Power Function Review II
Kick Off Meeting

January 23, 2006

January 23 Meeting Agenda

- **9:00 – 9:15** **Welcome and Introductions**
- **9:15 -10:15** **Review rate impact analysis: to provide context for the PFR II BPA plans to provide information on how specific changes in costs, revenue credits and risk treatment would affect the level of the rate**
- **10:15 – 12:00** **Review status of specific PFR follow-up areas (see list below)**
  - accomplishments to date
  - current view of savings potential
  - risk of cost increases
- **12:00 – 1:00** **Lunch**
- **1:00 – 2:00** **Continue pre-lunch discussion**
- **2:00 – 2:30** **Discuss priority focus areas for PFR follow-up and next steps**
- **2:30 – 4:00** **Briefing on CGS Debt Extension (link below)**
  http://www.bpa.gov/corporate/Finance/Debt_Management/presentations/docs/CGS_Debt_Extension_Update_1.11.06.pdf

Where We Have Been and Where We Are Going

- January-June 2005 PFR I
  - Reviewed Power costs for FY 2007-09
  - Found $96 M in cost reductions
- November 2005 Power Rate Case Initial Proposal
  - Used PFR I Power expenses
  - Updated forecast for hydro assumptions, market prices, loads, debt management items, DSI ROD, and other rate case items.
- January-April 2006 PFR II
  - Seek additional cost reductions to be included in the final power rate proposal
- Final Rate Proposal expected Summer 2006
  - Incorporate PFR II program expense levels plus update rate case assumptions (i.e., market prices, hydro assumptions, etc.)
  - Rate takes effect October 1, 2006

Rate Case Initial Proposal

PFR II Purpose

To seek further cost reductions to make FY 07- 09 power rates as low as possible while still meeting mission objectives.

Opportunities to lower rates from three-year average PF Non-Slice expected value of $30.3/MWh* (posted rate is $30.6/MWh*):

1. **Risk Management**
   - Reduce need for PNRR through liquidity tools
     - If successful, this could lead to a possible $2/MWh decrease in the rate
2. **Increase Secondary Revenue Credits****
   - Improvements in FY 07- 09 Net Secondary Revenue
     - Rule of Thumb: Approximately $46 M = $1/MWh
3. **Cost Reductions**
   - Reductions that apply to Slice and Non-Slice Rate
     - Rule of Thumb: Approximately $59 M = $1/MWh
   - Reductions that apply only to Non-Slice Rate
     - Rule of Thumb: Approximately $46 M = $1/MWh
4. **Other Impacts**
   - Improvements in FY06 Modified Net Revenue
     - Rule of Thumb: Approximately $125 M = $1/MWh

*This rate includes the operating reserve credit included in the initial proposal

**This would likely have an impact on Risk and PNRR which may offset potential savings

Changes In The Components Of The Proposed PF Rate

Changes that Impact Slice and non-Slice Rates				
Change in $M	Rate Impact Using $59M=$1, Rule of Thumb *	PF, non-Slice Rate, Without PNRR	Posted Rate, PF, non-Slice Rate, With $97M PNRR	Expected Value, PF, non-Slice Rate, Includes CRAC/DDC
$ 200	$ 3.4	$ 32.0	$ 34.0	$ 33.7
$ 150	$ 2.5	$ 31.1	$ 33.2	$ 32.9
$ 100	$ 1.7	$ 30.3	$ 32.3	$ 32.0
$ 50	$ 0.8	$ 29.4	$ 31.5	$ 31.2
Initial Proposal		***$ 28.6***	***$ 30.6***	***$ 30.3***
$ (50)	$ (0.8)	$ 27.8	$ 29.8	$ 29.5
$ (100)	$ (1.7)	$ 26.9	$ 28.9	$ 28.6
$ (150)	$ (2.5)	$ 26.1	$ 28.1	$ 27.8
$ (200)	$ (3.4)	$ 25.2	$ 27.2	$ 27.0

* Assumes Slice and non-Slice loads are subject to the cost increase/decrease. In a scenario where IOU Benefits are below the cap or above the floor, use $84M/MWh for non-slice PF rate comparisons.

Changes that Impact non-Slice Rates Only				
Change in $M	Rate Impact Using $46M=$1, Rule of Thumb *	PF, non-Slice Rate, Without PNRR	Posted Rate, PF, non-Slice Rate, With $97M PNRR	Expected Value, PF, non-Slice Rate, Includes CRAC/DDC
$ 200	$ 4.3	$ 32.9	$ 35.0	$ 34.7
$ 150	$ 3.3	$ 31.9	$ 33.9	$ 33.6
$ 100	$ 2.2	$ 30.8	$ 32.8	$ 32.5
$ 50	$ 1.1	$ 29.7	$ 31.7	$ 31.4
Initial Proposal		***$ 28.6***	***$ 30.6***	***$ 30.3***
$ (50)	$ (1.1)	$ 27.5	$ 29.5	$ 29.3
$ (100)	$ (2.2)	$ 26.4	$ 28.4	$ 28.2
$ (150)	$ (3.3)	$ 25.3	$ 27.4	$ 27.1
$ (200)	$ (4.3)	$ 24.3	$ 26.3	$ 26.0

* Assumes non-Slice loads only are subject to a cost increase/decrease. In a scenario where the IOU Benefits rare below the cap or above the floor, use $65 M/MWh for non-slice PF rate comparisons.

To Note:

- A forecasted increase in a highly volatile item may result in a higher level of PNRR needed.
- For categories that have energy associated with the cost reduction, the rules of thumb do not recognize the loss of revenues.

Scenarios showing the effects of combinations of liquidity tools, cost reductions, and secondary revenue components will be discussed at the January 23 meeting.

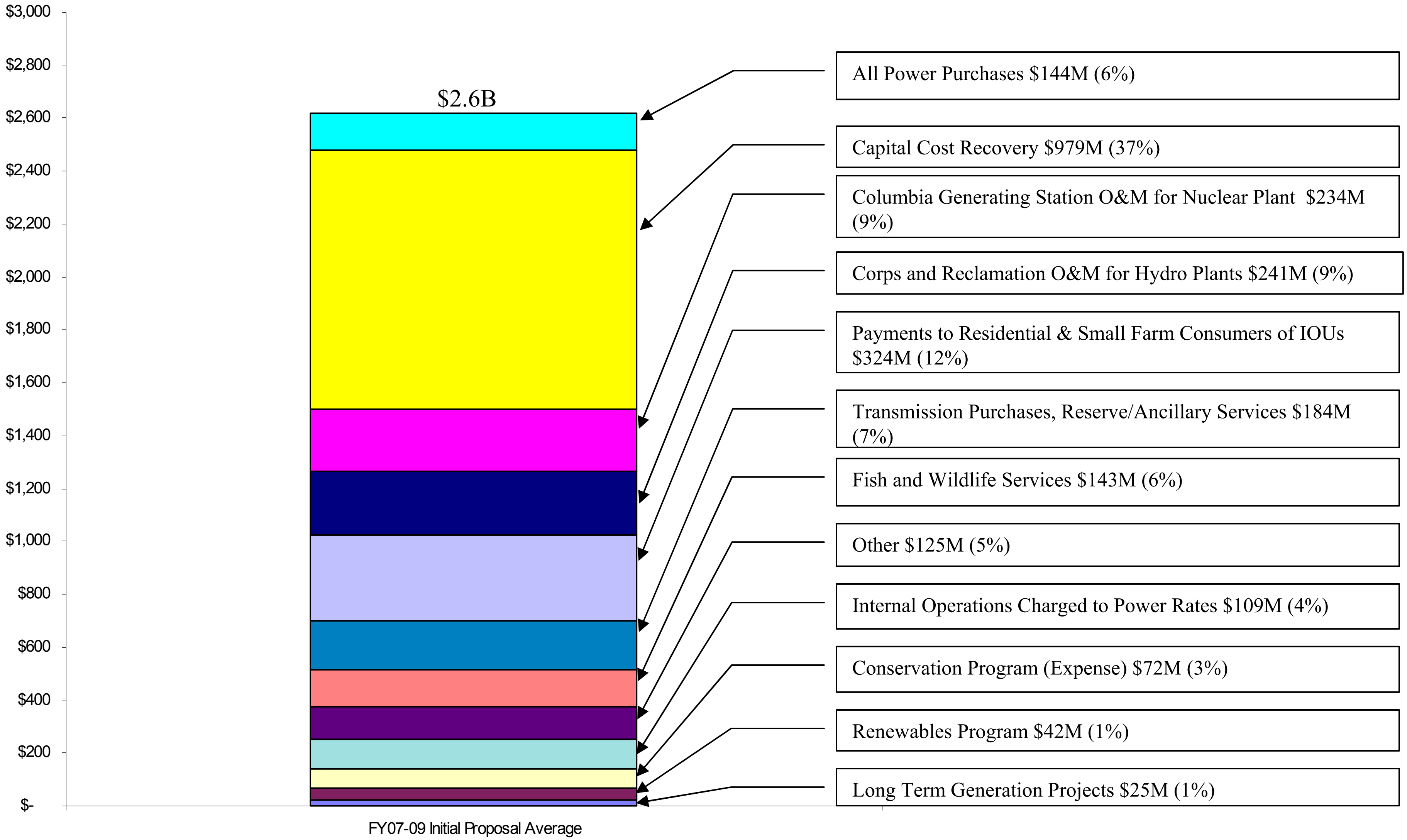
Rate Case Issue: Liquidity Tools

- **Why they are important:** Liquidity tools would provide BPA with temporary access to cash. They do not provide more cash, but change the timing of when BPA receives the cash. This may allow BPA to be less reliant on its own reserves to meet the TPP standard, thereby allowing lower rates.
  - **History:**
    - Pre 2002: Rate structure mostly relied on reserves to cover risk.
    - FY 2002 – 2006: Rate structure relied on variable rate mechanisms and PNRR to cover risk.
    - FY 2007 – 2009: Initial Proposal rate structure utilizes variable rate mechanisms and PNRR to cover risk. Liquidity tools would help lower this cost of risk.

- **The tools being pursued by BPA**:
  - Direct pay of Energy Northwest budget
  - Pre-payment of power bills by select customers, as needed
  - Delaying advanced payment of certain Treasury obligations from September to December with debt optimization proceeds
  - Line of credit with the U.S. Treasury

- **The current status of the situation:** Internal analysis is on-going for all of these tools. BPA staff are working with external parties as appropriate. For example, an IRS tax ruling has been requested on the direct pay option, and members of Congress have urged an expedited IRS ruling. Energy Northwest is supporting the effort. Staff are talking with Treasury about a line of credit. In addition staff are working with a group of customers to develop a pre-pay proposal to offer to interested customers.

Average Annual Power Expenses for FY07-09



Power Program Cost Categories

What we have to work with:

- Proposals brought up in the PFR I
  - Many proposals are still under consideration for BPA's Final Rate Proposal
  - We will explore these issues further in the upcoming technical and managerial workshops
- Other proposals from participants raised during the PFR II Process
- Maximum Discretion Reductions
  - These are costs related to programs that BPA is not contractually or legally required to continue, but are in the forecast because BPA has so far concluded they are mission critical
  - BPA is not recommending the adoption of any of these options

PBL Program Cost Categories

Capital Cost Recovery

- **Proposals from the PFR:**
  1. Change Columbia River Fish Mitigation (CRFM) analysis plant-in-service schedule – **Pending ($5M/yr)**
     - Status: In Process. Awaiting opinion of DoD IG. The decision could increase FY 2007 – 2009 rates.
  2. Debt finance new CGS capital projects with final maturity of FY 2018 (Consider financing through 2024 – **Pending ($13M/yr)**
     - Status: Initial proposal assumes new CGS capital financed with final maturity of FY 2018. BPA advocates financing CGS capital projects through 2024 where appropriate based on the expected life of the asset. The EN Executive Board is scheduled to vote on this proposal on January 26.
  3. Finance All Nuclear Fuel – **Partially Accepted**
     - Status: Accepted for the Uranium Tails Project. The Uranium Tails Project is a source of new fuel for CGS, and is being financed.
  4. Extend a portion of the current CGS debt beyond FY 2018 – **Pending ($16M/yr)**
     - Status: BPA has suggested extending $350 million of existing CGS debt into the 2019-2024 period. The EN Executive Board is scheduled to vote on this proposal on January 26.
  5. Change the amortization period for Conservation investments - **Pending**
     - Status: This is a rate case issue, but will be explored in the PFR II.
  6. Utilize a revised interest rate forecast for the initial power rate proposal - **Accepted**
  7. Include interest income on cash balances from the Bonneville Fund - **Accepted**
  8. Lengthen the amortization period for F&W capital – **Not Accepted**
  9. Amortization/recovery periods used for BPA F&W investments as compared to amortization periods for other F&W capital investments – **Proposed Workshop Topic**

Discussed in afternoon

Power Program Cost Categories

CGS O&M

- **Proposals from the PFR:**
  1. Eliminate the license extension spending for CGS in FY 2007-2009 – **Not Accepted ($3M/yr)**
  2. Include the forecast reductions proposed in the CGS long range plan – **Accepted ($22M/yr)**
- Maximum Discretion Reductions:
  - None identified without high risk to reliability and safety

Power Program Cost Categories

<u>Corps & Reclamation O&M</u>

- **Proposals from the PFR:**
  1. Reduction in funding for WECC/NERC compliance – **Accepted ($1.5M/yr)**
     - <u>Status:</u> Study completed. Results indicate proposed reduction of $1.5M/year are appropriate while still being able to manage compliance requirements.
  2. Benchmark against similar regional hydro facilities to capture efficiencies – **Pending**
     - <u>Status:</u> Held initial kickoff meeting and first workshop. Second workshop is scheduled for February 1. Results expected in late March.
  3. Include any efficiencies in staffing for Final Rate Proposal – **Accepted**
  4. Include funding to continue the remote operation of projects – **Accepted**
  5. Eliminate discretionary overtime funding – **Not Accepted**
  6. Reduce proposed level of funding for extraordinary maintenance – **Not Accepted ($8M/yr)**
  7. Reduce costs of management of security requirements – **Not Accepted**
  8. Process used to review and approve elements of the Corps Columbia River Fish Mitigation program (CRFM), including what, if any, independent review process is used. (This item is related but separate from the plant-in-service date for CRFM project funds) – **Proposed Workshop Topic**
- **Maximum Discretion Reductions:**
  1. Eliminate Non Routine Extraordinary Maintenance **($8M/yr)**
  2. Reduce Capital Investment into FCRPS by the remaining amount of uncontracted or uncommitted budget **($7M/yr)**

Power Program Cost Categories

<u>Residential Exchange</u>

- For FY 07-09, this program expense is a result of the Residential Exchange Program Settlement agreements with the IOUs. It is based on a formula set in the settlement agreements, which are currently being integrated
- **Proposals from the PFR:**
  - None
- **Maximum Discretion Reductions**:
  - None

<u>Transmission Expenses</u>

- **Proposals from the PFR:**
  1. Reduce forecast for Metering/Telemetry/Equipment Replacement – **Accepted ($0.8M/yr)**
  2. Reduce 3rd Party GTA Wheeling Forecast – **Accepted ($4M/yr)**
  3. Model the transmission expense associated with secondary energy at the minimum expense across the 3000 secondary energy scenarios rather than the average of 3000 secondary energy scenarios – **Accepted**
- **Maximum Discretion Reductions:**
  - None without revenue losses in excess of cost reductions

Power Program Cost Categories

<u>Fish and Wildlife</u>

- **Proposals from the PFR:**
  1. Examine the timing for spill tests on the Snake River in relationship to installation of surface passage technologies such as removable spillway weirs, while continuing to ensure that our Endangered Species Act commitments are met – **Pending**
     - <u>Status:</u> coming
  2. Fund the expected baseline O&M costs for the Lower Snake River Compensation Plan (LSRCP) hatcheries, plus some additional funding for high priority non-routine maintenance – **Accepted**
  3. Cost management efforts regarding F&W Monitoring and Evaluation (M&E) – **Proposed Workshop Topic**

- **Maximum Discretion Reductions:**
  1. Targeted Spending Reductions and Program Closeouts **($15M/yr)**

Power Program Cost Categories

<u>Other</u>

- **Proposals from the PFR:**
  1. Remove Spokane Settlement forecast from forecasted program level spending– **Accepted ($6M/yr)**
     - Congress is currently considering legislation that would provide the Spokane Tribe with benefits similar to those received by the Colville Tribe to compensate for the loss of land resulting from Federal dam construction.
  2. Adopt Conditional Budgeting – **Not Accepted**

- **Maximum Discretion Reductions:**
  1. Eliminate DSI Benefits **($59M/yr)**

*The "Other" Program category includes: US Fish & Wildlife Lower Snake Hatcheries, Planning Council, Colville Settlement, Spokane Settlement, Trojan Decommissioning, WNP 1&3 Decommissioning, PNCA Headwater Benefits, Hedging/Mitigation, Other Environmental Requirements, Civil Service Retirement System, DSI Benefits, Misc. Expense/Income adjustments.

Power Program Cost Categories

<u>Internal Operations</u>

- **Proposals from the PFR:**
  1. Continue the Enterprise Process Improvement Project and other internal cost control initiatives – **Pending**
     - <u>Status</u>: Five Enterprise Process Improvement Program (EPIP) study areas have moved into the implementation phase. Early estimates of savings from these studies are being incorporated into budgets. Indications are that the PFR1 agreed-upon savings target of $8M per year is still a valid estimate. Four other EPIP study areas are in the review phase, with no estimate yet of potential savings.
  2. Include forecast of savings from process improvement efforts – **Accepted ($8M/yr)**
  3. Include but reduce spending level of uncommitted technological innovation spending (TCI) – **Accepted ($1.3M/yr)**
  4. Reduce monetary awards – **Not Accepted**
  5. Reduce PBL budget by $3.3M, reduce corporate non-IT by $20M, reduce IT costs by $24M, and reduce allocation of industry restructuring costs by $1.3M – **Not Accepted**
- **Maximum Discretion Reductions:**
  1. Do not fill retiree positions **(Approximately $1M/yr)**

Power Program Cost Categories

<u>Conservation</u>

- **Proposals from the PFR:**
  1. Credit conservation done by public utilities “on their own nickel” against BPA’s target, reducing BPA’s spending – **Pending**
     - <u>Status:</u> Tracking tool put in place in January; customers decide if they want to provide this information
  2. Don’t require load decrement on rate credit – **Accepted**
  3. Reduce BPA target for “naturally occurring” conservation – **Accepted**
  4. Reduce conservation acquisition funding by $5 million/year (i.e., from $80M to $75M/year) – **Not Accepted**

- **Maximum Discretion Reductions:**
  1. Eliminate Conservation Rate Credit (CRC) **($36M/yr)**
  2. Eliminate the 4-State Low Income Weatherization (LIWx) Program **($5M/yr)**
  3. Eliminate uncommitted Bilateral Conservation Contracts **($8M/yr)**

Power Program Cost Categories

<u>Renewables</u>

- **Proposals from the PFR:**
  1. Remove the Calpine geothermal project from projected costs – **Pending ($21 in FY 2009)**
     - <u>Status:</u> In PFR I, Calpine costs were taken out of FY 07 and FY 08. BPA staff are currently in the process of determining what action, if any, is appropriate for FY 09.
  2. No further renewable spending beyond what is already contractually committed – **Not Accepted**

- **Maximum Discretion Reductions:**
  1. Eliminate Uncommitted Facilitation Costs **($6M/yr)**
  2. Eliminate Renewable Rate Credit **($6M/yr)**

Power Program Cost Categories

<u>Long Term Generation Projects</u>

This $25M/year program consists of output contracts for generating resources, such as Cowlitz Falls, Billing Credits Generation, Waunapum, 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.

- **Proposals from the PFR:**
  - None
- **Maximum Discretion Reductions:**
  - None

What's Next – PFR II Process

• Technical and Managerial Workshops	Feb – Mar 2006
• Draft Closeout Report out for comment	March 2006
• Final Report	April 2006

BPA Financial Disclosure Information

1. All FY ’06-’09 information was provided in January 2006 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.

2. All FY ’97-’05 information was provided in January 2006 and is consistent with audited actuals that contain BPA-approved Agency Financial Information.