Northwest **Power** and
Conservation Council

Council Meeting
June 9, 2015
Coeur d'Alene, Idaho

Council Chair Phil Rockefeller called the meeting to order at 2:00 p.m. All members were in attendance.

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

Council Member Bill Bradbury, Chair of the Fish and Wildlife Committee, said his group had a very productive session.

First, the committee recommended extending the charter of Wildlife Advisory Committee until Oct. 31, 2015, to complete its recommendations for operational impacts for the hydro system, and for future use or replacement of the HEP methodology. This recommendation will come before the Council for its approval.

The committee heard a presentation on the spread of northern pike, an invasive and highly voracious predator that hit Box Canyon Reservoir in the early 2000s. The pike population in the reservoir grew from 400 in 2006, to 2,500 in 2010, before the Kalispel Tribe and Washington Department of Wildlife took on a highly successful eradication effort. But pike are now in Lake Roosevelt and removal efforts are planned there next spring. There is a need for greater regional coordination to address the pike problem, and the committee asked staff how the Council could help. Staff will report next month.

At the committee meeting, Council Member Bill Booth provided an update on the Operations and Maintenance Subcommittee activities. They have a fish screen inventory from the four states. It needs to be refined to add the beneficiaries of the screening to look for potential cost-sharing sources. Hatcheries that have the benefit of an audit for that can serve as a template for additional O&M reviews on the other 12-15 program hatcheries. Booth will present his findings to the committee next month and it will go before the Council.

Bradbury reported that Council Member Jennifer Anders presented an update from the Cost Savings Subcommittee. They abandoned the idea of achieving $3 million in savings by 2016. Instead, they're getting what they can in 2016, but are targeting one percent of the costs as savings by fiscal year 2017. They shared a draft process document, which will be posted today for a two-week comment period. The subcommittee will consider comments and the document at its next meeting in July.

Council Member Pat Smith, Chair of the Power Committee began with a summary of a presentation given on conservation momentum savings. According to Carrie Cobb, BPA's market research lead, conservation momentum savings are efficiencies occurring outside direct utility program incentives, and there is a conservation spillover effect on non-program participants. Momentum savings count toward the Council's conservation targets, and they are significant: BPA estimates they account for 30-50 percent of Sixth Power Plan energy-efficiency accomplishments. With each power plan, the momentum savings are reset to zero, and will reset with the Seventh Power Plan. BPA forecasts a total of 306 MW of momentum savings for 2010-15, which are determined by relying on regional retail data and resources.

Smith briefed the Council on the process of staff getting drafts of the Seventh Power Plan to the power committee and full Council. Staff is still working to deliver a complete draft in September. The proposal is not to distribute the entire draft at once. Instead, the chapters will be delivered to the Power Committee as they are finished. After editing and input, the drafts will go to the Council. Smith forecasts that a lot of charts and figures will come to Council members in July, with the real meat of plan (resource strategies and action plan) to come around mid-August. The full Council may have to schedule some additional meetings to review them.

Next, John Fazio, staff senior systems analyst, presented the final resource needs assessment for the Seventh Power Plan. It compares existing resources with anticipated load growth in the region for energy and capacity. The assessment provides planners with the ranges of potential load and capacity for the next 20 years. An important addition is that the adequacy reserve margins for energy and capacity have been created, based on a loss of load probability of 5 percent. Those numbers have been crunched and those adequacy reserve margins will be used in the Resource Portfolio Model (RPM). The major outcome of this assessment is that the region needs peaking resources. There will be some energy needs, but they start arriving after Centralia 2 goes offline in 2026. Under the load demand forecast, staff is predicting 50 MWa of energy in the next years but on the capacity side, 4,300 MW is needed to maintain the 5 percent LOLP. A more robust analysis will be conducted through the RPM. The System Analysis Advisory Committee has been very involved in this process. Fazio said that we'll have more accurate projections of our capacity needs by using these adequacy reserve margins, and will avoid overinflating gas plants on the energy side of things through this process. The Power Committee approved the assessment.

Smith said that the Oregon Physicians for Social Responsibility asked to amend Scenario 4a, which currently examines an unanticipated loss of a major resource. The group requested an additional scenario anticipating a planned loss of Columbia Generating Station (CGS). The intended purpose of the 4a scenario and 4b scenario (the planned loss of Snake River) is just to address the strategic risk question of what new resources should be deployed in the event of a resource loss. These scenarios were not intended to address why a resource was retired. The Council generally does not conduct an economic analysis about the viability of existing resources. It does update operating costs and dispatch costs of resources. The Northwest Power Act puts a focus on new resources to meet future growth. Staff recommended not to review the economic viability of CGS as part of the Seventh Power Plan. The Committee agreed that it wasn't feasible to get into right now. Another option was to look at the 4b scenario, and to do a sensitivity analysis. The Committee agreed that everyone has a pretty full plate with the Seventh Power Plan, but the Power Committee didn't rule out revisiting the issue after the Seventh Power Plan is produced.

Smith then provided a scenario analysis update. Staff held a webinar on May 26 on five scenarios. Staff has fine-tuned them further with updated inputs. The full Council will get that presentation tomorrow. One outcome with the changed inputs, which also included adequacy reserve margins where they could focus on capacity impacts, is that demand response numbers went up.

Member Anders, Chair of the Public Affairs Committee, reported that the committee met last month and continued its discussion on BPA's Fish and Wildlife costs report. Staff suggested that the report should be shorter and provide less detail. While the Council acknowledged it might make the report more accessible, the members hesitated to stop publishing the more detailed report. Council Member Tom Karier said the Council is the only organization that develops the report, and considering the size of the program and magnitude of its expenditures, it should continue to make it available to the public. The committee directed staff to publish it to the website, and publish a hard copy of the summary report, which will be available to members at the close of the meeting.

The staff distributed a four-page summary brochure of 2014 fish and wildlife amendments, and the 2015 update of the Council's pocket guide.

A short briefing was given on plans for the August Congressional staff tour in Orofino, Idaho. Official invitations will be sent out this month.

Anders discussed the value of social media. She announced that the Council has a Facebook site, "So check it out, like us and make us more popular," she said. Carol Winkel and the rest of the staff are doing a great job with our social media presence.

At the conclusion of the committee reports, Karier introduced Tom Trulove, mayor of Cheney, who used to be a Council member.

Council Business

Northwest Power and Conservation Council Motion to Meet in Executive Session

Member Booth moved that the Council meet in Executive Session on Wednesday, June 10, 2015, for the purpose of discussing civil litigation. Bradbury seconded.
No discussion.
All members voted in favor in a roll call vote.

1. Panel Discussion by representatives of five Idaho utilities:

Member Booth welcomed the Council to Coeur d'Alene, Idaho, where he was raised and lives. He assured the western Oregon and Washington delegation that there is a Starbucks nearby.

Shirley Lindstrom, staff power coordinator in the Idaho Office, introduced Jim Robbins, who serves on the board of Kootenai Electric Cooperative. Robbins then introduced Annie Terracciano, general manager of Northern Lights, Inc.; Dave Hagen, general manager of Clearwater Power; Steve Boorman, city administrator of City of Bonners Ferry Electricity; Cliff Tacke, board director for Idaho County Light and Power; and Doug Elliott, general manager of Kootenai Electric Cooperative.

Elliott began the panel presentation by telling Council members that the role the Council plays in safeguarding and guiding BPA is vital to the 23,000 members who count on Kootenai to provide competitively priced electrical service. They find value in clean, renewable power from the hydro facilities in the Columbia Basin. He also recognizes that 50 percent of that power bill goes to pay for that power. Elliott said that Kootenai members' median income is 8 percent below national average, and that 13 percent live below the poverty line. Therefore, maintaining competitive rates is extremely important.

"The power BPA provides and the policies established by this Council are not trivial to our membership," he said. He described having worked for a cooperative in Kentucky that had rates among the lowest in the nation, but the power was carbon-based. Then, when he began working at Kootenai six years ago, and considered buying carbon-based power, it was seen as ludicrous, if not heretical.

Today, those considerations are more prevalent, he said. He described BPA as a servant of many masters: the Council, BPA preference members, Kootenai, the Biological Opinion, and Columbia River Treaty. He foresees that the guidance provided by Seventh Power Plan will impact BPA's rates and the wallets of his members, who are still trying to recover from the economic downturn.

"Our members suffer financially when BPA is seen to fund projects that stray beyond the scope of its mandate under the Northwest Power Act," Elliott said. "The cost of unnecessary or poorly conceived conservation initiatives, or fish and wildlife programs that aren't based on sound science, or that don't go to benefit our region or country, only compound this."

He asserted that his members don't think it's fair that they should bear the costs of those programs or pay them alone.

The cost of natural gas (and cost of subsidized renewable power) is making BPA increasingly uncompetitive, he said. Consider that at the onset of the regional dialogue contracts a couple of years ago, the cost of tier 2 power was forecast at $75 per MWh. No longer. With the availability of natural gas, Kootenai Electric recently secured its tier 2 power for the next two years at rates below Bonneville's. For the next four years, Kootenai will buy all of its electric power, incremental to what it buys from BPA, at rates below what BPA sells us at its tier 1 rate. "If we could buy all our power at that rate, we could lower our rate by 3.2, saving the average residential member $40 per year," Elliott said. "I'd like to think we're just lucky and it's a short-lived opportunity. How long can market based power with carbon risk and fuel costs be priced below what we buy from Bonneville?"

He said that the reality is the fuel supply market forecast remains suppressed for the next several years, certainly through 2020. In the meantime, BPA faces cost pressures and is passing those on through rates. In October, Kootenai expects its wholesale power costs to increase by 7 percent, which will cost the average member another $40 per year. This is on top of the $162 per year members are expected to pay to fund existing fish and wildlife programs.

"If BPA's rates remain uncompetitive, what happens to our regional dialogue contracts when BPA's preference customers terminate?" he asked. "Our members will expect us to consider more-affordable alternatives. If that happens en masse, what will become of BPA, and who will fund the FCRPS projects? I've heard the FCRPS referred to as the golden goose that funds all these projects. We have to be careful not to kill the goose, and I think the golden goose is the ratepayers who buy at retail rates."

He concluded by saying it's their hope that the Council can help BPA maintain competitive rates by sticking to its mandate through the Northwest Power Act and by not diverging arbitrarily beyond it.

Steve Boorman discussed the desire for a base rate with all the costs included. He said that the City of Bonners Ferry Electricity rates are about 50 percent fixed and 50 percent variable. Distributed generation creates a problem going forward, as does the integration of renewable energy. There are many factors associated with renewables' impact on the Seventh Power Plan: tax subsidies, gas price predictions, and other issues. He said that he read an article on coal, and how renewables are cheaper, but the article didn't talk about capacity and generation in real time. "The proliferation of renewable generation, large scale and distributed, are pushing our hydro system's ability to balance that load generation, and that will impact the Seventh Power Plan's predictions," he said.

Boorman continued, stating that the Northwest has over 20 balancing authorities that need to match their loads and generation in real time. There's potential for these to work together. He said they're looking at two options, such as CAISO (a high-priced, organized market solution, which doesn't show good results for the rate payers) and the NW Power Pool's market committee's incremental approach (which is cheaper, less sophisticated and provides better value for the investment). But the decision of which way they go will impact the Seventh Power Plan.

BPA rates will be affected. A growth of distributed generation will be a factor in secondary sales. As secondary sales go down, their prices go up. Their customers don't want to subsidize transmission for other regions. Recalling when the current, 20-year regional dialogue contracts were developed, he said two things stand out:

1. The sages in the room who negotiated those deals are gone.
2. We'll be negotiating those new contracts in six years. This generation of managers will be negotiating contracts for our successors. The worst thing we can do is make imprudent capital investments today that make BPA rates uncompetitive when we go to negotiate those contracts.

Annie Terracciano has 18,000 members at Northern Lights, which serves Northern Idaho and western Montana up to the Canadian border. She said they are proud to have a hydroelectric dam in western Montana that produces 10 percent of their power and charges 50 percent less than BPA. She said that as a region, they have far exceeded Sixth Power Plan conservation goals. What we aren't all aware of is what those goals cost. About 6 percent of what they pay in wholesale power costs is what makes those conservation dollars up. For Northern Lights, that's $700,000 a year in conservation dollars. Their rebates are only $300,000 per year, which means they pay in twice as much as what they're allowed to get back and filter into their communities.

BPA's rates for Northern Lights has increased 28 percent in the last six years alone. Every utility is a little different in how that rate affects them.

She wondered how she's supposed to spend that $300,000. Rural utilities are different than city utilities in that it takes twice as long to do the same thing. "If you have a great urban program, it will take two to five years to get to us," she said. Pointing to the duct-sealing program, she said they did 500 homes and achieved 450,000 kw in savings. It cost her members zero dollars with a $400 rebate. Then BPA changed the program to $200 when they were getting traction. It was no longer affordable to get two certified contractors out for four hours."The low-hanging conservation fruit is gone, we're now looking for coconuts," she said.

One coconut is prepaid metering. It eliminates disconnect costs, late fees and high deposits. If a customer has $25, we'll sign them up. The meter is free. It's such a win for everyone. She said the problem is that they need their conservation dollars for our meters, and she asked the Council for those dollars to be used to deploy prepaid metering programs.

Cliff Tacke said that Idaho County Light and Power has 3,174 members in the southern part of the Idaho panhandle. With 3.6 services per mile of line, it mostly serves residences and small farms. Tacke said his members have some of the highest retail rates in the Council's area of impact. He said they maintain and operate a modern operating system in the face of many daunting obstacles and issues. His members are from a diverse mix of families that have lived off the lands for generations. While they come from diverse backgrounds, they share a common thread of taking the conservation and preservation of our resources seriously.

One of the two responsibilities of the Council is to preserve and restore the abundance of fish species in the great river system. He applauds the Council's efforts and accomplishments to reach consensus and implement programs. "Restoring salmon runs to a self-sustaining population is the right and honorable thing to do," he said. "Our concern is that these efforts are being undermined by unilaterally catering to special interest groups with programs that are in conflict with the U.S. Entities regional recommendations for the Columbia River Treaty." He said that we need to maintain a regional support for recommendations that were built through difficult consensus building. His members carry more than their fair share of the burden of the Columbia River Treaty. This needs to be corrected, but it won't be unless the region brings a unified voice to bear in urging the State Department to allow the regional recommendation in negotiating with the Canadian government.

Regarding fish passage in Chief Joseph and Grand Coulee, the U.S. should undertake a joint program with Canada, with shared costs to investigate and, if warranted, implement restored fish passage on the main stem of the Columbia River to the Canadian spawning grounds. In addition, all such federal actions at Chief Joseph and Grand Coulee projects should be subject to Congressional authorization and appropriation. The Council's proposal to fund and conduct these studies not only conflict with regional recommendation and efforts of the regional BiOp, they put the burden on ratepayers instead of sharing the costs with Canada and the nation's taxpayers.

Dave Hagen said Clearwater Power Company in Lewiston has 11,000 customers, in three states and 11 counties, including the Nez Perce and Coeur d'Alene Indian Reservations. It has about 3.6 customers per mile, compared to Avista, which has 35 to 40 customers per mile. It holds a BPA sales contract and network transmission agreement and is a member of PNGC, which meets its tier 2 needs. He said the service area is finally seeing recovery from the recession. Sales are now at 2008 levels, and there's been some load growth after seven straight years of decline. They are in a rural and depressed area with aging infrastructure. At 74 years old, the utility is spending a lot of money on power poles, wires, transformers and other items.

They also are spending on new software and hardware, and they have an advanced metering system. They are seeing rising operating costs. BPA has announcing new rates next month and they are projecting an 8 percent increase in the wholesale cost of power. Couple that with increasing expenses, labor, material, and interest, on top of cost of regulatory compliance with cybersecurity compliance, it's like a death spiral, he said.

Hagen said that all utilities need to grapple with their future rate structure. "Every one of us will admit that our rates aren't where they need to be," he said. They're looking at rates structures that support declining sales, aging infrastructure, rising operating costs, distributed generation, battery storage, energy efficiency and new technologies, and they're going to have to adjust their rates.

It is Hagen's 32nd year working for Clearwater. In 1996, his charge was to look at diversifying 50 percent away from Bonneville, and they did it. The reason was because BPA's rates were above market at that time. They weren't the only ones to do that. As utilities look to 2028, they're looking at different resource mixes. They have saved their customers several hundred thousand dollars.

He wondered what BPA will look like in 2028. He said Elliot Mainzer knows he has to have a long-term view. He wondered about the impacts of conservation, demand response, distributed generation and other technologies.

"What rate structure will we need at the wholesale and retail levels to send the proper price signal to our customers and guarantee fairness across customer classes?" he asked. "Will utilities be able to collect their fixed cost by increasing their monthly facilities charge? Will residential time of use rates and demand rates need to be implemented?"

How will the Council help Northwest utilities address these questions while balancing cost containment and the development of BPA's value proposition?

Hagen said electric utilities need to balance reliability, affordability, safety and environmental stewardship.

Member Smith asked about demand response. Rural co-ops in western Montana expressed interest and it comes up quite a bit. What are your thoughts?

Boorman replied that a key factor is if you have commercial and industrial customers you can work with. Residential has cultural barrier in that they don't want big government messing with their water heater. Hagen said we need to get to the point where we have residential demand rates. With proper price signal, these programs will be better received.

Member Karier commented that a lot goes back to Power Act, which directs the Council to identify least-cost resources and cost-effective conservation, and to mitigate impacts of the dams. One dilemma is that it’s so much different when they hear urban utility issues, and then hear these issues; they’re worlds apart. Some say BPA has to accommodate the differences and have a different approach to small cooperatives than big ones. But then you want to be treated all the same. It’s a Catch 22. Is there room to negotiate around that? The Council doesn’t implement, BPA does that.

Hagen said that a good example is that BPA is going to cut its glazing program this year, when he still has customers with no insulation in floors and walls. Market transformation is in the I-5 corridor, but not in western Idaho, Hagen said. Building codes don't require it. We need tools and some flexibility in those programs.

Hagen recounted an event where they gave away smart plug strips to attend a town hall meeting. It cost the utility $20, it got a $40 rebate and another $26 in administration. “That’s $66, with no guarantee that the plug strip will ever get used,” he said. “That money is better spent on a window program. Those are real kilowatt savings that will continue for many years.”

Elliott pointed to BPA’s rural residential program. There’s also the low-density discount and irrigation discount, and they appreciate BPA’s efforts in that. He said the crucial part is that they are a part of that conversation and can help design the programs. On prepaid metering, they implemented it two years ago. They knew statistically that some implementations could reduce consumption by 13 percent because they were more attentive to their consumption. They learned that their members could cut consumption by 8 percent because they paid more attention to what they used.

Member Booth said the Council continually hears “it’s a different culture here” arguments. Why couldn’t there be some program for smaller utilities with flexible funding intended to go toward the most efficient, cost-effective programs? One shoe doesn’t fit all. Has BPA proposed or reviewed something like this?

Boorman said that for a little utility, when you kick off a program, takes awhile to ramp it up. If you ramp up a program, it might end by the time you get it rolling.

Council Member Henry Lorenzen said that in the Power Committee, it looks like capacity constraints will play a big role going forward. We know how conservation plays a role in that, but you see conservation as a cost. What’s very real are the benefits that flow back from the conservation from an overall system standpoint. How we communicate that benefit isn't clearly defined, but the benefits are very real. Umatilla's manager said that BPA could put out RFPs to the region as a whole to see where you could acquire conservation for the lowest price to benefit the region as a whole.

Member Karier said that we have a system that needs to be fine-tuned. People all over the region want to get credit for the conservation they do. We have a Regional Technical Forum that grapples with this. Several times, we've intervened to make sure they're sensitive to rural issues. A lot of behavioral stuff is harder to measure, but we still can measure it and should give credit whether it's a large building in Seattle or heat ducts. Your utilities will never have the industries with the potential for efficiencies. Trying to treat them the same is going to be difficult.

2. Briefing on Clark Fork Delta Restoration Project on Lake Pend Oreille.

Member Booth introduced Charles (Chip) Corsi, Idaho Department of Fish and Game, Region 1 supervisor. There have been a number of Council-funded projects in northern Idaho; one is the trout removal project in Lake Pend Oreille to help rebuild the kokanee population.

Booth explained that the project being covered today also is on Lake Pend Oreille, where the Clark Fork River from Montana comes in to the lake. It's a cooperative partnership, a cost sharing project that BPA funding helped kick off. It is good for the environment and Bonneville gets credit for a mitigation project. It's positive for ratepayers. We're getting 2-for-1, which Corsi will explain. Booth helped work out the deal and saw it before construction started.

Corsi said that Clark Fork Delta is a biodiversity hotspot due to location, habitat quality and diversity, and species richness. The problem is that it is highly vulnerable to dam-caused erosion processes, losing 12 to 15 acres annually with current operations of the Albeni Falls project.

Lake Pend Oreille is the largest natural lake in Idaho, and the Clark Fork River is the largest bordering Montana. Albeni Falls (operated by the Corps of Engineers) and Cabinet Gorge (operated by Avista) are two projects that impact the delta.

He said that Parametrix did a study in late 90s during Avista's relicensing process. He discussed dam-caused erosion using aerial slides. In the upper northwest corner, 100 percent of that area has vanished. In the area of the delta that fronts the lake, two-thirds to four-fifths have been lost. The highest concentration of losses occurred in the Clark Fork Delta and Denton Slough area, and in the Pack River area.

Erosion is happening because of wave action. Prevailing winds come from the southwest and blow up the lake right at the Delta. If you're duck hunting in the wintertime, it sounds like the ocean. The Avista project is a load following system, so flows may change from 5,000 cfs to 30,000 cfs, which can contribute to bank erosion.

Fish and Game mitigation approaches include identifying impacts and causes, placing a priority on in-kind/in-place projects and getting bang for the buck.

Restoration Planning: We started talking about restoration of the Delta in the late 1990s. They developed a letter of agreement (Idaho Fish and Game, BPA and COE) that assigns money to do the restoration. The agreement was $4.5 million. Avista's obligation was figured at $3 million. For a project in its entirety, it is a $17 million project. They needed to identify partners and get in-kind resources. They learned from the Pack River Delta experience and took a multiagency/organization approach to developing plans. They worked to be ambitious, but realistic and phased the project to meet the funding level. They also included the community with public meetings and field tours.

They came up with a plan to address "Area 3," one of the most heavily eroded areas. They started locating and stockpiling materials to build barrier reefs, rebuilding some islands and other measures. This included more than 50,000 tons of rock, 50,000 willow shoots, and 330 trees with root wads.

Kathy Cousins (IDFG Biologist) and Doug Heck with Ducks Unlimited provided oversight.

They worked during winter because the lake level is down, stream flow down and frozen ground easier to work with. They had to cross two channels of the Clark Fork River and put down pads to cross to the work area. The cost has been $7.5 million. The Delta is an incredibly rich wildlife habitat, including snails to bears, and wildfowl, songbirds and eagles.

What's left to do: Finish phase 1, and then implement and complete phase 2, which is to protect White Island and Derr Island.

Avista has met its obligation, but we can still compete for dollars from its wildlife fund. They can't do anything this winter, as they need to regroup first.

Heavy lifters on the project are Avista, BPA, the Council, Ducks Unlimited, the Bureau of Land Management, the and Kalispel Tribe.

Corsi then showed a short video about the project.

Member Rockefeller asked who owns the land. Corsi said it is mostly owned by the Corp of Engineers, some is owned by the by BLM and some by Idaho Fish & Game, with some public ownership. Support from public has been very good. People realized that this place is literally disappearing. There was some frustration with hunters who couldn't use it this winter, but they understood. He said he hasn't heard anything negative at all about this project.

Council Business

Northwest Power and Conservation Council Motion to Approve the Renewal and Update of the Wildlife Advisory Committee Charter

Member Booth moved that the Council approve the renewal and update of the Wildlife Advisory Committee charter to October 31, 2015, as presented by staff and recommended by the Fish and Wildlife Committee [with changes made by the Members at today's meeting]. Member Anders seconded.

Discussion:
Mark Fritsch, staff manager of project implementation, said that as per the 2014 program, the staff is working on some definitions. Our current charter expires on June 11, and we want to update it until the end of October. There was one edit to the charter on page 5, tab 3, where two words were deleted from item 7.

Member Booth added that there is very strong committee support for this extension. Member Rockefeller remarked that it comes at no additional cost.

The motion was unanimously approved.

The Council adjourned for the day at 4:09 p.m.

Wednesday, June 10

Council Chair Phil Rockefeller called the meeting to order at 9:31 a.m.

3. Dry year implementation strategy presentation by U.S. Army Corps of Engineers, Bureau of Reclamation, Bonneville Power Administration and NOAA Fisheries.

Jim Ruff, Council staff's manager of mainstem passage and river operations, introduced panel of federal action agencies: Tony Norris, operations research analyst at BPA; Steve Barton, chief of the Columbia Basin water management division at the Corps of Engineers, John Roache, program manager with the Pacific Northwest Region river and reservoir operations group from Bureau of Reclamation; and Ritchie Graves, chief of the Columbia Hydropower branch at NOAA Fisheries.

Ruff said that the FCRPS is in a dry-year operation. Dry-year operations are implemented when the May final April through August volume runoff forecast for the Columbia River at The Dalles is less than 72.2 million acre-feet (MAF), which is less than 82 percent of average. NOAA's final May forecast was for a runoff volume of only 62.4 MAF, which is only 71 percent of average, and nearly 10 MAF less than the dry year trigger.

The federal action agencies have been working to determine the best way to meet the needs of salmon migrating in the Columbia and Snake rivers with a limited amount of water

— in addition to managing the system to meet the multiple purposes of the FCRPS through the remainder of the year, including power needs.

When dry year operations are triggered under NOAA's 2014 Supplemental FCRPS Biological Opinion, such as in this year, federal storage reservoirs are drawn down further than normal to provide more water for fish. A benefit of reservoirs is the ability to capture water in storage and release it later during drier times.

Steve Barton provided an overview of the snow situation that led to the low water forecast. As of May 4, most U.S. basin snow below 5,000 feet was either already gone, or melting ahead of normal. Only the Upper Columbia Basin snowpack is in decent shape.

Barton explained that under BiOp year operations, Libby and Hungry Horse will receive an extra 10 feet of draft by September. Another resource, new to the BiOp, is a Non Treaty Storage (NTS) agreement, where 0.5 MAF draft of dry-year storage is held.

Member Karier asked if the treaty augmentation is above normal operations.

"It's proportional draft," Barton said. "When treaty storage regulation stream flow doesn't meet the load, it proportionally drafts the reservoirs to meet that load. The water comes out when there are low-stream flow periods. It's there to meet power need, which coincidentally meets fish needs too."

At Grand Coulee, the summer draft limit is lowered two feet and at Libby, if volumes go below 4.8 MAF, there is no sturgeon pulse.

Next, Barton discussed the 2015 augmentation volumes from May through September, which will total about 8 MAF. "About 4.5 MAF is coming out of Canada this year, which is a significant contribution."

John Roache discussed for operations for Banks Lake, Grand Coulee, Hungry Horse and Upper Snake.

The flow augmentation for the Upper Snake (above Milner) is expected to deliver 427 kilo acre feet (kaf), with basin values likely to be adjusted as augmentation releases continue.

Grand Coulee operations: The reservoir was drafted to 1,255 feet or lower from March 15–May 11, after which they delayed refill of Grand Coulee to maintain 185 kilo cubic feet per second (kcfs) at McNary through May 21. On May 22, they maintained average flows at McNary at 200 kcfs through end of month, and began refilling it on June 1. They are targeting between 1285–1287 feet by July 3 for recreation interests. They plan to fill it to 1289 by July 12 and then draft 12 feet by the end of August for flow augmentation.

Member Booth asked, what is the total elevation of draft planned for Grand Coulee? Roache said the summer is 12 feet and winter is usually 82 feet.

Booth said that Grand Coulee is a peaking regulator for the region. During the day, is there a set max you can draw to augment wind? Roache replied that there are limitations. You don't want to drop too much too fast. But day to day, there is quite a lot of flexibility. The limit is 1.5 foot a day because of landslide concerns. But during a cold snap, sometimes they need to drop more. They could get 4 feet out in two days in extreme circumstances.

Member Karier said, "But you're not drawing out in the summer so much. Don't you hold it fairly steady?" Roache replied that you don't want to draw too much or it will impact the river downstream. Right now they are filling, and there's no restrictions on the fill side. They can fill faster if they have the water available.

Booth said they'll be somewhat limited by fish requirements. In the summer it won't move as much, but in the spring it might move more. Roache said that depending on the flood control curves, they could have a pretty big draft in April, about 30 feet plus over a month.

Or a large change in water supply forecast would precipitate a deeper flood control draft, said Barton.

Roache added that to do that, you have to put quite a bit of flow through the project, and there are limitations of where we can draft to and how fast.

Member Smith asked, "Regarding the half MAF from Canada, what if you had two dry years in a row? Could you get that two years in a row?"

Barton replied that the half MAF of dry year treaty storage is new. It doesn't preclude getting it a second year in a row, but we don't have the firm release rights, so it's not guaranteed. In addition, we have to pay all this back, including the proportional draft, so that's 3MAF that would have to go back into the reservoirs.

Roache then discussed Hungry Horse operations. The volume that ran off in March was the highest in last 45 years in the Flathead Basin, and a lot of low- and mid-elevation snow went away. Precipitation in April and May were far below average, resulting in a low-volume inflow forecast in May and June. June's May through September inflow volume forecast was 64 percent of average.

Member Smith asked about impacts on Flathead Lake.

Roache said it looked like Flathead Lake was going to fill. They have FERC requirements to fill certain flows that they have to meet downstream as well. We have coordination calls monthly with Reclamation, and it looked like they were in decent shape. 2001 is last year there were issues with it filling.

Discussing rain volume for the Hungry Horse area, Roache said that Hungry Horse will fill to within the top five feet of elevation. Beginning July 1, Hungry Horse will begin to draft 20 feet by the end of September, for flow augmentation in the lower Columbia River.

Tony Norris discussed Libby operations. The April through August water supply forecast dropped from 6.3 MAF in January, to 5.4 MAF in May (92 percent of average). The sturgeon flow augmentation volume was 0.8 MAF (Tier 2). Releases began May 22 at full powerhouse for seven days, ramping down to stable summer flows. Estimated flows should be steady through August, drafting to 2,439 feet by August 31.

At Albeni Falls, Norris said that the April – July water supply forecast dropped from 2.1 MAF in January, to 1.3 MAF in May, which is 54 percent of average. The project augmented spring flows on three occasions to assist spring juveniles, and the reservoir refilled the first week of June. The reservoir will remain full until temperature operations are necessary, or until releases are needed to reach 1,535 feet by August 31. They plan to maintain Lake Pend Oreille at between 2,062 and 2,062.5 feet into September.

Dworshak Operations had the worst drop in water supply forecasts. From 2.1 to 1.3 MAF in May, which is 54 percent of average. It's quite dry. The April-July water supply forecast dropped from 2.1 MAF in January to 1.3 MAF in May, which is 54 percent of average. The project augmented spring flows on three occasions to assist spring juveniles. The reservoir was refilled the first week of June, and it will remain at full until temperature operations are necessary, or until releases are needed to reach 1,535 feet by August 31. Right now, it's a nominal operation.

At the Lower Snake and Lower Columbia, flows are benefitting from upstream flow augmentation operations. With the flows at current levels, it's still going to be dry. They're going to be low, but it's not unprecedented. We've had dry years in the past. Operating consistently with the BiOp to make sure we're releasing water to benefit the salmon and provide ancillary benefits to the river. There are no new known navigation hazards other than season accretion. Low flows may make special operations difficult to implement in late summer.

Ritchie Graves shared a juvenile fish passage presentation. He said that we still have BiOp flow objectives during the juvenile migration. For example, the objective at McNary is 220–260 kcfs in the spring, and Snake River, it's 85–100 kcfs. We're going to be below those levels. We held on to 200 kcfs at McNary for most of May when fish were migrating, and about 60-75 in the Snake River. This is well below the objectives in the BiOp and it accentuates that it's a low year.

We're the 51st out of the 55 lowest-flow years for Columbia and Snake River.

Through the tech management team and through the BiOp, there's an emphasis placed on spring juvenile migrants. There are 60 evolutionarily significant units (esus) of listed fish, plus two or three others not listed that benefit from operations during the spring period. There's only one esu migrating in the summer period, the Snake River fall Chinook. Compared to others, there's a healthy stock right now. Also, unlisted summer/fall Chinook from Upper Columbia and Deschutes rivers are migrating.

Dry water operations have helped guide decision processes. The Corp was helpful in approving flood control shifts that helped keep flows higher in April and May than they otherwise would have been.

2001 was a similarly horrible, low-flow year. They ran a max transportation operation. Snake River had no voluntary spill. All fish that came down were barged and travel times were poor. But Graves said he prefers to equate conditions in 2007 to today. 2004 and 2007 were lower-flow years too. He said that due to surface passage routes, travel times were decreased.

Graves said if you look at changes in median travel times since 2005, we have affected the passage time. It’s been a big deal for steelhead. On average, travel times through the lower granite to Bonneville reach 10 days at the lowest end, and are still high in the early spring. Some of it is behavioral.

2001 was the lowest year in the Snake River and it was 2007 in the Lower Columbia. We’re somewhere between those. Graves said he doesn’t think 2001 is representative of today’s operations. He thinks that 2007 or 2010 is a better surrogate of what to expect this year.

Graves discussed PIT tag data for Snake River spring Chinook and steelhead, and passage timing and magnitude. It doesn't look like migration timing has varied much for spring Chinook. They’re a little late at McNary and steelhead even later. We’re getting fewer PIT tag detections at almost all projects for Snake River esus, but they are getting lots of them at Bonneville Dam. They’re trying to decipher what this means. Either there are fewer fish surviving Granite, or fewer detections. They’re leaning towards fewer detections. Thinking under these circumstances surface passage takes at lower granite dam takes 10,000 cfs of water. Just through that one route. In a 60,000 cfs year, that represents a large fraction. Maybe the spill efficiency curves developed under normal circumstances aren’t fitting very well under these low flow circumstances. If fish are using surface passage at a higher rate than typical, might explain why we’re seeing as many fish.

Getting PIT tag detectors on the spillways would be helpful, Graves said.

Yearling Chinook and sockeye smolt passage indices were discussed, and the same pattern is evident. Yearling chinook don’t seem to be late and sockeye seems to be in the middle.

Graves concluded by saying that the time of ocean entry important because later migrants generally have lower returns. Ideally want to get as many fish to the ocean as early as possible in as good a condition as possible, he said.

Member Lorenzen asked, during low flow years, what role does transport play? Do you look to that to get more smolts downriver? Ritchie replied that there’s a bit of an irony operating in these conditions. Because some programs at some of the dams, such as Lower Granite are set to a low volume, we actually transport fewer fish in these low flow conditions than higher flow conditions. That’s because they’re moving over the spillway and downstream.

They will be transporting 30 to 35 percent of spring Chinook and Steelhead. Back in 2003, 2004 and 2005, we transported 98 percent of the fish from three cluster projects. There will be lots of fish left in the river. We'll still be transporting fish and we'll see how the adult returns turn out.

Lorenzen followed by saying, "I'm as much of a neophyte about the Biological Opinion as anyone, but the materials provided to us indicate that during years with high temperatures, there would be an attempt to maximize transport." Ritchie said that is generally correct. Through the adaptive management implementation plan every year, they wrap up what they think they have learned, and consider what if any changes need to be made. A decision was made this year to continue with spill operations. This is consistent with the BiOp and with ISAB's advice to spread the risk and learn from this among a wide range of conditions.

Member Booth remarked that he's very interested in graphs showing increase in number of hits at Bonneville compared to upscreen hits on PIT tag arrays. "Have you done work yet on survival from the first array down at lower Granite down to Bonneville?" Graves said that the Science Center generates those estimates during the summer. He said they received a memorandum form Rick Sable in late August or early September on how the spring migrants did. They normally don't change that much between then and the report that comes out in February and March. "My guess is we'll see pretty decent survival rates, nothing like 10-20-30 percent survival rates we saw in 2001," he said. "This is partly due to the 24-hour spill in the Snake River projects and that surface passage routes have been a real benefit to fish. Also, we're leaving so many fish in the river from those test groups in 2001, only fish left in the river form the snake river basin were left there on purpose. They were study fish. What we've learned about avian predators is that those fish probably got pounded. We'll see survival results in early fall.

Member Karier remarked it was a good presentation, but one set of slides he's looking for is the effect of flow augmentation. Not survival, but flows and water temperature. "Do you collect that data? Something that shows the flows at The Dalles or McNary – what they would have been without the 8 MAF, what they were because of the flow augmentation, how much difference does it make in the actual flows, and how much difference does it make in the travel time, ultimately for NOAA and the temperature that would help fish?"

Norris replied that he had a table that gave an approximation of the augmentation volumes and the estimated periods they were to be delivered, and their estimated flow contributions for that period.

Karier asked what it would be without flow augmentation? Norris said it would be minus those numbers. In July, 43 kcfs, absent all that flow augmentation, would be -43 kcfs. In July we're forecasting 130 kcfs, minus 43 puts you minus 100 in July.

Karier asked the panel to provide those two columns of information so the Council can look at it.

Norris replied that it gives it a precise reality, which doesn't exist because they're estimates. "Then you have forecasts. We can do a retrospective in the end. The stream flow forecast we showed you was just one potential outcome."

Karier said, “Is it 10 percent more flow because of our flow augmentation … is it 40 percent, is it one percent … I don’t get a sense at what it would be without augmentation.”

Norris estimated 33 percent in July or about a third.

Karier said, “So it’s significant. Can I get it in a slide? If it’s a third, it’s much more important than three percent. So I think that would be helpful. If there’s a way to estimate impact on travel time and maybe change in temperature in the mainstem.

Norris said that as far as water temperature in the Lower Columbia, and by the time you get to last project on the Snake, the water temperature is driven by atmospheric temperature, not dam operation, except for Dworshak. That impact disappears by the Lower Snake. He said they have very specific temperature operations for Dworshak, so they’ve modeled that all the way down the mainstem, but that impact diminishes as you move down the system.

Ritchie added that with the pit tags we have in hand, it looks like it’s taking fish 14 days to get from Lower Granite to Bonneville. For last five or six years, the median range has been 14–16 days. The limitation with PIT tags is that you only measure what the survivors are doing. Nine days from Granite to McNary, and four to six to get from McNary to Bonneville. That’s similar for steelhead. Snake River sockeye is taking three days from McNary to Bonneville.

Karier asked if there is a change in travel time due to flow augmentation. With a third more flow, are your getting faster travel times?

Richie replied that they would need to use their COMPASS fish passage model to try to assess that question. It’s also hard to de-couple flow travel time from the travel time benefits provided by surface passage. It seems like it would be a simple question, but it’s not that simple.

Member Rockefeller remarked that we could spend a lot of time on metrics. “But what I’m hearing you describe is a pretty resilient system,” he said “I’m amazed at how well you have to integrate all the different systems, for power and fish. First of all, my admiration goes to you, because you’re the core of a team that figures this out.”

Regarding resilience, Rockefeller asked if they were to project conditions that we’re experiencing this year, going to the next year, if it becomes a pattern or a chronic condition, would they have the confidence that they could maintain the scenario we’re seeing this year. Or are they drawing upon reserves that may not be available in a second or third year?

Barton replied, “Dry years happen. It’s not the worst we’ve seen, but it’s in that group. The BiOp sees that they will happen. The Columbia Basin is storage shy. We have much more runoff than available storage. If we have a subsequent dry year, all the same provisions apply, absent the firm release right of the Non Treaty storage. In a second dry year, in terms of the strategy and objectives, those would remain the same. I’m confident that employing same strategies, we’d have a good prognosis.”

Roche said that they have a pretty good probability of refilling Grand Coulee and Hungry Horse. In the Upper Snake, they're projecting low base flows in the summer. Irrigation will be high, which could have an impact if we have another dry year.

The BiOp contemplated this with draft limits and objectives to help protect against subsequent dry years. Fortunately, we do expect it to rain sometime, we store very small percentage of total river volume. We do have to pay it back, but depending on how our fall and winter shake out, it could create consequences there.

Rockefeller remarked that we've benefitted from rainfall in the Upper Columbia and British Columbia. Reservoirs there are getting filled.

Ritchie said that the BiOp has required that we hedge a bit, that we don't throw everything in and get caught flat footed in subsequent dry years. If we had a persistent three to five years, it will nibble away at those programs. It's a pretty resilient system and we're eager to see how the fish respond. Will be an interesting year in assessing how well the hydro system performs for fish under these circumstances.

4. Discussion of Scenario Analysis Results

Tom Eckman, director, power division; and Ben Kujala, manager, system analysis, briefed the Council on three least cost resource strategies across 800 futures:

- 1a Existing policy without uncertainty, w/o GHG reduction risk
- 1b Existing policy with uncertainty, w/o GHG reduction risk, and
- 2c Existing policy with uncertainty and with uncertain GHG reduction risk/target.

Staff looked at cumulative and average developments of energy efficiency conservation in MW of energy average and capacity. They also examined demand response, Renewable Portfolio Standards (RPS), the probability of building renewable resources beyond the standards in the states, and the probability of building thermal resources. Plus, they looked at the CO_2 emissions produced with each scenario.

Eckman said that since the webinar last week, they revised their peak load forecasting method, and now use historical relationships between temperature and weather sensitive loads. They have a way to separate the energy needs and the capacity requirements.

The RPM does not yet have an integrated component to reflect different seasons of peak capacity values for conservation.

In all scenarios, least cost resource strategies rely heavily on energy efficiency to meet both winter capacity and energy needs.

The supply curve for energy efficiency isn't as robust as it is in the Sixth Power Plan. Energy efficiency for capacity purposes and energy purposes show up in a very narrow range.

Impact on loads

Eckman said looking at net load, we begin to develop thermal resources at the end as loads begin to grow past 2030. Net load stays flat for a 20-year period because we're adding energy efficiency. We use conservation to stay within existing load generating resources, and build resources to replace resources being retired.

Member Karier commented that if you look at the next 15 years, it looks like a 15 percent decrease in load. Eckman replied, that's right – from 2,100 to 1,950 aMW. Kujala added that it wouldn't take too much for an upturn in loads. The supply curves show us what's available in the near term.

Demand response

In all scenarios, least-cost resource strategies rely on low-cost demand response options to maintain adequate capacity margins. Demand response is optioned because it has a shorter lead-time, smaller incremental resource size and lower cost than generation options

Eckman said that we see about the same amount developed across all years. We build it up and maintain it. In all scenarios we build about 1,000 MW in 2021 and sustain it. Demand response is used for capacity reserve margins, and it's not deployed very often during the year. It's a big part of the story.

Member Booth asked, when you generated this data, you're showing 900 MW coming online quickly. Is that based on actual plans of utilities? What are you using to base your data upon? Staff member John Ollis replied that Navigant guided us on these assumptions. There has been input from stakeholders, but most have been driven by Navigant.

Booth said that if you're talking about a large amount of demand response to come on, you must have utilities ready to do it. Eckman said that we do have utilities that have indicated that they plan to use demand response, but not to this degree. Kujala said this model can't tell you all of those considerations, it just looks at it from a cost variable.

Council Member Jim Yost said that the telling story is that there may be potential for that much demand response in five years, but the key is that it's only 50 hours. So if you use it, it's gone. Eckman said that in many futures, it's held as a reserve, it's not deployed.

Member Lorenzen remarked that it will be interesting to see what the model will produce without demand response.

Kujala said they have a lot of different water conditions in the model. A lot of times you're deciding whether you're buying demand response or a gas plant. And there are a lot of futures where it's going to be left unused. It's less expensive to buy demand response and not use it than to buy a gas plant and not use it.

In all scenarios, least cost resource strategies build renewable resources to satisfy state RPS requirements. Renewable Energy Credit (REC) banking delays the need for constructing RPS resources until well past the action plan period.

In the 2021 period, there's very little development. By and large, there's no renewable development until 2026. It's not a big number, about 300 MW. Adding another 900 MW is not a big number. Much of this is to satisfy the RPS.

RPS are a function of load. Least cost strategies already have low risk. The planning period starts with an immediate need for capacity in most futures. Adequacy requirements and RPS drive resource builds, thus reducing market price risk exposure.

Economic builds are few and far between. There are no economic builds in Scenario 1A, they occur in less than 1 percent of futures in the least cost resource strategy in Scenario 1B, and less than 5 percent of the futures in other Scenario 2C.

Thermal build options selected for adequacy are related to retirement of the second unit of Centralia. Half the time we don't build any.

Member Bradbury said that in 2020, there will be the significant closures of Boardman and Centralia. I assume that's a big hit. Eckman replied that there's enough existing capacity and surplus energy. Currently, we're deficit capacity, but between energy efficiency and demand response built by 2021, that's enough to meet the planned retirements. By 2026, it's not.

If we look at thermal capacity development, we see about 700-800 MW peak capacity built in 2026, which will carry us to 2035. Our resources will be running at close to nameplate capacity.

Bradbury: EPA 111d and carbon, how do they relate? Eckman: we tracked them. The probability of carbon emissions. EPA's proposed limit is 26 million tons. In the two scenarios, they would be below the EPA limits. When given the way we model things, EPA only models w/in state boundaries. But we also rely upon plants outside state boundaries. Looking at total power system, a much bitter footprint. When we include Valmy and Bridger, it's much higher, but still reduced significantly.

Thermal resource dispatch, with and without carbon risk, were discussed.

Regarding carbon assumptions, Bradbury asked how 111(d) and carbon risk relate? Eckman said that we tracked carbon emissions from the plants proposed for regulation under 111d. The probability of carbon regulation is modeled. We are looking at the average between the scenarios. The EPA limit is 26 million metric tons (MMT). The 2c and 1b scenarios would be under EPA limits.

We need to model the resources in the four states, and the affected plants in those areas. In low water years, we'll run carbon resources more often. Our actual carbon footprint is higher than 111(d), since it doesn't take Valmy and Bridger into account.

Bradbury asked what is meant by carbon risk? Eckman said that we need to show that carbon regulation is pending. We don't' know what form it will be yet. So we use the tool we have, which is to invoke a higher price for carbon in the marketplace and model our response to that. We'll see less coal dispatched and more natural gas. It's cheaper to boost gas use than it is to buy more conservation and renewables. That's what we would do, given these prices.

That's the cheapest way. It might not be what will happen. States will have to figure it out. This assumes we have perfect arrangements across state boundaries, none of which exist today. Bradbury said, "But it could." Eckman replied that it could.

Member Lorenzen said that the model stays away from market purchases due to variability in price. One of the utilities yesterday went to market and purchased tier 2 power cheaper than tier 1. The question is, how deep is the market? Where does the power come from?

Kujala said that they do allow some reliance on the market. There is a little bit of market purchase in the model and some reliance on independent power producers (IPPs) as well. We don't see a lot of IPPs coming on line. Some are picking up resources on rate-based contracts for longer terms.

Member Karier said that some of the findings should encourage the Council to think about its policies. "In the past, we developed conservation targets for the region on a five-year basis, but the time period is not five years, it's six years," he said. "We're also seeing that second six year period is dramatic change because of the closure of the second part of Centralia. Energy efficiency ramps up significantly to make up for that. We need to look at two, six-year periods and think about efficiency targets."

Karier said that maybe we should have two-year check-ins as BPA does two-year budgets. Another thing changing is first-year savings targets. A lot of savings were compact fluorescent bulbs. Now LEDs can last 20-30 years. We need to think about the lifetime of these savings. A number of policy implications are coming out of this analysis.

5. Council business

Northwest Power and Conservation Council Motion to Approve the Minutes of the May 5-6, 2015, Council Meeting

Member Booth moved that the Council approve for the signature of the Vice-Chair the minutes of the May 5-6, 2015 Council Meeting held in Portland, Oregon. Member Anders seconded. Motion passed unanimously.

Northwest Power and Conservation Council Motion to Release the Draft Annual Report to the Governors on Bonneville's Fish and Wildlife Costs in Fiscal Year 2014 for Public Comment

Booth moved that the Council release the draft annual report to the Governors on Bonneville's fish and wildlife costs in Fiscal Year 2014, for public comment through Friday, July 10, 2015, as recommended by the staff [with changes adopted by the Members at today's meeting].

Discussion:

Staff information office John Harrison explained that this motion is made every year. The proposal is to release it and to take comments through Friday, July 10.

Member Karier said there are two versions: printed and Web versions. Mark Walker said they are not releasing the summary, just the report. Harrison said that staff created a shorter version that Council members can look at and comment upon.
Motion carried unanimously.

Public comment on Council Draft Fiscal Year 2017 Budget and Fiscal Year 2016 Revisions

Sharon Ossmann, director of the administrative division, said that the public comment period would end July 1st, and that so far, the Council had not received any written comments. Ossmann said that there is always time reserved at the June Council Meeting for anyone wanting to make oral comments to the Council regarding the draft budget document. There was no public comment.

Notice of financial disclosure statements

Staff general counsel John Shurts said that every year, we make a statement at the next meeting following the filings of the financial disclosure forms. Plus there's a report on earned outside income. Member Lorenzen reported income from his outside law practice. Member Booth reported his board membership.

Public comment on any issue before the Council

Washington State Senator Tim Sheldon commented on behalf of the Columbia Generating Station. He is a member of the CGS board. There are 11 members on the executive board, of which three are governor appointees and three are outside directors. Sheldon said, "We represent the ratepayers. We're doing well, coming off our third year of increased generation, and we reached a mark of 683 days of continuous generation. We want to be a continuing partner with you."

Chair Rockefeller thanked Member Booth for hosting the Council and adjourned the meeting at 11:52 a.m.

Approved July ___, 2015

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Vice-Chair

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