**Northwest Power & Conservation Council**
**Systems Analysis Advisory Committee**
**April 28, 2021**

John Ollis, NWPCC, began the meeting at 9:00am with a review of the agenda. Chad Madron, NWPCC, reviewed how to best interact with the Go-to-Webinar platform.

**Analyze Bonneville's Portfolio**
**Ben Kujala, NWPCC**
*Kujala reminded the committee that this scenario is intended to analyze what resources are required to meet or reduce the Administrator's obligations, noting portfolio costs are just one factor of many the Council will consider in making its resource recommendations to the Bonneville and the necessary continued coordination with Bonneville to accomplish this work. Kujala then discussed each element needed to analyze the portfolio, explaining how it differs from the rest of the region, and providing preliminary results.*

Craig Patterson, independent, voiced concern over the verification of EE savings [Slide 24] noting that 97% of EE is deemed or projected. He called for verification at the end-user meter. Patterson then said that economics are an important driver in consumer decisions, and asked how to tease apart reduction of use due to conservation versus the economy. Kujala said the BPA approach is the same as the regional approach. Kujala added that economics will be discussed later in the presentation.

Fred Heutte, NW Energy Coalition, moved back to [Slide 21] and asked about how the 80.9% figure is derived. He also wondered if BPA is paying for EE that is not applicable to their customer load. Kujala clarified that anyone who buys EE in a public utility is impacting BPA's load.

Heutte was still unclear and read from the Power Act about the BPA administrator "meeting his contractual obligations." He said he always thought what BPA pays is applicable to customer loads. Kujala said this is more about the current contractual structure. Kujala also noted that what the Power Act says and what BPA's obligation is starting in 2029 is a much broader subject to be covered today.

Heutte was concerned that it looks like Bonneville spends a dollar on conservation and gets back 81 cents. Heutte referenced language on the slide, "for 10aMW of EE purchased from the supply curves," and asked, "purchased by whom?" Kujala said the Council is agnostic on that. Heutte was still confused.

Patterson commented that it would be useful to see historical trends in the graphs on [Slide 39.] He then addressed price implications, noting that Pacificorp uses a majority of coal. Patterson asked what happens to the market and what the ripple effects are when a major IOU loses its majority energy source.

Kujala offered to send presentations that give more detail around the forecast, adding that an assumed retirement of coal is included. Kujala acknowledged that PacifiCorp is bigger than the region and those out-of-region differences are captured as best as possible. He referenced an early retirement scenario that pulls more coal out of the system that could be used as well.

Patterson again asked what are the implications of that resource going away quickly. Kujala said that is incorporated on [Slide 38.] Ollis offered to get results of the early retirement scenario to Patterson.

Nicholas Garcia, WPUDA, asked if the baseline includes electrification of transportation and buildings. Kujala answered yes, but cautioned that the data they used was probably not as ambitious as the recently proposed legislation. Kujala called this a blended approach, adding that the Paths to Decarbonization scenario might reveal more information.

Garcia thanked him, noting that his challenge is not having data to show legislators about the consequences of rapid electrification. Kujala said more information is coming.

**Questions:**
Heutte said that BPA has a relatively flat, declining load and no retirements and asked what the first dot on [Slide 45] represents. Kujala said it’s Q4. Heutte said Q2 is not a high demand quarter and wondered why so much energy was needed.

Kujala said there is more resource in the winter, even though loads are higher. He said spring and summer shows lower results adding that this will be explored further. Kujala reminded Heutte that this is a look with low water and early April can have a severe need in the climate change record.

Heutte asked why the shape drops off in the late 2020s. Kujala answered that BPA’s obligation is dropping until it starts to rise again in the 2030s.

Heutte then asked who will build the renewables that fill BPAs energy needs. Kujala did not know, adding that [Slide 45] is on average. Heutte said he was baffled.

James Vanden Bos, BPA, said to Heutte that BPA sees some spring needs as well, due to cold Aprils locking up fuel. Vanden Bos then asked what the market purchase limits were in GENESYS. Kujala said it’s the same market depth as in the resource program and it has a monthly shape. Vanden Bos said GENESYS has a market purchase limit to inform hydro shape and another market limit on the backend to inform how much we can go to the market. Kujala said they are separate but he didn’t reference the second limit as it doesn’t impact need.

Vanden Bos referenced a presentation bullet [Slide 56] that said BPA cannot solve problems with short term market purchases. He wanted to confirm that the market is not the preferred

option. Kujala said short-term markets are taken into account but he is not referencing long term.
Ollis asked if Vanden Bos is wondering if the RPM can use the market to fill an adequacy need. Vanden Bos answered yes, noting that BPA's modeling includes some amount of market purchases. Kujala said RPM does not use market above and beyond what is in GENESYS.

Jim Waddell, independent, noted that the model can look at individual projects and wondered what cost was associated with each individual project. Kujala clarified that RPM looks at incremental resource costs and not individual projects.

Waddell voiced concern that the cost of hydro is going up as the technology ages while renewables drop in costs. He pointed to the split and wondered how the model captures that. Kujala said the model is limited as it looks at meeting incremental needs at the lowest cost and not questioning the existing system.

**Cost-Effective Methodology for Providing Reserves – Issues**
**John Ollis, NWPCC**
*Ollis explained the role of reserves in the Plan, how reserves fit into the analysis of different resource strategies and how cost-effectiveness of reserve strategies is evaluated.*

Heutte confirmed that the 7000-7500MWs of reserves described on [Slide 6] is held every year no matter the hydro conditions. Ollis answered no. Heutte said he is thinking about the planning reserve, saying you kind of know what the summer will look like by late spring. He said this made him wonder how that reserve number would be applied. Ollis said these numbers are operating reserves and not planning reserves.

Heutte asked what the INC and DEC reserve number are. Ollis answered 2900MW for INCs and 3345MW for DECs. He added that this is a bit conservative but felt it was warranted. Heutte then asked how these numbers relate to the 7000-7500MW mentioned earlier. Ollis said they are added up and include contingency reserves.

Patterson asked how extreme and unknown effects of COVID are incorporated. He then asked how Texas's recent "Markets Gone Wild" experience is addressed considering the competition that will arise when coal goes away. Patterson noted that renewables are intermittent but coal is available 24/7, calling it a mismatch.

Ollis said resource intermittency is simulated with forecast error parameters in the model. He said unit accounting is an issue that will be addressed later in the presentation. For COVID, Ollis said the RPM deals with a variety of load futures and reserves must cover them.

**BREAK**

**Cost-Effective Methodology for Providing Reserves-Preliminary Findings**

**John Ollis, NWPCC**
*Ollis walked through preliminary results, which point to a few high-level findings: resource additions and reserve strategies should be used to maintain adequacy, energy efficiency improves regional adequacy, and new solar resource within the region does not improve regional adequacy, but it does decrease system costs enough that reserve and resource strategies will work with solar because of the value it brings. .*

Sashwat Roy, Renewable NW, asked why the LOLP isn't decreasing to a much lower value if the INC reserves are provided based on the size of needs in each quarter [Slide 3.] He asked if the availability of reserves is also a factor here or if something else is at play. Ollis thought there may be a limited capability of the hydro system causing this. He theorized that INC reserves are better at solving winter problems and perhaps some of the summer issues may be resource problems.

Scott Levy, Bluefish, said increasing reserves seems like a low-water year strategy and wondered if the models are assuming bad water years are coming. Ollis said it's more likely that particular types of water conditions have less flexibility. He said in really bad water years prices are high enough to incentivize thermals.

Patterson asked how costs of fish and wildlife and Columbia generating station are projected, especially as fish and wildlife are declining [Slide: Strategy highlights Portfolios with solar.] Ollis said this information is passed to the model, adding that projections are not in the scope of the Power Plan.

**Questions**

Levy suggested including all of the solar and battery in the queue and not be agnostic. Ollis said they see more than that in the RPM and they intend to look at higher penetration of solar and other resources. He said that energy limited resources play well in some ways but on a regional basis thing like a TOU are more advantageous.

Scott thought the study was great but was worried that the monumental build out may not be the correct picture. Ollis said batteries are in competition with thermals and emission costs may change that.

Levy addressed Patterson's concern, saying that [Slide 10] assumes the hydro system is fixed and unchangeable but there could be beneficial changes. Ollis said hydro system costs were the same in two runs and not part of this analysis.

Levy addressed fixed costs in GENESYS for the hydro system asking if the number changed from zero. Ollis said he could put that in depending on what they are using the model for, however since we were comparing costs and the fixed costs stay the same, he was inclined to keep the analysis as presented.

Ollis ended the meeting at 12:20.

**Attendees via Go-to-Webinar**

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|---|---|
| John Ollis | NWPCC |
| Ben Kujala | NWPCC |
| Chad Madron | NWPCC |
| Glenn Blackmon | WA Dept of Commerce |
| Leann Bleakney | NWPCC |
| Frank Brown | BPA |
| Aaron Burdick | E Three |
| Aaron Bush | PPC |
| Zhi Chen | PSE |
| Rachel Clark | Tacoma Power |
| Robert Diffely | BPA |
| Ben Fitch-Fleischmann | Northwestern |
| Villamor Gamponia | SCL |
| Nicolas Garcia | WPUDA |
| Eric Graessley | BPA |
| Doug Grob | NWPCC |
| Elain Hart | Moment Energy Insights |
| Fred Heutte | NW Energy Coalition |
| Tina Jayaweera | NWPCC |
| Scott Levy | Bluefish |
| Ian McGetrick | Idaho Power |
| Barbara Miller | US ACE |
| Tomás Morrissey | PNUCC |
| Heather Nicholson | independent |
| Elizabeth Osborne | NWPCC |
| Patrick Oshie | NWPCC |
| Craig Patterson | independent |
| Will Price | EWEB |
| Sashwat Roy | Renewable NW |
| Kathi Scanlan | WA UTC |
| Adam Schultz | ODOE |
| Jaime Stamatson | Montana |
| Peter Stiffler | BPA |
| Tyler Tobin | PSE |
| Ben Ulrich | EWEB |
| James Vanden Bos | BPA |
| Jim Waddell | independent |
| Seth Wiggins | PGE |
| Brian Dekiep | NWPCC |
| Tanya Barham | Community Energy Labs |

Shauna McReynolds PNUCC