COUNCIL MINUTES
December 12 and 13, 2017
Portland, Oregon

Tuesday, December 12

Council Chair Henry Lorenzen called the meeting to order at 1:28 p.m. All Members were in attendance.

Member Lorenzen acknowledged the attendance of former Council Chair Phil Rockefeller and former Oregon member Melinda Eden.

Reports from Fish and Wildlife, Power and Public Affairs committee chairs

Fish and Wildlife Committee

Committee Chair Jennifer Anders reported on five items:

1. There was an update on the habitat monitoring and evaluation strategy that staff is engaged in. It's an offshoot of ISEMP and CHaMP, it and looks at how to measure habitat successes. The committee got its first look at it and it will keep the Council posted.
2. There was a presentation on Atlas, which is a tool BPA uses to prioritize habitat restoration projects. It's a collaborative effort between agencies and biologists. Three watershed plans are in preparation.
3. A polycyclic aromatic hydrocarbons (PAH) story map from the toxics workgroup was shared.
4. There was a discussion on Northern Pike suppression in Lake Roosevelt. Managers put together a five-year suppression plan. It has been turned over to the ISRP for review.
5. There was an update on emerging priorities implementation, including a briefing by Lynn Palensky on the sturgeon conference held in Coeur d'Alene, and an update by Mark Fritch on lamprey work. Things are looking up in the lamprey world.

Power Committee

Committee Chair Tom Karier reported on four topics:

1. The Power Committee heard a report by staff on utility load sales and revenues. Sales and loads continue to be flat, something that has continued for 10 years, and which will continue for another year. Regional electricity sales in 2016 were lower than 2015 by 750 aMW, but were a little stronger in 2017. There were load fluctuations due to weather. 2016 was a particularly warm year, six percent warmer than average, and 2017 was comparatively colder in the winter and hotter in the summer. In addition, they discussed how just 0.5 percent of region's customers have time of use rates. Idaho power, PacifiCorp and PGE have the most. They also discussed the need for growth in the smart meter market.

2. The committee looked at long-term emerging technologies, such as enhancing geothermal — the kind that requires fracking resources. Offshore wind and tidal generation is generating a lot of interest, but there's very little of it in the Northwest. Offshore wind is popular in other parts if the world, such as Germany, the U.K. and China. But it's the fixed-base variety, not floating structures. Prices for offshore can be $100 per MWh, but they are coming down to $70. Off the West Coast, there's not a lot of offshore wind. It remains a long-term challenge.

3. BPA briefed the Power Committee on barriers to demand response. Demand response is a key component of the Seventh Power Plan. The agency conducted a comprehensive survey of customers and other stakeholders, and found that in addition to technological and organizational barriers, cost remains a key issue. Other market barriers include:

    a. A lack of clearly defined needs and value to BPA;
    b. Low power costs;
    c. Lack of a regionwide framework for valuing and pricing demand response;
    d. Absence of organized market for demand response resources in the Northwest; and
    e. Inadequate and inconsistent price signals.

4. The U.S. Department of Energy (DOE) released a proposal to revise the processes for the design, development and enforcement of federal energy-efficiency standards. Its concern is that energy-efficiency regulations aren't the lowest cost or providing the most choice, so there's a request for information to use economic incentives to try and improve it. Federal standards have been a key delivery mechanism for cost-effective energy savings, and are critical to Seventh Power Plan efficiency goals. The Council is working with stakeholders to identify issues of Council interest and draft a response by March 2018.

Public Affairs Committee

Committee Chair Jim Yost reported that the committee has nothing to report.

Member Lorenzen announced that Council Members would meet in Executive Session after today's meeting.

1. Presentation on Puget Sound Energy Demand Response, Behind-the-Meter Technology and Future Risks

Tina Jayaweera, staff senior analyst, introduced David Mills, Puget Sound Energy's senior vice president of energy operations, and Elaine Markham, Puget's policy analyst.

Mills said he was there to talk about five risks:

1. Transmission capacity
2. Generation capacity
3. Efforts to make demand response cost effective
4. New metrics needed in the power space (more than MW)
5. A high degree of market penetration

Puget just released its integrated resource plan (IRP) and it's a good example of the change that's underway in the industry right now, Mills said. Contrary to past plans, where Puget came out swinging with new thermal or gas-fired generation to meet load, this plan calls for investments in demand response, energy efficiency, battery storage, renewable resources and increases in wholesale market purchases. Market purchases are the least-cost resource. "You can't have $2 natural gas and not have that be an attractive resource," Mills said. "But it's an addictive resource and it comes with some risk." Like other IOUs, Puget will be increasing its market reliance up to the point of their transmission capacity contract rates.

The purchases Puget is making at the wholesale level are generally under a Western States Power Pool contract. "It's financially firm, not physically firm," he said. "You can cut that schedule and pay liquidated damages to your seller. I tell my traders if you have to make a choice between serving our customers with load, or curtailing an outbound schedule from a sale we might have made, you'll curtail the schedule and pay liquidated damages. The point being it will be very difficult to serve load on that contract."

He said it will be aided and abetted, by a new five- and 15-minute energy market. But when we think about challenge of distributed energy resources (DER), higher renewable portfolio standards (RPS), and the Internet of Things, it will be difficult proposition.

Puget's IRP shows that up to 103 MW of demand response and 50 MW of storage would be cost-effective in its portfolio by 2023.

On demand response, Mills discussed Puget's pilots at three sites that are planned and underway for winter 2017-18. The available peak capacity for the projects will be about two megawatts. They can call upon the resource twice a day from 7-10 a.m. and 5-7 p.m. It's a demonstration of the technology. They had to call it a pilot because it's not currently a least-cost resource that they could get into rates. In addition to refining the process so it will appeal to customers, Puget's operators have to be comfortable with dispatching it and relying upon it. Also, he said they needed help in the regulatory space in terms of making demand response more cost effective. A simple measure might be to take a hard look at the capacity value of megawatts not having to be generated during those peak hours, and attribute that to the cost-effective value.

Looking at Puget's utility business model, they will compete in five different areas at once:

1. Reliability
2. Carbon
3. Price
4. Customer experience (in King County, they're not competing against other utilities, they're competing with every other customer experience, he said)
5. Technology

Mills said Puget's behind-the-meter programs and technologies would help it balance customer expectations for reliability, for carbon-free resources and it would provide choices in energy supply.

Also, while customers are looking at emerging technologies (such as bitcoin, edge processing, etc.), the Internet of Things will provide new opportunities to improve the efficiency and use of distributed energy resources.

When it comes to a growth in electric vehicles, we've yet to see the impact on electricity loads, he said. It's woefully underestimated by utilities. As we grapple to adjust and adapt, we need to be mindful and take care of utilities. If they can't invest in those new technologies, they won't be molded to the energy space.

Mills said the most important part of utility systems in this brave new world is the distribution lines. "No matter what happens, someone will have that connection to the customer."

With all the growth in distributed energy and meter technologies, partnerships with industry will be needed. Mills described how utilities have to get more involved in technologies that can do things such as remotely dispatch trucks and other efficiency improvements.

He said that demand response and batteries could help meet peak demand and help balance the grid. However, the most valuable resources are those that will provide flexible capacity. We'll need to define what flexible capacity is and provide a standard, he said. Least cost might not always be reliable.

Member Karier said the Council is aware that Puget has explored other measures of adequacy and the value of lost load. We're doing something similar on the regional adequacy advisory committee. We hope to build something off of what Puget is doing to develop better metrics as a whole, he said. What do you think is the first thing we should be doing? The flexible capacity piece for reliability, Mills replied. We may need to start that dialogue at NERC or WECC. But we'd need this body to help transcend that through regulatory commissions. The flexible capacity piece first would drive a lot of the conversation because you probably couldn't meet your flexible capacity standard with the level of market purchases that we're making today. The distributed energy resource issue is coming at us regardless. We'll need the technology to address all those transactions that homeowners and companies are going to want to make. But I spend most of my time worrying about reliability.

The Council does look at reserves, INCS and DECS, Member Karier said. Is that the kind of area you're talking about to identify if we're sufficient in those categories?

I think it's another category, Mills said. Similar to PSE's IRP, we do a load resource balance based on average energy. We also do load resource balance based on peak capacity and extreme peak capacity. I think this is a load resource balanced based upon the flexible capacity of the region's generating system in light of the volatility. The changes in demand will probably move faster than the changes in supply.

Member Lorenzen asked, "Looking at reliability, do you focus on the five-minute increment, the one-hour increment or all the above?" All the above, Mills replied. "There is a discussion of expanding the scope of the EIM beyond just the five and 10-minute. Our region was the last to move away from an hour scheduling and trading cycle. In the first 10 months, my customers have benefitted by $10 million in revenues that we wouldn't have seen. More important than that power cost reduction, which goes back to my customers, we've seen an increase in reliability. To play in that patch in California – the five and 10-minute market – CAISO has very strict resource adequacy standards. We don't have hiccups in the five and 10-minute market." Mills added that he's not saying the Northwest needs an RTO, but there are things, such as the resource adequacy concept that they can learn from the organized markets.

Member Lorenzen said the Council uses the GENESYS model to look at loss of load probability. Is that an appropriate measure? I don't know, Mills said.

Member Lorenzen said laypeople think of batteries as a Nirvana to help back up wind generation, but the capacity available now pales in comparison to the output of a wind farm. What is the energy storage capability of a 5–10 MW battery? Mills said at Glacier substation on the border with Canada, they sited a 4.2 MW lithium ion battery near an area with 1,000 customers. That would provide about 8.5 hours for that size load. On Thanksgiving, they had a polar express and flooding, he said. The battery was charged and ready, but the dispatch technology failed. So there was no electricity for two days.

Member Lorenzen asked how many MWh? Mills didn't know. Member Lorenzen said, "My understanding is that it pales in comparison to one wind generator. Mills agreed and said he hopes we don't confuse the value of pump storage versus a battery.

Member Yost asked how would Mills start a flex capacity market in the region. "All good things start with a governance structure," Mills answered. "Is this like a power pool or an energy imbalance market? We'd have to design what the market mechanism would be. The devil is in the details. The problem we had with the Northwest Power Pool, when we tried to form our own energy imbalance market in this region, is the minute we talked about bringing in others from outside the region, the dialogue got messy. We could import the technology and staff to make that happen. We could pattern market development for any type of a capacity market: you could have a regulation market, a load-following market; you could stand it up with ancillary services or flexible capacity. You could have several products — I don't think that's a challenge. The challenge is getting the right people in the room, having a common definition of the problem and a commitment to fixing it."

2. Briefing on vision, priorities and resources for Bonneville energy-efficiency activities

Charlie Grist, conservation resource manager, introduced Kim Thompson, who recently was named Bonneville Power Administration's vice president of energy efficiency. She has worked at BPA since 2009, most of it in energy efficiency. She has a science background with a business overlay. Before BPA, she worked in marketing. She said that utilities and BPA's energy-efficiency programs are the interveners. "We have a vested interest in helping consumers make the decisions they're making," Thompson said. She described the different areas she has worked in at the agency, including managing program delivery, engineering and marketing. She ran a requirements marketing organization and, for the past 18 months, has been working to help BPA kick off its strategic plan, which is wrapping up shortly.

Thompson described the motivators that drive an entity to market energy efficiency: the power resource, customer service and public benefit. They work in concert with one another and we see all three as essential to the program we're running, she said. Otherwise, BPA would be all about least-cost acquisition, but that's not the program BPA has. But the agency isn't trying to be less cost-effective, she said. "On the public benefit side, everything we do is grounded in a public benefit, but there's a limit to it. The investments we make must bring a benefit to BPA's system. I look at intersection of the three objectives and see our program as trying to find the best balance among the three."

BPA takes it to heart that the Power Plan tells them to implement energy efficiency to the extent possible through its utilities and spread it in an equitable way. The agency's budgets are spread proportionally across BPA's customers. It has made allowances for social justice and other factors that aren't just about power resource. An example is allowing special consideration for low-income customers. "We can find flaws with our program, we understand it doesn't deliver against one of these objectives, but we do see a balance," Thompson said.

BPA is striving for scale of program delivery it wants, but it may not always match the level the utilities want. So it introduced flexibility mechanisms, such as the bilateral transfer of budgets that allows utilities to direct funding elsewhere. So far, the stacked benefits approach has worked pretty well for BPA's system. Thompson said the agency recognizes the pressures and market pricing is questioning the short-term value of energy efficiency.

When you look at energy efficiency implementation, and some customers require a 1.5-year break-even point, given power prices in the Northwest, it's a high hurdle to meet in some cases, she explained. We see stress in the system, and we're looking at at the long-term value of energy efficiency, trying to maintain a staked approach to the extent we can. But it won't serve us in all circumstances and we're aware of where those economic pressures will push us to look differently at our program design.

A snapshot from the Energy Efficiency Action Plan shows a savings forecast of 580.7 aMW over 2016-2021. Thompson said that in the first two years, BPA had its sites set on achieving 117 aMW of programmatic savings. That was split between the savings funded through energy-efficiency incentives and the savings it expected customers to deliver with their own funding. BPA hit 121 aMW in 2016-2017, a number that will go up. She there is a lengthy period when utilities can still report savings. A greater percentage of utility self-funded savings was realized: 67 percent of the savings is EEI funded and 33 percent is utility self-funded. BPA expected a ratio of 75-25 percent.

From a planning position, the agency thought the commercial sector would deliver a greater amount of savings than was realized, and they expected industrial wouldn't deliver as much. It ended up being about even between residential, commercial and industrial.

Member Booth asked how much of the savings was due to LED lighting. It's significant, she replied. Commercial lighting is about 30 percent.

Bonneville had 2,500 invoices submitted and it administered 84 bilateral transfers, where one utility releases available budget to another utility to deploy a program. That moved almost $9 million of the total energy-efficiency incentive.

They rolled out real-time oversight, which ensures that BPA or the utility has the records to demonstrate that the efficiency exists. It's not at 100 percent implementation, but it's taken a lot of friction out of the system. The agency heard a steady drumbeat from customers to slow down the churn and provide stability in its programs. It rolled out its first rate-period-based Implementation Manual in October and implemented new Energy Conservation Agreements.

Bonneville increased self-funding reliance from 25 to 30 percent, starting in FY2018. It increased EEI rollover, which helps utilities navigate the uneven timing or scale of energy-efficiency opportunities.

Member Tim Baker asked if there's more appetite for bilateral transfers. He said Montana has small customers struggling to meet their obligations, so he appreciates the flexibility.

Thompson said Bonneville does see utility agreements where they can work with each other to balance out the unevenness and opportunity over time. A utility may pledge budget to a counter party with the agreement that they'll get it back in a different rate period. That's a way for smaller utilities to flatten out their budget instead of boom and bust.

Baker said the rate period Implementation Manual is an awesome change as well. "When I talk to these folks, every one of them will say, 'We were just ramping up to get things going and all of a sudden, it's gone.'"

Thompson said two years seems like a long time to freeze a program, as they want their programs to be response to changes in market conditions. But that's a balanced tradeoff they decided to try. A bigger risk is our customers unable to get traction on their programs, she said.

Thompson discussed a pyramid hierarchy of strategies at the agency. The overall agency direction for energy efficiency is to assure that energy efficiency and demand response investments are aligned with the needs of the FCRPS and BPA customers.

Within the agency's power strategy, there are three overarching objectives:

1. Modernizing its energy-efficiency program to meet evolving BPA business needs.

2. Ensuring that agency planning and implementation include demand side and distributed energy resource solutions.

3. Having BPA advance its energy efficiency, demand response, and distributed energy resource program management and implementation.

The agency envisions modernizing its energy-efficiency program to meet evolving business needs. That includes maintaining its important regional partnership with the Council, and optimizing energy efficiency for BPA's needs and the administrator's forecast obligations. Bonneville envisions adaptively ensure the energy-efficiency program delivers least-cost, risk-managed EE with characteristics tuned to address BPA's identified needs.

BPA will start looking at its needs with a finer-toothed comb, Thompson said. Location, seasonality and time of day might be considered. In the past, its paradigm was average megawatts. That might not serve the agency's needs in the future. Congestion, constraints and other forces may push them in different directions.

Member Karier asked, "When you define Bonneville's needs, do you include needed load of your customers as well as sales? So if you're marketing and there's a high price in the market, and you can make money off it and pass it on to your customers ... is that a need for Bonneville?"

Thompson replied she'd need support from legal counsel as they have some conservative guidance about what BPA can acquire for economic advantage purposes. Most of what they're looking at from a resource planning perspective is resources to meet their load-service and transmission obligations under contract.

Thompson read from the slide presentation. The second high-level objective is expecting that agency planning and implementation will include demand side and DER solutions. They seek to fully evaluate energy efficiency, demand response and DER solutions, alongside traditional supply-side solutions for power and transmission.

The agency will select appropriate solutions for implementation, including energy efficiency and other demand side management and DER solutions, based on standardized valuation and commercialization tools.

Thompson said they have work underway to look at evaluations for demand response. That work is still underway.

A 'One BPA' demeanor drives demand side-management and DER solution definition, delivery and associated organizational support. The agency has two district areas: power and transmission, and it can't afford redundancy and duplication. It will formalize roles, processes and capabilities to develop demand side and DER products and services, carefully managing relationship, accountability and process seams. BPA will establish mechanisms to connect program costs to benefitting business line, and drive cost effective and priority-aligned demand side-management research to create an adaptive and evolving suite of solutions.

Thompson provided a list of upcoming collaborations with the Council:

- Mid-Term Assessment
    - Including check-in on regional progress on the Seventh Plan Action Items.
    - Changes to the landscape since the Seventh Plan plan passed.
    - Working with staff to provide data and reporting on achievements.

- Conservation Potential Assessment – Council staff has been an essential partner in the development of the BPA CPA.

- Resource Program – Working closely with Council staff to review inputs, assumptions and draft results.

- Continued engagement in hard-to-reach market research

- End-Use Load-Shape Research

Member Lorenzen said he had met with Thompson earlier and wanted to bring up the issues they discussed. "Within the action items there were three that were of interest: Action Items five, six and seven, he said. Item five is the quantification of the value of conservation and inclusion of that analysis in the IRP and rate settings. In the past, it seems as though conservation was viewed as a cost and there appears to be a lack of emphasis on ultimate system benefit.

Another was a look at the methodology by which you go about implementing conservation. There are conflicting considerations that BPA faces, yet it was one of the action items. Finally, the power committee gave an in-depth presentation of the barriers to implementing demand response. There also are barriers that exist with respect to implementing energy efficiency. It may assist the Council and Bonneville in understanding the barriers to implementing energy efficiency if we have an explicit discussion of those barriers. You have three weeks to finish it, because it was due by the end of December. I hope these items will be addressed, to the extent of recognizing the political realities Bonneville faces and the benefits that could come from that analysis in the midterm assessment."

Thompson said, "You may find my comments unsatisfying, but that's a risk I'm wiling to take." First, regarding the value of energy efficiency, she supports any work they can do in concert to help customers understand what problems the energy efficiency they're pursuing are slated to solve in our power system. "Looking at the slide, where in this stack the Power Plan's scale is solving problems and for whose benefit? Our customers focus on the retail utility's benefit and their customers' benefit. Anything upstream from that they don't focus on or consider. I see BPA's role in energy efficiency as solving BPA's system challenges and resource planning needs — filling a gap that we've projected for that power resource, because it's the best buy for the region. If we were not doing that, we'd presume BPA's costs and rates would be higher. There's an overarching value proposition in it being embedded in Bonneville's rates, and that's BPA's primary driver."

Thompson said because they have the ability to organize the program in a way that the local utility can benefit from a siting decision (of having the energy efficiency in their service territory), it is an additional benefit beyond the Bonneville system benefit. Then consumers get the benefit of a more comfortable home or a more efficient business process. The idea of decomposing the stack a little bit, I support, she said. Whether that fits in with our IPR proceedings or not, I'm not sure yet. In parallel to the Seventh Power Plan and Action Plan items, we're looking at our processes for establishing our cost projections and program needs. We're reinventing the IPR the next time we go through it. The concept for action item five isn't lost, but the fit for IPR, I have to assess. That's to be determined.

Member Lorenzen said the focus on marketing and helping the customer understand the benefits really resonates. Maybe it was not artfully described in the Action Plan and maybe overly specific, but the concepts she put forward are very exciting.

Thompson said, "Action Item six asked for us to convene a study to look at alternate design principles and approaches, and quantify the potential impact those different approaches could have on cost effectiveness, mix, delivery, etc. I don't plan to convene that study at this point in time. The objectives we're trying to solve for are those average megawatts, and that balancing act I painted a picture of. This is the program design decision we reached after extensive public process. Two years of an ongoing public process. I presented a couple of months ago to the Power Committee the every-other-year cadence with which we have opened dialogue on whether we have the right balance, and arrived at the same place, and said, yes, we are going to maintain our equity principal and how budgets are distributed among customers. To me, the right trigger for asking that set of questions again, about do we have the right program design, is when we need our program to deliver something different. We are delivering at the scale we intended to today, successfully within the budgets we established. What we designed is working given the objectives we fed it."

Member Lorenzen said that action item might be broader. It could be convening a group or some analysis of the program being effective enough in terms of its administration. Some of those things are within its purview. It may be worthwhile to take a look at that, just keep an open mind.

Thompson replied that they have regular and routine engagements with those who are implementing the program. We hear friction and we seek to address it. We do strive to have an adaptive and responsive approach to our program administration. That's a practice I will always hold onto. We need to understand where we have challenges and we have to be willing to face those challenges.

Member Lorenzen said, "I'm going to repeat myself on this particular Action Item. Take a look at it in the broadest sense and where it could provide some benefit to you and the Council, without going contrary to the hard processes you already put in place. There's room within this to take a look at that and come up with something that would be a benefit. The final one is the barriers."

Thompson said they don't have an exhaustive sense of barriers, but they understand the areas of friction in the system. They understand pretty well the dynamic is that keeps certain utilities distant from the program, and others eager to have more funding than what Bonneville is making available. "We understand a lot of the consumers' side of things. I gave an example of a commercial entity that had a 1.5-year break-even on an energy-efficiency investment and we just didn't have an energy-efficiency opportunity that provided them that hurdle rate to have them undertake.

"We've not gone through the type of documentation process that the demand response process is undertaking. We're in a very different implementation space. We don't have a commercial demand response program running, so we're seeking to understand if we identify a need, and we decide we need to invest in demand response to address that need, what do we need to overcome? For energy efficiency, we have contracts with our customers. We're getting energy-efficiency achievements in every service territory we serve, it's at the scale we expected to deliver at, and at the cost we put in place."

Lorenzen said, "I understand you're making your targets. But having been in my position for almost six years, I often hear utilities say: 'It doesn't make sense to do energy efficiency because we have no load growth, diminishing loads, we're small, rural and don't have the contractors to assist us.' These are all things that, if they were explicitly identified, there may be ways to address those within the confines of your existing contract. I do believe there would be a benefit to a study that would look at this. It doesn't have to be extensive. You have the knowledge. But by making it explicit, it helps address those shortcomings. I continue to urge Bonneville to take a hard look at how you would comply with that in a way that would meet the objective of that Action Plan, but do so within the confines you face. I know you know what the barriers are, because your customers are vocal and articulate as to why it doesn't work for them. It would be beneficial to the region if we could make them more explicit so we can start dealing with some of those issues and overcome some of those barriers. That's the reason for that action plan and I hope Bonneville will look at it in the future. And I'll pass that message on to my other Council Members and hopefully they'll carry the flag."

Member Karier said these are good questions and issues to follow up on in coming months. The Council always thought of its Power Plan as providing guidance. In the modeling, if you can invest in demand response or energy efficiency, it allows you to sell hydropower under conditions when prices are high for the lowest rates long-term, and makes it less likely that BPA could default in 2028 or sometime in the future. If implementation is wrong, we need to look for better ideas. I'd hate to see us go in different directions, he said. "On slide seven, looking at Bonneville's targets, I didn't hear you say anything about momentum savings. Have you calculated those? I remember staff being skeptical if those were the right numbers, and that they could be lower than that. But I didn't hear you mention that at all. Is it measured? Will it be measured?" Member Karier asked.

Thompson replied, "The research plan that will quantify momentum savings is built over time.

What I prepared today was a snapshot of programmatic savings. We have ongoing market tracking that will contribute to that quantification of momentum savings, but we have no intention of slicing that out by year for reporting in this type of an early-bird look."

"When will you have it?" asked Member Karier. "I can't answer that of the top of my head, I'll have to report back," Thompson replied.

"Because if you fall short of those targets, and need to adjust, the sooner you know it the better," Member Karier said. "You're not waiting five or six years, are you?"

"It's not a big bang at the very end, but I don't know our schedule for quantifying it," Thompson said.

"If you let me know when you do know, that would be helpful," Member Karier said.

Member Bill Booth asked about the approach on bilateral transfers. "We have small providers in remote areas that are difficult to fit into the one-size fits all program that BPA would like to have because it's easier to manage. Why not just look for the least cost to the system? If you approach Bonneville as a system, it's all one system. Maybe some of that thinking might help. If you're willing to take a look at the bilateral transfer concept, why not look at the entire system and see where you can achieve the best, lowest-cost energy efficiency, and go there. It might not be in some of these rural areas, not that they should get a complete pass. There might be come flexibility.

But first, Member Booth asked about breaking down BPA's Savings Forecast into a megawatt-hour cost. He said it's important to show a trend analysis, where it's been, where it is now and the cost.

Thompson said regarding the first point, it's interesting because from a BPA program administration perspective, the program would be simpler if they could direct where their emphasis was and the implementation of it. Yet there is language in the Power Act that directs the agency to the maximum extent possible to implement through its utilities, and that the benefits of energy efficiency are spread equitably throughout the region. That could be interpreted in various ways. "When we designed the current program, the post-2011 design process, and as BPA moved to a tiered-rates methodology and our current regional dialogue construct, we had substantive input from our customers asking for the first right of refusal that the efficiency be sited locally and proportional to the costs embedded into tier one rates," she explained. "That's the program implementation approach that we have. There are no quotas or targets established at a local utility level. It is aggregate performance we're tracking. That first opportunity to also have the siting in a local utility territory, and the bill savings spread across the consumers of the region is our program design. We've revisited it almost like clockwork every two years and, of all the things that are controversial that we've opened up, our customers have time and again quickly coalesced that the first right of refusal, that equity construct, as something they don't want to see us change. If our objectives change, that may be a different question. I acknowledge the challenges, potential and opportunities and economics that exist in the smaller and more rural residential utilities we serve. It is a real challenge. That's why we have the ability for our customers to elect to free the funding up to go somewhere else if that's the best choice for them."

Member Baker said, "I differ from Member Booth in that regard. I rarely hear them say we don't want to do it, because they have customers who want to do it. When I think about bilateral transfers, I think why not go to an online marketplace that allows seamless trading and bidding for opportunity that might lower costs?"

Thompson said that the question comes up from customers and Council Members about why BPA has a prohibition on the sale of energy-efficiency incentive budgets. "We worked to streamline bilateral transfers to the maximum extent possible, but we ask utilities to certify that they are not exchanging value as part of that transaction. The rationale is our program design also has a reliance on utility self-funding to meet the total target. Our customers don't want the full incentive cost of energy efficiency to be captured in rates. That makes sense because we're not serving the full load of public power; we're serving a share of that load. So I would expect to see a contribution in kind from utilities that have their own resources.

"With a reliance on self-funding, and if we maintain that self-funding construct, and empower a marketplace where that budget can be bought and sold, then over time, in lieu of self-funding savings, utilities would use available local budgets to buy access to someone else's budget. And the entire pie would shrink over time. Because that self-funding would shift and not directly deliver savings, it would be buying budget that today is freely given to someone who may not have the ability to buy it. That decision would start to get skewed. It is our program design belief that we would harm the overall delivery of energy efficiency if we opened that market if we also maintained our reliance on self-funding. If we removed the reliance on self-funding, and we assumed that BPA should be funding the entire programmatic base, that does shift costs from partial requirements customers to full requirement customers because of how those costs are collected in our rates. With deeper analysis, the smaller utilities that might see a gain, in the possibility of selling some of their energy-efficiency incentive, would not like the rate impact.

3. Briefing on Public Generating Pool Decarbonization Study

Ben Kujala, Power Division director, introduced Therese Hampton of the Public Generating Pool, and Arne Olson, with E3 Consulting.

The Public Generating Pool commissioned E3 to study what policies best support a least-cost approach to reducing carbon emissions, and to examine what the implications were for the Northwest utility portfolios. Randy Hardy referenced this study at the November 2017 Council meeting.

Hampton said the Public Generating Pool is a group of 10 consumer-owned utilities, nine in Washington and one in Oregon. All the member utilities operate generation, about 6 MW total. Eight of the 10 utilities purchase power from BPA, accounting for 34 percent of Bonneville's preference power. Renewable policies have impacted and have the potential to impact the wholesale power markets. How do we want to respond to that and engage?

Hampton said they employed E3 to look at least cost approach to carbon emissions reductions. It was done to inform themselves. It's not a policy position at this point. Members are reviewing this and seeing how it impacts them.

Olson provided an overview of the analysis. He first thanked Kujala and the Power Division staff for providing data and advice.

Olson referred to a graph that showed that the 80 percent reduction case is the one that hits the target. It costs $1 billion more a year than the reference case. The RPS cases cost more and don't achieve as much carbon reductions. E3 modeled 80 percent reductions by 2050. The largest producer of carbon is transportation, the second is buildings and industry, and third is electric generation. The West has less coal in its power generation mix than the East. Also the West drives larger cars for longer distances, which adds to the transportation impact. We start from a good place in the West — about 70 percent comes from zero carbon sources, Mills said. We have the system that is the envy of the country.

Due to a large fleet of existing zero-carbon resources, electric emissions intensity in the Pacific Northwest is already below other regions in the United States.

In Oregon and Washington, a handful of plants are responsible for most of the electric-sector greenhouse gas emissions in the Northwest, he said. Natural gas plants emit less carbon and don't run as often. Natural gas is less expensive going out a number of years. The low-hanging fruit is to replace coal with natural gas and you'll get a long way with carbon reductions that are relatively low cost.

Member Karier asked about smaller coal plants. He believes the Council only focuses on coal plants with dedicated contracts with the Northwest. "Do those smaller coal plants do that or do they sell into the market?" he asked.

Olson replied that the ones that look small on the map are the PacifiCorp coal plants in Utah and Wyoming. We're only capturing the load-weighted share of plants that serve load in Oregon and Washington, he said.

Olson listed the assortment of renewable technologies that could be selected, but in the short run, wind and solar are cheap, low-risk, mature technologies. But they are limited and a power system has to be built around them to mitigate reliability issues. Kujala provided some energy-efficiency data that not was picked for the Power Plan.

E3 ran five, core policy scenarios. The first reviewed the reference case, which assumes current policy all the way out to 2050, and then they reviewed carbon cap cases looking at 40, 60 and 80 percent reduction below 1990 levels by 2050. Under a "no new gas" scenario, they found that new resources are needed in 2025-2030 time frame to ensure resource adequacy due to coal plant retirements and load growth. The primary source of capacity added under the "no new gas" case is energy storage via pumped hydro and batteries.

The current-policy reference case achieves a regionwide average 20 percent RPS by 2040.

E3 ran a sensitivity analysis on various impacts, such as the loss of carbon-free resources (hydro and nuclear) and other scenarios.

Results: In the reference case, the model adds about 5 GW of new wind and solar, and 9 GW of natural gas by 2050 to meet load. Retiring coal is replaced with natural gas as a least-cost capacity resource.

Olson talked about energy balance. We have more energy than we need in the basin, so we are a net exporter. But we're growing into our hydrosystem, so we'll be using more and exporting it less. Beyond 2030, we see emissions picking up as load grows, so that's met with natural gas. By 2050, we have a 21 million metric ton gap we have to meet to get to our 80 percent goal.

Member Booth asked if 21 million metric tons is just for the electric sector. Yes, replied Olson. What's total for system? Booth asked. Maybe 120 million metric tons, Olson replied. Booth wants to get those numbers.

Olson talked about carbon cap cases that meet the 80 percent goal. In the 80 percent carbon reduction case, 11 GW of wind and solar are required. It also places a price on carbon to drive the behavior that the system needs to get down to that level. It will become too expensive to burn coal to make electricity. The incremental cost is about $1 billion a year to achieve 12 million metric tons of emissions reductions. There's enough renewables to hit a 31 percent RPS, and there's enough zero-emission generation to hit a 100 percent RPS. It calls for 7 GW of new natural gas capacity for reliability.

Member Lorenzen asked, if you want to stay away from gas, could the region maintain reliability by using battery and pumped storage? Olson replied that, the federal system was planned for that 1937 hydro year. How much benefit would energy storage have to meet peak loads? We didn't try to answer that here; it's a different study.

Member Lorenzen said, "I think people think have the false idea that the deficiency can be met without gas."

Member Karier asked, "Is there a level of adequacy associated with this? We use loss of load probability. Do you have anything like that?" Olson replied, yes, they assumed a 15 percent planning reserve margin. Then they used the load-carrying ratings of wind and solar, and used the sustaining peaking capability ratings of hydro to meet that planning reserve margin. The mid 2020s is when the region has to add capacity to avoid being short. We have that as a hard constraint in the model.

Member Booth asked if they considered the effect solar has on the California duck curve. "Did you look at morning and evening demand, and how that could be met without gas or coal? We've had presentations from PG&E today on what's going on in California. The big solution seems to be we can't build gas, so we'll go to the market. It seems like we're building ourselves a problem in the morning and evening every day. Maybe we need demand response. Maybe Johnny can't take a shower; you're not dirty enough yet. Did you look at morning and evening demand and what are you using to fill the blanks?"

Olson said they're considering the specific times when wind is available. They looked at wind from the entire region. They're trying to figure out most efficient way to meet those needs, and the market structure isn't set up for that. He's not worried about that; we'll figure that out. He is worried about reaching resource adequacy in the Northwest. By 2022, we might not be able to meet load during a drought condition. Olson said in their model, they're adding natural gas. He's worried that we're not set up to understand and act on this problem.

Olson discussed the details of the various cases: Carbon cap scenarios, carbon tax scenarios, high RPS scenarios, "no new gas" scenario, and their cost and emissions impacts.

The study's key findings are that:

1) The most cost-effective opportunity for reducing carbon in the Northwest is to displace coal generation with a combination of energy efficiency, renewables and natural gas. Existing coal plants (9 units) are responsible for 33 million metric tons of emissions — roughly 80 percent of all emissions attributed to Washington and Oregon. This includes contracted generation in Montana and Wyoming.

2) Renewable generation is an important component of a low-carbon future, however a Renewables Portfolio Standard results in higher costs and higher carbon emissions than a policy that focuses directly on carbon. RPS policy has been successful at driving investment in renewables but ignores other measures such as energy efficiency and coal displacement. RPS policy has unintended consequences such as oversupply and negative wholesale electricity prices that create challenges for reinvestment in existing zero-carbon resources.

3) Prohibiting the construction of new natural gas generation adds significant cost but does little to save GHG emissions.

4) Meeting decarbonization goals becomes significantly more challenging and costly should existing zero-carbon resources retire. Replacing 2,000 aMW of existing hydro or nuclear generation would require nearly 6,000 MW of new wind and solar generation and 2,000 MW of natural gas generation at an annual cost of $1.6 billion by 2050.

5) Returning revenues raised under a carbon pricing policy to the electricity sector is crucial to mitigate higher costs.

6) Research and development is needed for the next generation of energy-efficiency measures.

7) Vehicle electrification is a low-cost measure for reducing carbon emissions in the transportation sector.

Member Karier said this mirrors what the Council saw. Were revenues from taxes returned? Yes, Olson said, they were returned to ratepayers.

Member Karier said, "I thought a Council finding was a price for carbon on the entire West Cost where the Northwest would benefit because we're an exporter of carbon-free power. Would that be taken into account in this model?"

"We didn't look at what a Westwide greenhouse gas reduction regime would look like," Olson said. "You could see a situation where the Northwest over complies and California under complies."

Member Yost asked, "When you looked at increasing renewable wind from Montana and Wyoming, did you assume mitigation to increase the transmission capacities?" Olson said yes, they got the information from Council staff, BPA and PacifiCorp. Each resource regime has different transmission costs associated with it.

Member Yost said at Idaho Power, if you add up the resource stack with wind and solar, it exceeds its load in the winter and spring months. And they still have wind and natural gas resources that have to be sold off somewhere.

Olson said it just happens a few hours of the year and doesn't have much of a cost impact. In the 80 percent case, there are not a lot of hours where that happens. It's a much more balanced system.

Member Lorenzen asked, "To what extent are your conclusions dependent upon a continued low-price of gas?" It is a factor, Olson said. Coal to gas displacement is the low-hanging fruit. If natural gas price is higher, the renewables become more cost effective. But we still have natural gas for capacity.

Lorenzen said he hopes that policymakers take these studies into consideration.

Hampton said the materials are available on the Public Generating Pool's website: www.publicgeneratingpool.com/e3-carbon-study

The meeting recessed at 4:24 p.m.

Wednesday, December 13

Chair Lorenzen brought the meeting to order at 8:33 a.m.

4. Council Business

Northwest Power and Conservation Council Motion to Approve the Minutes of the November 14-15, 2017, Council Meeting

Member Booth moved that the Council approve for the signature of the Vice-Chair the minutes of the November 14-15, 2017, Council Meeting held in Coeur d'Alene, Idaho.

Member Baker second.
Motion passes without objection.

Northwest Power and Conservation Council Motion to Authorize the Deferral of Review of Bonneville Power Administration's 6(c) Policy

Kujala said the Council is at a place where it needs to look at 6(c) again. The policy has been in place awhile. It has been deferred for quite some time with the logic that BPA isn't looking to acquire a major resource. We're still there. This is for anything that is over the 6(c) threshold. If they changed their minds, we would revise our policy at that time. We want to continue an understanding.

John Shurts, staff general counsel, said that 1993 is the last time the policy was revised. We've looked at it every five years, he said. It's a BPA policy, but they review it jointly with us. We have had conversations with BPA and they do not want to reopen it. So we need a Council decision that we'll look at it again in five years. If the Council goes along with the recommendation, we'll draft a letter to be signed by both agencies that we'll look at it again in five years.

Member Lorenzen asked if this requires a formal action. Shurts replied it doesn't have to have one, but it allows them to put the finishing touches on it.

Member Booth moved that the Council agree with Bonneville to again defer review of Bonneville Section 6(c) policy, until such time as there is a reasonable possibility Bonneville may need to acquire a major resource; this to be expressed in the letter of agreement signed by Bonneville and the Council, and revisited in another five years.

Karier second.
Member Lorenzen asked if there's any discussion.

Member Karier said that on page two, there's a list of sources for other information that reads like a time capsule — people who are no longer there. It looks stuck in 1993. If anyone picked it up and wanted to know more, none of these people work here, he said. Is it possible to change those and put some contact number that would make sense?

Member Lorenzen suggested that, in order to carry forward with the motion as it is written, could we have a cover letter that identifies those associated with the rule?

Shurts said you couldn't change this because it's a federally registered notice. But you could attach some updated contact information.

Member Karier said someone's going to find it on the web and this won't be helpful, so anything like that.

Kujala said they'll figure out a way to address it.

Without objection, the motion carries.

5. Update on Spill Proposal

John Shurts began the update by explaining that this is not just an ESA litigation issue, this is against the Northwest Power Act. These are actions being discussed to protect fish that migrate through the hydrosystem. When the federal agencies take action, it's not just compliance with

ESA; it's also Section 4H10 and 4H11 actions of the Northwest Power Act. So it's appropriate to step back and look at what's happening, he said. Judge Simon issued an order last March and amended it in April, asking the sovereigns to work on proposal for increasing spill in spring 2018 for juvenile migration, and see if they could reach a consensus with the plaintiffs. That has happened. A lot of work has been put into this over the last seven or eight months. It has produced an order that has been filed with the courts. This is a review of what's in that proposed order and what else is happening in this proposed litigation.

Shurts said between the time he left the office yesterday and arrived that morning, he received two more items relevant to the litigation, so it's the gift that never stops giving. A lot is going to be happening in the next couple of months.

What got filed on December 8 is a proposed order on spill for spring 2018. It includes a chart with what spill will be at each project. Also filed is a 2018 Spring Fish Operations Plan (FOP). What's in front of the court is a proposed order of the chart. The FOP isn't because that's not something the plaintiffs were a part of. The operations plan is to implement the specific plans in the order. It was a joint filing from State of Oregon and main parties. In the spill chart, it is gas cap spill at the different projects — four in the Snake and four in the Lower Columbia. There are tweaks, constraints and concerns at various projects. This is a gas cap spill operation at all the projects. If it's a high-water year, it's not a problem. If it's a moderate-to-low year, it could be a problem. The dates are April 3 to June 20. It's a one-year operation.

The order has flexibility in it. One, is it allows for in-season adaptive management to address unintended biological consequences. There are concerns about spill and how it will impact adults entering the ladders. Second, there can be an in-season adjustment to address conditions in Section 4.1 of the FOP. There are a lot of possibilities that will require operational flexibility during the season. The premise is that you'll do the minimum amount needed, and get it back to a gas cap spill when you can.

There was an issue raised in the original injunction order about PIT tag monitoring. Working with the Corps, an agreement was reached to start PIT tag monitoring on March 1 at John Day, Little Goose and Bonneville dams.

Karier asked, "On the PIT tag monitoring, what's different? Will they open up the bypass earlier?" Yes, those will start March 1, Shurts said. They normally don't start until April.

Shurts said the plan doesn't say a lot about transport. It will begin May 1. It doesn't say anything about spreading the risk.

That's what's in the order that came in front of the court on December 8. At the same time, the federal government filed a separate filing. They signed on to the joint filing, but also wanted to make the court aware of their concerns. They also wanted to describe the complexities they see in implementing this operation. They don't like being forced into the injunction order and want to reserve their right to appeal. They summarized three things:

1. It's a technically complex operation to hit that gas cap – balancing this operation with other obligations is more challenging than what some may think it's going to be;
2. There may be be a different operation in high water years; and
3. They have a greater concern about biological consequences of passage than some others do.

When the spill order was filed, the parties agreed to the joint proposed order. All the entities that appealed the judge's order said they agreed to the process, but they are still appealing the order. NW River Partners won't oppose it, but because they weren't a part of the technical process, they're not signing on to it. The Columbia River/Snake Irrigators Association objected and wanted an evidentiary hearing. That was rejected. Their objection is that operations have gotten too far away from a spread the risk transportation operation and it causes less survival instead of greater survival.

Last night, Judge Simon said some people expressed an interest in responding to these filings. Therefore, they can file by December 31 for a reply in January. There could be a slew of filings.

This is separate from how to get through the NEPA process, and how it lines up with the 2018 BiOp. There will be filings on that in January as well.

The second thing that came in today was a letter from the Department of Justice to the plaintiffs of Oregon. During the status conference, the issue was raised about not doing the 2018 BiOp and pushing it off to the end of the NEPA compliance and leaving the spill order in place. But the federal government came back and said that leaves us out of compliance with the ESA. I expect they'll figure a way out, Shurts said.

Finally, there is an appeal by the federal government of the spill order and have filed briefs. The government moved to expedite the appeal. The Ninth Circuit agreed to expedite the appeal and agreed to briefing filings by the end of January. What happened is an agreement to expedite this by going to the comeback panel. It's back with Chief Judge Thomas. There will be 25 things filed between now and the end of January.

Leslie Bach said that the other side of this is whatever analysis is done to evaluate the benefits of the operations. It's not a spill study with a hypothesis and things you monitor. It's a spill operation. However, there are plans to collect data and evaluate the impact on fish. The details are still being worked out. The study review workgroup and the systems configuration team will be looking at those.

Member Lorenzen asked whether it's an Oregon or a Washington cap. Shurts said the most restrictive is Washington's.

Member Lorenzen asked to what extent does this operation line up with the spill experiment? That was a proposal that would go beyond the gas cap, Shurts said. That's not what this is.

Member Karier said Washington supported designing this as a real experiment. That's not what the federal agencies proposed. The other interesting thing is the transport percentage. Our program calls for spread the risk, since we don't know when operation will be beneficial and when it's not, he said. Now there's an example of what happened in 2015 where we put the fish in the river when conditions were so adverse, they died at twice the rate. If we had followed Council's program and spread the risk, we would have had better runs. The Council's program isn't irrelevant. It's worth talking about the merits of that idea again.

Guy Norman said he appreciates the summaries of the court hearings. We were able to attend. Looking at the adaptive management piece, there are issues associated with that. The TMT and the RIOG (federal-state-tribal Regional Implementation Oversight Group), and the fish advisory committee below that provides the first heads up and tries to resolve in-season issues. That's where the transportation piece will come in and other issues that could arise by unintended biological consequences. One of the keys in this plan is how do you move through adaptive management piece, through the TMT, through the RIAB in terms of making decisions in season. I thought we agreed to have the current structure and try to settle outside of the courtroom. The challenges of implementation will be directly related to the water year. The Washington gas cap, the 120 and 115, are based on 12-hour rolling averages. How they work the system within that (the challenges associated with meeting, but not exceeding the gas cap, the power reliability piece and the biological piece) are part of the juggling that will occur n 2018.

Shurts said the court would be available through the RIOG to solve any in-season problems.

Member Anders said, to follow up on Member Karier's remark, we've had mainstem operations in our program for many years. Resident fish provisions as well. This is focused on anadromous fish and listed species. Is there any inconsistency on what's happening here and with our program?

Shurts replied that we do talk about spread risk and in-season adaptive management process work. The Council wasn't specific on what these points mean. We don't give as much guidance as you might want. When it comes to operations and how it might affect other species might not come into play here, but it did come into play in the status conference before the judge at the end of November. We've got listed species on both ends of the river, and operations that support important listed and unlisted species, and we can't lose sight of that in the NEPA process.

6. Presentation on evaluating an experimental commercial pound net trap for stock-selective fishing in the Lower Columbia River

Stacy Horton, staff policy analyst/biologist, introduced Adrian Tuohy of the Wild Fish Conservancy. Horton said the 2014 Fish and Wildlife Program encourages agencies and tribes to investigate opportunities for selective harvest. Washington outlawed Pound nets in 1935, and by Oregon in 1949. The Wild Fish Conservancy has been testing a pound net in the Lower Columbia River.

Tuohy discussed the decline of Columbia River salmonids, which are now less than one-tenth of their historical abundance, he said. It has had obvious consequences for tribal and commercial fishing. Despite the decline, fishermen still want to fish on the Columbia, using the gill net.

The challenge is that fishermen are using the only gear that's legal and available, gill nets, in a mixed stock fishery. This non-selective gear causes high rates of by-catch mortality, which impedes wild salmon and steelhead recovery. It limits commercial and tribal fishing opportunities. When the fisheries are closed down, it enables the hatchery fish to move upstream and spawn with the wild fish. It's quite a challenge in the Lower Columbia.

In 2009, the Washington Fish and Wildlife Commission released the Hatchery and Fishery Reform Policy Decision to "develop and implement alternative fishing gear to max catch of hatchery-origin fish with minimal mortality to native salmon and steelhead."

Since 2009, there's been improvement in gill nets. The Colville Tribe has been trying alternatives. There still is room for improvement. There is substantial mortality for Chinook and coho.

Member Karier asked about the mortality rates. "Are they the by-catch fish? These are high mortality rates." The Colville tests upriver were showing a mortality rate of one percent or less.

Tuohy said this is work from Washington Fish and Wildlife in 2011 and 2012, which found different results in the Lower Columbia River where they're operating.

Tuohy said Blair Peterson, a commercial fisherman from Cathlamet, Washington, was interested in testing Washington's first commercial fish trap in 80 years. It had potential as stock selective gear. WFC teamed with him and, in 2015, they secured funding from the Western Coast Initiative to test the first salmon trap in 80 years.

Year one objectives: In 2016, they conducted a feasibility study. They learned how to build traps and determine their effectiveness.

Working with Peterson, they found that these traps were everywhere in the late 1880s. They settled on a basic design for a trap. Tuohy explained the process of the trap where fish are guided into the spiller compartment. Once they're in the tunnel and the live well, one can assess how many there are, minimize air exposure and select the fish for harvest.

Year one results: A total of 2,144 salmonids were captured, there were nine Coho jack mortalities, and there was a 99.6 percent survival rate. After the first-year trial, they sent out grant application to NOAA Fisheries. In July 2017, they secured funding from NOAA's by-catch program.

They discussed year two objectives to test and refine operation of a modified pound net trap. Tuohy described test fishing and tagging. They tagged 2,000 Chinook and 1,000 steelhead.

They made modifications to prevent entry by seals and sea lions. They opened the tunnel last August 26 and were thrilled with the Chinook catch. They scanned the fish to detect existing fish tags. The fish were implanted with a biomarker gun and they took clip samples. The fish were scanned and the information goes to computer database. Then the fish are sent upstream. In year two, they captured 7,129 salmonids. Tuohy said fish traps could catch a commercially viable amount of fish. The Chinook relative survival is 99.6 percent.

The benefits include wild salmon recovery, coastal community revitalization (increased commercial/tribal fishing opportunities), and the development of lasting, sustainable, wild fisheries.

Next steps are to determine the feasibility in spring Chinook, shad and summer Chinook fisheries. They will work to secure funding, obtain required research permits, and take coverage, perform research, identify success, failures and required modifications in each fishery.

They will join the Lower Columbia alternative gear emerging fall fishery, and obtain an emerging fisheries permit and license for fall 2018.

Their needs for 2018 are to secure funding, acquire a permit and license, and obtain letters of support for state, federal and foundation grant proposals.

Member Karier said the Council supports selective harvest. Going back to older techniques is a creative way to do this. How can Council help? On the legality issue, is that in state law? Perhaps the Council could provide technical advice to legislatures on the merits of this. Funding? The Council funds other selective harvest projects through the Bonneville Fund. We have a science panel that could review it. I think a science review would be something people across the region would pay attention to.

Member Booth said that fish wheels also were used effectively, but they were considered too effective. Where does the opposition come from? Who are opponents and what is their reasoning?

Tuohy said change is tough for anyone. Gill nets have been the law of the land since 1934 and people are invested in gill nets. There are boats for gill net fishing. This is enormous change. If it's ever made legal, there would have to be government assistance. Perhaps a buyout or trade program. It's just a massive change in the Lower Columbia River.

Member Norman said there is promise for this gear. "I'm not sure it's opposition, it's a matter of perspective," he said. "When it comes to managing Columbia River fisheries, I encourage you to collaborate with Columbia River fish managers. It's a complex game, particularly under the ESA constraints. Over the years, managers have worked with commercial and recreational fisheries to use every tool at their disposal to maximize the catch of harvestable fish, in particular the fish with the most market value, in the highest ratios to the impacts on ESA-listed fish. Because the timing of the stocks change, what the mixed-stock configuration is, where in the river those fish are, what gear you use is not the same... there isn't a one-size fits all. The value of experimentation with this gear is where does this gear fit? Getting the most bang for your buck out of those ESA constraints. The ESA constraints are set with the consultation with NOAA through the BiOp. They don't change no matter what gear you use. There are a number of ways to have selective fishing. This is one of them. There are other forms of selective fishing, one of which is avoidance. Commercial fisheries with gill nets have evolved over time. There is the use of tangle net gear to decrease mortality, different mesh size, etc., to avoid steelhead. My message, my request as this moves forward, is to try and make sure that's coordinated. The bottom line of have the most bang for your buck is the focus.

"The mortality study, which is relevant to the ESA consultation, I noticed that in that set, it was mostly thule Chinook. There are thules at Spring Creek Hatchery as well as the lower river, and I'm not sure those are genetically different enough. Are you taking that into account?"

Tuohy said they are working with geneticists who believe this is a worthwhile strategy and could improve survival estimates. "I'll keep people posted when we have our final product. It was a concern as we went into this."

Member Norman asked if there is an opportunity to develop a trap that's mobile?

Tuohy said they built this trap based on how they were constructed historically. There were floating traps in Alaska in the 1920s. You'd have to consider flows and foul weather. It could work and is worth investigating. They haven't gotten there yet.

Member Lorenzen said an issue was raised issue on a letter of support. Is there a consensus on this? "I suggest working with Tony, get a buy in from Council members, then I can sign it."

Member Booth said we should run it by the fish and game departments in each state and get a read back.

Member Lorenzen said we could get it out quickly to Members to run it by their fish and game departments. "I'd like to help to the extent we can as appropriate."

Member Norman said he appreciates Member Booth's recommendation to coordinate with respective agencies. "It would be a matter of context in terms of the letter," he said. "I wouldn't be in favor of support that would be a replacement of existing tools. I think it's an expanded tool for managers to use in the particular complex game of management under ESA. I want to put that on the record."

Member Lorenzen said he's not one most knowledgeable in this area. Guy could work with Tony to draft a letter.

Tony Grover said that was precisely his request. He'll work with Mark Walker to fit the Council's general standard for letters.

7. Update on Columbia River System Operations Environmental Impact Study

Tony Grover, Fish and Wildlife Division manager, introduced Sonja Kokos, Bureau of Reclamation; and David Kennedy, Bonneville Power Administration. Rebecca Weiss, U.S. Army Corps of Engineers, could not attend.

The panel updated the Council on the process underway to prepare an environmental impact statement on the Columbia River System operations, and configurations for 14 federal projects in the interior Columbia Basin. A draft will be issued in spring 2020.

As part of the National Environmental Policy Act process, the lead agencies are currently evaluating a range of alternatives for different system operations and structural modifications to existing projects. The EIS will analyze potential effects on resources and identify measures to avoid, minimize, and mitigate impacts associated with the system operations.

Kennedy discussed the development of these alternatives. He recently provided an update to tribal partners and the general public at the Oregon Convention Center last December 7.

He said that under the National Environmental Policy Act, they are evaluating their approach to the long-term system operations, maintenance and configuration, including:
Costs, benefits and tradeoffs of updated approaches; actions within and outside of current authorities; and measures to avoid, offset or minimize impacts to resources affected by management of the system.

The co-lead agencies held a series of 18 public meetings, attended by 2,300 people, to discuss how the system's dam and reservoir projects are operated. The meetings were held between October 2016 and January 2017 in Montana, Idaho, Washington and Oregon, and via webinar. The public outreach effort has generated more than 390,000 comments. They collated a report and posted it to the CSO website.

To date, there are about 25 cooperating agencies, including 19 tribes and representatives from the four states.

Kennedy said they came up with some key definitions, including refining objectives, measures and some alternatives. There are about 180 people working on this.

The objectives are fairly broad:

1) Improve juvenile and adult fish passage and long-term survival of anadromous fish;

2) Improve survival and habitat connectivity of resident fish;

3) Provide a reliable power supply; minimize carbon emissions by generating carbon-free power (includes hydropower and integration of other renewable energy);

4) Maximize operating flexibility and adaptable water management strategies to be responsive to changing conditions, including hydrology, climate and the environment; and

5) Provide unmet, authorized regional water supply.

The identification of mitigation measures will be worked on in 2018. "Until we know what we need to mitigate for, we'll just be guessing," Kokos said.

They'll have to be fairly robust, Kennedy said, and 2018 will be a heavy lift. There will be a development of a reasonable range of alternatives.

The 2018 public outreach schedule is planned out. By mid-May they hope to have alternatives identified before moving into modeling and analysis. The plan to have a quarterly schedule of newsletters posted to the website: www.crso.info.

Member Lorenzen asked what the resource cost is. The three agencies estimated the three-year effort would cost a combined $80 million to complete. The technical experts and biologists, for example are all existing employees. We haven't hired anyone new. We're repurposing current employees. It's almost a bit of double counting since those employees are already part of the agencies' budgets. New money will be contracting for modeling and analytical support.

Member Karier asked how the money is allocated among the three agencies. Kennedy said $45 million from the Corps, $23 from BPA and the remainder from the Bureau.

The project's completion date is 2021.

Kokos said they are reprioritizing staff to the project. Everything we do is project driven, she said.

Member Karier said if you could keep it under 20 pages, that would be helpful.

Member Booth said a number of alternatives you have identified would degrade the electrical generating capacity of the FCRPS. Given that the region is losing a large portion of its firm generating ability in the form of closing coal plants, are you looking at alternatives to enhancing the generating capability of the FCRPS?

Kokos said they are required to look at all resource impacts. The resource alternatives are bookends to give us the full range of impacts. As we walk through the process we have stacking. The first level is a look at alternatives to give us a better idea of what those extremes are. Then we move to integration and we'll have a full range of possibilities. The goal is to tell the story of what those impacts are when a decision is made.

Kennedy added that they'd have a hydropower-focused operational reliability draft alternative that will speak to some of the constraints put on the system. They'll also be incorporating an analysis of the transmission system because that's an important component. It's not as easy to remove a resource, or constrain a resource, in one particular area, and just plug in another resource to balance the load. The transmission system is extremely complicated and has its own constraints. They have transmission planning folks to help us explain the impacts on the system.

Member Anders asked about the project coordination. How will you identify and address the overlap with what we do in terms of power planning, mitigation and obligations under the Power Act? Will that occur in phase three?

Kennedy replied, yes, in terms of fish and wildlife, and power as well. Fish and wildlife might be on a faster timeline. We need to coordinate with staff to combine suites of mitigation measures. We haven't started coordinating that yet, but we're getting to that point. Early 2018 is good time to start working together on these.

Kokos added that they needed to wait on the impact analysis to know the results of a particular alternative to show us what we're losing or gaining. That's needed to formulate a package to mitigate a particular alternative. Otherwise, we're just guessing. In a NEPA process, we wait until we have that analysis to mitigate for particular resource areas. She said they wouldn't be having a good NEPA process if they were using mitigation that someone else is paying for.

Member Anders said there are other ongoing EIS inquiries, such as resident fish and the Libby BiOp. Will those be coordinated with this process? Kennedy said they would. They've been looked at through the process, both on the ESA side and the NEPA side. Kokos added that, for the Libby BiOp, they have had conversations with tribes. They pointed out the overlap and made sure we had that as part of the EIS.

Member Yost said in Idaho, they're concerned about the interaction and discussion between cooperating agencies with Idaho staff. You broke it into hydro and operations ... we're not getting a lot of information about what you're looking at and the data. We have reason to be concerned about federal agencies doing things on their own without adult supervision. We want to know what's going on and what's being discussed. The three agencies could do better job of working with sovereign states. You spend a lot of time working with the tribes, but I don't think you spend a corresponding amount of time working with the sovereign states. That's one issue I have a concern about. I suppose that when going through a five-year process for an EIS, and preparing for a Biological Opinion, but what will you do with the harvest Biological Opinion and the EIS is a major component, and how will you address that?

Kokos, my understanding is that your person is Mike Edmondson in the Governor's Office. We talk with him quite a bit. If there's some other avenue we need to pursue, let us know. If you're not getting the right information, we need to hear that.

Member Yost said Mike designated certain folks in Idaho in an internal Idaho process for certain individuals to be on different committees — the operations committee, they hydroelectric committee, that sort of thing. We're not getting any information about those meetings, when they're taking place or what happens internally at those meetings. The Governor's Office, OFC and Mike, he's not doing it all on his own. He has to have a group of people helping, but they're not getting any additional information. They have fish and game, and others who aren't getting that information. I'll visit with you and try to get that arranged.

Kokos said that would be great to hear and how we can improve that. Russ works very closely with our team. We put out a report every two weeks on what we've done and what we'll be doing over the next two weeks. We'll check on that.

Kennedy said the harvest activities being evaluated in U.S. v Oregon will have to be a component of the analysis. That related effort and its related BiOp are a faster timeline than our effort. We can use that information in our analysis as well. They're due to be wrapped up in the next couple of months.

Member Yost said when we did the system review in the early 90s, and consequently developed the biological opinions, when you do a harvest BiOp, or an EIS and a BiOp, that's established.

You can't impact that, you can't change that. When you're looking at your BiOp, on the rest of the components of the BiOp, so all the mitigation that wasn't assigned in the harvest has to be assigned to the rest of the components. You won't be able to determine what impacts are caused by the other actions, whether it's hydro or habitat or whatever it is. You're only going to be dealing with a small component of the BiOp impacts because you've already set aside harvest. Your information may show there's more of an impact by harvest than what is there, but you can't change it. I don't know how you're going to handle that. Unfortunately, they should have been done together with a complete BiOp — an EIS and a BiOp, with harvest included and the rest of the Hs that you're looking at. But I'm going to be interested in how you approach that when you go through your EIS and you find out what the impacts have been and then how you address the mitigation. Because if harvest has been excepted for its share of the amount of mitigation or impact, then the rest carry the burden unnecessarily.

Kokos: will be interesting to see how the impacts analysis will come out to highlight things we may not have seen in the past. Maybe what you're suggesting will happen. I don't have an answer for that at the moment. Part of the NEPA process is showing the cards and getting the region to deal with what those impacts are and where the agencies are required to mitigate, and areas where it isn't part of our mitigation package. It's going to be painful.

Grover said the preferred alternative under that harvest EIS is to roll over the existing process for another 10 years, but that decision won't be made until sometime late in January. Barry Thom will probably make it. We could we get Barry Thom to come in January to talk about how he plans to do this integration.

Member Yost said, "I don't want to talk to Barry Thom. What I want these folks to recognize is that as you go through the analysis, that you to be pragmatic and systematic about looking at what the impacts to other components, whether it's hydro or habitat. And that you just don't take the balance of the mitigation that harvest hasn't included and divide it up amongst the others because you have to do it that way, which is what they did last time.

"You need to look at it and accurately assign the mitigation required for the impacts that have been caused by specific actions. If you do that, and some additional left over, then region can look at harvest and say that harvest didn't take their full share, so we've got to address that in some way. If you're honest brokers, the process would be that."

Kokos said, "We completely agree with you. That's something that we've talked about in terms of that's what the point of the impacts analysis is, is to show what the system is connected with and essentially what it's not."

Member Karier said, "If NOAA is racing ahead with their BiOp, ahead of the EIS, I would be interested in hearing from NOAA about what they're doing and how much it constrains what options are left to recover salmon. And if it's not integrated with the overall 4H process of recovering salmon, which we're committed to in this region, then why not. I think it's worth hearing more from NOAA.

Member Norman said, "In terms of moving forward with modeling the integrated alternatives over the next three years, how do you envision bringing the cooperative agencies in terms of analysis, the expertise and the understanding of the various components?

Kokos said they're part of the team, they're not separate. They sit on the team meetings with the agency folks and discuss everything together: how they're going to do the models, what the assumptions are, they're part of the writing of the document, they're part of the entire steps. The cooperating agency group — each MOU has defined what they're bringing to the table and how they want to engage. Some may be in some groups and some in other groups. Some agencies, such as states, have someone in all the groups. So they'll see what those models look like.

Public comment

Former Council Member Phil Rockefeller

Member Rockefeller said he recognized that when he left the Council, that he might miss it, but he didn't realize how much. It's been a distinct pleasure to see my friends and colleagues continuing to fulfill the mission of the Council, as a counterpoint to the actions of the Federal agencies. After all, you are representing the four states. You not only provide your individual feedback relative to the concerns of your state, but collectively, as a Council, you're counterweights to actions, you examine and scrutinize them and provide appropriate pushback. I've seen that happening here the past day and a half. And I say thank goodness for the Council. It's doing its job.

It takes enormous mental agility to go from project-level scrutiny in the most obscure details, to the level of program strategy such as energy efficiency, to the strategic zone of the interplay of power and mitigation obligations and how they're balanced. You move from zone to zone in terms of narrow, close-order examination of data and alternatives to the stratosphere of strategic concerns. It's remarkable how the Council as a body, with the help of a very capable staff, are able to navigate and plumb the depths of this array of responsibilities. Were it not for your curiosity and being an articulate group, unafraid of asking tough questions and providing feedback and guidance to the federal agencies, and to anyone seeking benefits or support, you couldn't begin to carry out this mission. I've valued the opportunity to watch the work, and to step away from process as a retired council member.

As a retired Council Member, I thought I'd come to catch up on the here and now issues, but what I've learned is that they are forever issues. They haven't changed. The iterations are different, the personalities have changed, but the issues are totally recognizable. That was true a year and a half ago, but also five years ago, when I joined the Council.

Some of the species are more obscure, such as lamprey; those issues have been around awhile. It's remarkable to see the continuity. These issues are persistent, long-term and strategically important.

Most of all, Mr. Chair, I want to say how much it was been a pleasure to associate with you and Bill Bradbury. I know you're both about to retire. I wanted to come and say how much I enjoyed working with the two of you. I also enjoyed working with Bill, Jim and especially Tom as my colleague from Washington.

Member Rockefeller recognized Guy, Tim and Jennifer as well.

Member Lorenzen said it was joy of working with Member Rockefeller and the Council. It's rewarding and there is adversity of opinion with no hesitation to express it.

Member Lorenzen said in one month, Bill and I will ride off into the sunset. As a judge I once clerked for said, these aren't article three positions.

Member Bradbury said I really enjoyed serving with him and enjoyed his commitment to the issues.

Member Lorenzen said an Executive Committee is immediately following.

Member Lorenzen adjourned the meeting at 11 a.m.

Approved January __, 2018.

Vice Chair