need to work through that and understand what happens to that fuel if we don't take it. Somebody else would take it. Would it just be the same result? Because this is a true wood waste facility. We're not out harvesting trees to burn.

Woodward, Jim (UTC): Right, just wondering what we're seeing here could be how that might change going forward? Thanks.

Gall, James: Yep. And Art, you're next.

Art Swannack Whit Co Comm (Guest): I just was thinking about your comment about would it be burned somewhere else, the wood waste at Kettle Falls. I don't know if it's that simple and I've got two thoughts. One, it could be incorporated into some recycling type thing where they use composting as part of the factor in that, which would then bring in what's it emitting at that point, which would be probably a different substance than burn particles. Or, you know, we're also having regulations now on methane emissions from landfills and saying so, I think it's going to be tough to say what the other end result of biomass would be other than we know they've said biomass is supposedly granted some status as a positive thing for energy generation, so I don't. I'm just commenting that to me it's going to be tough to do that analysis.

Gall, James: I agree. It's been a good discussion. Obviously, this generates a lot of thoughts and that's what we're here for. So, I'll let Stephanie keep going and keep asking questions. We have until 11:30, a little less than another hour, so continue.

Whalley, Stephanie: OK, sounds good. Next, this is the figure for sulfur dioxide in health costs per MW hour. Coal has the largest impact compared to the other resources here which is to be expected based on sulfur content and these impacts are nearly all outside of Avista's territory. Next, this figure shows the operational nitrogen oxide’s health costs per MW hour, again for proposed and existing resources. For existing resources, Northeast natural gas has the highest health costs throughout the US and in the Avista territory. Colstrip had the next highest cost per MW hour throughout the US. I think one thing to note, like we are looking at dollars per MW hour, which I think gives us the cleanest comparison across technologies. But when there are large differences in the amount of electricity produced. That's another factor to think about here.

Gall, James: Art, I still see your hand up. Did you have another question or was this done before?

Art Swannack Whit Co Comm (Guest): I don't see my hand up.

Gall, James: Must be frozen on my end. Sorry.

Whalley, Stephanie: OK. Any questions on public health before we move to safety? For safety, we looked at direct fatalities which occurred during construction and operations and could include things like workplace accidents, catastrophic failures, things like that. And indirect fatalities, which include accidents related to production and transportation of materials, including things like construction operations and decommissioning. Whereas for public health we were only able to really focus on operations for safety, we do include the larger life cycle.

Whalley, Stephanie: I think I just missed part of that comment. Let me look at it. Yes. We focused on deaths and not injuries in this case. That was primarily driven by data availability here as well. In terms of the costs, we used the EPA's value of a statistical life which is the same value embedded in the COBRA model used for public health.

Whalley, Stephanie: And then we looked at fatalities per MW hour. Then the value of a statistical life to monetize dollars per MW hour. This figure shows the monetized fatality impacts. The light blue bars are from a single paper that didn't distinguish between direct and indirect fatalities, but they are both included in those bars.

Whalley, Stephanie: And then for coal and natural gas, we were able to distinguish between the two. Wind had the highest dollar per MW hour impact here. And the source had discussed some potential reasons for that included lots of smaller accidents, like plane and helicopter crashes related to wind farms a blade transport crashes into. The authors had suggested there might be more reported fatalities because of increased scrutiny around certain wind projects. Coal had the next highest impacts and that was largely driven by mining risks. And then hydro’s numbers were relatively high. This appeared to be driven by rare catastrophic events like dam failures.

Whalley, Stephanie: Before we move on, anything on safety?

Joni Bosh: I had a question. This is Joni from Northwest Energy Coalition again. I'm struggling here with the idea of only fatalities and some of these seem to be pretty much widespread. I mean, you were talking about potential airplane crashes or whatever and not including injuries and not including long term illness. I think that's something that needs to be discussed a little more because I'm not sure I need to go and look at what you actually measured here for various fatalities. For solar, I'm curious what were they?

Whalley, Stephanie: OK, so I don't remember that one off the top of my head, but I don't know if Sean, you might have the report open. We might be able to say something there now or maybe in a little bit.

Bodmann, Shawn: But I don't have it open. I'll go check it out.

Joni Bosh: OK. Thanks.

Whalley, Stephanie: And did you have another question on fatalities or we can maybe come back to that when we get to the discussion so that we have time to double check.

Joni Bosh: Yeah, continue.

Whalley, Stephanie: OK, great. Next, economic impacts. We used NREL's Jedi models for most economic impacts. They have six different models grouped by technology type. You specify the location, year of construction and then size for each simulated facility. We used Jedi default assumptions for other inputs such as share of local labor, financial parameters, decommissioning rates, and technology, like the specific technology components of the facilities. To the right here you can see an example of the Jedi output. Impacts broken up into construction and operational impacts. Additionally they're broken out into direct, indirect and induced impacts. Direct impacts include labor directly related to things like construction or operations focusing really on the onsite component of the labor and impacts. Indirect impacts are the more supporting industries, including things like construction material, gravel, fuel, those types of supporting industries. The third component is induced impacts. And these are the impacts related to reinvestment in spending driven by direct and indirect impacts. For instance, increased like people going out to restaurants more or things like that that are driven by the economic activity from construction and operations. The Jedi models give us the direct, indirect and induced jobs for construction and operations, and then they also monetize those impacts in three different ways. Earnings focuses on essentially wages paid in those cases, but we used valued added because we're trying to find which impacts made the most sense when looking from a non-energy impact. That line between what's already in the cost for energy and what's not. The value added is the difference between total gross output and the cost of those intermediate inputs. It's similar to GDP, gross domestic product. We focused for the NEI economic impacts on value added induced impacts.

Whalley, Stephanie: Before I move on, we also did have a few exceptions. Don't want to go into too many details because they were a number of things that we had to look at a little bit differently. For offshore wind, we had to make an adjustment to the induced impact based on the factor that was in the model. For coal with carbon capture, we adjusted the impact we had from the coal model. And then the biggest gap here that we will talk more about when we get into the gap analysis. There is no solar PV Jedi model. Or no up-to-date one. So, that was a limitation here.

Whalley, Stephanie: This figure shows the construction impacts for each proposed generation resource. We didn't include existing projects here because the impacts have already occurred. Other things to note, resources with longer construction periods and more infrastructure needed to support that generation tend to produce more induced impacts. And for construction, we used dollars per MW as it is more of a size dependent metric. This figure shows the operations impacts in terms of dollars per MW hour. The Jedi outputs showed the results in terms of dollars per megawatts, but we did convert to MW hours because the operations have a lot of a variable impacts, but that does in certain instances drive some of the variation you're seeing here particularly for hydro. Any questions on the economic impact here?

Joni Bosh: I do have a quick question. This is Joni again. Is this chart actually saying, let's say Kettle Falls first line in both has a more positive economic impact than Rocky Reach Hydro, is that with this chart is saying?

Whalley, Stephanie: Yes. In terms of non-energy impacts, the value add.

Gall, James: Per MW hour though.

Whalley, Stephanie: Right. Yes, that's another important distinction.

Gall, James: Yeah, because Kettle is 50 megawatts and Rocky Reach is 1,200.

Joni Bosh: Right. Well, that's what I was trying to figure out. It seems like. OK. Yeah.

Bodmann, Shawn: And it's just induced. Right. It's just the additional economic impacts from the direct and the indirect jobs that are being provided there.

Gall, James: Kettle has quite a bit of a trucking industry that supports that plant, which is why that one pops out.

Joni Bosh: OK.

Whalley, Stephanie: OK. So, one more question, go back.

Woodward, Jim (UTC): Thanks, Stephanie. I was actually waiting or deliberating whether I ask this question now or wait till the end of this session, but I'll go ahead and ask it now because I did look ahead in the slides. What I'm curious about is, I see these existing and proposed view graphs and I think I understand the meaning behind that. However, was there any analysis done to overlay these study results, especially from a price or cost standpoint? Based on the approach of Avista and my understanding, pretty much all three of the IOUs took in the 21 IRP, where they essentially used a proxy value across the board. Because if not, I would find that interesting to see how we're trending. Because my understanding is that's not conveyed in this existing and proposed parallel graph. That's basically looking at Avista's current fleet, if you will, or portfolio versus where the company plans to go as opposed to previous NEI treatments and NEI quantification the company did in 2021.

Gall, James: Jim, we didn't do any NEI treatment for supply side resources ever before. We did it for energy efficiency. The energy efficiency study had a kind of a blanket covering. And since then we have started looking at and breaking it down by resource type for energy efficiency. But this is the first of its kind for supply side resources.

Woodward, Jim (UTC): So basically, this is compared to zero in 2021?

Gall, James: Correct.

Woodward, Jim (UTC): OK. I think I'm going to ask the question.

Gall, James: Actually, I think probably the first ones to start looking at this in an IRP as well. So, it might be zero for a lot of entities out there.

Whalley, Stephanie: Right. We didn't. We didn't find any other spots they were looking for the through the jurisdictional scan.

Gall, James: We got about 30 minutes left. I'm hoping we can get through the next couple because there's going to be a bit of discussion I would imagine towards the end. Go ahead Stephanie.

Whalley, Stephanie: This is an example of how we apply the database to the various proposed or existing resources. This is looking at specifically the monetized impacts for a proposed large wind farm in Eastern Washington. The graph on the left, this waterfall chart, shows how the NEIs interact with each other. You see that the economic operational impacts are positive, that first light blue bar. Then the safety or fatality impacts are negative in the green bar public health, because specifically operations is zero here and then you get the total dollars per MW impact in the dark blue bar here. On the right, this is the impacts per MW, which were only the construction impacts. So that's a single value here. It's important to keep in mind that as we've talked throughout this and at the beginning when we were looking at the different NEI metrics we were considering that there are other impacts that these do not particularly include. We face this challenge with trying to figure out how to monetize all of the different impacts that that we did identify. Are there any questions on application?

Whalley, Stephanie: We'll move on to the gap analysis. Throughout this process we did identify a number of data gaps. This slide summarizes what those gaps are as well as where we thought they best fit on the value in effort diagram. On the X-axis you can see the estimated level of research effort we think would be needed to address the gap with the greater the effort, the further to the right the categories are on this chart. The Y-axis shows estimated value of the additional research with the highest value at the top. One thing that might stick out to you is if you look at this, there's really nothing on the low effort side. The study we just completed was trying to pick up as many of those lower effort pieces as we could. Moving into the mid effort and especially high value economic impacts from solar PV. NREL doesn't have a current Jedi model for solar PV. For the other resources we looked at, economic impacts tended to be some of the larger ones. We also had an old model that could potentially be updated, which is why it's more in the mid-level of effort. You can see there's also the higher effort. High value are wildfires and trying to figure out how to quantify those impacts. Economic impacts and public health impacts for batteries, we also identified as high value but also high effort. This is a summary of the gaps. We will also have discussion after this or we could start it now. This is our summary of the gaps from this study.

Whalley, Stephanie: So are there? Let's see. I'm just trying to look through the comments here. I haven't had a chance to read them. I think there might have been another question.

Gall, James: Let's go to Art's question on chat. He's asking about negative impacts to wildlife or changing weather downstream from wind turbines. Obviously, that's probably a gap that maybe we add to the list. But any thoughts on that one?

Whalley, Stephanie: Yes. We did not consider weather impacts from wind turbines. The wildlife impacts we did see some bird fatalities from wind turbines. We did not quantify, or we did not monetize those, and that was another one where it's challenging to monetize what that actually looks like in terms of dollar value.

Gall, James: Go ahead, Art.

Art Swannack Whit Co Comm (Guest): These are couple things I've heard about regarding this issue and I would look at beyond birds. One of the big issues is bats also. We know we have problems nationally and locally with bat populations survival. I think that's a valid thing to try and look at. I don't know how easy it's going to be on wildlife biology major, but farming county commissioner so we've heard about some of this stuff early on. The weather is one that I've heard more in the last five years from people that are farming downstream from where the primary wind blows. And you're taking energy out of the air, so you do affect what they get for weather and how that affects what's going on in the climate downstream for a ways from these. And I think it's another fact that hasn't been talked about, but it would be interesting to see the data on that if there's any out there. I think it's relevant.

Whalley, Stephanie: Sure, and on the wildlife we did talk about that. We didn't find a good source that crossed resources, but that's certainly something that we should add to this. They also talked a little bit about offshore wind was one of the things we're considering marine wildlife impacts, there's fish impacts, lots of different wildlife impacts and one of the challenges we were facing is just trying to find something that was more generalized across resources. So many of those resources are very specific to a specific location, technology type and ecosystem.

Bodmann, Shawn: Many of the wind farm permitting studies I've seen, bat and bird mortality is one of the things they look at specific to the sighting of that development.

Gall, James: This is James I have a question to the TAC. You see this list of gap analysis and effort and value is their areas of preference. I'm curious if anybody has, when we look at this again, try to continue this work as there are areas that you think we should concentrate at. I'm writing down a lot of the comments that have been made so far but with this list is there any thoughts that you would like to see preference for? Jim, you have a comment.

Woodward, Jim (UTC): I do, James. I guess it's sort of a comment maybe a little bit of saving face from my previous question to be completely honest, but when we're talking about gap analysis here, I'm equating next steps and where do we go. What I'd be curious in is, again confirming that, NEIs have not been considered for supply chain options in any previous IRP cycle. I do wonder what's the result of this so far based on these numbers run by DNV. I wondered if your team had plans to let's say initially feed this cost information into the 2021 PRS to see how the results may change or if they would change. I'm just wondering if that data point would be helpful to let this group then see a chart of where we go from here. Had you planned or are any steps like that underway right now?

Gall, James: As far as implying that the last IRP we had not discussed that we were planning on included in the new IRP. Maybe I'm just looking at the dollars we're talking about here. Would it have an impact on the previous plan? I don't think it likely would have a major impact. The only one that I would say is probably at risk would be the Kettle Falls discussion we had on emissions, but some of the early discussions we had on that plant is if we did expand it, there would be an emissions reduction. So that would need to be flushed out a little bit more, but given the dollar quantities here, I don't think it would have had a significant impact on the previous plan. Will it have an impact on the new plant? It likely it could, but I think they are reasons why this is important is when we come up with these non-energy or customer benefit indicators for Washington, this is a way to prioritize the value of some of these non-energy impacts as far as how they relate to the customer benefit indicators, because what we're seeing is the customer benefit indicators we discussed in the last TAC meeting, some of them are counter to each other. We can't necessarily improve some metrics and improve and prove all of them that there's going to be weightings between each of those by putting this into a financial term, this creates the kind of the weighting through the economic value at least for the ones that we can quantify. So there there's value in keeping it, including it would have an impact in the last plan. It's hard to say if it would have, but looking at the resources that we picked, I had the feeling that it may not have had a radical change in resource selection.

Woodward, Jim (UTC): That's helpful James, getting your gut reaction there. I am also glad you raised the CBI. I'd almost forgot the NEI / CBI interface because while this study and this discussion has been focused on the non-energy impacts, the CBIs are there and there is, at least in my mind, maybe some sort of interaction overlap, whatever you want to say. OK, so at least in terms of further study, I'd be curious to see how this effort better relates to that, because I think ultimately the idea is to go towards where possible, where feasible, a quantification of not only NEIs but also CBIs where it makes sense. Obviously, some won't. I think other discussions have indicated some won't allow for that, but others may. Maybe in terms of gap analysis, almost an interaction overlap analysis of how this effort is dovetailing with Avista's plan, future work on CBI and evolving those.

Gall, James: Yep, and that's going to be on our agenda if it fits the August or September meeting. That's the plan to discuss how this all connects and fits together.

Woodward, Jim (UTC): Great. Looking forward to it.

Gall, James: Yep. Any other thoughts, priorities, questions or ideas? I know there's more slides from Stephanie, but I just want to wrap this thought up on the slide and move on.

Terri Carlock: James, this is Terry Carlock. It's not so much from this slide. It's a follow up to your discussion with Jim and the overlap for August and September meetings that type of thing. Are you anticipating for those meetings some more results and evaluation with and without? Just so I have a better idea how this works.

Gall, James: I think we were going to talk about the process and how it would be used at that time. I don't anticipate we will have results yet about with and without these benefits and costs, that might come later. I think we want to talk about how the process would work, how it fits together before we share results, just in case there are ideas for changes that will need to be made. And then another question we have is this a requirement for Washington and what's Idaho’s thoughts on including this or not including it.

Terri Carlock (IPUC): Thank you.

Gall, James: Alright, there's another hand up, Gavin, do you have a comment?

Gavin Tenold (Guest): Yeah, is there a plan to separate? How would this visualization you're looking at change if you were to separate commercial rooftop and utility solar in terms of the gap analysis? Or are we lumping them all together there? Would wonder those categories move at all on the visualization?

Gall, James: I think it would be best to have a separate analysis for each one. Stephanie, you have any additional thoughts on that one.

Whalley, Stephanie: Yeah. Specifically, for the economic impact is that the question? I think that this top one here.

Gavin Tenold (Guest): Yeah.

Whalley, Stephanie: I had NREL’s model I think it was 7 years ago. I'd have to go back and look at it to remember if they had broken out rooftop from the other two. Lots of times their models have a variety of scenarios. They might have community and utility. They may not have rooftop, but they might have had all three. Shawn has talked to NREL and they do have a model and are considering updating it. If they update it and it has all three, then I'd put it at the same level. But if it was broken out, I just don't remember.

Bodmann, Shawn: Another thing to clarify here, value means the informational value of having that gap filled in, not necessarily the monetary value that would result from that particular NEI. Right. And so solar and battery are high in the informational value because that's likely to be a big part of future generation mixes. In knowing that information for those technologies specifically is going to be very helpful. They may or may not have high economic values in terms of jobs or induced dollars.

Gavin Tenold (Guest): I was just wondering if we're able to separate them to help guide the conversation. I think that would be valuable.

Gall, James: I agree. Alright, we got 10 minutes left before our break. Stephanie, want to finish up? I know we have some more conversation coming.

Whalley, Stephanie: Actually, the next slide is just to open the discussion. I think we're in good shape just to carry on with other discussion I think I had one last slide that I wasn't planning to present that has the abbreviation breakout for anyone who might be reviewing the slides at a later point, so I'll open it up for discussion.

Gall, James: I see a couple hands up. I think, Heather, you're first.

Moline, Heather (UTC): Thanks, Heather from UTC. I think we talked about some of the price impacts of water contamination being included in the resource cost, and then similarly, when we were talking about energy burden, I think my point was wouldn't the resource cost in and of itself reflect what the potential burden of paying for that resource is to a customer? I wondered if you could just tease out for me a little bit, and I think the explanation of energy burden you gave is the impacts to the levelized cost of energy of a resource? How is that not reflected in a resource cost?

Whalley, Stephanie: I think the cost impact should be the relative comparison in the cost comparison. I think the reason we talked about it in the report and brought it up here is that trying to draw the connection between the resource costs and how they vary and the impacts on the customer because while they're tied, there is a different impact on the customers based on how much their energy would cost. I think that's the way to draw the comparison and we used the levelized cost of energy for our discussion point, but we weren't suggesting using that as a separate number to add onto the monetization component of the non-energy impacts. Does that help?

Moline, Heather (UTC): Got it. OK. It's more a conversation point that different resources have different prices and as such have different impacts on the customer. It's not necessarily that you all are recommending adding or subtracting any amount to what that cost is in order to emphasize the effect on energy burden.

Whalley, Stephanie: Right. I think that's a good summary of what we were trying to do, yes, more qualitative discussion. And then could you repeat your question on water contamination costs?

Moline, Heather (UTC): Oh no. I was just giving an example that some impacts are already included in the cost of a resource. Thank you.

Whalley, Stephanie: Oh, sure.

Gall, James: Joni, go ahead.

Joni Bosh: Thanks. This is just a clarification and thank you for Shawn for sending the abstract. I'll see if I can find a way to open it to the full study, but it says it's from 2016 and I'm curious is this worldwide or limited to the United States because, I can't find that in the abstract. First question.

Bodmann, Shawn: It's worldwide.

Joni Bosh: OK. And second, I'm having trouble with my computer so I can't pull up a separate presentation to look backwards, some of these measurements seem to be very broadly based and some are very narrowly based. Is there going to be a summary table that we can look at all these again because just trying to figure out what the sources are on this. The fatalities come from across the world, where I could imagine there might be fewer safety standards, say in China, when they're putting together a wind project as opposed to the NOx and SOx measurements. I'm just curious.

Bodmann, Shawn: I don't think that we have a table that compiles all that together in a single place. Case we did as part of the deliverables that we gave to Avista, we have a spreadsheet that has all these values in it, and we tried to annotate that spreadsheet with the specific source for each of the values. It's a very long table that spreadsheet has a lot of rows in it. For each row, where we have a value we tried to make sure that we annotated it so that someone could go back in and do that kind of identification that you asked about.

Joni Bosh: And that you've provided to the utility, right?

Bodmann, Shawn: Yeah, this to have that.

Gall, James: This is James, we are going to be providing this draft report in the next couple weeks to the TAC to provide any other comments and also I've been taking down notes as well from the comments. We will also be providing the tables as well. I don't know if it'll be the full spreadsheet, but will be providing the tables that are in the spreadsheet form from the study as well at that time.

Joni Bosh: I would be curious, this is just a very small thing, but looking at the safety fatality injuries that are historically in the United States versus worldwide. I'm just curious why is it? Was it just lack of data or you couldn't extract it from that study?

Bodmann, Shawn: That study doesn't go into a lot of detail about where in the supply chain the fatalities come from.

Whalley, Stephanie: I think the ideal approach for that specific metric would have been to use global numbers for the supply chain and then use US numbers for the more direct impacts, but that source didn't split them out. For instance, a lot of solar panels aren't manufactured in the USA, but we weren't able to disaggregate.

Joni Bosh: OK, I guess I'm trying to remember back on which slide where I think Heather was asking about mining. Mining is to me a part of the supply chain save coal, but I you did or didn't include that for the pollution impacts.

Whalley, Stephanie: For pollution, like the public health impacts, that was only operations or safety, including fatalities that did include mining and upstream fife cycle.

Bodmann, Shawn: The mining pollution, except where that would have resulted in a fatality, that's not included in what we have. The pollution effects that we have are from the generation part of the energy production.

Joni Bosh: So only at the point of generation, not what it took to generate.

Bodmann, Shawn: That's right.

Joni Bosh: I'll think about that one.

Gall, James: We're at 11:30. I know we want to get to our lunch break. Any last comments? Thoughts? I see a comment from Patrick. I don't know if that's a comment or question. If it's a question, maybe you want to go ahead and take yourself off mute and ask, but if it's just a comment we can move on to lunch unless there's something else that's pressing.

Whalley, Stephanie: James Patrick is from the DNV team and actually did the calculations for coal and natural gas externalities.

Gall, James: Got it. Excellent. Alright. With that, I think we will take a break. We'll be back at 12:30 Pacific Time and I just want to thank DNV for presenting. This is great work. Looks like there's a lot more work that needs to be done and we're going to have to figure out how to do that going forward, but we will be sharing a draft of this presentation and of the other report very shortly with for your comment and suggestions. So again, thank you DNV team and I will see you all at 12:30.

Whalley, Stephanie: Thank you.

Natural Gas Price Forecast, Tom Pardee

Pardee, Tom: James, let me know when you're ready to start.

Gall, James: John's going to kick us off and we'll get going.

Lyons, John: I think we're all set. Looks like we've got quite a few people back online here in time. I can see your natural gas price forecast up online.

Pardee, Tom: Perfect. Thanks for confirming that.

Lyons, John: If you want to get started up then.

Pardee, Tom: Hopefully everybody had a good break up to catch up on some emails and maybe take a walk outside. I'm Tom Pardee, the natural gas IRP manager. This is named Natural Gas Price Forecasts, but there's some market dynamics involved in it. Before I start flipping through the slides, this is last year's Annual Energy Outlook from the EIA. I am aware that they just released one in March, but for the price forecasts it simply wasn't quite enough time for us to do the prices and the stochastics prior to this meeting. I believe that we're intending on updating the price prior to the final IRP, but for the RFP that's going out, this will be the price forecasts used. Interrupt me at any time for any questions. I like that type of dialogue better.

Pardee, Tom: OK, the Annual Energy Outlook. On the chart on the left, you have your reference case in the black and this is in trillion cubic feet. Going back to 2000, there is only about 20 trillion cubic feet being produced and this is dry production. The difference between dry production and what they call wet gas is wet gases liquids. Think of that as propane, butane or even oil. This is only the dry gas and I'll cover the associated gas from the oil in future slides and so you can see they have a number of different scenarios on here and it looks like the colors didn't transfer over, but they're all in the same order. The high oil and gas production is going to lead to the lower prices here. When you're looking at what they're expecting to produce from a dry production side here by 2050, there it looks like we're going to be around 42 TCF of production over that year. Let me explain the difference between the chart on the left and right. The chart on the right is just US consumption. If you're looking at why it's less than what is being produced, that would be explained by the exports, so you wouldn't have Mexico exports on here, we export to Canada in the east. And then there's also the LNG exports. With the production you have some inferred prices on here, like any supply and demand, what you're going to have is the more production you have, the lower the price. The chart on the left, you'll see the high oil and gas supply to that 52 TCF figure is going to equate to lower overall gas price on the chart on the right. To note, these are in 2020 or real dollars, so it won't have that rising effect that the nominal or inflated dollars would normally have. But essentially think of it as what the expected price would be is roughly less than $4 throughout the timeframe here and the overall production is expected to be somewhere around 42 TCF by 2050.

Pardee, Tom: So, where do we obtain this production from? This is the primary areas that we get this production from. The southwest, if you've heard of the Permian Basin, that's what's in the southwest. It's mostly oil, but there's some other dry spots in there that they do drill for. And then the east, most probably heard of Marcellus and then the Utica. It's a pretty prolific shale resource that comes out of the east there. Gulf Coast is

Haynesville and some other areas and then the rest of the United States. What do we get here in our service territories? Do we get a lot of our gas or some of our gas from the Rockies? The Rockies regions. But primarily from Canada. So, with this production is the oil, so the other was the dry gas, this is the oil. Any oil extraction has associated gas. Think of this as people or companies are primarily drilling for that WTI oil. The Permian, again that's in the southwest, you'll see the blue there, that's the largest drilling region for oil at this time. And then another thing of note that is falling off a little bit was in North Dakota in the Bakken. You can see there's some still in the Gulf Coast for oil.

Pardee, Tom: Everybody is likely heard of the Ukraine scenario in Russia. What is being discussed is banning Russian oil and gas imports and what that could do. Even Elon Musk has stated that the US needs to start producing oil as quickly as possible to counter dependence on Russian oil and natural gas and what that could do. If it does start to ramp up, it could push these projections up in the short term. Maybe they would stay the same because of the way that shale production comes off. It's very high in the front end and then it really goes down to the smaller percentage later in its life. But you would potentially see a vast increase and associated gas from these new drilling rigs that may be coming online due to that scenario in Ukraine.

Pardee, Tom: The natural gas consumption by sector, you can see there's electric power on the very top. Commercial residential transportation, we have trucks, we have the waste management runs on compressed natural gas. Think of that as the large vehicles that use that to power their rigs, industrial and then liquefaction, so LNG. You can see they're expecting natural gas consumption by sector through 2050 to be right around 96 BCF a day. Most of these do not decline. There could be some discussion on that as to whether or not residential might decline based on some policy, whether electric might decline. But anything I've seen to date, they're not expecting a huge delta in the amount of power or the amount of gas that the power sector uses or any of these other major classes of customers. To give you an idea of that, what this represents here on the left is the natural gas disposition by sector and net exports. What you're what you're looking at here is the 10-year basis.

Pardee, Tom: And if I were to exit this presentation and put numbers on there, you would see electric power actually is an increase. I think at the very end it's around 12 BCF a day by 2050. Now I mean this is just the projection. It's likely going to be wrong, but again a lot of these that have come out, even with all the renewables in the news and more renewables being taken, there's still the need for backup and for when the wind isn't blowing in, the sun has been shining for that power to be there and. But having said that in their reference case, they are assuming that some gas plants or some delta is coming off probably based on some may be more inefficient plants.

Gall, James: Tom, you have a question from Fred.

Pardee, Tom: Go ahead, Fred.

Fred Heutte (NWEC) (Guest): Hi everybody Fred here from Northwest Energy Coalition. I'm just trying to interpret this slide a little bit. Net exports, that's the lowest bar there on the graph on the left, the gray part. It makes me wonder, lots of things about the AEO making me wonder, current exports out of the US are over 10 billion cubic feet a day. And this chart does not represent that. It's not a hard number to figure out the amount of LNG export capacity, there's a dozen now, roughly speaking LNG export terminals, most of them are in the Gulf Coast, they're really big. It's not hard to track what they're doing it. And I just have to say that a lot of the assumptions about gas, and this is one, have to be revised going forward and it's no longer just a notional thing. What's been happening the last six months of course with Ukraine and what's happening with global gas markets and ultimately with the overall production of shale gas in the country, where most of the shale plays are now in decline. I mean the really big ones are still growing like Marcellus. But I just have to say it's reaching the point now where I've been grumbling about the AEO and the other national forecasts for quite awhile now. I think we actually have to confront the issue. Are they really assessing the situation as it actually is going to be going forward? The export quantities here really suggest to me that they are not.

Pardee, Tom: I don't disagree with you. I'm not sure these projections are right. In fact, I'll say they're wrong. But you know, I've looked at their new one, the new Annual Energy Outlook the 2022 one, and it doesn't differ vastly now on the net export piece here I would say what that is that we would be exporting to Canada as well but we also import from Canada.

Fred Heutte (NWEC) (Guest): Yeah, exactly. I'm not sure.

Pardee, Tom: So that's likely where that delta is.

Fred Heutte (NWEC) (Guest): Alright, fair enough. That's a complicated story. The amount of exports from Canada has been limited, has been reduced by the vast expansion of shale development in the US, which also has led to a vast expansion of exports. A fair point, I have to go back and look at the numbers, but I just think that we are seeing a pretty dramatic and this is not just because of what's happening with Russia and Ukraine, all that's very much a gas story. In addition to the war part of it and the disruption that's already causing any gas markets globally is going to affect us because we're now exposed to those events by the very fact that we're exporting gas and that the demand for exports as long as the global prices are a fair bit higher than the domestic price, that producers are going to export.

Pardee, Tom: Yep.

Fred Heutte (NWEC) (Guest): Because I can make more money doing that which is going to raise, and this is really my underlying point, which is going to raise our prices going forward. Not to jump too far ahead, but that's the real conclusion I've reached, which is we have to look seriously now at a higher gas price deck then we have been the $3 to $4 range per million BTU that also underlies market prices. It could go back to that I suppose, but we have to think seriously now about what? Through the next part of this decade, the remainder of the decade, what are the gas prices likely to be? Exports is just one factor in that. Sorry to jump in and make a lot of comments, but that's the way I'm seeing it.

Pardee, Tom: Yeah, you're good. Thanks for those comments Fred. On the LNG, you can see where some of these exports are basically going to I mentioned Mexico that's in the lighter blue. Then you have the LNG that's in the dark blue. you'll see the net imports from Canada. We also have LNG imports, that's mostly on the East Coast and they're in small quantities, but they're the net effect. It's about seven or eight TCF overall. One thing about why I was a little hesitant on including this chart, I have to be honest. That's why it's important to understand is because LNG, and I think Fred alluded to this, LNG is really up, it has a higher demand or uptake based on the price of oil. Think of oil, not just what we would use for gasoline, but for heating oil or bunker fuel. Those types of things start to come into view when you're looking to how you can most efficiently or cheaply heat your home. That's really where it's been tied to that and historically that's where the LNG price has been tied to is the price of oil. I know there's some different ways of pricing LNG now, but overall think of LNG as having a price tied to oil because you can switch it out. You can switch out LNG potentially at a cheaper price. It of course depends but it's based on oil price. If say oil is $140 a barrel now, LNG is in the money as far as switch over. I wanted to include this rig count, it’s important. Really stopped being a one to one. Let me explain this a little bit. When you're looking in the historics prior to shale, so take 2008 and go back, that's really conventional drilling. When you just basically think of it as strong going into the ground. It's really more of a known production quantity, you put it in the ground because there's a high likelihood that the oil is going to be prolific there or enough to offset.

Pardee, Tom: What they do now, and I know most of us on the phone, have heard of this, but essentially what they can do now is they can do horizontal drilling or vertical or, all kinds of even essentially make whichever you want the drilling rig and then they set charges at the end of the line and you can go 6 miles out. They set charges in the line. Why that's important is because now one line it might cost $15 million, but it might be more cost effective than say drilling a mile line. The cost might be more but it's going to be a higher production and so why I wanted to show this is that even though the oil and gas rigs are lower than what they have been in the US, and this is US, by the way, this is an international, but so gas has that associated production that comes from the oil. The oil does matter as well, but you can see there's been an uptick and that's due to the price of oil going up. Now there's been some corrections and some bankruptcies since COVID, but I think for the most part that's all been all the takeovers and mergers have occurred. Fred, did you have another question?

Fred Heutte (NWEC) (Guest): No, I think I need to figure out how to get my hand to go down.

Pardee, Tom: Oh no, that's good. I also wanted to include this. This is something we get from NBC Energy. And. Not as in BC Energy and National Bank of Canada is NBC and S&P Global, so they come out with the morning commentary. What we saw in the prior slide was just forecast so they're going to take their economic indicators into play. But what's interesting is and the chart on the left is going to show you that over the past say 4 winters production has mostly increased year over year and I'll explain what those dips are 2020 to 2021 or that red line that was six BCF that came off. There was some cold weather in the southern United States for a lot of this production is and so with production in warmer states, they don't have protective equipment, so I think I've heard windmills, has protective equipment as well, but if you remember the energy event that happened in in Texas in 2020 or the winter of 2021 that occurred in February and that's where they were having to buy energy at exorbitant amounts and there is a decent amount of press about that and the reliability of electric and gas was not there. That's the story of those two big blips. But just overall of note that you know from just 2018, the winter of 2018, we've risen almost 10 BCF. Now if that's sustainable, I don't know.

Pardee, Tom: Also, of note, if you look at the LNG export, this is something my friend was alluding to. We've had a number of new facilities come in and there's one Canada LNG that's just north of Vancouver or quite a bit north of Vancouver, but on the West Coast of Canada that's been approved and is in construction and has the ability to export as much as three BCF a day, maybe a little bit over three BCF today. You can see the amount of additional demand LNG is pulling and with that, if production doesn't come on, it will raise prices because it's that same supply and demand conundrum that affects everything. Are there any questions before I get into the expected prices and I'll explain how these were put together? Any market questions? Perfect. OK.

Pardee, Tom: We have two energy forecasting consultants doing fundamental forecasts and we use the NYMEX, or the forward prices forward price curve, and we also used the Annual Energy Outlook of 2021. You can see the vast differences mostly where the price differences are going to come from is expected uptake of demand and of course the cost or the uptake, or production of supply. I think more studies provides a better idea of what a better average might be. Rather than taking a single study and saying that's good, we've included a number of studies. We have the actual market right on this day and that was done on February 16th. We took the market price on February 16th of this year and then we had a recent study from our consultant and another study.

Pardee, Tom: We'll be updating along with the Annual Energy Outlook for the next round of prices, but you can see that expected price starts a little warm, a little higher in 2023. That's the seasonality that seems the forwards are doing to us these days and the near term is always priced a little higher or it has been priced a little higher due to supply fears and potentially weather-related fears and storage. But what you'll see is this forecast expects by 2045 we'd end up somewhere between $5.50 and $6. Let me show you what this looks like on the levelized basis. These are our local basins, we have a code that's up in Canada. It comes in at the Idaho border at Kingsgate, but think of where AECO is right around Calgary, Rockies, Sumas. The Rockies is down and say California and Wyoming, Sumas over on the west side of Washington state. It's at the Huntington, it's the other side of Huntington and Canada. It's at the border, the transfer point. Moline is in Southern Oregon. And Stanfield is kind of where the two pipes meet. The two pipelines being Northwest Pipeline and GTN. And that's an important factor because that's close to where our Coyote Springs plant is. What you'll notice here, and I guess a benefit for us, is that Henry Hub is the highest price on here. Saying that differently, although Sumas can go higher during certain points of the season, overall, it's a lower price than the Henry Hub. AECO is where we primarily transact for our thermal plants. Avista you'll note here is the lowest price on here. Taking it on a levelized basis from 2023 through 2045, we're starting between $3 and $4 for all of these basins including Henry Hub, and that's really where it starts to differ by basin. At the end you have $6, between a little over $4 for AECO and about $6 for Henry Hub. Let me show you what this looks like on a levelized cost. Taking those costs from the prior chart, what this shows is essentially an average price. We use some other financial terms in here like our capital rate, but essentially it's the price throughout this time series on a levelized basis. AECO is just a little over $3 and Henry Hub is hitting around $4.10 over this time frame and the others are roughly in between.

Gall, James: So, for that question.

Pardee, Tom: What is it like? Yeah.

Fred Heutte (NWEC) (Guest): Hi, this is Fred again. I have two points I want to make. First is the Henry Hub or the NYMEX prices are an enormous market in the short run. They always like to brag they've got the third largest commodity market in the world with a trillion dollar plus turnover. I mean real money. For about two years you have a real market with lots of buyers and sellers, a lot of in-depth insight into what the prospects are for gas supply and demand, all of that. And then after that it just falls off the cliff, which to me is not surprising in a commodity market. But it really says is the people who actually do have skin in the game don't want to make bets out beyond about two years, the market interest, number of contracts available to buy or sell. All you know is around 200,000 right now for each month drops down to maybe 15 or 20,000 a year or two from now and then goes off to virtually nothing going forward, so I don't hold those future prices in very much regard at all. You can look at fundamental analysis, how much gas is out there, how much demand do you expect and come up with some estimates, but I really don't think of them as being market set prices, futures in any real fashion. That's the first point. The second point is about the differentials. And this is a complicated issue. I'm certainly no expert on it. I know a lot of attention is paid to for example, the differential between Kingsgate and Henry Hub, or AECO, any of them. It's a pretty important thing because a lot of contracts are written in a way that regarding those spreads and there are a lot of factors that go into why those prices stay very similar or converging. You're showing it, a bit of convergence, a bit of dissimilarity here, actually that's the AECO price is 25% less than the Henry Hub price here. And I also wonder about that in particular because of the LNG export issue you mentioned with at least one maybe there are only ever be one, but we now know there will be one LNG export terminal way up north in BC that's going to pull from the same supply region that most of our supply, the Northwest comes from and we get some Rockies gas, but most of it is from BC and Alberta and that's up to three BCF a day. I'm trying to remember off the top of my head, I think BC and Alberta now are around 10 or 11 BCF a day production. You could correct me if I'm not right and it's higher. It's gone higher and it could go a little higher potentially, but they're already drilling in the best.

Pardee, Tom: It's about 15 or 16.

Fred Heutte (NWEC) (Guest): Rocks they've got and that costs or that amount can only continue if the price goes up. I really wonder about the differentials here going forward and whether the national services that you're subscribing to really, I'm not asking for any proprietary information, but really how much in-depth analysis do they do or are they basically just doing trend projections. That's my concern here because I think we've had two or three decades where we haven't had to worry too much about gas price in the northwest, we're a small part of the market for what BC and Alberta produce after all. And for the most part those prices have been pretty close to Henry or even below as you're pointing out. But is that really going to continue in the future? I think there's a very good question.

Pardee, Tom: No, I agree with you. And actually, how we how will weight these, we can mostly find liquidity on the market for three years. That's roughly what it is now. I agree with you. Sometimes it's harder to get out in that third year for sure, but on ICE where our traders are, buyers transact roughly about three years. In this forecast there's a specific weighting that we do to this and I didn't include it and I can in the final pitch. It it's really how we will blend these because that's important as well. As you're mentioning Fred, for the first two years we take the forward market. In this price, in other words, what the forward say for that day is what we consider the best estimate. But after that we don't consider it a very good indicator, and we really reduce it fairly quickly after the that third year. Good points, fair points.

Pardee, Tom: I do know, I mean, I can't tell you that. IHS is one of our consultants and I'd say they're probably the best in the industry. I could, we could probably get them. I can ask some of their analysts to see if they're looking at just trending. I doubt it. So what they generally will do is they put it into their overall global model. That will affect prices, so they have people that will look in and say we think that LNG is going to go on here and it's in this specific location and what is that going to do to the price of supply. In other words, how that global model interacts is what they will mostly do their reporting on. So fair point. Spread on a basis to Henry Hub this is just a levelized, and it was what Fred was just mentioning, is throughout the timeframe here what you're looking at is comparing Henry Hub is zero here, how much further down below is that right. AECO is a dollar, over a dollar basis on levelized cost basis lower than Henry Hub. Now there is some seasonality to this. So just keep in mind the levelized is just, think of it as an average of what the basis is to Henry Hub. It doesn't mean it's always going to be a dollar, of course, like Sumas will be higher in December than Henry Hub or potentially in January, but say maybe in June, it's not as high or it's much lower. But this is roughly what the spread is we're looking at between the hubs. Rockies has the least amount and then you'll go down from there.

Pardee, Tom: Running into the stochastics here, so stochastic forecast input, that's the expected price that we put in there from the past couple slides that I've gone over. The pyramids are what the 95th percentile of this forecast is, and then you have the 50th percentile, so that's just below the average on some of these. You'll have the average in the bar, the light yellow bar or orange. I shouldn't say colors because I'm mostly color blind. Then you have the 25th percentile in that green sideways square. These are in nominal dollars. We're running between just south of $4 in 2023 and then by 2045 we're expecting it to be somewhere around $6.

Pardee, Tom: And my final slide is this histogram of where those prices lie. The frequency of $4.20 looks like it has the highest frequency. In other words, the amount of draws had the most in that bin for between $4.11 and $4.20 or $4.21 and $4.30. But it's a fairly good distribution. And you can see the higher price on, and I think that's probably toward the end, is around that $5.96 range. Is there any questions? That's it for me.

Fred Heutte (NWEC) (Guest): Not really a question, but just a suggestion which is not asking you to shift this kind of analysis. But I wonder if it would be possible to run as a scenario another stochastic approach where the price at the center of the distribution is a fair bit higher. I mean not crazy high, but you know 6 bucks instead of 4 bucks to reflect a potential for a different pricing environment going forward.

Pardee, Tom: Yes.

Fred Heutte (NWEC) (Guest): Number of reasons for that, just to say for over the last year ago compared to now gas price today is about $4.50 at Henry Hub. It was about half that or maybe a little bit more than half that a year ago. It has been going up for the last six months and now we have the disruption with the war in Ukraine and European situation, they're very dependent on gas there, a lot of supply is going to flow to them to replace the Russian gas. It's a short-term thing, perhaps, but really the question I have is over the long run. If we're in a higher gas price environment, it's not just that the company is buying gas for customers directly, but also the effect in the power market. I really want to encourage an alternative gas price analysis this time that doesn't just include the higher prices like the stochastic approach here does, but in fact has a higher base or central priced ends so we could see what that looks like and consider what the potential resource, a good resource portfolio will look like if that happens.

Gall, James: Hey, Fred, this is James Gall. We will do that scenario just to let you know and all previous IRP's we've done a high and a low gas price forecast. If you're interested in seeing how our portfolio changed in that scenario last time that's available in our IRP.

Fred Heutte (NWEC) (Guest): Yeah, I can go back and pick it up. But you know, there's a whole lot of material to look at. But thanks for the reminder.

Gall, James: Yeah. I don't know if we'll do a full stochastic study on high, but we will do a high case. I'm glad you're on board with us to keep looking at this rather than let it go.

Fred Heutte (NWEC) (Guest): Yeah. Thanks.

Pardee, Tom: Yep. Any other questions? I will say one last thing. I have seen one of the recent studies that we need to update from our consultant and to your point Fred, it is a higher overall price by probably at least $0.40, so you'll see that reflected in in the prices that we use in the IRP's.

Electric Price Forecast, Lori Hermanson

Gall, James: I guess it's a good time to transition to the next forecast which makes all this important on the gas side. Why we talked about it is like Fred mentioned, the impact to the electric price forecast, which we're going to transition to now. Lori is going to go through our price forecast. We have about an hour, so we have a little bit more time than expected. I'm going to turn over to Lori. She was gracious enough to take on the price forecasts this time around. I've been doing it since 2004. This will be her first shot at it, and I'll turn it over to you, Lori.

Hermanson, Lori: OK. Can you see that? And can you hear me OK?

Pardee, Tom: Yeah, we can see it in here Lori.

Hermanson, Lori: OK, perfect. Thanks. I'm Lori Hermanson, senior resource analyst. A little bit newer to the group, not as new as Mike, but as James said this is my first time through this. Just to give you an overview before I get started, this is a preliminary price forecast analysis. We're going to use it for comparing the RFP responses that we expect to come in the end of this month if I have my dates right or early April. Later this summer we'll be updating this for new gas prices and other assumptions such as new IHS forecast and things like that, possibly FERC form 714's if those are in by then. Any of that data we're going to be incorporating the most recent assumptions and that will go into this IRP. And then finally we haven't completed our stochastics yet on the electric price forecast. After we've done that, we will be sharing the results with the TAC.

Hermanson, Lori: Just to back up and talk about why we do this. Price forecasts are basically trying to estimate the value of resources within the Western interconnect and of course this feeds our IRP and is just to establish the dispatch of the dispatchable resources and all of these resulting prices that we get from it helps inform our avoided cost. Finally, it could change our resource selection based on the resources in other areas of the Western Interconnect. For example, if there's a lot of solar in California and Arizona, maybe there wouldn't be as much solar selected up here. So that's not determined, but it's a possibility that it could change as a resource selection.

Hermanson, Lori: Our methodology, we use Energy Exemplar's Aurora. It's a third-party production cost model that incorporates electric price fundamentals market and it simulates the dispatch of generation and the regional load, and the outputs we get are the market prices that include both electric, just a base electric and then also an emissions price, our regional mix, our transmission usage, our greenhouse gas emissions, power plant margins, generation levels, fuel costs and then of course our variable power supply costs.

Hermanson, Lori: This is a historical look at the Mid-C electric prices and as you can see in the late 1990s, we had cheap natural gas and good hydro, so the prices were fairly low. We had the 2001 energy crisis and prices skyrocketed. The natural gas market tightened during the early to mid-2000s, we had higher prices until shale development increased supply and brought prices down. Finally, in 2021 we had some higher prices, a combination of a handful of things like the Heat Dome, low hydro year and maybe a little fear in the market. But higher prices there, and you see the forecast as of the end of February forwards going out for a few years.

Hermanson, Lori: This is a look at the historical generation mix for the Western Interconnect. I don't think any of this is surprising. Some of the big changes are increases in renewables such as solar and wind. There is an increase in natural gas, but that's mostly to offset coal plants being retired and that's everything I had to say on that slide.

Hermanson, Lori: This is basically the same look at the generation mix for the Northwest, which includes Idaho, Montana, Oregon, Washington and hydro at the bottom. You can see the variability in our hydro over the last 20 years and the significant changes you'll see as the natural gas, or I'm sorry, it's the coal plants are being retired that's being offset by natural gas and then there's increases in renewables such as solar and wind.

Gall, James: And Lori, have a hand up from Mike Louis.

Hermanson, Lori: OK.

Mike Louis (IPUC): Hi, Lori. I would like to go back to the methodology that's going to be used in this IRP. My understanding and could you tell me? The first question is the methodology that you plan to use this year the same as the methodology that was used in the previous IRP?

Hermanson, Lori: Yeah.

Mike Louis (IPUC): My understanding is that you used some market prices to make some adjustments for specific hubs in the Aurora generated price. My understanding is that it wasn't just a purely Aurora generated electricity price. Could you confirm that?

Hermanson, Lori: OK. I might need James to weigh in on that. I know that we do have one difference in this, and I'll talk about it more in a later slide. But since some of the legislation is up in the air and Washington and Oregon, we know there's going to be an emission price component, but we don't know what that is. In the mean time we have a placeholder of California's emission price. But in regards to the rest of your question, James, do you want to comment on that?

Gall, James: I'll try it. Mike, I'm a little confused. I'm not sure what you're referring to as far as adjustments. We did not adjust any prices from our last IRPs or runs, so maybe that's not the right question. Maybe I'm confusing something.

Mike Louis (IPUC): I may have got that wrong, James, but I seem to remember there were some changes made in the last IRP that basically didn't produce a pure Aurora generated electricity price. I'll dig something up and see if I can adjust my question. How's that?

Gall, James: Yeah. I can see maybe you're thinking about our RFP when we evaluated our last round of bids. We combined an Aurora forecast in a forward market.

Mike Louis IPUC): It could be.

Gall, James: Yeah, but in the IRP, we typically forecast out far enough where we don't make any near-term market adjustments.

Mike Louis (IPUC): OK, let me see if I can dig this up so I could ask a more precise question.

Gall, James: Alright, no problem.

Mike Louis (IPUC): Yep, thank you.

Hermanson, Lori: This slide is a closer view of the 2020 fuel mix, both for the Northwest and for the Western Interconnect. You can see for the Northwest where 59% hydro compared to 24% in the WECC, about half of nuclear compared to the WECC at 4%. Wind is on par with what you're seeing in the WECC. Solar we're a little bit lower at 1%. Coal we're about half of what you're seeing in the Western interconnect. And then also natural gas we're about half of what you're seeing in the Western interconnect, so the Northwest has greenhouse gas emission where it was 75% greenhouse gas emissions free and 2020, whereas for the Western Interconnect they are 49%.

Hermanson, Lori: Here's the collection of charts that is basically indicators of what's happening in the market and what we're seeing is the markets tightening. This first chart is a comparison between the natural gas and on peak electric prices. In the past, there's been a very tight correlation between natural gas and electric prices and each years IRP was pretty close to that relationship.

Hermanson, Lori: A natural gas and on peak electric was pretty close to that line in the last two IRPs, and the 2020 and 2021 IRP just starting to see a little bit of splintering or divergence from that from that tight line. And then in the 2023 IRP with these preliminary price forecasts, you're seeing a huge divergence and so basically that splintering is indicating that maybe there's more impacting the prices than just the cost of natural gas. The spark spreads are an indication of the profitability of the gas turbines historically used. See that it has been around 7700 and these last few years, with the exception of 2020, we’re seeing a lot more disparity there and higher margins, higher profitability. In the future, as we see carbon emissions as a component of the price, you should see some decreases in the spark spread going forward regarding the implied market heat rate in the past.

Hermanson, Lori: The efficiencies of the units that are being run, around 8 thousand and in the future or I'm sorry, whoops, and the more recent years of 2018 through 2021, you're seeing a more in the 12,000 level and so that's indicating there's this more inefficient mix of units being run in the Northwest, and those are the units that are setting marginal price. Finally, standard deviation of the Mid-C prices, while there was some volatility in the early years, it really spikes in these later years and you're seeing not only more volatility but more differential between on-peak and off-peak prices.

Hermanson, Lori: This slide is a closer look at that implied market heat rate, the efficiencies of the units being operated in the Northwest and it's basically the last five years on a monthly basis. Again, you're seeing higher levels of that implied market heat rate, which is indicating more inefficient units being operated.

Hermanson, Lori: In regards to greenhouse gas emissions, these are numbers for the entire Western Interconnect in millions of metric tons. The trend is that it's coming down. Up and to the left, you can see the percent change either plus or minus. Some of the states leading the pack are Wyoming, New Mexico and California. Wyoming, I think, in 2019 they converted a coal plant to natural gas. I think that's causing that big drop between 2019 and 2020 because that conversion was in 2019. New Mexico and California having some larger decreases. So same look, basically the greenhouse gas emissions, but only for the Northwest and same thing, you're seeing this downward trend. Maybe in 2020 there is, if I'm remembering right, it was retirement of units one and two at Colstrip.

Gall, James: Lori, Mike, his hand up still, I don't know. Mike, did you have another question or comment, or was it left up from last time?

Mike Louis (IPUC): Sorry about that. I need to figure out how to turn it off.

Gall, James: No problem.

Hermanson, Lori: An overall look at our modeling process. We start with Energy Exemplar’s 2020 database and from what I understand they get that database or they update that database from various sources such as NERC and EIA. And then the FERC Form 714 and Statistics Canada. We started with that database. That database is an update from the one that we used in the last IRP. To that we add other inputs such as our 80-year hydro and natural gas prices, both deterministic and stochastic. We add in regional loads, our loads and resources and other operational details. After that we run a capacity expansion module and that tells us how many new resources to add, and then we also include retirements or conversions such as the one I mentioned earlier like a coal plant being converted to natural gas. We may tweak that by adding additional new resources to meet planning targets.

Hermanson, Lori: After that, we run stochastics on our electric prices to test for resource adequacy. Then we'd rerun a capacity expansion module, maybe adjust again for meeting those targets and by either increasing or decreasing those new resource adds. Then we'd run another full stochastics and deterministic forecast, and then finally we'd run our scenarios that James was talking about earlier with high gas prices, low gas prices and others that we've collectively decided to do. So, where we are in the process, we're just starting our stochastic. We're about halfway through this process and later this summer, after all this is finalized, will meet again and update on where this all shakes out.

Hermanson, Lori: This is the load forecast, we get the regional load forecast from IHS and their forecast includes energy efficiency. We add to that net metering and electric vehicles including the hourly shape and then all this goes into Aurora to determine what the load shape is and how it differs over the 22-year planning horizon.

Gall, James: Question from Jim, Lori.

Hermanson, Lori: OK.

Woodward, Jim (UTC): I appreciate the discussion so far. I had a quick question regarding the confidentiality, if any, of the data. Given you know this is run out of Aurora, that Energy Exemplar maintains, is there any again confidentiality or sensitivity around those database prices for public purposes of discussion or review.

Gall, James: I'll try to answer that Lor. The input database is a proprietary input database. Some of the information we're getting from IHS is as well. The output prices on the other hand, we will provide on an hourly level to the TAC. It'll be on our website.

Hermanson, Lori: OK.

Gall, James: Including, if you're interested in the last IRP, all of our prices are included on the website. We're trying to keep the output as much as possible available. The inputs that are not proprietary, we try to provide those when possible as well, such as the natural gas price forecasts we use will be available.

Woodward, Jim (UTC): That helps, James I guess, just trying to wonder if we do have questions forthcoming on the outputs we may I guess start to hit up on you or your team. Let us know if we start to hit up on confidentiality concerns as far as drivers for those prices. Is that fair to say?

Gall, James: Yep, I think that is appropriate.

Woodward, Jim (UTC): OK. Thanks.

Hermanson, Lori: And I have a slide about the outputs at the end. Usually what comes out of this process. We'll talk more about that in detail as we get towards the end too.

Hermanson, Lori: This is a closer look at our rooftop solar as well as our electric vehicles forecasts for the 22 years and rooftop solar. We start with EIA estimates for historical and then we use IHS's regional growth rates for electric vehicles. This is a snapshot in time, these penetration rates, but for 2040 were using 15 to 65% penetration for light duty, 12 to 15% for medium duty and 5% for heavy-duty vehicles.

Hermanson, Lori: I touched on this earlier. There's a lot of new legislation in the Northwest. For Washington, it's the Climate Commitment Act. For Oregon, the Climate Protection Program. And until those are more finalized and we know what the emission prices are going to be, in this preliminary forecast, we included a carbon price forecast based on California's emissions prices. The source for that was the 2019 EPRI carbon price projections. On a levelized basis, it was about $41.47. In addition, we also included an adder to the transmission cost for regions exporting into the northwest. This is our new resource forecasts that came out of our capacity expansion module we ran. This is comparable to what the Northwest Power Planning and Conservation Council has come up with some nuances. I think they may have more wind and we have more solar, but they're in the ballpark. And you can see, not surprisingly, renewables are increasing, coal is declining, natural gas as increasing somewhat to offset the coal, and there's increases in storage is the general trend here. As far as the resource, both historical and forecast by resource type, this is a look at the entire Western Interconnect, the major changes similar to what you've seen earlier increases in renewables. The change for 2023 to 2045 are about 42.7 average gigawatts for renewables. You see gas, or I'm sorry, coal units being retired and being replaced and actually natural gas coming off. And then there's a few other smaller resource types in there. As far as the northwest, the hydro now it's flat after the stochastics, there will be some variability in that hydro. You can see renewables are increasing for 2023 to 2045, natural gas and coal are coming off and there's a few changes in the smaller categories.

Hermanson, Lori: Greenhouse gas forecasts for the entire Western Interconnect for historical and forecast going forward. Basically, you're seeing that same trend. Emissions are coming down and this is broken out by state. When you see a huge decline in in Arizona and California, those bigger drivers that are dropping off, but everybody is trending off. And same thing greenhouse gases, both historical and forecast for the Northwest. Again, trending downwards, you see some retirements around 2025. One of those is Colstrip and I think there's a Centralia plant retirement there in that time frame. The general trend is reductions overall.

Hermanson, Lori: This is our electric price forecasts for the expected forecast. Both on an average off-peak, on-peak and super evening peak. you're seeing something similar to the last IRP where there's that differential between on-peak and off-peak, but it's a more pronounced margin between those, so they start out on par in 2023 and by 2025 you start to see this fracturing with the off-peak prices being pretty high, similar to that super peak evening price on a levelized basis these costs are $41.76 per MW hour.

Gall, James: Lori, I want to make a point here. In the last IRP, we were in the high 20s for prices, so we're seeing a significant increase in our price forecasts right now. So, it's going to have some effects on the resource choices in the next plan.

Hermanson, Lori: This is a similar look at the Mid-C, but on a seasonal basis for a handful of years. You're seeing the same sort of trend each season. However, in winter, summer and fall you're seeing more pronounced evening peak prices where the middle of the day is suppressed due to solar and possibly EV charging causing this upward spike in the evenings. This is our Mid-C price forecast compared to our IRP. All of our price forecasts from our past IRP is comparing them with how actuals are coming online in the actuals are this thick gray line and for this 2023 IRP, we're looking at the dotted black line. You can see the last IRP was 2021, this red line, so you can see how much it's increased. This black dotted line does include that carbon price, but without carbon, it would probably be in between the two. We plan to run a no carbon case so we can quantify that differential. You're seeing higher prices, those James just mentioned.

Hermanson, Lori: Next steps as I mentioned, we’re starting to do our stochastic modeling, starting to build those cases in Aurora. We'll be running stochastics to verify our resource adequacy later this summer. We plan to update the price forecast and other assumptions such as changes from the WRAP program, IHS forecast and any more information on Washington and Oregon carbon pricing as well.

Hermanson, Lori: Finally, these are the outputs from this whole process of the deterministic electric price forecasts. Typically, if this were final, we would be posting all this on our website, but since its preliminary, maybe we post it after it's finalized. If anybody has any interest in the meantime reach out to us and we can provide these outputs now. That's everything I had unless anybody had any questions?

Gall, James: Not hearing any questions. This is the last presentation. It looks like we are going to end a little early, which is not a necessarily a bad thing, but I want to leave the line open if there's any additional thoughts. While you're thinking, next steps where we're going to take a break from TAC meetings for a little while we start evaluating the RFP results. I think our next meeting, John, you presented that earlier is in August.

Lyons, John: Yes, next TAC in August.

Gall, James: OK, so what we'll be doing before August, we'll settle on a date and get that out to each of you. I'm also remembering next steps. We will be sending you a copy of the DNV study. Also be on the lookout, we may start posting more additional data as we find it available on our website. Like John mentioned, there is a new website available to look at. It’s better organized, so please check that out. Is there anything else John or Lori, or from Avista before we call it a day?

Lyons, John: No, I think that's it besides my Wiener dogs barking in the background.

Gall, James: Any questions? Jim has a question, go ahead.

Woodward, Jim (UTC): Thanks, James. Regarding there is going to be a little bit of a break between now and the next meeting in late summer. Was wondering if the team had plans to add significant data updates to the website. Would you perhaps sync that with an email out to the group just to alert us? Or are we basically on point to check your website periodically. Just kind from a public participation notice standpoint.

Gall, James: I think we'll send out an email if there's something significant. So that's a good reminder. Thank you.

Woodward, Jim (UTC): Sure thing. Thank you.

Gall, James: Alright. You guys have been quiet. We thank you for participating today. Lots of good input, especially in the NEI presentation. And again, thank you and I hope you have a great rest of your day and for some of you I will be seeing you in a couple hours that are in the CEIP discussion.

Gall, James: Alright, thank you.

Woodward, Jim (UTC): Thanks everyone. Take care.