Bonneville Power Administration
Power Function Review II Draft Closeout Report

Overview
In a time when the region's electric industry is emerging from the lingering effects of the 2001 power crisis and the process of setting new power rates is underway, BPA is committed to making FY07-09 rates as low as possible while still meeting its mission objectives. Meeting that mission requires a careful balance of applying cost pressure to each program area without going too far and jeopardizing the accomplishment of other key goals for the region. BPA conducted an extensive Power Function Review (PFR) in 2005 in anticipation of the 2007 Power Initial Rate Proposal. The purpose of Power Function Review II (PFR II) was to re-examine each of the major power cost categories to seek additional cost savings prior to setting FY07-09 power rates.

Like the first round of the PFR last year, PFR II has involved many meetings between BPA, customers, interest groups, the Corps of Engineers, the Bureau of Reclamation, and Energy Northwest. The ongoing sharing of information has led to new ideas and long-term cost savings and program review that would not have been possible without this effort.

Last year, $96 million per year in cost savings for the FY07-09 rate period were identified in the PFR process. The PFR II followed up by exploring the issues left outstanding in the 2005 PFR combined with a top-to-bottom look at each of the cost categories in order to identify any further cost reductions. There are few "easy" cost reductions left after several rounds of thorough public cost review in the last several years, including the Financial Choices process in 2003, the General Manager Workgroups in 2003, the Power Net Revenue Improvement Sounding Board in 2004, and PFR in 2005. However, no category was spared due to size and every program manager was held accountable to support the program funding levels and objectives. PFR participants questioned and examined programs to ensure that cost projections were as low as possible while still meeting key mission objectives. As detailed below, $29 million in annual cost reductions has so far been identified in PFR II, partially offset by $9 million in annual increases, for a net annual reduction of $20 million. This is in addition to the $96 million in annual reductions identified last year through PFR I.

Noncost Changes Since the Initial Proposal

Although the PFR II process has been primarily focused on costs, BPA and PFR II participants have used the process to stay up to date on other changes that are likely to affect FY07-09 power rates. The table below is a nonexhaustive list of both known and potential changes in these noncost factors, with rough estimates of their effect on three-year average rates. These are shown for information purposes only. Decisions around these issues will be made in the ongoing power rate case.

Line #	Issue	Update	Potential Rate Impact on FY 07-09 Rate	Estimated Average Yearly $ Amount
1	Liquidity Tools	Direct Pay Approved **Others**: Progress on Treasury Note Some progress on customer pre-pay Deferred work on pre-payment	-$1.5/MWh reduction Others ~ -$1+/MWh reduction	--
2	FY 2006 Net Secondary Revenues	Net Secondary revenues are so far remaining ahead of target	Rule of Thumb: Increase of $125M = -$1/MWh reduction	--
3	Reactive Credit	Change in proposed reactive credit	+$.2/MWh Increase*	$12M
4	Change in Operating Reserve Agreement	Proposed rate case agreement	+$.2/MWh Increase*	$8M
5	Change in Fall Chinook Transport Study and Removable Spillway Wiers Schedule	Update to reflect change in schedule	+ $.3/MWh Increase	$15M

** Mostly offset by transmission rate decrease*

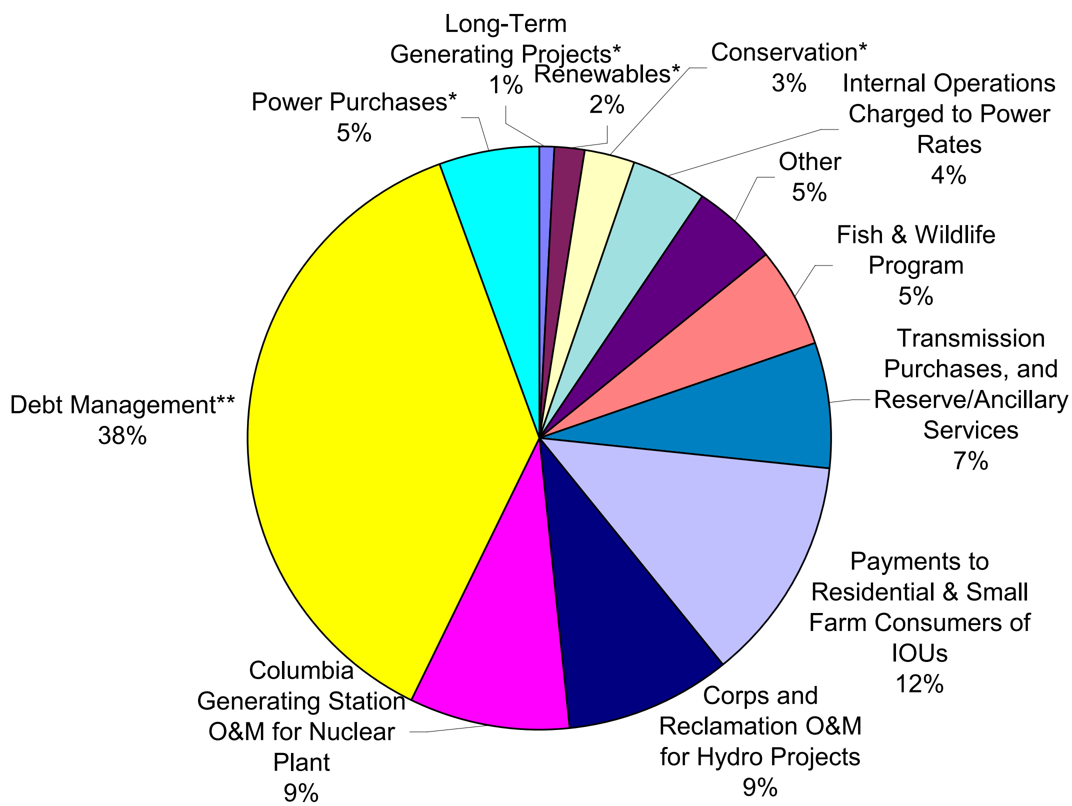
Overall changes since the power rate case initial proposal last fall are pointing toward lower rates in the final power rate proposal. By far the biggest improvement so far is the direct pay arrangement, which was secured through a strong collaborative effort between BPA, customers, Energy Northwest, Department of Energy officials, and the Northwest congressional delegation. The greatest remaining opportunities for further improvement lie in the FY06 net secondary revenues and additional progress on liquidity tools. Net secondary revenues are currently running ahead of planned levels. The net secondary revenue forecast will be updated in the BPA Second Quarter Review at the end of April.

BPA continues to explore a possible agreement with the U.S. Treasury on additional liquidity tools. A customer pre-pay arrangement has been discussed between BPA and customers. This arrangement could provide some of the same rate reduction as the Treasury agreement in the event that BPA cannot reach agreement with Treasury. However, customers have so far expressed limited interest in moving forward on the prepay arrangement.

These improvements and potential improvements are partially offset by two factors. First, credits to power rates for reactive power and operating reserves are likely to be reduced, as discussed in the rate case. But these increases in power rates are offset by similar decreases in BPA transmission rates.

Two more factors that are anticipated to negatively impact rates are the change in the timing for installation of fish passage improvements at hydro projects, and a change in the schedule for the Fall Chinook Transport Study. The likely higher levels of spill without the weir improvements, along with the change in the Transport Study schedule, are expected to increase the annual cost of operations for fish. The forecast amount of this increase will be determined in the final rate studies.

Average Annual Power Costs in the FY07-09 Initial Proposal



**This category has offsetting MWs attached..*
***Includes rate case EN debt service.*

Following are the changes BPA proposes to make in each of the major cost categories for use in setting power rates, based on the recommendations made by PFR II participants and updated information and analysis. BPA is seeking comment on whether these are the most appropriate changes.

Proposed FY07-09 Cost Changes

Capital cost recovery

The largest area of power cost is capital cost recovery. However, unlike other program areas, this cost is not a single, discrete program but rather primarily the result of capital investments the agency and its partners have made over time. In addition forecasts of future investments and BPA's debt management practices have some bearing on the cost level. In the 2005 PFR, participants examined each of the major areas in this category and the drivers behind those costs. At the time of the 2005 PFR closeout, several factors remained uncertain so BPA committed to review progress on outstanding issues prior to publishing the final power rate proposal, as well as to examine other areas of interest to participants. The outstanding issue held over from the 2005 PFR process was whether to extend Columbia Generating Station debt, both new and existing. Other interest areas included amortization periods for conservation as well as for BPA's Fish and Wildlife program including capital investments, capitalizing land and water acquisitions for fish, Columbia River Fish Mitigation plant-in-service assumptions, and updating for actual FY 2005 financial results. In the PFR II, participants re-examined costs in each of these areas. The proposed decreases and increases to be included in the final repayment study in the power rate case are described below and listed in the score card at the end.

The main purpose of the PFR is to examine costs that are outside the scope of a rate proceeding. Capital cost recovery is a category that is within the scope of the rate case and will be discussed and decided there. It is being discussed in the PFR because of the importance of having a public process in which all cost categories are "on the table" together.

CGS debt extension: In the 2005 PFR BPA and Energy Northwest (EN) were encouraged to pursue extending some of the current CGS debt and debt financing of CGS capital projects to FY 2024, which is the year through which the plant is currently licensed. BPA, its customers, and EN collaborated to evaluate this concept in advance of the PFR II process due to the timing necessary to be effective in the final power rate proposal. The EN executive board approved the debt extension, and BPA and EN priced bonds in March, securing the estimated $17 million annual cost savings shown below in the score card. This is the largest single cost reduction identified through PFR II.

Conservation amortization period: Following PFR discussions of the topic last year, BPA changed the amortization period for conservation investment in the initial power rate proposal from a declining 10-year period to a five-year period. This change was a result of a shift in the nature of investments from one of power augmentation to conservation acquisition. PFR II participants asked BPA to analyze and consider changing the conservation amortization period from five years to 15 years. Analysis indicates that this change would create almost no change in the revenue requirement in FY07-09. There would be a significant decrease in the FY12-15 period. Then after FY15, the reduction would shrink markedly. Additionally, the five-year treatment puts less pressure on BPA's access to limited borrowing authority, reduces the risk of stranded investments, and appears to be more consistent with industry practice. For these reasons, and because the longer amortization period would have virtually no rate impact in FY07-09, BPA leans toward retaining the five-year amortization period for conservation acquisition investments.

Fish and wildlife amortization period: Participants requested that BPA analyze and consider amortizing BPA's Fish and Wildlife direct program capital investments over a longer period than the current 15-year period. BPA evaluated the impact of a longer amortization period as part of the PFR II process and found that such a change would have virtually no impact on rates in the upcoming rate period. While BPA will consider incorporating such a change for its final power rate proposal, it is inclined to not change the existing policy.

Capitalization of land and water acquisitions for fish: Participants asked BPA to consider capitalizing land and water acquisitions for fish. BPA has explored this proposal and is not inclined to change its existing treatment of this type of acquisition. BPA believes these acquisitions do not meet criteria for capitalization under Statement of Financial Accounting Standards (FAS) 71, Accounting for Certain Types of Regulation, with which BPA complies.

Updating capital cost recovery estimates to reflect 2005 actual financial results: PFR II participants encouraged BPA to update its capital investments and payments to reflect 2005 actual results. The final rate proposal will reflect all actual FY 2005 transactions. As shown in the score card below, the current estimate is that this update will bring annual costs down by $3.5 million.

Columbia River Fish Mitigation Program: Customers asked for an update on the Corps of Engineers' (Corps) Columbia River Fish Mitigation (CRFM) project plant-in-service schedule. BPA has stated it intends to reflect in the final power rate proposal any decision made by the Corps regarding its schedule for placing investment into service based on new guidance to the Corps from the Department of Defense Inspector General. In the PFR II process, BPA shared the most recent estimate from the Corps, which differs in all years from those used in the initial rate proposal. The major change is that significantly more investment is to be placed into service in FY 2006 than was forecast in the initial power proposal ($284M versus $22M). The impact of this change is estimated to be roughly a $5 million increase in interest expense per year. The Corps has indicated it will provide final plant-in-service forecasts in the near future. There is some indication that these forecasts could be higher than the current forecasts. If revised forecasts are received prior to development of the power final rate proposal, BPA will include them in the repayment study used to establish final power revenue requirements.

Increase in borrowing for CGS capital needs: Since the 2005 PFR, several issues have developed related to equipment reliability and performance at Columbia Generating Station (CGS). EN has embarked on a plan that increases CGS maintenance and equipment replacements in order to improve equipment reliability and plant performance. The plan will focus on items such as pump and motor failures, turbine controls, dose reduction, and condenser leaks. As a result, there are increases in the forecast in both FY07 and EN's 2005 long-range forecast (LRF). A significant portion of the cost increases (an average of about $43M per year) is related to capital projects and will be debt financed. This leads to an annual average increase in debt service payments of approximately $2.5 million (this figure will be revised for the final rate proposal when the Repayment Model Study is updated). The forecast by EN for the FY07-FY09 rate period includes place-holder funding of $35 million to replace the main condenser at CGS. EN acknowledged that the plan, design, and cost estimate for the condenser replacement has not yet been fully developed. BPA is not currently comfortable with justification for this project yet and will continue to work with EN to explore the need for condenser replacement and reasonable alternatives, and we will make a final determination in the final PFR II report regarding the inclusion of replacement condenser costs in the power final rate proposal. BPA customers expressed interest in receiving a follow-up report on EN's plan in regard to condenser replacement, and EN and BPA intend to provide this follow up. In addition, with the significant investment in CGS being made to improve performance and reliability, customers asked that consideration be given to developing improvement targets and performance measures to track the results of the reliability improvements. BPA will work with EN to determine if reasonable performance measures can be developed and adopted.

Columbia Generating Station O&M

In the 2005 PFR, CGS was facing many issues including rising security costs, rapidly increasing fuel prices, aging and obsolete equipment, on-site spent fuel storage, and rising employee benefit costs. In response EN went through a benchmarking effort in order to help identify areas for efficiency improvements. As a result, EN committed to bring down its forecast of O&M costs in the FY07-09 period by $22 million per year on average. Since then, as noted above, EN has reviewed and refined its forecast for the FY07-09 timeframe and identified the need for additional O&M funding for plant maintenance and equipment reliability improvements. These increases are offset however by active management of nuclear fuel procurement and planning for CGS that has resulted in savings over projected costs in the 2005 PFR. This results in a net decrease of $2 million per year in CGS O&M forecast. This, coupled with the increase in capital financing costs mentioned above, results in rate case costs very close to those assumed in the power initial proposal. BPA proposes adopting the new long range forecast for CGS O&M for the final power rate proposal.

Corps & Reclamation O&M

In the 2005 PFR process, the Corps and Bureau of Reclamation (Reclamation) worked hard to develop spending levels that reflected minimum cost requirements while still meeting power generation and reliability requirements for the region. One of the checks and balances the Corps and Reclamation use in running the hydro facilities is the results of national benchmarking efforts of like hydro facilities. The Northwest federal hydro projects score well, coming in under the average overall in operations and maintenance costs as do many other NW hydro facilities. However, as part of the 2005 PFR process, participants suggested that the federal agencies benchmark themselves against regional nonfederal hydro facilities in order to identify additional efficiency opportunities.

BPA committed to follow-up and initiated the regional hydro benchmarking effort last fall with participation of the Corps, Reclamation, Grant County PUD, Chelan County PUD, Seattle City Light, and Tacoma Power. Included were 23 federal and nonfederal hydro projects. The report of this study is publicly available. The report finds that, for the majority of functions benchmarked, costs for federal projects and other NW stations were similar. However, the report also points out opportunity areas for potential efficiencies in the longer term for the O&M program. These include potential automation of more federal projects, review of the water management function at the three federal agencies for process and cost efficiencies, and sharing of maintenance practices among the various projects to identify opportunities for improvement. BPA will work with the Corps and Reclamation to assess these opportunity areas.
Though BPA intends to follow up on these opportunities, it also proposes that it would be premature to include cost savings in rates now. BPA's commitment and practice is to include costs in rates that it can and will manage to. BPA proposes no change in the FY07-09 forecast, but is committed to pursue long-term cost savings identified in the benchmarking recommendations.

An important message that came through both PFR processes is the need to regularly share information about the operation of the hydro system. BPA, the Corps, and Reclamation agree and are committed to meet regularly with interested parties such as the Public Power Council (PPC) technical and executive committees to brief them on hydro program activities and performance as well as any changes that are appearing in the future.

Finally, even though the benchmarking process is complete, collaborative efforts among other regional generating facilities are not over. BPA, the Corps, and Reclamation have committed to a series of follow-up meetings with Pacific Northwest regional generating utilities to pursue best practices in operations and maintenance. This kind of information exchange will benefit both the federal and regional utilities, and ultimately will improve practices and system reliability in the region.

Transmission expense

At the beginning of the PFR II process, participants requested that BPA examine how it accounts for its transmission expenses related to secondary energy sales. Some participants thought there may be some double counting involved in recording actual transactions, and that it was a potential area for reduction if that were true. Interested parties met with BPA subject matter experts to thoroughly examine this concern. At the conclusion of this review, parties determined that the transmission expense is accounted for correctly in accounting records and through the rate setting process.

Fish & wildlife O&M

In the 2005 PFR, BPA emphasized its commitment to fulfilling its fish and wildlife obligations through managing to clearly defined performance objectives and implementing the most cost effective strategies for meeting these objectives. As part of this commitment the F&W program managers identified the need for a more strategic and focused research, monitoring, and evaluation program and shifted funding from Research, Monitoring & Evaluation (RM&E) activities to more "on the ground" work, such as habitat protection and enhancement strategies as identified in the Power Planning Council's newly adopted subbasin plans, directly benefiting fish and wildlife. PFR II participants asked for follow-up on how BPA is planning to deliver its fish and wildlife RM&E commitments at the reduced funding level.

BPA is working with the regional fish and wildlife managers and others through the Council's FY07-09 Proposal Solicitation Process to further refine and develop a draft framework for integrating RM&E efforts into the fish and wildlife program. Regional federal, tribal and state resource management agencies are completing and summarizing a survey of key management questions, needs and monitoring inventory. The Council has recently adopted its Regional Fish and Wildlife Research Plan and BPA and the regional federal agencies are updating their RM&E Plan in 2006. The NOAA Fisheries Recovery Planning Framework developed to date also includes an RM&E framework consistent with these other regional efforts. By further refocusing RM&E efforts in the basin, including identification of appropriate cost-sharing and partnering with others, more funding will be made available to implement on-the-ground efforts as identified as priority strategies in the recently completed subbasin plans.

As concluded in the 2005 PFR, BPA believes its proposed $143 million per year fish and wildlife program funding level allows for significant implementation of its Power Act and ESA offsite mitigation responsibilities. These may include high priority habitat strategies as identified in the subbasin plans such as riparian habitat protection for anadromous and resident fish, tributary passage improvements, hatchery improvements, and the continuation of effective measures that mitigate for wildlife losses due to construction of and inundation of land by the FCRPS. Any savings in the RM&E arena will be redirected to projects yielding direct benefits to fish and wildlife affected by the federal hydropower system. As new ESA needs are identified in developing a new FCRPS biological opinion through the Redden Court Collaborative Process, these will be incorporated into the ongoing Council Proposal Solicitation and Review Process for potential implementation in FY07-09. Some PFR participants urged that fish and wildlife costs used in setting power rates be significantly increased to reflect spending increases they saw as necessary to implement subbasin plans and other planning processes (for example, the Redden Collaborative Process, NOAA Fisheries recovery planning, regional hatchery review, and the Council's Provincial Review Process). BPA believes that a refocusing of spending from monitoring and evaluation actions to habitat and hatchery efforts will provide more room for on the ground benefits to fish and wildlife, as identified in the subbasin plans.

<u>DSI benefits</u>

The June 30, 2005 record of decision (ROD) on direct-service industry (DSI) benefits noted that BPA would revisit the decision to offer service to the DSIs once the financial impact of changes in the hydroelectric system operations stemming from court rulings were better known. The ROD proposed capping the benefits at $59 million per year with the possibility that actual amounts could be lower depending on actual DSI operation levels and the difference between market prices and BPA's priority-firm (PF) rate. (Because it is not certain that the DSIs will actually be able claim all these payments, the expected value of payments in the initial rate analysis was $53 million.) Based on comments from a follow-on public process reviewing draft smelter contracts, BPA decided to include the level of DSI benefits in the PFR II.

The additional review time has provided an opportunity to consider the DSI benefit levels in light of more recent information on expected hydro system operations and a more refined understanding of net secondary revenues BPA will achieve during FY06. In light of discussions in the PFR II and the updated information on expected hydro operations and revenues, BPA proposes to retain the maximum DSI benefit level at $59 million per year. BPA originally chose the $59 million level to balance benefits to smelters and their jobs with the rate impact on other customers. Had the actual FY05 results been worse than expected or had FY06 hydro operations or water conditions made expected net secondary revenues substantially lower, BPA may have needed to reconsider the balance, but BPA believes recent information shows financial results are on track to be at least as good as had been expected when the DSI service decision was originally made last year.

During the PFR II discussions, participants raised questions about PF rate adjustments and the effect on DSI benefit levels. When benefits are provided solely as a direct power sale tied to the PF rate, changes in the rate would directly impact the price the DSI pays. However, when the power sale is monetized as BPA intends for at least FY07-09, the impact is more indirect but the formula that determines the DSI benefit levels is subject to all rate adjustments of BPA's PF rate. The contract sets a cap on DSI benefits of between $12 million per megawatt-hour and $24 million per MWh depending on the smelter's operating level. To the extent that difference between market and PF is less than these levels, the smelters would continue to be directly impacted by changes to PF. During the PFR discussions it was suggested that BPA consider a more direct application of changes in the PF rate, applying adjustments directly to the benefit level rather than indirectly through PF. BPA's draft contract limits DSI benefits such that their effective power costs can't be lower than PF. The direct approach would also mean that, in times of high power prices, their business risk would increase further since they could not count on the BPA benefit. Changes in PF already have a significant effect on the DSIs. For these reasons BPA believes that the indirect approach best meets our dual goals of broadly applying rate adjustments and providing benefits to support DSI operations.

Internal operations charged to power

Even though this category is only 4 percent of total costs, it represents BPA's most direct opportunity to demonstrate its commitment to cost management. BPA has a longstanding commitment to hold its internal costs in power rates to 2001 actual levels with no allowance for inflation. To accomplish this, staffing reductions have been necessary. Power Business Line staffing has declined steadily since 2002 and overall agency staffing has been declining since 2003. We expect staffing reductions will continue.

With customer involvement, BPA initiated the Enterprise Process Improvement Program (EPIP) to help improve internal processes and bring internal costs down. During the 2005 PFR, BPA estimated that the EPIP project should allow an $8 million annual reduction from the 2005 PFR base in power internal costs for the FY07-09 period, although EPIP process reviews were not complete at that time. This $8 million reduction brought power internal costs back down to FY01 levels (except for the $2 million technological innovation program).

BPA committed to re-examine these estimated savings once several of the EPIP studies were completed. Subsequent work on EPIP Phase I studies and early process improvement efforts have confirmed this early estimate as being reasonable, giving us greater confidence that EPIP improvements will yield the $8 million per year in savings assumed in the 2005 PFR. These studies indicate that estimated power cost savings from the EPIP base in the $11 million to $12 million annual range should eventually be achievable over time, but not by FY07. BPA proposes holding the estimate of EPIP savings at $8 million per year on average for FY07-FY09. Much of the savings in each area relies on process redesign, automation, and reduced staffing levels through separation incentives and attrition, all of which will take several years to fully implement. Staffing reductions take time and are not easy to predict. In addition, it takes time to fully implement each of the recommended process improvements. As a result, all of the projected savings will not be realized in the FY07-09 rate period. BPA will seek to prudently maximize internal cost savings and those savings will be passed through in rates as they are achieved.

Conservation program

Prior to the 2007 initial power rate proposal, BPA designed a portfolio of energy efficiency programs that would achieve BPA's conservation goals at the least cost. BPA relied heavily on the Post-2006 Conservation Workgroup's recommendations in designing its proposed program approach. As part of the PFR II process, two additional areas were examined for their potential cost savings. The first suggested that BPA consider counting conservation done by utilities "on their own nickel" towards BPA's target. BPA has put in place a systematic way for customers to voluntarily report their self-funded conservation. BPA will monitor this information in order to see how much occurs in the region and if it would lead to cost savings by reducing BPA's conservation targets. At this point, BPA proposes that it is too early in the process to count on such self-funded conservation in rates, but the program will be monitored and evaluated with customers throughout the rate period to determine if there is any potential for cost savings, and BPA's proposed rate adjustment mechanisms will allow any savings to be reflected in rates.

A second area of interest in the PFR II was how much it would cost rate payers to increase the amount of conservation funding. BPA reviewed and analyzed this suggestion, which showed a very small rate increase in the short term. Even though it is a small rate impact, there was no tie to program objectives. BPA is committed to achieving its share of the Council's conservation targets at the lowest possible cost, and BPA believes that its funding levels are appropriate for accomplishing this objective. BPA does not feel it is prudent in a time of increased rate pressure to increase its funding to conservation without it being directly linked to program objectives. However, BPA will monitor its progress on achieving its share of the Council's conservation targets and make the necessary funding adjustments should there be a risk of not achieving the targets.

Renewables program

As part of the short-term Regional Dialogue process, BPA decided in February 2005 to focus on facilitating the development and acquisition of renewable resources by its customers rather than directly acquiring renewable resources. In addition, the energization date for Calpine's Fourmile Hill geothermal project was delayed to FY09 (Fourmile Hill was originally slated for energization in early FY07).

In the PFR II, both the Calpine Fourmile Hill geothermal power purchase contract and the facilitation costs were re-examined. Since the 2005 PFR, the Calpine contract has gone through arbitration, which extended Calpine's allotted time to energize the project by more than four years. Subsequently, BPA determined that the soonest the Calpine project could be energized would likely be FY10. Due to this delay BPA plans to remove the energy expenses from the project from the FY09 renewables program forecast. This results in a cost reduction (net of the value of the output of the project) of around $18 million in FY09 or $6 million per year averaged over the rate period.

With respect to facilitation costs, BPA remains committed to its 2005 decision that it would spend up to $21 million per year in the FY07-11 period to facilitate the development of renewable resources. Another $5 million will carry forward from the FY02-06 program, representing BPA's commitment to "back up" the Conservation and Renewables Discount program in the event that customers chose not to devote at least $30 million of their C&RD funds to renewables in that period (they actually will spend about $25 million). This brings the annual facilitation spending cap to $23 million for the FY07-11 period.

Six million dollars of this $23 million maximum is earmarked in the rate case for the rate discount program. The remaining question is how much additional facilitation spending is likely to occur in the FY07 rate period. BPA does not believe it is appropriate to forecast that the full cap amount will be spent when there is so much uncertainty about how much will actually be spent. Therefore, BPA is proposing to retain the flexibility to spend up to the cap for facilitation efforts as necessary, but to assume that the expected value of actual spending will be 25 percent of the cap in FY07 and 50 percent of the cap in FY08 and FY09, but to include the full range of uncertainty in spending from zero to the cap in the rate case risk analysis (NORM). This would translate to expected values of $4 million in FY07, $8 million in FY08 and $8 million in FY09. If these expected amounts later appear to be insufficient for needed facilitation efforts, BPA will then consult with interested parties on the matter and will increase spending up to the cap if necessary. For comparison, the initial rate proposal included point estimates of $5.5 million in FY07, $11 million in FY08 and zero in 2009 but without allowance in the risk analysis for higher levels of facilitation spending.

Conclusion and next steps

As BPA develops its final proposal for power rates for the FY07-09 period, the 2005 PFR and PFR II provide the basis in funding levels for programs that will directly feed into those rates. Through the hard work of all the participants, the PFR II found net savings for the FY07-09 rate period helping to put downward pressure on the final rates this summer. The draft results are summarized below in the table.

BPA now seeks comments on these draft conclusions. Final decisions on costs must be made by the end of April so that final rate studies can proceed. BPA must, therefore, receive comments on this draft by April 26. A Management Discussion to review the draft report is schedule for April 10, 2006, from 9 a.m. to 3 p.m. in the BPA Rates Hearing Room, located at 911 NE 11th Ave., Portland, Ore. BPA Administrator Steve Wright will be attending this discussion.

Comments can be submitted on-line at: http://www.bpa.gov/comment, e-mailed to *comment@bpa.gov* or mailed to: Bonneville Power Administration, Public Affairs Office -DKC-7, P.O. Box 14428, Portland, OR, 97293-4428.

PFR II Draft Report Scorecard

	PFR II: Areas of Priority Focus Average Annual FY 2007 - 2009 ($ millions)	Changes from Power Initial Proposal	
		+	-
1	**Estimated Capital Cost Recovery**		
2	Longer amortization period for conservation acquisition		$ 0.0
3	Longer amortization period for fish and wildlife investments		$ 0.0
4	Use BPA borrowing authority for land and water acquisitions for fish		$ 0.0
5	Extend existing CGS debt to 2024		$ (16.0)
6	Longer maturity (to 2024) on debt for new CGS investments		$ (1.5)
7	Update to reflect 2005 actuals in repayment studies		$ (3.5)
8	Columbia River Fish Mitigation plant-in-service schedule -- DOD IG decision	$ 5.0	
9	Potential increases for CGS deferred maintenance (capital)	$ 2.5	
10	**CGS O&M**		
11	Potential increases for deferred maintenance (expense)		$ (2.1)
12	**Corps & Reclamation O&M**		
13	Benchmarking federal projects O&M against other regional hydro projects		$ 0.0
14	**Residential Exchange**		
15	None		
16	**Transmission**		
17	Review transmission expense for secondary sales		$ 0.0
18	**Fish and Wildlife**		
19	F&WL Monitoring and Evaluation (M&E)		$ 0.0
20	**"Other"**		
21	DSI $59 million annual support ($53M/yr is expected value in I.P. with risk)		$ 0.0
22	Review Spokane settlement status		$ 0.0
23	**Internal Operations**		
24	Examine potential for additional EPIP savings		$ 0.0
25	**Conservation**		
26	Consider conservation done by utilities "on their own nickel"		$ 0.0
27	Increase BPA funding for conservation	$ 0.0	
28	**Renewables**		
29	Remove Calpine geothermal net cost from 2009		$ (6.0)
30	Consider averaging facilitation costs and funs backstop in FY09	$ 1.4	
31	**Long Term Generating Projects**		
32	None		
33	**TOTAL**	**$ 9**	**$ (29)**
34	**NET PFR II SAVINGS/INCREASE**	**$ (20)**	
35	**2005 PFR SAVINGS**	**$ (96)**	
36	**TOTAL PFR PROCESSES SAVINGS**	**$ (116)**	