PFR-019
APR 15 2005

From: Edwina Allen [edwinaallen@homeinternet.net]
Sent: Friday, April 15, 2005 10:06 AM
To: BPA Public Involvement
Cc: Bill Arthur
Subject: Power Function Review, Sierra Club comments

April 15, 2005

Bonneville Power Administration
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FOR THE HEARING RECORD

BONNEVILLE POWER ADMINISTRATION POWER FUNCTION REVIEW

The Sierra Club, on behalf of its more than 60,000 members in the Pacific Northwest states of Washington, Idaho, Montana and Oregon served by the Bonneville Power Administration (BPA), appreciates this opportunity to urge BPA to increase its investments in energy efficiency ("conservation" in the terms of the Northwest Power Act of 1980). BPA has the responsibility, the need, and the budget to accomplish this investment.

Historically, while BPA has generally given strong policy support and has had a substantial record of success overall in energy efficiency investment, the commitments and budgets actually deployed have been very inconsistent, and failed to achieve the full cost-effective level of energy efficiency that is attainable in the region.

Energy efficiency is different from other resources in having more deployment flexibility. But this characteristic also makes it more vulnerable to short-term changes in the business context. After the Northwest Power Act passed in 1980, requiring BPA and the region to consider energy efficiency a true resource, BPA quickly proved that conservation programs could be scaled up, acquire substantial savings, and do so in a measurable and cost-effective way. Over time, several hundred megawatts of savings have shielded the region from even greater price swings and potential shortages than it would have faced otherwise.

The difficulty is that while energy efficiency is indeed flexible, there must be a consistent effort in order to obtain effective results. Time and again, whether because of lagging demand, falling prices, rising prices, the WPPSS debacle, the rise of deregulation, and other factors, BPA has gained momentum on energy efficiency programs only to relax its efforts within a year or two at most.

In short, at nearly the 25th anniversary of the Northwest Power Act, BPA has fallen well short of the Act's mandate to give energy efficiency the top priority for development. In 1983, founding member of the Northwest Power and Conservation Council, Charles Collins, summarized the resource priorities of the Act as, "buy only what you need, and buy the cheapest things first." BPA has laudably stated this goal in its planning and public statements, but has failed to invest sufficiently to actually achieve this goal resulting in BPA and its utility customers having to purchase more expensive resources because not enough efficiency measures have been implemented, despite detailed regional and local planning, successful programs, and this clear legal mandate.

It is not only the region's ratepayers who have suffered from this variable effort. Increased pressure on our lowest-cost generating resource, the region's hydro system, has also resulted in reduced flows for fish passage, countering the extensive efforts also being made under the Act for recovery and restoration of fish and wildlife resources affected by operation of the Federal Columbia River Power System. Because low water is a crisis for both the economy and the fish, insufficient investment in energy efficiency exacts a double price when streamflows are low as they have been at several points in the last quarter century, including the present year. BPA has too often "balanced the low water books" on the backs of the salmon. By maximizing cost-effective energy efficiency investments we increase system flexibility and the benefits to consumers, communities, and the fish.

BPA is legally responsible for meeting its customers' entire increase in electricity load growth. As BPA develops upcoming power-supply contracts with its customers, BPA has a choice in how it meets those needs. Examining BPA's proposed budget, we find the energy efficiency target far too conservative.

The Power Function Review and other BPA policy initiatives offer an opportunity to refocus attention on the underinvestment in our most cost-effective resource. If we are fully investing in energy efficiency, we will have more confidence in the other measures required to generate the power needed by our economy and provide the streamflows and other environmental protection needed by our Columbia Basin fish and wildlife.

We request that BPA increase the amount it will pay for cost-effective conservation. We note that BPA has calculated Bonneville's fair share of the Council's regional-wide efficiency goal based on what percentage of each customer's power the agency now provides.

To meet customer load growth with the cheapest available resource (energy efficiency) BPA needs to acquire at least 70-72 average megawatts of conservation per year, not the proposed 56 aMW. Based on past conservation acquisitions, we suggest it will cost $106 million a year to acquire 56 aMW, and $133 million to acquire 70 aMW. Clearly, capping annual efficiency investments at $80 million, a scant 8 percent increase, will not meet even BPA's too-modest efficiency target. It is hard to comprehend why even the larger figure is not eagerly adopted, since the region's portfolio of conservation programs is well-tested and has proven investment return. This is even more important in hedging the increasing risk of exposure to short-term markets driven by the unpredictable but rising cost of natural gas and coal.

Energy efficiency pays for itself, both from the point of view of the customer and the utility. Consumers save by installing efficiency measures (their bills are reduced immediately), resulting in lower direct sales revenue for BPA and its customer utilities, but netting them higher returns in resale of the same power and reducing the extent and cost of wholesale power market purchases. The end result is that BPA's proposed efficiency investments can be repaid in as little as seven years (depending on how much surplus BPA power the utilities are allowed to keep and resell themselves). After that, these investments generate a "profit" for BPA and the region that will reduce rates, build our economy and help protect fish and wildlife.

Investing $133 million a year, as we recommend, would extend the payback period two years, still well ahead of the return for generating resources. It is important to note that many of the installed efficiency measures will long outlive the payback periods. Unlike new coal or natural gas plants, efficiency measures yield a long-lasting revenue stream with little further spending. The previous calculations are based on market prices of about $55 per megawatt-hour. Higher market prices make energy efficiency more valuable and shorten the payback time. And efficiency programs can be aimed at reducing exposure to the most expensive on-peak market purchases, and work in conjunction with BPA's leading efforts to reduce transmission bottlenecks, congestion and costs.

In examining rates, we suggest the only things that can be sure to protect commercial, industrial or residential consumers from rising electricity rates are investments in energy efficiency and non-fossil resources. Increasing BPA's proposed annual conservation investments to a more reasonable level would increase overall agency spending about 1 percent. The upfront costs of the conservation measures can raise rates in the short run, but so will acquiring any other new power source and, as noted, BPA is legally required to acquire new resources to meet all customer load growth. Energy efficiency is cheaper than all other sources. The Northwest Power and Conservation Council concludes that not achieving the regional conservation goal could cost Northwest customers $2 billion to $2.5 billion over the next 20 years. We can simply not afford to continue the erratic course of energy efficiency investment that has characterized the past 20 years in the next two decades.

A steadfast commitment to full development of the region's energy efficiency resource is essential to the stabilization of the Northwest's energy costs, protection of fish and wildlife, and sustained development of our economy. BPA must commit to an unwavering course that maintains full speed toward achievement of this legally required and economically and environmentally beneficial goal.

Sincerely,

Edwina Allen, Energy Subcommittee Chair
Sierra Club Northwest Conservation Strategy Team
Representing the Oregon, Cascade, and Northern Rockies Chapters

PFR- 020

APR 27 2005

Bonneville Power Administration
Power Function Review Technical Workshop
April 5, 2005

BPA Rates Hearing Room, Portland, Oregon
Approximate Attendance: 50

Fish & Wildlife Program

[The handouts for this meeting are available at: www.bpa.gov/power/review.]

Introduction

Michelle Manary (BPA) welcomed participants to the meeting. At the end of tomorrow's meeting we'd like people to fill out the feedback form that will be included in the packet – we want your ideas for the wrap-up meeting May 9, she said. Manary also noted that an updated Scoresheet was posted on the website Monday.

F&W Program

This is the fifth in a series of workshops on BPA's fish and wildlife (F&W) costs, Greg Delwiche (BPA) began, saying the previous workshops in Portland, Spokane, and the Tri-Cities were to raise awareness about the components of the F&W budget and the drivers of increased costs. We thought we might have a proposal by today, but we are not at that point yet, he stated. Today we want to have more discussion about the drivers and the options before we develop a proposal, Delwiche said.

Suzanne Cooper (BPA) explained how BPA calculates the monetary impact of F&W hydro operations and how they are used in rate setting. The operations effects are estimated to be $356.9 million annually in the fiscal year (FY) 2007-2009 period, a figure that includes the cost of power purchases and foregone revenues, she said. Cooper pointed out that there is not a line item in the budget for fish operations. The operations are dealt with in modeling hydro operations, she said. They become assumptions we input to HYDSIM, the model used to estimate period-by-period average energy production, Cooper said.

She listed the three main areas of fish-related assumptions accounted for in the hydro regulation models: reservoir elevation objectives, juvenile bypass spill objectives, and flow augmentation targets. Cooper explained how BPA establishes fish operations criteria for modeling, and she listed several uncertainties about the next rate case period, including timing of installation and operation of removable spillway weirs (RSWs) and a proposed summer transportation test requiring additional spill at collector projects. She offered an example of operations at eight federal hydro projects taken from the Updated Proposed Action/Biological Opinion (UPA/BiOp), along with the proposed schedule for RSW and other surface passage improvements that could occur during the 2007-2009 period.

Cooper explained assumptions used to model the generation at five hydro projects with the passage improvements installed, and she offered a table of the results. She noted that improvements such as RSWs are operated in a test mode for two years, and as result, benefits are not immediate. If these improvements meet the biological performance criteria, the table reflects the energy gains that would occur over time, Cooper said.

What happens if survival does not improve during the test mode? Scott Levy (Bluefish.org) asked. Then the Corps would look for a different way to operate, Cooper replied. There would be a lot of tests before "we scrap" the improvement, she added.

Could we get the math behind the calculation of the $356.9 million in hydro operations effects? Dave Hoff (PSE) asked. We could make that available, BPA staff said.

The proposed summer transportation test would involve some in-river migration of Snake River fall chinook, along with summer spill, she said. If the test is conducted, the model shows that generation would be reduced in July and August by 473 aMW and 448 aMW respectively, Cooper said. But there is uncertainty about the assumptions for the modeling since the study design is still under discussion, she noted. The study, which would compare in-river versus transportation survival, is expected to start in 2007 or 2008, Cooper said.

Again, there are uncertainties surrounding the decisions we need to make in modeling the fish operations, she reiterated: the RSW schedule; what operations will be when the RSWs and other bypass improvements are installed; and the design and timing of the Snake River fall chinook transportation study. Cooper indicated that an optimistic outlook would be to assume the biological performance is achieved and the schedule holds, and a pessimistic outlook would be to assume that is not the case. We're interested in hearing your views, she wrapped up.

Are there choices here that are not mandated by the BiOp? Fred Rettenmund (Inland Power) asked. "Our discretion is limited," Cooper responded. We have discretion about assumptions in the hydro regulation studies – that's where our discretion lies, she said.

It looks like some assumptions are already made, Geoff Carr (NRU) commented. Are they optimistic or pessimistic? he asked. The numbers assume the schedule that has been laid out for bypass improvements, Cooper answered. These are our best estimates, but there is a wide range of uncertainty, Delwiche added.

Levy asked about the effect of reservoir elevations on power generation. Roger Schiewe (BPA) explained that holding water in the system to provide flow augmentation affects reservoir elevations. Under the BiOp, we store water in reservoirs and release it to provide flow augmentation, he said. But storing that water so it is available in the spring takes away from generation in the winter, so flow augmentation does not provide a net gain for the power system, Schiewe added. Overall, there is a loss since power prices in spring and summer are lower than in the winter, he said.

Moving on to the Northwest Power and Conservation Council's (NWPCC) annual budget, Delwiche said the annual average for 2007-2009 is estimated to be $9.1 million, of which F&W pays 50 percent. How does that figure compare to the statutory limit on the NWPCC's budget? Bill Drummond (Western MT G&T) asked. Have they reached the cap? he asked. Delwiche said he did not know, and Manary said she would try to provide the answer.

There is a formula in the Northwest Power Act that relates the Council's budget to BPA's firm power sales, Larry Cassidy (NWPCC) explained. But changes that were made to the residential exchange have rendered that formula unworkable, he indicated. We think we are below the limit set in the Act, and BPA thinks we are above, Cassidy said. It is a continuing discussion we are having with BPA, according to Melinda Eden (NWPCC chair). We are working this out with BPA, Cassidy agreed, adding that the Council "sits tight" on its expenses.

Bob Austin (BPA) explained the expenses BPA covers for O&M at the Lower Snake River Compensation Plan (LSRCP) hatcheries, which are operated by the U.S. Fish and Wildlife Service (USFWS). He went over the program goals, which he noted are stated in terms of adult returns, and objectives, performance measures, and program funding mechanisms.

Through FY 2000, the LSRCP program was funded by Congressional appropriations, which BPA repaid, but a direct funding agreement for program expenses is now in place between BPA and USFWS, Austin explained. The agreement covers only expense, not capital, he pointed out.

Austin listed several drivers of costs and future uncertainties, including hatchery reform, new BiOps, cost of living increases, outcome of the U.S. v. Oregon litigation, and unexpected maintenance costs associated with aging facilities. He went over LSRCP spending levels since 2002 and noted that a new funding agreement will need to be put in place by 2007. Negotiations will begin within the next year, Austin said.

He outlined three alternative approaches to funding and the costs associated with each for the 2007-2009 period. The approaches are: baseline O&M; baseline O&M plus some non-routine maintenance; and baseline O&M and a more comprehensive inventory and schedule for non-routine maintenance. These are the alternatives we have looked at, but there are others, Austin wrapped up.

There is a lot of monitoring and evaluation (M&E) associated with hatcheries, Kevin Banister (PNGC Power) pointed out. Given the limited resources, have we looked at whether there are hatcheries doing similar things and whether there are redundancies? Banister asked. Has a hatchery ever been closed? he asked. Austin said the LSRCP hatcheries are reviewed and evaluated periodically, and there is an annual report issued on them. No LSRCP hatchery has ever been closed, he added.

Joe Krakker (USFWS – LSRCP Project Manager, Boise Office) said LSRCP programs have been modified over the years to address issues in the evaluations, as well as issues raised elsewhere. He said that meeting adult return goals depends on ocean conditions and other things "outside our control." We've done better in recent years, but we can't do anything at the hatcheries to improve things when ocean conditions are bad, Krakker indicated.

The direct funding agreement is up for renewal, Carr said. How would you compare the old funding mechanism with the new? he asked. In hindsight, "it's a double-edged sword," Krakker said. With appropriations, we could carry funds forward, and as the facilities began to age, we were very careful about keeping money back to address problems at them, he indicated. With the new funding agreement, we lost our ability to carry over funds, so we try to incorporate the needs we have each year, Krakker said.

Could you capitalize things that are done to extend facility life? Kevin Clark (Seattle) asked. In some cases we could, if the item meets our capitalization standards, Austin replied. We do not currently have a capital agreement, but we have raised that as an issue, he added. Clark asked that LSRCP capitalization be put on the PFR Scoresheet.

The current direct funding agreement is silent on capital, Delwiche said. There is a policy choice here about whether we add something on capital to the agreement or whether we work with Congress to get appropriations to cover capital needs, he said. The approach that's taken would affect the amortization period for capital investments, Delwiche noted. We will provide a proposal on the LSRCP funding level in our PFR closeout letter, he stated.

Rettenmund asked if USFWS benchmarks its hatchery facilities with others. Krakker said that such an exercise was done, but costs depend on a number of variables. A simple comparison does not adequately capture the differences among facilities and programs, he said. Rettenmund said he had seen both the USFWS and Idaho Power hatcheries, and the government facilities are like "a Cadillac" compared to the utility's "Chevy."

How do the LSRCP fish figure into harvest? Levy asked. We assume these fish are for harvest, Krakker said. But, he added, some of the fish in our facilities could be considered part of ESA-listed species – their relationship with ESA recovery is uncertain.

One of the uncertainties with F&W funding has to do with hatchery reforms, Ed Sheets (Yakama Nation) pointed out. What part of your proposed budget is dedicated to these activities? he asked. We don't have a good indication of those costs, but we've put in about a quarter of a million dollars per year as a placeholder, Krakker replied. The costs could be more, but there is a large amount of uncertainty, he added.

Lon Peters (PGP) asked where the LSRCP hatchery goals came from, and Krakker said they were taken from a Corps report on mitigation for the Lower Snake River dams. Peters asked how the U.S. v. Oregon case could affect the cost of achieving LSRCP goals. The uncertainties relate to how you implement the program to reach objectives that could come out of the litigation, Krakker responded. The decision could shift harvest objectives, and that could lead to changes in how we implement the program, he indicated.

One of the goals here is for rainbow trout, Banister commented. Is the habitat behind the dam good for rainbow trout? he asked. No, Krakker said. Anticipated habitat improvements "were sidelined" – the reference to rainbow trout ties back to the fishing opportunities lost due to construction of the dams, he said.

Integrated Program

Delwiche said the Integrated Program refers to integrating BPA's Northwest Power Act and ESA responsibilities. In developing the scenarios, we've attempted to do a zero-based budget, but the subbasin plans and BiOp may mean the region will need to tweak the Program's project portfolio in the future, he said. Using the current projects as a base may not be realistic, Delwiche stated.

The current Integrated Program budget is $139 million annually, Austin said. He described the general categories of expense, reflected on pie charts in the meeting packet, and pointed out that BPA would like to see 70 percent of the money dedicated to on-the-ground projects, rather than the current 53 percent. Austin went over the assumptions for future F&W funding, explaining a matrix of recent spending, budget drivers upward and downward, and a base figure for each expense category that reflects the "slew of projects" currently funded that will need to be continued. He also noted that habitat actions are an area of great uncertainty when it comes to the next F&W budget.

Doug Marker (NWPCC) said Council staff has worked with BPA to establish the base, which he described as a "very conservative" figure that includes projects BPA has "an explicit commitment" to do. Even so, the projects are subject to the Council's project-selection process, he noted. We excluded some long-term projects that have ongoing costs but for which there is no specific funding commitment, Marker pointed out. There is a high level of agreement between the Council and BPA on the base, he added.

There are three primary issues associated with mitigation and getting to an appropriate funding level for the next rate period, according to Austin: pace, prioritization, and mitigation responsibility. He pointed out that in the current budget, about $40 million is spent annually on research, monitoring, and evaluation (RME), and that BPA and the Council are looking for ways to be more strategic and efficient with those expenditures. We would like to get RME down to 25 percent of the budget – "it's a lively issue for us," Austin stated. BPA is also very interested in cost sharing and how to structure such arrangements and is also looking for input on capitalization of investments such as land acquisitions and conservation easements, he said.

Austin laid out the background for BPA's decision on a funding level for the Integrated Program, noting again uncertainties such as subbasin planning, hatchery reforms, BiOp litigation, and a BiOp for the Willamette. In developing the funding level, BPA is seeking to keep rates as low as reasonably possible, while meeting its F&W and environmental responsibilities, he stated.

Austin listed key elements in BPA's long-term vision for 2007 that are integral to establishing an appropriate funding level, and he laid out four alternatives for funding in the next rate period: decrease to $125 million; status quo with a small increase ($139 million to $150 million); increase above status quo ($150 million to $164 million); and providing a rationale only with costs to be determined.

Delwiche presented, in more detail, three cost scenarios (see attachment) for the upcoming rate period with specific categories of expense (i.e., habitat, RM&E, etc); with the three scenarios roughly equated to the low, medium and high alternatives previously described by Bob Austin. He noted that Council staff helped develop the numb

You have subbasin plans and the new BiOp on the same line, Tony Grover (NWPCC) pointed out. Do you see a linkage? he asked. Yes, we do, Delwiche said. Joan Dukes (NWPCC) asked about the 5 percent reduction from FY 2001-04 spending based on "assumed efficiency gains." Could you share some specifics? she asked. We don't have specifics, and some say there are no efficiencies available, Delwiche responded. But from the experience you think your organization is," there are efficiencies that can be gained, he added.

Danielson asked what the assumptions are about the Northeast Oregon Hatchery (NEOH). We tried to get at that in the drivers that could push costs upward, Austin responded. NEOH is one of the costs that is likely to drive an increase in the production category of future expenses, he said.

Will you use one of these cost scenarios in the draft closeout letter for PFR? Clark asked. Yes, or something close to one of these, Delwiche responded. There is also the fourth option, which is to delay deciding upon a specific budget and instead take more time to determine costs after first developing performance standards, priorities and funding responsibilities, but "I've recommended internally against that option," he acknowledged. It would perpetuate the uncertainty and would not serve anyone well, Delwiche stated.

Carr pointed out an April 1, 2005 letter to Steve Wright and Melinda Eden stating the customer position on a F&W memorandum of understanding (MOU). On the last page, we express support for increasing the allocation for on-the-ground projects, he said. What's the process for moving the funds? Carr asked. It takes a commitment between the Council and BPA, Delwiche responded.

We are designing the project selection process for 2007, and we are looking at a more strategic and deliberate approach to RME funding, Marker said. But, he added, the allocations to RME are used to gather information we need to make decisions.

We would like to work with you to promote cost sharing, Carr said. We are working on a cost-sharing agreement, Delwiche said, adding that the Columbia Basin Fish and Wildlife Authority (CBFWA) would sponsor a workshop in June about cost sharing.

Who would be the cost sharers? Levy asked. Delwiche provided several examples, including federal agencies, such as the U.S. Forest Service, and agricultural entities, such as farm bureaus who have similar responsibilities to BPA for habitat protection and enhancement. Also, landowner cooperation is significant in many F&W projects, Marker pointed out.

Peters raised the issue of assuring that the M&E being funded under a proposed 70-25-5 split is best from a biological perspective. Delwiche pointed out that M&E costs at new facilities can be as large as the O&M. We are looking at M&E expenditures that are more focused and strategic, he said. Given the total that is being spent in the basin for M&E – it approaches $100 million annually – "it cries out for more prioritization and competition," Delwiche said. Constraining the available monies will help, but we need to ask more questions in terms of what information we need, he continued. "We are all ears" about what might be a more strategic way to get at this, Delwiche added.

There is a cost versus risk issue here – how much investment in M&E will we forego given the risk of not having the information, Marker pointed out. How this will occur and be prioritized are questions for the Council since we select projects, he added.

"It is not that M&E is bad," but we need to look at it more closely, Delwiche said. We've been at this since the 1980s, and our body of knowledge is much greater than it was then, he pointed out.

CBFWA has been funded to do a major evaluation of M&E, to develop standards and protocols, and implement them across the region, Rod Sando (CBFWA) said. We will hold a regional workshop to share our information, he added. The M&E in the basin has not been systematic, and we will be looking at options for making it more efficient, Sando said. We are aware of the issue, and "I think we are in good shape for resolving it," he stated, adding that the CBFWA evaluation is under way. We need to appreciate that "M&E is bread and butter" for many agencies – they need it to provide species regulation, Sando said.

Where is the Fish Passage Center (FPC) budget? Drummond asked. It's included in the "Information Management, Coordination, and Administration" (IMCA) category, Marker responded. Is the review of overlap between the FPC and other entities still going on? Drummond asked. We are looking at the relationship between FPC and DART and StreamNet, Sando said. Will the review be done in time for the BPA budget proposal? Drummond asked. Yes, but I don't expect to see much change – there's not much overlap, Sando responded.

Asked whether funding option four, establishing the rationale only, means the F&W budget might be set in the rate case, Delwiche said it did not. This PFR process is about setting the funding level – we won't revisit it in the rate case proceeding, he stated.

UCUT Presentation

Warren Seylor (STOI/UCUT) said as chair of the Upper Columbia United Tribes (UCUT) he had asked staff and UCUT members to put together a proposal for the region to use in developing a package for funding F&W mitigation in the Upper Columbia. We wanted to develop something everyone could work from – our proposal doesn't have all the answers, but we felt the upriver issues were not given the merit they deserve, he said. We wanted to get out that message, Seylor stated.

Mary Verner (UCUT) explained the proposal, calling it a comprehensive approach to implementing subbasin plans in the Upper Columbia Ecoregion. We developed the proposal to show people a comprehensive proposal to address subbasin plans and move from plans to implementation, she said. And we wanted to get going on BPA's mitigation responsibilities, Verner stated. She outlined the steps UCUT went through, starting with submittal of subbasin plans to the NWPCC for adoption and submittal of measures to be implemented. The UCUTs also submitted a 10-year estimate of costs to implement the plans at a reasonable pace, Verner continued.

The UCUT proposal is based on biological outcomes, she said. It includes only measures that are BPA's responsibility, according to Verner. Our determination in that regard is based on institutional knowledge of BPA's obligations under the Northwest Power Act, she said. Verner pointed out that the tribes seek other sources of funding to carry out activities that are not related to the power system. She provided examples and said all five UCUT tribes use cost sharing to further their work.

UCUT estimates its proposal will cost an annual average of $45.3 million for 10 years, Verner said, noting this represents both expense and capital. The average would go down if stable funding is provided over 10 years, in part because there would be less process – "we could get managers out of meetings and into on-the-ground work," she said.

Verner said the UCUT cost estimate is part of the Integrated Program budget and would remain the same regardless of the direction that budget takes in the future. If there is no increase, she acknowledged, our proposal would require shifting funds currently being used elsewhere in the basin. Verner offered a method for equitable allocation of funds to the Upper Columbia Ecoregion, and she said mitigation funds should be proportional to F&W losses and relative to the benefits derived from each dam.

The UCUT proposal supports a 70-15-15 split among anadromous fish, resident fish, and wildlife, as well as the BPA goal of a 70-25-5 split among on-the-ground projects, RME, and coordination, she continued. It also supports the Council's F&W program goal of mitigation in the blocked area, she said. Verner listed ways in which the proposal moves toward achieving goals and closing out BPA's obligation, including restoring habitat and resident fish substitution. She said it also addresses species bordering on an ESA listing.

Could you speak to how this proposal has been received by other F&W managers? Banister asked. CBFWA is looking at an allocation formula, Verner responded. We've asked for response to our proposal, she said, adding that people are struggling with the 70-15-15 split overlaid with the 70-25-5 split. The challenge is the lack of money, Verner stated. If there is not enough money, we are asking the region to address the unmet needs that exist above the Upper Columbia dams, she said.

Sheets said he is working with CBFWA on the allocation formula, and the UCUT costs "are in our estimates." We intend to finalize our work this week, so if you have more information to offer, "we're eager for it," he stated.

How do you fit this program under a $139 million budget? Carr asked. We've heard (from recent CBFWA estimates) it could take hundreds of millions of dollars to implement subbasin plans, he added. There isn't enough money to do all that is required, Verner responded. Our proposal is based on a worst-case scenario – a frozen budget, she said.

What we are proposing is no higher overall spending, but higher spending in the Upper Columbia, Ron Peters (Coeur d'Alene Tribe) stated. We are talking about funding shifts into the Upper Columbia, which has been undermitigated, he said. The proposal represents an increase in emphasis on undermitigated habitat units, Peters explained.

We don't just look at $139 million, we look at the $700 million total F&W expense, Banister pointed out. That is what's behind our drive toward efficiency, he said. We've seen increases in the F&W program that outpace the rate of inflation, Banister added.

Corps and Reclamation F&W O&M

Paul Ocker (Corps) explained the Corps' expense budget for F&W O&M, describing how projects are prioritized into four categories. The priority 3 and 4 items don't always get funded, he said. About 85 percent of the budget goes toward anadromous fish O&M, 10 percent toward wildlife and resident fish, and 5 percent toward water quality, Ocker said. He went over the expense history and where the budget is expected to head through 2011. The budget is beginning to level off as we meet BiOp requirements, Ocker stated.

He listed items that have changed the budget in the past and those that could affect the future, and he explained how cost-effectiveness and biological effectiveness are addressed in developing measures and budgets. Ocker described the role of the Regional Forum in deciding where money is directed, and he said the Corps prepares comprehensive planning documents on its F&W O&M activities.

I'd like to encourage you to coordinate your research with what is happening in the Integrated Program, Banister suggested. He also encouraged the Corps to look for redundancies among programs and gain efficiencies. Ocker explained that not all activities are funded from the same budgets, but the expenditures are funneled through a central body where they are linked up.

What is your request for dollars associated with the Willamette BiOp? Carr asked. The Corps total estimate for the 07 to 09 rate period is $36.9 million per year, of which a small amount is allocated for use in future Willamette BiOp coordination activities. Alder responded.

Is there coordination on cost-effectiveness between your program and BPA's Integrated Program? Mark Stauffer (NWE) asked. Where is the highest benefit? he asked. A lot of the Corps costs are at the dams on the mainstem, Austin pointed out. There may be some overlap with the Integrated Program, but we have not looked at a comparison, he added.

Dave Lyngholm (Reclamation) described the Leavenworth Fish Hatchery Complex, which provides mitigation for Grand Coulee Dam. The complex of three hatcheries is operated by USFWS and produces spring chinook for release into Icicle Creek, and the Entiat and Methow rivers, he explained. Lyngholm went over the percent of the budget allocated to various activities and a history of Reclamation's F&W O&M expense.

Marker said the Colville Tribe has asked the Council to support a new facility for Grand Coulee mitigation. Lyngholm said he was not aware of the facility, but if it were to be constructed, it would be funded through Congressional appropriations and repaid by BPA. Delwiche said he understood the Colville proposal to be additional mitigation for Grand Coulee and that four hatcheries are envisioned. Ratepayers pay either way whether the funding is through appropriations or the Integrated Program, but the amortization schedule would differ, he said.

Asked about goals for the Leavenworth hatcheries, Delwiche said the goal is to have enough broodstock to release an established number of smolts. Marker said the Council's website has goals, identified as part of the Artificial Production Review and Evaluation (APRE), for all hatcheries, and Delwiche said a lot of information about hatcheries is also on the BPA website.

Is there a plan to develop a single yardstick to measure the effectiveness of hatcheries? Peters asked. Marker said the Council is working to integrate the subbasin plans and APRE into an amendment to its F&W program. He acknowledged that it is difficult to find a uniform measure since hatcheries are operated under different statutes to meet different objectives.

<u>CRFM</u>

John Kranda (Corps) described the Columbia River Fish Mitigation Project (CRFM), providing background about the purpose and authority. The project was initiated in 1991, predating the BiOps, and is expected to be complete in 2014, at a total estimated cost of $1.5 billion to $1.6 billion, he said.

How do you define completion? Clark asked. We are tied to the BiOps now, and they are guiding our project, Kranda responded. The passage objectives in the BiOp drive our investments in improvements at the dams, he said. The CRFM is made up of programs to design and complete juvenile passage improvements at Corps dams, Kranda explained. Juvenile passage was not thought about when the original dams were built, and "we are now paying the piper for that," he added.

Kranda explained that BPA repays the power share of construction and O&M costs once a project is transferred to "plant-in-service." There are research and study components of the CRFM that are not usually seen in a Construction General project, and the money spent on those components has grown quite significant, he acknowledged. A lot of that expense has not been transferred to plant-in-service, and the Corps' accountants think the issue ought to be revisited, Kranda said.

He outlined the history of CRFM transfers to plant-in-service since 1997 and went over two scenarios for future transfers through 2009. He noted that one of the transfer scenarios is aggressive and the other less so. Of the $300 million related to the CRFM mitigation analysis that is outstanding, how much is interest that has accumulated? Carr asked. I will get that figure for you, Kranda offered.

What is your normal guidance for these transfers? Clark asked. We would not normally have this level of studies under our Construction General program, Kranda responded. This is an unprecedented situation, he indicated.

Kranda described the primary focus of the CRFM studies along with the 2005 program highlights, including passage and predation research, and RSW construction and design. He explained the approach to cost-effectiveness and said comprehensive decision documents are prepared for improvements. Our decision documents have gone through Independent Scientific Advisory Board (ISAB) review, Kranda added.

The Corps coordinates with its Regional Forum partners to identify and prioritize, he said, explaining how that process works. Kranda described the steps in project execution and the reviews that take place along the way.

The list of anticipated future actions includes surface bypass improvements, transportation analyses, as well as continued work on biological performance issues, he said. The CRFM cost through 2004 is $930 million; $75 million has been appropriated for 2005 and $89 million was requested for 20006, Kranda reported. The annual estimate for costs from 2007 to 2014 is $70 million to $90 million, he wrapped up.

Clark asked where issues related to extra-ordinary maintenance at Corps dams and CRFM expenses come together. We bring that together across districts at the division level, Witt Anderson (Corps) responded. To the extent that division has discretion about putting CRFM into plant-in-service, we could have "more head room" to fund extra-ordinary maintenance, Clark stated.

We could discuss that with BPA, but we are working to meet BiOp-driven performance objectives, Anderson said. "We want to stay out of jeopardy," he stated. But if there is discretion to choose between the two, we could have more dollars if the plant-in-service transfer is slower, Clark reiterated. The driver for us is good accounting practices, Anderson replied. Those principles will drive our recommendations, he said.

What the customers want is a way to mitigate the effects of the plant-in-service transfers, Carr said. In the end, this has to hang on accounting principles, Delwiche stated.

On April 18, there is a management level discussion of F&W costs and risk, Manary said. That will conclude the F&W topic in the PFR, she said. We'll put out our draft closeout letter May 2, comments close May 20, and we'll have final program levels out the week of June 13, Manary announced.

Borrowing for F&W Capital

Ron Homenick (BPA) explained the mechanisms available to BPA for funding F&W capital investments: bonds issued to the Treasury and capital appropriations. He described both mechanisms, as well as the capital components of the F&W investment, including depreciation, amortization, and net interest. These items are a direct result of the decisions made on capital investments, Homenick said.

Rettenmund asked about the period of depreciation. A hatchery funded through appropriations is depreciated over 75 years, but a hatchery funded through the Integrated Program is depreciated over 15 years, he pointed out. Why the difference? Rettenmund asked. Part of it is the difference in our view of ownership and whether the investment is an asset to the agency or to someone else, Homenick said.

Section 4(h)(10)(b) is the law on amortization, and it provides for a period longer than 15 years, Clark said. Section 4(h)(10)(b) guides our capital policy – it is guidance, according to Phillip Key (BPA). When a project is funded using our borrowing authority, there is an interest in seeing amortization occur more quickly to restore borrowing authority, he added.

Homenick went over the F&W-related net interest, depreciation, and amortization estimates for FY 2007-2009 and listed risks for increase, opportunities for reduction, and drivers of change. He also went over historic levels of CRFM transfers to plant-in-service, F&W Integrated Program investment, and capital expenses. There is considerable investment listed under the individual hydro projects that is fish related, Homenick noted. The accounting "can shuffle the deck" and make it difficult to follow all of the F&W expenses, he added. Homenick concluded with possible scenarios for plant-in-service transfers from 2005 to 2009, a base case and options A and B, and the interest and depreciation associated with each.

Would accounting policies justify either A or B? Carr asked. Yes, Homenick said.

It would be helpful to have a coordinated customer position on the plant-in-service schedule by April 18, Delwiche said. We will need the background on the scenarios in order to develop a position, Carr responded. We also have to understand the implications for the repayment study, he said. And how this interacts with BPA's other debt service, Homenick added.

The meeting adjourned at 4 p.m.

Follow-up questions and information requests

Responses to questions and requests for information received throughout this process will be posted on the Power Function Review Web site on an ongoing basis. The Web address is www.bpa.gov/power/review.

1. Provide the math behind the calculation of the $356.9 million in hydro operations effects.
2. The Northwest Power and Conservation Council's (NWPCC) annual budget is estimated to be $9.1 million, of which F&W pays 50 percent. How does that figure compare to the statutory limit on the NWPCC's budget? Have they reached the cap?
3. How is it determined who funds new hatchery capital – BPA or the Corps?

PFR-021

APR 27 2005

Bonneville Power Administration
Power Function Review Technical Workshop
April 6, 2005

BPA Rates Hearing Room, Portland, Oregon
Approximate Attendance: 35

Risk Mitigation

[The handouts for this meeting are available at: www.bpa.gov/power/review.]

Introduction

Michelle Manary (BPA) welcomed participants and reminded them to use the green form in the packet to submit ideas for the May 9 PFR wrap-up workshop. She announced that conservation Q&As are now posted on the website, and Q&As on internal operations and Corps O&M are soon to follow.

Diane Cherry (BPA) said the main purpose of the risk workshop is to solicit input about the ways BPA can deal with "this variable resource we have." We need to have ways of dealing with risk when anticipated revenues don't materialize, she explained. We don't have a proposal yet, but we want to start the conversation about risk mitigation so we can wrap things up by early June and start the runs to get to an initial rate proposal, Cherry said.

BPA is taking a systematic approach to evaluating risk and finding the best way to mitigate it, she continued. The package we have prepared focuses on secondary risk, Cherry said. She noted that there would be rate case workshops in which "to dive into the details" of forecasting assumptions. Right now, our direction is to develop an initial proposal on risk that meets our Treasury payment probability (TPP), Cherry said. She clarified that arguments on the appropriate level for TPP are part of the rate case and that BPA assumes it will not make changes to the current contracts to mitigate risk.

Is the use of TBL reserves to calculate risk a rate case issue? Linc Wolverton (ICNU) asked. Yes, Cherry said, adding the issue would be clarified on the Scoresheet. What about lowering PBL costs and budgets when times are bad, rate case or PFR? he asked. There was some debate among participants about whether the issue was PFR or rate case, and Manary said she would check with Paul Norman for clarification.

Ed Bleifuss (BPA) went through a list of policy questions associated with risk mitigation, explaining terms and pointing out there are choices and tradeoffs among the alternatives. Some contend that BPA would have to do a 7(b)(2) test if rates are adjusted during the rate period, Dave Hoff (PSE) said, noting there is litigation pending on the question. We are gearing up for a full rate case and will do a 7(b)(2) rate test, Cherry said. We can flag the issue you raise, but we consider we will have done the necessary test, she said.

Arnold Wagner (BPA) explained the major drivers of risk modeled in the current analysis: supply variability, market price variability, and IOU benefits. He noted that people have asked BPA at what point it will move beyond the 50-year water record. Our operations people say we need more data and also that new data does not change the spread much, Wagner said.

In your supply variability risk, you list wind project output, Bill Drummond (Western MT G&T) said. How much risk is there associated with wind? he asked. About $10 million, Wagner answered. The wind risk is related to what we pay for output and what we can sell it for in the market, he added.

We keep hearing about a big problem with capacity that is being used by the wind folks, Kevin Clark (Seattle) commented. I'd like to know more about that problem, he said.

Will you do an analysis with a rank order of risks and how to mitigate them? asked Michael Schilmoeller (NWPCC). We've generally aggregated risk and come up with a total package, Wagner responded. It would be a significant piece of work to that kind of ranking, and I'm not sure how we would do it, he added. There are standard methods within the risk industry that could be used, Schilmoeller replied.

Wolverton asked about getting information on the components of the wind risk. There 's a lot of detail, and we'll have to talk about it, Wagner responded. I'd also like to get information on the variability of the wind supply, Rob Sirvatis (PRM) said. These are estimates – the rate case numbers will be different, Cherry reminded the group. Even if they are preliminary, I'd like to see the figures as soon as possible, Wolverton stated. Sirvatis agreed. I want disaggregated information to the extent possible, he said. There may be offsetting risks, and we want to see the specifics, Sirvatis added.

With regard to the risk related to IOU benefits, there is none in the first year, only in years two and three, Scott Brattebo (PacifiCorp) pointed out.

Clark asked about unexpected expenses in the "other risk" category, labeled in the packet as "Not Modeled" in the current analysis. Will different fish rules or a new BiOp have an effect? he inquired. We don't know yet; we are very early in the rate design process, Wagner stated. We're talking about things "outside the norm," Cherry added. We'll hold a "no surprises" workshop in late August or early September so you will have a heads-up on the initial proposal, she said. That's the latest date we would have a clearer idea about unexpected expenses, Cherry added.

How do the three categories of risk connect in the model? Hoff asked. We have independent distributions and feed the information into AURORA, Wagner said. He explained how the process works, saying "we bring the information together on a game-by-game basis." The final outcome is the net revenue month by month, Wagner stated.

Brattebo asked about the use of a forward price curve. We have to establish a forward price curve for 2008 and 2009, Wagner said. We have to have a way to come up with the IOU benefit, Byrne Lovell (BPA) added. Can you use the AURORA model to come up with a price? Clark asked. We have a separate model for the IOU benefit, Lovell replied. There was more discussion of details of the modeling, including inputs to the forward price curve model.

Wagner went on to explain how BPA calculates planned net revenues for risk (PNRR). It's a very complex calculation, he said, going over the PNRR equation. Wagner also explained tables displaying the level of risk, PNRR needed to meet the TPP at a given level, and the relationship between PNRR and cash reserves. The TPP for the upcoming three-year rate period is 92.6 percent, he pointed out.

In the last rate case, we were able to address the variability with large reserves, but without the reserve, we have nothing to get us to the TPP, and the PNRR is higher, Wagner explained.

Even with a higher market price, there is little gain, Mark Stauffer (NWE) observed of the calculations. That's true, Wagner indicated. As the average market price goes up, you still have risk to deal with, he said. If you have more in cash reserves to absorb the variability, PNRR goes down; but if you don't have reserves, "you feel the bump in PNRR," Wagner responded.

A key element to get buy-in from us on this is a clear understanding of cost recovery, Clark said. There has to be a way to protect against the high and low case, he said.

Lovell moved on to BPA's initial calculation of risk and pointed out that it is based on a traditional three-year flat fixed rate, with the cost of risk represented by a PNRR-based number and no other risk mitigation tools included. BPA estimates the cost of risk to be between \$430 million and \$530 million per year in the next rate period, he said, acknowledging that the number is "extremely high" compared to past rate cases.

Both reserves and PNRR mitigate risk, Lovell continued. If we start with enough reserves, we may not need PNRR, he said. But in the next rate period, it does not look like we will start with a high level of reserves, and that means higher PNRR, he explained. Lovell listed the PNRR drivers, which in addition to low starting reserves, include depleted fish cost contingency funds (FCCF), a higher TPP standard than in the last rate case, reliance on volatile secondary revenues in base rates, and an increase in power liquidity reserves.

Ending PBL reserves for this rate period are expected to be around \$180 million, which is pretty low, he said, adding that BPA does not expect 2006 net revenues to be positive. In one-third of the computer runs, the forecast of starting value of our reserves is about \$50 million, he said.

Is the 92.6 percent TPP standard a final decision? Annick Chalier (PPC) asked. Yes, but you can argue that in the rate case, Lovell said.

Stauffer said he thought the IOU benefits would mitigate volatility rather than pose a risk. Hoff said he also saw the IOU benefits as reducing rather than increasing risk. Lovell said while the IOU benefits are different from other risks, they pose another source of variability. Clark suggested BPA explore the possibility of postponing IOU payments if the secondary revenues forecast didn't materialize. That would require a contract change, and we're assuming we'd operate under terms of the current contract, Cherry reiterated.

Lovell went over a point-by-point explanation of why PNRR is so high. Pete Peterson (PGE) said he wasn't convinced of the logic in the model. If you use 3,000 cases of variability, it seems you have already incorporated variability into the model, he said. Lovell said PNRR is set on all games. Peterson said he would like to see more detail on the runs.

Clark said he'd like to see documentation on the need for greater liquidity reserves. Our liquidity problem is in the fall, Lovell explained. After we pay Treasury, we still need to have cash to pay our bills – it's a seasonal problem, he said. I'd like to see your cash-flow figures during that period, Clark said. Has there been any thinking about shifting expenses to another period to ease cash-flow problems? he asked.

What would happen if the TPP is left at 80 percent? Sirvatis asked. You can use the model and calculate that yourself, but we have very clear orders about TPP, Lovell said.

The PNRR includes both secondary energy revenues and IOU benefits, Geoff Carr (NRU) commented. The full requirements customers will pay the PNRR, and we would like to know how much is related to secondary energy revenues and how much is related to IOU benefits, he said. "You need different risk mitigation tools for different problems and different customer classes," Carr stated.

Mike Normandeau (BPA) explained who currently covers BPA's risk: the agency itself through reserves; customers through rate design; Treasury through timing of payments; and third parties through hedging, water derivatives, and insurance. Are you using any of mechanisms in the third-party list? Jon Piliaris (WPAG) asked. The trading floor uses forward purchasing and selling, and we are looking at water derivatives, at least as a due diligence, Bleifuss replied.

In another discussion about risk tools, we heard about a $250 million short-term note you could exercise, Carr said. Treasury isn't keen on us using it, Lovell responded. It is unlikely we could exercise that option for a liquidity need that is not associated with a capital need, he said. We have not discussed this fully with Treasury or pushed to the point of a decision, but it would not be simple, Lovell stated.

Normandeau went over a list of past and future risk mitigation tools, and he noted that the FCCF available in the past was exhausted in 2003. He also made note of the background information in the packet on risk mitigation strategies used in prior rate cases.

You haven't included one big risk mitigation tool, Hoff said: Slice. If we weren't slicing, the PNRR numbers for 2007-2009 would be bigger, Cherry agreed.

A number of tools are available to manage risk, Normandeau continued. He listed options that include changing water-year modeling assumptions, using rate-adjustment mechanisms, and purchasing weather derivatives. All of the options are on the table, but some are more feasible than others, he said. "There is no silver bullet," and the solution is probably a combination of things, Normandeau added.

You don't have "the budget action" option on the list, Brattebo pointed out. You could cut costs, he said.

Normandeau said BPA has surveyed other utilities to find out about risk mechanisms that are used. A variable rate, fuel adjustment mechanism is common practice among hydro-based utilities, he said. Alex Lennox (BPA) explained how the fuel adjustment mechanism works, adding that some utilities have an automatic adjustment based on changes in fuel prices, or volume of water for hydro-based utilities.

The region is using a cost recovery adjustment clause (CRAC) in this rate period, Normandeau said, acknowledging that customers have found the volatility of the mechanism troublesome and want more stability. He recounted what BPA has learned in using CRACs, pointing out that over the past four years, despite dry conditions and price volatility, the agency has maintained a high credit rating and made every Treasury payment.

Linda Finley (Snohomish) said BPA's statements about its reserves aren't tracking with the cash shown in its bank balances. Our bank balances reflect cash and borrowing, and we have large cash payments to make toward the end of the year, Lovell said. We are talking here about year-end reserves, he said.

But it appears your reserves are growing – we see an increase from $692 million in December 2003 to $880 million in December 2004, Lloyd Jordan (Snohomish) said. Net billing arrangements and amortization payments can make a big difference on our cash situation during the year, Lovell said. Our cash picture may not be tracking with our reserve picture, he said. Clark suggested BPA provide clarification on the issue at the managers' meeting by providing a record of reserves for 20 years, broken down into cash and deferred borrowing.

Normandeau went on to a list of issues to consider in evaluating mechanisms for risk mitigation, including available tools; timing, frequency, and complexity; distribution across stakeholders; sensivities; data sources; and other parameters such as impact on current contracts and staying within the Northwest Power Act. And he and other staff offered detailed descriptions of several risk mitigation options that have undergone a preliminary analysis: fixed flat rate, fixed shaped rate, secondary revenue rebate, rate adjustment mechanism, and a complex mechanism. The impacts of each on cost of risk (PNRR), initial rate impact, effective rate impact, rate variability, and secondary revenue credit was displayed on a summary table, along with statements of pros and cons.

Option A, Fixed, Flat Rates, relies on PNRR only to mitigate risk, according to Lovell. Chalier asked if staff could provide another column to the table for ending reserves, and he said he would look into it. Wolverton pointed out that there is a dichotomy between what BPA needs in the first year of the rate period and what it needs in the following two years. You would be collecting too much, he said. We are not building reserves – the value of the reserves is tempered by the reality of the variability, Lovell responded. A dividend distribution clause (DDC) is included in the option as a way to mitigate if large reserves accumulate, he explained. Option A could be very expensive, but we think we need to talk about it, Lovell stated.

Option B, Shaped, Fixed Rates addresses the problem we have in 2007, he continued. The shaped rate addresses what we think we will need due to starting the rate period with low reserves, Lovell explained. The option would collect higher PNRR in 2007, with a significant drop in 2008 and 2009, he indicated. Clark suggested the DDC ought to be part of Option B.

Option C, Secondary Revenue Rebate, sets rates based on rebating secondary revenue annually or more frequently, Normandeau explained. There would be a surcharge if secondary revenues fall below a critical threshold, he said. There were numerous questions about the option. "The option makes sense, but the math needs work," Clark commented. It's a concept that makes sense, he added.

Option D, Rate Adjustment Mechanism, is similar to the CRAC in current rates, and the mechanism could be triggered prior to August 2007, Lovell said. PNRR could be eliminated altogether with this option, he stated. You've assumed you could do this without running the 7(b)(2) test, even though there is a legal challenge, Hoff commented.

Option E, Complex Mechanism, provides a mix and match of tools, Lovell said. We would credit rates with one-half of expected secondary revenues, and there would be a CRAC if we start the year with less than $400 million in reserves, he explained. If reserves are greater than $600 million, actual secondary revenues above those assumed in the base rate are returned as a rebate. The rate impacts with this option were estimated using methods different than those used in the other options, Lovell said. We think the complex mechanism could fine-tune risk and reduce rates, but it could be more volatile, he said.

The problem with having BPA keep the secondary revenue is that we need to be sure it's used for rebates and not spent for other programs, Carr commented. Could BPA continue to agree to confine its spending to certain cost categories and levels? Piliaris asked. You could pre-empt the skepticism by "walling off the revenues" to assure rebates, Clark suggested. These are good options that we ought to consider, he said.

We have not been assuming we would have a rate adjustment for "controllable costs," Cherry said. "Steve Wright is clear on that," she added.

The Joint Customers have a task force focusing on risk, Brattebo said. It would be good if as a team, we could develop a proposal that we all support, he stated. We've put aside time to come together every other week to work on this, Cherry responded. By mid June, we need to know what kind of mechanism we're looking at so we can run the numbers, she said. We absolutely want to work with you on this, Cherry added.

Lyn Williams (PGE) asked about the list of dates at the back of the packet. Those are for rate case workshops, Cherry said. We have a tentative hold on those dates and this room for meetings, she said.

When we started out, we talked about the tradeoffs and choices, Bleifuss said. Are there any thoughts on the policy questions? he asked.

The customers have "a paranoia" about BPA spending, Clark said. The managers need to get an explanation of the concepts and macro options on risk – they need the policy questions that drive the options, he said. Trust with BPA is the problem, Clark continued. We need a more candid discussion about building trust, he said. Risk exists, but "it's a good news risk," according to Clark: "it's a great resource, but when we bank on it and it doesn't happen, then there is a problem." All of these tools require trust and that has to be up front in here, he stated.

NRU has 42 members and a lot of those folks are expecting a rate decrease, Carr said. The managers need the math that shows where these options will get us, he stated. "There will be shock," when people see the effect of these mechanisms, Carr predicted.

There is a rate level limit you have to be aware of – it isn't an increase, it's a decrease, Wolverton said.

What about arraying the choices through good and bad years, Clark suggested. If we say that rates have to go down, it guarantees we'll have a CRAC, he stated. The managers would like to see more numbers – maybe they could be graphically portrayed, Carr said.

The managers won't understand why reserves are down or why 2007 is so bad, Finley said. They won't understand why things look like they do with the energy crisis over, she added.

You could transfer more risk via Slice, Sirvatis suggested. That would entail changing contracts, but it may be a viable idea in time, Cherry replied.

The reasons things look like this is that the TPP standard was relaxed and is now going back up, and rates are not recovering costs, Lovell stated. I'd suggest you put that in graphic form, Finley said. You also need to tell managers why you are going to a higher level of TPP, Sirvatis advised.

Chalier listed risk mitigation options the customers have been working on, including: using BPA's total reserves, not just PBL; waiting to 2008 to change the liquidity reserve level; using a lower TPP; instituting "a spending CRAC" and a market CRAC for BPA; and changing the due date for the net-billing payment to Energy Northwest.

Clark pointed out that changing the due date for Slice payments could be worth millions of dollars. He also asked if Energy Northwest needs so much cash in September, and if not, whether another payment arrangement could be made. It would be nice to test some other options, such as $75 million, for the liquidity reserve, Carr suggested.

Talk "big picture" first with the managers, Clark advised. You need to convey that the volatility is there, then talk about how to work together to resolve it, he said. Basically, you need to move $500 million, Clark stated. "Yes, it's big," Lovell agreed.

Managers will also want to talk about the snow pack, the possibility of an SN CRAC in 2006, and the range of what you'd enter 2007 with if 2006 is a good or bad water year, Clark said.

We will post a packet for the managers on April 11, Cherry said. Staff could meet with you about the models April 20, so you would have tools to use to explore options, she added. We'll get information out about other rate case workshops as soon as possible, Cherry said.

The meeting adjourned at 2:15 p.m.

Follow-up questions and information requests

Responses to questions and requests for information received throughout this process will be posted on the Power Function Review Web site on an ongoing basis. The Web address is www.bpa.gov/power/review.

1. Provide more information on the big problem with capacity in regards to wind.
2. Provide information on the components of the wind risk and on the variability of the wind supply.
3. Provide documentation on the need for greater liquidity reserves.

PFR-022

APR 2? 200?

Bonneville Power Administration
Power Function Review Regional Meeting
April 13, 2005

BPA Rates Hearing Room, Portland, Oregon
Approximate Attendance: 10

[The packet for this public meeting is available at: www.bpa.gov/power/review.]

Introduction

Paul Norman (BPA) welcomed participants to the Power Function Review (PFR) regional meeting. He began with a brief PFR overview, noting BPA's mission statement on the opening page of the meeting packet. The question the PFR addresses, according to Norman, is what costs will go into the power rate case. We would like to set rates as low as practicable, consistent with meeting its mission.

Where does your mission statement address public purposes? asked Rachel Shimshak (Renewable Northwest Project). Norman responded that "create and deliver the best value to our customers and constituents" gets at the public purposes, along with a sentence about mitigation of the FCRPS' impact on fish and wildlife (F&W).

Steve Weiss (Northwest Energy Coalition) said BPA should be neutral in the PFR and leaving public purposes out of the mission statement "makes it seem like you're leaning in a particular way already." You have a legal obligation on conservation and renewables, he stated. So you are asking us to be more explicit about that in the package, Norman clarified.

Norman went over a 10-year BPA rate history, noting that rates were $21.2 per megawatt-hour (MWh) in FY 1997 and are estimated to be $30.7 per MWh in 2006. In real dollars, your rates have stayed about the same, Weiss commented. He suggested BPA display the nominal and real dollars side by side on the rate history graph.

Norman explained that BPA will be doing a formal rate case to set rates for its power services, but a rate case does not include program costs. Costs are outside the rate case, and the PFR is a process to address those costs, he said. Norman went over which elements in BPA's rate equation are part of the rate case and which are PFR.

This is our cost structure in its simplest form, he said of a graphic displaying BPA's forecasted expenses for 2007-2009. The PFR is looking at the components of cost and seeing if each is as low as it can, while still allowing us to meet our strategic objectives, he explained.

Norman moved on to a graph of the range of possible PF rate outcomes, and noted that the program costs point to an average rate of 28 mills per kilowatt-hour (kWh). But if we set our rate at that level, we'd have only a 50 percent chance of making our Treasury payment, and that is unacceptably low, Norman said. A huge issue in the rate case will be what we have to add to rates to get to a 95 percent chance of paying Treasury, he indicated.

There is a policy choice to make here, Norman continued: go with a higher fixed rate to cover the risk or set a variable rate that fluctuates depending on the revenue we collect. If we were to go with a fixed rate, we estimate it would need to be about 36 mills, he said. We don't think that will work for customers, and we'll probably have to have something variable, Norman stated.

People have asked why rates can't go back to 22 mills, like they were in the previous rate period, he said. We are going to try to keep rates as low as we can, but some things are different than they were in 1997, Norman said. He listed several factors that are pushing costs upward, including the investor-owned utility benefits, F&W program increases, higher public utility loads, O&M and debt service increases, and the conservation and renewables discount. There are also offsets, Norman noted, such as reduced aluminum loads and higher prices for surplus sales. But the offsets are far short of the increases, he added.

The resource augmentation costs of $600 million annually in the current rate period will go away in the next rate period, and that makes a significant difference for our cost structure, Norman continued. The average costs for preference loads are expected to fall from 31.5 mills to 28 mills, he said. But we also expect to go into 2007 with low cash reserves, Norman said.

Isn't a lot of risk already incorporated into the 31.5 mills? consultant Joel Brown asked. If you're covering your costs at 31.5 mills given bad water, haven't you already taken care of a "big hunk of risk"? he asked. The market has been so robust that we have gotten decent secondary revenues despite low water conditions, Norman said. But if we set a fixed rate, it has to have a risk adder that is almost equal to our estimated secondary revenues in order to get to the desired Treasury payment probability, he explained. The issue is the great variability in our secondary revenues, Norman said.

We have been discussing our costs in meetings and workshops for some time now, and in May, we will issue a proposal of costs we intend to use for our initial rate case proposal, he explained. The items on pages 10-11 are recommendations we have heard so far about changes we should make to our costs – most are reductions, but there are some increases, Norman pointed out. We are also keeping "a scoresheet" of the suggestions, he said. Norman went over several items on the list.

You have not listed all of the comments you've heard, Weiss stated. We have told BPA that it is not spending enough on conservation, and that not doing so is costing you money, he said. If you capitalize investments in conservation, it will pay you back in seven or eight years, according to Weiss. You have also heard that you should "front load" budgets to get the conservation as early as possible in the rate period, he indicated. You don't have enough money in the conservation budget, Weiss stated.

We said we would use the Council's Power Plan as a guide for our conservation target, Norman responded. We are also seeking the lowest cost way to achieve that, he said. "Our philosophy is to do the right things at the lowest possible cost," Norman said. He also said that BPA would add the suggestion to increase conservation targets to the list.

You have heard warnings this budget is cutting it too close, Weiss said. The answer is not necessarily to increase the budget; you could also put in place "a serious backstop," he said. "Raise the budgets now or have a credible backstop," Weiss recommended. It is a good thing that you will meet the Council's target, but you may not have budgeted enough money to do that, he stated.

Why not close the Columbia Generating Station? asked Jay Formick (Oregon Heat). It's the most expensive power that you have, he said. Energy Northwest has cut its costs, and the average for power from the nuclear plant is around 25 mills, Norman stated. If you look at the going-forward operating cost, it is competitively priced power, he added.

Norman said BPA would put out its proposal on costs May 2 and take comments until May 20. Our final closeout letter for the PFR will come out the week of June 13, he said.

Public Comment

Jenny Holmes, Ecumenical Ministries of Oregon, said her organization strongly supports energy conservation as a way to address global climate change. Climate change will have a big impact on the hydro system, and conservation and renewables should be a high priority in BPA's budget, she said. We need to have resources to move the region in the right direction, Holmes said, adding that BPA's budget can influence the way the state and the region go with conservation and renewables, she said. Your public responsibilities – F&W, conservation and renewables – are important to the citizens of the region, and we urge you to take them seriously, Holmes stated.

Jay Formick, Oregon Heat, said BPA's F&W funding must be adequate to address uncertainty in the legal arena. The court may grant injunctive relief due to the way the ESA has been "misconstrued" in the region, and BPA must be prepared to pay the relief if that happens, he advised. We would push strongly for adequate funding for F&W, Formick reiterated.

Steve Weiss, NWEC, took issue with the graph of F&W costs on page 37. We had a commitment the graph would change, "but here it is again," he said. It does not show the 4(h)10(c) credits and displays the cost only of F&W on operations and not the costs of industrial withdrawals, irrigation, and other uses, Weiss said. In these policy debates, BPA must be more neutral, he added. The $356.9 million attributed to F&W operations is an old number, Weiss continued. Two-thirds of that number is associated with spill and one-third is associated with the timing of flows, he said. But the seasonal price differential for electricity is flat this year, and when the water moves this summer, the market price of power could be even higher than it was in the winter, Weiss said. The fish operations could make you money this year, he stated.

You need to have enough money to address the risk of the unknowns with F&W, Weiss advised. As part of the cost-recovery adjustment clauses (CRACs) in the last rate case, BPA agreed to limits on spending, and that seemed to me to unduly tie the hands of the Administrator, he commented. You need to have good risk mechanisms, Weiss said, adding that he favored the CRACs.

He praised BPA for its efforts on behalf of low-income weatherization. The changes made in the contracts were very responsive, and your work has been "super," Weiss stated. Your work on transmission has been good too, he said, but he questioned opening capacity up to those in the queue ahead of renewables. You need to make sure renewables have a way to get on the system, Weiss said. Operating on "a first-come, first-served basis" is not the way to divvy up a scarce resource, he added.

Weiss said BPA should not count IOU accomplishments on conservation toward achieving its goal. You pledged to meet the target in the Council's plan, and if you count IOU conservation, you should raise your target, he added. Weiss also said "decrementing" utilities when they achieve conservation savings would effectively raise the cost of their conservation. It's a problem especially for utilities that are facing the possibility of system allocation – people don't like to lose a resource, and it's both "a money and perception problem," he said. Weiss suggested BPA treat all conservation the same – decrement all or none, and/or monetize the benefits of conservation. He also pointed out that there is no inflation in the conservation budget and that by the third year of the rate period, the budget wouldn't go very far.

BPA also needs to provide a conservation backstop, Weiss stated. You could use the rate credit to do this – if utilities are not doing enough conservation, you could double the rate credit, he suggested. I'd recommend doing it retroactively if it's needed, so people don't hold back on their efforts, Weiss said. You're doing well on some things and badly on others, he summed up. You provide great opportunities for public input, Weiss added.

Joel Brown, Energy Risk LLC, said he viewed the $356.9 million estimate for the cost of fish operations to the hydro system as too low. The hydro system offers the ideal way to load follow when wind generation is integrated into the system, he said. But if hydro is being used as a base-load resource and is not available to follow variability, "you force people to go out and build CTs that create the greenhouse gas that you are trying to avoid" with the wind generation, Brown said. There are huge hidden financial and environmental costs here, and the $356.9 million understates them, he stated. The biggest cost is a result of not being able to use the system to handle variability – hydro is the fastest reacting and cheapest resource to follow load, Brown said. If you don't regulate wind with hydro, you regulate it with thermal, he stated.

Pete Peterson, Portland General Electric, said his company is working with the joint customers on PFR comments. Risk management is a big issue, he said.

Jim Abrahamson, Community Action Directors of Oregon, thanked BPA staff for great work in removing contract barriers to low-income weatherization. It is very frustrating to see structural barriers to programs, especially when there is money available, he said. This will make an enormous difference, Abrahamson said. Once the currently available money is spent, "we'll be back for more – the need is there," he added. Do what you can to keep costs down, Abrahamson went on. Lower electricity bills are also an important way to help low-income people cope, he indicated. But don't underfund conservation and renewables – they will help low-income consumers in the future, Abrahamson concluded.

Rachel Shimshak, Renewable Northwest Project, commended BPA on its transmission policies for renewables, which she said are leading the nation. Since the tax credit for wind generation exists for 2005, you are focusing on getting projects on the ground, and we appreciate it, she said. Shimshak recounted that when BPA was in financial trouble in 1999, renewables advocates agreed to a reduction in the budget from $40 million annually to $15 million. Now, you are going forward with $15 million in rates for renewables, she commented.

We'd like you to have consistent funding available to invest and retool programs that meet customer needs, Shimshak urged. She called on BPA to be open to opportunities to collaborate with customers and to stay in the renewables market. "I can't figure out where you are headed," and I don't see the dollars in your budget to actually address the renewables needs, Shimshak said. I don't see the tools to follow through on your commitment – it takes dollars to do this, she added.

Shimshak pointed out the problem wind developers have with getting funding and permits to build without a commitment for transmission. "It's a chicken and egg problem," she added. We may need to provide money that people can use up front and repay, Shimshak suggested. You need to think long term, she said. With fossil fuel prices going up, the value of conservation and renewables increases, Shimshak said. We know "your customers look at every penny you spend," but you need to think long term, she stated.

The meeting adjourned at 6:40 p.m.

PFR-023
APR 27 2005

Bonneville Power Administration
Power Function Review Regional Meeting
April 14, 2005

Mountaineers Headquarters, Seattle, Washington
Approximate Attendance: 15

[The handouts for this meeting are available at: www.bpa.gov/power/review.]

Introduction

Paul Norman welcomed participants to the Power Function Review (PFR) regional meeting. He said he would do a brief overview of the PFR and then move to Q&As and comments. The purpose of this process is to make sure the costs on which BPA will base its rates are as low as they can practically be and still assure that BPA achieves its mission, Norman stated. We want the thoughts and insights of those with a stake in our costs to make sure they are where they should be, he said.

Norman went over a 10-year BPA rate history, noting that rates jumped from 2001 to 2002, and have since come down a little. The question now is where will they go for 2007-2011, he said.

Norman explained that BPA will be doing a rate case to set power rates, but costs are not part of that process. We decide costs outside the rate case, he said, referring to an equation on the Rates Overview page of the meeting handout. The risk *discussion* is part of the PFR, but the risk *decision* will be part of the rate case, he clarified.

Norman moved to the graph displaying BPA's forecasted expenses for 2007-2009. In the PFR, we have been drilling into these categories of cost to explain what they are, why they are growing, and identify opportunities for bringing them down, he explained.

If you take all of our costs and subtract the secondary revenue, which can be "extremely variable," you get a rate of about 28 mills, Norman continued. But a rate of 28 mills would only give us a 50 percent Treasury payment probability (TPP), he said. The question is, what does it cost to mitigate the risk, Norman stated. One approach would be to have a lower variable rate that would change, depending on revenue, and another approach is to have a much-higher fixed rate, he explained. Risk is a big driver of where the rate will end up, he stated.

We are coming out of period of large purchase power costs, and people have asked us, if these costs are going away, why can't we return rates to historic levels, Norman went on. We are dedicated to making rates as low as we can, but there are things that have changed since 1997 that would make that difficult, he said. Norman listed five key factors that are pushing costs up: the investor-owned utility benefits, up from $70 million annually in 1997-2001 to $300 million annually; F&W program costs that increased about $120 million annually; 3,000 additional megawatts in public utility load; increased O&M and debt service expenses; and conservation and renewables costs "that were hammered down in 1997-2001" are back up.

Moving to a comparison of the 2002-2006 period with the upcoming 2007-2009 period, he said resource augmentation costs of about $600 million are going away, but there are offsetting expenses. Without a risk adder, costs to our preference customers are expected to fall from an average 31.5 mills in 2001-2006 to 28 mills in 2007-2011, but low reserve levels and higher volatility in secondary revenues increase the rate allowance needed for risk, Norman indicated.

The next couple of pages are a condensation of what has come out of the PFR so far, he said. We have listed potential changes we could make, mostly cost reductions, Norman said. "I am confident that the costs coming out of the PFR will be lower than those going in," but I can't say by how much, he added.

On May 2, we will put out proposed changes in our costs, Norman said. We will take three weeks of comments, then once we digest the comments, we will put out a final PFR closeout in June, he wrapped up.

Norman explained an item in the conservation list, saying BPA agreed to meet the Council's target for its share of regional conservation. It was suggested that we count toward that target the conservation that utilities are funding on their own, Norman said.

To illustrate this issue, Jean Ryckman (Franklin PUD) said Franklin established a five-year goal under BPA's conservation and renewables discount (C&RD). We achieved our target within two years, and at that point, rather than stop, our board chose to continue the conservation efforts, she said.

Patton said the Franklin example is encouraging. But the Council's analysis and Green Book do not show this is happening in many places in the region, she said. BPA is still legally responsible for meeting the load growth in the region and for meeting the conservation associated with that load, Patton said. That would make BPA's target about 70 MW instead of 52 MW, she added. C&RD does not get at all of the conservation potential that exists in the region, Patton added.

Franklin is a Full Requirements Customer, and if we are spending money on conservation, BPA should be given the credit, Ryckman stated.

Given that the Council's analysis of what is cost effective is a considerable increase over what the region is doing, "it seems silly" to talk about doing that, Patton commented.

Norman pointed out that the conservation workgroup recommended increasing funds for administrative costs and infrastructure, and we've noted an $8 million increase on the list of suggested changes in costs.

Mike Little (Seattle) asked how the workgroup recommendations were processed. "They went into the black box," and I wondered what happened to them, he said. We lined up the recommendations, talked about them, and we said yes to a lot of them, Norman replied, noting that BPA changed its mind on some things, including decrementing, based on the recommendations. From my point of view, we said yes on a lot of workgroup recommendations, he stated.

If you decrement utilities, you should net out the revenue from selling the conservation resource you gain and credit it toward conservation costs, Patton suggested.

Little asked how the conservation proposal that was just released meshes with PFR. The PFR is the process for deciding the conservation budget for the rate case, Norman responded. The comments we receive on the conservation proposal will influence our May 2 budget proposal for the rate case, he added. Other aspects of the conservation program that are mentioned in the paper will be decided elsewhere, but the budget will come out of the PFR, Norman said.

I've never seen the value in conservation, meeting participant Paul Locke stated. There is no generating capacity gained – it's just making better use of what you have, and I can't understand why we spend millions of dollars on it, he said. It gives BPA more energy to sell on the open market, and it's energy BPA gains without having to plan or purchase other resources, another participant responded.

The fundamental choice about whether to pursue conservation was made for us by Congress, Norman said. If it costs less than other resources, Congress told us to acquire conservation, he added.

<u>Public Comment</u>

Jean Godden, Seattle City Council, thanked BPA for holding the PFR meetings and giving people the opportunity to offer their comments. She noted that the City Council works with a citizen advisory board and gets good advice on energy and environmental matters. We have a new City Light superintendent, and we are excited about the direction he is taking, Godden indicated. We'd like to be good partners with BPA, not litigants, she said. We appreciate that PBL and TBL have held their costs down to 2001 levels – "that has helped build trust with your customers," Godden said. I want to encourage you to make the right investments for our energy future – it's very important for stability and for the environment, she added. Thank you for thinking long term on conservation – some of the region's pioneering efforts were begun here, and we can be proud of that, Godden wrapped up.

We recognize the importance of the lowest-cost energy future for the Northwest, **Stan Price, Northwest Energy Efficiency Council**, said. The role of low-cost energy is fundamental to our economy, he stated. At issue is how to approach getting to that future, according to Price. I'm concerned about whether BPA is adequately funding the conservation that will get us to the lowest-cost energy future, he said. We applaud BPA for committing to its fair share of the Council's conservation target, Price said. But it is a higher target than you have had in years past, yet you have a lower budget, he pointed out. Your budget suggests you can reduce spending and still meet the target, but I haven't heard a way to do that, Price said.

If we gamble on whether we can achieve the conservation target, we add more risk, he said. If we miss the target, BPA will spend more in low water years to buy energy, and BPA will also miss out on energy it could sell, according to Price. I am "distressed" to hear conservation referred to as adding to the budget since it is the lowest-cost resource out there, he said. We know that spending on conservation adds to costs, but if you think long term, not spending will lead to a higher-cost energy future, Price said. It isn't reasonable to assume you can achieve a target that is 20 percent more ambitious with a flat budget, he stated.

Richard Sorenson, University Heights Center, described how the non-profit center had benefited from Seattle City Light's retrofit program. After a ballast exploded and signaled the need to replace aging light fixtures, we were able to convert to fluorescent lighting with a $17,000 rebate from City Light on a $50,000 expense, he said. We are also saving on our energy bills, Sorenson stated. Would you have done the project without the help from City Light? Ryckman asked. No, Sorenson said. Along with providing the rebate, City Light was able to help us arrange the financing, he added.

Ed Henderson, Mountaineers, said his organization has "a long proud history of environmental activism." With global warming and climate change, we are very mindful of the role played by production and use of energy, he said. BPA has "a golden opportunity" to have a positive impact, Henderson said. All projections point to growing demand for energy, and you are obligated to buy conservation and renewable resources to meet it, he said. But BPA's conservation budget is inadequate to meet its goals, Henderson stated. You should aim to acquire 70 MW – it's money well spent, he said. BPA should also continue to promote renewables, Henderson added.

We are very concerned about the priority for F&W, he continued. BPA is legally bound under the Northwest Power Act to give power and F&W equal priority, Henderson said. Opinion polls show strong support for funding to meet this obligation, he wrapped up.

Sara Patton, NWEC, thanked BPA for the processes that allow people an opportunity to participate in its decisions. With regard to energy efficiency, we are concerned about meeting the goals with funding levels so low, she said. BPA is legally obligated to meet the load growth of utilities, so your conservation goals should be based accordingly, which would put the goal at 70-72 MW, rather than 52 MW, Patton indicated. We are worried about whether you can get that amount at the budget level you have committed; a more realistic budget would be $99 million to $100 million to achieve 52 MW and $133 million to achieve the more appropriate goal of 70 MW, she said. Investment in conservation is a risk strategy, according to Patton. We need to get energy efficiency now and forego the Montana coal plants, she said. If your conservation staff can achieve the target for less, don't spend all the money, Patton suggested. But it's a big gamble not to budget more, she added.

If you decrement utilities, you will get revenue for the decremented load, and "it is only fair to show it as an offset" to the cost of energy efficiency programs, Patton said. We commend BPA for its continued commitment to low-income weatherization – thanks for taking it seriously, she said. We are happy you have participated in renewables projects, but we're worried about BPA just carrying forward with the $15 million from the last rate period, Patton stated. We think that would be minimal, she said. We think you need to make investments in renewables to avoid the spikes in fossil fuel prices, Patton said.

In terms of risk management, we think it is important for you to have the Safety Net CRAC, she continued. It was vital in this rate period to help you meet the TPP, Patton said. The $139 million for your integrated F&W program is a figure that has not increased in years, she said. There has been no allowance for inflation, Patton pointed out. We don't know what is going to happen with the Biological Opinion, and it could require major changes, she said. We think you should plan for the potential actions you might have to take, Patton said.

Jean Ryckman, Franklin County PUD, said BPA has been responsive to its customers in the PFR, and "we appreciate it." Rates are a huge issue for us – "they are the life and death" of our businesses, she said. Low power rates have been "the saving grace" in our region, Ryckman stated. A 27-mill rate target is achievable, and you should work toward that, she said. We think we have been undercounting conservation for years, Ryckman continued. A lot has been happening that is being paid for by others, and we need to recognize efforts that have been going on, she said. Ryckman also pointed out that irrigators are doing a lot with conservation of electricity and water.

We need to take steps to see that fish mitigation costs are cost-effective, she stated. We know we have a mitigation obligation, but we also have an obligation to spend wisely, Ryckman said. She asked BPA to consider the amortization period for projects funded under its F&W program versus projects built by the Corps and Reclamation. A longer amortization period for F&W projects would have an impact on rates, Ryckman said. She also asked BPA to reconsider its augmentation schedule for ConAug investments. The amortization schedule depends on the period remaining in the contract and doesn't relate to the life of the measure, Ryckman added.

Paul W. Locke, citizen, said there is not adequate generation being built in the region. As you add more residents, you need more power, and right now, we don't have power for industries, he said, pointing to business, such as steel and aluminum, that are leaving the region. Locke said he did not think money being poured into programs for fish is money well spent. As a ratepayer, I'd like to see rates go for more modern turbines that turn out more energy for the amount of water being used, he said. You need electricity to create jobs, Locke said. It's absolutely essential that we change course, he stated.

"Energy efficiency is a gift that keeps on giving," according to **Dave Kerlick, citizen and NWEC member**. Energy efficiency should be funded, and meeting targets should be accelerated, he stated.

Tom DeBoer, Puget Sound Energy, thanked BPA for the opportunity provided by the PFR. Your customers appreciate it, he said.

Robert Cowan, Fred Hutchinson, said the cancer research center is saving $1.5 million a year on its power bills as a result of energy conservation measures. There is "a perfect storm" brewing for conservation, he said: energy prices are high across the board; utilities have programs to encourage energy efficient buildings, and new technologies are emerging for energy efficiency. You can get a lot of leverage with the dollars you put out because we can join you and put out dollars too, Cowan said.

Energy conservation is a tough sell in the Northwest because our rates are low and we have a mild climate, he said. An energy project here with an eight-year payback would have a four-year payback somewhere else, according to Cowan. He offered tours of the Fred Hutchinson facilities, saying the buildings provide many examples of energy conservation and technology for energy efficiency. We have technology that is saving a lot of energy – we've done great things, some of which is not being counted in City Light's conservation achievements, Cowan indicated.

Mike Little, Seattle City Light, said he didn't know where Seattle would be with conservation without BPA's funding. He said Nucor Steel chose to stay in Seattle because of the help City Light could offer in upgrading their furnace. They are saving about 8 million KW a year now, according to Little. I agree with those who have pointed out the risk you face in meeting your conservation goals, Little said. Decrementing for conservation gains is an issue for some utilities, he said. "Incrementality" is a new term that has surfaced, and it refers to using BPA funds to pay for things a utility would already be doing – there will be reaction to that, Little predicted. I also think there is a lot of conservation being done that is not being counted, he summed up.

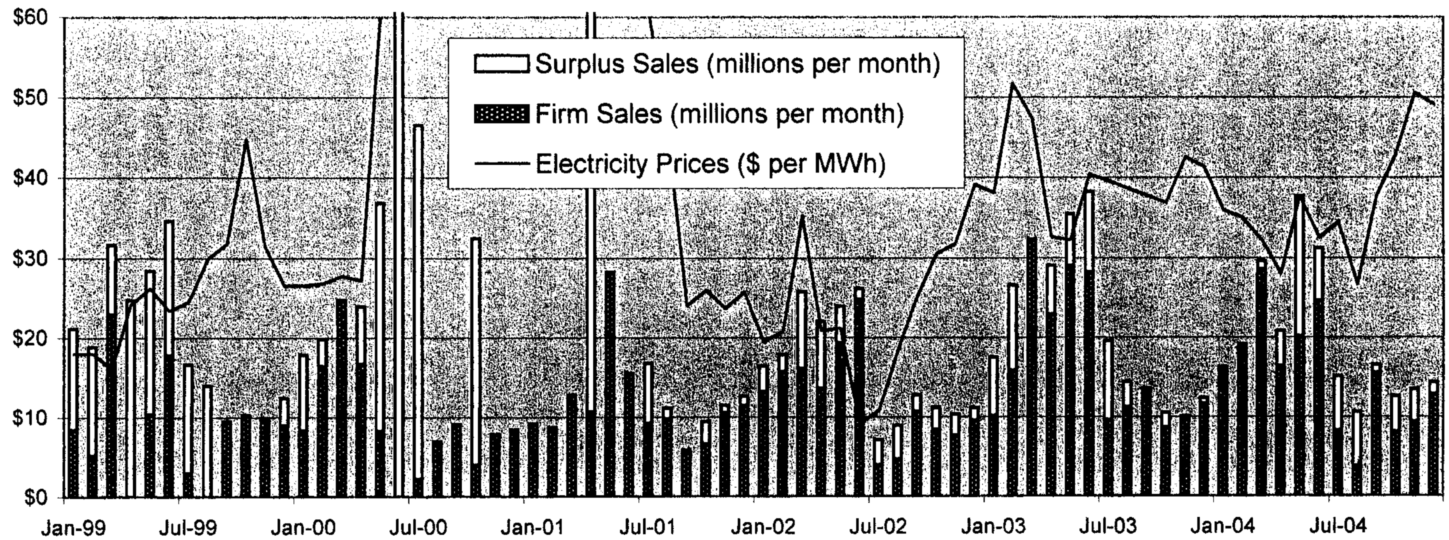
The meeting adjourned at 7 p.m.

Costs & Revenues

associated with the

Lower Snake River Dams

by **www.bluefish.org**



Our Mission at **www.bluefish.org** is to facilitate an open and honest dialogue concerning the plight of Idaho's wild Salmon & Steelhead. It is hoped that the growing library of news and reports will assist the public and decision-makers in making well-informed choices regarding the recovery of Idaho's anadromous fish.

APR 27 2005

PFR-024

Spill for Salmon Passage sends water and fish over spillways rather than past turbines where electricity is produced and about 8% of juvenile salmon are fatally injured. Spill is the safest way for juvenile salmon to pass dams (97% survival is typical) but potential hydropower is not generated.

The 2004 Updated Proposed Actions places great emphasis on a new technology called the Removable Spillway Weir (RSW). The RSW requires less water to pass juvenile fish downstream and thus more water is available for power production. To date, two new RSWs have been installed on the Lower Snake River with costs running from $11.5 to $20 million each.

Juvenile Salmon Survival Benefits of Removable Spillway Weirs

Project	*Fall Chinook*	*Spring/Sum Chinook*	*Steelhead*	*Electric Benefit*	*Estimated Cost*
Lower Granite Dam	1%	0.8%	0.6%	**23** aMW	$11.5 million
Little Goose Dam	1%	Slight	Slight	**2** aMW	
Lower Monumental	1%	2%	1.4%	**16** aMW	
Ice Harbor	0.9%	1.4%	1.4%	**76** aMW	$20 million
McNary Dam	1.6%	1.1%	1.1%	**16** aMW	
The Dalles Dam	N/A	N/A	N/A	**47** aMW	

Salmon survival benefits estimates from the NOAA Fisheries 2004 Updated Proposed Actions.
Electric benefit estimates from BPA's Power Function Review and phone conversations with ACOE.

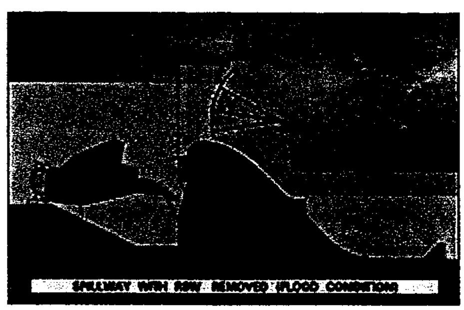
Of note is the energy benefit that the Removable Spillway Weirs provide on the Columbia River as compared to the smaller Snake River. The Columbia Basin Bulletin (10/29/4) reports:

> The Corps of Engineers noted that the action agencies' Updated Proposed Action suggests that lower Columbia River passage improvements should in most cases have priority.
>
> That document advises that the hydro projects with the lowest juvenile passage survival should receive attention first, but that improvements at the Columbia's Bonneville, The Dalles, John Day and McNary dams would benefit all species originating above Bonneville. Lower Snake improvement would benefit only Snake River fall and spring/summer Chinook and Steelhead.

Testing has been done for Spring/Summer Chinook at Lower Granite but no tests are currently scheduled for Fall Chinook at Lower Granite. The Columbia Basin Bulletin of (10/29/4) continues:

> Biological testing at Lower Granite has shown that the RSW is five times more efficient at attracting juvenile salmon and steelhead than traditional spill, effectively passing more fish with less water. The studies have also shown that the fish don't hesitate or delay as long before passing the structure, making them less vulnerable to predators and allowing to them stay closer to their natural migration timeline.

More complete survival data will be available when test adults return in 3 to 5 years. Currently the BPA is budgeting for more RSW at all Lower Columbia and Lower Snake dams. After each installation, testing will take place for two or three years with operations being adjusted so as to not increase salmon mortality.



SPILLWAY WITH RSW REMOVED (FLOOD CONDITIONS)

When asked at April 5th Power Function Review what would happen if salmon survival were to decrease, Corps of Engineers responded that further testing would be done to find the optimum operating conditions. When asked whether a RSW would be removed if all operating conditions brought a decrease in salmon survival, officials again responded that testing would be done to find the optimum operating conditions.

SPILLWAY WITH RSW DEPLOYED (OPERATING POSITION)

NOAA Fisheries' 2000 Biological Opinion of the Federal Columbia River Power System estimates that the Little Goose spillway has a 100% juvenile salmon passage survival. This will be difficult to improve upon.

In an average water year, Lower Snake River dams produce $270 million of electricity at a $186 million cost. Below, **www.bluefish.org** has assembled all the pertinent costs involved with emphasis on accuracy and thoroughness. For further discussion on these numbers please contact **www.bluefish.org**.

Lower Snake River Dam Costs

Primary Source: BPA's Financial Choices Workshop & Power Function Review

	$ Million	Paid by
ACOE Operations & Maintenance		
Lower Snake River Dams (ACOE budget FY05)	$ 35.1	BPA Consumer
U.S. Fish & Wildlife O & M		
Lower Snake River compensation Hatcheries	$ 17.1	BPA Consumer
Lower Snake River Debt (annual payment)		
Lower Snake River compensation hatcheries	$ 16.5	BPA Consumer
Lower Snake River Dams current facilities	$ 35.5	BPA Consumer
2000-2004 capital investments averaged 11 million annually.	$ 0.8	**Increases yearly by $800,000**
Idaho Sockeye 'Safety Net' Program $ 0.5 NOAA fish culture, $ 0.5 IDF&G Eagle hatchery O&M $ 0.4 Shoshone-Bannock limnology, $ 0.15 U of I genetics work $ 0.2 IDF&G research, monitoring & evaluation	$ 1.8	BPA Consumer
10% of BPA Internal Costs	$ 11.6	BPA Consumer
Habitat Expenditures (Idaho for year 2000)	$ 22.2	BPA Consumer
Columbia River Fish Mitigation		
Completed $300 million of $700 million projected total cost.	$ 19.7	BPA Consumer
BPA Consumer share to reach $46 million annually in 2014.	$ 2.6	**Increases yearly by $2,600,000**
	=====	
Cost to BPA Electricity Consumer	$ 163 million	per year
Taxpayer share of Capital Expenses		
Lower Snake River compensation Hatcheries	$ 1.6	**Increases yearly by $350,000**
Lower Snake River Dams' current facilities	$ 3.5	Taxpayer pays 9% of capital,
Lower Snake River Dams' new capital investments	$ 1.9	the cost of navigation's share.
Columbia River Fish Mitigation to reach $4.6 million in 2014		
Pacific Coast Salmon Recovery Fund (Idaho for 2005)	$ 6.0	Taxpayer to State Programs
Salmon Habitat Restoration Initiative (Idaho for 2005)	$ 0.3	Taxpayer to US Dept Agriculture
Flow Augmentation		
427,000 acre-feet to Brownlee Reservoir	$ 3.5	Taxpayer to Bureau Reclamation
Lower Snake Channel Dredging (1980-2000 average)	$ 3.6	Taxpayer to ACOE
Costs to Protect Lewiston from Flooding	?	Taxpayer to ACOE
Legal Costs to Defend Bush's 2004 UPA	$ 3.0	Taxpayers to NOAA, ACOE, BPA & Department of Justice
	=====	
Cost to Taxpayer	$ 23 million	per year
Total Annual Cost	**$186 million**	

Preferred Firm average annual Revenue	**$150 million**	
Surplus Sales average annual Revenue	**$120 million**	Next page has calculation details

ACOE: Army Corps of Engineers
BPA: Bonneville Power Administration
NOAA: National Oceanic and Atmospheric Administration, Fisheries
UPA: The 2004 UPA suggests that since Idaho's salmon were not listed until after the LSR dams were built, that the dams should be considered as part of the background condition. Additionally, the 2004 UPA discards a dam removal contingency plan, even though the previous Biological Opinion called this contingency plan as essential in reaching a 'no jeopardy' opinion: Actions 147 and 148 of the 2000 Biological Opinion for the Federal Columbia River Power System have been removed.

Power Sales - How are they estimated?

Each Lower Snake River dam converts the gravitational energy of 100 feet of water into electricity. Hydroelectricity production is limited by the amount of water coming into the reservoir upstream, as the 100-foot elevation would decrease if outflows were to exceed inflows. Thus, electricity production is greatest during floods typical of the spring runoff.

On a typical day from September through December, the four Lower Snake River dams combined are generating about 500 aMW of electricity while the four dams on the much larger Lower Columbia River are generating nearly five times that. During the spring runoff from March through May, production on the Lower Snake nearly triples to around 1400 aMW, while the Lower Columbia picks up by a third in size to generate about 3200 aMW.

During 80% of the year, the BPA has more electricity to sell than the Northwest region consumes yet the water continues to flow downstream and the turbines harness what they can. This "surplus" electricity is sold at market prices that are often below the "preferred firm" price Northwest utilities have agreed to pay in long-term contracts. The Northwest utilities find benefit from these "surplus sales" as a swelling BPA cash reserve tends to reduce the price of future long-term contracts.

"Preferred Firm" Sales average $150 million per year from Lower Snake dams (1999 - 2004).
BPA makes multi-year contracts with numerous Northwest utilities. The price is set for the term with several pricing mechanisms that may adjust the total price in a given year. Using the BPA's yearly Load & Resource Study, aka. The White Book, we estimate the yearly revenue from the Lower Snake River.

First we compare each year 1999 through 2004 to a water year between 1929 through 1978 to find a close match. With a good prediction of the "preferred firm" load for an upcoming year, the White Book projects the monthly surplus or deficit if that year were to be identical to the water conditions of a year between 1929 and 1978.

Next, the total yearly production of the Lower Snake is compared to the total production of the federal hydropower system. (The Lower Snake represented 9% of the total in 2000 and 2002, 11% of the total in 2003 and 2004, and 12% in 1999). The respective year's percentage multiplied by the White Book's surplus/deficit projection provides an estimate for the "surplus" attributable to the Lower Snake dams. The difference between this "surplus" and the actual Lower Snake production is assumed to be sold at the "preferred firm" rate. Multiplication yields an estimate of firm sales from the Lower Snake dams.

"Surplus Sales" averages $120 million per year from Lower Snake dams (1999 - 2004).
Arriving at the "surplus sales" revenue provided by Lower Snake dams follows the same approach as above. The "monthly surplus" energy is a percentage of the White Book's projected surplus/deficit for a similar water year. If no surplus is projected for that month then no surplus sale is assumed. If the "monthly surplus" is greater than the Lower Snake's actual production for that month then the "monthly surplus" is reduced to the actual Lower Snake production for that month. Multiplying the monthly average Mid-Columbia electricity prices by the "monthly surplus" yields the estimated "surplus sales" attributable to the Lower Snake dams each month. Note that all "surplus sales" are priced at daytime, peak-load pricing: reduced off-peak pricing was not used. Details are at www.bluefish.org/lsrmoney.xls.

Total Hydropower Sales averages $270 million per year from Lower Snake dams (1999 - 2004).
Total Lower Snake River hydropower sales is the "preferred firm" combined with "surplus sales". As a check of this combined estimate we look to BPA's annual reports and from the total sales we subtract transmission sales. This difference is then compared to our estimated total sales from the Lower Snake dams. While taking into account that BPA's fiscal year ends September, we find the estimate tracks well with the annual reports.

A request by the region's electric utilities would likely prompt BPA to refine the estimates provided here.

Year	Water Year Likened To	Preferred Firm Sales	Surplus Sales	Total Sales Estimate
1999	1955 and 1972 averaged	$106	$126	$232
2000	1948	$113	$229	$342
2001	1930	$138	$83	$221
2002	1978	$148	$46	$194
2003	1935	$202	$57	$260
2004	1936	$183	$54	$237

Where could 1150 aMW come from to replace the power generated by Lower Snake River dams?

There are many ways to provide 1150 aMW, which represents 4% of the Northwest regional demand. One possible scenario combines wind energy (480 aMW) and by finding efficiencies in the existing Federal Power System (690aMW).

<u>480 aMW of Wind Energy</u>: 1463 MW x 33% average availability of wind resource.
The Pacific Northwest has the potential to generate 133,000 average megawatts of electricity from wind power. Montana alone could provide 15% of U.S. electricity needs.

350 MW from Blue Sky Wind near Dayton, Washington has begun connection work.
300 MW from Klondike III Wind Project by PPM Energy is near Wasco and Rufus, Oregon.
200 MW from Big Horn Wind Project Klickitat County, Washington is seeking interconnection.
200 MW from Arlington CEP Wind Project is seeking to interconnect on the McNary-Santiam line.
200 MW from Leaning Juniper Wind Project is seeking to interconnect on the McNary-Santiam line.
150 MW from Hopkins Ridge by Blue Sky Wind is seeking interconnection.
63 MW from Combine Hills Wind Project is seeking to interconnect on the Walla Walla-Pendleton line.

<u>690 aMW Finding Efficiencies in Federal Power System</u>: median age of generating units is 45 years.

400 aMW employing computer technology to optimize plant operations and gain generating efficiency.
A software tool called the Near Real Time Optimizer is at the heart of the effort. $188,000 per aMW, total investment of $75 million is expected to gain up to 400 aMW over the next decade. Thus far, head sensing & flow index testing has achieved 80 aMW.
99 aMW, McNary Turbine Runner Replacement, $172 million or 1.7 million per aMW.
85 aMW, Grand Coulee, 8% efficiency gain with new turbines, $130 million or 1.5 million per aMW.
50 aMW, Removable Spillway Weir will reduce spill at The Dalles.
40 aMW, Chief Joseph Turbine Runner Replacements by 2011.
15 aMW, Removable Spillway Weir will reduce spill at McNary dam.
? aMW from increased energy efficiency at California's DC intertie substation near Los Angeles.

<u>2,800 aMW of Conservation</u>: 700 aMW every 5 years over 20 years.
Efficiencies are deemed achievable and cost-effective with an average cost of 2.4 cents per kWh.

700 aMW deemed achievable in 5 years, Northwest Power & Conservation Council 5th Regional Plan.
280 aMW is BPA's 40% share for 5 years invested at $70 mil/year or $1.25 million per aMW.

<u>3000 aMW from a Substantial Reduction of Northwest Load</u>

3000 aMW of demand has disappeared from the Northwest as aluminum smelters have closed.
Aluminum prices have not increased enough to make up for increased cost of NW electricity.
Under consideration is a proposal where aluminum companies receive $40 million per year from BPA.

<u>3,470 aMW proposed in Natural Gas Combustion Turbine projects</u>

1,200 MW gas-fired combined-cycle turbine project proposed from Wanapa Energy Center Generation by Confederated Tribes of the Umatilla Indian Reservation east of Pendleton, Oregon.
1,160 MW a combined-cycle turbine is proposed by People's Energy near the California-Oregon border.
720 MW cogeneration combustion turbine is proposed next to BP refinery near Canadian border.
306 MW combustion turbine from Plymouth Energy is seeking interconnection near McNary dam.
90 MW proposed by Idaho Power near Mountain Home Air Force Base east of Boise, Idaho.

Lower Snake River dams typically provide $120 million in "preferred firm" sales to Northwest utilities. An additional $150 million comes from "surplus sales" primarily to California. Surplus sales improve BPA's cash reserves thereby helping to keep future contracted rates low to NW utilities.

PFR - 025

APR 2 2005

Yakama Nation Statement on Fish and Wildlife Costs for BPA Rate Case

April 18, 2005

I am Virgil Lewis, Sr., the Vice Chairman of the Yakama Tribal Council. I am here to provide policy comments to BPA and its customers on the need to adequately fund fish and wildlife in the next rate case.

The Yakama Nation is the largest Indian tribe in the Northwest. We are also the largest employer in Central Washington, with over 4.600 jobs in our tribal government and tribal enterprises.

The Yakama Nation also has the largest number of tribal fishermen on the Columbia River. We signed a Treaty with the United States in 1855 that guaranteed our rights to fish and hunt to support our culture and tribal economy. The loss of salmon has had a devastating effect on our community.

Over the last forty years the United States and several of the Northwest states have asked us to reduce our tribal harvest as part of an effort to rebuild salmon runs. These governments promised to restore salmon habitat to rebuild health salmon runs.

We voluntarily stopped our commercial harvest of spring chinook in 1965 and summer chinook in 1975.

More recently, our salmon harvest has been further constrained to protect salmon listed under the Endangered Species Act. The Federal government developed a biological opinion that left the dams in place and promised aggressive efforts to restore habitat.

We had a couple of good years recently where there was some commercial harvest on spring and summer chinook, but this year is looking very tough.

We have a lot of promises from the Federal government and the states, but very little action that has improve habitat or migration survival.

That is why the Yakama Nation was a party in the last BPA rate case. We spent considerable resources trying to convince BPA to include sufficient funding to fully implement the Council's Fish and Wildlife Program and the Biological Opinion.

We were not very successful in that rate case and we are currently suing BPA in the Ninth Circuit because we believe BPA violated the Northwest Power Act in setting its rates. It rates were not sufficient to meet its costs, including fish and wildlife costs, and assure repayment to the Treasury as required by the Act. That case is pending.

Now BPA is starting a new rate case. We need to ensure that BPA provides adequate funding to implement the Council's Program and The ESA.

The Yakama Nation has been working very hard with other fish and wildlife managers to develop the costs to fully implement the Council Program and the Biological Opinion.

Working with CBFWA, we have developed the most detailed budgets ever prepared for this kind of effort. Those budgets clearly show that implementing the subbasin plans, wildlife program, and other ongoing activities will require a significant increase in BPA funding. That should not come as any surprise. Restoring the habitat in the Columbia Basin—an area the size of France—will require a major effort.

CBFWA is recommending that BPA ramp up its funding during the next rate case from $186 million in FY 2006 to $240 million in FY 2009.

This will put us on a path to complete implementation of most of the Council's Program during the next ten years. This is an essential first step in meeting the Council's rebuilding goals for salmon and steelhead.

An aggressive implementation schedule has the lowest biological risk. There are a number of listed species that are declining; improving habitat is critical for their survival.

Implementing these actions quickly will save money in the long run. The costs of acquiring land or easements for riparian habitat are going up very fast in Eastern Washington.

Implementing the subbasin plans will also provide thousand of jobs in rural and tribal communities in eastern Washington and Oregon and in Idaho and Montana. This is an important issue for us.

In recent years, unemployment on our reservation was about 70 percent outside of the fishing season. We have worked very hard to bring that down to about 40 percent. Providing jobs to restore habitat and rebuilding our tribal fishery are really important to the Yakama Nation.

We are also ratepayers. We are in the process of forming Yakama Power—a tribal utility that will buy power from BPA. We calculate that the increased costs of implementing the Program and ESA represents about $1 per month for the average residential consumer served by utilities that buy <u>all</u> of their power from BPA. The costs would be more for Yakama Forest Enterprise, our casino, and Yakama Juice and other tribal enterprises.

The impacts on customers served by utilities that don't buy all of their power from BPA would be smaller. It is important to balance these costs with the benefits to rural and tribal communities from implementing the habitat restoration plans.

I would also note that under BPA's low and medium alternatives, it would take more than 100 years to implement the subbasin plans and other parts of the Council's Program. This is unacceptable to the Yakama Nation—it would mean the extinction of a number of salmon runs.

Under BPA's high case, at $174 million per year, it would take more than forty years to implement the subbasin plans and other measures in the Council Program. This is also unacceptable.

BPA says that it is looking for clear objectives. You already have one.

The Council set a goal in the 2000 Columbia River Basin Fish and Wildlife Program to rebuild salmon and steelhead to five million fish returning above Bonneville Dam by 2025.

The current runs are less than 2.5 million fish—about the same levels as when the Council originally set its goal in 1987.

Under BPA's high case, you won't implement the Council's current subbasin plans until 2045! You will not come close to meeting the Council goal.

We are here to ask BPA to do two things:

First, incorporate the cost estimates developed by the Columbia Basin Fish and Wildlife Authority into the next rate case. These are the best estimates available. Fish and wildlife managers have asked BPA and the utilities for comments on our report for months. We were looking for any better assumptions about costs and schedules. To date, we have received nothing from BPA, the utilities, or the Council.

Second, BPA needs to address the fact that there are a number of events that could significantly increase fish and wildlife funding.

For example, the current lawsuit against the FCRPS biological opinion could result in higher costs.

CBFWA assumed that other Federal agencies will fund habitat restoration on federal land. Given the tight federal budget, these costs could fall on BPA.

The BPA and Council have assumed that monitoring and evaluation costs will decrease. These assumptions are untested and the ESA may require more monitoring.

NOAA fisheries Service has said recently that the recovery plans under the ESA may go well beyond the actions called for in the subbasin plans in the Council's Program. This would add to costs.

When the currently favorable ocean conditions deteriorate, BPA may be called upon to fund additional activities to address weak-stock survival or productivity.

The costs for hatchery reforms are not addressed in the BPA estimates.

None of the estimates adequately address the effects of inflation. The fish and wildlife program has been flat funded for the last four year.

During the last rate case, BPA promised the Yakama Nation that it would increase its rates if necessary to meet fish and wildlife costs. What BPA actually did was reduce fish and wildlife costs over the five year rate period and eliminated spill and flow protections in 2001.

We need an effective cost recovery mechanism that will ensure that BPA makes adequate progress in meeting the Council's goal to double the runs by 2025.

The Yakama Nation wants to work with other fish and wildlife managers, the Council, and BPA to resolve these issues in the region. However, if BPA goes forward with its current alternatives, we will have no alternative but to nationalize the issue.

PFR - 026

APR 27 2005

BPA Power Function Review
Spokane, WA
April 26, 2005

Inland Power & Light Co.
Comments

I'm Fred Rettenmund from Inland Power & Light Co.

Thank you for holding a PFR session here in Spokane. We do appreciate the effort involved to travel here and conduct this important meeting re BPA's future power costs.

Kris Mikkelsen, Inland's CEO, had planned on attending tonight, but she needed to go to Seattle so was unable to attend this evening.

Background

- Inland is a full reqts customer of BPA and is currently served under a Pre-Subscription contract. In the 2007-2009 rate period, Inland will be operating under its Subscription contract with BPA.

- Inland serves approx. 34,000 retail customers in rural eastern Washington, and North Idaho. Over 90% of Inland's members are residential, with some commercial and irrigation customers as well.

- Of Inland's total cost of business, some 53% relates to purchases from BPA and this % may increase to above 60% in 2006. Clearly, at over 50% of Inland's total costs, BPA costs are a very important factor to Inland and its members.

- Of Inland's total cost of business, 2 of the top 5 program cost categories that determine retail rates, are for individual BPA program costs – Fish and Wildlife ($3.2m/year, approx 10% of Inland's total costs) and Transmission ($2.7m/year, 8.5%).

General

- As indicated, Inland is currently a pre-subscription contract holder. Inland's signed a collared/fixed rate contract and therefore Inland's current average power cost from BPA is approx 22 mills/kwh.

- While Inland has benefited significantly from the risk it took when it signed the pre sub contract, any BPA rate level for the 2007-09 rate period on the order of say 30 to 32 mills/kwh or even to the range of 28 mills, will be a very significant increase.

- The rural economy is very fragile and many of Inland's members are on fixed income, so please be sensitive to the impacts of any large wholesale rate increase.
- Many of our members, and others in the region, will have to make very tough choices between paying increased electric bills and other bills, including medical and other expenses.

PFR Specifics

- First, BPA senior management, and its staff , and others, need to be complimented for the high quality of the cost and program information made available through the PFR process. The PFR is by far the most comprehensive and in-depth cost sharing effort BPA has undertaken since it stopped including a revenue requirement component to its rate cases.

- The information is voluminous, but well organized and supported by staff. One of BPA's desired outcomes for the PFR is to have customers see BPA staff as being very responsive to info requests and interested in customers input.

- Thus far, Inland gives BPA high marks regarding these items.

- PFR is not the end all for cost control mechanisms, but it could be an important part of a multi part effort to more effectively manage and control BPA's costs, while also achieving BPA's varied objectives.

- Inland will be incorporating many of its PFR comments into those of the NRU. Nonetheless, here are a few comments to share this evening.

Conservation

Inland will be submitting its own, separate written comments by the end of this week on BPA's conservation proposal. A few comments include:

- We support the general structure of conservation program with a rate credit, bi-lateral and other program components. Utilities need the structural flexibility BPA seems to be proposing.

- Given Inland's high proportion of residential load, the nature of the housing stock and other factors, we are quite concerned about the limited number of measures being proposed for Inland in the BPA programs.

- We are very uncertain that there will be sufficient conservation measures of the necessary type for Inland to actively participate.

- Conservation can be a very positive resource, even though in some cases it can raise the overall rate level.

- An increase in rate level is ok so long as there is an opportunity to actively achieve conservation in a utilities service territory. If there is not such an opportunity, wholesale power and retail rates could go up without the corresponding measures to reduce consumption and lower the electric bill -- the 'non –participation' problem.

- The 'decrementing' issue did not generate the fully informed discussion, with an in depth issue paper, that this important topics warrants. BPA is encouraged to prepare such a paper.

Renewables

- Inland's is supportive of the general direction BPA is taking regarding renewables --more of a facilitating and support role. If and when BPA needs additional resources to meet load obligations, and respond to utility requests, renewables should be evaluated for cost effectiveness, reliability, risk and other factors.

- We urge BPA to do everything it can to terminate and not include the $30 to $40 million in rates for the Four Mile Hill geothermal project. Such project seems prohibitively expensive, and the developer does not seem to have satisfied various performance requirements.

Fish and Wildlife

- Inland fully supports the use of ratepayer monies to undertake cost effective F&W efforts that are largely focused on 'on the ground' projects producing real benefits for F&W.

- Fortunately, many fish stocks seem to be rebounding, but the fish program itself has reached an unacceptably high level of cost.

- Inland is quite concerned with the overall level of the F&W program --$692 million/year before offsets -- and the need for greater accountability and efficiency in operating the F&W program.

- Fundamental changes are needed in the control and management of this vast, complex, multi agency effort. There needs to be a greatly increased emphasis on results, not dollars spent.

- We compliment BPA on recent F&W management changes that should bring much of the needed attention to cost control and achieving F&W objectives with fewer dollars. But the challenge is huge!

- We encourage BPA senior management to take a large and active role in all efforts and programs which have F&W costs that go into the BPA costs and rates, including those programs where BPA is not the decision maker.

- Columbia River Fish Mitigation (CRFM) program, involving the large scale retro fit of many of the federal hydro projects, and an investment of around $1 billion to date, and at least another $700+ million, not counting interest, is an area where improvements appear possible and costs reduced.

    - Improvements in the timing of the plant in service dates for capital projects.

    - Careful, broad based assessment including an independent scientific review, of the basis for proceeding with all CRFM projects.

    - We were surprised to read in a April 2004 report from the Independent Scientific Review Panel (ISRP) that "...(CRFM) process does not have clear decision points where ISRP review can provide value to the scientific quality of proposed studies and inform project selection and funding." At a capital investment of approx $2 billion, and over $300 million for studies, the CRFM warrants careful and independent review, including review by utility customers.

- The whole area of Research, Monitoring and Evaluation (RM&E) is long overdue for change and streamlining. While RM&E is clearly needed, millions of ratepayer dollars are being spent each year in a largely uncoordinated, duplicative and ineffective manner. Glad to see BPA management beginning to emphasis the need for substantial improvements in this area.

- We believe there are opportunities to benchmark the efficiency of various hatchery operations, including benchmarking by groups of similar types of hatcheries, and benchmarking by input factors.

- The subject area of capitalization and the depreciation and amortization practices regarding F&W investments needs a fresh look. For instance, the vastly different depreciation periods used for some fish hatcheries compared to short depreciation periods (and more costly) for other fish hatcheries seems inappropriate and in need of change.

- There are opportunities to improve fish populations without needlessly spilling water at hydro projects.

- BPA should not include the cost of foregone revenues from the Snake River Fall Chinook Transport vs. In River Migration Study, In PFR fish packet, I believe there is an estimate that this unnecessary test while reduce July and August hydro production by over 400amw in each month and cost about $23 million/year. Numerous studies have shown that transportation works. Don't need to waste any ratepayer dollars on this test.

Risk

- Inland has some appreciation for the various risks associated with the BPA system. We will work thru NRU to provide BPA with input on this complex topic over the coming months.

- We would like to indicate on a preliminary basis, however, that we do not favor approaches wherein BPA would establish a very high base rate to cover all likely risk contingencies (i.e. BP) holds all the monies to cover risk)

- While it is early yet in the process to assess options, Inland is leaning towards favoring an approach that balances the initial level of BPA's rate, and cost of risk included therein, with the use of a tightly constructed adjustment clause for the variability of snow pack/runoff and market prices for secondary energy.

- We look forward to discussions on the critically important topic of risk.

Conclusion

- Thanks a lot for the opportunity to provide this input to BPA this evening.

- BPA has long been a key partner of Inland's in delivering affordable, environmentally sound and reliable electric energy to our consumers.

- **We want to work constructively with BPA to achieve future successes.**

PFR-027

APR 27 2005

Benton PUD Comments on 2005 Power Function Review
Randy Gregg – Director of Power Management
April 26, 2005

Introduction

BPA's current PF rate is $31/MWh. The Joint Customers are united on a $27/MWh maximum PF rate including risk. Rate reduction is crucial to economic health of the region.

Conditional budgeting should be utilized. Set rates based on absolute minimum levels of program costs. Fund additional projects out of cost savings or non-firm sales improvements.

Conservation and Renewables (-31m)

Naturally occurring and utility sponsored conservation must count toward BPA's goal and reduce BPA's budgets.

BCPD continues to question the reasonableness of the Council's targets. BPA should back away from a firm commitment to capture its share of the Council's targets.

Terminate the geothermal project.

Internal Operations (-27m)

Roll back non-IT corporate spending to 2001 levels (as the business lines have done) except for security and Industry Restructuring. Manage inflation to 2% per year for FY 07-09. This would result in a $20m overall reduction and $10m reduction in the PFR.

Reduce corporate IT 25% from the FY 05 levels through the EPIP initiative. This would result in an $11m reduction in the PFR.

Base PBL internal costs on the FY 05 start of year forecast and two percent inflation going forward. This would result in a $3.3m reduction in the PFR.

Reduce the allocation of Industry Restructuring costs from 40% to 10% to better reflect the value PBL receives from these efforts. This would result in a $1.3m reduction in the PFR.

Reduce Technology Confirmation/Innovation to $1.5/yr. Approve projects beyond this amount only if PBL finances improve. This results in a $1.3m reduction to the PFR.

Debt Service (estimate -50m)

Develop and present a sustainable capital program to customers.

Amortize Con Aug over its useful life.

Amortize the Integrated Program capital costs over their useful lives.

Debt finance the ENW capital and fuel costs.

Include interest income on cash balances in the Bonneville Fund.

CGS (-36.4m)

Incorporate the $36.4m reduction to the PFR based on the ENW presentations.

Continue to pursue operating license renewal.

Corps/Bureau

Aggressively look for ways to reduce the capital expenditures on the CRFM.

Fish & Wildlife (-22 to -57)

Include in the PFR the O&M only case for the LS hatcheries and the low case for the integrated program. Use conditional budgeting to fund initiatives beyond these levels based on customer review. This would result in a $15m reduction in the PFR.

Adopt scenario B for CRFM transfers to plant in service. This would result in a $7m reduction to the PFR. Seek to reduce the overall need for funding for this project.

BPA should aggressively seek to delay or end the transport vs in river migration study. This would reduce costs by $20m to $35m depending on market prices. BPA should continue to press for modifications to operations that result in increased secondary sales such as spill reductions during periods when fish are not in the river. The savings from these operational improvements could be shared between customers and new fish projects.

Risk

It is recognized that risk mitigation will not be decided in the PFR but in the rate case. Large Planned Net Revenues for Risk (PNRR) are unacceptable for mitigating risk. $27/MWh is the target. The above recommendations would reduce the PFR by between $166m and $200m, which should get the base rate at or below $27/MWh allowing a small amount for PNRR.

BPA should separately view the risk of increases in program cost from hydro volume/market price risk.

Program cost risk: BPA should set rates based on the PFR for program costs. Any risk from increase in program costs in one area should be offset by cost cuts in other areas within the rate period. If actual costs for a FY are lower than the budgets set in the PFR, then BPA should engage customers to determine which projects deferred in conditional budgeting should now be funded.

Hydro volume/market price risk: BPA should take the following actions to mitigate these risks in FY 07:

- Cut costs between now and 9/06 to build reserves
- Delay increasing liquidity reserve to $100m until after 10/07
- Count all agency reserves toward TPP until after 10/07
- Leave TPP at 80% until after 10/07
- Secure a line of credit for FY 07. If treasury payment is in jeopardy due to hydro volume/market price use the line of credit, then pay it off with the following CRAC mechanism.

Implement a CRAC that could trigger at the start of FY 08 and FY 09, each of one year duration. The CRAC would be similar to the FBCRAC and would be based on the difference between final rate case levels and audited actuals of the algebraic sum of the following:

- Secondary sales
- 4(h)(10)(c) credits
- Secondary purchases (not augmentation purchases)
- IOU benefits
- Transmission for secondary sales and purchases

Bills going out in January for December would contain CRAC amounts for October, November, and December. If the CRAC calculation shows a surplus, BPA should engage its customers and constituents to determine what projects (if any, decision could be made to leave it in reserves to offset the next years CRAC) deferred under conditional budgeting should be funded.