BONNEVILLE POWER ADMINISTRATION

P.O. Box 3621
Portland, Oregon 97208-3621

July 2, 2002

To BPA customers, tribes, constituents and interested parties:

Financial choices for the region FY 2003-2006: BPA power rates and costs

One of BPA's highest priorities is to preserve the financial integrity of the Federal Columbia River Power System while minimizing the impact of our wholesale power rates on customers and meeting our various public responsibilities. The best way to achieve this goal is to be successful in managing our finances.

As you know from letters that Steve Wright and I sent to you earlier this year and from the enclosed letter from Steve, BPA is facing a significant financial shortfall. As we near the end of the first year under our new rate structure and look out to the future, we see a second year in a row of net revenue losses and a very low cash balance going into FY 2003. If we rely solely on letting the established rate mechanisms work, without implementing other options, BPA's wholesale power rates likely will increase over the remainder of the rate period relative to the FY 2002 actual average rate.

Regional discussion

It is important that we now consider a wide range of financial and program options to address the situation BPA faces in the FY 2003-2006 time frame. Finding the right financial, program and value choices necessary to balance our public responsibilities, rates, reliability, financial integrity and risk will not be easy. We invite you to work with us to meet this challenge. Tough financial and program decisions must be made with active regional involvement if we are to achieve sustainable solutions. BPA's ultimate objective is assuring the agency's future financial health while continuing to provide the power, environmental and other public-purpose benefits currently enjoyed by the citizens of the Northwest.

My May 2, 2002, letter stated we would provide you with a draft cost management plan for FY 2003-2006 and ask for your review of that plan. However, we now believe it more useful to ask reviewers to consider a full range of financial and program alternatives. We understand that some of these alternatives will be highly controversial. We do not intend to provide any explicit or implicit endorsement by including them here. Rather, we wish to represent the full range of potential actions that could help resolve our expected financial shortfall.

To initiate this regional discussion, we are providing power rate and cost information on the choices we believe face the region over the next four years. This information includes background on the financial challenges we are now facing, the actions we have taken to date to address the problem and BPA's financial outlook for the remainder of the rate period. In addition, and more importantly, we have identified a set of key questions (value choices) and a variety of potential financial alternatives that form the basis of possible financial and program options.

Your input

We particularly want your comments and recommendations on the financial alternatives and value choices that should be included in the tough conclusions we will make for the next four years. Therefore, when you provide your comments and recommendations, please:

- Consider the key questions (value choices) presented in the following section and identify how the issues raised by these questions influenced your evaluation of possible policy choices. Many of these questions address the tradeoff between providing long-term benefits and reducing short-term costs. Please also provide us with any additional value choices not covered by these key questions that you believe should be considered.
- Let us know what you consider to be the best approach (either a single approach or a combination of elements from various approaches) that should be included in the financial strategy we will implement for the remainder of the rate period. We also want to know if there are other alternatives not listed in this package that you would recommend for consideration.

We encourage your active participation in this financial review process. We will accept comments through Sept. 30, 2002. The "Next Steps" section at the end of this letter identifies how you may submit your comments and recommendations to us.

Key questions to consider when evaluating policy choices

We welcome input on specific steps we can take to reduce costs or otherwise relieve pressure on our rates and finances. We also think there is a strong need for a discussion of the values, or criteria, that would drive those choices. From the advice provided through the regional discussion, we will be looking for an appropriate balance between rates, reliability and other public purposes; financial position; and the probability of meeting our Treasury payment obligation (also called Treasury payment probability, or TPP). The questions below identify some of the issues (and associated values) to be considered. These questions reflect views we have heard across the region in recent months.

- To what degree should BPA push financial impacts into the future through the use of financial tools to cover current operations, maintenance and other program expenses?
- How much risk is it reasonable for BPA to take regarding our annual (and five-year) ability to pay Treasury to keep rate increases low or to preserve program accomplishments?
- BPA has begun to act to strengthen the region's infrastructure to improve the region's supply/demand balance and limit the potential for another energy crisis similar to that of FY 2001.
    - How do we strike the right balance between spending levels and levels of reliability and output at the U.S. Army Corps of Engineers and Bureau of Reclamation projects and at the Columbia Generating Station?
    - Should BPA reduce its spending on conservation acquisitions in order to minimize near-term rate impacts?
    - Should BPA continue to acquire additional renewable resources during this rate period?
- How can BPA fish and wildlife be more cost effective while still achieving the performance standards of the FCRPS biological opinion (Endangered Species Act) and our mitigation obligations under the Northwest Power Act?
- The number and complexity of BPA's responsibilities are now greater than envisioned in the 1998 Cost Review, making BPA's internal costs correspondingly high. What specific changes (if any) could BPA make in the

number and complexity of those responsibilities to reduce BPA's internal costs?

- BPA has power purchase and load reduction contracts with several parties that cannot be modified unilaterally by BPA – such as Enron and the investor-owned utilities within the context of the Residential Exchange Settlement. What part should contract renegotiations play in helping BPA reduce its rates?
- What cash reserve level should BPA have at the end of FY 2006 to be in a sound financial condition going into FY 2007 and beyond?
- Because we are ending FY 2002 in a weakened financial state, we are particularly concerned about our financial position in FY 2003. What actions or tools should BPA consider using to address potential cash shortfalls in FY 2003? What would be the out-year financial and program impacts of these actions and how could they be mitigated?
- The Pacific Northwest economy seems to be initiating a recovery from its recent downturn, although rural areas are still suffering. What priority should be given to stabilizing or reducing BPA's rates to benefit the regional economy?
- Are there actions or financial tools other than those identified in the materials BPA has prepared that should be considered?

Original expectations

Back in May 2000, we set our base rates with the expectation that we could achieve our financial objectives. These included:

1. Achieving all of our public purpose responsibilities, including conservation and renewable resources;
2. Meeting 1,700 average megawatts of load requests above federal system generation capability at prices in the $28/megawatt-hour range;
3. Meeting fish and wildlife obligations, including an average increase of $100 million per year;
4. Increasing internal operating efficiencies and decreasing costs within BPA, the Corps, Reclamation and the Columbia Generating Station;
5. Achieving higher-than-historic levels of surplus sales and revenues; and finally,
6. Achieving an average wholesale power rate around $20/MWh for "flat" power.

We set out to achieve these high goals with guidance from the region. In our base costs, we established a number of cost targets based on the 1998 Cost Review. While these cost targets were aggressive, we thought we could manage to them and still provide the region with the benefits requested.

But the environment changed

Over the last two years the environment changed. Customers requested an additional 1,500 aMW more service, for a total of 3,200 aMW (referred to as the amount by which we must "augment" the federal system) in excess of the federal system generation capability, requiring large purchases from the market at higher-than-expected prices. Then, skyrocketing market prices caused the cost of augmenting the system to rise astronomically.

In June of 2001, when BPA finalized its wholesale power rates for the FY 2002-2006 period, the agency adopted a customer proposal to address the significant financial uncertainty through the five-year rate period by implementing a three-part cost recovery adjustment clause (CRAC) provision in its power rate schedules. They are the load-based (LB) CRAC, the financial-based (FB) CRAC and the safety-net (SN) CRAC. The application of the load-based CRAC, which covered the costs of meeting the additional 1,500 aMW of load service and the cost above the $28/MWh for the original 1,700 aMW of load, drove a major rate increase.

Since June 2001, market prices have dropped dramatically, reducing the revenue we expected from surplus sales and fish credits. In addition, Residential Exchange Settlement costs increased as a consequence of rate case determinations. Also, because of the drought and higher market prices, we lost $260 million in FY 2001 and ended the year with low reservoirs. Further, we continue to face a need for investments in conservation and, since Sept. 2001, increased security measures to ensure BPA meets its mission obligations, resulting in increased program expense levels.

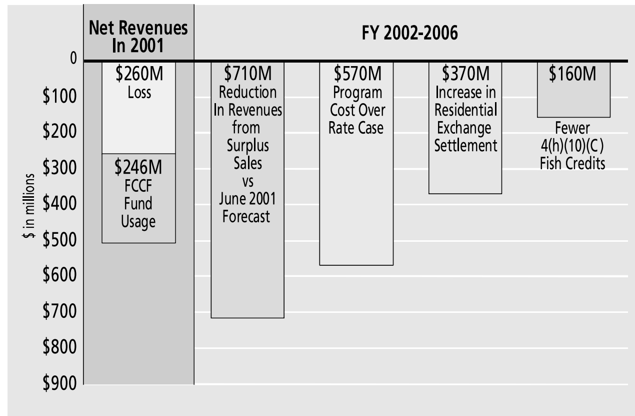
Our rate structure, with the three CRACs, is set up to deal with the kind of financial circumstances we now face. We could simply let the LB, FB and SN CRACs play out. But we also need to explore other alternatives to manage this financial challenge.

Major drivers of expected financial impacts

FY 2001 was a tough year for us, as it was for many other businesses. We were in the middle of a drought, the effects of which were exacerbated by high market prices. Fish credits minimized our loss in net revenues, but a big portion of the Fish Cost Contingency Fund (see "Primer on Fish Credits" box on page 6) was used in FY 2001, decreasing the amount available, and that we had counted on, for the remainder of the FY 2002-2006 period.

As shown in *Figure 1*, the four main drivers of BPA's financial challenge include a reduction in forecast revenues from surplus sales, an increase in program costs over the cost review targets, an increase in Residential Exchange Settlement costs and a decrease in available 4(h)(10)(C) fish credits (see "Primer on Fish Credits" box on page 6).

Figure 1, Expected Adverse Financial Impacts FY 2002-2006

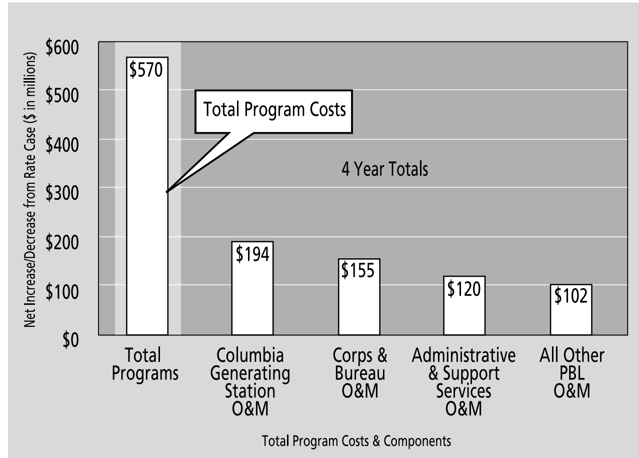


Surplus sales: In July of 2000, because of changes in loads and skyrocketing market prices, we saw we would have a problem meeting the rate targets we had established in May 2000. At that time, we reopened our rate case and, in June 2001, adopted the LB, FB and SN CRACs to address the additional augmentation costs and other uncertainties. We also significantly increased our projections of secondary revenues, especially for FY 2002. In addition to these adjustments, we kept assumptions in all other areas the same as those used to develop the May 2000 rates. We expected additional projected revenues from surplus sales at the higher forecast market prices to cover any additional expenses. When market prices dropped in the fall of 2001, the additional revenues from surplus sales we had forecast in June 2001 dropped dramatically. As shown in *Figure 1*, we now estimate a decrease of $710 million in revenues from surplus sales over the rate period. This revenue loss consists of $360 million in FY 2002 and $250 million over FY 2003-2006 in reduced revenues resulting from lower market prices; and $100 million in lost revenues associated with approximately 600 aMW of generation lost in FY 2002. The lost generation is from a combination of lower reservoir levels in Canada at the start of FY 2002 (because of the dry year in FY 2001) and an expected below average water year in FY 2002.

Program costs: Not only were market prices changing during fiscal years 2001 and 2002, but our environment was also changing from what the 1998 Cost Review envisioned. For example, the Cost Review and other forecasts used in the base rates assumed we would:

- Realize Columbia Generating Station nuclear plant operation and maintenance costs of $19/MWh by 2000. Today, CGS costs are forecast around $26/MWh for FY 2003-2006.
- Reduce Corps of Engineers and Bureau of Reclamation O&M expenses and improve project availability. However, the Corps and Reclamation costs for security and labor needs for plant maintenance are greater than identified at the time of the cost review.
- Reduce internal costs significantly because of minimal conservation and renewable resource activities, simple contracts and rates that would require little staff time to develop and administer, no augmentation and greatly simplified business processes through automation. The demands placed on BPA have not been reduced in the ways envisioned in the cost review. Automation of business processes has proceeded, but it has just kept pace with the rapidly growing complexity of the work.
- Limit our financial support of conservation acquisition to current contractual obligations (1998) and self-sustaining (reimbursable) activities, based on the assumption that an open electricity market would spur a market-driven conservation response. Since that time, we have committed to meet the Northwest Power Planning Council's conservation target of 220 aMW by the end of FY 2006, increasing the program cost to meet this target.

Figure 2, Total FY 2003-2006 Net Increase in Program Costs



Residential exchange: In May 2000, the non-power benefits of the Residential Exchange Settlement were valued at $350 million for FY 2002-2006. The rate case settlement with customers increased the level of the five-year market forecast, which increased the financial benefits to $720 million. We expected to cover the additional cost through revenues from surplus sales and, hence, did not adjust base rates for this increase.

4(h)(10)(C) credits: The drivers in the decrease in credits are a decrease in market prices used in the credit calculation, the reallocation of project purposes at Grand Coulee and a reduced forecast of fish and wildlife expense and capital spending.

Primer on Fish Credits, 4(h)(10)(C)

Under the Northwest Power Act, the administrator makes expenditures from the BPA Fund to protect, mitigate and enhance fish and wildlife affected by the federal dams.

These expenditures cover nonpower as well as power uses of the dams.

So that ratepayers pay no more than the power share of fish and wildlife costs, section 4(h)(10)(C) of the Northwest Power Act directs BPA to take credits for the portion of the expenditures allocated for nonpower purposes.

Until FY 2001, the nonpower purposes of the federal dams were calculated to be 27 percent. Beginning in FY 2001, because of new interim cost allocation by the Bureau of Reclamation for Grand Coulee Dam, the nonpower purposes of the federal dams changed to 22.3 percent of:

- BPA's fish and wildlife and ESA-related O&M expenses;
- BPA's capital expenditures for tributary passage habitat construction;
- Net replacement power purchase expenses (value of lost firm capacity because of fish mitigation measures) assessed at prevailing market values for power; and
- Interest.

Fish Cost Contingency Fund Credits

The Fish Cost Contingency Fund consists of 4(h)(10)(C) credits that were earned but not taken prior to FY 1995.

By agreement with executive branch agencies in FY 1996-1997, this fund may be accessed:

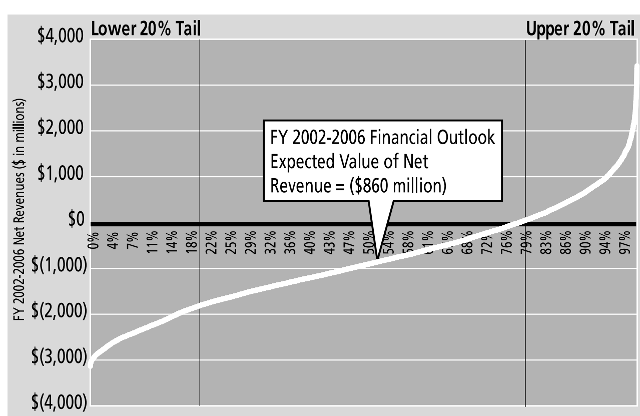
- When court-ordered changes increase the average cost of BPA's fish program to more than $435 million;
- When a natural disaster or fishery emergency is declared; or
- If adverse hydro conditions equivalent to the worst 25 to 35 percent of the 50 years on the hydro record reduce nonfirm revenues and/or increase power purchases (which occurred in FY 2001).

The outlook for FY 2002-2006

With all the changes we have experienced over the last two years, our outlook for FY 2002-2006 is not good. If we took no additional measures beyond implementing the current level of the LB CRAC and a maximum FB CRAC for FY 2003, our forecast revenues would fall short of costs by about five percent, or $860 million, over the five-year rate period. The financial challenge in FY 2003 is exacerbated by starting the year with an expected cash balance of only $128 million because of significant net revenue losses in FY 2001 and FY 2002. This low cash balance leaves us little flexibility in FY 2003 with which to manage changing financial conditions, which makes the timing of any additional cash very critical.

There is a great deal of uncertainty around the forecast. As shown in *Figure 3*, the ($860 million) estimate is an expected value (at the 50 percent probability), not a "point forecast." There is a 20 percent probability the loss could be eliminated if market prices are higher than expected and/or if we experience greater-than-average hydro conditions. However, there is also a 20 percent probability that the loss could double in the event of lower-than-expected market prices and/or lower-than-average hydro conditions. Plans to address the net revenue gap need to recognize this large range of uncertainty.

Figure 3, Uncertainty Around the Forecast



What we have done so far

We have already made significant efforts to improve our financial results for the rate period. We took a hard look at our FY 2002 expenses and reduced them from the start-of-year forecast by $100 million as noted in Steve Wright's and my previous letters. Since then, we also have looked at FY 2003-2006 forecasts and reduced them by over $200 million. We have established tighter controls for approving new spending items, and we are undertaking a significant effort to gain additional expense reductions for FY 2003-2006. We also terminated Enron contracts when it was within our contractual rights to do so, saving $100 million over the rate period, and asked FERC to review the remaining Enron contracts. We are upholding our take-or-pay contractual provisions and are reviewing all contracts to maximize flexibility and value.

Tough choices

Even with all the actions we have taken so far, we still have a large net revenue gap we must close. But we understand the distress increased rates cause to the economy, our utility customers, individual businesses and families in the region. We have no greater priority than to manage this situation to keep rates as low as possible while still meeting critical mission objectives, and we are working hard to do that. By the end of the year, we intend to put a four-year plan into place to address our financial condition. That plan will recognize the range of uncertainty around our expected financial results. This will require some tough choices and tradeoffs in order to get us back to financial health while maintaining the balance of benefits throughout the region.

Before reaching conclusions on a plan, we want regional input on five potential approaches, or a combination of them.

The Five Approaches

Approach #1. Simply let the established rate mechanisms (LB, FB and SN CRAC) play out over the next four years (which includes cost cuts and capital and expense reductions already in place).

Approach #2. Cut more costs (both capital and expense) down to levels that put mission accomplishments at risk and raising rates, as necessary, to cover the remaining gap.

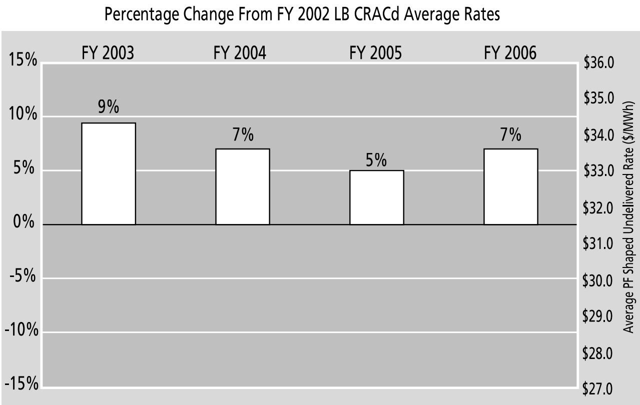
Approach #3. Take more risk in paying the Treasury (no SN CRAC).

Approach #4. Use financial tools to manage net revenue and cash shortfalls and to push the financial problem into the future.

Approach #5. Make a one-time adjustment to FY 2003-2006 rates through the SN CRAC to achieve a five-year 80 percent TPP, then applying no further FB or SN CRAC adjustments, potentially combined with using cash tools to increase FY 2003 TPP.

Approach #1 – Close the net revenue gap through rates only

Figure 4

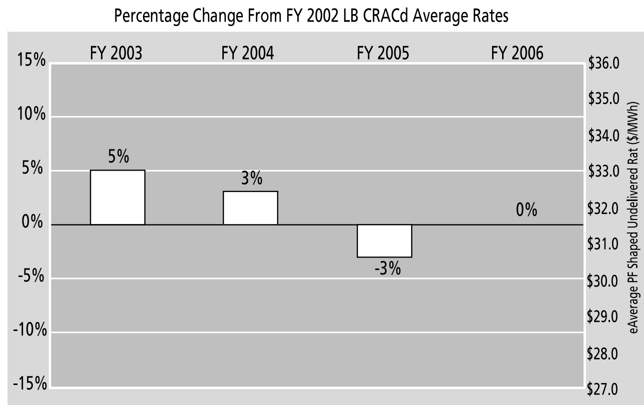


In order to approximate how the rate mechanisms would play out, we evaluated the possible future rate increase (FY 2003-2006) necessary to offset expected net revenue losses of $860 million over the FY 2002-2006 period assuming:

- FY 2002 net revenue of ($259 million);
- Maximum FB CRAC in FY 2003;
- Total rate (FB and SN CRAC) increases required to cover a FY 2002-2006 net revenue loss of $860 million;
- BPA would still be committed to manage its annual TPP to high levels through the rate period;
- Incremental IOU Residential Exchange Settlement load reduction payment of $50 million for FY 2003 is deferred to FY 2004-2006; and
- Additional BPA cost cuts of $103 million for FY 2003-2006 are not included in this rates only scenario but are included in Approach #2.

Approach #2 – Cut costs & increase efficiencies

Figure 5

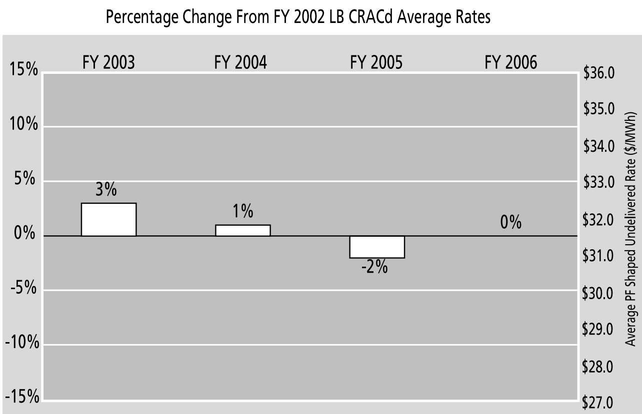


Approach #2 cuts costs, both capital and expense, to the point that mission accomplishments are put at risk, and raises rates to cover the remaining net revenue gap, assuming:

- Cost cuts reduce the net revenue gap of $860 million by $400 million. Rate increases over and above the current forecast of LB and FB CRAC adjustments during the FY 2002-2006 period cover the remaining $460 million;
  - Mission-risking cuts include reductions in Corps of Engineers and Bureau of Reclamation O&M, fish and wildlife, Energy Web, renewable resources, conservation augmentation and incentive programs;
  - Additional BPA cost cuts of $103 million for FY 2003-2006 are included in the $400 million of total cost cuts;
- BPA would still be committed to manage its annual TPP to high levels through the rate period;
- Maximum FB CRAC in FY 2003;
- FY 2003-2006 rate increases may include FB and SN CRACs; and
- Incremental IOU Residential Exchange Settlement load reduction payments of $50 million/year are eliminated for FY 2003-2006 by agreement with the IOUs (every other approach assumes this for FY 2003 only).

Approach #3 – Increase financial risk to Treasury (no SN CRAC)

Figure 6

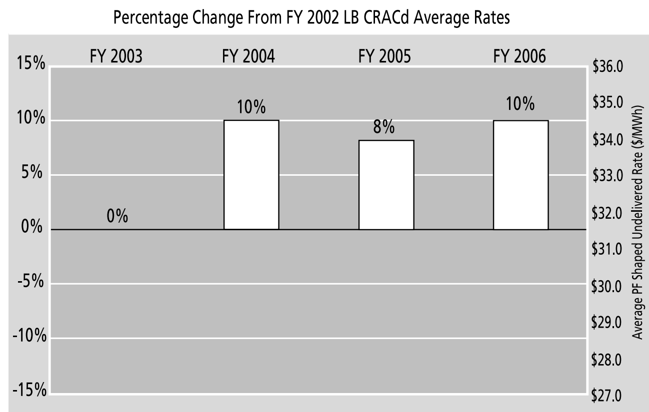


Approach #3 increases financial risk to the Treasury by using only the LB and FB CRACs (not the SN CRAC), which will only cover $325 million of the $860 million net revenue gap, assuming:

- BPA will take on additional risk in its annual TPP;
- Maximum FB CRAC in FY 2003;
- Incremental IOU Residential Exchange Settlement load reduction payment of $50 million for FY 2003 is deferred to FY 2004-2006; and
- Additional BPA cost cuts of $103 million for FY 2003-2006 are not included.

Approach #4 – Defer costs and push problem to future

Figure 7



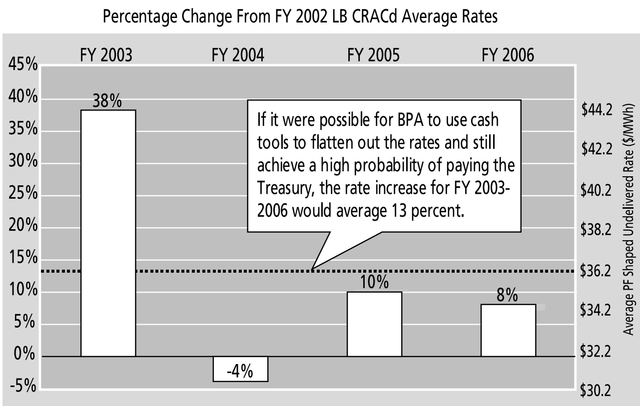
Approach #4 uses Approach #1 as a base and then assumes no additional rate increase in FY 2003 from the FY 2002 average rate of $31.8/MWh. The revenues not recovered in FY 2003 are spread out evenly over FY 2004-2006, assuming:

- Net revenue gap of $860 million is recovered by the end of the rate period;
- BPA would still be committed to manage its annual TPP to high levels through the rate period;
- FY 2003-2006 rate increases may include FB and SN CRACs;
- Incremental IOU Residential Exchange Settlement load reduction payment of $50 million for FY 2003 is deferred to FY 2004-2006; and
- Additional BPA cost cuts of $103 million for FY 2003-2006 are not included.

This approach could eliminate the potential rate increase in FY 2003 but would create greater increases in FY 2004-2006. Although there are ratemaking implications, another choice could be to use cash tools to cover the financial conditions for the full FY 2003-2006 period and recover those costs post–FY 2006. This is not depicted in the graph.

Approach #5 – One-time adjustment of rates through SN CRAC

Figure 8



Approach #5 involves a one time establishment of a series of rate adjustments (through the SN CRAC) for each of the next four years to achieve a high TPP of 97 percent each year in FY 2003-2006, with the intent of locking in those adjustments and not making further rate adjustments. This equates to an 80 percent TPP over the rate period, assuming:

- BPA would manage its annual TPP by the one-time setting of rates to cover future financial volatility;
- Maximum FB CRAC in FY 2003;
- Use SN CRAC for one-time rate adjustment;
- Incremental IOU Residential Exchange Settlement load reduction payment of $50 million for FY 2003 is deferred to FY 2004-2006; and
- Additional BPA cost cuts of $103 million for FY 2003-2006 are not included.

Similar to the situation BPA faced in early FY 2001, if there is no ability to adjust rates later, then a large rate increase would be needed to cover the wide range of uncertainty over the next four years. This increase results in the Power Business Line ending the rate period with cash reserves of approximately $1.1 billion and a net revenue gain of $497 million. The large FY 2003 rate increase replenishes low financial reserves, which then carry over as lower rate adjustments during FY 2004-2006. As a point of reference, BPA's 2002 power rate proposal included, as a guideline for rate design and risk mitigation, the goal of 88 percent TPP for the five-year rate period (97.5 percent per year).

Next Steps

The public comment period will be open from July through September 30, 2002. There are several ways for you to submit your recommendations to us. You can send written comments to:

David Basaraba
Communication and Liaison – PL-6
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621

You can also send comments electronically via e-mail or fax at the following addresses:

E-mail: financialchoices@bpa.gov

Fax: (503) 230-3613

Throughout the comment period, Power Business Line account executives and BPA constituent account executives are available to respond to your questions or to schedule informal discussions. BPA managers, as well as program and financial staff, will also be available to participate in these discussions.

Later this summer we will also schedule public meetings to engage all interested parties in this financial discussion. As soon as the schedule of meetings has been set, you will be notified.

Conclusions resulting from this process will be made later this year. Steve Wright plans to announce the agency direction in a closeout letter in December.

The choices outlined in this letter are tough on everyone. We look forward to receiving your recommendations on this critically important issue and will consider all comments received as we begin developing a financial plan for the remainder of the rate period.

Sincerely,

Paul E. Norman, Senior Vice President

Power Business Line