PFR-085

MAY 24 2005

From City of Seattle

May 20, 2005

Paul E. Norman, Senior Vice President
Power Business Line
Bonneville Power Administration
PO Box 14428
Portland OR 97293-4428

Regarding: Power Function Review and Conservation and Renewable Programs

Dear Paul:

Thank you for the opportunity to participate in the Power Function Review to advise you on the revenue requirement for BPA's 2007-09 power rates. This was an important effort both for Bonneville and its partner agencies to explain the challenges you face, and for your customers to bring forward creative suggestions for lowering your costs. The large rate increases of the last few years make it more important than ever for us to work together on this. I want to thank the BPA, Energy Northwest, Corps of Engineers and Bureau of Reclamation staff who provided such good information, and were responsive to questions and suggestions. In particular Michelle Manary did a superb job running the process. This cooperative spirit will help foster better understanding and working relationships with your customers.

Naturally, customers will press for the lowest possible costs. In your draft closeout letter, I appreciate that you have accepted several suggestions, and remain open to some others. Most importantly you have said that the work of controlling costs is not finished, but ongoing. Seattle has worked closely with others in the Joint Customer group whose comments sent from the Public Power Council we support generally. In this letter I want to highlight some remaining items to which I hope you will further consideration.

<u>Conservation and Renewables</u>
Most of the power revenue requirement pays for the current costs of generating power, but these two items invest in a better future for the region. In addition to the Power Function Review, you have convened work groups to review these programs. BPA has tried to put these good programs on a sustainable basis. The customers have tried to keep local flexibility. I urge you to strike a balance that builds on the current success and keeps customer participation high.

Like the Conservation Work Group and the Northwest Power and Conservation Council, Seattle is concerned that you have cut this part of your revenue requirement too much.

Please consider restoring the $5 million cut in conservation funding proposed in your draft closeout letter. This funding is necessary to ensure you can achieve the regional goals for cost-effective conservation, especially in bilateral efforts. It could also fund worthy new initiatives like irrigation efficiency that can save both energy and water, and the energy saved in peak-shaving "non-wires" solutions being sought by the Transmission Business Line to relieve congestion.

In the re-design of the Conservation and Renewables Discount, Seattle shares the preference of other customers for keeping the current flexibility between these components instead of separating them into two discounts. A few years ago, BPA asked generating utilities to help share in the cost of the Northwest Energy Efficiency Alliance for market transformation. Seattle agreed to do so, and such funding support should continue to qualify for the discount. Similarly, Seattle made a major purchase in the Stateline Wind Energy Station, enough to meet our net load growth this entire decade. BPA should not penalize customers who made such large purchases by requiring additional "new" renewable purchases to qualify for the full discount.

Seattle appreciates that BPA is re-considering its amortization of Conservation Augmentation costs. Clearly, recovering all these costs in rates though 2011 is not appropriate. But an arbitrary five year amortization period also put conservation on an unequal footing with other resources. BPA should recover such costs over their useful lives, such as the 20 year amortization period Seattle uses. Since a portion of BPA's federal borrowing authority is reserved for conservation investments, this should not impair your ability to finance other capital infrastructure.

Internal Costs

Seattle applauds BPA's commitment to holding your internal costs at the 2001 actual level. Both the Power and Transmission Business Lines have done a good job on this, and the $8 million per year cut to Corporate costs charged to power proposed in your draft closeout letter should achieve this. But we encourage you to continue pursuing more reductions in overhead costs, such as your Enterprise Process Improvement Project.

Corps and Bureau Costs

The federal Columbia River Power System is a great resource for the region, and we appreciate the need to maintain and invest in it. In the last decade the region was not investing enough in it, and unit availability and forced outage rates worsened. To preserve this resource, Seattle supports the nearly $400 million of capital investments proposed for 2007-09 ($287 million of reliability investments and $104 million for generator efficiency). However operating and maintenance costs need further scrutiny. In this rate period, BPA added $50 million per year to this funding (a 35 percent increase) and the performance has improved. However, the proposed $44 million per year additional increase has not been justified, and we urge you to look further at reducing it. In addition to trimming this increase, the proposed $8 million of extraordinary maintenance should be funded only in years BPA finances are healthy.

Conditional Budgeting
BPA should give more consideration to this suggestion. The toughest challenge in setting power rates is how to ensure Treasury payment with such natural volatility in hydro production. In dry years, before raising rates BPA should creatively pursue additional spending cuts and deferrals. Corps of Engineers extraordinary maintenance and technological innovation spending should be funded only in good financial times.

Transmission Expense
The program spending for transmission should be budgeted at the lowest level, and any additional transmission costs incurred for higher water conditions should be a deduction to the full array of surplus sales under all water conditions. These are not base program costs, but really a reduction to incremental revenues. In dry years, this spending authority should not be available, and in very wet years, would not be enough sufficient. The statement in the draft closeout letter on this subject is unpersuasive, especially since BPA is actively considering assuming less than average water in setting rates. Similarly, stating that the properly funding this item might add to Planned Net Revenues for Risk (PNRR) simply indicates that padding lines items is a hidden form of PNRR.

Debt Management
Seattle supports the proposed capitalization of Energy Northwest capital investments, Columbia River Fish Mitigation amortization and interest income assumptions in the draft closeout letter.

Risk Mitigation
Seattle will be buying 260 aMW of Block during 2007-11, so the risk mitigation components of your non-Slice rates are important to us. We are open to BPA options to assume less surplus revenues in base rates if we can have confidence in a rebate mechanism. Some rate adjustment mechanisms may also be appropriate for costs outside BPA's control. One of the best risk mitigation strategies for BPA is the Slice product which transfers the hydro and price volatility to Slice customers. We urge you to keep this product viable, so that customers will be willing to take those risks.

Thank you again for this opportunity to provide input on BPA spending levels. If you have any questions about this letter, please contact Kevin Clark of my staff at 206-684-7571.

Sincerely,

Jorge Carrasco, Superintendent

UEC UMATILLA ELECTRIC COOPERATIVE

PFR-086
MAY 24 2005

May 20, 2005

VIA: Facsimile (503)230-5026/230-5211

Stephen J. Wright
Administrator and Chief Executive Officer
Bonneville Power Administration
PO Box 3621
Portland, OR 97208-3621

Dear Steve:

Please accept my thanks to Paul Norman and other BPA employees for their detailed information gathering and responsiveness to questions and concerns. The Power Function Review approach of having technical, public and policy level discussions is a good approach. All of the various levels were discussions with, not direction to, the agency. As a result, the people who provide BPA the money it plans to spend are not satisfied with BPA's rationale for its proposed budgets.

The six points you mentioned in the letter of May 2nd as some of the reasons for BPA rates remaining much higher than pre-2002, leave out the over-arching reason. The over arching reason for higher than needed BPA rates is:

> "... Benefits for all customer and constituent groups..." This philosophy also contributed to BPA decision making in response to the deregulation debacle of 2000-2001, which resulted in undesirable outcomes.

This philosophy causes BPA to fund many nonessential efforts of "constituent groups".

We were unable to obtain enough detailed information to adequately respond to the referenced approximately 3,000 aMW of Public Power load growth. About 800/aMW returned to BPA from market in 2001 and it's very difficult to imagine that Public Power's load has doubled in ten years. In fact, contracted for resources are about 800 aMW more than in 1998 for a total of 1744 aMW for 2004. Is the BPA buy-back of its energy from IOU's included in this number?

Public Power load growth is claimed to be three times the energy sold to the IOU's then bought back and about twice the energy once sold to the DSI's. So, it appears that energy

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that was once sold to the DSI's and the IOU's is now being sold to Public Power. If this is correct, then Public Power load growth is much less an issue than fish and wildlife, the IOU settlement, the increasing BPA debt, or de-rating the FBS.

BPA has the hydro resources necessary to meet firm load during critical water and total resources to meet firm load at much less than critical water. BPA seems to believe that success is for its rates to be 30% under market, a market at least 50% thermal power plants. BPA should be at least 50% under market since nearly 80% of its firm energy supply is hydro power. (Compare BPA's rates to the mid-Columbia PUD's whose rates are 50% or more lower than BPA).

In conclusion, it is our belief that BPA's seeding many Pacific Northwest "constituents group" with dollars and comparing BPA rates to market instead of the cost of production – is what is keeping BPA rates 20% higher than they should be.

Please change BPA's propensity to fund non-power supply programs and reduce the overheads added to hydro generation costs.

Thank you.

Sincerely,

Steve

M. Steven Eldrige
General Manager and CEO

MSE/dkt

MASON COUNTY
PUD
PUBLIC UTILITY DISTRICT

COMMISSIONERS
LINDA R. GOTT
BRUCE E. JORGENSON
JOHN H. WHALEN
MANAGER
WYLA J. WOOD

PFR-087
MAY 24 2005

May 20, 2005

SENT BY FACSIMILE & REGULAR MAIL

Mr. Paul Norman
Senior Vice President, Power Business Line
Bonneville Power Administration
P. O. Box 14428
Portland, Oregon 97293-4428

Re: BPA's Power Function Review Process

Dear Paul:

First of all, I would like to thank you and all the Bonneville staff who put in so much time and effort into the PFR process. It was obvious to all of us that a lot of thought and planning went into the process. BPA is to be commended for being willing to lay out its affairs to such an extent and expose itself to this public process.

Mason County PUD No. 3 supports the comments made by PPC and WPAG. In addition, I would like to make some general comments about the process and several observations.

As a manager with many complex and pressing issues to deal with back home, it was difficult for me to absorb and comment on the large volume of technical information provided to us within the time frame of the PFR meetings. In spite of that, this set of meetings has had a lot of value and I hope that Bonneville will make this a first step in developing an ongoing process to address various issues and work on developing consensus in the region.

BPA and its public customers are connected in a very special and unique way. I believe it is in both of our interests to work on forming a more interactive and cooperative relationship. I for one would really like to be able to tell the delegation on my next trip to Washington, D.C. that BPA has been responsive and the region is working though the very difficult issues that face it.

During the PFR meetings I heard several things that caused me concern and make defense of BPA more difficult. One was concerning some studies on the lower Snake dams. When the comment was offered that the studies were not going to give good, usable information because of a change in the operation of

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the dams, the response from BPA staff was, "The decision has already been made." This intransigent holding to a decision when conditions have changed and value received is questionable is an example of just the kind of thing that the public holds against perceived bureaucracies and government agencies. I really would expect that BPA management would exercise strategic control over this type of expenditure that has doubtful benefits. I have concerns that other similar situations exist of which we are not aware.

Another issue that I found bothersome was the admission that secondary revenues are not tracked. While I recognize that individual electrons cannot be classified, other utilities seem to accomplish this feat without problems. Especially when BPA uses the amount of secondary revenues as justification for various actions, the lack of good tracking again damages the credibility of the agency.

I would like to join the comments of WPAG and PPC to emphasize that corporate costs be brought under control. Our utility has absorbed the loss of eight positions since 2001 and presently operates with 114 employees. This reduction has affected our operation in that some tasks take longer or don't get done at all, work has to be prioritized and evaluated for its true value and each employee has had to recognize that belt tightening is the order of the day. I would really like to fill all those positions but our customers are expecting that we reduce our expenses before we look to them for additional revenue. It is no different with BPA. Your customers expect that you will do the same as they have done.

Again, the Power Function Review is a great step in the right direction. We, at Mason PUD 3, pledge to work with BPA to develop a beneficial working relationship and look forward to receiving confirmation of the adoption of many of our recommendations.

Thank you.

Sincerely,

Wyla J. Wood
Manager

c: Mason County PUD No. 3 Board of Commissioners

PFR - 088

CHRISTINE O. GREGOIRE
Governor

STATE OF WASHINGTON

OFFICE OF THE GOVERNOR

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RECEIVED BY BPA ADMINISTRATOR'S OFC-LOG #: 05-0060
RECEIPT DATE: 4.20.05
DUE DATE: APP ACTION

April 13, 2005

APP ACTION: DR-7C
cc: FO3, DC/Wash, DR-7, L-7, P-6, PF-6, PL-6, Cindy Custer-DR/WSGL, Rob Swedo-DR/Spok

The Honorable George Bush
President of the United States
The White House
1600 Pennsylvania Avenue
Washington, D.C. 20500

Dear President Bush:

I write to oppose two provisions included in your fiscal year 2006 budget pertaining to the Bonneville Power Administration (BPA). I understand that the Senate has taken steps to ensure these provisions are not enacted. At this time, I would ask that they be withdrawn by your administration.

First, the proposal to require BPA to dramatically increase its electricity rates from cost-based to market rates over time is unjustified, ill-advised, and would have serious harmful consequences for the Pacific Northwest's citizens and economy. Respectfully, a reliance on the argument that BPA's electricity rates are artificially low and subsidized by the nation's taxpayers is inaccurate. All of BPA's loans from the Federal Treasury are at market and above-market rates. BPA's pre-1974 appropriated debt was refinanced almost a decade ago at market rates, and BPA agreed to pay the Treasury a $100 million refinancing fee to complete the transaction. Moreover, BPA consistently has made its Treasury payments on time, even making substantial prepayments in recent years. Requiring BPA to transition to market rates would, in fact, be a reverse subsidy – the region's electricity ratepayers would be repaying the Federal Treasury at a rate of return greater than it could negotiate in the marketplace.

I also am troubled by the other budget proposal that would limit BPA's ability to borrow money to make critical investments in its system. The proposal to count non-federal, third party debt toward BPA's borrowing cap unduly punishes BPA for seeking partners to address our region's needs for an adequate and reliable electric system. Given the importance of the BPA system to our region, any diminution of its access to capital is a direct threat to the health of infrastructure essential to our well-being. As the events of the eastern blackout of August 14, 2003, demonstrated, the costs of failure upon our citizens' health and welfare are severe, and it is critical that we continue to make necessary, wise investments in the system.

I urge you to reconsider these budget provisions. My state has worked diligently to overcome the serious economic hardship imposed by the western energy crisis of 2000-2001. Manipulation of western energy markets by Enron and others took billions of dollars from the regional economy – money that, despite our constant and ongoing efforts before the Federal Energy Regulatory Commission and the courts, we have been unable to recover. Implementation of your proposal to move BPA rates to market would effectively replicate the harm imposed by Enron. Such a result would be devastating to regional economic health and ultimately counter-productive to your administration's attempts to stimulate the economy.

Sincerely,

Christine Gregoire

Christine O. Gregoire
Governor

cc: Washington Congressional Delegation
Steve Wright, Bonneville Power Administration

PFR - 089

Oregon

Theodore R. Kulongoski, Governor

RECEIVED BY BPA
ADMINISTRATOR'S
OFC-LOG #: 05 · 0076
RECEIPT DATE:
5 · 20 · 05
DUE DATE:
6 · 3 · 05

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May 18, 2005

Steve Wright, Administrator
Bonneville Power Administration
PO Box 3621
Portland, OR 97208-3621

ASSIGN: DR-7C
cc: FO3, DC/Wash, DR-7, L-7, P-6, PT-5, PN-1,
Anne Morrow-DR-7C

Dear Steve:

Re: BPA's 2007-2008 Renewable Energy Budget

This letter is to urge BPA to fully fund renewable energy development in the next two federal fiscal years. Governor Kulongoski has adopted a Renewable Energy Action Plan for the State of Oregon with specific goals for renewable electricity generation: 10 percent of Oregon's total electric energy in 2015 growing to 25 percent renewable energy by the year 2025.

BPA, as the main supplier of Oregon's consumer-owned utilities, has a key role to play in order for these targets to be met. The growth necessary to reach these goals does not happen instantly but requires a steady policy that promotes renewables throughout this period. Steady progress in meeting these targets is also necessary to avoid costly new fossil fueled power plants which the Northwest Power and Conservation Council's Plan indicates will be necessary next decade if renewable energy resources are not available.

I strongly recommend that you adopt a budget in FY 2007 and FY 2008 to fully fund the actions necessary to help achieve these renewable energy targets. For example, BPA's budget should be sufficient to fund grants to reduce upfront costs for renewable energy projects; BPA should also help fund the upgrade of distribution facilities to make more renewable energy projects possible.

Investments in renewable energy now will avoid the high economic and environmental costs that undue reliance on new fossil fuel plants will cause. The best way to assure that BPA's rates remain as low as possible over the long term is to avoid the need for new fossil-fueled plants by investing in renewable energy.

Thank you for your ongoing commitment to developing renewable energy.

Sincerely,

Michael W. Grainey

Michael Grainey,
Director

PFR - 090

MAY 20 2005

Bonneville Power Administration
Power Function Review Technical Workshop
May 9, 2005

BPA Rates Hearing Room, Portland, Oregon
Approximate Attendance: 20

Draft Closeout Letter and Wrap-up

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

Introduction

Michelle Manary (BPA) opened the workshop, noting that it was the last of the technical sessions and an opportunity for wrap-up and Q&A on the draft Power Function Review (PFR) proposal. Staff members from most areas in the PBL are available today to answer questions, she said. The PFR closeout letter "is very draft" at this point, and your comments are welcome up to May 20, Manary added.

She went on to the table of spending levels. I have added a column entitled "Could be Updated for Rate Case," Manary pointed out. In addition to updates prior to the rate case, we could make changes as a result of recommendations made during the PFR comment period, she clarified.

Linc Wolverton (ICNU) asked if treatment of the period for amortizing capital outlays would be open for discussion in the rate case. Manary said that it would.

She started through the PFR decision areas on the table, noting that in the closeout letter, BPA proposed to remove $11 million associated with the Calpine geothermal project from the forecast of renewables costs in 2007 and 2008. The "maybe" indicates the forecast could be updated for the rate case if the ongoing arbitration on Calpine comes to a conclusion in time, Manary explained.

The budget figures in both renewables decision areas – Calpine and facilitation – are subject to change before the rate case, according to Deb Malin (BPA). The future of the Calpine plant is uncertain due to arbitration, and figures for facilitation are not yet nailed down, she said. We are working with a focus group and discussing things we could do to facilitate customer development of renewables, Malin explained. The $11 million forecast for the Calpine project is based on what the project costs "at $4 gas," she said. We are proposing to use part, but not all, of the $11 million for facilitation, Malin said.

If the Calpine project goes away entirely, would you provide $11 million for other renewables? Annick Chalier (PPC) asked. We will likely know about the outcome of the Calpine arbitration before the rate case begins, Malin responded. If the plant is terminated, that's something we would consider, she added.

Manary continued through the list of PFR decision areas and proposed reductions and increases. These budget numbers are the deltas from the initial PFR forecast, she clarified. The final numbers for the Enterprise Process Improvement Project (EPIP) will be out between the initial and final rate case proposals, Manary said. In the initial proposal, we will reflect an $8 million reduction as a result of EPIP, which we'll update later, she indicated.

When we update forecasts for the initial rate proposal and make changes in the budget numbers, would you want to meet again? Manary asked. Some of these changes are really important because 2007 is such a financial problem, Geoff Carr (NRU) answered. It would be valuable to bring it all together, he said. It would be nice to have an update every couple of months, Wolverton agreed. How about a session around September, the time of the initial rate proposal, and another in a couple of months? he suggested.

Manary pointed out that the "maybe" with regard to the Columbia Generating Station (CGS) forecast reflects the fact that the Energy Northwest (EN) board has not yet approved the cost-cutting initiatives proposed by EN management. Has EN assured us that if the board approves the budget reductions, they won't come back for more money? Michael Early (Alcoa/CFAC) asked. I'll check on that, Manary replied.

What would cause the funding for WECC/NERC compliance to change? Lon Peters (PGP) asked. We have a program review going with regard to WECC/NERC operating requirements for the Federal Columbia River Power System (FCRPS), Mike Alder (BPA) responded. We will have more certainty about the budget numbers for compliance by June, he said.

Carr asked about the tables on page 16 of the PFR closeout report. The first table compares the PFR base with the PFR base adjusted for debt financing of CGS capital, Manary explained. The second table reflects the concern about rising nuclear fuel prices, she said. The table reflects what would happen with O&M if certain items were capitalized and if fuel prices increase, Manary said.

She explained that the uranium tails processing project is part of the uncertainty surrounding nuclear fuel prices. The price goes up and down, but we should know soon about whether the uranium tails project will proceed, Manary said.

Does the $143 million budget for the integrated fish and wildlife (F&W) program depend on Council approval? Peters asked. Yes, Manary said. Bob Austin (BPA) explained that BPA and the Council are in discussions about a memorandum of agreement (MOA) on F&W costs. The MOA is two part, he said: the first is "the rules of the road" with regard to the F&W spending, and the second part is the budget. We think we are close to an agreement, and we expect to sign an MOA in late spring or early summer, Austin stated.

This figure reflects only BPA's responsibility for F&W, Val Lefler (BPA) said in response to a question about other agency contributions. Why does BPA alone have to spend so much money? Early asked. This budget should not reflect just a Council decision, BPA can also make a decision, he said. I understand that Greg Delwiche is preparing a response to parties that wanted an even larger F&W budget, and one point he intends to make is that the F&W spending is not all the responsibility of the hydro system, Early said. But where are the other agency's contributions? he asked. BPA pays the hydro share of the costs, and we get 4(h)10(c) credits for the non-power portion, Lefler replied. We take a 22.3 percent credit against the F&W expenses when we make our annual Treasury payment, she stated.

Manary went on through the list of decision areas, pointing out that the future of the Spokane settlement is "iffy," and BPA proposes to take those costs out of the 2007-2009 forecast. With regard to the Columbia River Fish Mitigation (CRFM) costs, if the Corps does not come to a decision about moving them to plant-in-service, you can debate their treatment in the rate case, Lefler said. But if the Corps makes a decision, we will include it in the rates, she added.

How can we affect the Corps decision? Carr asked. Can the customers be more involved in that? he inquired. BPA staff said they would look into that question and report back.

What if the Corps makes its decision after the rates are set? Howard Schwartz (WA ETED) asked. By the end of the rate case, we will have set our repayment schedule, Lefler stated. A later decision would not affect the schedule, she indicated.

There are CGS fueling outages in the schedule during the rate period, Pete Peterson (PGE) commented. What if they are longer than expected? he asked. That's a risk, and it could affect the 2007-2009 rate period, Manary responded.

What do we know about the CRFM decision schedule? Mark Thompson (PPC) asked. There is "a sense of urgency" at the Corps about this, but we don't have a schedule, Alder acknowledged.

Most of the "maybes" on the table relate to things that mean giving up any savings, Joe Hoerner (Tacoma) pointed out. Some could go either way, Manary replied. We tried to put our "best case" into the budget, but we will true things up for the rate case, she said.

And there is no chance the $11 million for Calpine would stay in the budget and $5.5 million would also be added to renewables? Doug Brawley (PNGC) asked. No, that won't happen, Malin answered.

It looks like the only "maybe" that could be beneficial for cost reductions is EPIP, Early noted. The $8 million is a goal we are setting for ourselves, Brian Crawford (BPA) responded. We feel comfortable with the $8 million – "we aren't being grossly conservative" either, he said. By the time the final rate proposal comes around, we would have identified savings that are actually related to EPIP work, rather than a forecast, Crawford indicated. The customers came up with a much larger number than $8 million, Hoerner said.

Manary went over the bullets on page 2 of the four-page meeting handout. The first relates to Corps of Engineers and Bureau of Reclamation savings as a result of benchmarking, she said. In the PFR, we heard from other utilities that they had ideas for cost savings and innovations that could benefit the FCRPS, Mike Alder (BPA) elaborated. There are several utilities we could sit down and talk to about costs and see if there are innovations we could incorporate into FCRPS O&M that would lead to efficiencies and savings, he said. We've been talking about getting this done by next April before the final rate case proposal, Alder stated.

Our benchmarking shows that the FCRPS O&M costs, excluding those associated with F&W measures, are lower than for other utilities, he continued. But if there are efficiencies we could gain, we want to sit down and talk about it, Alder said.

With regard to the Corps and Reclamation's "2012 program" and potential staff savings, the agencies have an efficiency program under way, but we don't know what the outcome will be, Alder stated. It's too early to say, but they offer the potential for cuts, he added.

The last bullet refers to the $40 million DSI "placeholder" in the budget, Manary wrapped up. A final number will be based on the DSI Record of Decision, but we wanted to have a budget number even though it will be replaced, she explained.

<u>Participant Comments</u>

If you look at the $80 million in savings you've come up with, it falls into two pieces, Early pointed out: first, there are changes related to financing, and second, there is a correction and actual costs you will not incur, at least not now. Of the second group, the biggest is related to CGS, where EN took an aggressive stance to get costs down, he said. If you add all of the reductions in the second group together, it's about $41 million – only CGS "has done the right thing and cut costs," Early stated. It is hard to believe this is all you could do, he added.

Before the PFR started, "we scrubbed the numbers" and we came in with the tightest budget possible, Manary responded. PFR was not about cost cutting, but about educating you on our costs and asking are they as low as possible, she said. The CGS budget was based on an old number, and it was high when the came into the PFR, Manary said. There was a lot of room to cut, she added.

We are trying to get rates down, yet when I compare the 2007-2009 forecast with the 2002-2006 actuals for the first 11 items on the page 32 table, there is a $194 million increase, Lyn Williams (PGE) pointed out. The purpose of our workshops was to explain what is driving the costs up, Manary replied. It's primarily three things, she said: debt management, Columbia Generating Station, and Corps and Reclamation O&M.

Your costs have only gone down the equivalent of a mill since you started, and we still have to deal with risk, Carr commented. The folks I work for are expecting a rate reduction, he said. The joint customers came up with cost decreases that were much greater than what you have laid out, and ours "weren't slash and burn," Carr said.

Kevin O'Meara (PPC) questioned why BPA is assuming IOU benefits are a big risk, if they are going into the budget at the highest possible level.

You are telling us that the PFR was to demonstrate to customers that these are the budget levels you need to operate, Early said. You rejected the customers' recommendation of conditional budgeting, and you have budgeted at a level that "you are comfortable with" in performing your mission, he said. What we want to know is, what is the minimum you can budget to perform the necessary functions, Early stated.

Has BPA done an analysis of the value of activities "on the margin"? Karin Bulova (Snohomish PUD) asked. In the PFR, we were asking, what is the lowest we can go and still meet our basic obligation, Manary responded. She pointed out that the Corps and Reclamation, for example, have many more projects they want to do on the hydro system, but we have said we won't fund them, she added.

But what is the minimum cost to perform your functions? Early asked. If a utility had to take a five percent reduction in its budget, it would still perform its basic functions, he said. "What is so special about BPA that you can't do that?" Early asked.

This budget is viewed internally as minimal and "bare bones," Manary said. It's what we think we can get by with, she said. BPA managers are not "comfortable" with these numbers, Manary added.

But what if someone said, the rate has to be 26 mills, "now do it"? Wolverton asked. You push against the Corps and Reclamation on costs, but "we don't see you pushing against yourselves," he said. A clear example is renewables, Wolverton stated.

This proposal is still draft, and it could change, Manary responded.

The 2002-2006 capital O&M for the Corps and Reclamation was $110 million, but it's forecast at $28 million higher, Williams pointed out. Why is it higher than the absolute minimum? she asked. Our asset management strategy set out two things, Alder replied: restore the reliability of the FCRPS and increase revenues by $50 million a year. We have not yet restored reliability, he said. We are also pursuing revenue increases as we make improvements, Alder said, adding that there is efficiency to be gained in such projects as the runner replacement at Grand Coulee. And we are gaining efficiency with the Near Real Time Optimizer, he stated.

In response to a question, Manary clarified that risk mitigation would be a rate case decision. Byrne Lovell (BPA) said BPA would propose a 95 percent Treasury Payment Probability in the rate case, "based on guidance from the Administrator." Data and information will be updated at the time of the rate case, he said. The "risk tolerance questions are not up for grabs," but we are open to considering how to address risk, Lovell said. Rate design issues will be addressed in the rate case, and we're open to talking about the approach to risk, he said.

Paul Norman (BPA) joined the meeting and asked for a recap of the discussion.

When you came out with your first PFR numbers, you made a presentation at PNUCC and were apologetic the numbers were so high, Early began. You asked for customers help to get them down, he said. The original numbers would have meant a rate increase, and there was no "political will" to accept a higher rate and the repercussions it would have for the economy, Early said.

Now, with the PFR closeout, you have identified $80 million in cost cuts that fall into two roughly equal pieces Early said. The first $40 million has to do with financing changes and basically things you will be paying later, and the second is made up of a $13 million correction, a $6 million settlement that you don't control, and the "big ticket" item is CGS, he pointed out. The $22 million CGS reduction represents "an aggressive stance" by EN, and a response to customers, who told them to get their costs down, Early said.

At the end of the day, even though you said months ago that the costs were too high, we see no real savings in most areas, he indicated. Yet there is no change in the political will about the acceptability of a rate increase – that hasn't changed, Early added.

And this could go even higher when you add in risk, which could mean another six to eight mills, Carr pointed out. We have not gone far enough in reducing costs, he stated.

This process was about full disclosure of our costs and to have you give us advice about how to manage those costs down, Norman responded. Our costs are $80 million less than when we started, "and that is not trivial," he added. I am motivated to get the costs down – "I have 27 mills written on the whiteboard in my office," Norman said. It's a real target, and if this is not good enough, that's a problem, he added. But we need to know where we can look for opportunities to cut, Norman said.

We will try to "sharpen our pencils" and identify areas, Hoerner said. But we heard that the cost levels are at "bare bones," and so I'm not sure there is room for improvement, he said. "With cost control, you are never done," Norman responded. I don't think we are done, he added. If all you want to tell us is "do better," that's okay, but it would be helpful to have you direct us to particular areas, Norman stated.

That is hard to do from outside the agency, Hoerner replied. "The door is only cracked so far," and we don't see the whole picture, he said. Have we not been forthcoming enough? Norman asked.

The "KEMA kind of thing" is the most helpful to us, Wolverton responded. We're at a disadvantage being on the outside, he said.

You rejected conditional budgeting, and that was the way we hoped you could help us, Bulova stated. It would also help us if you would say, “here are our programs, and if we eliminated *this* part, *this* would be the outcome,” she explained. Or suggest another way you could fulfill the responsibility, Bulova said. We are disappointed that you rejected the suggestion on conditional budgeting, she said. We would ask you to look at it again, inform us of the repercussions of eliminating things or doing them a different way, Bulova urged. That would be a benefit to you and to your customers, she stated.

Are you suggesting that if we look at our programs from that angle, we may see something new? Norman asked. Yes, Bulova responded.

I want to reinforce that you talked about tradeoffs, Early said. We asked you to explain what the consequence to our service would be if you did not do something, he said. But we just got a justification of the expense levels you put out, Early said.

It is hard to have this conversation in the abstract, Norman commented. I hear your point, but it’s a more meaningful conversation if we have it around a specific category of costs, he suggested.

We have not seen yet what would happen if you cut your budget 5 percent or 10 percent, Lon Peters (PGP) stated. “What would not get done or done less well – what would break?” he asked. We don’t know, but your managers do, he said. Without that type of analysis, “I’m flying in the dark,” Peters said.

Brawley pointed out that some of the cost justification is too general to judge. We hear that something can’t be cut because “it would jeopardize your mission,” he said. Maybe your essential services are too much for us to afford, Brawley said. Conservation is one example, he said. We still hear people say that the conservation budget does not need to be so high, Brawley said. Part of the problem is that you decided the Council’s goals were your goals, he added. Maybe customers should do the conservation – maybe it’s not part of your job, Brawley suggested.

There is no good answer, Wolverton commented. Sometimes the best way to approach cutting is to just say, cut 10 percent and see what happens, he stated. That’s why a target makes sense – you set it and figure out how to get there, Wolverton said.

Norman pointed out that he has only $100 million of BPA’s budget on which to affect direct cuts. As for the public purposes, I’m not sure it’s responsible to cut regardless of whether we know the effect, he said.

You almost have to make “a fiat-type decision,” Wolverton responded. There are probably categories that could not take a 10 percent cut, he acknowledged, but we are talking about proposed increases above 2002-2006 levels.

You are asking us to do more work and get more specific, Carr said. The KEMA analysis was the most helpful thing for us, he said. It got to the level of detail needed, Carr stated. We'll do the best we can, but we are up against not knowing what the tradeoffs are, he added.

Where we had that information, we gave it to you, Norman replied. It's hard to know the exact impacts of a 5 percent cut, he said.

To make an informed recommendation, it takes an analysis like the one KEMA did, Hoerner said. The only way we could do that is "to dive in, take up residence here, and act like auditors," he pointed out.

We're trying to give you that type of information, Norman responded. But you are saying we are not doing a good enough job – "that's not what I expected to hear, but I hear it," he said.

When we hear a vague reason like "it would jeopardize reliability," it's not enough detail for us to make a judgment, Williams said. We don't have enough information to know what that means, she said. If we have any information that could help you with efficiency, such as with our hydro operations, we want to sit down and talk about it, Williams added.

"I'm cautiously optimistic" there are things that can change before our final proposal, Norman said. We need to have this conversation – we need to get down to specifics, he said. The Corps and Reclamation feel they are doing a KEMA-type process internally with the 2012 program, and we could get value out of that by the first of next year, Norman added.

It comes down to a value choice, Hoerner said. We saw value, for example, in the Technology Improvement Initiative, he pointed out. It comes down to whether value is being created – we need enough information on that to make informed decisions, Hoerner said.

The frustration we have is that we are facing "a mass of costs" that will be put to bed, and then in the rate case, we will be talking about how much to add for risk, Carr pointed out. I want to get this part as low as possible before we put it to bed, he stated. "We need to make room for risk," according to Carr.

Peters asked whether there is benchmarking going on with hatchery programs. The Council has conducted the Artificial Production Review and Evaluation – it's an area that could be fruitful in the future, according to Bob Austin (BPA).

What would you do if you had to cut costs, if you were above market? Hoerner asked.

We have a lot of fixed costs – it's a somewhat inflexible cost structure, Norman acknowledged.

The meeting adjourned at 3:40 p.m.

BENTON P·U·D

PFR-091
MAY 25 2005

May 19, 2005

Paul Norman
Senior Vice-President, Power Business Line
Bonneville Power Administration
P.O. Box 14428
Portland, OR 97293-4428

Re: **Benton PUD Comments on 2005 Power Function Review (PFR) Close Out Letter**

Dear ~~Mr. Norman~~: Paul

Thank you for the opportunity to comment on the draft PFR close out letter. BPA is to be commended for a well-managed process. However, the District does not view the outcome of the process as a success, as it appears the PF rate will be $27.5/MWh before risk premiums or CRACs are added. The Joint Customers are united on a $27/MWh maximum PF rate, including risk. Rate reduction is crucial to the economic health of the region.

The District also does not consider the PFR process an acceptable model for cost control in the long term. BPA needs to reconsider the proposals discussed by the Joint Customers and BPA staff during the last several months.

Conditional budgeting should be utilized in the areas specifically discussed below. PBL's rates should be based on absolute minimum levels of program costs. Funding for these additional projects should come out of program cost savings or non-firm sales improvements. The District has specific comments on spending levels, as follows:

Conservation and Renewables

Naturally occurring and utility sponsored conservation must count toward BPA's goal and reduce BPA's budgets. We continue to question the reasonableness of the Council's conservation targets. BPA should back away from a firm commitment to capture its share of the Council's targets.

The geothermal project should be terminated and not replaced with facilitation net costs. The District and other Washington PUD's have shown the willingness to invest in renewables through participation in the 63 MW Nine Canyon Wind Project. Many of the participants have integrated the project directly into their systems. Facilitation should only be funded as part of conditional budgeting.

Internal Operations

PBL is to be commended for keeping its share of the internal operations costs at the 2001 level through 2005. PBL needs to continue this discipline. PBL internal costs should be based on the FY 05 start of year forecast and 2% inflation going forward. This would result in a $3.3M annual reduction to the PFR base.

Unlike PBL, corporate costs have increased dramatically since 2001. For example, non-IT total corporate costs (before allocations to the business lines) were $34M in 2001, increased to $54M in 2005, and are projected to be $60M in 2008 (based on slide #31 of the 3/1/2005 workshop).

BPA should institute cost reductions in its non-IT corporate spending to 2001 levels (as PBL internal operations has 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 an associated reduction in the annual allocation to PBL.

In addition, BPA should reduce the allocation of industry restructuring costs to PBL from 40% to 10% to better reflect the value PBL receives from these efforts. This would result in a $1.3M reduction in PBL allocations.

BPA should institute 25% reductions in corporate IT from FY 05 levels through the EPIP initiative. FY 05 IT spending is $58M and a 25% reduction would reduce this to $44M. The FY 08 budget for IT is $68M (slide #31 of the 3/1/05 workshop). This would result in a $24M reduction in total IT spending ($68M minus $44M) and an associated reduction in the allocation to PBL.

Reduce the budget for Technology Confirmation/Innovation to $1.5/yr (increases the base PFR since it was not initially included). Approve projects beyond this amount through conditional budgeting.

Debt Service

BPA must develop and present a sustainable capital program to customers. Conservation Augmentation should be amortized over its useful life. The F&W Integrated Program capital costs should be amortized over their useful lives. The Energy Northwest capital and fuel costs should be debt financed. Interest income on cash balances in the Bonneville Fund should be included in the initial rate proposal.

CGS

BPA should reduce the PFR base by the $22M proposed by Energy Northwest.

Corps/Bureau

BPA and the Corps need to aggressively look for ways to reduce the total capital expenditures on the Columbia River Fish Mitigation (CRFM) capital program. BPA should encourage the Corps/Bureau to seek staffing grade reductions.

Fish & Wildlife

The Integrated Program should be implemented through a zero-based budget, based on biological goals and objectives that have been prioritized to meet BPA's legal mitigation obligations. The measure of success for BPA's fish and wildlife program should be biological effectiveness, not the amount of money spent. BPA cannot justify increasing its Integrated Program without performance standards, and a clear zero-based budget approach. Any amounts spent above the program's nearly $70 million of contractually obligated funding should be carefully evaluated to ensure it will be used for high priority, cost-effective and biologically sound measures. Include in the PFR base the O&M-only case for the Lower Snake hatcheries.

Customers support BPA's proposal to re-prioritize the Integrated Program towards "on the ground" projects. This will increase the pace of implementation of projects that directly benefit fish and wildlife, which is the goal of BPA and the Council's program.

BPA must be a proactive participant in all forums where fish and wildlife costs are incurred by its customers. BPA has a responsibility to ensure that fish and wildlife programs outside of BPA's management (i.e. USACE programs, etc.), but funded through ratepayer dollars, are pursued in the most biologically sound and cost-effective way possible, and that they relate directly to BPA's mitigation responsibility.

Adopt Scenario B for CRFM transfers to plant in service. This would result in a $7M reduction to the PFR base. 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 increase revenues 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 endangered species are not in the river.

Transmission

BPA should only include in the PFR base those transmission costs that are fixed. Any additional costs should be included as an offset to secondary revenues and determined in the rate case.

Other Costs

We agree with BPA's decision to not include the Spokane settlement and Environmental Benefits costs in the PFR base.

Thank you for the opportunity to comment on the PFR close out letter.

Very truly yours,

James W. Sanders
General Manager

JWS/gcb

PFR-092
MAY 25 2005

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Dear Paul:

This is to express Inland Power & Light Co.'s appreciation for the opportunity to participate in BPA's Power Function Review (PFR) process. The staff and management of the Power Business Line, and others, are to be complimented for the hard work and professionalism exhibited throughout the PFR process.

As you know, the level of BPA's power rates and the costs that drive those rates are of critical importance to Inland. Further, we would like you to know we understand the challenge involved in achieving key objectives and responsibilities, while controlling costs, because that type of challenge is one we deal with on an ongoing basis.

The PFR process has been useful in many respects and it has served to more clearly bring into focus the multiple parties and agencies that set policy, manage programs, and incur costs that impact BPA's revenue requirement and rates.

Inland firmly believes, however, that the ultimate accountability to the regions ratepayers for BPA's rates rests with BPA. Accordingly, on an ongoing basis we strongly urge senior BPA management be more engaged and assertive with all those officials and organizations responsible for policy, program and cost decisions impacting BPA rates.

It is our view that too often decisions, or a continuation of past practices, which in total can materially impact BPA rates, are being made without sufficient vetting, exposure to alternatives views, and careful scrutiny by BPA senior management and others. It is important that those making decisions impacting the BPA revenue requirement fully appreciate the need for the highest level of fiscal responsibility, the impact on the region's economic health and accountability to ratepayers.

While the PFR process has been a step in the right direction in terms of FCRPS related entities being made more aware of ratepayer interests, we believe that additional effort in this area is needed. For example, the proposed annual growth rate in 2007-2009 O&M expenditures of the Corps of Engineers, Bureau of Reclamation, and Columbia Generating Station are excessive. We do not believe that either the reliability or security of generating facilities would be lessened by aggressive cost control.

Additionally, the PFR process has demonstrated that the Columbia River Fish Mitigation program is an undertaking of major proportions, likely involving some $2 billion in capital expenditures. It has become clear that this area is not subject to sufficient review by BPA senior management, utility customers, or independent scientific experts.

The challenges are significant in virtually every aspect of the FCRPS, but the cumulative impact of the numerous FCRPS related decisions is too great to warrant anything less than a rigorous and thorough review.

Thank you for consideration of these comments. Inland looks forward to our continuing partnership with BPA.

Sincerely,

Kris Mikkelsen
CEO
Inland Power & Light Co.

CC: Steve Wright
John Saven