BPA Power Function Review
Scoresheet: Decisions that Could Decrease BPA Power Rates

As of April 4, 2005

This document will be updated throughout the Power Function Review process

Important Note: This table lists the possible decisions that BPA and/or other PFR participants have flagged as potential opportunities to bring down BPA power costs in FY 2007 - 09. Because the table lists different approaches bringing down power costs, the values are not all additive. Some of these cost decreases involve an increase in risk or a deferral of a cost into a future period. Inclusion here does not indicate that BPA necessarily agrees with or intends to decide these issues in a particular way.

Potential Decisions	FY 2007-09 Cost Impact[1]	Comments/ Tradeoffs
Conservation		
◆ Credit conservation done by utilities "on their own nickel" against BPA's target, reducing BPA's spending	E.g., they do 10 aMW, then we need only 46 aMW @ $1.4M/aMW Savings = $14M/yr	For partial requirements customers, would need to be careful to count MWs achieved in excess of "their share" of Council target.
◆ Reduce BPA target for "naturally occurring" conservation.	$5M/year capital and $1M/year interest savings $2.7M (over 3 years) (if expense savings vs. capital)	$2.7M is based on 4 aMW naturally occurring conservation and assuming $1.3/aMW cost to BPA. If assuming this reduction occurs in the capitalized Bilateral Contracts program. BPA is now proposing to make this adjustment in its post 2007 Conservation Proposal.
◆ Don't require load decrement on rate discount program, making utilities more willing to implement conservation at lower cost to BPA	0	No savings since there is no decrement in the current C&RD and customers say a decrement would reduce their participation in C&RD below levels we now assume.
◆ Count aMW of conservation achieved by IOUs through the rate credit program toward BPA's target.	0	The argument for this action is that though this conservation would not be occurring "in the load BPA serves," it would be regional conservation accomplished through BPA spending. This treatment is required to enable BPA to meet the Council target without an additional budget increase.

[1] Average annual 2007-9 revenue requirement impact. For capital cost reductions, includes only the debt service effect.

Potential Decisions	FY 2007-09 Cost Impact[1]	Comments/ Tradeoffs
Renewables		
◆ Remove Geothermal project from projected costs, because forecasted online date moved out to late FY08 or FY09.	$11 M/yr	Removing geothermal project would free up additional spending under the $21M cap, which could offset these savings.
◆ No further renewables spending, beyond what is already contractually committed	$11 M to $12 M/yr	Inconsistent with recent Regional Dialogue policy discussion. This policy direction would be contingent on successful termination of Geothermal project. Against $4.00 gas, projected headroom in 2009 above and beyond Geothermal project savings ($11M) is only $1M.
BPA Internal Costs		
◆ Include forecast of savings from process improvement efforts (Enterprise Process Improvement Project), early retirement offer, staffing strategy, and grade reduction initiative.	$20 M	◆ $20 M is purely a placeholder, assuming about a 17% reduction in internal operating cost budgets based on the cumulative impact of all initiatives in both Corporate and PBL. **Risks & Trade-offs:** Now being assessed as part of the BPA process review.
◆ Reduce monetary awards budget to FY 2004 actuals level of $150,000 in PBL.	$1.8 M/yr	Less incentive for staff and managers to perform well, or “go the extra mile”. Savings are less if reduction in FTE is achieved (see above)
◆ Reduce monetary awards budget to FY 2004 actuals level of $300,000 in Corporate.	$3.6 M/yr	Less incentive for staff and managers to perform well, or “go the extra mile”. Savings are less if reduction in FTE is achieved (see above)
◆ Eliminate uncommitted technological innovation budget	$3 M/yr	May add to risk of keeping up business systems; may not fit DOE or agency mandates.
◆ Manage total Internal Costs Charged To Power to FY01 level	$8M/yr	The proposal is to manage this category to FY01 levels in total so if one area is higher, than another has to cut by that amount.

Potential Decisions	FY 2007-09 Cost Impact[1]	Comments/ Tradeoffs
CGS		
♦ Forecast EN borrowing to pay for capital items in FY 2007 - 09 period	See Debt Management Section	In base PFR budget assume revenue financing of items that could be considered capital. See Debt Management section
♦ Forecast EN borrowing to pay for fuel in FY 2007 - 09 period	See Debt Management Section	Base PFR budget assumes revenue financing for fuel. See Debt Management section
♦ Eliminate license extension budget for CGS in FY07-09	$9.9 M	CGS current license expires 2023. Preparation of license renewal application will take approx. 3.5 to 4 years and cost approx. $10.8 M in total. Currently, the FY07-09 budget reflects an assumption to pursue license extension process in FY07-09.
♦ Forecast EN borrowing to pay for uranium tailings pilot project	See Debt Management Section	This project will only partially offset the increase in market price of uranium. See Debt Management section
Hydro System (Corps and Bureau)		
♦ Reduction in funding for WECC/NERC compliance	$2.7 M/yr	Stretch out over additional years. Apply less conservative criteria to compliance standards. Accept higher level of risk to system operation.
♦ Reduce proposed level of funding for extraordinary maintenance	$ 8.0 M less expense **minus** $ M lost revenue = Net Impact +/-$ M	Impact of not funding maintenance will reduce revenues by $__M.
♦ Eliminate discretionary overtime	$1.0 M to $1.5 M less expense **minus** $ M lost revenue = Net Impact of +/-$ M	Impacts would be longer unit outages with $ M revenue impact.
♦ Pursue remote operation of projects	Initial Cost: $6.0 M (capital) Savings: $600K to $900K/year	Initial cost is hardware. Saving occur from reduction in operators. Not currently assumed in base forecast.
♦ Lower cost ways to manage the security requirements	TBD	

Potential Decisions	FY 2007-09 Cost Impact[1]	Comments/ Tradeoffs
Debt Management (Note: quantifications below are exemplary, provided to indicate general magnitude of incremental impacts. Amount, shape and interest rates of financings will change results. Results for individual debt management actions are not necessarily additive – combinations of actions may have different results.		
♦ Debt finance CGS capital projects with final maturity of FY2018	TBD	1. Could put additional upward pressure on rates due to the shape of existing debt and repayment methodology 2. Requires EN Board approval 3. Potential regional political issues 4. Pushes costs into future rate periods 5. Rate case issue 6. May decrease potential debt optimization
♦ Structure financing for uranium tailings pilot project to benefit the 07-09 rate period.	TBD	1. Could put additional upward pressure on rates due to the shape of existing debt and repayment methodology 2. Requires EN Board approval 3. Potential regional political issues 4. Pushes costs into future rate periods 5. Rate case issue
♦ Debt finance CGS fuel.	• Over FY 2007-2009 period - decrease in expense ($138M, ave. $46M/year), plus debt service on new financing, nets to $55M decrease. (Ave $18M/Year) • Over the FY 2010-2012 period - Increase of $74.6M. (Ave. $25M/Year)	1. Could put additional upward pressure on rates due to the shape of existing debt and repayment methodology 2. Requires EN Board approval 3. Potential regional political issues 4. Pushes costs into future rate periods 5. Rate case issue

Potential Decisions	FY 2007-09 Cost Impact[1]	Comments/ Tradeoffs
♦ Change Columbia River Fish Mitigation (CRFM) plant-in-service dates	Two scenarios provided by COE: Scenario "A" - large transfer to plant in 2005/2006, but lower overall plant - results in a $30M overall decrease in depreciation and interest for 2007-2009 ($10M ave./year), but an increase (Ave. $8M/Year) in FY 2005-2006. Scenario "B"-much lower investment overall until FY 2014. $60M decrease for FY 2007-2009 (Ave. $20M/Year). These results reflect depreciation, and do not include repayment study results on debt service.	1. BPA does not control the decision to change in-service dates 2. COE decision will need to be consistent with GAAP and statutory authorization of projects.
♦ Lengthen the recovery period for Conservation investments (currently Declining Amortization Period through FY 2011, based on contract duration. Potential to lengthen to max of average composite measure life for package of measures.)	TBD	1. Need to justify a change to outside auditors and in the rate case 2. Must demonstrate cost recovery of regulatory assets after FY 2011 3. Keeps regulatory assets and debt associated with them on the books longer 4. Accounting policy issue, reflected in rate case
♦ Utilize a revised interest rate forecast for initial proposal	TBD (This also could increase, rather than decrease, Power Rates—see p. 8, below)	1. Current forecast was completed June 2004 2. The outcome is uncertain as it depends on what a revised forecast would be 3. Rate case issue

Potential Decisions	FY 2007-09 Cost Impact[1]	Comments/ Tradeoffs
♦ Flexible modeling of 3rd party debt and assume that we "call" (retire) some of the bonds prior to their scheduled maturities to ease the impact of critical years, for repayment modeling purposes	Unknown until forecasted capital structure is determined.	1. Freeing up debt service reserve funds early increased peak years of 2017 and 2018 2. This action could reduce the size of the full Debt Optimization program if we stay with principle of "no overall negative impact on rates" 3. Rate case issue
♦ Include interest income on cash balances in Bonneville Fund	Based on FY 2002 – 04, the additional credit may be in the $10M per year range.	This will be reflected in rate case
♦ Finance new and existing CGS capital through 2023 instead of 2018.	TBD	1. The current policy is to finance CGS capital only through 2018. The current operating license for CGS runs through 2023. 2. Creates a better match to the asset life 3. Requires EN Board approval 4. Potential regional political issue 5. Rate case issue
♦ Extend some of the current CGS debt beyond 2018.	TBD	1. Creates a better match to the asset life 2. Requires EN Board approval 3. Potential regional political issue 4. Rate case issue.
♦ Lengthen the amortization period for F&W capital	Unknown	Would require change in BPA F&W Capitalization Policy. Impact is dependent on terms of replacement policy.

Potential Decisions	FY 2007-09 Cost Impact[1]	Comments/ Tradeoffs
Transmission acquisition costs		
♦ Model the transmission expense associated with secondary energy at the minimum expense across the 3000 secondary energy scenarios rather than average of 3000 secondary energy scenarios.	~$45M	Would result in secondary revenue assumptions and transmission expense assumptions not being linked.
♦ Remove forecast for telemetering	$1M/yr	Removing $1million per year estimate reduces expenses but increases risk.
Fish and Wildlife		
♦ Fund only Lower Snake River Compensation Plan O&M costs.	TBD	Essential non-recurring maintenance needs for aging facilities would not be addressed.
♦ The allocation of appropriate responsibility to other parties for mitigation where the impacts to fish and wildlife can be attributed to other sources beyond the federal hydrosystem	TBD	Pressure for additional spending, driven by increasing Bi-Op and Council Program requirements, is greater than targeted savings.
♦ The use of Program savings realized through managing overall spending to performance guidelines (i.e., 70% "on-the-ground vs. 55% currently.")	TBD	Pressure for additional spending, driven by increasing Bi-Op and Council Program requirements, is greater than targeted savings.
Other		
♦ Spokane Settlement	$20M	This is not a signed deal yet, but the expense that is associated with the Colville Settlement is embedded in the PFR base forecast. Removal of this assumption will decrease expenses but increase risk.

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As of April 4, 2005

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Important Note: This table lists the possible decisions that BPA and/or other PFR participants have flagged as potential increases which would put upward pressure to BPA power costs in FY 2007 - 09. Because the table lists different approaches that would increase power costs, the values are not all additive. Inclusion here does not indicate that BPA necessarily agrees with or intends to decide these issues in a particular way.

Potential Decisions	FY 2007 - 09 Cost Impact[2]	Comments/ Tradeoff's
Conservation		
• Not planning to pay enough to capture new target.	$11M to $40M/year	Conservation targets not met, regional costs for energy will be higher and more volatile.
• Conservation Workgroup recommended 20% administrative costs be included in current cost estimates.	$7M/year	Without sufficient admin. costs, utilities don't run quality programs and we don't meet the new target.
• Conservation Workgroup recommended a 2% infrastructure budget.	$1.6M/year (minimum)	BPA has proposed 10% for admin. costs; new measures and technologies need to be evaluated because savings are less certain.
Renewables		
BPA Internal Costs		
CGS		
Hydro System (Corps and Bureau)		

[2] Average annual 2007-9 revenue requirement impact. For capital cost increases, includes only the debt service effect.

Potential Decisions	FY 2007 - 09 Cost Impact[2]	Comments/ Tradeoff's
Debt Management		
◆ Utilize a revised interest rate forecast for initial proposal	TBD	1. Current forecast was completed June 2004 2. The outcome is uncertain Rate case issue
◆ Plan for some level of revenue financing		Since BPA's ability to borrow from the U.S. Treasury is limited, adopting some level of revenue financing preserves that ability over time. Rate case issue.
Transmission acquisition costs		
Fish and Wildlife		