PNUCC REPORT Council

Northwest Power and Conservation Council

Meeting Notes – September 15 & 16, 2015

Eagle, Idaho

The Council's Power Committee is dotting the i's and crossing the t's on the Seventh Northwest Power Plan, including a 25-page action plan for its implementation. It will hold a webinar October 1 at 9:30 a.m. to discuss final edits before it releases the draft for public comment later that month. Next Council meeting: October 13 & 14 in Vancouver, Washington.

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The Agenda

Idaho Power shares its demand response experience

With all the talk about the need to expand demand response in the region, it was helpful to hear from a utility with a long history of using it. Idaho Power's Quentin Nesbitt, energy efficiency program leader, oversees the company's demand response program.

Nesbitt said Idaho Power has three demand response programs:

1. Irrigation Peak Rewards – 2,258 sites representing 320 MW of expected potential reduction. It's not used all summer long, just during the peak of the irrigation season. There are 400 MW of nameplate enrolled, but only 320 MW are expected.
2. Flex Peak – 71 sites representing 25 MW.
3. A/C Cool Credit – 29,017 sites representing 35 MW.

The rules limit the programs to summer. This past summer, Nesbitt said, Idaho Power would have hit a system peak of 3,407 MW if not for demand response.

Idaho Power began demand response in 2003 with an A/C pilot program and then continued in 2004 with an irrigation timer program. They signed up customers for one or two days a week of interruption, so they could have the same amount of load reduction during 4 and 8 p.m. In 2009, they started their irrigation program where they installed devices that could control the load. The company was able to increase incentives and participation.

In 2013, the company suspended the irrigation and A/C programs because of a lack of need. They were spending more than $20 million in 2012 on demand response, and were able to modify the programs working with the commission. Idaho Power is running all three programs for under $10 million today.

Idaho Power pays a fixed incentive for irrigation and flex peak based on demand, and a variable incentive if it has more than three events in the summer. For A/C, there's a flat, $15 per-season incentive.

Idaho Power uses demand response because of its integrated resource plan. "In 2004, we showed significant deficits in our planning criteria," Nesbitt said. "That capacity need drove us to look at demand response." This deficit was due to its large irrigation load and growing air conditioning load. The energy growth has been at a slower pace. The area's wind power has brought a lot of energy, but not much capacity for a summer peak.

"When it comes to building natural gas peakers or demand response, you're building something that won't need to run — just during extreme scenarios," he said.

Nesbitt discussed some of the myths surrounding demand response:

> *It saves energy*: Our demand response does not save energy, he said. It shifts it. There's a percentage of the irrigation energy that's never made up.
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> *It's the cheapest*: "Not true for us," he said. "It's the most expensive thing we have in our IRP, because it's available for so few hours. We pay customers to not use energy they would otherwise use. Paying $15 per customer for an air conditioner may not seem much, but it is for a few hours. It's the cheapest resource from a per-kW point of view, but from a kWh point of view, it's the most expensive. Customers just can't handle you using it all the time. We're doing it cheaper than most other utilities I've looked at, but it's still not cheap."
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> *We need it all the time*. "We only need it in a 1-in-20 load year or a 1-in-10 water year," he said.

It is used to avoid buying from the market. – "That's not true — it's about capacity potential," he said. "We wouldn't have the ability to get the energy in on the transmission we have at any price."

Currently, Idaho Power is all the way into the 2020 timeframe before there is any additional need for capacity resources.

When asked how long it would take to build a demand response program from scratch, he said he could start an irrigation program in November and have it up by spring. However, with A/C cycling, that isn't possible. It took Idaho Power a few years to build that up.

Banks Lake Pumped Storage benefits and costs outlined

Columbia Basin Hydropower (CBHP) managers briefed Council members on a prefeasibility study conducted earlier this year of the Banks Lake Pumped Storage Project. CBHP provides the administration, operations and maintenance for 150 MW of hydro facilities owned by the irrigation districts that make up the Columbia Basin Irrigation Project.

CBHP's pitch was similar to its presentation at PNUCC's September board meeting. The Banks Lake Pumped Storage Project would be located at the North Dam of Banks Lake in central Washington, near Grand Coulee Dam. Originally, CBHP considered building a project capable of generating 1,000 MW, but after conversations with PNUCC, it has amended its focus to a 500 MW project. Banks Lake Pumped Storage could be used in coordination with the Keys Pumped Storage Plant and Grand Coulee Dam operations, and could integrate into the Mid-Columbia hourly coordination.

"The region is looking for resources that will meet our capacity needs," said Tim Culbertson, CBHP manager. "What will the capacity requirements be in 2020-2025? As utilities, we tend to put our eggs in one basket; first it was combustion turbines, then wind, and now solar's price is coming down. They're all great, but we need capacity resources. We have the ability to serve a lot of our needs with a pump storage project."

Larry Thomas, CBHP's assistant manager, pointed out that Washington State has the Keys Pump Storage Plant, which was built to pump water from Grand Coulee to Banks Lake. Turbines were added later in the early 1980s. Today, Keys is old, often out of service and requires a substantial amount of capital investment. CBHP is talking with the Bureau of Reclamation on whether some of the Keys budget should be shifted toward a new facility. With the prefeasibility study completed, they will continue refining its plans and cost estimates, and will submit the necessary filings to FERC.

Culbertson said that the project doesn't have a carbon footprint and it will be located in a region that knows hydro projects. The project is needed due to:

- A slowdown in the construction of base-load power plants.

– An increase in nondispatchable, intermittent generation resources (wind and solar) that are stressing the grid.

– The utilities' need to meet state-imposed renewable portfolio standards.

– The early retirement of two, large, coal-fired power plants in the region.

– Greenhouse gas restrictions that may limit the installation and operation of gas-fired combustion turbines.

– The need for additional electrical capacity in 2019 -2021.

"Construction of this type of project takes about 7-10 years, so we think the time is right," Culbertson said.

The cost of the project would be between $1.5 and $2 billion.

The potential purchasers of the power include IOUs, public power entities, power marketers, independent power producers, and it could have benefit for CAISO. The next steps include entering into contracts. They are continuing their talks with the Bureau of Reclamation, and are having monthly check-in meetings with BPA.

Idaho utilities urge Council to look at efficiencies before mandates

Representatives from United Electric Cooperative, Lower Valley Energy, and Fall River Rural Electric Cooperative discussed issues that the Council should consider as it goes forth drafting and implementing its Seventh Northwest Power Plan.

Jo Elg, United Electric Cooperative general manager; Rick Knori, Lower Valley Energy director of engineering; and Bryan Case, Fall River Rural Electric Cooperative general manager, each shared how their utilities operate and the issues they deal with in their respective service areas.

Elg outlined her concerns about transmission and resource adequacy. United Electric, which is served under a BPA transfer service agreement, gets its power transferred over Idaho Power's transmission system. There is 700 MW of BPA native load that puts demand on transmission and reliability in the region. The entire Magic Valley region has experienced industrial and commercial growth, much of it in the last couple of years. Short-term market prices are attractive, but could create potential risks, such as ones that were experienced in the 2000-2001 energy crisis. She is concerned that the region is going to rely on conservation, renewables and low-market prices in place of a long-term vision. Can conservation and intermittent resources sustain the growth we're seeing in Southern Idaho?

Regarding conservation, United Electric is a member of the Idaho Energy Authority, a joint action agency. Thirteen utilities have partnered under it to gain efficiencies to administer and implement conservation programs. This is the first year it contracted with a number of Community Action Programs, most of which have used less than one-quarter of the funds allocated for conservation. So before CAPs look to the Council for more mandates, they need to work with their local utilities.

Utilities and BPA are looking to evaluate conservation holistically. There are different customer profiles, geographic differences and between different utilities. One size does not fit all.

In addition, the Fish and Wildlife Program is the largest of its kind and it should be finite, Elg said. She asked the Council to find redundancies and seek efficiencies instead of assuming that new dollars will be available. She asked for the Council to seek federal assistance to pay for mussel mitigation. In addition, she said that her organization's greatest concern is the request to fund studies to introduce fish passage above the dams. Any proposal that would jeopardize the efficient operation of the dams should be scrutinized.

Bryan Case said Fall River is a progressive utility that serves 15,000 in Idaho and small portions of Montana and Wyoming. They belong to the PNGC Power Pool. He sees that conservation is primarily for the financially affluent, so they've focused on low-income customers. It also started an energy efficiency program with its irrigators, with some help from neighboring utilities. It expects to hit its conservation targets in the next rate period. He's unsure how much conservation potential is out there since load growth is fairly flat.

He also shares Elg's concerns about fish reintroduction above the dams. "We don't mind paying our fair share, but those aren't costs we should incur since 30 percent of our power costs already are devoted to fish and wildlife," Case said. "Our ratepayers will be talking about it, and I always cringe at that. But even those little adjustments impact fixed-income and poverty-level customers. If Bonneville's rates were less than market, it might be different, but you can get rates lower than its tier-one rates."

Case also mentioned Fall River's use of demand response this past year when a feeder went out. They called some of their major irrigators to reduce their load, and it was successful. They will look to implement a demand response program with irrigators. It will be voluntary with no equipment installed. The goal is to try and save some transmission costs through PacifiCorp during peak times.

Rick Knori said that Lower Valley's serves a diverse area in eastern Idaho. He described their programs to reduce demand, including placing load controls on water heaters. The pilot program has been successful and a lot more customers wanted to participate. However, they are delaying expansion because smart devices are now being built into water heaters.

Member Tom Karier replied to Elg's concern about mussel mitigation expenses, explaining that the inspection stations are state expenditures. Still, the Council is seeking $4 million from the federal government to address the issue. "If the mussels come in, they'll cost BPA tens of millions of dollars to clean them out," Karier said. "So sometimes, not spending money can cost more than spending it."

On the issue on energy efficiency, Karier said the Council looks at it from a regional view, trying to figure out how to serve everyone's interests. He defended the Fish and Wildlife Program as extremely successful in bringing back sockeye in Idaho and fall Chinook throughout the region. However, he agreed that there's been wasted money as well.

"Ask your associations that represent you to identify those (wasteful) projects and bring that information to us," Karier said. He also explained that when it comes to the reintroduction expenditure, it is a $200,000 habitat survey lying entirely within the savings identified in the Fish and Wildlife Program. "It's a test of feasibility and we plan to do that very carefully," he said.

Council staff prepares to release draft plan for public review

Tom Eckman, staff's power division director, briefed the Council on the finishing touches to its draft of the Seventh Plan. Some of the changes made were on the action plan on the Model Conservation Standards category at the request of Member Smith to focus on hard-to-reach customers who may not be participating in cost-effective opportunities. These include small rural, low-income, manufactured housing and middle-income customers. Member Lorenzen also asked for ways to remove high-level barriers for Bonneville customers to secure energy efficiency.

Eckman also reported that staff ran a scenario at the request of Washington Governor Jay Inslee, which evaluates maximum carbon reductions coupled with new emerging technologies. Under Scenario 3B, no new gas generation is built and the region relies only upon renewables and conservation to meet new loads out to 2050. After running it through the model, the scenario called for "huge amounts of utility-scale solar and wind, as well as rooftop solar panels." The staff looked deep into the possible impact of new technologies, but they didn't discuss the price tag. "We do know that it would cost a lot more," Tom said. There will be a detailed discussion of this scenario in the Seventh Plan's resource strategy section.

Four more chapters are coming for review. They are fairly short and include the executive summary, transmission, flexibility and balancing, and the status of the system.

Council Chair Phil Rockefeller echoed many of the Council Members' comments about the staff's work on the draft, saying, "The Power Committee has done a remarkable job. It's been a smooth process to date and I see no controversies or issues at this late hour."

The Council members had a robust discussion before the meeting close after Council Member Bill Booth asked if the Seventh Plan addressed concerns that BPA's rates aren't competitive with the market.

Council Member Henry Lorenzen replied that nobody's been able to respond to the question, "how deep is the market?" "How many megawatts can be acquired for what period of time?" he asked. "If you want a fixed, 10-year contract that's guaranteed, you won't get it on the sport market. The question is that suppose you go to market for 500 MW, you won't find it at $35 per

MWh. It's a market that's being priced at the variable cost of generation because there's surplus. Once you get beyond surplus and have to go out and build a new plant, you're at $80 per MWh."

"You're not going to find anyone offering 20-year contracts for market prices today that are load following," Eckman added.

Council Member Yost said that the other side of the issue is that if we continue to raise the cost of BPA between now and 2028, there might be other options for co-ops to purchase power. He said that the problem is that they have heard from a lot of co-ops that, due to no-load growth, conservation costs their customers more money. "On energy efficiency, on the whole it's a good deal," he said. "The amount of energy efficiency we're putting into the plan is a good number. But there should be a way for BPA to make adjustments to get the most conservation done for the price, and not do harm to some of these smaller utilities where their customers have to pay more," he said.

Eckman said that the action plan has identified different approaches to deliver the best bang for the buck, in different ways than what's occurring now. It's a way of getting the regional benefits without doing harm, he said.

Karier remarked that the new plan is a least-cost plan. "We checked what happens if you do less energy efficiency, the system cost rises," he said. "If you do less demand response, you pay $1 billion more in the system. So those aren't the cost drivers, they're the cost savers. We have to make sure we're keeping rates as low as possible."