Appendix -

Regional Meetings

BPA’s Financial Disclosure Information

- “All FY05-09 information was provided in April 2005 and 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 FY97-04 information was provided in April 2005 and is consistent with audited actuals that contain BPA-approved Agency Financial Information".

Power Strategic Direction That Applies to the Power Function Review

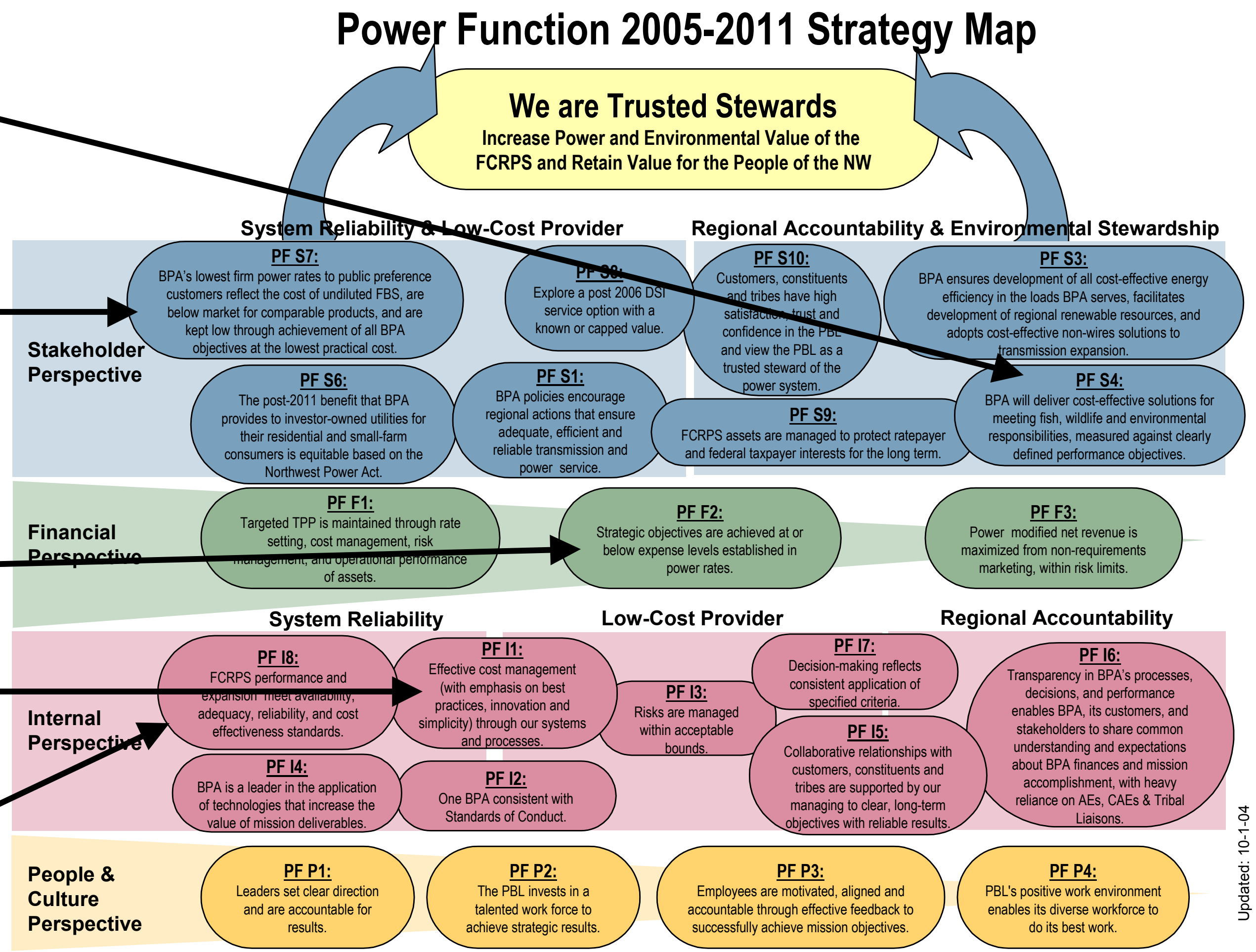
PF S4: BPA will deliver cost effective solutions for meeting fish, wildlife and environmental responsibilities, measured against clearly defined performance objectives.

PF S7: BPA's lowest firm power rates to public preference customers reflect the cost of undiluted FBS, are below market for comparable products, and are kept low through achievement of all BPA objectives at the lowest practical cost.

PF F2: Strategic objectives are achieved at or below expense levels established in power rates.

PF I1: Effective cost management (with emphasis on best practices, innovation and simplicity) through our systems and processes.

PF I8: FCRPS performance and expansion meet availability, adequacy, reliability, and cost effectiveness standards.



Power Function Review Process

Power Function Review Process

After a large BPA power rate increase in 2002 and ongoing scrutiny and reduction of many budget items, the level of interest from customers, constituents and Tribes in the costs that go into BPA's rates is higher than ever before. In response, and consistent with BPA's desire to increase the transparency of decisions that impact rates, BPA will provide clear information on those costs, along with robust opportunities to provide input into BPA's cost decisions prior to the publication of the 2007 power rate case initial proposal.

The PFR is BPA's public involvement process for the costs that go into power rates. It is a collaborative informal process designed to lay out the nine major program costs and seek customer feedback and suggestions for each program area prior to these numbers being included in rates. These areas are listed below in order of magnitude:

1. Federal and Non-Federal Debt Service and Debt Management (discussion)
2. Columbia Generating Station operation and maintenance costs and capital investments (decision)
3. Corps of Engineers and Bureau of Reclamation operation and maintenance costs and capital investments (decision)
4. Transmission acquisition costs (decision where applicable)
5. Fish & Wildlife program expenses and capital investments (decision where applicable)
6. Internal operations costs charged to power rates (decision)
7. Conservation program costs (decision where applicable)
8. Risk Mitigation Packages and Tools (discussion)
9. Renewables program costs (decision where applicable)

Power Function Review Process, cont.

There are several areas that are not included in the PFR and the decision process for these other topics is the 2007 Rate Case:

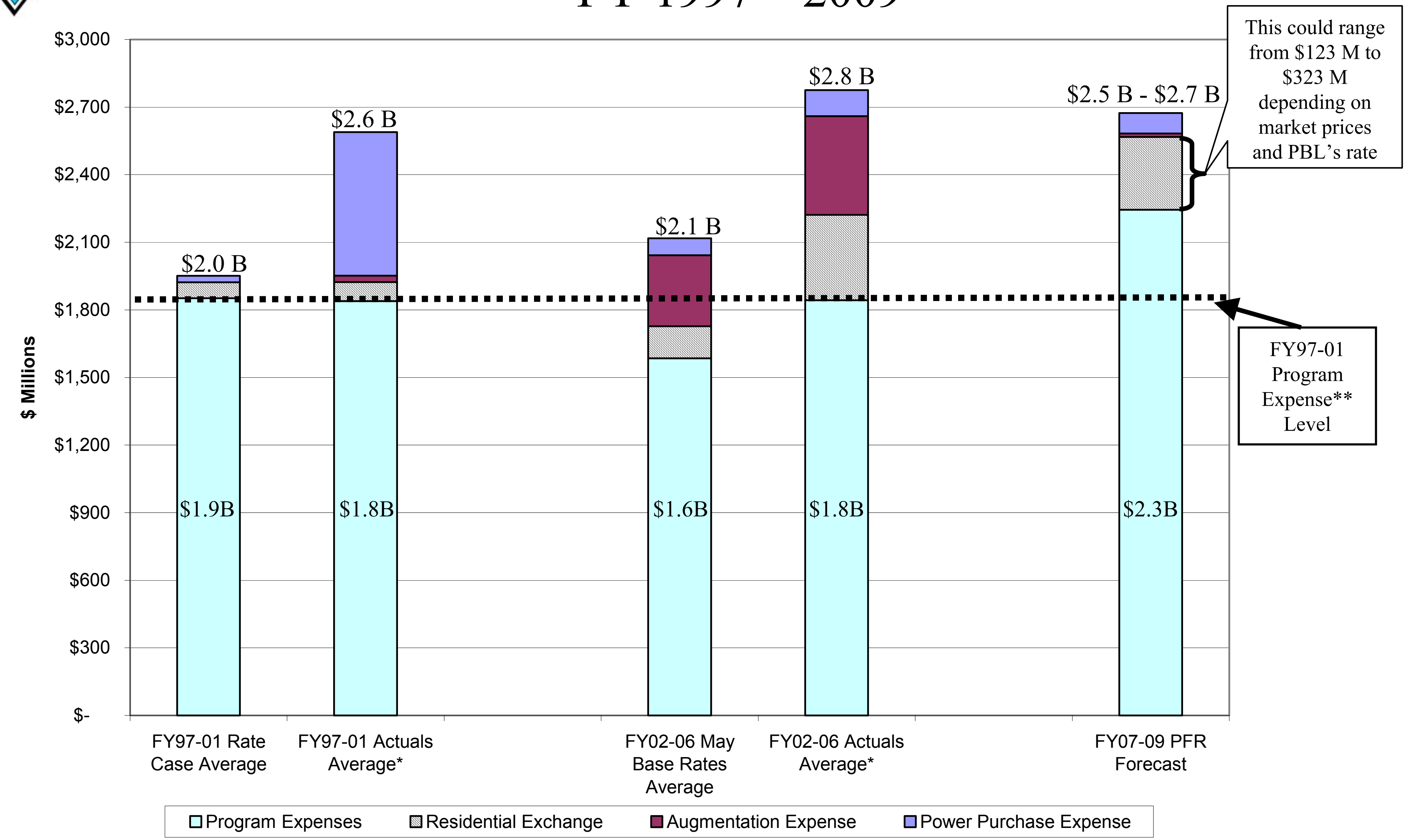
- Loads and Resources
- Revenue Credits, including Secondary Sales Revenues
- Reserve Levels
- Rate Design
- Rate Level
- Risk Mitigation

Background:

Power Rates Summary FY 1997-2009

FY 97-09 Actual and Forecasted Expense Levels

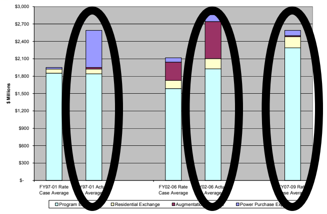
What Are Expenses Doing in Nominal Dollars From FY 1997 – 2009

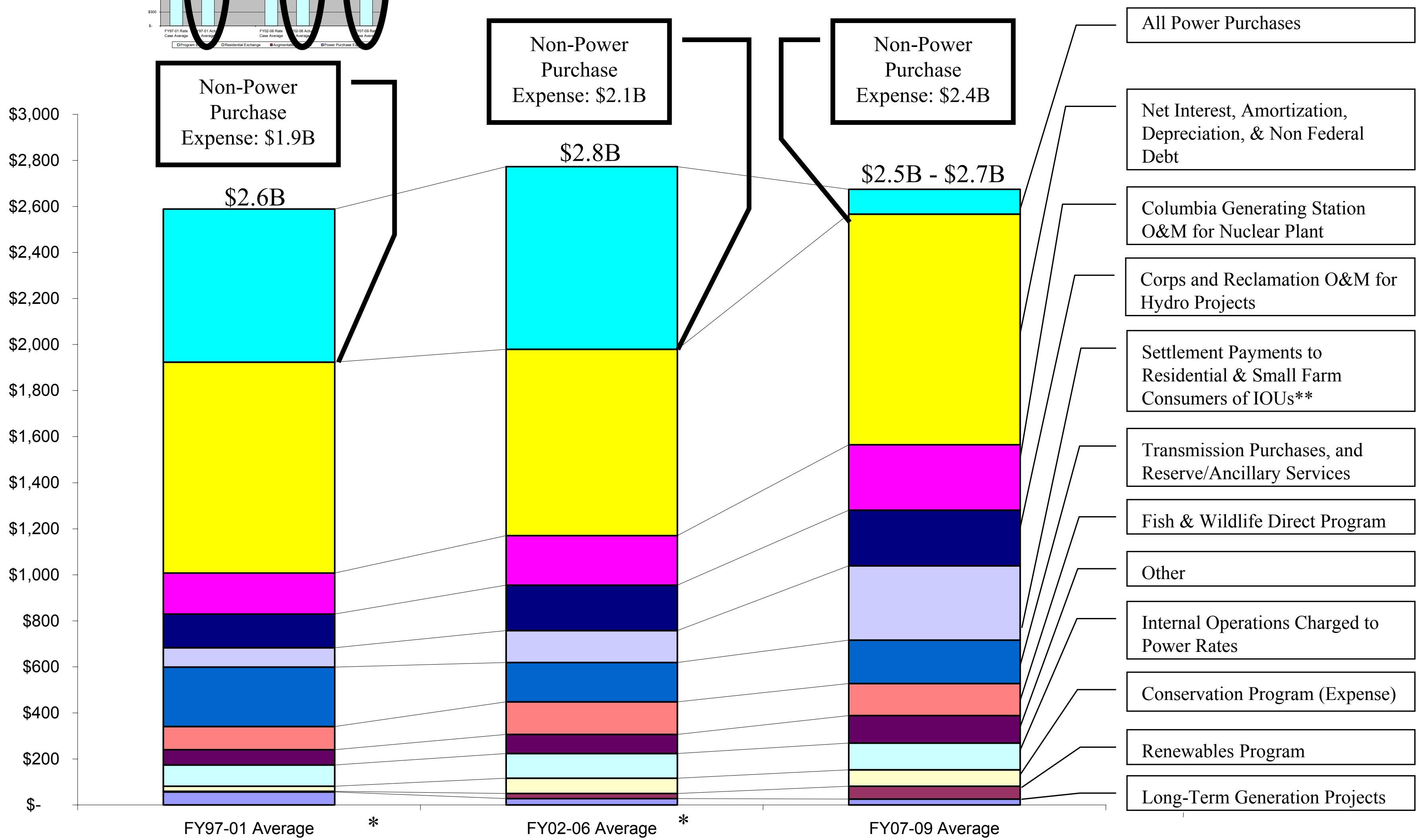


*FY01-04 Actuals include debt optimization results, FY05-06 include a forecast from the August 18th SN CRAC workshop

**Program Expenses includes all PBL expenses except Residential Exchange, Augmentation and Power Purchases

What Is The Expense Breakout in Nominal Dollars From FY 1997 – 2009

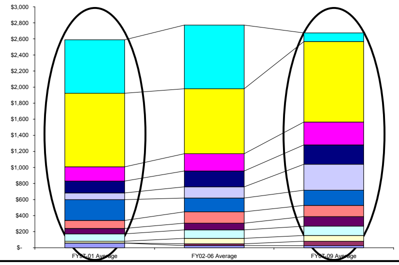


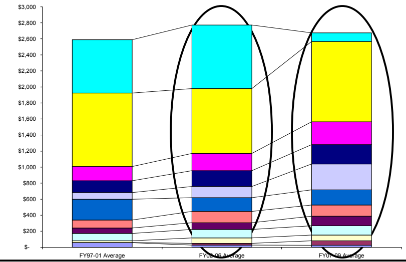


*FY01-04 Actuals include debt optimization results, FY05-06 include a forecast from the August 18th SN CRAC workshop

**This expense can vary between $123M and $323M depending on the market price and PBL rate.

What Are The Expense Changes in Nominal Dollars From FY 1997 – 2009





FY97-01 vs FY07-09 Annual Average (Nominal $)

•Net Interest, Depreciation & Amortization, and Non-Federal Debt Service	$88M
•Columbia Generation Station O&M for Nuclear Plant	$106M
•Corps and Reclamation O&M for Hydro Plants	$96M
•Settlement Payments to Residential & Small Farm Consumers of IOUs	$39M - $239M
•Total IOU benefits range is $39M - $239M	
•Transmission Purchases & Reserve/Ancillary Services	($70M)
•Fish & Wildlife Direct Program	$39M
•Total F&W Program less hydro ops $119M	
•Internal Operations Charged to Power Rates	$23M
•Conservation Program (Expense)	$49M
•Renewables	$53M
•Long-Term Generating Projects	($32M)
•All Power Purchases (includes Augmentation)	($559M)

FY02-06 vs FY07-09 Annual Average (Nominal $)

•Net Interest, Depreciation & Amortization, and Non-Federal Debt Service	$193M
•Columbia Generation Station O&M for Nuclear Plant	$69M
•Corps and Reclamation O&M for Hydro Plants	$46M
•Settlement Payments to Residential & Small Farm Consumers of IOUs	($16M) - $184M
•Total IOU benefits range is ($252M - $52M)	
•Transmission Purchases & Reserve/Ancillary Services	$18M
•Fish & Wildlife Direct Program	$0M
•Total F&W Program less hydro ops $55M	
•Internal Operations Charged to Power Rates	$9M
•Conservation Program (Expense)	$5M
•Renewables	$34M
•Long-Term Generating Projects	($3M)
•DSI benefit (placeholder)	$40M
•All Power Purchases (includes Augmentation)	($687M)

Changes To Power Rates Over Time

Costs, Credits and Load Changes From FY02-06 to FY07-09

$$\frac{\text{Costs} - \text{Credits} + \text{Risk}}{\text{Loads}} = \text{Rate}$$

•The numbers presented here are forecasts being used as the starting point for PFR review. No increases or decreases as a result of the PFR process are included.

•The purpose of this presentation is to provide PFR participants with a ballpark sense of where the rates **could** end up under various assumptions about the future.

Major Changes In Costs and Revenues Between 2002-06 And 2007-09

- Augmentation Purchases Expire
- IOU Residential Exchange Settlement Changes
- DSI Service Changes
- Higher PF Loads
  - 720 aMW Presub. load converting to PF load
  - 780 aMW public load increases due to stepped-up blocks from their initial level in 2002 and load growth for load-following customers (including expiration of PF buydowns)
- Higher O&M Costs
- Higher Debt Service Costs
- Long-Term Surplus Sales expire
- FY02-06 below average water, FY07-09 average water
  - 02-06 122 average annual maf *(assumes FY05-06 is average water)*
  - 07-09 134 average annual maf

Pending the PFR outcome, average costs to PF load (with no adder for risk mitigation) are forecasted to fall from 31.5 mills/kWh in 2002-06 to 28 mills/kWh.

Risk Mitigation Changes From FY97-06 to FY07-09

$$\frac{\text{Costs} - \text{Credits} + \text{Risk}}{\text{Loads}} = \text{Rate}$$

Tools	1997-2001	2002-2006	2007-2009
Rate Period	• 5-years	• 5-years	• 3-years
PBL Forecasted Starting Reserves	• $314M	• $840M (May 2000 Final Proposal) • $500M (Supplemental)	• E.V. ~$180M [3/]
PNRR	• $13M	• $98M	• $430-530M
Depreciation vs. Amortization [1/]	• +$80M	• -$3M	• -$45M
Power Liquidity Reserves	• $50M	• $50M	• $100M
FCCF Credits [2/]	• $325M	• $325M (Fund exhausted in 2003)	• Unavailable
Rate Adjustments	• N/A	• CRACs: – LB CRAC ('02-'06) (Supplemental) – FB CRAC ('03-'06) (Modified in Supplemental and SN CRAC Rate Case) – SN CRAC ('04-'06) (Supplemental and SN CRAC Rate Case)	• ?

1/ Depreciation was greater than amortization on average in the past rate cases resulting in additional cash available to mitigate risk. In 2007-2009, amortization is forecasted to be higher than depreciation. Therefore, the additional cash is not available for mitigating risk. Because amortization is higher, rates for 2007-2009 must recover this amount through the calculation of minimum required net revenue calculation (see PFR Debt Management Package). When comparing the past two rate periods to the upcoming rate period the minimum required net revenue produces an increase in the revenue requirement and therefore less cash available to mitigate risk.

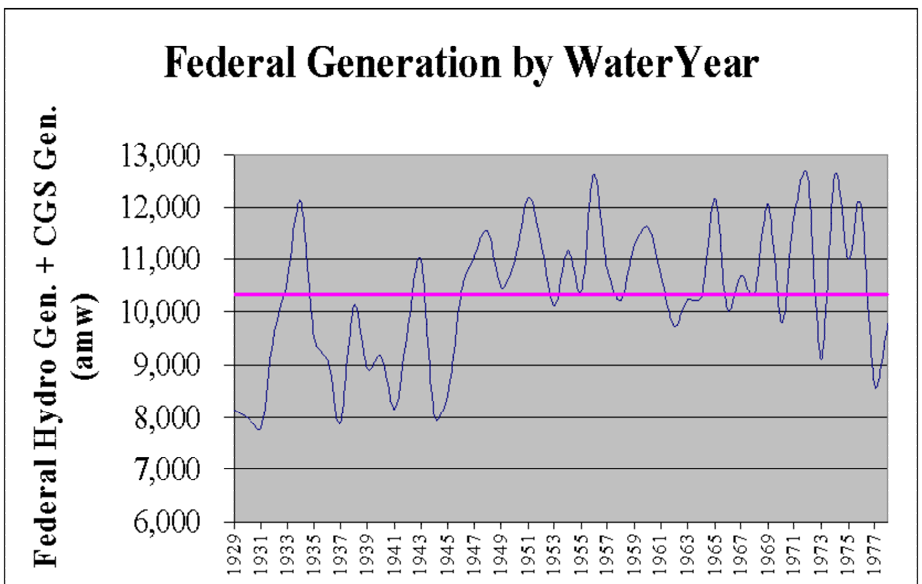
2/ FCCF fund was exhausted in 2003 and these credits are no longer available.

3/ See page 16 for an explanation of the FY 2007 forecasted PBL starting reserves.

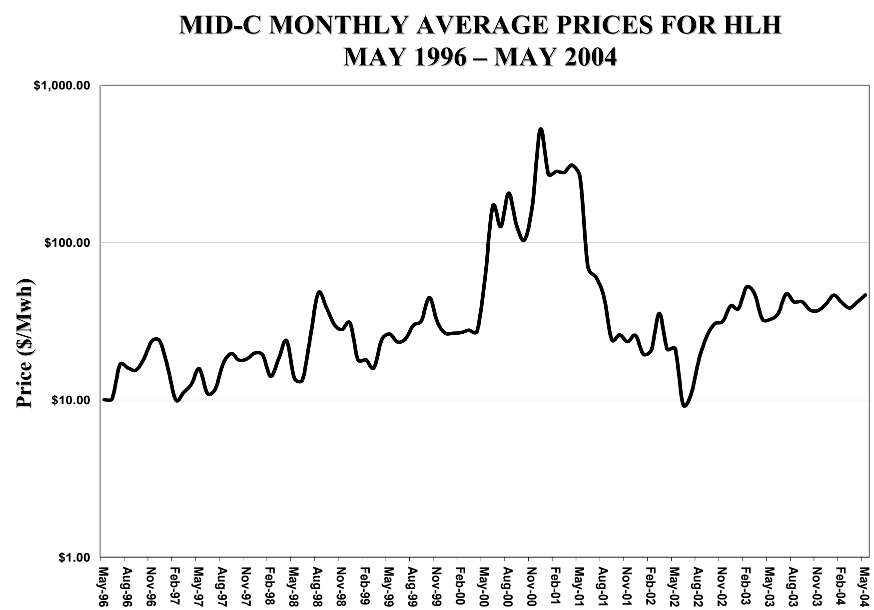
Risk Mitigation - Net Secondary Energy Sales Revenue Variability

- Water and market price variability combine to create huge net secondary sales revenue uncertainty:
  - 2005 and 2006 PBL net secondary sales revenue ~ \$500m with a standard deviation of ~\$300m (August 18th Workshop)
  - Average market prices used (Aug. ’04 SNCRAC assumptions):
    \$39 - \$44 per MWh 2005-6 Std. Dev. \$14
  - Risk level varies with market price assumptions

Historical Market Price Variability



Historical Water Variability



Risk Mitigation - Drivers of Power Rate Risks

- Hydro supply variability (both annual volume and seasonal shape of run-off)
- Market price variability (level and volatility)
- Fish and Wildlife costs from lost generation resulting from non-power requirements for operations
- CGS performance
- Other resource availability (wind, conservation, hydro plant performance and availability)
- Loads
- Unexpected expenses, expense overruns ("non-operating" risks)
- IOU Settlement cost variability

Risk Mitigation - TPP: Treasury Payment Probability

- As a not-for-profit, Federal enterprise, BPA does not seek to maximize net revenue; BPA must use other financial performance measures.
- Key performance – making all scheduled payments to Treasury on time.
- High probability of making payments to Treasury has become a key financial metric.
- BPA must pay other vendors before paying Treasury; TPP measures overall financial health.

Risk Mitigation - Factors Affecting TPP

Currently reserves are the main protection against net revenue variability. The 4 main factors affecting TPP in a rate case are:

1) The starting reserve level;

2) The expected value of the change in reserves from one year to the next (i.e., the E.V. of BPA's cash flow);

3) The annual variability (risk) in BPA's cash flow;

4) The length of the rate period.

Risk Mitigation - Tools to Mitigate Risks

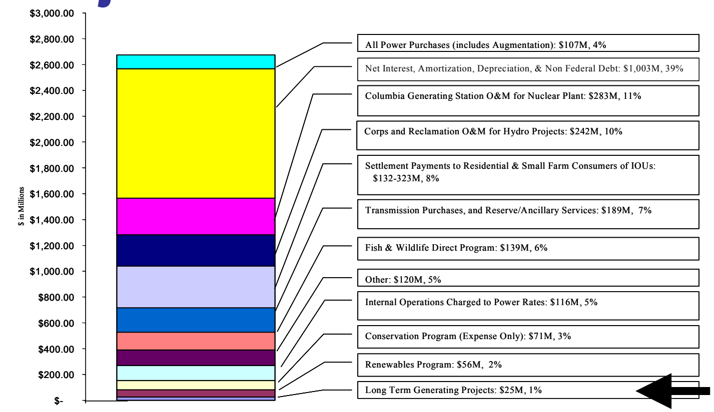
Different tools have different impacts on risk. Some tools are more effective than others. Some tools have an associated expense that may reduce risk but increase costs.

- Cash Reserves
- Planned Net Revenues for Risk (increases cash reserves)
- Rate Design
  - Flat rates & reserves
  - Shaped rates (eg. front-load revenues or back-load costs)
  - Rebates (send rebates to customers if certain conditions occur)
  - Surcharges (raise rates if certain conditions occur)
  - Indexed rates (index the level of rate to a measurable variable)
- Potential to engage others to explore risk mitigation alternatives – cost and feasibility issues
- Length of rate period (generally less risk with shorter rate periods)

PFR Program Area Overviews

FY07-09 Power Expenses

Long Term Generating Projects



	FY97-01 Average	FY02-06 Average	FY07-09 Average
Program Level	$57M	$28M	$25M
Increase/Decrease		($29M)	($3M)
% increase		-51%	-11%

Program:

- This $25M/year program consists of output contracts for generating resources, such as Cowlitz Falls, Billing Credits Generation, Wauna, and Clearwater Hatchery Generation.
- Most of the expenses associated with the long term generating projects are based on energy production at the generating units, and therefore are offset by revenues.

Risks:

- Unplanned/forced outages resulting in reduced secondary sales.
- Non-Routine Extraordinary Maintenance – infrequent, high dollar projects due to plant failure or overdue maintenance that cannot be capitalized.

Opportunities for Reductions:

- Not much because expense is made up of contracted prices.

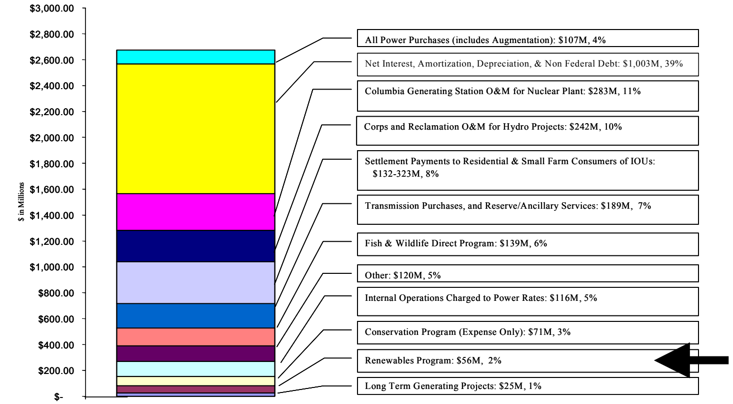
Drivers of Change:

- These expenses are down primarily because Tenaska settlement payments are included in the 1997-2001 period and not in the subsequent periods.

Background Paper

FY07-09 Power Expenses

Renewables



	FY97-01 Average	FY02-06 Average	FY07-09 Average
Program Level	$3M	$22M	$56M
Increase/Decrease		$19M	$34M
% increase		633%	155%

Program:

- This program actively supports BPA’s strategic direction to “ … facilitate[s] development of regional renewable resources …”
- The expense associated with the renewables program is largely offset by revenues from energy generation, green tag sales, and “environmentally preferred product” sales.
- *Program components of $56M/year annual expense for FY07-09:*
  - 56% Geothermal Project – Fourmile Hill project. This project is uncertain.
  - 41% Wind & Solar Projects – Footcreek, Condon, Stateline, Klondike, and Whitebluffs Solar
  - 3% Support Costs – Data collection, Project development costs, Corporate charges

Risks:

- Minor operational risk – Bonneville only pays for the power it receives.
- Purchase prices are fixed so any prolonged period of low market prices could make the net cost of this power higher than expected.

Opportunities for Reductions:

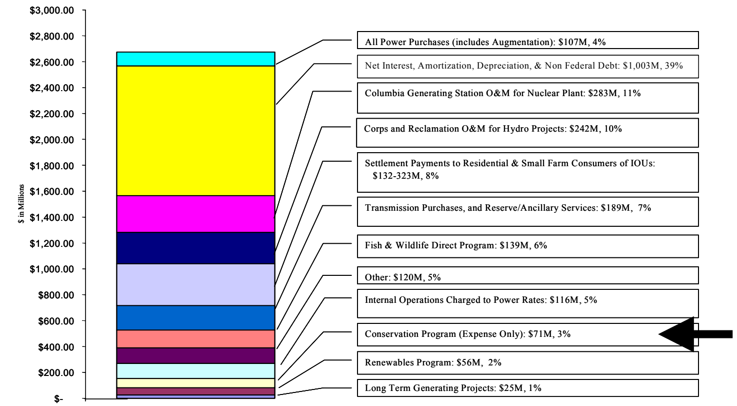
- Uncertainty surrounding Calpine's Fourmile Hill project.

Drivers of Change:

- These expenses are up in 2002-2006 primarily because of wind project acquisitions. Costs are up in 2007-9 primarily because we are continuing to assume purchase of power from the Calpine geothermal project, even though we are in binding arbitration over that contract.

FY07-09 Power Expenses
Conservation

	FY97-01 Average	FY02-06 Average	FY07-09 Average
Program Level -Expense	$22M	$30M	$71M
-C&RD	NA	$36M	NA
Total	**$22M**	**$66M**	**$71M**
Increase/Decrease		$44M	$5M
% increase		200%	7%



Program:

- This program actively supports BPA's strategic direction to " … ensure[s] development of all cost-effective energy efficiency in the loads BPA serves …"
- BPA's conservation program (expense & capital) has a goal of delivering 56 aMW of conservation savings per year during the FY07-09 period. This compares to and average of 44 aMW per year over the rate period.
- Not reflected in the expense portion of the conservation funding level is $32M/year in conservation capital.
- *Program components of $71M/year annual expense for FY07-09:*
  - 53% Proposed Conservation Rate Credit (currently being designed in a public process) - Based on a discount off firm power rates for all customers that implement approved conservation and renewable resources related initiatives.
  - 18% Reimbursable Program - Supports other Federal agencies as they strive to meet their energy efficiency mandates; this program is rate-neutral becuauase revenues equal expenses. This category of expense is fully reimbursed by the Federal agencies.
  - 14% Market Transformation - Supports the Northwest Energy Efficiency Alliance (NEEA) in their efforts to improve the energy efficiency of buildings, appliances and equipment, and to help new energy efficiency technologies become commercially viable.

FY07-09 Power Expenses
Conservation, *continued*

- *Program components of $71M/year annual expense for FY07-09 (continued):*
  - 7% Low Income Weatherization - Supports the weatherizating the homes of the economically disadvantaged residents in the four PNW states.
  - 4% Legacy Contracts - Covers invoices for previously installed measures under existing pay for performance legacy contracts.
  - 2% Technology Leadership - Provides technical assistance to customers and continues BPA’s conservation information/education/outreach activities.
  - 1% Energy Web - Supports non-wires solutions to transmission construction and to leverage/partner with others implementing new technologies.

Risks:

- Achieving the higher aMW targets while assuming a small increase in funding for this program.

Opportunities for Reductions:

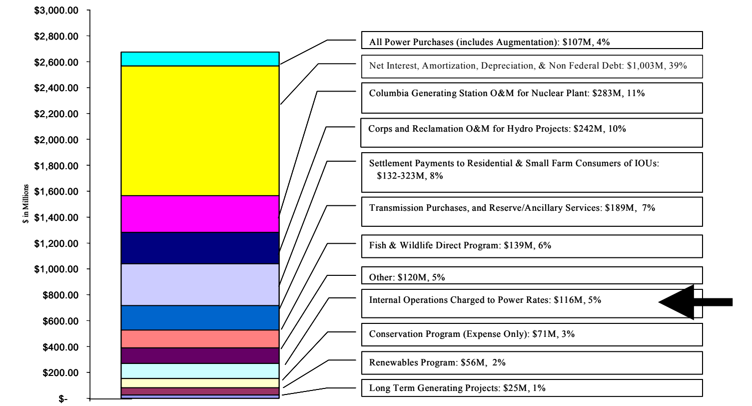
- Regional coordination and cooperation.
- New and innovative approaches and technologies for acquiring conservation.
- Different funding mechanisms (e.g., different blends of expense, capital, rate discounts, rate credits, pay for performance contracts, 3rd party contracts, etc.).

Drivers of Change:

- These expenses are up because BPA took a more active role in conservation development in 2001 and ramped up its programs in the FY2002-06 period in response to power shortages and plans to continue that effort.
- New Council conservation targets are suggesting, on average, a 27% increase in delivered aMW savings for BPA.
- BPA has a strategic objective to meet its share of the Council's target.

FY07-09 Power Expenses

Internal Operations Charged to Power Rates



	FY97-01 Average	FY02-06 Average	FY07-09 Average
Program Level	$93M	$107M	$116M
Increase/Decrease		$14M	$9M
% increase		15%	8%

Program:

- This program is driven by BPA's strategic direction: "Effective cost management (with emphasis on best practices, innovation and simplicity) through our systems and processes."
- *Program components of $116M/year annual expense for FY07-09:*
  - 77% Employee Compensation – Personnel compensation and overtime for BPA staff and compensation for contract labor.
  - 14% Service Contracts – Such as projects to optimize the use of water at hydro projects thereby increasing generating output and secondary sales.
  - 9% Other – Travel, training, materials & supplies, rents & utilities, and miscellaneous.

Risks:

- Unanticipated requirements from new industry requirments, customers, constituents, and other stakeholders.

Opportunities for Reductions:

- Enterprise Process Improvement effort.
- Implementation of Voluntary Separation Incentive & Voluntary Early Retirement Authority.
- Position Management Initiative to reduce overall grade structure.

<u>Drivers of Change:</u>

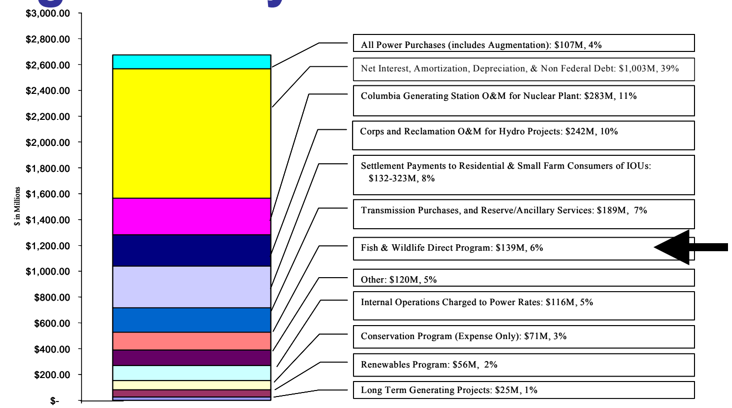
- Total PBL staffing is declining. Decreased staffing in many areas has been offset by increases in operational functions, partly reflecting efforts to extract more generation from the hydro system through various efficiency projects.

FY07-09 Power Expenses

Fish and Wildlife Direct Program Only

	FY97-01 Average	FY02-06 Average	FY07-09 Average
Program Level	$100M	$139M*	$139M
Increase/Decrease		$39M	$0M
% increase		39%	0%

*Does not include High Priority Action Items



Program:

- This program is driven by BPA's strategic direction that we " … will deliver cost-effective solutions for meeting fish, wildlife and environmental responsibilities, measured against clearly defined performance objectives. "
- *Program components of $139M/year annual expense for FY07-09:*
  - 26% Production & Harvest– Operation and maintenance of resident & anadromous hatchery projects.
  - 25% Research & Evaluation – Includes studies that collect and analyze new information.
  - 22% Habitat – Includes habitat restoration, land acquisition, irrigation screening, and tributary passage improvement.
  - 12% Monitoring - Monitors and evaluates mainstem passage, hatcheries and habitat inventories.
  - 11% Coordination – Includes coordination and data management of administrative projects.
  - 3% Mainstem Survival – Includes predator control and mainstem passage improvements.

Risks:

- Assumes no funding increase – even for inflation.
- Change in hatchery operations, habitat restoration, and predation programs due to the Biological Opinion Remand.
- Expectations of external parties - the Council's creation of new Sub-basin Plans have identified many new areas that will require funding. External parties will expect BPA to increase program funding to implement plans.
- Development of Memorandum of Understanding (MOU) will define roles and responsibilities and may establish higher program funding levels.

Opportunities for Reductions:

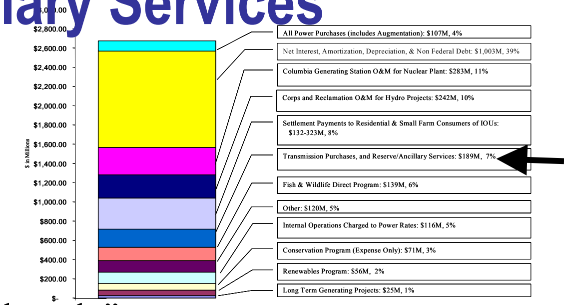
- Development of Memorandum of Understanding (MOU) will possibly identify areas to increase efficiencies.

Drivers of Change:

- The program level is being held constant for the 2007-09 period pending completion of an existing public process (See slide titled BPA's Total Fish & Wildlife Program).

FY07-09 Power Expenses

Transmission Purchases & Reserve/Ancillary Services



	FY97-01 Average	FY02-06 Average	FY07-09 Average
Program Level	$259M	$171M	$189M
Increase/Decrease		($88M)	$18M
% increase		-34%	11%

Program:

- This program is driven by BPA's strategic direction that "Risks are managed within acceptable bounds."
- Generally, this category represents costs associated with services necessary to deliver energy from resources to markets and loads: transmission, ancillary services, real power losses.
- *Program components of $189M/year annual expense for FY07-09:*
  - 65% Transmission & Ancillary Services – Payments to BPA's Transmission Business Line for transmission and ancillary services associated with bulk sales.
  - 30% 3rd Party Expenses – Payments to 3rd parties for transmission and ancillary services associated with Transfer Service Agreements and bulk sales.
  - 4% Reserve Services – Payments to BPA's Transmission Business Line for generation integration costs.
  - 1% Equipment & Replacements - Metering, telemetry, communications equipment, & replacements are to meet increasing PBL business requirements for frequency and granularity of meter data.

Risks:

- Increased transmission rates.
- Increased costs associated with congestion on the transmission grid.
- Limited access to transmission.

Opportunities for Reductions:

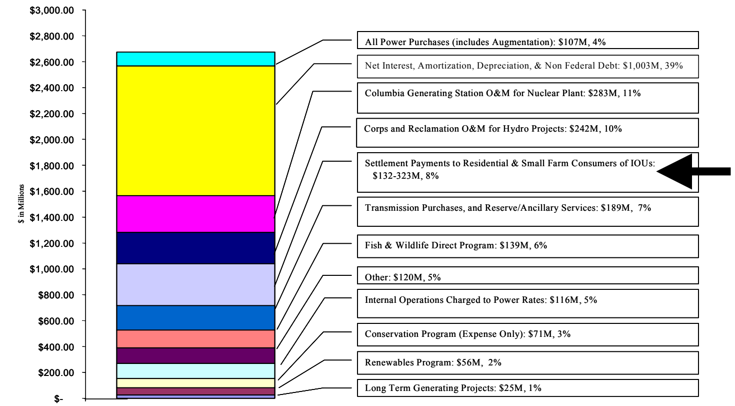
- Maintain expertise to manage transmission portfolio - efficient utilization of existing transmission contracts and incremental transmission purchases.
- Coordination with BPA Account Executives and transfer customers regarding load growth and plans of service.

Drivers of Change:

- Shape and level of surplus energy.
- Unbundling of power and transmission.
- Deregulation: Movement to Open Access Transmission Tariff Service.
- Changes in investment and associated annual costs.

FY07-09 Power Expenses

Payments to Residential & Small Farm Consumers of IOUs



	FY97-01 Average	FY02-06 Average	FY07-09 Average
Program Level	$84M	$139M 1/	$123-323M
Buy Down Payments 2/	$0M	$235M	$0M
Total	$84M	Approx $375M	$123-323M

1/ 900 aMW of Monetary Benefit

2/ Approximately 718 aMW of load augmentation (BPA power buyback) from PacifiCorp and Puget at $38/MWh.
Avista, Idaho, and NorthWestern converted 124 aMW of power to financial payments at ($38 - CRACed PF).
Includes assumed average benefits of $19M from 258 aMW power purchase by PGE.
Includes FY 2003 deferral of $55M and subsequent payback of $41M over FY 2004 - 2007.

Program:

- This program is driven by BPA's strategic direction that the benefits we provide ". . . To IOUs for their residential and small-farm consumers is equitable based on the Northwest Power Act."
- For FY 07-09, the program expense is a result of the Residential Exchange Program Settlement agreements with the IOUs.
- As part of the Settlement agreements, we reduced $100M in expenses over the FY 02-06 period, deferred another $100M out of the FY 02-06 period and into the FY 07-11 period, and agreed to a $100M floor and a $300M cap on the remaining benefits for the FY 07-11 period (excluding repayment of the FY 02-06 deferred amount).
- *Program components of the annual expense for FY07-09:*
  - Most of the annual expense is the calculated benefits within a range of $100M-$300M =
    - (Market Price – Priority Firm power rate) * 2200 aMW * 8760 hours/year
  - The rest of the annual expense is the deferred benefits (roughly $23M/year deferred from the FY02-06 period).

Background Paper

FY07-09 Power Expenses

Payments to Residential & Small Farm Consumers of IOUs, continued

Opportunities for Reductions:

- Market Price Level: For the calculated component, as market prices decrease, benefits could be reduced down to $100M (although this decrease will likely be partially offset by reduced prices we will receive from secondary sales).

Drivers of Change:

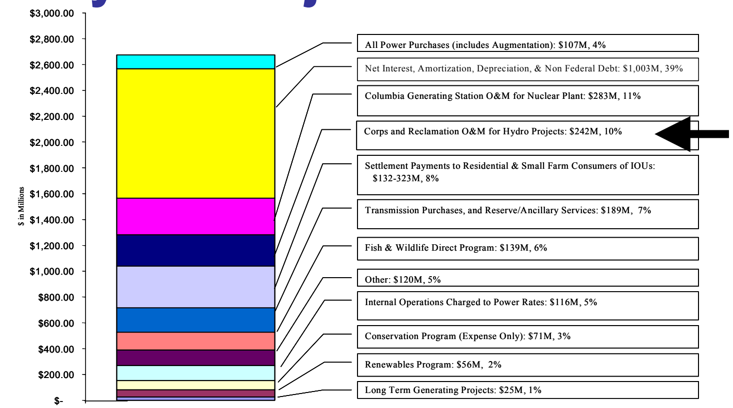
- Annual costs prior to 1997 averaged approximately $200 million.
- Payments dropped to $84 million per year in 1997-2001, via legislation and termination agreements.
- FY2002-2006 planned costs were $142 million per year, but jumped to about $400 million per year, mainly due to load buydowns during the power crisis.
- FY2007-2009 costs reflect settlement agreement. By formula, could be as low as $123 million per year, or as high as $323 million per year.

Background Paper

FY07-09 Power Expenses

Corps and Reclamation O&M for Hydro Projects

	FY97-01 Average	FY02-06 Average	FY07-09 Average
Program Level	$146M	$196M	$242M
Increase/Decrease		$50M	$46M
% increase		34%	23%



Program:

- This program is driven by BPA's strategic direction to ensure that hydro projects' " … performance and expansion meet availability, adequacy, reliability and cost-effectiveness standards. "
- BPA works with U.S. Army Corps of Engineers and the Bureau of Reclamation to ensure implementation of all regionally cost-effective system refurbishments and enhancements to federal hydro projects.
- *Program components of $242M/year annual expense for FY07-09: (percentages based on expected FY04 costs)*
  - 74% Labor – Salaries and benefits, including some Fish & Wildlife and Security related employee costs.
  - 11% Support Services & Contracts – Fish & Wildlife costs, security costs, buildings maintenance, etc.
  - 9% Miscellaneous – IT, communication costs, multipurpose costs, travel, training, rental space, etc.
  - 5% Materials and Supplies – Hydropower O&M materials & supplies, non-capitalizable supplies, etc.

Risks:

- WECC/NERC compliance requirements.
- Security Costs: Cost Forecasts are based on current threat level. Higher level will increase costs.
- Environmental compliance requirements.
- BiOps: Requirements still unknown (Willamette BiOp pending). Likely will increase costs.

FY07-09 Power Expenses

Corps and Reclamation O&M for Hydro Projects, cont.

Opportunities for Efficiencies/Reductions:

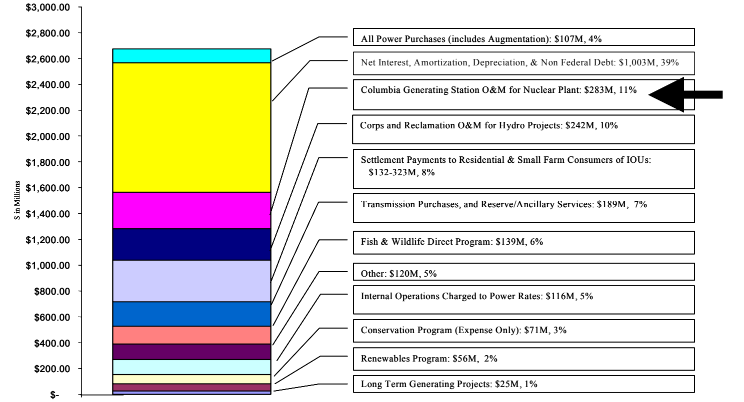
- BPA, U.S. Army Corps of Engineers and the Bureau of Reclamation Hydro Program process review and long term strategic planning.
- Improved maintenance management practices.
- Remote operations of feasible plants.
- E-procurement – the reverse auction for the lowest cost materials and supplies.
- Power Plant Efficiencies Improvement (PPEI): expense of $500-800K/year thru 2011. Through 2004 PPEI has added 80+aMW to the system, worth ~ $24M/year in revenue (based on average water @ $35).

Drivers of Change:

- Extraordinary maintenance
- COLAs for labor
- Security Costs
- NERC/WECC compliance requirements
- Environmental compliance requirements
- BiOps
- Grand Coulee cost reallocation

FY07-09 Power Expenses

Columbia Generating Station O&M for Nuclear Plant



	FY97-01 Average	FY02-06 Average	FY07-09 Average
Program Level	$178M	$215M	$284M
Increase/Decrease		$37M	$69M
% increase		21%	32%

Program:

- This program is driven by BPA's strategic direction to ensure that the Columbia Generating Station (CGS) nuclear plant's " … performance and expansion meet availability, adequacy, reliability and cost-effectiveness standards" and that it is operated in a safe manner.
- *Program components of $284M/year annual expense for FY07-09:*
  - 71% O&M – Costs, other than capital costs, associated with operating and maintaining CGS. Included are security expense costs, which have increased to $9.1M from $4.6M due to 9/11.
  - 18% Fuel – Includes purchases of uranium, enrichment, conversion and fabrication.
  - 8% Capital – Costs related to improvements and modifications to the plant or the purchase of equipment that exceeds $10,000 and has a service life of greater than one year.
  - 2% Decommissioning Trust Fund Contribution – Contributions into a trust fund that will be used for the Decommissioning of CGS.
  - 1% NEIL Insurance - Insurance that is purchased from Nuclear Electric Insurance Limited to insure CGS for costs associated with interruptions, damages, and other related nuclear risks.

Risks:

- Level and volatility in nuclear fuel price (uranium & uranium conversion).
- Possibility of additional security measures required by the Nuclear Regulatory Commission (NRC).
- Needs for major equipment replacement.
- Escalation of O&M costs.

Opportunities for Reductions:

- An ongoing Energy Northwest efficiency initiative.
- Meeting lower cost of power targets consistent with industry measurement standards.

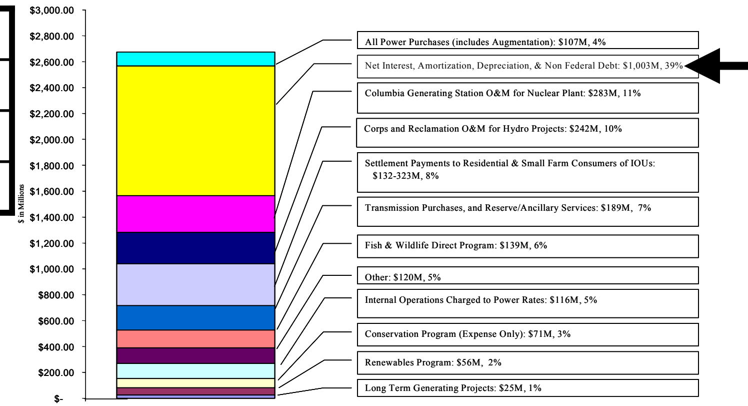
Drivers of Change:

- 2007-9 average is biased upward somewhat because two refueling outage years are included in this three-year period.
- O&M costs were pushed below sustainable levels in the 1997-01 period. Deferred costs are now being incurred.
- Increased costs due to security requirements, equipment obsolescence, and restoration of nuclear fuel inventory.

FY07-09 Power Expenses

Net Interest, Depreciation & Amortization

	FY97-01 Average	FY02-06 Average	FY07-09 Average
Program Level	$344M	$363M	$437M
Increase/Decrease		$19M	$74M
% increase		6%	20%



Program:

- This program is driven by BPA's strategic direction related to our financial objectives: ensure sustainable access to capital, ensure cost recovery over time, and maintain adequate cash flow for liquidity and Treasury payment.
- *Program components of $437M/year annual expense for FY07-09:*
  - 55% Net Interest – Comprised of interest on bonds & appropriations netted against interest credit from the Bonneville Fund.
  - 26% Depreciation – The depreciation of revenue producing assets and ongoing infrastructure investments through BPA direct funding for hydro projects, and appropriated investment for fish mitigation program at hydro projects managed by the Corps of Engineers.
  - 19% Amortization – The depreciation of non-revenue producing assets such as conservation and direct fish and wildlife capital investments (non-appropriated).

Risks:

- Rising interest rates, affecting the cost of future Treasury borrowing.
- Changes in the plant in service schedule of the Columbia River Fish Mitigation project by the Corps of Engineers.
- Reduced cash balance, decreasing interest credit.

Opportunities for Reductions:

- Continued aggressive debt management to reduce interest costs.
- Continuation of the Debt Optimization Program.
- Lower interest rates.
- Increased cash balance, increasing interest credit.

Drivers of Change:

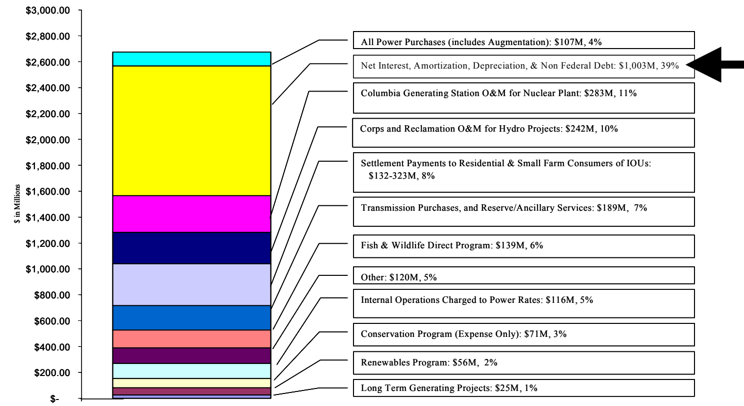
- Debt Optimization increased repayment of Federal debt ("Advance amortization") in the same amounts as non-Federal principal payments decreased (2002-2005).
- Decreased Federal interest expense due to advance amortization (2002-2009).
- Increased capital investment.
- Change in projected interest income due to change in cash balance.

Note: Depreciation and amortization are direct results of the level of capital investment, so will increase or decrease based on investment levels. Net interest has several components, and is influenced by other factors in addition to capital investment levels.

FY07-09 Power Expenses

Non-Federal Debt Service

	FY97-01 Average	FY02-06 Average	FY07-09 Average
Program Level	$571M	$446M	$566M
Increase/Decrease		($125M)	$120M
% increase		-22%	27%



Program:

- This program is driven by BPA's strategic direction related to our financial objectives: ensure sustainable access to capital, ensure cost recovery over time, and maintain adequate cash flow for liquidity and Treasury payment.
- *Program components of $566M/year annual expense for FY07-09:*
  - 56% Non-Operating Generation Projects – WNP 1 & 3, Trojan, Conservation Augmentation Program, Northern Wasco, CARES, Tacoma.
  - 44% Operating Generation Projects – Columbia Generation Station, Cowlitz Falls.

Risks:

- Variable Rate Debt: Bonneville has a limited amount of basis risk exposure associated with $500 million of variable rate debt (VRD) outstanding. This debt has two swaps associated with it to turn it into a synthetic fixed rate debt, however, in low interest rate environments the variable rate received does not fully offset the variable rate paid out creating this basis risk.
- Rising interest rates affecting the cost of future non-Federal borrowing financings and refinancings.
- EN may not agree to continue the Debt Optimization program.

Opportunities for Reductions:

- Continued aggressive debt management to reduce interest costs.

Drivers of Change

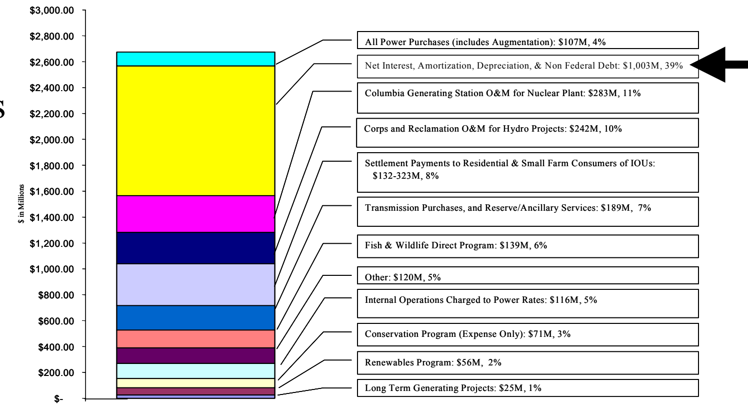
- Extension (roll-out) of EN debt, resulting in decreased non-Federal principal in the same amounts as increased Federal payments (FY 2002-2005), and increased non-Federal interest costs (FY 2002-2009).
- Early reserve fund free-ups resulted in decreased interest expense in FY 2002-2004, and increased interest expense in FY 2005-2009.
- Increased capital investment.

BONNEVILLE POWER ADMINISTRATION

FY07-09 Power Expenses

Impacts of Debt Management Actions

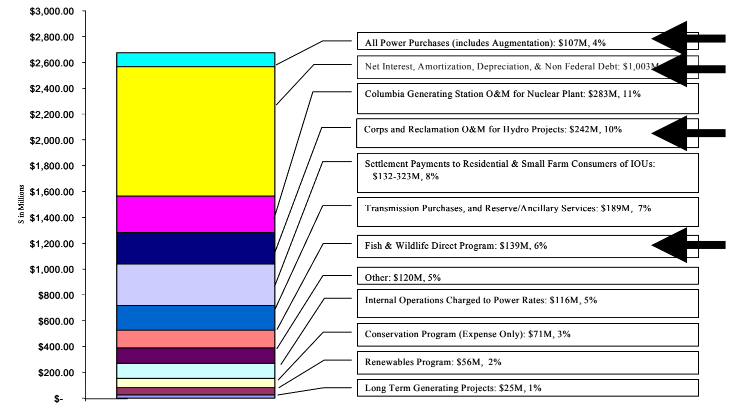
BPA manages its Federal and non-Federal debt at an agency level, as a single portfolio. The debt management actions BPA takes affect various components of BPA's capital costs, and those affects are not always apparent without looking at each of the components. In the FY02-05 period there have been numerous actions, in some cases with off-setting impacts. The table below indicates how some of the major changes in the FY 2002-2005 period impacted costs. Further information will be provided at the technical workshop.



	FY02 Compared to Rate Case	FY03 Compared to Rate Case	FY04 Compared to Rate Case	FY05 Compared to Rate Case
Reserve free-ups	(27) ↓	(137) ↓	(46) ↓	32 ↑
Energy Northwest Principal	↓	↓	↓	↓
Federal Principal	↑	↑	↑	↑
Energy Northwest Interest	↑	↑	↑	↑
Federal Interest due to advance amortization	↓	↓	↓	↓

FY07-09 Power Expenses

BPA's Total Fish & Wildlife Program



The line items marked with this arrow are those areas where Fish and Wildlife program expenses are embedded.

Program:

- BPA intends to explore all options to efficiently meet its fish and wildlife obligations while not unduly burdening the Northwest ratepayer consistent with BPA's strategic direction that we "… will deliver cost-effective solutions for meeting fish, wildlife and environmental responsibilities, measured against clearly defined performance objectives."
- However, BPA's fish and wildlife program continues to be one of our most significant costs. While BPA's integrated fish and wildlife program is directly linked to our financial statements, other aspects of the program indirectly impact power rates as well, such as reduced hydro system generation due to fish mitigation operations.
- BPA is currently working with Northwest Planning and Conservation Council (NPCC) and other parties to negotiate a Memorandum of Understanding (MOU) which will establish fish and wildlife funding levels. The Biological Opinion (BiOp) which guides future operations of the Federal Columbia River Power System (FCRPS) has been re-written, but is still undergoing legal challenge.

Risks:

- Litigation over Biological Opinion Remand
- Funding pressure from the NPCC
- Surface Bypass Technology (e.g., Removable Spillway Weirs) with spill: Pressure to direct fund, schedule slippage, and performance less than expected
- Changes in 4(h)(10)(C) methodology

Opportunities for Reductions :

- Implementation of Surface Bypass Technology.

See next page for Total Program components of $692M/year annual expense for FY07-09

BONNEVILLE POWER ADMINISTRATION

BPA's Total Fish & Wildlife Program: Total Annual Average Cost to BPA Rate Payers

Percentage of Budget Categories Allocated to F&W		FY 2007-2009 ($ in Millions)
UNSLICED 50-year Annual Average Hydro Operations Effects (Power Purchases & Foregone Revenues)		356.9*
Integrated Program	100%	139.0*
NWPCC – Annual Average	50%	4.6
US Fish & Wildlife Service – Annual Average Lower Snake Compensation Plan	100%	19.8
Corps of Engineers O&M – Annual Average	~25%	37.5
Reclamation O&M – Annual Average	~7%	4.2
Plant in Service		129.6
		TOTAL 691.6

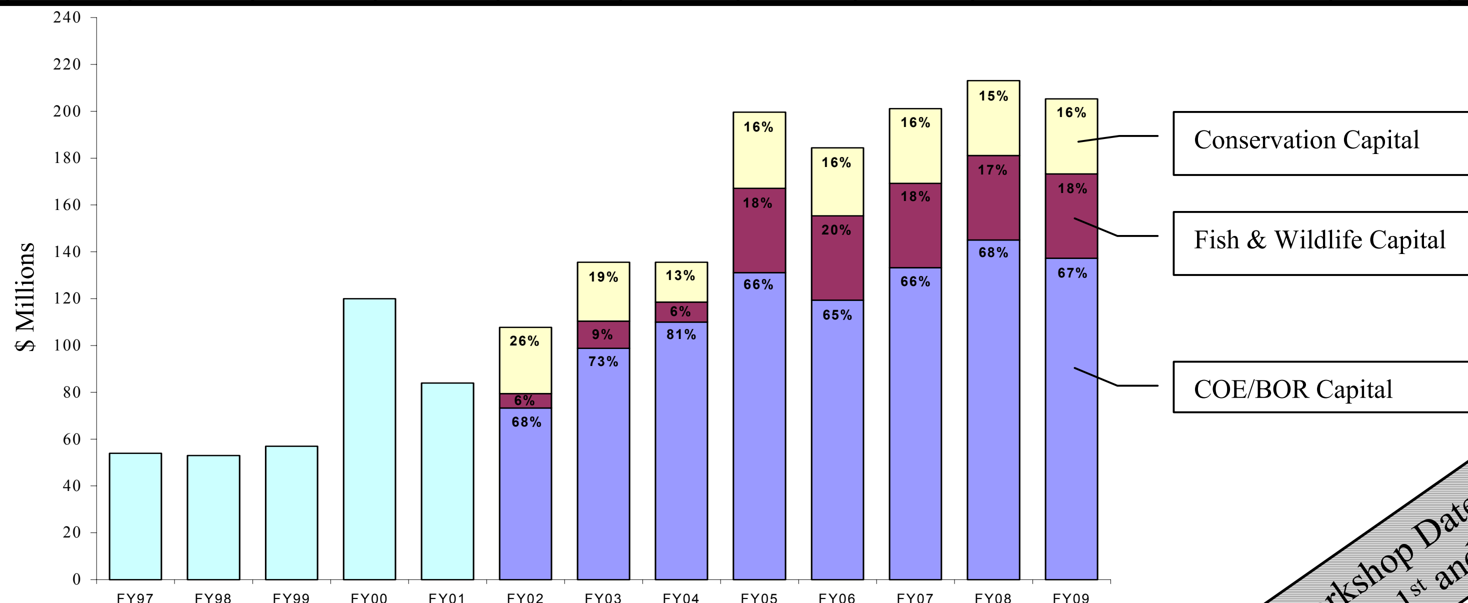
Total repayment obligations for current & past F&W investments

- COE/Reclamation/USF&WS Appropriations for Capital F&W Investments
- BPA Borrowing for Capital F&W Investments

*Note: Operational costs reflect expected 2007 river conditions with RSWs operational at IHR and in test mode at LMN and a BGS in test mode at TDA – actual operations may be more costly. Potential savings of additional RSWs and cost effects of a Snake River Transport vs. In-River migration study make operational costs highly variable during this period. One possible range of average annual OPS costs for FY07-09 is $352M to 369M; even this range is optimistic in that it assumes no schedule slippage and implementation of assumed spill levels.
Integrated Program assumes additional projects funded within existing budget.

Planned Power Function Capital Expenditures for FY07-09

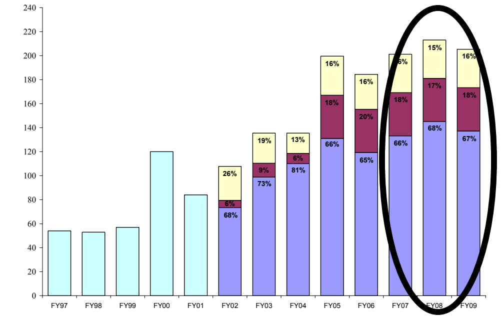
	Actuals								Forecasted				
	FY97	FY98	FY99	FY00	FY01	FY02	FY03	FY04	FY05	FY06	FY07	FY08	FY09
COE/BOR						$95M	$92M	$111M	$131M	$119M	$133M	$145M	$137M
Fish & Wildlife						$6M	$12M	$9M	$36M	$36M	$36M	$36M	$36M
Conservation						$29M	$25M	$17M	$33M	$29M	$32M	$32M	$32M
Total*	**$54M**	**$53M**	**$57M**	**$120M**	**$84M**	**$130M**	**$129M**	**$137M**	**$200M**	**$184M**	**$201M**	**$213M**	**$205M**
Increase/ Decrease		($1M)	$4M	$63M	($36M)	$46M	($1M)	$8M	$63M	($16M)	$17M	$12M	($8M)
% increase		1%	8%	111%	-30%	154%	1%	6%	46%	-8%	9%	6%	-3%



Workshop Dates – March 1st and 17th

*Data not available by individual program during this time period.

FY07-09 Power Capital



Program:

- *Program components of $206M/year annual capital expenditures for FY07-09:*
  - 67% Hydro Capital – Corps of Engineers/Bureau of Reclamation projects and includes turbine efficiency improvements, hydro optimization projects, powerhouse auxiliary equipment upgrades, replacements and refurbishments, and generation equipment upgrades.
  - 17% Fish & Wildlife Capital – Such as hatchery and acclimation projects, mitigation, fish screens, habitat improvement, and land acquisition.
  - 16% Conservation Capital – Includes lighting in residential, commercial, and industrial facilities, industrial motor improvements, and envelope work on commercial buildings.

Risks:

- Increases in construction costs

Drivers of Change:

- New Council conservation targets are suggesting, on average, a 27% increase in delivered aMW savings for BPA.
- BPA has a strategic objective to meet its share of the Council's target.
- Investments in the hydro system in order to maintain and upgrade performance.
- Fish and Wildlife investments.

PFR Scorecard –

What We Have Heard So Far

(See Attachment 1: PFR Scoresheet as of April 4, 2005)

2007-2009 Power Costs, Credits, Risk Overview

(See Attachment 2: "Overview" Handout from February 23, 2005 Management Discussion)

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.

BPA Power Function Review
Scoresheet: Decisions that Could Increase 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 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		

2007-2009 Power Costs, Credits, Risk: Overview

Purpose of this presentation:

- The Power Function Review (PFR) is about the costs that will be recovered in the 2007-09 power rates. It is not about the rate level.
- But PFR participants need to know roughly where rates **may** be headed in order to comment on the costs.
- The purpose of this presentation is to provide PFR participants with a ballpark sense of where the rates **could** end up under various assumptions about the future.

Important disclaimers

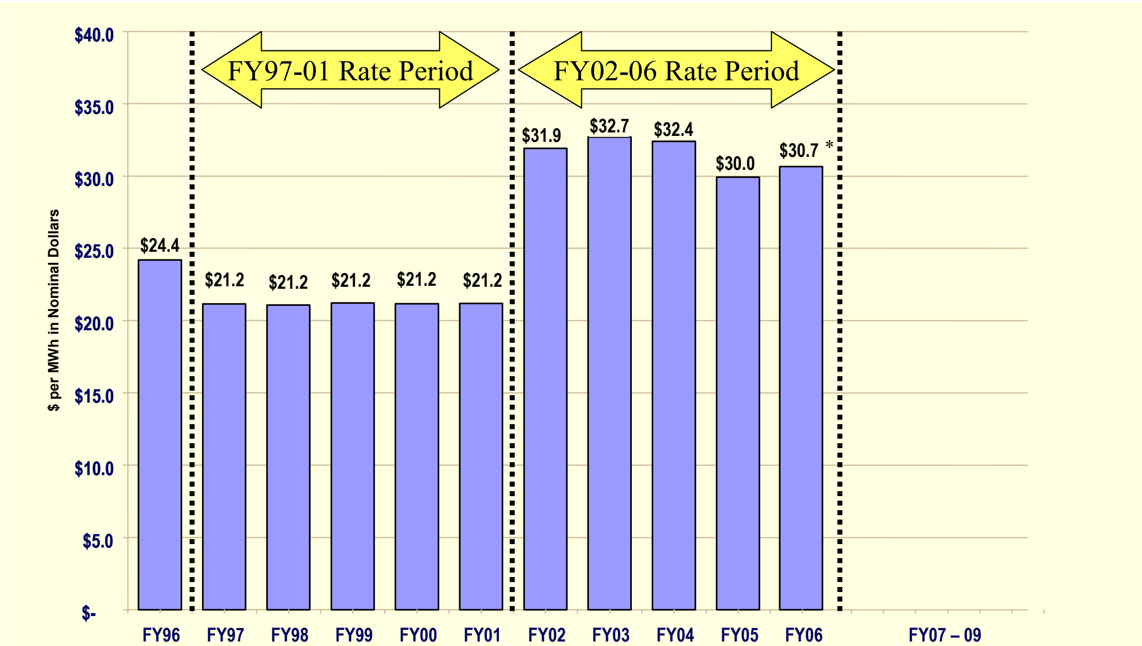
- The PFR is about the costs that go into the initial rate proposal. Several other issues that will be decided in the 2007 rate case will also have major impacts on the rate level.
- The numbers presented here are forecasts being used as the starting point for PFR review. No increases or decreases as a result of the PFR process are included.

FY07-09 PF Rate Overview

$$\frac{\text{Costs} - \text{Credits} + \text{Risk}}{\text{Loads} * 8.76} = \text{Rate}$$

Point of Reference Used Here:
2002-2006 Average PF Rate: 31.5 mills/kWh

Actual and Forecasted
Nominal Power Rates: FY 1996-2006



*Forecasted FY06 rate from August 18, 2004 SN CRAC workshop

Note: Nominal Power Rates do not include Transmission Rate Component

<u>**Note:**</u> 2002-2006 actual PF rates are expected to fall somewhat short of covering actual net expenses. BPA was in the black for 2003-04 and expects to be in the black for 2005, but not enough to cover the loss in 2002. On average, annual modified net revenues for the 2002-2006 period are expected to be -$54 million/year for a loss over the rate period of just over $250 million.

Major Changes In Costs and Revenues Between 2002-06 And 2007-09

- Augmentation Purchases Expire

- IOU Residential Exchange Settlement Changes

- DSI Service Changes

- Higher PF Loads
  - 720 aMW Presub. load converting to PF load
  - 780 aMW public load increases due to stepped-up blocks from their initial level in 2002 and load growth for load-following customers (including expiration of PF buydowns)

- Higher O&M Costs

- Higher Debt Service Costs

- Long-Term Surplus Sales expire

- FY02-06 below average water, FY07-09 average water
  - 02-06 122 average annual maf *(assumes FY05-06 is average water)*
  - 07-09 134 average annual maf

Summary:

- Pending the PFR outcome, average costs to PF load (with no adder for risk mitigation) are forecasted to fall from 31.5 mills/kWh in 2002-06 to 28 mills/kWh.

- However, lower reserve levels, higher secondary revenue volatility and other factors substantially increase the need for risk mitigation in the 07-09 rates.

- Depending on the approach used, risk mitigation could more than offset the average cost decrease.

$$\frac{\text{Costs} - \text{Credits} + \text{Risk}}{\text{Loads}} = \text{Rate}$$

Total Annual Costs: $230 million/year lower in 2007-2009.

- Augmentation and buydown costs down by $640 million/year
- Other purchase costs down by $70 million/year
- O&M costs up by $125 million/year
  - CGS: up $70 million/year
  - Hydro: up $45 million/year
  - BPA internal: up $10 million/year
- Debt Service costs (net interest, depreciation, amortization, nonfederal, minimum required net revenue) up by $120 million/year
- Residential exchange settlement payments to IOUs (not including 2002-2006 buydown costs) up by $145 million/year (Assumes IOU payments are near the $300 million cap. This number is highly sensitive to market forecast and PF rate level)
- DSI financial benefits (assuming this is the outcome of ongoing discussion) up by $40 million (this comparison does not count actual sales, augmentation costs, and buydown payments to DSIs in 2002-6)
- Other increase by $50 million/year
  - Transmission and Ancillary & Reserve Services up by $20 million/year
  - Renewables and L-T purchases up by $30 million/year

$$\frac{\text{Costs} - \text{Credits} + \text{Risk}}{\text{Loads}} = \text{Rate}$$

Total Annual Credits and Non-PF Revenues: $435 million/year lower in 2007-09

- Revenue from DSIs down by $60 million/year
- Revenue from IOUs down by $90 million/year
- Revenue from presubcription sales to publics down by $130 million/year
- Revenue from other long-term firm contracts down by $100 million/year
- FCCF credits down by $15 million/year
- Secondary revenue down by $20 million/year
- Other revenue credits down by $20 million/year (small credits and non- trading floor surplus sales)

$$\frac{\text{Costs} - \text{Credits} + \text{Risk}}{\text{Loads}} = \text{Rate}$$

Total PF Load: 1500 aMW higher in 2007-09

- 780 aMW in PF load increases from load-following customers, and contractual step-ups for slice and block customers
- 720 aMW of presubcription sales converting to PF

Average Cost to the PF load (without risk mitigation) in 2007-9: 28 mills/kWh
(vs. average actual PF rate of $32/MWh in 2002-06)

Sensitivity Analysis on $28 mills/kWh average cost:

- Increase in the average secondary price of 4 mills would **reduce** average cost to PF loads by 1 mill
- Decrease in the average secondary price of 4 mills would **increase** average cost to PF loads by 1 mill
- Decrease of the market forecast for IOU benefits of 3 mills would **reduce** average cost to PF loads by 1 mill
- A higher market forecast for IOU benefits does not increase average net cost to PF loads significantly, because IOU benefits are near their cap.

$$\frac{\text{Costs} - \text{Credits} + \text{Risk}}{\text{Loads}} = \text{Rate}$$

Risk Mitigation in 2007-09

Setting rates just to cover expected costs minus expected revenues (per the analysis above) leaves TPP too low.

In the past, BPA has addressed risk thru Planned Net Revenues for Risk (PNRR) and CRACs

1997-2001:

- Agency reserves were forecasted to be around $340 million going into this rate period in 1996, and full Fish Cost Contingency Fund (FCCF) credits of $325 million were available
- Low PNRR and no CRAC included in rates for 97-01
- Worked out OK because actual secondary revenues were far higher than rate case estimate, actual costs were near rate case estimates, and FCCF/4h10c credits, along with reserves, offset much of the 2000/01 drought and power crisis impact

2002-2006:

- Power reserves were around $500 million at the start of the period
- Some FCCF remained
- Low PNRR and multiple CRACs were used to address risks

2007-2009: Multiple factors are driving up the need for risk mitigation

- Low Power reserves (current forecast: under $200 million)
- Bringing TPP target up from three-year 80% standard to historic three-year 92% standard
- FCCF is gone
- High reliance on volatile secondary revenues and its associated risk
- Increase in Power liquidity reserves (formerly known as working capital) from $50 million to $100 million

Appendix: 2002-2009 Power Costs, Credits and Loads

Annual Averages, $ millions

#	Item	2002-6 May Base Rates Forecast	2002-4 Actuals, 2005-6 Forecast	2007-9 Forecast	Delta May Base Rates vs. 2007-09	Delta 2002-4 Actuals, 2005-6 Forecast vs. 2007-09	+ = Change that increases 07-09 rate - = Change that decreases 07-09 rate
1	**Credits**						
2	Revenue from DSIs	$182	$60	$0	($182)	($60)	+
3	Revenue from IOUs	$173	$91	$0	($173)	($91)	+
4	Revenue from Presubs	$157	$174	$45	($112)	($129)	+
5	Revenue from Long-Term contracts	$304	$181	$75	($229)	($106)	+
6	4h10c and FCCF credits	$118	$92	$76	($42)	($16)	+
7	Reserve and Ancillary Revenue	$81	$77	$80	($1)	$3	-
8	Other revenue credits	$31	$25	$18	($14)	($8)	+
9	Other surplus sales (Non-TF sales)		$12	$0	$0	($12)	+
10	BPA Secondary Sales	$516	$592	$575	$59	($17)	+
11	Total Credits	$1,561	$1,304	$868	($693)	($436)	
12	**Total Credits for Non-Slice customers**		$1,260	$829		($431)	
13	**Power Purchase and Buydown Costs**						
14	Augmentation purchase costs	$426	$356	$16	($410)	($340)	-
15	IOU buydown costs		$242	$23	$23	($219)	-
16	DSI buydown costs		$29	$0	$0	($29)	-
17	Public buydown costs		$50	$0	$0	($50)	-
18	Renewables	$20	$22	$56	$36	$34	+
19	Long-Term Generating Projects	$28	$28	$25	($3)	($3)	-
20	Other purchase costs (Non-TF purchases)		$38	$0	$0	($38)	-
21	BPA Secondary Purchases	$75	$117	$85	$10	($32)	-
22	Total Power Purchase and Buydown Costs	$549	$882	$205	($344)	($677)	
23	**Total Power Purchase and Buydown Costs payable by Non-Slice Customers**		$709	$178		($531)	
24	**O&M Costs**						
25	Net interest, Depreciation, Amortization, non-fed	$966	$925	$1,003	$37	$78	+
26	CGS	$169	$215	$284	$115	$69	+
27	Corps/Bureau	$159	$197	$242	$83	$45	+
28	Internal Ops	$45	$107	$116	$71	$9	+
29	Conservation Expense	$29	$66	$71	$42	$5	+
30	Other	$65	$83	$80	$15	($3)	-
31	Fish and Wildlife Direct	$139	$139	$139	$0	$0	
32	Minimum Required Net Revenue	$3	$3	$45	$42	$42	+
33	Transmission and Reserve/Ancillary	$186	$171	$189	$3	$18	+
34	Residential Exchange Settlement Payments (not including buydown payments or costs of power deliveries to PGE) 1/	$69	$147	$295	$226	$148	+
35	1/ 2007-09 value calculated using a PF rate assuming zero PNRR expense.						
36	DSI Financial Benefits (not including buydowns or costs of power deliveries)	$0	$0	$40	$40	$40	+
37	LDD & Irrigation Discounts	$18	$18	$35	$17	$17	+
38	Total O&M Costs	$1,848	$2,071	$2,539	$691	$468	
39	**Total O&M Costs payable by Non-Slice customers**		$1,629	$1,994		$365	
40	TOTAL COSTS	**$2,397**	**$2,953**	**$2,744**	**$347**	**($209)**	
41	**TOTAL COSTS PAYABLE BY NON-SLICE CUSTOMERS**		**$2,338**	**$2,172**		**($166)**	
42	**Loads (aMW)**						
43	PF	4343	3869	5383	1040	1514	
44	Slice (not available in May 2000)	0	1635	1650	1650	15	
45	DSI	990	186	0	(990)	(186)	
46	IOU *	1000	382	0	(1000)	(382)	
47	Pre-Sub Load	845	923	210	(635)	(713)	
48	**Drivers of Secondary Revenue Change**						
49	Average Net Secondary Sales Price ($/MWh)	$21.5	$29.0	$32.0	$7.5	$3.0	
50	Average 12-month Runoff (maf)	134	122	134	(12)	12	
51	Average Annual Net Secondary Sales (aMW)	2335	1928	1750	(407)	(178)	
52	NTS drawdown (+) and refill (-) (aMW)		15	-39		(54)	
53	Canadian Entitlement Return (aMW)		626	664		38	
54	Long Term Contracts (aMW)		517	124		(393)	
55	Augmentation (aMW)		1121	35		(1086)	
56	Public load (PF and Pre-Sub) (aMW)		4792	5593		801	
57	Residential Exchange Settlement* (aMW)		382	0		(382)	
58	Actual DSI Sales (aMW)		186	0		(186)	
59	System efficiency improvements (cumulative aMW)		40	180		140	

* 2002-4 Actuals, 2005-6 Forecast includes 258 aMW to PGE and 124 aMW to Idaho, Northwestern, & Avista

This document has been updated with:

• May 2000 Base Rates forecast for FY02-06.

• Average cost to PF load with and without Planned Net Revenue for Risk (PNRR).

Avg. cost to PF Load w/o PNRR

FY07-09 Forecast		
NS Expenses		$2,172
NS Credits		$829
PF Load		5383
$/MWh	$	28.47

FY02-06 Actuals		
NS Expenses		$2,338
NS Credits		$1,260
PF Load		3869
$/MWh	$	31.80

FY02-06 (May / No Slice or PNRR)		
Expenses		$2,397
- PNRR		$102
Credits		$1,561
PF Load		4343
$/MWh	$	19.29

Avg. cost to PF Load w/ PNRR

FY02-06 (May / No Slice)		
Expenses		$2,397
Credits		$1,561
PF Load		4343
$/MWh	$	21.96