Bonneville Power Administration

Power Business Line's
Power Function Review Final Report
June 24, 2005

BONNEVILLE
POWER ADMINISTRATION

Power Function Review Final Report

After a large BPA power rate increase in 2002 and ongoing scrutiny and reduction to many program levels, the level of interest from customers, constituents, and tribes in the costs that go into BPA's power rates is higher than ever. In response, and consistent with BPA's desire to increase the transparency of decisions that affect rates, BPA kicked off the Power Function Review (PFR) in January 2005 to examine the power cost forecasts for fiscal years (FY) 2007-2009 rate period prior to the start of the rate case. Throughout this process, BPA held numerous workshops to share information and listen to participants' ideas and comments on the nine major cost areas addressed in this process.

In May 2005, BPA issued a draft report with proposed program cost levels and solicited feedback on those levels. Participants dedicated many hours to this process, and BPA would like to thank those participants for the commitment and feedback they have provided. This report addresses the comments received and lays out BPA's final decisions in regard to the FY 2007-2009 program expense forecasts that will go into the power rate case initial proposal. As noted in the cover letter that accompanies this report, many of these areas will be revisited when more information is known before the rates are finalized in the summer of 2006. BPA will hold discussions separately from the rate case proceedings to share the updated forecasts and solicit feedback.

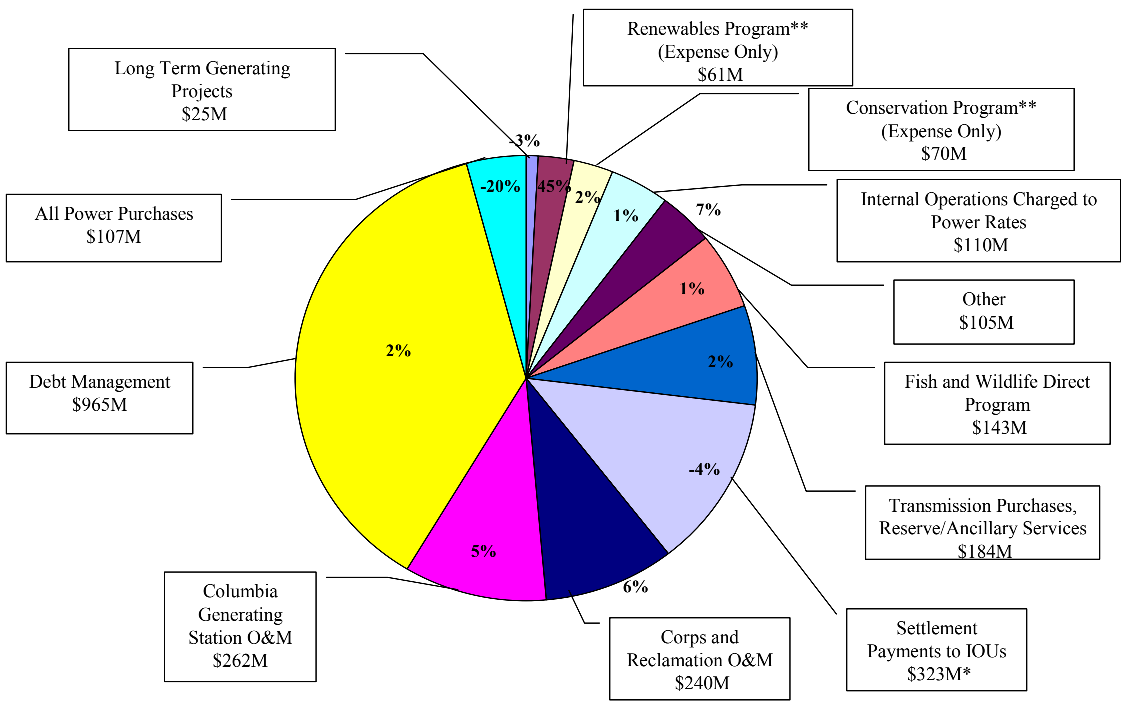
When the PFR began, many participants in the region were surprised to learn that FY 2007-2009 power rates were not expected to drop back to levels seen prior to FY 2002. Even though the total expenses for FY 2007-2009 are lower than in the current rate period, they are not as low as they were in the FY 1997-2001 period for many reasons that were explained throughout the PFR. One main reason is the increase in benefits BPA will provide the region in the FY 2007-2009 relative to the FY 1996-2001 period.

The average growth rates in many of the major program areas in the draft report have not increased significantly but have been fairly steady from the current rate period to the next (see Chart 1). It is also important to note that in the case of Conservation, Renewables and Long-Term Generating Projects, these programs provide offsetting revenues that are not shown so an increase or decrease in their expense forecast does not indicate the ultimate impact they have on power rates.

Chart 1:

FY 2007–2009 Power Expense Forecast

Totals and annual growth rates



*Total includes 900 aMW of Monetary Benefit ($139 M/yr average), and approximately 618 aMW of load augmentation (BPA power buyback) ($235 M/yr average)

**Does not include revenues from aMWs sold.

In response to the comments received on the draft report, BPA has made some modifications to its May 2 report for FY 2007-2009 expenses. These changes include the following:

- not adopting the proposed reduction to the Conservation Program of $5 million per year;
- revising the Renewables forecast for Calpine;
- updating the wind forecasting methodology; and
- revising slightly the Columbia Generating Station (CGS) forecast to include a change in the decommissioning trust fund contribution.

Many of the forecasts in the draft report were not modified as a result of additional comment, but will be re-evaluated prior to the final power rate proposal in 2006.

In summary, BPA proposed cost reductions totaling $80 million a year in the May PFR draft report. This has increased to $96 million a year in reductions in the final report. However, most of this $16 million additional reduction is due to a revised renewables forecast that also resulted in less energy production. Summary Table 1 provides the change in the expense forecasts from the beginning of the PFR process, the draft report and the final report.

Summary Table 1:

		PFR Base FY 2007-2009 Average Expense	PFR Base FY 2007-2009 Average Capital	PFR Draft Closeout Letter Average Expense	PFR Draft Closeout Letter Average Capital	PFR Final Report Average Expense	PFR Final Report Average Capital	PFR Delta Base to Final Expense	PFR Delta Base to Final Capital
1	Long-Term Generating Projects	$ 25	$ -	$ 25	$ -	$ 25	$ -	$ -	$ -
2	Renewables Program (Expense Only)	$ 56	$ -	$ 61	$ -	$ 42	$ -	$ (13)	$ -
3	Conservation Program (Expense Only)	$ 71	$ 32	$ 70	$ 28	$ 71	$ 32	$ -	$ -
4	Internal Operations Charged to Power Rates	$ 116	$ -	$ 110	$ -	$ 110	$ -	$ (6)	$ -
5	Other	$ 120	$ -	$ 105	$ -	$ 105	$ -	$ (15)	$ -
6	Fish & Wildlife Direct Program (Integrated Program)	$ 139	$ 36	$ 143	$ 36	$ 143	$ 36	$ 4	$ -
7	Transmission Purchases, and Reserve/Ancillary Services	$ 189	$ -	$ 184	$ -	$ 184	$ -	$ (5)	$ -
8	Settlement Payments to Residential & Small Farm Consumers of IOUs 1/	$ 323	$ -	$ 323	$ -	$ 323	$ -	$ -	$ -
9	Corps and Reclamation O&M for Hydro Projects	$ 242	$ 138	$ 240	$ 138	$ 240	$ 138	$ (2)	$ -
10	Columbia Generating Station O&M for Nuclear Plant	$ 284	$ -	$ 262	$ -	$ 263	$ -	$ (21)	$ -
11	Debt Management	$ 1,003	$ -	$ 965	$ -	$ 965	$ -	$ (38)	$ -
12	Power Purchases	$ 107	$ -	$ 107	$ -	$ 107	$ -	$ -	$ -
13	**Total**	**$ 2,674**	**$ 206**	**$ 2,594**	**$ 202**	**$ 2,577**	**$ 206**	**$ (96)**	**$ -**

1/ Total includes 900 aMW of Monetary Benefit ($139 M/yr average), and approximately 618 aMW of load augmentation (BPA power buyback) ($235 M/yr average)

2/ Total includes net impact of CGS capital decision. Final rate case outcome will show a reduction in CGS O&M and an increase in Debt Management.

The rest of this report takes each of the program areas and describes the recommendations made in the draft report, comments received, and any changes between the draft and final report.

TRANSMISSION PROGRAM

	Average Expense	Average Capital
FY 2002-2006 Transmission Purchases, and Reserve/Ancillary Services	$171 M/yr	$0 M/yr
FY 2007-2009 PFR Base Forecast	$189 M/yr	$0 M/yr
FY 2007-2009 Proposed PFR Forecast	$184 M/yr	$0 M/yr
FY 2007-2009 Final PFR Forecast	**$184 M/yr**	**$0 M/yr**

MAY 2 DRAFT REPORT:

The Transmission Acquisition Program represents costs associated with services necessary to deliver energy from resources to markets and loads. These costs include: transmission, ancillary services, real power losses, generation integration costs associated with the U.S. Army Corps of Engineers and Bureau of Reclamation transmission facilities, and metering and communication requirements.

The Transmission and Ancillary Service component represents costs associated with payments to BPA's Transmission Business Line for transmission and ancillary services associated with surplus sales. The goal of the BPA PBL transmission strategy is to determine the least-cost mixture of long-term and short-term transmission products that can meet the needs of PBL's surplus marketing strategy.

Possible Decreases Identified

1. **Proposal: Model the transmission expense associated with secondary energy at the minimum expense across the 3000 secondary energy scenarios rather than the average of 3000 secondary energy scenarios** – This is an issue to be decided in the rate case. BPA's intention is to keep a consistent treatment of secondary sales and transmission costs. Counting transmission costs associated with critical water but crediting rates with sales from average water would understate the expense associated with transmission for the sales from average water. **Draft Conclusion: No change in modeling of transmission expense.**

2. **Proposal: Reduce forecast for Metering/Telemetry/Equipment Replacement** - The metering, communications and TBL Engineering support component represents costs associated with the installation of metering, telemetry, communications equipment & replacements and ongoing charges to meet increasing PBL business requirements for frequency and granularity of meter data. In the PFR forecast there was $1 million per year spending level for equipment associated with forecasted future data needs. We have learned that in the future when this happens TBL will acquire the equipment and capitalize it so there is not a need to forecast for these costs in PBL anymore. There will continue to be ongoing costs associated with communications, which are expected to remain in the PBL expense forecast. Therefore, BPA concludes the Telemetry/Equipment replacement forecast should be reduced from $1 million per year to $200,000 per year. **Draft Conclusion: Remove metering/telemetry costs of $800 thousand per year.**

3. **Proposal: Reduce 3rd Party GTA Wheeling Forecast –** Revise the forecast for 3rd Party GTA Wheeling because when preparing the forecast there was an error in the formula when calculating the costs for the South Idaho OATT. The formula was double counting the expenses twice and then adding the inflation rate. **Draft Conclusion: Include update to reduce forecast by $4 million per year.**

MAY 2 DRAFT REPORT CONTINUED:

BPA Proposals	Proposed PFR Base FY 2007-2009 (Reductions)/Increases
Remove Metering/Telemetry Costs	($0.8 M/year)
Updated 3rd Party GTA Wheeling Forecast	($4 M/year)

Summary of Comments Received on Proposed PFR Forecast

- Hold an open discussion in the rate case process regarding using increased TBL revenues from PBL secondary sales, including but not limited to Treasury repayment.
- Capture the appropriate mix of short and long-term transmission services needed for secondary sales; remain active in TBL forums and verify forecasting used to estimate costs of third-party transmission.
- Think seriously before placing transmission into another agency [like Grid West] where you will not have direct control of costs.
- Lower costs of transmission acquisition - if BPA incurs costs for special generation or load requirements, specific costs should be borne by that customer or generator.
- Budget transmission spending at the lowest level. Additional costs for secondary energy should be a deduction to surplus sales.

Final Report Decisions

One issue raised was that of modeling transmission expenses associated with the full distribution of secondary sales rather than modeling an average transmission expense. In other words, in years of below-average water, the transmission purchases associated with the secondary sales of that water would be less, and vice versa in above-average years. BPA agrees with customers and plans to model this variability in the rate case, which it has not done in the past. BPA is very focused on capturing the appropriate mix of short- and long-term transmission services needed for secondary sales. Therefore, PBL will stay active in TBL forums, and verify forecasting used to estimate costs of third-party transmission. With respect to the comment of Grid West participation, BPA will continue to review the costs and benefits of Grid West participation.

For now, BPA believes the forecast that was proposed in the draft report of $184 million per year on average remains the most accurate, but will incorporate the customer-recommended risk analysis in the appropriate studies of the 2007 power rate case. The Transmission Acquisition expense forecast (associated with secondary sales) will be updated with the secondary sales forecast used in the FY 2007-2009 power rate case.

CONSERVATION PROGRAM

	Average Expense	Average Capital
FY 2002-2006 Conservation Program (including rate credit)	$66 M/yr	$27 M/yr
FY 2007-2009 PFR Base Forecast	$71 M/yr	$32 M/yr
FY 2007-2009 Proposed PFR Forecast	$70 M/yr	$28 M/yr
FY 2007-2009 Final PFR Forecast	**$71 M/yr**	**$32 M/yr**

MAY 2 DRAFT REPORT:
The portfolio of energy efficiency programs BPA is proposing for the post-2006 period is very similar to what is currently available. BPA relied heavily on the Post-2006 Conservation Workgroup's recommendations in designing its proposed program approach. The key features of the proposed program are as follows:

1. a **rate credit program** (similar to the current C&RD with key changes, such as paying for only cost-effective measures, BPA incentives based on a % of what it costs to install measures and not value to the system, and requiring that measures be incremental, measurable, and verifiable with appropriate oversight and more frequent reporting);
2. a **bi-lateral contracts program** for our utility and federal agency customers (similar to the current ConAug program);
3. a **3rd party bi-lateral contracts program** for cost-efficient, region-wide approaches (similar to the VendingMi$er program and includes BPA's support for the NEEA);
4. support of critical **infrastructure** elements, especially evaluations so we know if we are getting what we are paying for;
5. a separately funded **renewable resource option**; and
6. a proposed spending amount of **$75 million/year** to capture BPA's 52 aMW per year share of the Northwest Power and Conservation Council's (Council) regional cost-effective conservation target at an overall cost of **$1.4 million/aMW.**

Through the PFR process, several areas where decisions are yet to be made were identified as either potential savings or increases to the Conservation spending level from the PFR base. Each of these areas were discussed and taken into consideration when developing the proposed FY 2007-2009 Conservation forecast.

Possible Decreases Identified

1. **Proposal: Credit conservation done by utilities "on their own nickel" against BPA's target, reducing BPA's spending** – BPA's conservation target is based on cost effective conservation as defined in the Council's 5th Power Plan and reflects only loads BPA serves. Also, BPA serves only a fraction of some public utilities' loads. BPA agrees that if those utilities are effectively meeting some of BPA' target through their own non-BPA-funded programs, then BPA should not separately forecast for the same conservation MWs. BPA does not believe that currently there is enough information on how much cost-effective conservation public utilities are accomplishing on their own to warrant forecasting a reduction now. However, BPA will track this going forward and adjust its forecast accordingly. If this can be done before final studies are done for the FY 2007-2009 rate period, this adjustment will be made before the final rate decisions are made. **Draft Conclusion: Do not include this reduction in Initial Rate Proposal, but possibly include it in final rate studies.**

2. **Proposal: Reduce BPA target for "naturally occurring" conservation** – BPA originally set the target at 40 percent, which is roughly the percent of the regional load BPA serves (7,782/20,472 aMW= 38 percent based on FY 2003 White Book information). This calculation is fully consistent with the methodology for setting conservation targets in this FY 2002-2006 period, as agreed to between BPA and the Council. After

MAY 2 DRAFT REPORT CONTINUED:

consultation with the Council's staff, BPA estimated which specific measures are likely to become standard practice in absence of any BPA/utility conservation programs. Based on this analysis, BPA estimated that roughly 7percent of the Council's targets would be naturally occurring. Seven percent equates to roughly 4 aMW out of BPA's 56 aMW annual target. Based on the loads BPA serves, our share of the Council's regional target over the FY 2007-2009 period is 168 aMW (40 percent of 420 aMW). This equates to an annual target of 56 aMW. We anticipate that the "naturally occurring" conservation will come in at about 7 percent or 4 aMW per year. This would give us a 52 aMW per year target and a 156 aMW target over the 2007-2009 period. While there has been some comment that the Council has set too high a target for conservation, BPA believes it appropriate and achievable. The Council conducted an extensive public process as conservation potential was analyzed, and BPA and many others in the region participated in that process. Thus, BPA concludes the 52 aMW per year is the right target. **Draft Conclusion: Include $4 million annual capital and $1 million annual expense reductions in the Initial Rate Proposal.**

3. **Proposal: Don't require load decrement on rate credit** – PFR participants commented that it will be harder for BPA to meet its MW targets for conservation within its spending level limit if it requires block and slice customers to reduce their load on BPA by the amount of conservation they accomplish under the conservation rate discount program. Consistent with the advice of its Post-2006 Conservation Workgroup, BPA has now proposed not to require load decrements from slice/block customers under the rate credit program, but continuing to require load decrements under the new bi-lateral contract program. **Draft Conclusion: Make the change recommended, but no reduction in costs.**

Possible Increases Identified

1. **Proposal: Do not count IOU conservation BPA pays for toward BPA's target, or count these MW's but also add IOU residential conservation to BPA's target** – BPA proposes to count toward the 52 aMW annual target any cost effective conservation it helps ensure through its funding mechanisms, including the conservation achieved by IOUs under the rate credit program and the conservation accomplished by our Northwest Energy Efficiency Alliance (NEEA) funds. This decision is consistent with the current way we count delivered savings toward our share of the Council's target in the rate period as agreed to by Council staff. Further, BPA invests in regional conservation that is currently counted toward BPA targets, e.g., NEEA market transformation. Counting conservation funded by IOU rate credits is fully consistent with the methodology we use in this rate period, and should be extended to the FY 2007-2009 rate period. If BPA pays for it, BPA should count it toward our targets. **Draft Conclusion: Count IOU MW's and add to target, but no cost increase.**

2. **Proposal: Increase spending to increase certainty of meeting conservation targets** – BPA acknowledges that the $1.4 million per aMW target is a stretch. Based on recent conservation program performance and given the changes that have been made in the designs of the proposed program portfolio, BPA believes it has a reasonable chance to achieve its share of the Council's new conservation aMW targets with the proposed spending level. It is important to note that while BPA is targeting $1.4 million per aMW, that figure is an average of different program spending levels. BPA has been successful at lowering the cost of savings through the Con Aug Program, and BPA will seek to continue to average program costs in the revised bilateral contracts at the current level ($1.2 million per aMW). Similarly, NEEA has a demonstrated track record of $1 million per aMW. This leaves the budgets for local initiatives higher ($1.7 million per aMW). Thus, the success to date with driving down program costs and continuing to adapt new marketing strategies leads BPA to believe these forecasted targets are achievable. Just as important, BPA believes that setting and meeting aggressive cost containment goals is important both to keep rates down and to maintain support for steady conservation funding, since higher costs per MW make conservation spending levels less sustainable during periods of even greater financial stress. BPA will assess progress towards our aMW conservation goal and proposes to adjust for underperformance against the target in the next rate period. **Draft Conclusion: Keep funding at current forecast.**

3. **Proposal: Increase spending level for administrative costs** – BPA is proposing to pay up to 10 percent of administration costs under the new rate credit and bilateral contracts program. The Conservation

MAY 2 DRAFT REPORT CONTINUED:

Workgroup recommended 20 percent of administrative costs be included. The current C&RD credit allows credit of 20 percent for administration cost to support infrastructure building. For ongoing conservation programs, however, administration should be lower. A number of utilities and end users that are partners in capturing the regional conservation have told BPA they don't need a full 20 percent administration for on-going programs. BPA has included a number of activities and tools that should reduce utility administration costs (e.g., standard program design templates and marketing materials, mechanism for utility sharing, etc.). However, BPA received numerous written comments on this topic shortly before issuing this report and will consider them during the comment period. **Draft Conclusion: Keep funding at current forecast.**

4. **Proposal: Increase spending level for conservation infrastructure** – The Conservation Workgroup recommended a 2 percent infrastructure spending level (i.e., $1.6 million per year). BPA has proposed instead conservation spending levels for FY 2007-2009 that includes $1 million per year for the infrastructure spending that should be sufficient to cover these activities. The 2 percent infrastructure support forecast was not based upon detailed analysis and budgeting. More detailed analysis developed by BPA leads the Agency to conclude the necessary infrastructure support can be accomplished at the $1 million per year level. The $1 million per year is a component of the $75 million per year proposed conservation acquisition program level. **Draft Conclusion: Keep funding at current forecast.**

Table 1: Proposed Conservation Program Annual aMW Targets and Spending Levels

Program	aMW	Forecast	Cost/aMW
Rate Credit (at 0.5 mills = $42M*/year with IOUs and Pre-Subers included)	21	$36M	$1.7M
Utility & Fed. Agency Bi-Lateral Contracts	15	$21M	$1.4M
3rd Party Bi-lateral Contracts	6	$7M	$1.2M
Market Transformation (via NEEA)	10	$10M	$1.0M
Infrastructure Support and Evaluation	---	$1M	---
Total	52	$75M	$1.4M

* - *assumes $6 million per year of the $42 million per conservation rate credit will be spent on renewables .*

In total, BPA proposes to reduce the base PFR spending levels (both capital and expense) for achieving the Council's cost-effective conservation target by $5 million per year to $75 million per year (includes the conservation rate credit), which is a portion of the overall Conservation forecast of capital and expense spending. The proposed spending level is an actual increase of $5 million per year over the average annual spending level in the current rate period.

MAY 2 DRAFT REPORT CONTINUED:

Table 2: PBL Total Proposed Conservation Forecast FY 2007-2009

Program	Proposed Forecast	Annual MW Target Spending
Generation Conservation Expenses	**$34.0 M**	
EE Development (Reimbursable)	$12.9 M	
Energy Web/Non-Wires Solutions	$1.0 M	
Technology Leadership	$1.3 M	
Legacy (Contract closeout after FY 2000)	$2.8 M	
Low-Income Weatherization	$5.0 M	
Market Transformation	$10.0 M	YES
Infrastructure Support and Evaluation	$1.0 M	YES
Conservation Rate Credit	**$36.0 M**	**YES**
Expense Total	**$70.0 M**	
Generation Conservation Capital Total	**$28.0 M**	
Utility & Fed Agency Bi-Lateral Contracts	$21.0 M	YES
3rd Party Bi-lateral Contracts	$7.0 M	YES

BPA Proposals	Proposed PFR Base FY 2007-2009 (Reductions)/Increases
Reduce Conservation Expense Spending Level	($1 M/year)
Reduce Conservation Capital Spending Level	($4 M/year)

Summary of Comments Received on Proposed PFR Forecast

- Revisit the amortization period for Conservation Augmentation.
- Ramp up to meet additional conservation in next two years. Have a backstop in case the plan fails to meet target.
- Credit money generated by conservation against program costs.
- Resolve cost-effective measures and other issues before setting a conservation target.
- Carefully consider treatment of the rate credit.
- Continue to link conservation/renewables in discount program.
- BPA should get credit if utilities are doing conservation beyond BPA program; BPA program would accomplish more if utilities did not have to worry about decrement.
- Changes that would centralize the conservation program are unwelcome.
- If BPA money is being spent in an IOU service territory, it should count toward BPA target.

- Significantly increase investment in energy efficiency. Invest up to $150 million per year and acquire 70 to 80 aMW.
- BPA should not count IOU conservation accomplishments toward its target; decrementing raises the cost of conservation for utilities.
- BPA's conservation target should be 70 aMW, not 52; if you decrement, you should credit revenues from resources you sell toward conservation program. The funding level is too low to meet the target. A more realistic budget would be $133 million to achieve 70 aMW.
- Naturally occurring conservation should count toward BPA goal.
- BPA should back away from the commitment to meeting the Council targets.
- Raise your rates immediately to pay off more debt and promote more renewable energy programs.
- Restore the $5 million cut in the course of PFR. Add funds to increase the probability of meeting targets set. Include a contingency plan in case BPA and utilities fall short of meeting the target.
- No additional budget above $75 million for conservation unless there are robust measures that would work for all utilities. Budget is meaningless without a realistic target and measures that work.
- Design a conservation program that works for all customers; as designed, the program is unfair to some customers.
- One size does not fit all with conservation; provide flexibility for customers in different areas to capture potential.

Final Report Decisions

In the draft report, BPA proposed reducing the conservation forecast needed to acquire BPA's share of the Northwest Power and Conservation Council's (Council) new conservation targets by $5 million/year for the 2007-2009 power rate period. The original forecast was $80 million per year needed to capture the 56 aMW per year target. BPA felt that about 7 percent of this target was "naturally occurring" conservation that BPA, or anyone, should not need to fund. This reduced the target from 56 aMW per year to 52 aMW per year and, accordingly, the expense forecast BPA proposed to achieve the target.

In a parallel process, BPA developed and issued for public review and comment a post-2006 Conservation Program Proposal, including the PFR conservation forecast information. Table 1 provides a detailed breakdown of how the proposed $75 million per year forecast would be allocated across the portfolio of proposed conservation programs. Table 2 shows the total proposed conservation forecast for FY 2007-2009.

Many of the issues raised in the PFR comment periods are more properly addressed under the post-2006 Conservation Program process. Documents presenting BPA's final decisions on those issues will be available on BPA's energy efficiency Web site soon. With regard to the conservation forecast for FY 2007-2009, BPA has decided to return to the original $80 millon per year forecast to provide a greater confidence that it will capture the 52 aMW per year target, and to respond to customer and other comments on administrative costs and other issues. The rationale for this decision is further detailed in BPA's separate document on post-2006 conservation decisions. Table 3 provides a detailed breakdown of how these funds will be allocated across the final program portfolio. BPA also received comments regarding the need to focus on irrigation efficiency improvements to both reduce energy consumption and reduce water use. BPA has under development or recently launched several initiatives to pursue irrigation efficiency. A scientific irrigation scheduling pilot demonstration project was recently launched. A pump testing initiative is scheduled for launch in the early summer of 2005 with a companion rebate/standard offer program targeted at irrigation efficiency measures (the companion program was launched in June 2005 resulting in two customer utility contracts immediately).

Table 3: Final Conservation Program Annual aMW Targets and Budgets

Program	aMW	Budget	Cost/aMW
Rate Credit (at 0.5 mills = $42M*/year with IOUs and Pre-Subers included)+	20	$36M	$1.8M
Utility & Fed. Agency Bi-Lateral Contracts+	17	$26M	$1.5M
Third Party Bilateral Contracts	5	$7M	$1.4M
Market Transformation (via NEEA)	10	$10M	$1.0M
Infrastructure Support and Evaluation	---	$1M	---
Total	52	$80M	$1.5M

+ - includes a 15 percent administrative cost allowance.
* - assumes $6 million per year of the $42 million per year from a separate renewables budget will be spent on renewables.

Table 4 provides the final PBL total conservation forecast for FY 2007-2009.

Table 4: Final PBL Total Conservation Forecast FY 2007-2009

Program	Final Forecast	Annual MW Target Spending
Generation Conservation Expenses	**$34.0 M**	
EE Development (Reimbursable)	$12.9 M	
Energy Web/Non-Wires Solutions	$1.0 M	
Technology Leadership	$1.3 M	
Legacy (Contract closeout after FY 2000)	$2.8 M	
Low-Income Weatherization	$5.0 M	
Bi-Lateral Contract Activity	$1.0 M	YES
Market Transformation	$10.0 M	YES
Infrastructure Support and Evaluation	$1.0 M	YES
Conservation Rate Credit	**$36.0 M**	**YES**
Expense Total	**$71.0 M**	
Generation Conservation Capital Total	**$32.0 M**	
Utility & Fed Agency Bi-Lateral Contracts	$25.0 M	YES
Third Party Bilateral Contracts	$7.0 M	YES

RENEWABLES PROGRAM

	Average Expense	*Average Net Cost**	Average Capital
FY 2002-2006 Renewable Program	$22 M/yr	*$2 M/yr*	$0 M/yr
FY 2007-2009 PFR Base Forecast	$56 M/yr	*$13 M/yr*	$0 M/yr
FY 2007-2009 Proposed PFR Forecast** *w/o Rate Credit*	$61 M/yr *$55 M/yr*	*$15 M/yr* *$9 M/yr*	$0 M/yr *$0 M/yr*
FY 2007-2009 Final PFR Forecast** *w/o Rate Credit*	**$43 M/yr** *$37 M/yr*	***$16 M/yr*** *$10 M/yr*	**$0 M/yr** *$0 M/yr*

**Takes the Average Expense column and subtracts the estimate of revenues from the renewables program.*
***Includes Renewable rate credit of $6M/year in Average Expense. Previous forecasts did not.*

MAY 2 DRAFT REPORT:
BPA began funding renewable-related research nearly 30 years ago through solar monitoring, a wind demonstration project, geothermal and wind resource assessments, and a range of projects across other technologies, many in cooperation with other sponsors. As part of the Short-Term Regional Dialogue process, BPA decided in February 2005 to focus on facilitation of regional renewable resources by its customers and others, and to limit its financial contribution to a net cost of $21 million per year. BPA has identified a menu of facilitation actions and is consulting with a regional workgroup on which of those actions will maximize the amount of renewable resource development, within BPA's financial contribution limit. This group has advocated, and BPA agrees, continuing to include renewables in the utility actions eligible for the rate discount program for FY 2007-2009 at the level of $6 million per year. This leaves much of the $21 million annual net cost limit uncommitted due to higher long range market price forecasts that produce a break even cost for existing renewable contracts (the room under the target will vary as long range market price forecasts change). Rather than simply assume the entire $21 million level is spent, BPA intends to include the best estimate of actual spending in the rate case cost forecasts. This was the basis of the PFR base case cost levels.

Through the PFR process, participants have identified several areas that would both increase and decrease portions of the FY 2007-2009 renewables spending level forecasts.

Possible Decreases Identified

1. **Proposal: Remove the Calpine geothermal project from projected costs** – The assumption in the PFR base is that the Calpine project comes on line in FY 2007 and operates during the rate period. The Calpine contract is currently in arbitration and a decision is not expected to come until late summer. Some PFR participants urged that BPA assume that it will not have to purchase the high-cost output of this project, or that its online date will be significantly delayed. BPA believes that it is highly unlikely that it would be purchasing output from this project any sooner than FY 2009, even if BPA loses in the ongoing arbitration process. Therefore, BPA is proposing to move the forecast of the geothermal out of FY 2007 and FY 2008 but leave it in the forecast for FY 2009 for the initial power rate proposal. BPA does not believe the project costs should be removed entirely until the outcome of the arbitration is known. This forecast will be revised in time for the final rate proposal after the arbitration decisions have come about late this summer. **Draft Conclusion: Remove geothermal project costs in FY 2007 and 2008.**

MAY 2 DRAFT REPORT CONTINUED:

2. **Proposal: No further renewable spending beyond what is already contractually committed** – This option was not actually advocated by PFR participants, but was included by BPA as a "bookend" for discussion. Having recently decided on the $21 million limit after an extensive public process, BPA does not believe it is appropriate to now "zero out" its renewable resource support. **Draft Conclusion: Do not "zero out" incremental renewable resource facilitation.**

Possible Increases Identified

1. **Proposal: Add facilitation forecast for FY 2007-2009 if Calpine is taken out of the forecast** – BPA remains committed to facilitating customer renewable acquisitions and recognizes it's role in helping the region meet renewable targets. Removal of the Calpine geothermal project allows other facilitation actions to be added without exceeding the $21 million annual net cost limit. Some PFR participants and Renewable Workgroup members supported this. Others also recommended that the facilitation spending estimate be revisited annually in consultation with customers and together they would jointly assess the need for facilitation spending. BPA agrees that its rate proposal costs should include reasonably foreseeable renewable facilitation costs, but not simply "placeholder" dollars up to the $21 million limit. BPA believes the best estimate of this is $5.5 million in FY 2007 and $11 million in FY 2008. This estimate will be updated before final rate studies are done in consultation with customers. **Draft Conclusion: Include $5.5 million in FY 2007 and $11 million in FY 2008 for renewable facilitation actions.**

2. **Proposal: Include a Renewable Rate Credit** – The current rate period combines the renewable and conservation rate credit into one lump sum. Through the Conservation and Renewables Workgroups it has been proposed to separate this credit into distinct categories. BPA also heard the desire to give customers the option of committing for one year at a time rather than for all three years at once. The PFR base forecast did not have the renewable rate credit embedded. **Draft Conclusion: Include the $6 million per year rate credit.**

BPA Proposals	Proposed PFR Base FY 2007-2009 (Reductions)/Increases
Remove forecast of Calpine from FY 2007-2008	($11 M/year for FY07-08)
Include facilitation forecast for FY 2007-2008	$8 M/year for FY07-08
Include renewable rate credit	$6 M/year

Summary of Comments Received on Proposed PFR Forecast

- Take Four Mile Hill out of the projection for FY 2007-2009.
- BPA transmission policies for renewables are leading the nation.
- Renewables need consistent funding.
- Provide money up front to help developers get renewables projects under way.
- BPA can play a critical role in helping to deliver renewables in the region through transmission and integration, promoting promising technologies, and facilitating partnerships. Strategically target upgrades to transmission to open up development.
- BPA should maintain leadership role with renewables; continue facilitation with a $21 million investment over the rate period; continue $6 million for renewable in the rate discount; and an additional $15 million for renewables facilitation is prudent.
- BPA should continue leadership on renewable energy, provide continuity and continue to facilitate, follow through on existing commitments, define programs for customers that will provide incentives for new renewable energy acquisition and help customers

overcome unique barriers, provide new funding rather than use leftover funds from previous rate period, and continue to identify good acquisition opportunities. Budget for facilitation should be $15 million per year, and we reject $5.5 million (FY 2007) and $11 million (FY 2008) proposal.

- Cannot support construct for renewables, which creates an unclear revenue requirement, is selective conditional budgeting, perpetuates disconnect between BPA's avoided costs and other activities, provides favorable treatment to renewables versus conservation.
- Fund renewables fully in next two fiscal years. Oregon has adopted a renewables action plan and BPA could help to achieve it if it would fund grants and upgrades to distribution facilities that make more renewable projects possible.
- Cannot support "facilitation" cost placeholders in revenue requirement.
- Include money for facilitation only if BPA has above average secondary revenues.

Final Report Decisions

In the recent Record of Decision (ROD) on the Short-Term Regional Dialogue, BPA decided to accept a net cost of up to $21 million per year for renewable resource facilitation. BPA agrees with comments that it should stand behind this commitment, and that it should limit expenses covered by power rates for unidentified renewable projects. BPA agrees with the facilitation funding level set by the Renewables Workgroup as it strikes the right balance of these two interests. BPA will continue working with this group to better define these facilitation actions and their costs. However the question of using premium revenues from EPP, ARE, renewable attributes sales was also raised in the comment period. BPA is committed to devoting those revenues to renewable projects. Therefore BPA's conclusion is that $5.5 million in FY 2007 and $11 million in FY 2008 should be committed to renewable facilitation, in addition to all premium revenues from sales of EPP, ARE, and tags/renewable energy certificates. The latter revenues are estimated at $1 million in FY 2007 and $1 million in FY 2008, but could be higher or lower depending on actual sales.

In the course of the PFR draft report, it was noticed that the reductions in the renewable forecast due to removing Calpine in FY 2007-2008 were misstated. The net costs were removed instead of the gross costs. Making this correction reduced the renewables forecast by an additional $14 million per year on average (draft report had $7 million per year savings on average and it should have been $21 million per year on average).

Another area that changed from the draft report was the wind power purchase costs. BPA has historically based forecasted wind power costs on estimated capacity factors provided by project developers at the time the power purchase agreements were signed. Actual wind generation over the last 3 years has proven to be less than originally estimated. We are revising the wind project costs downward in FY 2007-2009 by $4 million per year to reflect our wind projects' historical generation profile, but are not capping wind power costs at the reduced level because actual generation, operation and maintenance costs vary from year to year.

BPA will revisit whether or not to include Four Mile Hill generation costs in the FY 2009 forecast in the final rate studies next spring, based on the outcome of the ongoing binding arbitration concerning that project.

INTERNAL OPERATIONS CHARGED TO POWER

	Average Expense	Average Capital
FY 2002-2006 Internal Operations Charged To Power Rates	$107 M/yr	$0 M/yr
FY 2007-2009 PFR Base Forecast	$116 M/yr	$0 M/yr
FY 2007-2009 Proposed PFR Forecast	$110 M/yr	$0 M/yr
FY 2007-2009 Final PFR Forecast	**$110 M/yr**	**$0 M/yr**

MAY 2 DRAFT REPORT:
This cost category is driven by BPA's strategic direction: "Effective cost management (with emphasis on best practices, innovation and simplicity) through our systems and processes." It includes BPA staffing costs, travel, training, consultant contracts, building leases, IT services, and other related costs. BPA has been managing these costs very actively over the last several years and has kept the rate of growth well below the rate of inflation over the last four years. Several actions are underway now to bring these costs down further, including agency-wide process reviews, reductions in high-graded positions, and consolidation of functions currently performed in both power and transmission business lines. The primary challenge for the PFR process is determining the level of savings to include from these ongoing efforts since they will not be finalized before the PFR process concludes in June. PFR participants urged BPA to include its best estimate of savings from these efforts in its PFR conclusions.

Possible Decreases Identified

1. **Proposal: Reduce monetary awards** – During the current rate period, BPA drastically reduced award budgets in response to the financial crisis the region faced. In the FY 2007-2009 base PFR forecasts BPA proposed to increase award budgets, but not to historic levels, and to tie them to financial standards, as they were in the past. If the financial standards are not met the awards are not paid out. This item was an area identified as a place to reduce the spending forecast in the PFR process. Advice from PFR participants was to keep the increased awards amounts but to make sure they are tied to financial performance standards. BPA agrees with this and proposes to maintain the amounts included in the base PFR forecast. **Draft Conclusion: No reduction in awards cost.**

2. **Proposal: Include forecast of savings from process improvement efforts** – As BPA is in the middle of process efficiency studies, many of the potential areas of possible reductions have not been fully studied and resulting savings quantified. Many customers, however, have voiced concern that these efficiencies will not be reflected in their FY 2007-2009 power rates unless savings are forecasted now. BPA agrees with this concern. As an interim target for inclusion in the initial power rate proposal, BPA proposes to reduce its total internal costs allocated to power rates in FY 2007-2009 to roughly the same amount spent on these functions in FY 2001, with no allowance for inflation. This is a reduction of $8 million per year from the PFR base. Given that BPA's responsibilities have increased and will continue increasing over this 8-year period, absorbing inflation in internal spending will require significant success in the ongoing efforts to improve internal processes along with reductions in staffing. Based on progress to date on these efforts, BPA is sufficiently confident in its ability to meet this target to include it in the initial rate proposal. Internal costs will be updated before the final rate studies are done in 2006. **Draft Conclusion: Reduce internal costs by $8 million per year to reflect process improvement efforts.**

Possible Increases Identified

1. **Proposal: Include but reduce spending level of uncommitted technological innovation spending (TCI)** – The mission of the Technology Confirmation / Innovation Program is to confirm the potential application of emerging technologies to BPA's enterprise to achieve BPA's strategic objectives more effectively and efficiently. Total TCI funding consists of the (1) base level of funding that is already

MAY 2 DRAFT REPORT CONTINUED:

incorporated into organizational forecasts and (2) incremental funding. The proposed funding in the Corporate G&A forecasts in the base PFR forecast is for incremental funding. BPA proposed to add to the base level of funding gradually, to yield a total TCI level that would be in the range of 0.3 percent - 0.5 percent of revenues by FY 2011. However, after listening to participants and customer concerns about adding additional costs to this rate period, but also understanding there is support for spending money on these efforts based on the belief that the electric industry is under-spending in this area and that the potential rewards from applied technologies can far exceed the development costs, BPA proposes to scale back but not eliminate incremental TCI funding. The resulting reduction in corporate TCI costs to $2.4 million per year (which translates to PBL costs of approximately $1.3 million per year) is a reduction of $400,000 per year from the corporate TCI PFR base. These numbers assume that both PBL and TBL undertake TCI-related actions over these years at levels that have been indicated in earlier discussions. For example, it is assumed that PBL will be picking up its half of the Bureau of Reclamation's hydro R&D expenses beginning in FY 2006 and that Energy Efficiency's TCI-related expenses will continue. **Draft Conclusion: Include the TCI forecast of $1.3 million per year in Internal Operations Charged to Power.**

TCI Program Proposal	**FY 2006**	**FY 2007**	**FY 2008**	**FY 2009**
PFR Base Total	0	0	0	0
PFR Workshop Total	$250	$1,500	$2,750	$4,100
Proposed PFR Total	**$ 500**	**$ 1,400**	**$ 2,400**	**$ 3,400**
PBL Share	*$ 250*	*$ 1,000*	*$ 1,200*	*$ 1,700*
TBL Share	*$ 250*	*$ 400*	*$ 1,200*	*$ 1,700*

BPA Proposals	**Proposed PFR Base FY 2007-2009 (Reductions)/Increases**
Include TCI forecast in Internal Operations Charged to Power	$1.3 M/year
Include process improvements in Internal Operations Charged to Power Forecast	($8 M/year)

Summary of Comments Received on Proposed PFR Forecast

- Early outs and retirements are an opportunity to consider new ways to staff. Drive toward lower number of FTE in the next rate period.
- Align reward targets with a rate target and customer benefits.
- Roll back corporate spending on IT.
- Use 2 percent annual inflation going forward.
- Reallocate industry-restructuring costs.
- Adjust budget for power non-generation operations.
- Reduce Corporate G&A due to efficiencies from Enterprise Process Improvement Projects (EPIP).
- Reduce funding for Technology Confirmation/Innovation.
- Make line item budget and spending available on line for scrutiny of specific expenditures, such as travel, consultants, office space, etc.
- Vigorously pursue EPIP study.
- The industry has been under-investing in technology.

Final Report Decisions

In the PFR draft report, BPA proposed a reduction of $6 million in internal operating costs to be recovered in power rates, which left those costs at roughly the same level in FY 2009 as they were in FY 2001, with no allowance for inflation. This amount includes both PBL costs and all corporate costs allocated to power including IT and industry restructuring costs. BPA is able to include this additional reduction through stringent cost management. The number of employees has declined since 2001, and is expected to decline further. This cost level is consistent with virtually all the recommendations made in PFR comments. BPA internal operating costs, unlike CGS and other operational costs, are not growing to any significant extent despite increased requirements for security and other new or increased functions.

We are proud of this accomplishment. BPA continues to work actively on better managing these costs through the on-going EPIP and position management. The EPIP processes follow up on efficiency recommendations made by KEMA, Inc. in its study conducted earlier this year. The $8 million reduction proposed in the draft report is an early estimate of the savings achievable through the implementation of the EPIP studies currently underway, as well as future EPIP studies. Results foreseeable at this time make us confident we can reach this level of savings in internal operating costs allocated to power. As such, the initial power rate proposal will include this level of savings, consistent with the draft report recommendation, even though they are not these savings have yet to be achieved. This estimate of savings will be updated for the final power rate proposal to reflect the implementation plans of the current EPIP studies, as well as any preliminary estimates from future studies. We feel that the EPIP studies are the most promising way for BPA to address efficiencies in internal operating costs. These studies will point us toward greater efficiency in performing the work needed to successfully deliver our power, transmission and public responsibility obligations and mission.

HYDRO SYSTEM O&M AND CAPITAL INVESTMENTS: CORPS OF ENGINEERS AND BUREAU OF RECLAMATION PROGRAM

	Average Expense	Average Capital
FY 2002-2006 Corps and Reclamation	$196 M/yr	$110 M/yr
FY 2007-2009 PFR Base Forecast	$242 M/yr	$138 M/yr
FY 2007-2009 Proposed PFR Forecast	$240 M/yr	$138 M/yr
FY 2007-2009 Final PFR Forecast	**$240 M/yr**	**$138 M/yr**

MAY 2 DRAFT REPORT:
The Corps of Engineers (Corps) and Bureau of Reclamation (Bureau) operate and maintain the hydro system that produces around 90 percent of BPA's power under average water conditions. The age and conditions of the facilities under each of these organizations is different, resulting in different needs and proposed spending levels in the base PFR forecast. Through the Sounding Board process, the agencies recognized that they need to be able to succinctly explain the hydro program's resource requirements. In the PFR process we've presented detailed information about the asset management business model we operate the hydro system under, as well as very specific data used to determine the resource requirements that comprise the FY 2007-2009 forecasts. Because these forecasts are one of the larger components of costs that will make up the FY 2007-2009 rate: BPA, the Corps, and Bureau have worked very hard to develop spending levels that reflect minimum cost requirements while still meeting the systems operational, power generation and reliability requirements for the region. There was much concern about the increase from prior funding levels in the O&M and capital forecast from some PFR participants in the FY 2007-2009 timeframe. Much of this increase is due to the Corps and Reclamation adopting a long-term asset strategy for management of the hydro facilities, and to enable the Corps to shift from a mode of breakdown maintenance to preventive maintenance. The age of the hydro facilities is also playing a part in the O&M forecasts where extraordinary maintenance items are starting to occur at the same time that there are increased costs from security mandates. Even with these cost increases, Corps and Bureau costs are below industry O&M benchmark costs (excluding F&W costs). Even though there are many cost issues facing the Corps and Bureau such as aging facilities and increased security and F&W costs, the PFR was still able to identify a few areas to decrease the base PFR forecast by relatively small amounts. Additionally there are longer-term efforts to manage costs that may yield savings in the future and the agencies are willing to engage in focused benchmarking efforts against Mid-Columbia hydro projects owned by BPA customers.

Possible Decreases Identified

1. **Proposal: Reduction in funding for WECC/NERC compliance** – The PFR base includes a forecast needed for compliance requirements. Although the final review of our program to manage these requirements will not be completed until the end of June, preliminary results are indicating that compliance can be achieved for about $1.5 million less than the initial estimate. There is still some level of risk associated with this value; both in terms of the uncertainty until the review is complete and in terms of any new WECC/NERC requirements that are not forecasted. BPA believes this is an acceptable level of risk and proposes to include the $1.5 million per year savings in the PFR forecast with the ability to update that assumption in the final power rate proposal after the studies have been concluded. **Draft Conclusion: Include $1.5 million annual reduction.**

2. **Proposal: Reduce proposed level of funding for extraordinary maintenance** – There currently is a forecasted need of $18 million per year for extraordinary maintenance items in the FY 2007-2009 time period and beyond, but only $8 million per year is included in the base PFR forecast. Some of the participants in the PFR workshops questioned that spending appeared to continue to increase over time even though some of the lagging performance indicators show acceptable performance standards for some time periods. BPA is concerned about the age of the facilities and the power generation and revenue

MAY 2 DRAFT REPORT CONTINUED:

Impact if the spending for extraordinary maintenance items is eliminated, directly impacting system performance. BPA proposes to keep the $8 M/year in extraordinary maintenance costs, understanding there are more projects identified than funding available. The Corps, Bureau, and BPA will continue to use a step-up approach to the proposed extraordinary maintenance costs that specifically identifies the projects to be funded and their priority in terms of benefits to the system and dollar impacts. **Draft Conclusion: No reduction in costs for extraordinary maintenance.**

3. **Proposal: Eliminate discretionary overtime funding** – This category has small dollars attached to it but big impacts. The discretionary overtime forecast is designed to fund work that is needed in order to get a unit back in operation as soon as possible to help avoid lost revenue. BPA does not recommend eliminating this item due to concerns about impacts on unit availability and power generation. **Draft Conclusion: No elimination of forecast for discretionary overtime.**

4. **Proposal: Reduce costs of management of security requirements –** The Corps, Bureau, and BPA are working closely to be as efficient as possible in carrying out security responsibilities, but security requirements included in the base PFR are mandatory for the Corps and Reclamation. **Draft Conclusion: No reduction in security management costs.**

5. **Proposal: Benchmark against similar regional hydro facilities to capture efficiencies** – The Corps and Bureau have participated in industry benchmarking for the past four years along with other regional hydro facilities. One way to capture savings over time is to find more efficient ways to perform the work required. During the PFR workshops it was suggested that facilities with similar operations on the Mid-Columbia get together and share information on costs and ideas on efficiency gains. BPA, the Corps and Bureau embrace this proposal and intend to pursue it. BPA proposes that any savings from this effort be accounted for in the final power rate proposal after the project is underway and potential savings are identified. **Draft Conclusion: Engage in regional benchmarking and include savings estimates in final rate studies.**

6. **Proposal: Include efficiencies in staffing** – There are several opportunities for staffing savings over the next few years. The average age of employees at the Corps and Bureau is similar to that at BPA and both these organizations are expecting to see a high number of their workforce retire over the next few years. This provides an opportunity to replace this more senior workforce with new employees at lower grades and benefits. The Corps is also implementing a nation-wide program called 2012 designed to improve efficiencies within its organization, as well as performing a functional review across multiple areas and disciplines. Results from these types of programs will increase operational efficiencies in the future but it is too soon to estimate any savings in the FY 2007-2009 time period. **Draft Conclusion: Do not include a forecast of efficiencies in the initial power rate proposal but will be included in the final power rate proposal if any are identified.**

7. **Proposal: Include funding for remote operation of projects** – Currently, the Corps is studying the possibility of remotely operating Albeni Falls and Libby from the Chief Joseph project. The initial costs of this project are for installation of the hardware and the payback comes over time. The savings are in labor dollars and occur from a reduction in the number of operators at the facilities after the project is completed. This capital project is currently assumed in the base PFR capital forecast, but because it is a capital project, any savings from eliminating the initial capital cost has essentially no effect on PFR rates. Due to the payback nature of the project, BPA recommends including this project with the forecast of savings beginning to be realized after the FY 2007-2009 rate period. **Draft Conclusion: Pursue project with negligible impact on FY 2007-2009 costs.**

In summary, BPA proposes to decrease the Corps and Bureau FY 2007-2009 O&M expenses by $1.5 million per year. This results in an average FY 2007-2009 level of Corps and Bureau O&M expense forecast of approximately $240 million per year for the FY 2007-2009 time period. BPA does not propose any changes in the FY 2007-2009 forecasted capital spending level in the base PFR forecast which is on average $138 million per year.

MAY 2 DRAFT REPORT CONTINUED:

BPA Proposals	Proposed PFR Base FY 2007-2009 (Reductions)/Increases
Reduce funding for WECC/NERC compliance	($1.5 M/year)

Summary of Comments Received on Proposed PFR Forecast

- Shift the drawdown at Grand Coulee for head gate repair to the fall.
- Set up a contingent financing fund for extraordinary hydro system maintenance.
- Don't place a hard cap on hydro O&M: some projects should be completed without crowding out others. The real emphasis should be on finding more cost-effective investments.
- Take the conservation and renewables budgets and direct them to hydro O&M.
- Increases for Corps and Bureau O&M are very large and unwarranted.
- We have a constrained transmission system in the region, and if we don't have sufficient generation, it could mean going outside for purchases.
- Include BPA customers' representatives on the Joint Operating Committee (JOC); develop better measures of success for O&M and capital programs; revise Asset Management Strategy.
- Keep up with capital programs on hydro system; a move from breakdown to preventive maintenance cuts costs.
- Work to prevent surprises like the $300 million in CRFM costs in the future.

Final Report Decisions

The final PFR FY 2007-2009 expense forecast level for Corps and Bureau hydro system O&M is $240 million per year. The capital spending forecast is an average of $138 million per year. The forecast levels are the same as the levels recommended in the May 2, 2005 PFR draft report. This reflects BPA's basic conclusion, detailed below, that cost cuts below this level would have too high of a likelihood of causing revenue losses through the loss of generation to forced outages and/or increases in costs to repair failed equipment that would more than equal the O&M cost savings. This conclusion will be further tested over the next eight months through head-to-head O&M benchmarking against Mid-Columbia and other regional hydro projects – an effort that was proposed by PFR participants and has been agreed-to by BPA, the Corps, Bureau, and Grant County PUD.

The range of comments submitted by stakeholders and customers was important in determining the final PRF forecast levels. Generally, the value of the hydro system to the region was recognized, with concerns ranging from the need to fund the program to maintain the level of production and reliability, to concerns about the increased funding levels and their effect on rates. Given that we have an aging hydro generation system with substantial maintenance requirements (as well as other expenses like those associated with security), the final funding levels are the minimum forecasts to continue to operate and maintain the system reliably through the next rate period.

Most of the incremental O&M costs for the FY 2007-2009 period are cost-of-living related expenses. Employee benefits, costs for materials and supplies required for maintaining the facilities, and service contracts for guard services, the fish trap and transport program, grounds maintenance, etc. are all tied to the cost-of-living indexes. The remaining O&M cost increases are associated with new requirements. Most of these new requirements like increased plant security, implementation of systems for management of maintenance activities, and environmental compliance activities are mandatory directives for the Corps and Bureau as determined by the Department of Defense and Department of Interior. The rest of the new requirements are NERC/WECC compliance and standardization of maintenance practices, which will improve the performance of the O&M program as well as ensure that system reliability requirements are maintained.

The other major factor contributing to the need for increased resource requirements in the O&M program is that the hydro system is old and has significant expenses associated with required extraordinary maintenance (particularly at Corps facilities). Most of the forced outages on the system currently are extraordinary maintenance type outages and directly affect our ability to generate. Lack of investment in the past has created a growing list of extraordinary maintenance items (estimated at $18 million plus per year through 2011) that have to be addressed in order to continue to generate revenue reliably and operate the system safely.

The incremental costs described above, when added to the significant costs required for extraordinary maintenance combine to determine a program funding need of about $250 million per year for the 2007-2009 period. This funding need for the O&M program is actually about $9 million per year more than the cost forecast of $240 million per year requested by the Corps and Reclamation and contained in this final report. The Corps and Bureau recognize the cost pressures the customers are under and will manage the hydro program to the lowest possible costs. They are committed to managing to the final PFR forecast even though O&M funding requirements are actually about $9 million per year higher than those forecasts. The agencies will accomplish this undistributed cost reduction by keeping current staffing levels generally flat through the FY 2007-2009 rate period and by seeking efficiencies through O&M program initiatives. It was noted in the PFR process that generating unit forced outages have trended up recently due to the increasing age of the system, emphasizing the need to address the increasing extraordinary maintenance requirements, as well as to continue to make capital investments in the system. Considering this, there is still some risk associated with the final PFR forecast level, particularly with respect to funding for extraordinary maintenance, but the agencies will do their utmost to minimize this risk through effective management of the hydro program.

As mentioned above, forecast levels may be updated to reflect the results of the study to review WECC/NERC requirements, and after completion of the initiative to discuss O&M practices and benchmark Corps and Bureau facilities against other Northwest regional utilities with hydro resources prior to the final power rate proposal in 2006.

COLUMBIA GENERATING STATION PROGRAM

	Average Expense	Average Capital
FY 2002-2006 Columbia Generation Station	$215 M/yr	See debt mgt.
FY 2007-2009 PFR Base Forecast	$284 M/yr	See debt mgt.
O&M	*$201 M/yr*	
Fuel, Capital, Decommissioning Fund Contributions & NEIL	*$83 M/yr*	
FY 2007-2009 Proposed PFR Forecast	$262 M/yr	See debt mgt.
O&M	*$179 M/yr*	
Fuel, Capital, Decommissioning Fund Contributions & NEIL	*$83 M/yr*	
FY 2007-2009 Final PFR Forecast	**$263 M/yr**	See debt mgt.
O&M	*$179 M/yr*	
Fuel, Capital, Decommissioning Fund Contributions & NEIL	*$84 M/yr*	

MAY 2 DRAFT REPORT:
The Columbia Generating Station (CGS) nuclear plant provides around 9 percent of BPA's power resources. CGS is facing many issues that will affect its costs such as mandated security levels, rapidly increasing fuel prices, aging and obsolete equipment, on site spent fuel storage, and rising employee benefit costs. Energy Northwest (EN) has recently tried to address these concerns through an industry benchmarking effort to help identify areas where efficiencies can be gained without compromising the safety and reliability of the plant. The initial results show that CGS has opportunities for substantial savings through staffing reductions and a more rigorous analysis of the need for proposed projects. These estimated savings are included in the March 2005 Draft Long-Range Plan but have not been finalized or reviewed by the EN Executive Board. Several of the areas of recommended reductions in the PFR are included in the draft Long Range Plan. The final EN Long-Range Plan Revision 1 is expected to be issued in June for Executive Board review. However, BPA must provide a CGS forecast for the initial power rate proposal as part of the PFR process before the Long Range Plan is reviewed and issued. Pending a timely review from the EN Executive Board, this forecast will be updated in the final power rate proposal.

Since the base forecasts were put together for the PFR process, there has been an increase in the market price of uranium mainly driven by a supply constraint. The PFR base forecast did not take into account these higher prices; if it had, the forecast would have increased by an average of around $5 million per year over the FY 2007-2009 period. BPA and EN have agreed, and EN has issued bonds backed by BPA to finance fuel acquisition in Fiscal Years 2005, 2006 and 2007. Please see the debt management section of this letter.

	FY 2007	FY 2008	FY 2009
PFR Base	**$317 M**	**$248 M**	**$286 M**
PFR Base w/high market price uranium	$319 M	$255M	$293 M

The above table reflects the PFR Base changed only to reflect the current uranium market prices in line 2. No other changes were made.

<u>MAY 2 DRAFT REPORT CONTINUED:</u>

<u>Possible Decreases Identified</u>

1. **Proposal: Include the forecast reductions proposed in the CGS long range plan** – In response to rising costs over the past years and concerns from BPA and customers, EN has recently undergone a cost competitiveness initiative as a result of benchmarking its costs of operating the facility to other like nuclear plants. Through this process, the opportunity for significant cost savings was identified that EN is now pursuing for adoption in the FY 2007-2009 time frame. While the Long-Range Plan that includes the cost competitive initiative reductions has not been finalized by EN and reviewed by its Executive Board, BPA proposes to include these O&M savings in the initial power rate proposal at an average of $22 million per year, subject to revision in the final power rate proposal based on Board action. PFR participants supported this proposal. **Draft Conclusion: Reduce CGS O&M costs by an average of $22 million per year per draft Energy Northwest plan.**

2. **Proposal: Eliminate the license extension spending for CGS in FY 2007-2009 –** The license for CGS expires in December 2023 and EN is proposing to spend approximately $8.5 million over the FY 2007-2009 period to pursue the license extension option. This process will take about 4 years and cost approximately $14 million in total. EN will capitalize the cost of license extension over the life of the CGS. Consistent with Proposal 3 below, BPA and EN expect that EN will issue bonds backed by BPA for future EN capital expenditures. BPA and EN will jointly consider and evaluate the feasibility and value of matching bond maturity dates for new capital investments with the expected lives of those investments. Please see the debt management section. The majority of this cost is embedded in the FY 2007-2009 base PFR forecast. EN had originally started work on this project in the current rate period but chose to defer this work at least two years as a result of the cost competitive initiative. There was much discussion around this topic at the PFR workshops. Feedback so far from customers was supportive of leaving this amount in the FY 2007-2009 forecast. PFR participants also urged a public process on the ultimate decision to extend the life of the project. **Draft Conclusion: Do not eliminate CGS license extension spending.**

3. **Proposal: Forecast Energy Northwest borrowing to pay for capital items in the FY 2007-2009 period** – See Debt Management section.

4. **Proposal: Forecast Energy Northwest borrowing to pay for fuel in the FY 2007-2009 period** –See Debt Management section

The PFR Base forecast for CGS assumed that all costs in the forecast were expense funded (no debt financing). Several suggestions were made in the PFR that EN should continue to debt finance capital investments as has been the most recent practice. The resulting reduction in FY 2007-2009 expenses would be offset in part by increased debt service. EN and BPA are continuing to review capital expenditures to identify items that are candidates for debt financing. This is addressed in the debt management section. Any decisions made in the debt management area about debt financing EN investments will have an impact on the forecast for EN O&M. The O&M forecast will be updated in the rate case to reflect the impacts of any decisions related to debt management.

MAY 2 DRAFT REPORT CONTINUED:

Forecast Comparison
PFR Base and PFR Base Adjusted for Debt Financing of Capital
BPA Fiscal Years
Dollars in Millions

PFR BASE	FY 2007	FY 2008	FY 2009
O&M	209	183	210
Fuel	62	44	51
Capital	38	13	16
Decommissioning Fund Contributions & NEIL	8	8	8
Total	**317**	**248**	**285**
PFR Base Adjusted for Debt Financing	**FY 2007**	**FY 2008**	**FY 2009**
O&M	209	183	210
Fuel	62	44	51
Capital	0	0	2
Approximate Capital Financing Costs	3	5	8
Decommissioning Fund Contributions & NEIL	8	8	8
Total	**282**	**240**	**279**

The table above assumes that 100 percent of capital investments will be debt financed. The capital financing costs are the estimated debt service costs. It is possible that results could change when considered in the context of BPA's total debt portfolio.

Forecast Using the Energy Northwest Draft Long Range Plan
Assumes Debt Financing of Capital
BPA Fiscal Years
Dollars in Millions

	FY 2007	FY 2008	FY 2009
PFR Base	**317**	**248**	**286**
O&M Reduction	**(23)**	**(19)**	**(24)**
Reduction in O&M due to Debt Financing Capital	**(38)**	**(13)**	**(16)**
Increase due to Market Prices of Fuel	**5**	**8**	**8**
Increase in Decommissioning Trust Fund Contributions	**1**	**1**	**2**
Latest Revised Estimated Total O&M Forecast	**262**	**225**	**256**

The table above assumes that 100 percent of capital investments will be debt financed and does not include debt service on funds borrowed for capital spending.

MAY 2 DRAFT REPORT CONTINUED:
In summary, BPA proposes adopting the draft version of the Long-Range Plan forecast and further proposes to assume debt financing for CGS capital items, though this latter decision is one made within the rate case, not the PFR. Debt financing is also subject to EN Board action.

BPA Proposals	Proposed PFR Base FY 2007-2009 (Reductions)/Increases
Reduce CGS O&M costs per Draft Long-Range Plan	($22 M/year)

Summary of Comments Received on Proposed PFR Forecast

- Capture fuel-savings through the uranium tails project.
- Let's decide in the future about keeping the plant in BPA's portfolio. Discuss with customers before extending EN debt beyond 2018.
- Assume more output from CGS.
- Close CGS, it is BPA's most expensive resource.
- Continue to pursue CGS license renewal.
- Include forecast reductions proposed in Long-Range Plan; debt finance qualifying capital projects; lower expense associated with nuclear fuel.
- CGS O&M and FTE and cost of production are out of line; increase is unwarranted and should be reduced substantially.

Final Report Decisions

Overall, the general comments received on the O&M portion of the CGS forecast favored the actions EN is taking to reduce FTE and overall costs. BPA is committed to working with EN to obtain the cost savings identified in the PFR process. The Final PFR forecast includes the $22 million average per year reduction in CGS O&M and increases associated with Decommissioning Trust Fund contributions. Estimated net reductions due to debt financing components of the EN forecast are reflected in the debt management section of this report. The forecast for fuel reflects an assumption that EN and BPA will be able to fully offset the steep increases in the market price of nuclear fuel through creative fuel sourcing strategies, including some financing of fuel purchases as recommended by PFR participants. The forecast for CGS O&M that will be used in BPA's final power rate studies will be contingent on the latest estimate available from EN. It will also be affected by anything that is done in the debt management area related to nuclear fuel acquisition and capital projects.

BPA has kept the funding for pursuing the license extension in its forecast but would also like to keep the option open to explore the possibility of extending CGS debt to 2024. BPA will not include this suggestion in the initial power rate proposal, but could potentially include it in final rate studies. BPA and EN will jointly consider and evaluate the feasibility and value of extending the final maturity of some existing CGS debt beyond 2018. If a change is warranted, before including such an assumption in the final proposal, BPA will review this alternative with its customers and others.

FISH & WILDLIFE PROGRAM

	Average Expense	Average Capital
FY 2002-2006 Direct Program (Integrated Program)	$139 M/yr	$20 M/yr
FY 2007-2009 PFR Base Forecast	$139 M/yr	$36 M/yr
FY 2007-2009 Proposed PFR Forecast	$143 M/yr	$36 M/yr
FY 2007-2009 Final PFR Forecast	**$143 M/yr**	**$36 M/yr**

MAY 2 DRAFT REPORT:
BPA is committed to fulfilling its fish and wildlife (F&W) obligations through managing to clearly defined performance objectives and implementing the most cost effective strategies for meeting these objectives. Fish and wildlife mitigation efforts affecting BPA power rates consist of several different components: (1) hydro operations effects (not a distinct expense line item), (2) the O&M of the Lower Snake River Compensation Plan hatchery system, (3) fish and wildlife mitigation projects funded under the Integrated Program (also known as the Direct Program or Council Program) in partnership with the Council, (4) the power share of the O&M of the Corps' fish passage facilities, its hatcheries and its juvenile salmon transportation program, (5) the power share of the O&M for the Bureau's Leavenworth fish hatchery complex, and (6) the debt service (depreciation, amortization, and net interest) associated with capital investments in fish passage facilities at the Corps of Engineers dams, and in hatcheries and land acquisitions under the Integrated Program. Additionally, 50 percent of the Council's internal operating costs are also categorized as an additional fish cost line item on BPA's Power Business Line Income Statement.

Up to this point in the PFR process, BPA has used current rate period funding levels for the capital and expense portions of the Direct or Integrated Program as placeholders. Other components reflect draft funding levels gleaned from informal discussions with the Corps, Bureau, and the U.S. Fish and Wildlife Service. With this letter, BPA will propose new draft fish and wildlife program spending levels for the FY 2007-2009 rate period. This draft proposal reflects BPA's current thinking, as informed by six fish and wildlife focused PFR workshops; numerous meetings with the Council, constituents, states, Tribes, and customers; and extensive study of the factors that may tend to push costs both higher and lower in coming years.

Possible Decreases Identified

1. **Proposal: Assume proposed installation and test mode of additional Updated Proposed Action (UPA) Surface Passage Improvements and Implement Snake River Fall Chinook Transport vs. In-River Migration Study –** One of the assumptions to be made in the FY 2007-2009 time frame is the timing and installation of additional surface passage improvements, including removable spillway weirs (RSWs), on three of the hydro projects. The PFR base case assumed installation of weirs and operation of these facilities during the FY 2007-2009 rate period at Lower Granite and Ice Harbor but assumed no surface passage improvements at The Dalles, McNary, Little Goose or Lower Monumental. PFR participants supported updating cost estimates to reflect assumptions regarding the planned installation schedule for additional improvements at these three projects. Some participants believed that this would allow spill reductions with the FY 2007-2009 rate period. BPA agrees that it is appropriate to assume installation and test mode of the UPA Surface Passage Improvements at The Dalles, McNary, and Lower Monumental. The construction costs for these facilities are funded via the Corps of Engineers' Columbia River Fish Mitigation (CRFM) project annual Congressional appropriation, with debt service not beginning until after the facilities are declared fully in-service (i.e., no longer in test mode).

   The other fish and wildlife proposal impacting hydro operations is the implementation of the Snake River fall Chinook Transport vs. In-River Migration Study. In the UPA/2004 Biological Opinion (BiOp) there is a commitment to study the relative survival of fall Chinook that migrate in river vs. via barge

<u>MAY 2 DRAFT REPORT CONTINUED:</u>

transportation. As part of this study, water that is normally used to generate electricity at the collector projects would be spilled instead, reducing generation. This assumption is not in the base PFR forecast and would tend to put upward pressure on rates. BPA heard many arguments for and against this evaluation. One concern was the timing of these studies and the installation of the RSWs listed above and its impact on the validity of the data collected. It was suggested that BPA postpone this test until after the RSWs are installed so studies can be conducted using the same operations from year to year. Others argue not to include it in the initial power rate proposal because it is costly. On the other hand, it was noted that these tests are part of the UPA/2004 BiOp and doing anything other that what is in the UPA/BiOp could endanger the BiOp. BPA intends to honor its commitment in the BiOp and plans to begin implementation of the test during the FY 2007-2009 time frame. Though the spill costs of this test were not included in the PFR base, neither were the spill reductions potentially resulting from the above-described installations of some surface passage improvements. The best current estimate is these spill cost increases and reductions will roughly cancel each other out. **Draft Conclusion: No net savings in spill costs.**

2. **Proposal: Fund the expected baseline O&M costs for the Lower Snake River Compensation Plan (LSRCP) hatcheries, plus some additional funding for high priority non-routine maintenance** – This program includes spending levels for 11 hatcheries, 10 satellite facilities, and monitoring and evaluation of fish health and hatchery program effectiveness in the Lower Snake River. BPA directly funds the expense portion of O&M only under a Direct Funding agreement that began in 2001. The base spending level in the PFR assumes funding for baseline O&M expenses as well as some non-routine maintenance; e.g., replacement pumps, motors, raceway and water line repairs. As with many of the items, there was much variation in suggestions regarding funding levels for these facilities. Some customers suggested BPA fund only the baseline level of O&M only with funding for additional needs made available only when BPA had positive net revenues. It was also argued that BPA not fund any capital items associated with these hatcheries. BPA proposes to fund LSRCP O&M costs at a level slightly lower than the initial proposed level, allowing some funding for the highest priority non-routine maintenance expense items but also taking into account the fact that historical actual O&M costs have come in under start-of-year budgets in recent years. BPA will negotiate a new direct funding agreement for the LSRCP with the U.S. Fish and Wildlife Service for FY 2007–2011 consistent with this principle. **Draft Conclusion: Reduce (LSRCP) O&M costs by $300,000 per year.**

3. **Proposal: Change Columbia River Fish Mitigation (CRFM) plant-in-service dates** – See Debt Management section.

<u>Possible Increases Identified</u>

1. **Proposal: Increase Integrated Program Funding Level** – The funding level for the Integrated (or Direct) Program covers numerous projects intended to meet BPA's mitigation objectives under the Northwest Power Act, as well as BPA's Endangered Species Act offsite F&W requirements under biological opinions from the U.S. Fish and Wildlife Service and NOAA Fisheries. Through the PFR process BPA has engaged interested parties in four different funding alternatives for this program. These alternatives ranged from $126 million per year to $174 million per year. Current rate period expense funding for this Program is $139 million per year, and the non-discretionary FY 2001-2004 funding level was determined to be approximately $125 million per year. As with many of the other fish related costs, the feedback was wide and varied. Some customer groups supported the lowest cost alternative, resulting in a $13 million per year reduction in spending from the current levels. Other customers proposed the low scenario but with the provision that in good water years, additional funding should be available up to an agreed upon percentage for previously-approved but unfunded projects, with provision to "bank" the money for future years if all approved projects were already funded. Other commenters suggested that funding levels remain at current levels for the next rate period, allowing time for more clearly formulated "rolling-up" and prioritization of subbasin plan driven fish and wildlife restoration efforts. The Columbia Basin Fish and Wildlife Authority (CBFWA) and others opined that even under the highest funding level, BPA would be under-funding its mitigation obligations associated with recently completed subbasin plans. CBFWA's preferred alternative advocated Integrated Program spending levels rising to $460 million annually. In the PFR, BPA proposed, and many commenters supported, that project funding be allocated such that 70 percent would go to on-the-ground projects (primarily hatcheries and habitat enhancement projects), 25 percent to research, monitoring

MAY 2 DRAFT REPORT CONTINUED:

and evaluation (RM&E), and 5 percent for coordination/information management and administration. The purpose of this allocation is to steer additional funding to on-the-ground projects, such as those recommended in the recently completed subbasin plans, without necessarily increasing overall funding levels. An analysis of FY 2001-2004 program funding indicated that only about 60 percent of total funding went to on-the-ground work and nearly one-third of total funding went to RM&E. One commenter suggested modifying the 70/25/5 allocation guidelines, to move even more funding ($10 million) from RM&E, and to also reduce BPA's fish and wildlife overhead costs by $2 million (approximately 20 percent) and move these dollars to provide for even greater on-the-ground funding levels without increasing overall funding of this program.

In numerous discussions with Council members, Council staff, and CBFWA members, drivers influencing future work efforts in the Integrated Program project categories of hatcheries, habitat work, RM&E and coordination were discussed. Among the drivers for increased funding are habitat restoration activities prioritized in subbasin plans and the 2004 FCRPS UPA/BiOp habitat enhancement work in the Columbia Basin tributaries. Additional drivers identified include inflation costs driven by salaries, health insurance costs and rising energy costs. However, the program's expense budget increased from $100 million per year in the FY 1997-2001 period to $139 million per year in the current period. While much of this additional funding was intended to cover increased ESA requirements, it also provided a very significant allowance for inflation. The allocation guidelines that were extensively discussed in the PFR process would provide for substantial increases in available funding for habitat enhancement work under the auspices of the subbasin plans and the new BiOp by shifting some funding away from RM&E and coordination contracts. However, some commenters pointed out that there are substantial pressures from both NOAA Fisheries and the Council's independent science groups (ISRP and ISAB) for elaborate monitoring and evaluation efforts, making such funding shifts to on-the-ground work challenging to accomplish. Additionally, it was suggested that given the hurdles associated with reinventing the RM&E program, funding decisions on habitat restoration projects should precede RM&E project selection, so as to not create a situation where RM&E funding pressures adversely affect available funding for habitat work. Additionally, under the Northwest Power Act, BPA has funded a substantial wildlife mitigation effort to replace habitat lost by inundation effects resulting from reservoir construction and operation. In recent years, some of this mitigation has been funded using capital borrowing under BPA's borrowing authority consistent with BPA's capitalization policy. Several Integrated Program partners have expressed strong concerns about the difficult thresholds required by BPA for using capital funding to meet wildlife mitigation objectives and are frustrated with the slow pace towards meeting such objectives. Some have suggested that Integrated Program funding levels be increased so as to use additional expense funding for increasing the pace of wildlife mitigation. Others suggested that the region be more aggressive in the pace of wildlife mitigation efforts, but with active use of BPA's F&W capitalization policy as opposed to using the expense budget. To more fully utilize BPA's F&W capital budget over this next rate period, new focus and energy will be needed to identify and plan projects that qualify for capital assignment under BPA's capitalization policy.

Draft Conclusion: After weighing all these arguments drivers, and extensive comments in the PFR process, BPA proposes to fund the integrated program at the $143 million per year expense level and to shift roughly $15 million of FY 2001-2004 average current funding away from RM&E and RM&E-related support activities to fund additional habitat enhancement efforts, and maintain hatchery programs - The result of this funding shift would be that overall funding for on-the-ground work (primarily habitat improvement and hatchery O&M) would be about $15 million greater than FY 2001-2004 levels, providing for both a substantial funding increase for subbasin plan- and UPA-driven habitat enhancement work, and also an allowance for inflation in the O&M for hatcheries funding under the program.

The completion of 58 subbasin plans offers the region the opportunity to refocus program implementation to target specific, high priority biological objectives that may appropriately be addressed as mitigation for the FCRPS. Additionally, the recently completed Updated Proposed Action and NOAA Fisheries BiOp call for habitat improvement efforts as strategies for avoiding jeopardy to ESA-listed salmon and steelhead. The development of BPA's PISCES computer program, enabling projects to be managed and tracked from

MAY 2 DRAFT REPORT CONTINUED:

solicitation to completion, will offer the ability for projects to be managed for specific work elements, accruals to be tracked as they are invoiced, and for the region to monitor progress towards more clearly defined performance objectives. All of these factors offer the region the opportunity to use the coming rate period as one of transition to a more performance based approach. To bring about this repositioning of BPA's implementation of the program, additional work needs to be done in the following areas:

- Subbasin plans need to be "rolled up" to provincial objectives (e.g., population goals, by province, for Chinook salmon) in a manner relevant to FCRPS responsibilities.
- Recommendations to BPA for program funding need to be prioritized to show where and when different species or geographically which habitat should be the focus for the next several years.
- Performance standards also need to be developed for use in the solicitation process (e.g., physical standards (streamflow levels, river miles of blocked habitat reopened, etc) and biological standards (population levels).
- Accounting for mitigation completed to date with ratepayer funding.
- Reallocating program funding to have 70 percent of funding serve projects that directly benefit F&W.
- Accounting for the effects of ocean conditions on anadromous fish.
- Assessing the role in the program for the causal factors for population decline that go beyond factors associated with the FCRPS or the hydro system.
- Creating new partnerships and cost-sharing protocols for application to mitigation objectives and strategies, especially where there are shared responsibilities.
- Completion of recovery plans and assessment of BPA's responsibilities under them.
- Adhering more closely to the program's 70/15/15 funding allocation guideline for anadromous fish, resident fish, and wildlife, respectively. This allocation would include and be consistent with the principles contained in the UCUT proposal that was submitted in the fish and wildlife PFR meetings.

Many of these issues will be addressed in the next 2 years, through, most likely a project selection process or a Council Program Amendment process. These efforts will not be finished in time for selecting proposed program spending levels for the PFR or the rate case initial proposal. In addition, a regionally accepted methodology for looking at the current Integrated Program project portfolio and determining which discretionary projects should continue in FY 2007, which projects should no longer be funded, and which new projects should begin being funded, is still at the initial levels of a work-in-progress. After tasks mentioned above are complete, the transition will be able to move to its final stages where the current project portfolio can be more rigorously assessed for how well it meets biological and physical performance objectives in the most cost effective manner.

After much debate over funding levels for F&W, BPA proposes the following changes to the forecasted amounts in the PFR.

BPA Proposals	Proposed PFR Base FY 2007-2009 (Reductions)/Increases
Increase Integrated Program Spending Level	$4 M/year
Reduce US Fish & Wildlife Service Spending Level	($0.3 M/year)

Summary of Comments Received on Proposed PFR Forecast

BPA Division of Fish and Wildlife conducted public review meetings regionally throughout the Power Function Review. The comment review period provided the Council, customers, states, tribes and other interested parties the opportunity to give feedback on F&W program funding levels for the 2007–2009 rate period.

- Reign in Fish & Wildlife (F&W) spending. The costs are being pushed to unacceptable levels.
- Support adequate funding for F&W in the next BPA rate case. Current funding is inadequate.
- Funding must complement the tribes' F&W management and support projects consistent with treaty, trust, and other obligations; support the budget developed by F&W managers to implement subbasin plans and other tribal proposals.
- Entering into long-term funding agreement on F&W will not allow BPA the flexibility it needs to prioritize expenditures.
- Coordinate Corps research program with what is happening in the Integrated F&W Program.
- $356.9 million understates financial and environmental costs of fish operations.
- Power is available to replace the generation at the Lower Snake River dams.
- The CBFWA recommendation to ramp up funding for F&W to $240 million is essential; a number of events could significantly increase F&W expense; the ESA may require more funds for monitoring.
- The F&W program has reached an unacceptably high level of cost. There is need for greater accountability and efficiency in operating the F&W program; need scientific review of CRFM project; greater coordination needed for RM&E; need a fresh look at capitalization, depreciation, and amortization of F&W investments.
- Reconsider the need for the Snake River fall Chinook transport study.
- Try a year without spill and see what happens; we are spending $110 million a year on spill.
- Customers would be better off moving the RSWs along; take the $23 million in funding out for the fall Chinook transport study. Look at the medium range ($144 million) for Integrated Program funding, take another $10 million out of RME, $2 million from BPA overhead and direct another $12 million to on-the-ground projects. Customers need better information about when the decisions will be made in other F&W processes so our participation counts.
- BPA should take a leadership role to stop the predation and harvest.
- We need better studies about what we are getting with F&W expenses of this magnitude.
- Wait to implement the transportation study until RSWs are installed. Study should not span period with and without the RSWs, which could cloud results.
- BPA spent $15 million on subbasin plans, and now it is a struggle to implement them. F&W managers have not been able to fully implement their programs.
- Adequately fund F&W responsibilities under ESA and Northwest Power Act.
- Many F&W related points, including: further increases to F&W funding are unjustified at this time; measure of success should be biological effectiveness; support proposal to reprioritize toward on-the-ground projects; fund only activities that relate directly to BPA's mitigation obligations.
- BPA budget assumptions place implementation of subbasin plans and wildlife component of F&W program at serious risk. Final proposal should maintain flexibility to fund with capital wildlife acquisitions that cost less than $1 million. Assumed reduction in RME costs is too aggressive, and inflation factor is inequitably low.
- Increase in Integrated Program budget is necessary to meeting obligations under the Northwest Power Act and ESA. Willingness to shift away from RME is speculative; budget sufficiently to fund the UCUT proposal for the Upper Columbia Eco-region; create a firewall around the resident F&W allocations; conditional approval of 70/25/5 split; fund BPA F&W overhead from other sources and not Integrated Program budget.

- Customers now have rigorous justification for F&W expenditures and if they refuse to support the necessary funding, other authorities will likely intervene forcefully.
- Support shift of funding in Integrated Program to 70/25/5 allocation; agree with need for greater RME coordination; it is inappropriate for BPA customers to mitigate for all problems identified in the subbasin plans and we object to paying for mitigation not directly related to federal hydro impacts. Further increases in F&W funding are unjustified at this time.
- Accelerate installation of surface bypass systems; modify Snake River fall Chinook transportation study; fund baseline O&M and provide greater clarity on role of hatcheries in meeting mitigation obligation; no increase in Integrated Program budget without biological goals and objectives and priorities to meet BPA mitigation obligation; more must be done to reduce F&W mitigation costs.
- Assume in-river transportation study will be moved out of the next rate period; include revenue from additional generation resulting from RSWs; could support $143 million level for Integrated Program if it includes obligations for subbasin plans, thorough bottoms-up examination of program, no special rate adjustment for unanticipated costs; amortize long-lived assets over their useful lives.
- May be time to survey BPA's electric consumers as to whether they would accept a .02 cent per kWh increase to forego the benefits and costs of Lower Snake River dams.

Final Report Decisions

Comments received on the F&W Integrated Program varied widely among participants. As stated in the draft report, BPA remains committed to an ongoing, progressive implementation of an integrated and collaborative plan for F&W mitigation and recovery. To be truly results-driven, our investments throughout the basin – aimed at the needs of both listed and non-listed species – must be linked to clearly defined biological objectives, must be as cost-efficient as possible, and must be linked to mitigating for the impacts of construction and operation of the federal hydropower system, and consistent with the *Columbia Basin Fish and Wildlife Program* vision of protecting and mitigating the natural ecological functions, habitats, and biological diversity of the Columbia River Basin. In recent years, BPA has made considerable strides to improve contracting, financial management, progress reporting, and program evaluation. Our renewed emphasis on performance provides a solid foundation for managing the Direct Program into the future.

As we begin planning for review and implementation of projects in FY 2007-2009, the funding allocations of 70 percent for on the ground projects, 25 percent for RM&E and 5 percent for coordination proposed by BPA in the PFR will be closely followed. During this new and challenging transition period, in coordination with the Council, regional F&W managers, tribes and others, we intend to move to a more performance and results-based approach for project solicitation and program management. It will emphasize sound science, greater cost-sharing and partnership agreements to address offsite mitigation of impacts caused by sources other than the FCRPS. In addition, we will emphasize this performance-based approach in BPA's program management priorities, policy goals, and implementation funding decisions through this reprogramming of current spending and in the prioritizing of new investments where needed. The result will be a more efficient project review and implementation process that facilitates the results-based work of the program and maximizes the effective application of fiscal and human resources.

1. **Regional Agreement Among States, Tribes, and Federal Agencies on Hydro System Management -** NOAA Fisheries, BPA, Bureau, and the Corps have been working collaboratively with the governors of Oregon, Washington, Idaho, and Montana for several months to address both short-term and long-term FCRPS management and operation solutions. We recognize that this work has been difficult – we have not yet reached agreement on these critical issues – and that the challenges are great. But we all share a tremendous responsibility and commitment to continuing our dialogue to develop a salmon recovery approach that meets mutually agreed upon biological objectives, that delivers clear results, and is regionally sustainable for the future. While it is unclear at this time whether the agreement, if reached and finalized, would change costs, we expect it could change how funding is used for recovery measures and also help make system operations and costs more predictable. However, we are not changing the forecast for the final report, and this issue will be updated as conditions warrant.

2. **Mitigating Additional Costs of Increased Summer Spill Requirements -** In *National Wildlife Federation v. National Marine Fisheries Service* the court on June 10, 2005, entered an order requiring spill in addition to what the FCRPS Action Agencies had already planned under the UPA. The costs of these additional spill operations to BPA ratepayers in 2005 are estimated to be $67 million. The amount will vary with actual energy market prices and stream flow conditions. BPA has not decided how to manage these costs if they are carried into FY 2007-2009. Due to the relationship between the financial effects of hydro system operations requirements for fish and the direct program, reductions in program cost levels may be necessary if generation and revenue effects are expected to be significant and persistent throughout the FY 2006-2009 period.

3. **Integrated Program Funding Level –** Through the PFR process and comment period, BPA has engaged interested parties in considering driving forces that might increase or decrease the program spending levels. We evaluated many drivers and their accompanying rationales, and generally reflected them in four different funding alternatives for the program. These alternatives for the expense portion of the program ranged from $126 million per year to $174 million per year. Current rate period expense funding for this program is $139 million per year. As with other areas of program investment, the feedback regarding the scope of direct expenditures was lively and diverse. Some customer groups supported the lowest-cost alternative, resulting in a $13 million per year reduction in spending from the current levels. Other customers proposed the low scenario but with the provision that in good water years, additional funding should be available up to an agreed upon percentage for previously-approved but unfunded projects, with provision to "bank" the money for future years if all approved projects were already funded. Other commenters suggested that funding levels remain at current levels for the next rate period, allowing time for more clearly formulated "rolling-up" and prioritization of subbasin plan driven F&W restoration efforts. The Yakama Nation and the CRITFC and others opined that even under the highest funding level, BPA would be under-funding its mitigation obligations associated with recently completed subbasin plans. These Tribes advocated Program spending levels of $310 million annually.

In the PFR, BPA proposed, and many commenters supported, that project funding be allocated such that 70 percent would go to on-the-ground projects (primarily hatcheries and habitat enhancement projects), 25 percent to research, monitoring and evaluation (RM&E), and 5 percent for coordination, information management, and administration. The purpose of this allocation is to steer additional funding to on-the-ground projects, such as those recommended in the recently completed subbasin plans, without necessarily increasing overall Integrated Program funding levels. An analysis of FY 2001-2004 Program funding indicated that less than 60 percent of total funding went to on-the-ground work and nearly one-third of total funding went to RM&E. One commenter suggested modifying the 70/25/5 allocation guidelines, to move even more funding ($10 million) from RM&E, and to also reduce BPA's fish and wildlife overhead costs by $2 million (approximately 20 percent) and move these dollars to provide for even greater on-the-ground funding levels without increasing overall funding of this program.

In numerous discussions with Council members, Council staff, and CBFWA members, drivers influencing future work efforts in the Integrated Program project categories of hatcheries, habitat work, RM&E and coordination were discussed. Among the suggested drivers for increased funding are habitat restoration activities prioritized in subbasin plans and the 2004 FCRPS UPA/BiOp habitat enhancement work in the Columbia Basin tributaries. The new subbasin plan priorities, however, created greater clarity for priorities, not new FCRPS obligations. Additional drivers identified include inflation costs driven by salaries, health insurance costs and rising energy costs. However, the program's expense budget increased from $100 million per year in the FY 1997-2001 period to $139 million per year in the current period. While much of this additional funding was intended to cover increased ESA requirements, it also provided a very significant allowance for inflation. The allocation guidelines that were extensively discussed in the PFR process would provide for substantial increases in available funding for habitat improvement work under the auspices of the subbasin plans and the new BiOp by shifting some funding away from RM&E and coordination contracts. However, some commenters pointed out that there are substantial pressures from both NOAA Fisheries and the Council's independent science groups (ISRP and ISAB) for elaborate monitoring and evaluation efforts, making such funding shifts to on-the-ground work challenging to accomplish. Additionally, it was suggested that given the hurdles associated with reinventing the RM&E program, funding decisions on habitat projects should precede RM&E project selection, so as to not create a situation where RM&E funding pressures adversely affect available funding for habitat work. Additionally, under the Northwest Power Act, BPA has funded a substantial wildlife mitigation effort to replace habitat lost by inundation effects resulting from reservoir construction and operation. In recent years, some of this mitigation has been funded using capital borrowing under BPA's borrowing authority consistent with BPA's capitalization policy. Several commenters expressed strong concerns about the difficult thresholds required by BPA for using capital funding to meet wildlife mitigation objectives and are frustrated with the slow pace toward meeting such objectives. Some have suggested that Integrated Program funding levels be increased so as to use additional expense funding for increasing the pace of wildlife mitigation. Others suggested that the region be more aggressive in the pace of wildlife mitigation efforts, but with active use of BPA's F&W capitalization policy as opposed to using the expense budget. Taking all these comments into consideration, BPA believes that its proposed $143million Fish and Wildlife Program funding level allows for significant additional funding of high priority habitat improvement efforts reflected in the recently completed subbasin planning effort, through the proposed 70/25/5 funding allocations between on-the-ground work, RM&E and coordination, through increased application of cost sharing and partnering where there are shared mitigation obligations, and through more strategic, efficient and better coordinated RM&E. BPA also believes its wildlife mitigation is on a steady pace toward achieving mitigation obligations, with up to 34,000 acres protected in FY 2004-2005—nearly one-tenth of what the FCRPS inundated. To more fully utilize BPA's capital funding availability over this next rate period, new focus and energy will be needed to identify and plan projects that qualify for capital assignment under BPA's capitalization policy.

4. **Proposed installation and test mode of additional Updated Proposed Action (UPA) Surface Passage Improvements and Implement Snake River Fall Chinook Transport vs. In-River Migration Study –** Though the cost of increased spill for the Snake River fall Chinook transport versus in-river evaluation were not included in the PFR base, neither were the potential spill reductions that may result from installations of surface passage improvements at The Dalles, McNary, Little Goose or Lower Monumental dams. The best current estimate is these spill cost increases and reductions will roughly cancel each other out. BPA acknowledges concerns raised about the timing of the transport versus in-river evaluation relative to installation of surface passage technologies. Given recent legal rulings about the 2004 NMFS BiOp and UPA, it is unclear what degree of flexibility there is to modify the timing of the evaluation. BPA will work with other federal agencies to further examine this issue. If adjustments in the timing can be made in a manner consistent with BPA’s obligations under the ESA, BPA will reflect any appropriate schedule changes in the final power rate proposal next year.

OTHER

	Average Expense	Average Capital
FY 2002-2006 Other	$83 M/yr	N/A
FY 2007-2009 PFR Base Forecast	$120 M/yr	N/A
FY 2007-2009 Proposed PFR Forecast	$105 M/yr	N/A
FY 2007-2009 Final PFR Forecast	**$105 M/yr**	**N/A**

MAY 2 DRAFT REPORT:
Throughout the PFR workshops several items where changes could occur were identified that did not fall into the major program areas examined during the PFR. Nonetheless, BPA thought it important to include these areas in the closeout report since they have an impact on rates.

1. **Proposal: Remove Spokane Settlement forecast** – Discussions have gone on for many years of providing the Spokane tribe with compensation for lost land resulting from federal dam construction, similar to the settlement BPA currently has with the Colville tribe. Congress has considered legislation creating such compensation. A placeholder for such compensation payments was included in the PFR Base. However, it is not appropriate to plan on such payments unless and until Congress has authorized them. **Draft Conclusion: Remove the forecast of Spokane Settlement costs in the rate case initial proposal FY 2007-2009 spending levels and revise it in the final proposal if it passes.**

2. **DSI Benefits Forecast** – During the time the PFR base forecast was assembled, there was an outstanding issue of what type of benefits the DSI's would receive in the FY 2007-2009 time frame and the cost associated with them. The PFR base adopted the then proposed DSI Record of Decision (ROD) amount of $40 million per year in benefits and assumed it would be delivered in money rather than power as a placeholder. Understanding this issue is one that will be resolved in the Short-Term Regional Dialogue and rate case arena, the forecast in the PFR will be updated in the rate case to reflect the decisions from the Regional Dialogue conclusions. **Draft Conclusion: This item will be updated in the rate case to reflect the outcomes from the Supplemental Regional Dialogue ROD on DSI Service.**

3. **Reduction in Environmental Benefits Forecast –** When the PFR base forecast was put together there was a forecast of around $7 million per year for mitigation of the proposed spill reduction in FY 2004 that was accidentally carried forward from that timeframe. This should not have been included and BPA has since made this correction and has included it in the forecast accompanying this letter in the "other" category. **Draft Conclusion: Update Environmental Benefits forecast in closeout report.**

4. **Proposal: Adopt Conditional Budgeting** – An idea brought up at the PFR workshops was to link BPA spending levels to its financial performance every year. When BPA faced a year where financial results fell below assumptions in the rate case then spending levels would be reduced to help offset some of the losses. On the other hand, when BPA had a good financial year the spending levels could be increased to make up some of the projects that were put off in the low water years. This would reduce the need for risk mitigation costs in the rate case and that BPA spending would bear some of the burden in poor financial years. BPA's employee award program, for example, already has this variability built into it. Given the magnitude of the risk management challenge in this next rate period, BPA considered this concept carefully. However, three concerns make BPA reluctant to pursue this concept at this time: First, it appears doubtful that enough of the budget can be put "on the margin" in this way to make a significant impact on risk mitigation costs, without jeopardizing essential functions. Second, constructing and implementing such a construct could add significant complexity. BPA is reluctant to add complexity unless risk management benefits are significant. Third, it is not clear how this concept could be

MAY 2 DRAFT REPORT CONTINUED:

implemented without making program cost levels a rate case issue – a step BPA does not wish to take. **Draft Conclusion: Do not pursue conditional budgeting.**

BPA Proposals	Proposed PFR Base FY 2007-2009 (Reductions)/Increases
Remove Spokane Settlement Amount	($6 M/year)
Update Environmental Benefits forecast	($7 M/year)

Summary of Comments Received on Proposed PFR Forecast

- Leave IOU benefits open to discussion; perhaps include ceiling.
- Do not subsidize the aluminum companies.
- Do not lock budget decisions down now.

Final Report Decisions

Cost control is an important aspect to BPA no matter how big or small the budget item. In the PFR process there were several categories of costs either outside the scope of the PFR (i.e., DSI benefits) or small enough not to warrant a workshop to understand the costs associated with the forecast. The categories associated in the "other" category consisted of items generally in the single-digit forecasts and many times ones where we make payments based on a calculation. A few of the items were discussed with a certain program area such as Council and U.S. Fish & Wildlife in the F&W workshops. The items in the "other" category are:

Other	FY02-06 Average	FY07-09 Average - PFR Base	FY07-09 Average - PFR Proposed	FY07-09 Average - PFR Final Decision
-US Fish & Wildlife Lower Snake Hatcheries	$ 16.6	$ 19.8	$ 19.5	$ 19.5
-Planning Council	$ 8.3	$ 9.1	$ 9.1	$ 9.1
-Colville Settlement	$ 17.9	$ 17.4	$ 17.4	$ 17.4
-Spokane Settlement	$ -	$ 6.7	$ -	$ -
-Trojan Decommissioning	$ 5.0	$ 5.6	$ 5.6	$ 5.6
-WNP 1&3 Decommissioning	$ 0.1	$ 0.1	$ 0.1	$ 0.1
-PNCA Headwater Benefit	$ 1.8	$ 1.7	$ 1.7	$ 1.7
-Hedging/Mitigation	$ 4.1	$ 0.3	$ 0.3	$ 0.3
-Other Environmental Requirements	$ 3.0	$ 7.5	$ 0.2	$ 0.2
-Civil Service Retirement System	$ 17.1	$ 11.6	$ 11.6	$ 11.6
-Other Income, Expenses, Adjustments (DSI benefits for FY07-09)	$ 9.2	$ 40.0	$ 40.0	$ 40.0
Total	**$ 83**	**$ 120**	**$ 105**	**$ 105**

The comments received on this category focused on three main themes: DSI benefits, not keeping budgets out of the rate case, and IOU benefits. While DSI benefits are a matter that will be decided in the Short-Term Regional Dialogue forum, it is important to note that a $40 million per year placeholder was used in the PFR forecast. The PFR did not assume any change to this forecast in the final report so if there is a difference in the amount decided upon in the DSI ROD it will either help or hinder the progress of the PFR total reductions identified.

While the argument to keep budgets in the rate case has been made, BPA has been taking a firm stand on this issue since the 1987 rate case. The Administrator took the position during and at the conclusion of each of the rate cases that rate hearing requirements do not comprehend all aspects of BPA's business, but only legitimate ratemaking issues; program and program level determinations are not ratemaking issues. Moving cost decisions into the rate case forum would also potentially bring those decisions into the purview of FERC review of BPA rates, thereby greatly expanding the scope of that review. It is BPA's intent to keep that position in the FY 2007-2009 rate case proceedings.

The IOU benefits are based on a calculation contained in a contract and already include a floor and ceiling. The method itself cannot be up for debate in the rate case because it is contractually defined, but there are still some aspects of uncertainty that will be open for discussion.

After consideration of the comments received in this category from PFR participants, the conclusion of the PFR is to not change the forecasts in the "Other" category from the draft report.

DEBT MANAGEMENT

	Average Expense	Average Capital
FY 2002-2006 Debt Management	$892 M/yr	N/A
FY 2007-2009 PFR Base Forecast	$1,003 M/yr	N/A
FY 2007-2009 Estimated PFR Forecast	$965 M/yr	N/A
FY 2007-2009 Final Estimated PFR Forecast	**$965 M/yr**	**N/A**

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Unlike many of the programs studied and discussed in the PFR process, the debt management area is not a program but a result of the capital investments the agency has made over time, forecasts for future capital investment, and BPA's debt management decisions. The PFR included discussion on these items because it was important for participants to understand the implications of past debt management decisions and proposed capital spending levels. But how BPA includes decisions and assumptions on debt management are rate case issues and will be discussed in that forum. With that said, the PFR process brought attention to many issues associated with program funding proposals. BPA's current thoughts are described under each topic below.

Possible Decreases/Increases Identified

1. **Proposal: Change Columbia River Fish Mitigation (CRFM) mitigation analysis plant-in-service schedule** – The Corps receives appropriated funds for the CRFM project to mitigate impacts to anadromous fish passage of construction of the Columbia/Snake River dams. Currently there is approximately $300 million of mitigation analysis being held in "construction work in progress" related to alternative analysis, prototype development and other studies done under this program. The Corps is currently evaluating to determine the appropriate schedule for putting this amount into "plant in service", at which time it will become BPA's obligation to repay the power share. The Corps has provided two different "bookend" scenarios (A&B). Many customers have expressed a preference for scenario B to avoid having additional costs hit the FY 2007-2009 rates. It is ultimately not BPA's decision when to put this amount into service. However, if the Corps has not made a decision at the time BPA prepares its initial power rate proposal, BPA will decide what assumption to include in its initial power rate proposal. This forecast may be updated to reflect the Corps decision prior to the final rate proposal. **Draft Conclusion: At this time, BPA prefers the Corps use scenario B.**

2. **Proposal: Debt finance CGS capital projects with final maturity of FY 2018** – Through 2001, EN included capital expenditures in its O&M projections and they were revenue financed through BPA rates. In the SN CRAC rate case, BPA and EN agreed that EN would issue bonds backed by BPA to finance expenditures that qualified under GAAP as capital investments for the FY 2002-2006 period. EN issued the first bonds for new capital investments in 2003. All new capital investment debt has been issued with the final maturity of 2018. As we head into the next rate period it has been suggested in the PFR that BPA and EN continue this practice of financing capital items through debt rather than revenue financing. **Draft Conclusion: Though the PFR is not the process for this decision, BPA expects to assume debt financing for CGS expenditures that qualify under EN's capitalization policy and limit the final maturity to FY 2018 in its initial power rate proposal. BPA and EN will jointly consider and evaluate the feasibility and value of matching bond maturity dates for new capital investments with the expected lives of those investments. Before including such an assumption in the final power rate proposal, BPA will review this alternative with its customers and others.**

3. **Proposal: Finance Nuclear Fuel** – The cost of fuel has always been treated as an expense through BPA rates, the EN net-billed budget, and BPA financial statements. On their financial statements, EN capitalizes fuel over the expected life. BPA assumed continued expensing of fuel in the base PFR forecast. Some

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PFR participants argued for debt financing fuel to help spread the costs over time. EN generally purchases roughly the same amount of fuel as is burned by CGS each year. Under these circumstances, borrowing to pay for fuel costs is somewhat similar to borrowing to pay O&M costs. However, if fuel for several years of CGS operation is purchased in one year, financing such "lumpy" fuel costs can make sense as a means of spreading the costs to the years in which the fuel is actually burned. BPA and EN have agreed and EN has issued bonds backed by BPA to finance fuel acquisition in FY 2005, 2006, and 2007. **Draft Conclusion: EN has issued bonds to pay for up to $93 million in fuel costs in FY 2005, 2006 and 2007. Initial proposal debt service forecasts will include debt service on those bonds. Remaining decisions on this topic will be made in the rate case.**

4. **Proposal: Change the amortization period for Conservation investments** – In the FY 2002-2006 rate case it was determined that conservation augmentation investments should be amortized over the term of the existing contracts, i.e., through FY 2011. The decision was made on the basis that these conservation augmentation investments had benefits that were only certain to accrue for as long as the contracts were in place. This decision has created concern among the customers because in the last few years of the contract period any new conservation investments are essentially expensed under this treatment. BPA examined the current practice against 5- and 15-year recovery periods and agrees that retaining the current policy of recovering all conservation costs by FY 2011 is too conservative. However at present there are unresolved issues about how conservation costs will be recovered in a likely tiered rate structure post-2011. Until this is resolved, a relatively short recovery period appears more prudent. In addition, preliminary repayment model analysis indicated only a small reduction in debt service resulting from the longer recovery period. **Draft Conclusion: Rather than the 10-year declining amortization period policy in place for the currently operating Conservation Augmentation program, for conservation acquisition activities planned to commence in FY 2007, BPA is leaning towards establishing a 5-year Straight Line amortization period policy.**

5. **Proposal: Utilize a revised interest rate forecast for the initial power rate proposal** – This is a standard practice in the power rate cases when circumstances warrant an updated forecast and will continue to be this rate case. The interest rate forecast used for the PFR Base is not significantly different from current forecasts. **Draft Conclusion: BPA will update the interest rate forecast in the initial power rate proposal.**

6. **Proposal: Include interest income on cash balances from the Bonneville Fund** – This is a standard practice in the power rate cases and will continue to be this rate case. The PFR is not a place where this decision is made, but because its base forecast did not include this assumption it needed to be noted. This amount will be greatly influenced by the rate structure adopted in the rate case. A rough estimate of the additional interest income is around $10 million per year. **Draft Conclusion: BPA will include interest income on cash balances in the initial power rate proposal.**

7. **Proposal: Extend some of the current CGS debt beyond FY 2018 –** The current practice is not to place any debt past FY 2018 when refinancing debt in support of the debt optimization program. This is in compliance with the EN Board policy. BPA will analyze the effects on ratepayers of implementing this suggestion and share its results with the EN Executive Board over the ensuing months. **Draft Conclusion: BPA will not include this suggestion in the initial power rate proposal, but could potentially include it in final rate studies. BPA and EN will jointly consider and evaluate the feasibility and value of extending the final maturity of some existing CGS debt beyond 2018. If a change is warranted, before including such an assumption in the final proposal, BPA will review this alternative with its customers and others.**

8. **Proposal: Lengthen the amortization period for F&W capital –** BPA's long-standing policy is to amortize BPA's F&W capital projects over a 15-year life. In comparison, any fish-related capital investments made at the dams are depreciated, with the rest of the project assets, over 75 years and repaid over 50 years. During the PFR process, several customers argued that the BPA F&W amortization criteria are too stringent and that the amortization period should be lengthened. This is a rate case issue. However, at this time BPA believes it is appropriate to continue with its existing policy, given that BPA's F&W

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investments are non-revenue producing assets, not attached to revenue-producing assets (as the Corps investments are), and are not owned by BPA. A change in accounting policy to allow more capital spending for assets only allowed to be capitalized under Financial Standards Board Statement #71 does not seem to be prudent, given BPA's limited borrowing authority. **Draft Conclusion: It is not appropriate to change the F&W amortization policy.**

Many of the decisions associated with the debt components of the power rates are appropriately debated in the power rate case forum. But BPA thought it important to show in the PFR the impact of past and future debt management decisions since these impact power rates. This PFR final report is not making any decisions associated with the debt management issues but instead is intended to portray BPA's current thinking on these issues heading into the FY 2007-2009 power rate case. The savings associated with individual items are current estimates of the incremental revenue requirement impacts of each action. They are indicative of what we would expect, but when several actions are taken together the results are not necessarily additive. In other words, the total savings may well differ when the items are combined in repayment studies.

BPA's Current Thinking	Proposed PFR Base FY 2007-2009 (Reductions)/Increases
Debt Finance CGS Capital	($13 M/year)
Adopt different CRFM schedule	($5 M/year)
Change Conservation Amortization Schedule to 5 years	($ 10 M/year)
Include Interest Income on cash balances from BPA fund	($ 10 M/year)

Summary of Comments Received on Proposed PFR Forecast

- Include a placeholder for debt reduction in revenue requirement.
- Resist pressures to push current expenses into future rate periods – revenue finance a portion of capital outlays.
- Re-examine capital policy regarding habitat acquisition; explore making capital more freely available.
- Work with other Federal agencies to minimize rate impacts of debt management.
- Increase amortization period of BPA-funded F&W investments.
- Amortize conservation investments over useful life of measures.
- Pursue opportunities to alter non-federal debt service associated with EN.

Final Report Decisions

As noted previously, debt management issues are not decided in the PFR. We are using PFR comments to inform our discussions of and decisions on debt management assumptions that will be incorporated into the initial power rate proposal. Those assumptions are subject to debate in the rate case process. At least two significant areas of public comment on the draft report will be explored further before final power rates are set – the possibility of a longer amortization period for conservation capital and the possibility of recovering CGS capital over the full license period of the project (i.e., through 2024). Both of these actions were advocated by PFR participants. The conservation capital amortization period will be reviewed next year, based on progress defining long-term conservation programs in the Long-Term Regional Dialogue process. BPA will further discuss the recovery period for CGS capital with the EN Board and interested customers and others. Both of these are power rate case issues and will be addressed within the rate case process. Any changes will be reflected in the final power rate proposal next year.

RISK

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The PFR looks at the costs associated with the PBL and provides an opportunity for public comment on those costs prior to them being included in the rate case. While the topic of risk mitigation is not a PFR topic it will be a major component of BPA's power rates in FY 2007-2009. Therefore, participants voiced concern that they needed to get a sense of the total picture in order to provide meaningful input into the PBL cost structure. In addition, BPA realized that risk mitigation will be a big issue in the FY 2007-2009 power rate case and wanted to begin discussions about different ways to mitigate risks. As a result, BPA included risk mitigation workshops in the PFR process with the understanding that any numbers used were preliminary and will be updated in the rate case itself. This first Risk workshop was really the beginning of FY 2007-2009 rate case workshops.

Risk mitigation will be a key topic in the next rate period because risk management is a greater challenge than in prior rate cases. Several factors are driving this amount to unprecedented levels. Gas prices have been at a historic high over the last few years. These gas prices are putting upward pressure on the electric power market prices. With the higher market prices also comes more volatility (risk) – not only does the volatility of prices for electricity increase, but the financial impact of hydro uncertainty increases, since each incremental or decremental MW of generation is worth more. This tends to increase the revenues from secondary sales but also causes greater swings in revenues when the market or hydro supply changes. Because secondary revenue uncertainty is one of the largest components of BPA's risk, the approach taken to manage it will have a large impact on the level of the FY 2007-2009 power rate, or its volatility, or both. BPA has customarily relied on financial reserves, which serve as a cushion to help manage the volatility of secondary revenues. Although the level of reserves that will be available for mitigating secondary revenue risk and other risks in FY 2007-2009 is still very uncertain, the expected value of these reserves is only $180 million going into FY 2007 (as of March 2005). That level is insufficient to manage the range of secondary market swings possible with the sustained high gas prices the markets are forecasting.

Key criteria BPA is seeking to meet in a risk management approach include meeting the established 3-year Treasury Payment Probability (TPP) standard of 92.6 percent, increasing PBL Minimum Liquidity Reserves to $100 million, and using only PBL reserves, revenues and risks in calculating the TPP except when the Administrator can forecast having additional reserves temporarily available. To meet these standards and cover the volatility, BPA's preliminary forecast shows it would need an additional $500 million per year in rates in order to set a flat, fixed rate without any adjustments during the rate period. This would lead to unacceptably high rates. On the other hand, if the volatility in secondary revenues could be covered by an adjustable rate, the need for large reserves could be significantly reduced, and the overall power rate could also be reduced. BPA did not propose a particular approach to risk management in the PFR but instead laid out a variety of options available to help mitigate risk and bring down the rate impact of risk management.

Though the regional discussion of this topic is just starting, some key views expressed by one or more customers to date are:

- Some customers have indicated a willingness to have an adjustable rate, if it results in a lower "effective" rate.
- Several customers have said they are much more comfortable with adjustment mechanisms that are automatic, clearly defined, and based on factors beyond BPA's control.
- Treat the variability of IOU benefits as a hedge against the variability of secondary revenues.
- Do not return to the established TPP standard for the FY 2007-2009 period, or do so on a phased-in basis.
- Review the need for an increase in minimum liquidity reserve, and/or phase-in this increase.
- In calculating TPP, recognize the availability of TBL reserves.
- Stepped rates
- Other cash management tools.

It is premature for BPA to respond to these comments now, since the regional discussion of risk management in BPA power rates is ongoing. BPA will work closely with its customers and others to find the best risk management approach from among the many candidates.

Summary of Comments Received on Proposed PFR Forecast

- BPA should not establish a high base rate to cover all risk.
- BPA should separate risk of program increases from hydro risk; implement a Cost Recovery Adjustment Clause (CRAC) with specific parameters.
- BPA needs an effective cost recovery mechanism to ensure meeting the F&W goal.
- Use CRACs rather than build up a huge reserve.
- Slice customers essentially self-insure risk. How about letting all customers self-insure.
- Use conditional budgeting, with a basic budget and a list of things you will do if revenues are better than expected.
- Delay increasing the liquidity reserve. Apply BPA total reserves in modeling, not just PBL. Keep TPP at 80 percent for first year of rate period.
- The TPP of 92.6 percent came from a 10-year old plan. This does not tell us where we should go with risk.
- Costs are a way to meet risk; start looking today at where you could cut costs. Consider a line of credit from the U.S. Treasury.
- Open to assuming less surplus revenue in base rates if there is a rebate mechanism; some rate adjustment mechanism may be appropriate for costs outside BPA's control.
- BPA could commit to carry a portion of the risk on the expense side.
- It would be a loss if the first response to risk is cutting budgets for conservation, renewables and F&W.
- Work to ensure you are not overstating risk; find a balance between customer and BPA holding funds for risk; revisit the recommendations made in the 10-year plan to see if they are appropriate.
- Establish budget category of unidentified cost reductions to close gap between implied rate and rate after risk target. Set the lowest initial rate in exchange for rate variability.
- A well-constructed surcharge can correct for secondary revenue variability.
- Give policy makers an opportunity to talk about risk before the rate case.
- Risk should be a partnership; put conditional budgeting back on the table for discussion.

Final Report Decisions:

Risk mitigation will be a widely debated topic in the FY 2007-2009 power rate case. BPA is acutely aware of the concern customers have on the size and magnitude of this category and shares the concern and will do everything it can to work with rate case participants to address this concern while meeting BPA's mission and objectives. A request from PFR participants for a more policy-level discussion of the topic before the rate case was met through a policy-level workshop held on June 23, with another one likely to be held in early September 2005.

BPA has examined carefully the concept of "contingent budgeting" or similar mechanisms by which expenses are adjusted on short notice in response to fluctuation in water conditions and secondary revenues. To have significant risk mitigation value, such expense adjustments would have to be made on short notice (2 or 3 months) and be in the tens of millions of dollars in magnitude. BPA reviewed each component of its cost structure for such opportunities and concluded that such opportunities are very limited, that the administrative costs of instituting it would be high since it would involve multiple parties in addition to BPA, and that negotiation of such cost flexibility with other parties would need to contemplate both increases and decreases in expenses in response to financial conditions. Moreover, it's an expensive way to operate programs given that the revenue variability on BPA's system would suggest changing funding levels on a regular basis up and down. For these reasons BPA does not plan to institute conditional budgeting. However, as addressed in each section of this PFR report, BPA does plan to review and potentially revise a number of specific cost components before preparing its final power rate proposal next year in hopes of identifying additional cost reductions over the next 8 months.

As noted previously, risk mitigation issues are not decided in the PFR. We will use PFR comments to inform our discussions of and decisions on risk mitigation assumptions that will be incorporated into the power initial power rate proposal. Those assumptions are subject to debate in the rate case process.

Final PFR Report FY 2007-2009 Forecast Levels

	EXPENSE	CAPITAL
BPA's PFR Final Decisions	**Final PFR FY 2007-2009 Average (Reductions)/ Increases**	**Final PFR FY 2007-2009 Average (Reductions)/ Increases**
PFR Decision Areas		
Remove Telemetering costs from Transmission Forecast	($0.8 M/year)	
Remove forecast of Calpine from FY 2007-2008 in Renewables Forecast ($31 M/year for FY 2007-2008)	($21 M/year)	
Revise wind contract output forecast	($4 M/year)	
Include facilitation forecast for FY 2007-2008 in Renewables Forecast ($5.5 M FY 2007, $11 M FY2008)	$6 M/year	
Include renewable rate credit in Renewables Forecast	$6 M/year	
Include TCI cost to Internal Operations Charged to Power Forecast	$1.3 M/year	
Include efficiencies forecast for Internal Operations Charged to Power Forecast	($8 M/year)	
Include reduced funding for WECC/NERC compliance in Corps/Reclamation Forecast	($1.5 M/year)	
Reduce O&M costs per Draft Long Range Plan in CGS forecast	($22 M/year)	
Increase CGS decommissioning trust fund contribution	$1 M/year	
Increase Integrated Program Forecast for F&W	$4 M/year	
Reduce US Fish & Wildlife Service Spending Level	($0.3 M/year)	
Include forecast updates for Environmental Requirements, Transmission Third Party GTA Wheeling and misc.	($13 M/yr)	
Remove Spokane Settlement amount in forecast	($6 M/year)	
Subtotal PFR Decision (Reductions)/Increases	**($58 M/year)**	**$0 M/year**
Rate Case and Other Decision Areas		
Debt Finance CGS Capital (net reduction)	($13 M/year)	
Adopt different CRFM schedule	($5 M/year)	
Change Conservation Amortization Schedule to 5 years	($10 M/year)	
Include Interest Income on cash balances from BPA fund	($10 M/year)	
Subtotal Est. Debt Management Reductions	**($38 M/year)**	
Grand Total	**($96 M/year)**	**$0 M/year**

Summary Table Incorporated Into BPA's Financials for PFR Final Report:

		FY 2002-2006 Average Expense	FY 2002-2006 Average Capital	PFR Base FY 2007-2009 Average Expense	PFR Base FY 2007-2009 Average Capital	PFR Draft Closeout Letter Average Expense	PFR Draft Closeout Letter Average Capital	PFR Final Report Average Expense	PFR Final Report Average Capital	PFR Delta Base to Final Expense	PFR Delta Base to Final Capital
1	Long-Term Generating Projects	$ 28	$ -	$ 25	$ -	$ 25	$ -	$ 25	$ -	$ -	$ -
2	Renewables Program (Expense Only) Removed Geothermal forecast FY07-08 - ($21 M/yr) Revise wind forecast FY07-09 - ($4 M/yr) Added facilitation budget FY07-08 - $6 M/yr Added renewable rate credit FY07-09 - $6 M/yr	$ 22	$ -	$ 56	$ -	$ 61	$ -	$ 42	$ -	$ (13)	$ -
3	Conservation Program (Expense Only)	$ 66	$ 27	$ 71	$ 32	$ 70	$ 28	$ 71	$ 32	$ -	$ -
4	Internal Operations Charged to Power Rates Included forecast for Process Improvements - ($8 M/yr) Included TCI forecast - $1.3 M/yr	$ 107	$ -	$ 116	$ -	$ 110	$ -	$ 110	$ -	$ (6)	$ -
5	Other Removed Spokane Settlement Forecast - ($6 M/yr) Updated Environmental Benefits Forecast - ($7 M/yr) Reduced US Fisheris Forecast - ($300 K/yr) Misc. Updates - ($1 M/yr)	$ 83	$ -	$ 120	$ -	$ 105	$ -	$ 105	$ -	$ (15)	$ -
6	Fish & Wildlife Direct Program (Integrated Program) Increased Integrated Program Forecast - $5 M/yr	$ 139	$ 20	$ 139	$ 36	$ 143	$ 36	$ 143	$ 36	$ 4	$ -
7	Transmission Purchases, and Reserve/Ancillary Services Removed Telemetering Forecast - ($800 K/yr) Updated 3rd Party GTA Wheeling Forecast - ($4 M/yr)	$ 171	$ -	$ 189	$ -	$ 184	$ -	$ 184	$ -	$ (5)	$ -
8	Settlement Payments to Residential & Small Farm Consumers of IOUs 1/	$ 375	$ -	$ 323	$ -	$ 323	$ -	$ 323	$ -	$ -	$ -
9	Corps and Reclamation O&M for Hydro Projects Reduced WECC/NERC complicance forecast - ($1.5 M/yr)	$ 196	$ 110	$ 242	$ 138	$ 240	$ 138	$ 240	$ 138	$ (2)	$ -
10	Columbia Generating Station O&M for Nuclear Plant Reduced O&M forecast per Draft Long Range Plan - ($22 M/yr) Increased contribution to Decomissioning Fund - $1 M/yr	$ 215	N/A	$ 284	$ -	$ 262	$ -	$ 263	$ -	$ (21)	$ -
11	Debt Management Debt Financed CGS Capital - ($13 M/yr) 2/ Adopted different CRFM schedule ($5 M/yr) Changed Conservation Augmentation Schedule to 5 years - ($10 M/yr)	$ 892	$ -	$ 1,003	$ -	$ 965	$ -	$ 965	$ -	$ (38)	$ -
12	Power Purchases	$ 559	$ -	$ 107	$ -	$ 107	$ -	$ 107	$ -	$ -	$ -
13	**Total**	**$ 2,853**	**$ 157**	**$ 2,674**	**$ 206**	**$ 2,594**	**$ 202**	**$ 2,577**	**$ 206**	**$ (96)**	**$ -**

1/ Total includes 900 aMW of Monetary Benefit ($139 M/yr average), and approximately 618 aMW of load augmentation (BPA power buyback) ($235 M/yr average)
2/ Total includes net impact of CGS capital decision. Final rate case outcome will show a reduction in CGS O&M and an increase in Debt Management.

BPA's Financial Disclosure Information

* All FY 2005-2009 information cannot be found in BPA-approved Agency Financial Information but is provided for discussion or exploratory purposes only as projections of program activity levels, etc.

* All FY 1997-2004 information is consistent with audited actuals that contain BPA-approved Agency Financial Information.