Bonneville Power Administration
Power Function Review Management Level Discussion
March 16, 2005

Rates Hearing Room, BPA Headquarters, Portland, Oregon
Approximate Attendance: 35

Columbia Generating Station O&M
Corps of Engineers and Bureau of Reclamation O&M

[The handouts for this meeting are available at: www.bpa.gov/power/review.]

I. Introduction

Paul Norman (BPA) welcomed the participants and noted that the topics for the next two days would cover "large hunks" of BPA's power costs. He called attention to a letter in the packet, sent to Public Power Council (PPC) manager Jerry Leone, that addresses several concerns about the PFR and the need for more clarity about decisions that will be made. In response to the PPC, as well as others' comments, we have provided "a road map" directing people to the appropriate comment and decision forums, he said. In most cases, the forum is the PFR or the rate case, but there are some others, Norman noted.

In addition, we've heard comments that people appreciate the information we are providing in the PFR, but would like to have the policy decisions highlighted, he continued. We have developed a matrix, which we're referring to as "the scoresheet," that lays out the policy questions, Norman said. We intend to continue to update the scoresheet as the PFR moves along to clarify where the choices are, he said.

A third comment we've heard is that BPA ought to come back with a proposal at the end of the PFR, and we have determined that we will put out a draft proposal and provide an opportunity for comment on it, Norman reported. We will have meetings of both the technical and management groups on the proposal before we make a final decision in mid-June, he said.

Every customer we talked to supports establishing a rate target, and public power has coalesced around 27 mills, Norman went on. I thought we ought to discuss risk mitigation before we talk about a target, he stated. I understand the message from public power, but if we do set a target, BPA isn't comfortable with setting a target ahead of the risk discussion, Norman said.

II. Columbia Generating Station O&M

Andy Rapacz (BPA) said his presentation would be oriented to the policy choices involved with Columbia Generation Station (CGS) O&M funding. CGS is "a significant part" of BPA's power rate structure at $284 million or 11 percent per year, he said. Rapacz pointed out that BPA purchases 100 percent of CGS output and pays all O&M costs. To explain differences in the numbers BPA presents versus those in the Energy Northwest (EN) material, he noted that the two agencies operate on different fiscal years and that EN budgets are cost, rather than cash.

Rapacz proceeded to a history of CGS costs and said BPA has not made decisions yet about debt financing CGS costs during the next rate period. We have assumed we would revenue finance in 2007-2009, he said, and he noted that BPA's repayment study would help inform the decision. Rapacz reported the amounts that could be financed in 2007-2009 as $34 million in 2007, $12 million in 2008, and $14 million in 2009. Norman clarified that debt financing would entail EN, not BPA, borrowing.

Joe Nadal (PNGC Power) asked about EN's capital policy. We can finance anything with over one year of life, Al Mouncer (EN) responded. And we try to be consistent with the rest of the nuclear industry, since we are benchmarked against our peers in the industry, Vic Parrish (EN) added. We assume your priority is in making a good business decision, not staying consistent with the industry, Steve Eldrige (Umatilla) commented.

Rapacz went through the categories of CGS costs, drivers of the projected increase, and the role of benchmarking in the nuclear industry. He pointed out that as a stand-alone plant, CGS is 15 percent more expensive to operate than "fleet plants." Among the risks of future cost increases, the price of nuclear fuel could go up significantly, Rapacz said. EN's procurement strategy is to enter long-term fuel contracts and buy very little on the spot market, he said. Since January 2003, however, the price of uranium has doubled – Russia has stopped supplying the market, fuel stockpiles are depleted, and China and other Asian countries plan to build nuclear plants, Rapacz explained. Not enough uranium is being mined to fill the need, he stated.

In order to mitigate the escalating fuel price, DOE approached EN about an opportunity to reprocess uranium tails and extract the usable fuel, Rapacz said. We are in the process of getting that project under way, and it could supply CGS with fuel for four reloads, beginning as soon as 2009, he said. We have a favorable fuel contract right now and will continue to take advantage of it, Rapacz added. The cost of the uranium tails project is $88 million over two years, he reported, adding that BPA has signed a letter agreement for the project, which has gone to DOE for signature.

We are in a unique position to undertake the tails project because of our relationship to BPA as an agency of DOE, Mouncer indicated. It's an opportunity available to us alone right now, he stated.

Did BPA's risk assessment office look at this project? John Saven (NRU) asked. Yes, we did an assessment of "what could happen" and potential negative impacts, Rapacz responded. We have "an escape clause" and can cancel the project at any time, he added.

Our risk was thoroughly analyzed, since BPA will temporarily be the owner of a large amount of uranium tails, Norman said.

We anticipate financing the $88 million, Rapacz said, noting that BPA is still analyzing possible financing scenarios in the context of its total debt portfolio. We expect to see a $20 million to $30 million benefit from the project over 10 years, he stated. Whose capital would that be, BPA's or EN's? Howard Schwartz (WA) asked. We're presuming it would be EN financing, Mouncer responded.

Rapacz continued with an explanation of issues related to relicensing CGS. The current license expires in 2023, he said. Many plants in the United States have sought relicensing, and the opportunity is open to CGS, Rapacz said. The projected cost of preparing the relicensing application and going through the Nuclear Regulatory Commission (NRC) process are $14 million over three years, he said. The question is whether we include the costs now and "strike while the iron is hot" since the NRC has been approving these, Rapacz explained. Vic Parrish strongly supports this, but we don't necessarily share that view, he said. We need to consider whether we want the plant in our portfolio, but having the option may be worth it, Rapacz said. The risk people tell us we should delay the decision about having the plant in our portfolio as long as possible, he added.

Is BPA's concern based on the belief that another resource would be available or on its view of what its future role will be? Saven asked. It isn't the latter, Norman responded. It depends on the risk, he said. It seems logical to agree to the extension, but there are risks, Norman pointed out. We want to make the decision in concert with those who are affected – our customers, he stated. It's a big decision, it costs money, and we feel we should have some consultation first, Norman said. BPA's current obligation is for the life of the plant, until 2023, he clarified.

There must be a way to work this out without committing BPA "to an eternity" with the plant, Eldrige commented. The question is what you are buying with an option, Nadal commented. You are buying a license to operate another 20 years, Rapacz responded. NRC could put conditions on the renewal, he added.

One-third of the plants in the country are already relicensed, Parrish stated. As an industry, we view this as "a sweet spot" since the NRC has staff that are up to speed on the issues and are moving the applications through quickly, he said. If you wait, there could be more onerous requirements, Parrish added, noting that some of the recently relicensed plants are older than CGS. He said EN had done an analysis of relicensing and assumed it would have to put $80 million into CGS to operate another 20 years.

Would relicensing raise the level of contributions to the decommissioning fund? Kevin O'Meara (PPC) asked. Yes, it would affect a lot of things, Parrish responded. Rapacz pointed out that decisions about upgrades and maintenance would have a different context if EN is going to go for a license renewal. There are things that are obsolete and need to be replaced, but there is a difference if the decision is being made for the long haul, Parrish added.

There may be merit to spending $8.5 million in the next rate period, Kevin Clark (Seattle) commented. Can BPA work with others in the region and EN to have a process about the license extension? he asked. That is a decision for the EN Board, Norman responded. We haven't yet considered the acquisition of the power beyond the plant's current life and are committed to consultation, he indicated.

It's an easier decision if it is "an option" on the plant, Eldrige commented. I like the idea of deciding sometime in the future about keeping the plant in the BPA portfolio, he said.

Dick Helgeson (EWEB) wondered whether a new license would obligate BPA into the future or whether it would really be an option. If EN applies for the license and gets it, it doesn't mean we've made the decision, but we have the costs of going through the process and decisions later about making upgrades and replacements, he commented.

How does the decision on relicensing overlap with making upgrades to increase production by 15 percent? Steve Marshall (Snohomish PUD) asked. If you commit to continuing to run the plant, it's better to run at 1,335 MW than 1,107 MW, Parrish replied. In that case, basic economics says you should do it sooner rather than later; but it's not necessarily tied to relicensing, he said. I took the uprate off the table this rate period – it's a $150 million project and would entail a 100-day outage, Parrish added.

Schwartz pointed out that with a decision to make a large capital investment in the plant, if BPA is to acquire the output, the Northwest Power and Conservation Council could have a role. The Council would want to look at whether this is the best expenditure for the additional resource, he said.

EN Presentation

Parrish started his presentation, saying EN has become a better organization in understanding risk, taking smarter and more informed risk, and in looking for innovative solutions. We have an internal rule that we don't amend the budget, he said. If we have an unanticipated expense, we try everything first to absorb it, Parrish said.

He listed several recent actions EN took to support the region, including the debt optimization program (DOP). What are the benefits of DOP to the ratepayers? Eldrige asked. There are interest cost savings, and it helps with BPA's borrowing authority, Norman said. Debt optimization is not increasing our total debt, he added. But how much lower are my rates? Eldrige asked. We can get you that information, Norman said.

Parrish continued through a list of unbudgeted costs EN has faced, including increased security. We have spent $22 million on security since September 11, and we anticipate other things that will need to be addressed, he said. According to Parrish, the nuclear industry as a whole has spent $1.2 billion on security since September 11, and the requirements "have gone beyond reasonableness." He suggested those who are paying the bills should send letters to legislators seeking more consideration of what is reasonable in terms of security. We went from 65 security people before September 11 to 138 now, and we are carrying an additional $7 million in expense forward every year, plus escalation, Parrish reported. "We need your help to stem the tide," he stated.

The nuclear industry has communicated with NRC about this, but the people making the decisions are people elected to office, Parrish said. "We have people on the East Coast making decisions for guys out in the desert," he pointed out.

State energy offices have been dragged into the security issues, and "we have found a rigid mindset" among federal officials, Schwartz said. The only way to change this is to have our elected officials "call time out," Parrish agreed. The NRC is more aggressive about security than the Department of Homeland Security, he said, relating industry experience with the NRC coming to plants to test security systems for threats beyond which they required the plant to prepare.

Parrish said CGS has generated more power than BPA forecast in almost every year, and in 2004, it recorded the largest amount of generation ever, with over 9,000 gigawatt-hours. Six plants in the country are stand-alone plants, and he reiterated Rapacz's statement that CGS has about a 15 percent cost penalty because it does not have the economies of scale provided with fleet operations.

Parrish explained a number of factors that are driving costs upward, including regulatory and waste disposal costs. Have you looked at ways you might join a fleet operation? Paul Elias (McMinnville) asked. Parrish said EN has explored linking up with other operators. The Board supports the idea, but nothing has come so far of talks with other nuclear operators, including Nebraska Public Power, he reported.

Parrish compared CGS operations and FTE to industry benchmarks and said the plant, which has more staff than its peers, will see FTE reductions. We are shooting for between 974 and 985 total, he said. Our aim is to continue to benchmark and go with what's best for the plant, Parrish said.

Could you contrast your efforts today with what you did in the 1990s to cut costs? Frank Lambe (Emerald) asked. We went too far with cutbacks in the 1990s, Parrish responded. He recapped CGS' generating history, the rolling average cost of power, which is about $27 per MW in 2004-2005, and direct and indirect FTE.

Mouncer explained EN's budget planning cycle and its budget objectives, which include staff reductions and reducing non-labor costs by 10 percent. Our forecast for O&M in 2006 is $199.5 million, he said.

Your objective of being in the top 50 percent of plants doesn't sound like the right message, Kevin Owens (Columbia River PUD) said. I don't think you have characterized it correctly – this isn't sending the right message, he said when Parrish explained that CGS has to walk a fine line between being cost effective and providing reliable operations.

Where do you stand with the NRC? Eldrige asked. We are in "column one," which indicates NRC is confident in our ability to operate and fix any problems, Parrish said.

Somewhere in this decision we have to look at all the costs, including debt service, Eldrige said. The cost isn't $26 per MWh, he said. I'd encourage BPA to be clear about what the total costs are, so we can make clear decisions, he stated. The debt costs are sunk, and there is not much we can do about them, Norman responded. But going forward, there are capital decisions, he added. The nuclear plant ought to be presented in the same way as the hydro system – we need the whole picture, Eldrige said. We can only avoid the O&M, and we don't want to create confusion about what the avoided costs would be if we didn't operate the plant, Norman said. I think there is more danger of misleading if the debt information is left out, Eldrige said.

Do you think this is a well-run plant? Eldrige asked. We're in the middle of the pack in terms of operations, Parrish responded. The question ahead is whether the nuclear plant can compete with other options, Eldrige said. So the right comparison is what can we do relative to the nuclear plant O&M, Norman commented.

Mouncer outlined budget reductions for 2006, and Parrish said he had to cut another $13 million to get to the numbers presented. How confident are you this will happen? Eldrige asked. Absolutely, it will, Parrish responded. Mouncer continued with the costs within various categories of the budget, and he noted that EN continues to pay a significant disposal fee, $9 million in 2006, despite the fact that DOE is "woefully late" in opening the Yucca Mountain facility. We have sued DOE for breach of contract and will try to recover costs we've incurred in having to develop on-site storage, Mouncer explained.

He outlined the activity based management approach EN uses, saying it is uniform across the industry and helps operators get a good view of costs and make decisions about cost cutting. Parrish noted that one decision EN is contemplating is whether to invest in technology that would move fuel quicker and shorten refueling outages. Parrish also said EN has an accredited training program and operators spend one week in every six in training.

Ralph Cavanagh (NRDC) asked if there is adequate capacity in the on-site spent fuel storage facility to meet EN's needs. It is set up such that we can add capacity as we go, Parrish responded.

Mouncer completed the 2006 budget explanation, noting the priorities in the baseline budget, and Parrish went over the long-range plan for 2006-2011, including CGS initiatives, assumptions, and costs. The numbers show a commitment on our part to keeping everything as constant as possible, he said.

We've seen a significant increase, $70 million, in CGS costs from the figures we saw in the opening workshop, Kris Mikkelson (Inland) pointed out. We have to update the original table to reflect EN's new numbers, Norman acknowledged. We did not have them for the opening workshop, he added.

Parrish continued with the budget projections for 2006-2011. We are presenting our budget to the Executive Board this month and expect to get final approval in April, he said. With regard to staffing, Helgeson asked about the use of contractors in addition to FTE. We do hire contractors to supplement the staff, but we are reducing the numbers, Mouncer responded. We hire contractors, but as a matter of policy, we don't like to do it, he added.

Parrish explained what plant modifications and major maintenance entails, and he noted there are incremental costs associated with a refueling outage. He listed the major projects anticipated in the 2007 outage year, which total $53.9 million. Parrish said CGS is captive to some vendors in the nuclear industry, and there have been times when costs were reduced by pursuing a reverse-engineering solution. He said the costs for some services are on "a value of service" basis rather than the cost of providing the service. If a service will increase generation, the providers "want a piece of the pie," Parrish pointed out. The list on page 88, security, fire protection, spent fuel pool cooling, transformers, power uprate, and new facilities are not included in the long-range plan, he noted.

The figures on page 75 are our bottom line, Parrish wrapped up. This is our best effort and the best input we can make to the process, he said.

Rapacz recapped where PBL has projected CGS costs in the next rate period. It seems we have an issue with the timeline, Marshall said. EN will continue to make cuts, so can't we wait until next year at this time to set the costs for the rate case? he asked. We'll put new numbers in for the final rates and reflect their progress, Norman responded. We have staff in Richland who work with EN to be sure BPA is comfortable with the costs, he added. Vic and his staff have taken an aggressive approach to cost cuts, and they are getting to where we think the target should be, Norman stated.

You should assume more output based on CGS' recent performance, Clark advised. Use the EN assumptions – yours is flat and theirs is going up, he pointed out.

Use a budget number that will keep rates flat and then see what else it will take to get down to 27 mills, Eldrige suggested. We want to know what it will take to get to 27; is it possible? he asked. We need to have a separate discussion about the 27 mills, Norman responded.

Schwartz asked about forecasting the borrowing to pay for capital items. It's an EN Board choice, but if BPA customers said to capitalize something rather than pay out of revenues, they would listen, Norman responded. I'm encouraged by your orientation to cost management – it feels really different than other parts of the budget, Helgeson said.

III. Corps and Reclamation O&M

We heard at the Sounding Board there is interest in having regular meetings with the FCRPS partners, Mark Jones (BPA) said. We like the idea, and would like to offer to start doing that, he said. We could also set up visits to the plants to see and discuss how they are managed, and for you to see specific projects that are being worked on, so that offer is open too, Jones said.

He began by clarifying questions that arose at the technical session about the forced outage factor. First, it is a lagging indicator, and we don't want to wait until a unit goes down before we address a problem, Jones explained. Also with regard to contractor levels at the Corps, they do not have contractors working in lieu of FTE, he said. There are contractors associated with specific jobs, but there is no large number of contractors who work on an ongoing basis, Jones said.

We're talking about a system here that generates 9,000 aMW, has a 22,000 MW capacity, and is operated with 1,601 employees, Cavanagh pointed out.

There was also an issue raised about the Integrated Business Management Model and why we started with resource planning, Jones continued. We realize that isn't typically the starting point, but it's where we were when the asset management strategy was developed, he clarified. So in this process, that is where we started, Jones said.

O&M Expense

Mike Alder (BPA) began his presentation by noting that O&M at the Corps and Reclamation projects includes fish and wildlife (F&W) O&M and cultural resources. He pointed out that Reclamation plants are at a baseline to maintain reliability and unit availability, but there are issues to deal with on the Corps side. The FCRPS agencies are continually benchmarking themselves against other hydro operators, Alder continued. Of the six indicators, we are in summary at or below industry cost on five, he noted.

We have examples of what we are doing to improve O&M cost-effectiveness, Alder said, going over the staff reductions at Reclamation projects. He explained the use of "multi-crafting" that combines the main mechanical crafts into a single staff position to accomplish maintenance more cost-effectively.

Dave Murillo (Reclamation) described "the cultural change" that has gone on at Reclamation projects in the Yakama Basin to break down "territorial" approaches to O&M and encourage people to assist each other across functions. Some of the changes required overcoming union objections, he acknowledged. But we told people we had to come up with the right number of FTE at a project, Murillo said.

Jim Mahar (Corps) said dollars are being saved at the Bonneville project with "smarter maintenance," and he pointed out that "attitude" and a maintenance management system called FEMS/MAXIMO are making a big difference. He noted that some positions are now filled for a specific term, during which a skill is needed. Staff is being mixed from one hydro project to another, and people with needed skills are borrowed when possible, Mahar said. The Corps is also being innovative and saving dollars by using crew foremen to do training, rather than hiring outside trainers, he continued. We're swapping inventory between plants, and the attitude is changing on how we can save money, Mahar reported.

Mark Jenson (Corps) pointed out that at Chief Joseph Dam staff did an in-house installation of the new automatic control system. We hired power plant trainees and did the installation ourselves – we achieved the results and trained new craft workers at the same time, he said. We are using creativity and innovation to save dollars, Jenson reiterated.

Alder listed opportunities for efficiencies and reductions, pointing out that the FCRPS agencies expect to see savings as a result of them.

I applaud you, and I understand what you are saying about cultural change, Eldrige said. Do your operations people really care about what things cost? he asked. Our operations people ask whether anyone notices the difference and the sacrifices they are making – they do care, and the staff is coming up with even more ideas, Murillo said.

Eldrige gave an example of inefficiency he had seen, noting that several agencies sent people out to check the same screens at an irrigation diversion. It sounds like a lack of coordination, Murillo acknowledged. We try, but people sometimes forget, he said.

Pete Gibson (Corps) pointed out the agency heads at the Corps and Reclamation signed an agreement that allows for sharing and being more efficient at FCRPS O&M. From the corporate level down, these two agencies understand the need, he said. Culture is difficult to change, and the leadership comes from management, Mahar added.

You point out that it's valuable to get more generation from the system, but for the irrigation savings, we've heard $20 per MW not the $35 on page 13, Cavanagh said. We should be consistent, he stated. Some of the irrigation districts are updating their pumps, and the Columbia Basin irrigators are looking at ways to be more efficient, Terry Kent (Reclamation) responded.

There are front-end costs associated with irrigation modernization programs, and there are few incentives to improve efficiency, John Saven (NRU) pointed out. We need incentives for both water and energy use, he said. Are there other programs through which we can make money available to the end-use customers? Saven asked.

Rick Lovely (Grays Harbor) asked if the drawdown schedule at Grand Coulee for a headgate repair could be revisited. Could it be shifted to this fall? he asked. We're very concerned about the drafting with no chance for refill, Lovely stated.

We have maintenance and security concerns to consider, but I'll take that comment back, Kent stated.

Most good ideas come from the field, Clark pointed out. We can't afford any more increases in maintenance, and I'd propose a gain-sharing program, he said. We can't fund the proposed level of increase in 2007-2009, but if we fund part of it, could you institute a program that rewards plants for every dollar saved? For a dollar saved, they get $2 for projects they choose at the plant, Clark suggested. Put some of the proposed activities on a gain-share basis, he urged.

Alder explained the proposed increase for non-routine extraordinary maintenance. We've looked at this and found the resources required are as much as $18 million annually, but we're proposing $8 million to keep the hydro projects at baseline reliability, he said. The McNary headgates are among the extraordinary needs – they're 50 years old and "we've tried to band aid the situation," Alder said. "It's a huge expense," but we lose $8.6 million in an average water year, he pointed out. A repair needed on a generator at Chief Joseph is another example of revenues being lost due to extraordinary maintenance needs, Alder explained.

Why can't you capitalize these expenses? Lambe asked. They're considered O&M – it's not a replacement or an upgrade, Alder responded. Couldn't you set up a contingent financing fund? Marshall asked. Why not try to save money in the good hydro years to set up a fund to do extraordinary maintenance, he suggested.

Clark raised the issue of the forced outage factor and whether it tracks with the investments. It's a lagging indicator, Alder responded. The forced outage rate has come down, and it is at a good level, Gibson added. We are not proposing to deviate from existing O&M, but are proposing new work that if it isn't funded now, the maintenance level will drop and the forced outage factor will go up, he explained. We are getting close to a baseline level of work, Gibson said. We see you proposing a $50 million increase over four years, Clark responded.

Couldn't you address the situation at Chief Joseph now? Helgeson asked. It is costing you money, he added. I had "a hopeful thought" that maybe you could amend the budget to address a situation like this, Helgeson said. We have extraordinary maintenance projects going on now, but we're constrained in our funding to address all the needs, Alder replied. But we can change budgets if needed, he clarified.

We have $6 million to $7 million in critical work we could do in 2005 if we had funding, Gibson said. We have “a hopper” of extraordinary maintenance that is needed, he added.

If the question is money, at some point we need “to tee up” the issue of the relationship of one FCRPS activity to these others – the revenue from summer spill could pay for some of these, Saven said. I would like us to describe other alternatives for where the money for these projects could come from, he said.

Do you do a cost-benefit study on these actions? Lovely asked. We do an energy benefits analysis that shows us the difference between doing something or not, Phil Thor (BPA) responded. The $242 million per year for the next rate period gets you the benefit we’ve depicted on this graph, he said, referring to page 36.

Is there flexibility to respond to outages and generators going out? Lambe asked. Yes, we don’t leave units out of service, Thor said. We always address forced outages, but we plan strategically about when to repair them, he added.

We look at every forced outage and analyze the revenue effects, Alder said. There is no denying that program costs have gone up, but $55 million of that is labor-related and due to things tied to inflation, he said. Asked about the FTE forecast, Alder said he did not expect it to go up for either Reclamation or the Corps. He explained the drivers of change on page 12, including NERC/WECC requirements. Jones noted that the East Coast blackout increased sensitivity to reliability requirements, and since generators support the transmission system, there is pressure for the FCRPS to get into compliance, he said.

In dealing with risk, could you identify the non-essential things, and if there are funds, fund them, but if not, don’t, Marshall suggested. Incorporate this approach into risk management – some things may not be essential now, but will be essential later, he said.

Gibson indicated the program is still evolving. We are seeking a business model with planning and a strategy to support decisions, he said. Let us finish this concept and then we’ll have a cost-effective way to make decisions, Gibson urged.

I’m suggesting that you prioritize things that you can put off – it will help with risk management, Marshall responded. And think in terms of a flexible strategy, so in wet years you can do maintenance, Clark added.

I’d like to push back on the idea of a hard cap on O&M, Cavanagh said. One of the most important things on the system has no internal rate of return (IRR) – you can’t measure it in terms of dollars and cents, he said. There should be some projects that you just do without crowding anything else out, Cavanagh said.

“We ought to be ashamed” that we have gotten to this point with some equipment in the system, Eldrige commented. We’ve let things go downhill too far, he stated.

Alder pointed out that environmental compliance poses a risk of increased costs. Does this budget cover the Updated Proposed Action? Saven asked. To the best we can estimate, it does, Alder responded. He turned to page 17, a table of the effect the O&M program has had on rates. Without the program, we'd have the equivalent of seven of 209 units out of service, Alder said. You make a reasonable case on the first two lines, the rest is too speculative, Eldrige commented, referring to the calculation of lost revenue if the O&M program had not increased.

The value of the O&M program shows up in annual revenue, Alder said. The extraordinary maintenance is a real issue for us, he summed up.

You need to correlate page 10, average program cost, with the forced outage factor graph on page 56, Clark stated.

Capital Program

The capital management program makes investments to meet the two objectives of the asset management strategy, Thor said: increased generation reliability and increased generation efficiency. The reliability investments involve spending to upgrade, replace, and refurbish equipment, and the efficiency investments aim "to squeeze the factory harder," leading to increased generation, he explained.

Thor pointed out where the FCRPS stands on five cost benchmarks comparing it to other hydro operators, noting the system is well below its peers on four of the five. As our program ramps up, we will get closer to the benchmark in these areas, he said.

According to Thor, BPA plans to invest $516.3 million from 2002 to 2006. Direct funding is the mechanism for achieving improvements at Corps and Reclamation projects, and all but $4 million of the dollars budgeted for the period are committed, he said, going through the budget on page 35. "We are in the hole for 2006," but it's netted out by the leftover from 2005, Thor explained. We can reprogram funds if needed – we do it all the time, he said.

Thor explained that one of the criteria for projects is the IRR. For things that affect reliability, the threshold is 13 percent, he said. But for efficiency improvements, we run the IRR and target things that get us the most, Thor said. The chart on page 36 is what we postulate would have happened since 1998 without the capital investment program, a steady decline in average MW of generation and revenue, he indicated.

The net present value of the program from 2005 to 2023 is shown on page 41, Thor continued. The IRR for the program as a whole is 29 percent, with 22 percent for generation reliability and 150 percent for generation efficiency improvements, he explained. Most of the efficiency gains are associated with turbine runner replacements, and "you can't do these projects overnight," Thor said. He went through the graphs on forced outage factor, with and without the capital program; explained the McNary turbine runner replacement project; and the effect the capital program has had on rates.

Will the increased output at McNary be factored into the generation forecast? Randy Gregg (Benton PUD) asked. It's out there in time a ways, so no, Thor responded.

Thor explained "a thought exercise" about the cost for a sustained equipment replacement program for the FCRPS. We would need to invest about $110 million a year to keep the system reliable, he said. In terms of the appropriate level for 2007-2009, Thor said benchmarking, forced outage factor, and the rate effect suggest we're proposing the right budget. We have the ability to invest at the proposed levels, and we have to be strategic with our investments, he said. We have a hopper of capital investment projects identified, and the sum is greater than what we are showing here, Thor wrapped up.

To manage the costs down, we need to look at opportunities to avoid revenue loss and opportunities to increase generating revenues, and identify projects that can be postponed, Schwartz commented.

Thor presented "the wish list" of projects identified by the hydro project managers. We can't meet all of these needs, so we will have to prioritize, he said. With efficiency gains, about the only choice we have, in addition to the optimization effort, is turbine runners, Thor explained, noting there are hydro plants in line for replacements.

I'd be interested in the following, Saven said: whether this document covers the proposed actions for BiOp implementation and how that compares to "a reference operation." We should be aware of what BPA may have to do, he stated. I'd also like to see the difference in effect of a 3 percent versus a 4 percent rate of inflation and an estimate of the value of eliminating summer spill, Saven said. "What size pot would that make available for extraordinary maintenance?" he asked.

Let's put the irrigation water back in the system and see the impact of that, Cavanagh suggested.

Eldrige made the following suggestions: take the conservation and renewables budget and put it into the hydro system, which is "the quintessential renewable resource"; and show what it would look like to ramp up to the $249 million O&M budget on a straight line. He also said he liked the idea of a fund for extraordinary maintenance and asked whether BPA is the only source of funds for the O&M program. Why can't there be appropriations for some of this? Eldrige asked.

I have concerns about the escalation in the O&M budget, and it's an area to focus on, Helgeson said. Regarding capital, "I couldn't connect the dots" to get to the increasing budget, he said. The most compelling information is on page 42, which spoke to meeting the equipment costs over time, Helgeson said. As for the budget on page 35, I'd like more information on what drives the efficacy of the investments, he said.

The investment level of $110 is good documentation, Clark said. With this level of spending, we would continue to see an investment in “the engine that makes the revenue,” he said. We need to get a handle on O&M spending – instead of escalating O&M, we need to find a sustainable level that customers can stick with, Clark said. We have to hold the line on O&M spending, he reiterated.

I’d echo the sentiments on O&M spending, Mikkelson stated. We need to know what we are trying to achieve with increased O&M, she said. The information on capital investment to maintain the integrity of the system speaks to the need to develop a major maintenance program that goes year to year, Mikkelson said. I am concerned about system degradation unless you dedicate funds to major maintenance and do it systematically, she added. What incentives are in place for cost effectiveness and to assure that the right projects are rising to the top? Mikkelson asked.

CGS O&M will cost $284 million a year, and O&M on the entire hydro system is $242 million – that’s 1,100 MW of capacity compared to 22,000 MW, Cavanagh pointed out. Is there any doubt “we were grotesquely under-investing in the hydro system”? he asked. The real emphasis should be on finding more cost-effective investments, Cavanagh stated. Think about the order of magnitude between CGS and the hydro system, he urged.

I want BPA to take money that is being directed elsewhere and direct it to this, Eldrige stated.

The hydro system is our cheapest resource, but we still have to control costs, Marshall responded. We’re struggling to get rates down, and our customers expect to see a reduction, he said.

We have a list of more information we need to get you – I can’t promise you about when we’ll get back with it, but “we will close the loop,” Norman stated.

The meeting adjourned at 3:50 p.m.

Follow-up questions and information requests

Responses to questions and requests for information received throughout this process will be posted on the Power Function Review Web site on an ongoing basis. The Web address is www.bpa.gov/power/review.

Columbia Generating Station/Energy Northwest

1. What are the benefits of DOP to the ratepayers? How much does it lower rates?

2. What opportunities will be provided for customer input on the decision on CGS license extension?

3. What is the all-in cost of CGS, including debt service?

Corps of Engineers/Bureau of Reclamation

4. There are front-end costs associated with irrigation modernization programs, and there are few incentives to improve efficiency. Are there other programs through which we can make money available to the end-use customers?

5. Can the drawdown schedule at Grand Coulee for a headgate repair could be revisited. Could it be shifted to this fall?

6. What are the alternative sources where money for these projects could come from?

7. Please correlate page 10, average program cost, with the forced outage factor graph on page 56.

8. Does the presented information cover the proposed actions for BiOp implementation and how that compares to “a reference operation?”

9. How much lower would this budget be if it were inflated at a 3 percent rate starting with 2003 actuals?

10. What is the estimated cost of spill this year?

11. What would the effect be of capitalizing federal FTE costs?

12. For the budget on page 35, provide more information on what drives the efficacy of the investments.

13. How many contract employees do the Corps and Bureau have (i.e. those who function like full time FTE, not short-term contractors)?