Northwest **Power** and
Conservation Council

Council Meeting
March 10, 2015
Eugene, Oregon

Council Chair Phil Rockefeller called the meeting to order at 2:31 p.m. All members were present.

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

Council Member Jennifer Anders, Chair of the Public Affairs Committee, reported that her committee met for the first time last month. They reviewed their plan for the year and the itinerary for a U.S. Congressional tour, which will take place in Idaho during the third week in August. The exact date will be determined.

Council Member Pat Smith, Power Committee Chair, reviewed his meeting earlier in the day, which began with a presentation on the Staff-recommended approach to considering capacity in the Council's Seventh Northwest Power Plan (Seventh Plan). According to the summary, the redeveloped Regional Portfolio Model (RPM) tests each resource strategy to determine whether it meets both energy and capacity adequacy requirements. Council Staff outlined the math for how it works, and the Staff's proposed approach to capacity was generally accepted. In addition:

- An update was provided on the RPM. The third phase of the model was delivered on time and is now in its 30-day review. Navigant can respond to comments, and then extend the time frame for comments if necessary, but that should be it. Staff feels very good about the results thus far, but the software has required a lot of effort.

- Last, there was a discussion of draft scenarios, RPM input assumptions and standardized metrics. There are now 15 different scenarios instead of 14 because the climate change category has been divided into two scenarios: one that studies the load impacts of climate change and one that incorporates climate change impacts to hydropower. The scenarios investigate five major areas: carbon policy, major resource loss, pace of conservation development, increased reliance on variable resources (PNW and CA), and potential effects of climate change. There also are two scenarios based on current assumptions and policy. There was a recommendation that these scenarios be evaluated with climate change impacts, particularly during the summer months. Also, the total number of heating days is going down and cooling days are going up. The consensus of the committee is to proceed with this approach to study its baseload effects.

- Smith speculated that the committee would require more than one meeting per month to keep up with the volume of data.

Council Member Bill Bradbury, Fish and Wildlife Committee Chair, summarized the meeting earlier that day. It began with staff's presentation of the Fish and Wildlife division's work plan for 2015, based on the Council's priorities. The committee supported the Staff approach. In addition:

- The first regional coordination forum with Fish and Wildlife managers is slated for March 19, 2015, from 9:00 a.m. to 4:00 p.m. Bradbury said he would attend the gathering with other interested parties to discuss the upcoming years' regional issues with Council Members and Staff.

- Staff member Mark Fritsch presented the three-step process for use in large projects such as hatchery construction. The step process could be a procedure to use for putting anadromous fish above Chief Joseph and Grand Coulee dams.

- The Upper Columbia Nutrient Supplementation project has received a negative review from the Independent Scientific Review Panel (ISRP), saying that it does not meet scientific review criteria. The project's goal is to quantify and evaluate nutrient status and availability for salmonids in the Methow River Sub basin. The Yakima Nation has been asked to restructure the project to get scientific validation by June or close the project.

- Bernadette Graham-Hudson, Fish and Wildlife Operations Policy Analyst for the Oregon Department of Fish and Wildlife, updated the Committee on the status of the Willamette Wildlife Settlement Agreement since the memorandum of understanding was signed. The Agreement established goals for mitigating the effects of the construction, inundation and operation of the Willamette River Basin Flood Control Projects in the Willamette Valley. Oregon and the Bonneville Power Administration (BPA) agreed to acquire at least an additional 16,880 acres of wildlife mitigation property to protect 26,537 acres (or more) by the end of 2025. The acquisition goal is on track.

1. Welcome and briefing on Eugene-area public power issues.

Council Chair Rockefeller expressed his pleasure in holding the first Council meeting of his tenure in Eugene, and hailed the city as the running capital of the world.

Bradbury introduced Roger Gray, general manager of the Eugene Water and Electric Board (EWEB); and Scott Coe, general manager of the Emerald People's Utility District. EWEB has been in operation for 104 years, providing water and power to about 200,000 customers in the Eugene area. Emerald was formed out of a chunk of 20,000 customers of the Pacific Power territory who voted to create the district in 1979. Emerald provides power at 18 percent below the cost that used to be charged by Pacific Power.

Gray, a 30-year-veteran of planning, said that it's important to build flexibility and adaptability into the Seventh Plan. "The Sixth Plan preceded the recession —it predicted one thing and we realized something different," he said. "So it's important to have conditional and situational-based plans."

EWEB is the largest municipal utility in Oregon. Its energy profile is about 50 percent BPA and 50 percent its own resources. The utility is 90 percent-plus renewable, with hydro, biomass, wind and solar. "Some consider us an anomaly. But we're a harbinger for what the region is going to experience as renewable power becomes more emphasized," Gray said.

Gray said that capacity is EWEB's number-one issue. Its conservation programs go back 30 years, so its cheap conservation is gone. The cost of acquiring conservation is the number-two reason for its rate increases. The first reason is that EWEB purchased too many renewables before the recession. EWEB has no plans to build peaking resources, but it is studying storage resources with Snohomish PUD.

"I'm concerned when we take the regional average and apply it to everyone across the board," Gray remarked. "Utilities have vastly different business situation in terms of how we've been doing conservation. It's important to apply the macro-level strategy appropriately at the micro level."

Emerald PUD has delivered power since 1983. Lane County has six public utilities (BPA customers) and one IOU. Emerald has 50 aMW of load in a rural service area. Therefore, outages can be frustrating, and reliability can matter more than cost. Conservation is part of its makeup, having achieved 6 aMW of conservation. Emerald has a landfill gas plant and 15 nameplate MW of wind. A dairy farm captures gas as well.

Coe agreed with Gray that the Council's planning has to have flexibility for changing circumstances. He commended the Council for the new software and applauds the scenario options. He also said that irrigation and conservation needs are different for different utilities. He cautioned the Council not to go out with energy-efficiency requirements.

Regarding solar, he said that the nightmare scenario is that storage becomes so cost effective, that someone puts an array on their house, stores it, and changes the utility's business model. He urged the Council to examine distributed generation that is outside of our centralized planning control. "When I think about reliability in our rural territory, all our resource planning could be all for naught if everyone has their own solar panel," Coe said.

Rockefeller paraphrased Donald Rumsfeld, saying, "What gives us headaches and nightmares is thinking about all the things that we don't know that we don't know. So it pays to be flexible, and I think the scenario approach is the best situational approach."

Coe said Emerald is in surplus energy for the next 10 years, and is in deficit capacity today for a one-in-five winter event. "We don't need traditional kilowatt-hour savings," he said. "You can have a conservation program, but it doesn't help the peak. Our situation is unique.

We're putting our eggs into the demand response and demand management baskets. We want to see if customers will help us by changing their peak. Our hope is that it will work as the least cost, least-carbon and least-risk approach. If it works, great. If not, you'll have a new general manager speaking to you." He reiterated that reliability is their number-one customer concern.

Council Member Henry Lorenzen asked Gray if the four cents per kWh for conservation is a levelized cost. Gray responded that it is a nominal first-year cost. "We don't use levelized cost," he said. "I worry about its application in the industrial world, which uses discounted cash flow with razor-thin margins."

Council Member Tom Karier asked if EWEB was conducting its own studies on capacity. Gray replied that EWEB sometimes works with BPA and sometimes conducts its own load research. "As a utility, we don't have good information since we don't have the meters." He explained that he would like to study the ability of Douglas heat pumps to operate in single-digit weather and provide capacity reductions."

2. Council decision on the adoption of the findings on recommendations and responses to comments relating to the 2014 Fish and Wildlife Program Amendments.

Chair Rockefeller said that the Council has an important step to take in rendering a decision on the adoption of the findings of the various recommendation and responses to comments received by the Council, in working out the Fish and Wildlife program, which it adopted last October.

John Shurts, general counsel, said that there's an obligation under the Northwest Power Act to either adopt a recommendation or explain why not. He said the Council doesn't need to call out every single recommendation or comment, just the key issues. Staff worked extensively on the draft. Once the Council makes a decision, a notice will be posted in the Federal Register. There is no comment period. There's a 60-day period when people can petition, or they can petition the Ninth Circuit Court of Appeals for judicial review.

Council Vice-Chair Bill Booth moved that the Council complete the 2014 Fish and Wildlife Program amendment process by approving the findings on recommendations, and the responses to recommendations and comments, as presented by Staff. Bradbury seconded. A roll call vote unanimously approved the motion.

3. Update on the Columbia River fish run forecast for 2015.

Paul Kline, Idaho Department of Fish and Game, and Bill Tweit, Washington Department of Fish and Wildlife, briefed the Council on 2014 fish run data and what they're forecasting for 2015.

Tweit said that the Columbia River is showing higher-than-average salmon productivity, and that managing abundance is a lot more fun than managing scarcity. He recalled the 1990s – a decade of true scarcity in the Columbia Basin. The figures he presented come from the *U.S. v Oregon* Technical Advisory Committee Sub-group. They have a large task to pull together the runs from the previous years and provide forecasts for the coming year, and they have done so without technical controversy.

Tweit said that we're looking at a strong return of spring Chinook to the Basin, an increase over last year. It supports recreational, tribal and non-Indian fisheries throughout the Basin.

The Upper Columbia spring Chinook run is smaller than in the Snake River. The 2014 return was quite strong, and another good one is forecasted for 2015. The 2015 wild forecast is 170 percent of the 10-year average. Wild fish are those not released from the hatchery. It has not built up as much as the total run — hatchery fish are responding better. But while we've seen some improvements, it's still not quite back up to the levels in the 1980s. This species has been difficult to recover.

Tweit said we should see another boost in Upper Columbia summer Chinook. All the fisheries are marked selected. They want to make sure that there's sufficient fish for the Chief Joseph hatchery. Upper Columbia sockeye numbers are very rewarding, and they are working out water flow management in the Okanagan River. They are working with First Nations and Canadian Fisheries and Oceans, and are hoping to open Skaha Lake to sockeye. The Wenatchee portion has struggled below the goal for several years, and they were able to have some fisheries last year. However, the bulk of these are the Okanagan fish. Tweit said that they'd be removing some fish from the mainstem to help jump-start the Yakima process.

Council Member Booth asked what caused the massive difference between the 2014 forecast and the actual. Tweit replied that they did get it right in that they predicted that it would be one of the larger runs. "When forecasting at such high ends, our forecast tools have very little confidence," he said. "Over time, you can build a more robust model." Rockefeller asked if they could you adjust the models based on this past year. Tweit replied that they could.

For upriver summer steelhead, Tweit is predicting a reasonably good return. The wild winter steelhead numbers in the Lower Columbia are generally small.

The biggest attraction is the Fall Chinook forecast: 747,300 for 2015. "We know we won't be at these levels forever," Tweit said. "They show long, cyclical variations due to ocean conditions and other conditions we don't understand."

Upriver coho at Bonneville have begun to show a lot of strength, and they are highly influenced by oceanic conditions. Overall, they're expecting a large return. Columbia River chum have responded well to the increase in ocean productivity and they should stay at the more recent levels. "We've made a lot of progress in restoring their fresh-water habitat," he said.

"We're trying to reconstruct smelt abundance," he said. "You can see we went through a low period, then a dramatic rise. It's as big as anything we've seen, but it doesn't mean that it will stay that way. This is heartening to us. We use smelt as a keystone species in the watershed."

A cost is that the large pinniped concentrations we've been seeing in the Lower Columbia are largely due to smelt — and at some point, they switch from the smelt to the sturgeon. But the overall, the system is working better when smelt are around.

He said we are up two million in a total return in upriver, salmonid stocks. "You can see just how depressed they were in the 1990s, and how much of a bounce back we've seen since then," he said.

In fisheries below McNary, tribal catches are fairly good. All fisheries were conducted within Endangered Species Act (ESA) limits. Recreational fisheries were very strong, particularly in the fall. It was a phenomenal year in the Hanford Reach. Overall, 2014 was a very good year.

Kline provided a look at fish Lower Granite upstream. He reviewed 15 years of trend information returns back to Lower Granite Dam for fall Chinook, sockeye, summer steelhead, spring/summer Chinook and coho.

Looking at fall Chinook at Lower Granite Dam, a good year is predicted for 2015 after a record year in 2014.

"For Snake River sockeye salmon, the forecast last year was the same as what we prepared this year," he said, "so there's a lot of uncertainty with a lot of these peaks. It's easier to predict with lower numbers than higher."

He said that four years ago, we were not blessed with large numbers of anadromous fish and hatchery-origin fish to plant into Red Fish Lake. But we're on a three-year ramp-up to Springfield being at full production. In 2017, we'll be at a full million smolts being released.

Steelhead counting takes place over a two-year period. Counting takes place at Lower Granite Dam, in July-December, and then again in January-April. Last year, just over 40,000 fish were above forecast. "This year, we're forecasting a high number of natural-origin steelhead, about 56,000," Kline said. "It's a remarkable forecast." Hatchery fish forecasts are lagging as habitat conditions impact them differently.

Spring /Summer Chinook have the same trend as summer steelhead. It is the second-highest number of fish forecasted for 2015. Despite that forecast for natural origin fish, the hatchery forecast of 55,000 isn't remarkable, but it's still respectable.

The Lower Granite Dam Coho's trend information provides an idea of the magnitude of the strength of the run. Hats off to the Nez Perce for developing this program as well as the fall Chinook program in the Snake River Basin. 2014 was off the scales.

Karier asked about how the wild numbers were getting better, but the hatchery numbers were not. Usually they move in the same direction, he said. What is the explanation?

Kline replied that the difference is in outmigration and the route of passage out, and that wild and hatchery fish survive differentially. Once they head out to the ocean, less is known about if they feed together or interact, but something is affecting them differently. He said they have met production goals for smolt releases. “If anything, we’ve increased production from 10 years ago,” he said. “There’s no indication that anything different is happening in the ocean.”

Anders asked if density dependence has a place in their forecasting. It’s like climate and weather, Tweit replied, in that you often don’t see density dependence in any given year — it’s measured over time. Freshwater conditions can be variable over years. They try to base their forecasts on the number of smolts out, based on how good the rearing environment was and the rate of mortality downstream. “It’s like forecasting weather — we’re looking for patterns in climate,” Tweit said.

Kline added that their first observation of density dependence was in 2001, when they had a high year of Chinook returns to Idaho. “We didn’t see much of an increase in smolt production,” he said. “It will be interesting if we continue to see limited levels of smolt production, even while we see increased numbers of spawners in the habitat.”

Booth observed that six months ago, there was concern that the ocean was turning. Had that happened? “It seems we’re still enjoying good ocean conditions so returns should be coming back in pretty good strength.”

Tweit replied that they’re seeing some science beyond 2015 that makes them nervous. Clearly more has been going on in the plume in the last couple of years. There have been some changes in the food chain, and sardines seem to be declining and moving on. They won’t be surprised if they start to see lower numbers in 2016 and 2017. “The only way we can know if it changed is looking in the rear view mirror,” he said. “We support work of the national fisheries, but none can give us perfect relationships. We have a shot clock going in our brains that it only stays good for so long before it starts to fall off. We’ve had 15 years of good abundance.”

4. Council guidance on Direct Use of Natural Gas Policy for the Draft Plan.

Tom Eckman, director of the Council’s Power Division, and Massoud Jourabchi, manager, Economic Analysis, provided an overview of the ongoing discussion about whether the Council should promote the direct use of natural gas for water heating, or if it should continue to allow the market to guide consumers in their decisions over which fuel to use.

Eckman said that the question is whether to revise the Council’s current policy, which was adopted several power plans ago. The policy is that the direct use of natural gas for some uses is both thermodynamically and economically more efficient, and that those uses would be advantageous. Second, current market forces seem to prompt customers to select the lower-cost fuel, without any intervention. “Because of that, we’re not intervening in that marketplace because it seems to be working,” he said.

Since 1986, the market share of electric water heating has been declining, while natural gas water heating has been growing over time, but less so in the recent past.

Booth asked if the trend can be explained as most people prefer gas where it's available, but it's not available everywhere. Eckman replied that it's the relative position of natural gas cost. Natural gas is about half the cost of electricity for heating water. During this period of time, the market share of electricity has dropped and natural gas has climbed to where they're about equal. Part of it is relative to price, to availability, and some is just customer choice — some people just don't want a flame in the house. Even though electricity is getting cheaper, natural gas is still more popular.

The Council did a study after the Sixth Plan, and identified existing single-family homes with gas space heating and electric water heating as the most likely to be converted. It was the segment most economically disposed to switching.

Runners-up would be houses with electric heat and gas water heating. Any time there's gas in the house already, it's more economical to go with gas. Otherwise, the cost of bringing it in from the street makes it less economical.

Jourabchi created a model to look at actual consumer choices: the business-as-usual scenario, and the least-cost scenario.

Jourabchi said that there are 400,000 electric water heaters in gas-heated homes. Water heaters last about 14 years and each year, 30,000 water heater decisions need to be made. The business-as-usual scenario shows that the choice of which technology to use depends upon the relative perceived cost (be it a natural gas water heater or a more-efficient electric water heater), which in turn determines the market share. The least cost scenario says that the technology that has the lowest life-cycle costs takes 100 percent of the market share. The least-cost difference may be $1.

If consumers selected their water heaters on the least-cost difference, the technical potential is 114 aMW by 2025, about a half-percent of the electrical load. As they switch to natural gas, it increases natural gas consumption by 2.7 trillion Btus.

Jourabchi remarked that one issue we need to think about is are consumers basing their decision on price or are there other factors? Yes, they do take other factors into account. Are there situations or programs to go after these consumers? Yes, one public utility is dual fuel and there's an electric utility that encourages switching to natural gas water heating. We need to consider gas consumption by utilities too, he said. The net effect is that regional consumption of natural gas will go down to 2.7 trillion Btus.

Council Member Henry Lorenzen said that if you use less electricity, you should have less gas use to produce electricity. Eckman said the slide's wording was in error, that natural gas goes down when we use less of it to produce electricity.

Jourabchi said that the impact on customer bills going to the least-cost scenario would be $750 million. In Washington, for a few years, the optimum choice is to go from electric storage water heaters to natural gas, up to around 2026. But starting in 2017, they should switch to electric heat pumps.

Eckman said they reached this conclusion in 2012 after the Sixth Plan. With these very closely competing technologies, your choice was very dependent upon your service area. Each condition produced a different least-cost answer. The entire state of Washington looks like it should be using electric water heaters. But the difference is on the order of $1.

Karier said that when you look at the total resource cost of $750 million, it's a lot of $1 impacts adding up, and a lot of water heaters.

Jourabchi replied, "But that's the technical potential, not necessarily achievable. Puget Sound Energy has a program to convert electric water heating customer to natural gas, and their savings is 1.4 aMW. So the actual achieved potential is not that large."

Eckman said we're comparing 100 percent conversion based on least cost versus less than 100 percent based on consumer choice. There's a $750 million differential and 114 aMW between the two views.

Lorenzen asked if demand management was taken into account. Eckman said it is, and will be discussed later on.

Jourabchi said they asked utilities if they had data that contradicts this data? We asked if their programs are designed to successfully switch people. Two utilities replied they were. We asked if there are possibilities of certain market conditions. We heard from a number of different groups, two private citizens, the Ellensburg Municipal Utility, NW Natural, Northwest Gas Association, Cascade Natural Gas, PGE, PSE and a 29-page comment from PSU students. Responses ranged from urging us to stay out of the market to asserting that we can't have a broad policy covering different service areas. Eckman said that another view was that removing water heaters would be removing batteries that could be used in the future for renewable integration.

Another asserted that there wasn't a level playing field in that electric appliances had incentives to keep people using electric appliances. In Oregon, a study was conducted to determine if incentives encouraged energy choices. It determined there is a wide range of factors. It found that reliability and comfort were greater factors in consumer choice than incentives.

The existing Council policy statement is:

- The Council recognizes that there are applications in which it is more energy efficient to use natural gas directly than to generate electricity from natural gas and then use the electricity in the end-use application. The Council also recognizes that in many cases the direct use of natural gas can be more economically efficient. These potentially cost-effective reductions in electricity use, while not defined as conservation in the sense the Council uses the term, are nevertheless alternatives to be considered in planning for future electricity requirements.

- The changing nature of energy markets, the substantial benefits that can accrue from healthy competition among natural gas, electricity and other fuels, and the desire to preserve individual energy source choices all support the Council taking a market-oriented approach to encouraging efficient fuel decisions in the region.

Staff recommends that the “business-as-usual” logic be continued and that the policy be slightly amended — changing “*preserve individual energy source choices*” to “*promote informed individual energy source choices.*”

Staff is seeking guidance on whether to change its assumptions, get more analysis, or maintain this approach and embed it into the Draft Plan.

Karier said he doesn’t object to the major theme and that the Council shouldn’t intervene. He was interested in the idea that electric water heaters might be more valuable down the road for renewable integration. He wondered what potential there is for converting them to demand response units.

Eckman replied that a certain fraction of them could be used and that their value would come out in subsequent analysis.

Karier continued, “One comment that seemed reasonable was a suggestion to encourage consumers to make the optimum choice. If they did, they would save money, the region would consume less fossil fuel, and there would be fewer carbon emissions — a lot of good things happen when consumers make the optimum decision. So why would we object to encouraging efforts to inform individuals that they should make the optimum choice?” He then suggested other language.

Lorenzen commented, “NW Natural would love that, but I can imagine the utilities of Bonneville would wonder what in the world you’re doing, going out spending our ratepayer money to get people to use more natural gas.”

Karier said, “I think it’s a statement of what we’ve seen, that conversion does have benefits, and that informed consumers can provide a net benefit for the region. I don’t think there’s anything in the statement that acknowledges those benefits. It seems like acknowledging the results of our research would be helpful.”

Eckman suggested additional work on the wording. What’s problematic is that it’s not a universal generalization, he said. Looking at 135 utility positions, each has a different rate relative to natural gas.

Karier still would like to see some kind of statement that the Council recognizes the benefit.

Rockefeller recommended setting it aside for the night and later consider changes in language.

Eckman said that, in the action plan, there would be language that lays out the results of this study and the advantages to the direct use of natural gas. “I’m treading lightly, not knowing what that will be. We may change our minds.”

He said that Staff will leave the load forecast embedded with the business-as-usual conversions, and compare the system benefits with the demand response of capacity benefits and consumer benefits. Then the Council can decide if it wants to promote more conversions or not.

Karier said he wouldn't change any language at this point. "I'd like to see the results of the demand response report and reserve the right to revisit it," he said.

The Council adjourned at 5:13 p.m. until 8:30 a.m., March 11.

Council Meeting
March 11, 2015

Council Chair Phil Rockefeller called the meeting to order at 8:31 a.m. All members were present.

5. Council guidance on Conservation Resource Characteristics (i.e. supply curves) and assumptions for use in Regional Portfolio Model (RPM).

Staff provided the results of the conservation potential assessment for the Seventh Power Plan. The assessment describes the energy, capacity and cost characteristics of achievable conservation, along with seasonal shape and annual availability characteristics. Staff asked for Council guidance on the suitability of the conservation potential assessment as Draft Plan inputs.

Charlie Grist, manager, Conservation Resources, introduced his team: Tina Jayaweera, senior energy efficiency analyst; and Kevin Smit, senior energy efficiency analyst.

Grist's presentation looked at the amount of conservation, the cost of it and the pace it can be acquired. Grist stated that there is a lot of conservation in this bundle, but you can't have it all right now. It takes time to build it. The costs shown are levelized over the 20-year plan in order to put conservation and generating resources on equal footing with one another. The intent is to compare them, apples to apples, in dollars.

Grist said there's a big impact from conservation resources. Initial results show that the total 20-year achievable conservation potential is about 5,100 aMW (11,000 MW). Approximately 1,400 aMW (2,900 MW) is available in the first five-years, of which about 870 aMW (1550 MW) costs less than $40/MWh. The cost and availability of conservation resources are inputs to the Regional Portfolio Model (RPM), along with characteristics data for generation and demand response resources.

He said that they are looking at the peak capacity impacts of efficiency at the peak hour: 18 o'clock in the winter.

He outlined inputs to the RPM:

"These are achievable conservation potential, not conservation targets," Grist said. He said they don't know what the cost-effective level of conservation is — they'll find that out after they run the analysis. The numbers aren't quite final and they will be ready for the RPM by March 27. There might be a few additional measures that will be added.

The achievable conservation potential equation is:
Number Units x kWh savings per Unit x Achievable Penetration

The number units are the number of homes, the floor area of retail, the number of refrigerators, acres irrigated and number of transformers.

kWh savings is (kWh/Unit at Baseline Efficiency – kWh/Unit at Improved Efficiency)

Achievable penetration is the fraction of available or remaining stock that is realistically achievable over time.

He said that if they don't have good data, they might have to leave a measure out. Throughout this process, they've been getting advice from the Conservation Resources Advisory Committee (CRAC).

Next, Grist outlined the Sixth Plan conservation achievements through 2013. Those achievements take away from what's available in the Seventh Plan.

Karier asked if the momentum savings are attributable to the programs indirectly or independent.

Grist said there are big contributions from previous programs. An example is more-efficient, commercial fluorescent lighting lamps, which is something the region has been working on for 20-30 years. T-12s have been replaced with one-inch lamps. Utility involvement has made that market much larger. Now customers have moved to more efficient-lighting on their own, and distributors aren't restocking the old ones.

Karier said, "So when the Council set a target of 1,200 aMW over five years, the region achieved it in four. When we set that target, we knew that some could come through codes and standards, and in fact, they did."

Grist agreed that there are a lot of forces at work; it's not just utilities. Manufacturers want to get their products in the marketplace. The point is that a lot got done.

Grist discussed the impact of federal standards on loads. Load goes from 21,000 aMW to just shy of 25,000 aMW by the end of the forecast period. Without federal standards in place at the end of 2014, the load would be 26,000 aMW. These won't produce savings until new products come on the market. There's about 1400 aMW in savings that will occur. We're not looking at savings potential above that standard. It has a big effect on what remains available in the lost opportunity realm.

Again, the total 20-year achievable conservation potential is about 5,100 aMW — 2,000 in retrofit remaining, 3,000 in lost opportunity potential and about 1,400 that will come out of loads going forward. While 5,100 aMW looks less than what we identified in the Sixth Power plan, when you add the federal standards accomplishments, it's a number not different from what we found in the Sixth Plan.

If all the conservation were acquired as fast as possible, you run out of retrofit conservation around year 12. We don’t know if that will happen until we run it through the RPM. The five-year look shows that overall, there’s between 1,200-1,400 aMW of conservation in all cost bins.

Grist reviewed the potential conservation breakdowns by price, sector and end use. Lighting is a big measure in the commercial and residential sectors. Heating is significant and there are many water heating measures in the residential sector.

Some notable new measures include: solid-state lighting, devices to control plug loads, variable refrigerant flow HVAC systems and efficient data center equipment. Just turning off the computers at night is part of that.

Televisions are now more efficient than they used to be, so they were removed from the Seventh Power Plan. But now, ultra-high definition televisions are appearing, which consume four times more energy than the flat screens we recently installed.

Peak capacity is an issue: Energy efficiency measures we find may or may not contribute to reducing peak. If they save energy at that 6-7 p.m. hour, they will reduce peak at that time. Grist showed a graph portraying how much peak and how much energy each cost bundle produced.

Council Member Smith asked what the graph on capacity would look like in the Sixth Plan. Grist replied that the number was not a lot different. What is different now is that we are now looking at a single hour. “We couldn’t produce this graph from our tools then because we weren’t looking at single-hour peak,” he said. Eckman added that they now use a single-hour metric for capacity now. In the Sixth Plan, it was a 16-hour sustained peak, high-load hour.

Grist also showed how savings are shaped by heavy and light loads, and that the conservation supply curves between the Sixth and Seventh Plans are similar.

Some overall observations on conservation are:

- Over 5,000 aMW in potential has been identified over 20 years.
- There is a similar cost profile to the Sixth Plan
- There is similar retrofit potential to the Sixth Plan
- Although there have been lots of accomplishments, there are also new substantive measures
- Less lost opportunity potential – due to new codes and standards in place
- There is a similar measure set
- There is a significant impact on January single-hour peak

Grist credited the help staff received from Northwest Energy Efficiency Alliance (NEEA), BPA, Energy Trust and the Regional Technical Forum.

Other areas Grist mentioned include conservation from:
Commercial – 1,700 aMW much in lighting and data centers
Agriculture – more efficient irrigation – 133 aMW

Industrial – last time 800 aMW was forecasted; it’s now down to 500 aMW.

Lorenzen: When you compute the cost, what goes into the calculations to determine the cost of a conservation measure?

Grist replied that they use total resource cost: capital, installation, markup, line for annual O&M cost changes and periodic O&M. We do all costs and all benefits. They have 20 percent of the capital cost as a proxy for program administrative costs. In the cost analysis, they add the cost of financing by the customer. The utilities aren’t financing for the most part. BPA has it a little different. They try to get it all. They add the benefits if there are savings on O&M. Some of the lighting measures last longer. That’s what they call a total resource cost.

Booth asked, on the cost of conservation, who pays? “There will be a cost to utilities for offering and running programs,” he said. “Consumers will pay to purchase a product. In many cases, there are state and federal subsidies, which means the taxpayer pays. Do you include the cost of taxpayer subsidies, utility subsidies to consumers, such as light bulb incentives? How do you get your mind around who pays for it and how do you get to the $30-$40 cost?”

Eckman replied, from our planning standpoint, we treat it as a total resource cost. Whoever pays them are in the bundle. “When we compared them to a generator or a demand response resource they’re on an apples-to-apples basis,” he said. “We get a total society cost. We were advised early on not to hide costs. If you only look at utility costs, you ignore what the consumer pays. We include all of those costs.”

Booth asked if it includes a federal subsidy. Eckman replied that if there’s a federal tax credit, they don’t discount the measure for that, so it shows up as a cost.

Booth wondered that if we take that view on conservation costs, do we take the same approach on producing energy? For example, will a federal wind subsidy get added on to the cost of the wind? Eckman replied that since there’s no Production Tax Credit (PTC), that number is currently zero.

Karier complimented staff on the impressive amount of work to see where the opportunities are. “I think it’s interesting and surprising to see how large the capacity value is,” he said. “I agree with you on need for better data. We’ve put that request out, and haven’t had much of a response yet. But regarding pacing, I don’t understand why there are limits on lost opportunities — you don’t replace a refrigerator, dishwasher or water heater until it wears out. But on retrofit, is that a technical or policy issue? How do you pace that?”

Grist said, “It’s a matter of judgment, largely. We get input from CRAC and look at historical data, such as how fast have we weatherized homes and how fast could we have? We haven’t tested the maximums of that. But in the retrofit world, with six million homes, you have to go to every one of them, and you just can’t do them all at once. One scenario is where we test the ramp rates. We’ll goose them to make them go faster or slower and help inform what it might be worth to accelerate that.”

Karier said, “I encourage you to take a look at that. Where there’s a hard technical limit on lost opportunity, it doesn’t make sense to push faster. But where’s there’s retrofit and discretion, it would be interesting to know how much more it would cost to acquire it faster. We should study what’s reasonable.” Eckman said that we’d be looking at individual ramp rates later on.

Lorenzen said, “I’m interested in the absorption rate and implementation rate, which depend on the econometric model of what makes sense from an economic standpoint. Also there are some real barriers to the implementation of conservation. One of the things we should be focusing on is how do we overcome those barriers, such as how utilities price their product, because it’s a great disincentive. There are small utilities that don’t have load growth and their boards of directors are reluctant to push conservation when it will result in an increase in rates. These are impediments to the implementation of conservation that otherwise, from an economic and regional standpoint, would be the most efficient way to go.”

Rockefeller said, “Our responsibility is to provide feedback if this assessment is suitable for the RPM.” The Council’s consensus was yes.

6. Council guidance on Demand Response (DR) Characteristics Assumptions for use in RPM.

John Ollis was introduced as the Council staff’s new power system analyst. He formerly worked with PGE, where he performed wind integration studies.

Ollis said that to develop the inputs necessary for DR analysis using the RPM, Staff commissioned Navigant to complete a regional DR potential study. This study’s scope was limited to a review of information from previous potential studies and surveys from investor-owned utilities.

Ollis said that you could think about DR by sector: residential, commercial, agricultural or industrial. For instance, a utility might have a deal with a large customer to shut off the load at a given time to help the system, in exchange for an economic incentive.

DR can be looked at by supply source and by dispatch method, and by whether they are firm or non-firm. The two main attributes for acquiring DR are seasonality (summer and winter peaking capability) and cost. DR resources could be used for other purposes (i.e., flexibility and balancing), but these are not modeled in the RPM. They could be down the road, however.

DR is a hybrid between energy efficiency and a supply resource. The RPM sees it as a supply-side resource even though it’s a demand-reduction resource. One reason to treat it that way is because there is a dispatchability component.

Booth asked, “Why not include DR as conservation? But you say it’s not, that you’re going to use it to adjust supply.”

Ollis replied that DR is not really used to adjust supply. But it's a similar mechanism. If you think about what the model sees, it doesn't make a difference. Because of its dispatchability component, it made sense to put it with the supply resource.

Eckman said that DR didn't fit the need because of capacity requirement. "We had to treat it as a peak generator that could be dispatched at a given hour," he said.

Booth said that DR isn't something we can direct the region to acquire. It's something being done by utilities as economic decisions. "You have to get inside their heads and figure out when it makes sense," he said.

Eckman said that the RPM is designed to make both energy and capacity economic dispatch decisions. That may not be the way the individual utilities are doing it, but that's the paradigm we're working with.

Karier said, "I think it is a key resource. If the Council identifies it as a great value to the region or no value, it will have implications for utilities' portfolios. It's like any other resource; we're not directing anyone to build it. It's either the right or wrong resource for the region."

Karier added that to meet capacity there are only a few options, be it building single cycle plants or DR. This is a good way to test DR at a regional level – is there an economic advantage to any one of these strategies? "I think it's an important finding and it will bear on future investments in the region, and it should, but maybe not individual utilities," he said.

Booth said, "So what you're saying is that we'll end up meeting a segment of the future supply needs with DR? And we will make that assumption planning for the future that they will go that way? Rather than a new generating plant, there might be 300 MW of DR in a plant? I don't know …"

Ollis replied that it's a system need. That's why it is treated like a supply-side resource. When will the RPM acquire it? When it is economic and least cost. But more likely, when there's insufficient peak capacity, it's an option. It can choose that or not. Looking at the state of the system, there is a need for capacity in the winter regionwide. In different areas you need different resources, such as Idaho requiring more summer peaking, and Oregon and Washington needing more winter peaking.

The DR seasonal attributes are important, but the question is, should we separate them as a resource by their seasonal attributes? It turns out, in the RPM, cost matters more. If you sort it by seasonality, the bins end up being really big with a lot of variations. Anything you draw from that, and then try to treat it as representative, would be less representative than if they were sorted by cost.

In new resource selection in the RPM, cost matters more than summer and winter shape, Ollis said. Therefore, DR resources are sorted into "resource blocks" by cost. The cost variation within each block or bin was minimized to make each more representative.

In addition, with all these bins, there’s a transmission full credit, but with a DR resource, we might not have to build that transmission line. The transmission credit is what makes the bin full.

What’s in each bin? Each has a summer peak and winter peak value. Ollis detailed the different resources that were placed in each of the three bins.

Karier inquired, “I’m interested in the price of this and the units: if you have 1,600 MW, you could call on that one hour a year, or two hours or 10 … is there a limit on the number of hours?”

Ollis replied, “This is one of the reasons that DR in the past as been very difficult to treat within the RPM. By giving it a capacity value and an energy value, right now for each program, I have an average number of hours that can be called upon. And that is used to come up with the energy amount that is associated with that DR.”

Karier said, “So you have an energy value that can limit the number of hours. It would be useful to see that for the bins. Then the pricing – dollars per kW year. So that’s $44,000 per MW to call upon for a certain amount of hours?”

Ollis said these are fixed costs. DR is treated like a resource of last resort. It’s not dispatched very often. It’s used to alleviate a capacity need.

Ben Kujala, staff systems policy analyst, said, “The variable cost determines when something is dispatched in the model. But the key driver isn’t dispatched in the model; it will be driven by capacity needs. Since we have planning based on critical water, it might be rarely needed in terms of dispatching it. It’s more like an insurance policy.”

Eckman added, “It would rarely be dispatched for economic reasons, it would be for reliability reasons. It may be cheaper than building plant, however. It’s the least expensive of a very expensive group of things.”

Ollis continued, explaining the bins. Looking at the bins, Bin 1 would be 1 percent of winter capacity and 2 percent of summer capacity. Other bins are representative, but never get above 2 percent. Bin 1 has the transmission deferral credit and the curtailable interruptible tariffs. These may not require a lot of installation, but they have to be available.

In Bin 2, the drivers are residential water heating and space heating.

Bin 3 is much more expensive. There’s less in it than the other two bins. The major driver is space heating for programmable communicating thermostats.

The RPM DR resource acquisition results will guide parts of the narrative in the Plan. The RPM DR resource acquisition results are not necessarily the same as the resource strategy recommendations for the Plan.

Eckman said that in the Sixth Plan, we had a rudimentary, one-bin model for DR. We didn’t have a lot of examples to point to, and now we do — both regionally and nationwide. DR has been used in the organized markets, so we’re actually behind the curve in using DR as a resource option.

Yost said, “I looked at the Navigant study, and I don’t know how they come up with 9 MW of DR for winter irrigation. I don’t know where they get that when you don’t irrigate in the winter. I don’t think they got out and beat the bushes and talked to the IOUs. They have the total MW saved in the summer for irrigation, and it’s probably low. Idaho Power does 300 MW of DR and, by paying another dollar or two, they could get another 50 MW in the summer. DR has to be considered a peaker plant. That’s what it is. It’s very difficult for us to consider it as a back up or for integration of wind or solar. DR is the most expensive resource you can get. You’re trying to back up with the most expensive energy generator you can get, so doesn’t make sense. And it’s hard to do. It looked like they had too much winter DR in the Navigant report. In the winter, all you could do is turn down your thermostat and water heater. If our friends on the west side want to do that, it’s fine with me.”

Kujala explained that it was a very small contract with Navigant. “The intent was that we’d use stakeholder feedback to guide what’s in the plan, and we’re still gathering that. Navigant was just to help us get to a starting point,” he said.

Yost continued, “DR is for capacity. That’s what you use it for. When I looked at the report, and looked at your preparation, I like the idea of categories. I don’t agree with all of the numbers in the bins. I’ll support this, because we need to do this for five years and see what happens, and get our feet wet on how it works. It’s a small and expensive amount. I don’t object to putting it in the plan — I don’t know how the model will react.”

Ollis assured Yost that they took out the irrigation in the winter.

Kujala wanted to comment on the negative cost. “We’re not sure we have the right number. $26 might not be the best number. I wanted it to be consistent with what we use for conservation. There’s a transmission and distribution credit. On generators, we’re going to give them the transmission credit. That treats everything with parity. We can look at that number and see things on a level playing field.”

Eckman said that this isn’t the plan value. We want to put enough in there so it can be tested. But at the end of the day, the Council can decide what the portfolio contains.

Rockefeller received thumbs up from the Council that they are pleased with the model as presented.

7. Council guidance on Generating Resource Characteristics Assumptions for use in the RPM

Gillian Charles, Staff energy policy analyst, presented a high-level summary of the proposed draft Seventh Plan generating resource characteristics that will be inputs to the RPM. It included an overview of the technologies, reference plants and cost assumptions, and a comparison with the Sixth Plan assumptions — and what has changed for Draft Seven. “What’s new for this round is a first look at the approach to incorporating Renewable Portfolio Standard assumptions into the RPM,” Charles said.

Staff is looking to the Council for guidance and acceptance to use these characteristics as the generating resource assumptions in the RPM analysis for the Draft Seventh Plan.

Charles reported that staff has had several Power Committee meetings and has received great feedback from its members. She next described the process used to analyze new generating resources for the Seventh Plan. They started by performing a generating resource analysis, looking at different and emerging technologies, specifications, costs and trends. They took that analysis and formed reference plants, which normalizes those technologies for the Pacific Northwest. Reference plants are evaluated on their resource configuration, capacity, general location, economic life, various cost attributes and construction time. From that information, they form resource blocks, which look at how much is available, where, when and at what cost.

Charles said they had input and support from the Generating Resources Advisory Committee (GRAC) every step of the way. They have had 10 GRAC meetings thus far and will have one more in April.

She next described how the different resources are prioritized. Prioritization is based on a resource's commercial availability, constructability, cost-effectiveness and quantity of the developable resource.

- **Primary, significant:** Resources that look to play a major role in the future Pacific Northwest power system. She said they do an in-depth, quantitative characterization to support system integration and risk analysis modeling. These do get modeled in RPM
- **Secondary, Commercial w/ Limited Availability**: Resources that are fully commercial but that don't have a lot of developmental potential in the Pacific Northwest. These will not be modeled in RPM.
- **Long-term Potential**: Resources that have long-term potential in the Pacific Northwest, but may not be commercially available yet. Similar to the secondary resources, they perform a qualitative evaluation, but they are not modeled in the RPM.

Charles said their presentation focuses on the primary resources: natural gas combined cycle combustion turbine, wind, solar and natural gas simple cycle, reciprocating engine.

Steve Simmons, staff senior economic analyst, described natural gas combined cycle combustion as the most efficient of the gas technologies. They also are the single-largest units at 400 MW. It's mostly used for baseload power, but the technologies are becoming more flexible. Through the GRAC, they developed two reference plants – a combined cycle 1, which is wet cooled and requires a water source; and a combined cycle 2, which is dry-cooled, easier to permit, but it comes with a higher capital cost. The costs compared to the Sixth Plan are similar. They're a little higher in capital costs, but the plants have a higher heat rate for more efficiency.

Simmons said that in the Northwest, we're benefitting from robust natural gas distribution system. We also have storage, so we're in better shape than back east.

Karier asked that since the plants seem similar, so why do we need two plants?

Simmons said that the idea is we can only permit so many of the wet cooled plants. We figured we'd better have a dry cooled one as well. They will be defined fully in the RPM and can be pulled out.

Booth asked about costs. Simmons explained that they have O&M fixed costs in dollars per kW year, and variable costs in dollars per MW year.

Charles said that gas peakers offer two major technologies: Single cycle combustion turbines and reciprocating engines. She described their operation, and said that they range in size from 2 to 20 MW. Historically, they were used to shape hydropower. They used to be heavy duty, less-efficient units, but advances in technology have improved their efficiency. They are good for shaping and peak load. There is a reference plant for each technology. They tried to structure the reference plant around Port Westward II, PGE's most recent peaking plant, which has a capacity of 220 MW.

Capital costs for these have gone up. Charles recalled that we were just coming out of recession in the Sixth Plan. "We recovered quicker than we actually did," she said. "This is primarily why prices are higher than in the Sixth Plan." Also, technologies are more efficient than they were just five years ago.

The GRAC recommendation is to use one gas peaker as a model for all of them. The Power Committee recommends the reciprocating engine, but Charles said we can choose any of them to plug into the model.

Simmons next discussed utility-scale solar PV systems, which he said have been coming down sharply in cost in recent years. He provided an overview of the technology.

The U.S. Department of Energy launched SunShot initiative several years ago to lower solar costs in the West. Its stated goal was a revolutionary advance of $1 per watt by 2020. It also published an incremental goal that's a little higher. Solar PVs are nondispatchable. They are emission free and it could play an important role in the Northwest, especially Southern Idaho. Solar PVs are strong in the summer, but not useful for winter peak.

Simmons showed the Utility Scale Solar PV Capital Cost Estimate. "There's a lot of uncertainty around where these costs are going," he said. "Our forecast is down the middle. It will be interesting to see where the costs go. A big change from the Sixth Plan cost is that Solar PVs are being put into the RPM."

The reference plant is in Southern Idaho – its capital cost is less than half of what it was in the Sixth Plan. The plant can serve local load and regional load via a potential new transmission line, B2H (Boardman – Hemingway Project).

Bradbury observed, "On the chart it shows that development time is three years, so I get 2018, not 2016."

Simmons said we could modify that in the RPM. There are some projects being planned in Idaho that are not built yet. There seems to be a big rush to develop to gain the Solar Investment Tax Credit (ITC) at 30 percent before it goes down to 10 percent.

Booth said that we now have plants industrial-scale in Florida and California. “Did you take their construction and operating numbers into account? Take a look at the construction costs of those two plants.”

Simmons said it’s a good point. “There are so many plants are being built currently, and it’s getting the latest costs for those plants. They may have purchased the PV modules years ago. We’ll stay abreast of PV projects that have good cost data.”

Charles said that they do look at existing and proposed projects, so it is incorporated into their cost estimates.

She continued with a discussion of onshore utility-scale wind, saying that we’ve developed 8,500 MW of wind capacity in the region. “A lot was spurred by the RPS and PTC, which were in play at the time,” she said. “2012 was largest year for development: 2,000 MW of capacity. We’ve seen a bit of a lull since, mostly because utilities on track to meet their goals. The PTC expired, so we won’t be including it.”

There are two wind reference plants – one in the Columbia Basin and one in Central Montana serving Northwest load. Both are 100 MW projects. They extended the life of the projects from 20 to 25 years and lowered the development time to four years. Capital costs are higher at $2,200. Capacity factors in the Columbia Basin are 32 percent, which is the same as Sixth Power Plan. For Central Montana it’s a 40 percent capacity factor. Montana is the third best state for wind.

Karier asked why capital costs went up so much. Isn’t that a 20 percent increase?

Charles replied that, in the Sixth Plan, they had a dip in the wind costs for the out years. By then they had the recession curve come down significantly, whereas it went further and then came down. They had overestimated the amount of its decline in the Sixth Plan.

Booth asked, “As you move forward w/RPM, will you incorporate the assumption to regulate the wind into the model?” Eckman said that currently, the model RPM is not seeing that. They’re not using wind for capacity.

Charles said that, similar to solar, there are five resource blocks for wind.

Next, Simmons discussed the levelized costs of the resources:

- Calculate Fixed Levelized Cost for each resource: $/kW-year, and
- Calculate full Levelized Cost of Energy (LCOE) for each resource: $/MWh

It takes into account how much energy each produces. For example, the graph shows that natural gas combustion turbines are the most efficient and largest. In RPM, it may see a higher base price. It may run more or less. It’s all based on assumptions.

Also, gas units have a big fuel component, which is an uncertainty in the future

Charles discussed the inclusion of the Renewable Portfolio Standards (RPS), which are regulatory mandates by individual states to increase the development and generation of renewable resources. There is no federal RPS in place.

There are a lot of details and nuances in each state, she said. We can't capture it all in the modeling. There is legislation in Washington and Oregon that could have an impact going forward. They should know in the next couple of months what happens with those. Idaho doesn't have an RPS, but it encourages renewable generation and development in its energy plan. Also, there are sourcing limits. Oregon can take them anywhere in WECC. Montana is stricter as they have to be used in the state. Washington says that they have to be used in the Pacific Northwest.

Also, how you can keep your Renewable Energy Credits (RECs) banked differs in each state: Washington is one year, Montana two years and Oregon is unlimited. We try to account for this in our modeling, Charles said.

The output from the RPM, which is run with 800 different futures, determines the RPS build in each future.

Outstanding issues include uncommitted Idaho RECs, Washington State cost cap issues, and the target achievement rate. In the Sixth Plan, we assumed the states would be 95 percent compliant toward their target. This time, the states are ahead of schedule, so we propose to bump that up to 100 percent.

Lorenzen asked if the availability of gas transmission is an assumption.

Simmons said it is for the combined cycle units. "We're restricting it to the east side, where there's ample capacity on the GTN pipeline system."

Rockefeller said, "The Washington State senate is considering easier off-ramps for utilities with slower growth, and possibly it will allow credit for carbon reduction in lieu of diversifying. I assume you'll have to plug in the latest iterations."

Charles replied that they are staying close to it.

The Council agrees that staff is on the right track.

8. Discussion of draft scenarios and strategies to be analyzed:

Eckman said, "We have a lot of things done. You've seen the report on conservation and generating resources, DR, and forecasts all brought to you. We'll try and answer when we need resources, how much we need, and what should we build or buy? How much does it cost? And what are the risks of doing the wrong thing?"

Eckman reviewed the high and low potential load growth ranges through 2035. "We have the major inputs to the model and we have existing resources," he said. "We see little growth of plants coming online in 2016 and 2017. And a gradual decline in coal with announced retirements of Centralia and Boardman. So loads are growing while the existing resource base is getting smaller."

He said that when we net out the low and high load growths, the difference between what we have and what we need is a gap that has to be filled. "That gap is between 1,600 and 3,000 aMW by 2025, and between 3,600 and 6,700 aMW by 2035," he said. "That's what the RPM will try to solve."

Eckman continued, "What should we build or buy? The statute says that we have to buy the cheapest thing first. These are ranked in terms of cost. We're looking for 1,600 to 3,000 aMW of energy. The model will buy the cheapest thing first; so don't be surprised when energy efficiency shows up as a big component in each analysis. When we look at the capacity side, DR is cheaper than buying engines. It doesn't have much energy contribution, but DR will be first because it's cheaper."

He said we have resource strategies. The model is given options to control: what we build, how much we build, when we build it and the associated costs. We can stress changes in futures to accommodate new regulations, technologies or other factors.

Staff proposed running 15 scenarios that were crafted to peek into possible futures:

- Scenarios 1a and b – The first is a good test of the model, as we know what loads will be going forward every year. The second will allow inputs to be uncertain, except for greenhouse gas (GHG) reduction risk.
- Scenarios 2a, b and c – Each looks at different carbon scenarios.
- Scenarios 3a and b – These test what can we do with technology to minimize carbon production. The first evaluates using current, commercially available technology. The second tests how far from 3a we can go, and then we define the hole that exists.
- Scenarios 4a, b and c – These impact resource uncertainty. The first evaluates the unexpected loss of a plant, and the second is a planned resource removal, such as CGS forced retirement, removal of the Snake River Dam or pace of conservation deployment. The third opens up more options for conservation.
- Scenarios 5a and b – These consider the out-of-region market scenario – the duck problem in California. This is a huge influx of low-cost renewable resources flooding the market. The second evaluates Southwestern market uncertainty. What if the market wasn't as deep as we anticipated?
- Scenarios 6a and b – These evaluate climate change load impacts and hydro impacts. The Northwest has less impact. As other areas of the country heat up, more people will move here. Hypothetically, we will look at moving the population up 3 percent.

Yost remarked that they received the information the prior day, and that they should have had two or three days to think about it.

Eckman replied that they need a decision early on in this one. Do we want it embedded in our analysis or treat it as a sensitivity study? "We're getting closer to the time where things on the climate change prognosis frontier start to happen significantly by 2035," he said. "It's a couple thousand MW expansion in the range that will be investigated in the RPM. We're recommending that expansion. I'll talk with the Resource Strategies Advisory Committee (RSAC) in the morning and get back to you."

Karier asked if we need to circle back and be polled, and schedule a discussion.

Eckman said that he'd get RSAC's view and get back to the Council.

9. Presentation on the Independent Scientific Advisory Board's (ISAB) report, "Density Dependence and its Implications for Fish Management and Restoration Programs in the Columbia River Basin.

ISAB Member Greg Ruggerone began with their report's key finding: Density dependence is now evident in most of the ESA-listed populations examined, and appears strong enough to constrain their recovery.

He defined density dependence and why it's important. Density dependence occurs when a change in the number of fish in a given area (fish density) causes a change in the fish population's growth rate. Most commonly, the population's growth rate slows as the number of fish increases, and, in turn, increases as the number of fish decreases. This decrease in a population's growth is most often caused by limitations in food or habitat—carrying capacity.

Density dependence is important in managing fisheries.

The ISAB's key recommendation is to account for density effects when planning and evaluating habitat restoration actions.

There is strong evidence of density dependence in 25 of 27 Columbia River spring and summer Chinook populations. Snake River fall Chinook is density dependent and all 20 interior Columbia River steelhead populations show strong density dependence.

This can help inform restoration activities. Ruggerone reviewed experimental spawning channels. Density dependence depends on the species. For example, chum is different than Chinook. He then provided a spawner-to-smolt stage review. There are fewer resources for juveniles so survival is lower.

Evidence for strong density dependence at current abundance suggests that habitat capacity has been greatly diminished. Showing a map of the basin, Ruggerone stated that 31 percent of previously accessible habitat is now blocked. The impact varies by species. Could density be greater today? Changes in abundance have been greater than changes in habitat.

All these habitat changes impact the capacity of the system to produce steelhead.

Other findings:

- Hatchery releases account for a large proportion of current salmon abundance. Total smolt densities may be higher now than historically. By creating unintended density effects on natural populations, supplementation may fail to boost natural origin returns despite its effectiveness at increasing total spawning abundance.

- Integrated hatchery approach is not possible without sustainable natural population.
- Supplementation lowers intrinsic productivity and resilience of Chinook, coho and steelhead (20 years of data, 71 populations).

There is little density dependence information on estuary and ocean rearing. It hasn't been studied since 2001, and should be updated.

ISAB Member Kurt Fausch said that density dependence is really about crowding. For resident trout, kokanee, sturgeon and lamprey, there are different questions.

Looking at trout, there are four questions:

- Does habitat restoration decrease density dependent limiting factors and thereby increase carrying capacity? Trout move in and stay, survive better the first year. But it's just a pulse of survival.

- Does stocking of hatchery trout reduce carrying capacity for natural origin trout, and thereby reduce their density? There are modest effects on growth and none on survival. A comprehensive study in Idaho detected no effects. Hybridization and disease are common.

- Do non-native trout ruin neighborhood for natives? Removal increased native trout 10 times. Brook trout pack in tighter.

- Can native trout populations rebound when fishing is reduced? Slow-growing bull trout can reach new limits.

Kokanee and sockeye salmon have characteristics that promote strong density dependence through wide population fluctuations and intense competition for food.

Sturgeon declined Basin-wide, especially above Bonneville. Density dependence has been detected among the endangered Kootenai River population. These study results underscore the importance of assessing the productivity and carrying capacity of habitats where sturgeon are stocked. Such assessment is particularly important for sturgeon now that dams have blocked or have greatly impeded anadromy and dispersal.

The abundance of Pacific lamprey in the Basin and along the Pacific coast has declined greatly since 1970, creating important gaps in food webs. Little is known about the role that density plays in their population dynamics, but one laboratory study showed that the growth of larval Pacific lamprey declines with density of conspecifics when food is held constant.

Ruggerone summarized the presentation saying that, "Understanding density dependence (e.g., stock-recruitment relationships) in salmon populations is central to evaluating responses to recovery actions and for setting spawning escapement goals that will sustain fisheries and a resilient ecosystem."

ISAB recommends setting biologically based spawning escapement goals or harvest rates that sustain fisheries and a resilient ecosystem, and to use those goals as a reference point.

Other recommendations include:

- Accounting for density effects when evaluating habitat restoration actions.
- Balancing hatchery production with the Basin's capacity to support existing natural populations.
- Considering density dependence findings and recommendations when implementing the Fish and Wildlife program.

Booth stated, "We need to look harder at it. People think it's important. Rather than get into anything today, can we come back to our Fish and Wildlife committee and delve into it in more detail, particularly its impact on the Fish and Wildlife program.

Rockefeller observed that this is a watershed study that will trigger a lot of questions. He asked Greg and Kurt to return to the committee.

Bill Bradbury also wants to see this brought before the Fish and Wildlife Committee. It's engaged in an effort to define quantitative goals and objectives in the Fish and Wildlife program.

Rockefeller wondered if it shouldn't be confined to the Fish and Wildlife Committee. He wants other Council Members to be kept apprised and to ask questions.

Karier also has other questions, and encouraged the Fish and Wildlife committee to bring a report to the Council on what implications they see. He remarked that this is one of the most critical studies ISAB has done.

Karier asked how hard was it to separate the hatchery impacts? In the past, we thought that, for natural fish, we should limit harvest more to limit escapement. This suggests going in the opposite direction.

Ruggerone replied that NOAA fisheries scientists tried to look at this. They tried to tease apart the density dependent effects of hatchery vs. native fish. Hatchery fish have a lower capacity than wild-origin fish. By adding hatchery fish, you lower the capacity that can be produced by fish spawning in the wild. Hatchery fish spawning will have lower productivity. "I forgot to mention an important aspect of hatchery supplementation," he said. "They may be greatly exceeding capacity. There are opportunities to harvest fish and harvest hatchery fish, as long as you can do it carefully without impacting the natural origin component. It's one idea we discuss in the report."

Rockefeller closed by saying that anyone with additional questions can share those with Bradbury or other member of the Fish and Wildlife Committee. It was very provocative and could lead to some thinking and rethinking of goals.

10. Council Business

Approve the minutes of the February 10, 2015, Council meeting

Booth moved that the Council approve for the signature of the Vice-Chair the minutes of the February 10, 2015, Council meeting held in Portland, Oregon. Motion seconded.

No additions or corrections to the minutes. Motion passed unanimously.

Approve the renewal of the Regional Technical Forum Policy Advisory Committee Charter

Booth moved that the Council approve the renewal for a period of two years of the Charter for the Regional Technical Forum Policy Advisory Committee, as presented by staff.

Yost seconded.

Comment by Jennifer Anziano, manager, Regional Technical Forum. There are two changes: When someone stands down in the Forum, they recommend a replacement. There has been a lot of turnover in the policy committee. Previously it went through approval of the chair. In nine months, we've seen eight turnovers. To streamline the process, we felt that replacements from the same organizations could be handled by the two co-chairs in consultation. That would be a change in the charter. Also, recognize that the two co-chairs be equal on the advisory committee.

Motion passed unanimously.

Approve the revised Bylaws of the Regional Technical Forum

Booth moved that the Council approve the revised bylaws of the Regional Technical Forum, as recommended by members of the Regional Technical Forum and the Regional Technical Forum Policy Advisory Committee, as presented by staff.

Yost seconded.

Anziano said this motion takes care of two clerical changes: On page three, we fixed a typo. The second change is on page five: the RTF manager will ensure the financials and not the vice chair.

Motion passed unanimously.

No public comment.

Adjourned at 12:31 p.m.

Approved April ___, 2015:

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Vice-Chair

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