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NORTHWEST POWER AND CONSERVATION COUNCIL
September 16-17, 2008

The Council, meeting in Astoria, got a rundown on the unprecedented 55 percent increase in fish and wildlife costs BPA anticipates as a result of the Biological Opinion and agreements with states and tribes. Clatskanie PUD's general manager reported on resource development and outlined concerns about the 20-year contracts BPA has offered. And investor-owned utilities said they are preparing for operations in a carbon-constrained world. Next meeting: October 15-16 in Missoula, MT.

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THE AGENDA

PUD Aims to Serve Growing Industry

General manager Greg Booth of Clatskanie PUD briefed the Council on his utility's resource acquisition. He noted the PUD, Oregon's oldest, serves significant and growing industrial load, including paper and ethanol producers. "Free, perfect, and now" is how Booth described what customers want in their electricity service.

We expect continued industrial growth, and the challenge is to meet load and remain the lowest cost electricity provider in the state, he said. Clatskanie is looking to develop renewables and take advantage of new technologies for conserving energy, Booth reported. Conservation is our first priority, and we are in the process of acquiring renewable resources, he added.

The PUD is 50-50 partners with the Eugene Water and Electric Board in a 36-megawatt (MW) cogeneration facility at Georgia Pacific's Wauna Paper Mill and has installed a gas turbine at Wauna to firm up nonfirm hydro purchases to serve industrial load, Booth explained. Clatskanie's latest project is an 18-MW hydro facility, developed in partnership

with five irrigation districts, he said. The PUD is issuing $41 million in project bonds, Booth added.

My view is that utilities should provide their own resources in the future and BPA should play a supporting role, he continued. BPA has had "a fairly poor record" with resource development, and we were happy with the current Administrator wanting to allocate the system, Booth said. That has been the subject of the Regional Dialogue, but "we aren't so pleased with the results," he acknowledged.

Booth said he has issues with BPA's proposed tiered rates methodology, and instead of offering an adequate amount of the "slice" product, the agency has come up with products that have limited flexibility. BPA seems more interested in using its resources to promote development of wind generation, much of which is going to serve load outside the Northwest, than preserving all benefits of the system for the region, he stated. And Booth said he is very concerned about whether the long-term contracts will lock in the benefits and stabilize power rates, "as promised."

Jim Yost asked Booth about the gas turbine the PUD is using. Booth said the PUD purchased a single-cycle turbine in the 2000-2001 energy crisis, with the idea of firming purchases of secondary power from BPA. We've been able to firm nonfirm power purchases and make them go further, he said. "It's used infrequently, but it's our insurance," Booth added.

Tom Karier asked for specific examples of Booth's concerns with the Regional Dialogue and contracts. Booth said one problem relates to how BPA proposes to resolve the residential exchange with investor-owned utilities (IOUs). BPA lost the legal challenge brought by preference customers, but rather than follow the Northwest Power Act and calculate average system costs, BPA has embarked on "an ad hoc system" as a remedy, he said. "The Administrator is substituting his judgment for the law," Booth added.

With regard to contracts, BPA has offered a one-sided agreement, he continued. The provisions for adjudication of disputes and audits are unsatisfactory, and there are other areas of concern with the way the "business relationship" is set up, Booth indicated. He also said BPA has set a low limit on the amount of slice it will sell and is attempting to retain the capacity of the hydro system, which its preference customers need to support new renewables they must acquire to meet state mandates, for other purposes.

Council chairman Bill Booth noted that the PUD's costs have dropped over time. Will the new contracts reverse that? he asked. The drop in our costs doesn't reflect a drop in BPA rates, Clatskanie's Booth responded. It's a result of our ability to get low-cost resources into our system and to market power, he said.

IOUs Tackle Carbon Constraints

A panel of IOU representatives reported that their companies are working to meet the challenge of reducing carbon emissions. Kyle Davis of PacifiCorp described "the backdrop against which we must lower carbon," which encompasses dramatically increased costs of raw materials, transportation, and labor; a generation deficit; transmission capacity needs; and renewable portfolio standards (RPS). In addition, Northwest utilities are experiencing load growth, some of which is "life-style driven" and includes consumer purchases such as high-definition television, he indicated.

Sunny Radcliffe of Portland General Electric (PGE) said that while generation in the Northwest is generally low in carbon, power imports also figure into the equation. Measured in terms of generation, CO_2

emissions in the region are relatively low; but measured by consumption, CO_2 emissions are much higher, and the carbon costs will follow consumption, she said.

Davis recapped activities PacifiCorp has undertaken to reduce carbon. The company will have 2,800 MW of renewables on its system by the end of 2008, including 1,000 MW of wind, and expects to add at least 1,000 MW more of wind by 2016, he said. The company invested $1.6 billion in renewables from 2006-2008, according to Davis.

PacifiCorp is also investing in transmission, including the Energy Gateway project, which crosses six states and will accommodate renewables development, he said. The project is expected to come online by 2014 at a cost of $5.2 billion, Davis reported. In addition, the company is buying natural gas generation to support wind integration and is actively exploring synthetic gas technology and evaluating nuclear opportunities, he said.

Puget Sound Energy (PSE) is investing in energy efficiency, which PSE's Ken Johnson called the first-priority resource. PSE will invest $140 million in energy efficiency over the next few years, he said. In addition, the company has two wind installations that bring about 400 MW of capacity into its system and is working on another 1,250 MW in four wind projects, which have the potential to fulfill PSE's RPS requirement, Johnson said. Solar is also on the PSE agenda, with an installation of solar panels at the Wild Horse project in central Washington, he continued. The solar project has a peak generating capacity of 500 kilowatts and cost $4.5 million, according to Johnson.

Radcliffe detailed PGE's renewable portfolio, including three operating wind projects and one under development. The company has issued a request for proposals for another 218 MW, she said. PGE has a solar demonstration project with the Oregon Department of Transportation for highway signs and is looking to do more such projects, Radcliffe said. In addition, the company has captured 108 MW in generation efficiency improvements over the past 10 years; embarked on a pilot carbon-capture project at Boardman that produces biodiesel; and installed 12 electric vehicle-charging stations in Portland, she reported. PGE is also investing in transmission infrastructure and considering the potential of the Southern Crossing project, a 500-kV line from Boardman to the Willamette Valley, Radcliffe said.

The three utilities, along with six others, paid for an Electric Power Research Institute (EPRI) study of how a carbon price signal at various levels could affect the power market, Davis said. EPRI looked at what happens to generation dispatch when CO_2 has a price, he explained. The most expensive resources to operate "bring up the tail end" of the supply stack, and when the CO_2 price gets to $40 per ton, more gas is dispatched in lieu of coal, Davis said. According to the EPRI analysis, the emissions cost has to get above $50 per ton "to force coal out of the system," he noted.

Davis went on to explain the impacts of a CO_2 emissions tax over time on wholesale and retail electricity prices. There is a real cost associated with how quickly you want to reduce emissions, he said, pointing out the difference in impacts from imposing a tax in 2012 versus 2030. When more time is available to reduce emissions, you temper price increases, Davis added.

The EPRI study concluded that higher electricity prices will be inescapable in order to cut CO_2 emissions; large reductions in emissions are possible if there is time to add significant amounts of nuclear, renewables, and carbon capture and sequestration; and the availability of natural gas is critical to achieving near-term emissions reductions, Davis summarized.

Skepticism on the WCI

Johnson described the Western Climate Initiative (WCI), which is an effort by Western governors to set a regional emissions cap. WCI is set to release its final cap-and-trade program proposal next week, he said. Johnson listed several utility principles for designing a cap-and-trade program, including that it address emissions economy wide. In Washington, for example, electricity production accounts for 20 percent of CO_2 emissions, while transportation contributes 50 percent, he said. In addition, a program needs to be consistently applied, administratively simple, transparent, and include a safety valve for costs, Johnson stated.

WCI is "fundamentally flawed," he said, citing a number of reasons. It is totally decentralized, and the point of regulation conflicts with the Northwest's system sales approach, Johnson explained. In addition, it is enormously complex, allows for a very limited use of offsets, and transportation and residential fuel combustion are not included at the outset, he said.

Davis described a number of critical legal issues that remain unresolved with the WCI, including whether states have an adequate scope of regulatory authority, the effect on interstate trading, allocation of emission auction revenue, and mandatory greenhouse gas reporting. In addition, a key question is whether there is state legislative support, he said. A very real risk exists that the WCI will split among seven states, with only Oregon, Washington, and California passing legislation, Davis said. Legislatures in New Mexico, Nevada, Arizona, and Utah want to wait for action on the federal level, he pointed out.

We three IOUs think a federal program is preferable to the WCI, Johnson said. It would be easier to develop a program if all affected states and provinces were at the table, which they are not, he said. We all believe there are ways to develop a regional emissions reduction program, but cap-and-trade is not the best way, Johnson stated.

Radcliffe explained that the method for allocating emissions allowances makes a big difference for Northwest utilities, but the WCI leaves this decision to the states. Punting to the states is not workable – you need a consistent market that shares the problem equitably, she indicated.

Davis outlined several items for the Council to examine in its modeling for the Sixth Power Plan. He said the Council should include: sensitivity runs on natural gas prices being higher than projected; a high load-growth case driven by plug-in electric vehicles; higher capital costs for new generation; no new nuclear generation; success with research on carbon capture and sequestration; energy-efficiency mandates; and a "wild-card" scenario with several simultaneous adverse outcomes. And he asked the Council to promote an accurate accounting of the region's carbon footprint. Your 2007 report was a realistic assessment, Davis added.

Yost asked whether the utilities are having problems delivering and integrating wind generation. Davis said Oregon's RPS targets pose integration problems. We can accommodate about 15 percent of the target, but beyond that, it's a real challenge, he said. We absolutely need new transmission and new technologies, Davis added. He also pointed out that the integration of small-scale projects like residential solar and distributed generation pose challenges for the distribution system.

It's very clear that new transmission will be needed, Radcliffe agreed. And we will need firming resources, like gas, she added.

Karier said the EPRI study parallels work the Council has done, but it also lacks the contribution of the transportation sector to CO_2 emissions. If we focused on transportation,

impacts to the power system would be reduced, he said. The issue of transportation is critical, Karier stated.

There are several great proposals out there for transmission, he continued. Do utilities expect state and federal help to get them built? Karier asked.

There are permitting challenges on the local level, and we'll need the public utility commissions to agree on cost recovery, Davis responded. Transmission can bring new renewables onto the system, but development is capital driven, and there are regulatory hurdles at several layers of government, he added.

Adequate, But Formula Bears Watching

Staffer John Fazio reported on the latest iteration of the resource adequacy assessment. The Council adopted an adequacy standard in 2007, and every year, the Council looks ahead three and five years to assess the adequacy of the power supply, he explained. According to Fazio, the assessment this year indicates the region has ample access to supplies over the next five years to avoid significant power curtailments. If you take planned resources into account, the situation looks even better, he said.

The gap between accessible generating capability and load has decreased since last year's assessment, primarily because of higher load forecasts, Fazio continued. The assessment shows that the region is more likely to face a summer peaking shortage than a winter peaking or annual energy problem, he said.

According to this year's assessment, the annual average energy surplus for 2011 and 2013 is well above the adequacy threshold, Fazio reported. There is a 2,600 average MW surplus in 2011 and 1,900 MWa in 2013, he said. For winter and summer capacity reserve margins, the assessment shows them to be above the threshold, with slightly more likelihood the region would experience a summer capacity shortage before it faces a winter shortage, Fazio pointed out.

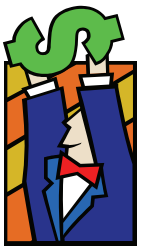
Since last year, the gap between generation and load has decreased substantially, particularly with regard to the 2013 annual energy surplus, which has gone from 4,000 MWa to 1,900 MWa, he said. This was largely due to an adjustment in the Council's short-term load model with more recent information, Fazio explained.

The bottom line, we're still okay, but the Resource Adequacy Forum has laid out a work plan to look at the data and review the assumptions, he said. The Council's Sixth Power Plan will address the resource adequacy standard, looking at an economic standard, as well as other issues, according to Fazio.

Melinda Eden asked about the difficulty of getting updated load information. Staffer Terry Morlan said the Council had been working with 2002 load data but was able to calibrate its models with more recent data for this year's assessment. He said the Power Pool does not share load data and utilities are reluctant to share that data publicly. Fazio pointed out that the Council's latest load forecast is closer than in the past to the Northwest Regional Forecast done by PNUCC.

Yost questioned assumptions in the model on the availability of independently produced power to meet regional loads. Things can change rapidly so I'm happy you will be watching this closely, he said. Fazio responded that the Resource Adequacy Forum can meet and run its assessment whenever there is a need to do so. He also said he felt the assumptions in the model are conservative. But we will be assessing them, Fazio added.

Karier said the process has given the region a better understanding of the supply situation. The progress on capacity has been good, he said, adding that work will be done to explore the length of time the region is most at risk and how long the region can cover a sustained peak.



BiOp and Accords Goose Costs

Greg Delwiche of BPA updated the Council on the agency's 2009 and 2010-2011 fish and wildlife (F&W) budgets, which now incorporate costs associated with the Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) and the Columbia Basin Accords with states and tribes. During its Integrated Program Review (IPR), BPA held workshops that focused on costs to be included in 2009 and 2010-2011 power rates, he explained. The agency had workshops on the 2009 costs in May and announced its decisions in July, Delwiche said. For the 2010-2011 costs, workshops were held in June, and a final decision is expected this month, he said.

F&W program spending is set at $200 million for 2009, $230 million for 2010, and $236 million for 2011, according to a BPA summary. Delwiche said the budgets reflect a 2.5 percent inflation factor.

He said a fundamental principle underlying the F&W budget is that it reflects what it will take to implement the new BiOp and Accords without reducing funding for other elements of the program. Delwiche acknowledged the increase in 2009, from $143 million in 2008 to $200 million, is the largest in the history of BPA's F&W program. But it is necessary to meet our commitments, he stated.

The 2009 and 2010-2011 F&W budgets include $90 million for research, monitoring, and evaluation (RME), up from $55 million in 2008, Delwiche pointed out. With the ramp-up in the program, there is a ramp-up in RME spending, he said. How much RME is sufficient is both a science and a policy question, and "we need to think hard about how much is enough," Delwiche said.

In the IPR, customers expressed concern about the budget levels, so we took a look at what would happen if we increased or decreased levels by 10 percent, he continued. For F&W, the Accords are firm commitments, so all the cuts would have to come from other areas of the program, Delwiche said. We found that result to be inconsistent with the building blocks of our proposed budget, he said. Half of the base program is the cost of keeping up past investments, Delwiche added.

As for increasing the budget, it would allow for funding previously proposed unfunded projects, he said. But many of these are RME, and BPA is reluctant to initiate any of them ahead of the Council's categorical review of RME and the application of high-level indicators, Delwiche explained.

While we haven't finalized our proposal, there's a strong inclination to stay the course of what we originally proposed, he stated. The final budgets will be brought into the rate case, Delwiche said.

He presented a summary of F&W spending for 2009-2011 sorted by several categories: geographic province; type of project, i.e., habitat, wildlife, hatchery; FCRPS BiOp; Columbia Basin Accords; and Non-BiOp and Non-Accord. There was an increase of $82 million from the 2009 planning budget developed in July 2008 to the current 2009 start-of-year budget, which includes the Accords and the new FCRPS BiOp, Delwiche indicated. Of the $82 million, $5 million is general increases, and the remainder is for BiOp and Accord work, he explained.

The planned spending for the F&W program for 2009-2011 is "an unprecedented" 55 percent increase over the previous three fiscal-year planning budgets, Delwiche acknowledged. He said $31 million is budgeted for new work in 2009 that is intended to implement elements of the BiOp outside the Accords. The project sponsors have already been identified for some of the work, but not for all, Delwiche said.

Joan Dukes asked if that meant there would be "a mini project selection" process. Delwiche said that it might. He asked the Council to play a role in recommending funding for mitigation actions that are scientifically sound and the most cost-effective means to meet program objectives, including new BiOp actions. We also need to get started on the RME review, Delwiche added.

Staffer Tony Grover responded that if the Council role is to assist, "we need to be sure NOAA Fisheries thinks this is needed work." We would need to focus the work before any Requests for Proposals are issued, he said.

Delwiche went on to outline the geographic distribution of budget increases, as well as the distribution by category of project. RME, at $90 million, is the largest single category within the budget, he said. Not all of us agree on your definition of RME, Eden commented.

It is a new challenge to manage this more complex program, Delwiche said. BPA is preparing a budget white paper to explain how it plans to manage the separate program categories, he said. We will release the paper and ask for feedback, Delwiche added.

We appreciate you getting this information for us, but there is more work to be done here, Booth said. He indicated that Council staff will need more data and the capital side of the budget to do a good analysis and inform the Council on provincial-level spending.

Karier said the region needs a long-term budget agreement for planning purposes. We have two years of budget here, but a long-term project cycle for recovery, he stated.

ISAB Orders Spill-Barge Combo, With Side of Data

Dr. Richard Alldredge reported on the Independent Scientific Advisory Board's (ISAB) Spill-Transport Review, which he acknowledged as a team effort among several board members and agencies. In March 2008, NOAA Fisheries asked the ISAB to respond to questions about the seasonal variation in the transportation benefits for smolts from four Snake River salmon and sockeye species, he said. Other questions from the Columbia River Inter-Tribal Fish Commission and the Oregon Department of Fish and Wildlife (ODFW) were subsequently added to the study, Alldredge explained.

He outlined the topics the ISAB addressed as: the relative benefit of transportation versus in-river migration during April and May; no voluntary spill from May 7 to May 20 versus continuing spill; results from recent years; impacts on other native species; and ecological/evolutionary issues. Our responses were developed using existing data, Alldredge said.

The magnitude of benefits relative to transportation in late April through May varies substantially across species and between years, he reported. But overall, statistical results indicate transport is a benefit in 75 percent of years, Alldredge said. As to the question of whether to terminate voluntary spill from May 7 to May 20, he pointed out that transportation in that period benefits both hatchery and wild chinook and steelhead, but as spill increases, inriver survival increases, too, and the relative benefit of transportation decreases. Terminating spill would eliminate the

possibility of learning about the effect of partial spill during this critical period of the year, Alldredge stated.

A third question relates to whether the results from 2006-2007 are different for spring chinook and steelhead in terms of travel time and downstream survival. Recent structural and operational changes have improved inriver survival, but we need more years of returns to see, he said. There are also the confounding effects of the ocean and a good flow year in 2006, Alldredge added.

A fourth question relates to the impacts of alternative spill-transport scenarios on other native species, in general, and Pacific lamprey and Snake River sockeye, in particular. He said data are very limited and impacts are expected to vary greatly. Juvenile lamprey impingement on screens and sockeye descaling in bypass systems present concerns, Alldredge said.

The fifth question addresses optimal spill and transport operations and the factors to consider. He described several factors in play, including predation, disease in barges, increased straying in barged fish, and the potential that a particular spill-transport regime year after year could influence the evolution of downstream migratory behavior.

The ISAB offered several recommendations, which Alldredge listed, including concurrent transportation and spill whenever river conditions allow during the late April and May migration season, compiling more years of data on various species and conditions, and evaluating juvenile passage alternatives against spill. "Although spill isn't natural, it's more natural than barging," he commented.

END NOTE

No Go on John Day. The Council declined to approve a proposed $340,000 FY 2009 budget for an ODFW fish habitat project on the Middle Fork of the John Day River. The Independent Scientific Review Panel (ISRP) found in April 2008 that the 24-year-old project did not meet scientific criteria, but after ODFW submitted more information, the ISRP rated it "meets scientific criteria (qualified)." A motion to fund the project failed on a four-to-four vote. The Council unanimously approved $365,000 in FY 2009 funds for ODFW's Blue Mountain fish habitat project.

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Council 2008 Calendar

October 15-16	Missoula, MT
November 18-20	Coeur d'Alene, ID
December 9-11	Portland, OR