BPA PROPOSED FISCAL YEAR 1994 BUDGET

OVERSIGHT HEARING

BEFORE THE

TASK FORCE ON
BONNEVILLE POWER ADMINISTRATION

OF THE

COMMITTEE ON
NATURAL RESOURCES
HOUSE OF REPRESENTATIVES

ONE HUNDRED THIRD CONGRESS

FIRST SESSION

ON

THE BONNEVILLE POWER ADMINISTRATION'S
PROPOSED FISCAL YEAR 1994 BUDGET

HEARING HELD IN WASHINGTON, DC
APRIL 28, 1993

Serial No. 103–20 Part I

Printed for the use of the Committee on Natural Resources

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CONTENTS

APPENDIX

April 28, 1993

BONNEVILLE POWER ADMINISTRATION'S PROPOSED FISCAL YEAR 1994 BUDGET

WEDNESDAY, APRIL 28, 1993

HOUSE OF REPRESENTATIVES,
TASK FORCE ON BONNEVILLE POWER ADMINISTRATION,
COMMITTEE ON NATURAL RESOURCES,
Washington, DC.

The task force met, pursuant to call, at 1:00 p.m., in room 1324, Longworth House Office Building, Hon. Peter DeFazio [chairman of the task force] presiding.

STATEMENT OF HON. PETER A. DeFAZIO

Mr. DEFAZIO. I think we are going to get started. It is one o'clock. You may certainly seat yourself, Randy. I have an opening statement. Since this is the first meeting of the task force, I am going to read an opening statement, something I don't usually do, and then I will recognize other members of the task force as they come in, and then we will go to your testimony and then questions.

Today the Natural Resources Committee's Bonneville Power Administration Task Force holds its first hearing. I particularly want to thank Chairman Miller for the creation of the task force and for naming me its chairman. I am looking forward to the hearings that we will hold over the next six months, and I want to play a creative and active role in helping the BPA to meet the challenges it faces, both in the near term and during the next decade.

Today's hearing will focus on BPA's near-term financial condition. A unique set of circumstances have forced BPA to consider a rate increase that could exceed 20 percent. But the BPA's short-term problems will not go away with a few good water years or higher world aluminum prices. The problems are much deeper than that, and the fix must be more fundamental. So regardless of the facts of the current situation, I believe we would be here today no matter what.

In 1937, just over 50 years ago, Congress created the BPA to market power from the federal projects on the Columbia River. In 1974, BPA was made a self-financing agency and given power to borrow money from the Federal Treasury. Then in 1980, Congress passed the Northwest Power Act which expanded the BPA's mission to include responsibility for acquiring resources to meet the region's energy needs. Energy conservation and renewable resources were given priority over other forms of generation, and fish and wildlife were given parity with power production.

The Northwest Power Planning Council was created to develop plans for the orderly acquisition of conservation and other electric

resources. The Council was also charged with developing a program to protect, mitigate, and enhance fish and wildlife populations affected by the hydroelectric facilities on the Columbia River system.

Today's hearing is a springboard to the real work of this task force. Over the course of the next six months, we will take a long and detailed look at how well Bonneville is meeting those expectations, the ones that Congress had when it passed the Northwest Power Act. We will consider ways we can restructure the BPA to enable it to better meet the extraordinary challenges it will face in its next 50 years.

The Northwest's failed experiment in nuclear power led to the passage of the Northwest Power Act. It also led to my first involvement in regional energy issues. In the early 1980s, I sued over the ability of the Washington Public Power Supply System, or WPPSS, to hold the ratepayers of Springfield, Oregon, liable for the costs of two of its five proposed nuclear power plants.

As it happened, only one of the WPPSS plants was ever completed. Two are in mothballs, and the region's ratepayers have been paying for that boondoggle ever since.

By the BPA's estimate, between 15 and 25 percent of the average residential ratepayer's bill is eaten up by BPA's liability for two unfinished WPPSS plants and one that is limping along, at best. At least 25 percent of the agency's budget goes toward debt service, operations, and mothballing costs of the WPPSS plants.

While we labor under the burden of WPPSS, an even larger crisis looms. Threatened and endangered Snake River salmon runs and the decline of other Columbia River stocks, could lead to a regional nightmare that would make the spotted owl look like a Sunday picnic. It is imperative that the BPA and all other users of the Columbia River system take responsible actions now—today—consistent, long-term, scientifically supportable actions to avert that potential crisis.

I have deep-seated concerns about the BPA's long-term prospects. We need a new and more competitive Bonneville, but one that continues to maintain its leadership in energy efficiency and environmental protection. These are concerns for the longer term. However, the task force cannot ignore the fact that decisions will be made this year that could have profound effects on BPA's ability to meet its long-term mandates.

I am disturbed that many of these decisions are being made in closed-door settlement discussions between Bonneville and a select group of its utility and industrial customers. BPA certainly has a responsibility to its customers, but it also has a broader responsibility to the region at large, as well as the United States Congress. And Congress—in the form of this task force, under the jurisdiction of this committee—intends to play a significant role in reshaping Bonneville for the future.

I share many of the concerns expressed by Bonneville's utility and industrial customers. Bonneville is too big, and it is too inefficient. It should look more like a business and less like a bloated bureaucracy. And, in my judgment, a more efficient BPA can not only deliver cost-effective conservation and reliable low-cost power but can better satisfy its broader social and environmental responsibilities.

My hope is that we can avoid another WPPSS or spotted-owl-type fiasco by making sensible energy and environmental choices today. That is the purpose of this hearing and of the many hearings we will be holding during the next six months.

In closing, I do have one caution for members of the panel. The BPA is in the midst of a formal rate case proceeding. The task force has no intention of influencing the Administrator's decision in the present rate case. I urge every member of the task force to exercise care in questioning or pressuring the Administrator. At the same time, this panel has a legitimate oversight function which I fully intend to exercise.

As we move through this, if I believe one of the members of the panel has gone beyond the bounds of question, I will caution the member, and if the Administrator himself, in responding or being asked to respond, has a concern, he should express it, and we will deal with it at that time.

At this point, I would like to recognize other members of the task force and see if they have any opening statements.

Mr. Sharp.

STATEMENT OF HON. PHILIP R. SHARP

Mr. SHARP. Thank you very much, Mr. Chairman.

I am very pleased to be a part of the task force and work under your leadership. You, I have learned from previous experience, have already been very active and given a great deal of leadership to concerns about energy supply and consumer issues in your part of the country, and those of us who are not from that part certainly respect that leadership.

I was personally involved in the legislation, the Northwest Power Act, when it was passed. I am not sure that it is wise for one to claim any involvement now or not, I don't know. We will find out as we go through this. So I am very much looking forward to working with you. Obviously, this is of profound concern to the people who are served by the Bonneville power system, but obviously it also has major implications for some of the surrounding States, California in particular. Also it has ripple effects throughout the entire electric utility industry in this country. So these issues are not to be taken lightly, and I appreciate your effort.

Mr. DEFAZIO. I am pleased to have the gentleman, particularly with his experience in the writing of the Act, and certainly with his work on the Energy and Commerce Committee, he will be very complementary. I am glad to have him here.

I would like to recognize my colleague from Oregon, Bob Smith.

STATEMENT OF HON. ROBERT F. SMITH

Mr. SMITH. Thank you very much, Mr. Chairman.

Mr. Hardy, welcome.

I want to thank you, Mr. Chairman, for holding this first meeting. I think it will be productive to have oversight responsibility over a very difficult time for Bonneville Power Administration.

I want to compliment Mr. Hardy's short but very successful term as a leader in the Bonneville Power Administration programs, and what a difficult time since he has arrived. We have got a horrible problem with the drought in the upper Canadian regions which

provide us with most of the runoff that fuels the river. We have a situation in which Bonneville has to increase its revenues and I know it has been struggling with that question. Of course, as we increase the rates, it is passed on to producers in the Bonneville Power canopy.

Beyond that, we are grappling with a Btu energy tax proposed by the Clinton Administration which will have an additional impact upon those users of energy in the Northwest, and many of us, I think, in our region question the reasonableness of taxing a clean, renewable energy source like hydropower at the same level that you tax fossil fuel plant energy development.

In fact, last month I had a representative from Northwest Aluminum in my office who testified before the Ways and Means Committee on the President's proposed tax package on hydropower. He said that if the proposed rate increase goes through, that they are out of business, and that means 489 people in The Dalles, Oregon, are out of work.

So with the energy tax and the inland waterway fee which will be passed on, I don't envy Mr. Hardy's position and job in juggling these numbers. But the rate increase which may be double-digit that Bonneville is discussing plus these additional taxes to be passed on seem to me to be an invasion of private interest and certainly of the people who convert energy to productive means in the Pacific Northwest.

So thank you, Mr. Chairman. I am looking forward to the testimony of Mr. Hardy.

[Prepared statement of Mr. Smith follows:]

STATEMENT OF CONGRESSMAN ROBERT F. (BOB) SMITH

Mr. Chairman, I want to thank you for holding this hearing. I am hopeful that in the next six months we can address some key issues about how we can make the Bonneville Power Administration more competitive and how they can continue to play a role in economic development in the Pacific Northwest.

In addition, I want to commend Mr. Hardy for the excellent job he has done during his relatively short tenure at BPA. He has a big challenge ahead of him and in many respects, he has joined the battle at perhaps the worst possible time.

Unfortunately, he's not getting a whole lot of help from the current Administration. To use a boxing analogy, BPA ratepayers have already been rocked by a left hook from extreme drought, low aluminum prices and the Endangered Species Act. Now President Clinton is poised to deliver the knockout blowout with his excessive and unjustifiable Btu tax.

Like many of my colleagues from the Northwest, I am not clear about the wisdom of taxing a clean, renewable energy source like hydropower on the same level as an average fossil fuel plant. It just doesn't make sense.

Last month, a representative of Northwest Aluminum in The Dalles testified before the Ways and Means Committee about the President's tax on hydropower. The message he gave to the Committee was simple: If you add an unfair Btu tax on to BPA's proposed rate increase, they are out of business and 489 people in The Dalles are out of work.

In my district, it doesn't end there. Like the mighty Columbia River, the taxes just keep rolling along. If you add the Btu tax to other Administration proposals like the 500% increase in the Inland Waterway User Fee, a typical Oregon wheat farm is going to pay over $12,000 in additional costs.

In my mind, a double-digit rate increase from Bonneville is serious enough. But if the Northwest keeps getting hit by the Administration's taxes, it goes beyond a knockout blow. It's kicking us when we're on the ground.

Mr. Chairman, I look forward to the testimony we will hear today from Mr. Hardy.

Thank you.

Mr. DEFAZIO. Thank you.

Ms. Shepherd.

STATEMENT OF HON. KAREN SHEPHERD

Ms. SHEPHERD. Thank you, Mr. Chairman. I am delighted to be here learning about this process.

Utah is one of those places that will be impacted by what the decisions are, and I look forward to representing their interests.

Thank you.

Mr. DEFAZIO. Mr. LaRocco.

STATEMENT OF HON. LARRY LaROCCO

Mr. LAROCCO. Thank you, Mr. Chairman, and it is with great pleasure that I refer to my colleague from Oregon as "Mr. Chairman" today, and hope that this reference becomes permanent in the future. Thank you also, Chairman DeFazio, for taking on the immense task of oversight of the BPA, or Bonneville Power Administration.

Both Bonneville and the entire Northwest, including Idaho, have benefited from strong leadership in the region's congressional delegation over the years. As a result, BPA has been able to provide electric power at consistent and predictable rates. It is vital to the future of both Bonneville and the Northwest that BPA remain strong and yet flexible to cope with the challenges which face the Nation and our region.

One of these challenges is whether and to what degree wild chinook and sockeye salmon will return to Idaho. Although I know the main thrust of today's hearing is budgetary, I do want to make a few comments about the endangered salmon which also affect BPA's budget.

Many of the members of this task force are well aware of the amazing odyssey of the Snake River salmon. For thousands of years, these salmon, born in headwater streams and lakes, migrated up to 1,000 miles to the Pacific Ocean. Beginning as far inland as Red Fish Lake, named for the color of the salmon, in Central Idaho, they roamed as far north as Alaska and as far south as California before returning upstream to their birthplace to spawn.

In 1985, Snake River coho salmon were declared extinct. In 1991, Snake River sockeye, spring, summer and fall chinook were listed as threatened or endangered under the Endangered Species Act. In 1992, just *one* sockeye returned to Red Fish Lake. For these magnificent fish to become extinct under our watch is simply unacceptable, so we have a lot of work to do.

Along those lines, Mr. Chairman, I have prepared a number of questions, which I ask to submit for the record, and will do so at the proper time. I look forward to Mr. Hardy's testimony and follow-up questions, and I appreciate his presence here today at this hearing.

Thank you, Mr. Chairman.

Mr. DEFAZIO. I appreciate the gentleman's remarks and would state that we will hold a future hearing focusing on this issue, and we will work together with the gentleman to coordinate the site of that hearing and the timing.

With that, we have one witness. This is, to my mind, a slightly unusual hearing. Usually we have an array of witnesses. But we have the very capable administrator and some support staff here, and I would recognize the gentleman at this time.

My understanding is, you will probably take 15 minutes or so in your opening remarks, and then we will go to questions.

So, Mr. Hardy.

STATEMENT OF RANDALL W. HARDY, ADMINISTRATOR, BONNEVILLE POWER ADMINISTRATION, DEPARTMENT OF ENERGY, PORTLAND, OREGON

Mr. HARDY. Thank you, Mr. Chairman.

With your permission, I would like to have my formal written statement entered in the record, and I would like to take 10 or 15 minutes at the opening to talk about the charts to my left—and I think you have handouts that replicate the charts. I will talk a little bit about our current financial situation to try to set the context.

Mr. DEFAZIO. Let's suspend for a second. Let's make sure people can locate these. This would be the initial rate proposal?

Mr. HARDY. Right. The top sheet is the same as on this chart here, the initial rate proposal. Then you have a variety of colored graphics that relate both to the water conditions and to different aspects of our budget and how that splits out.

Mr. DEFAZIO. All right. Thank you.

[The charts follow:]

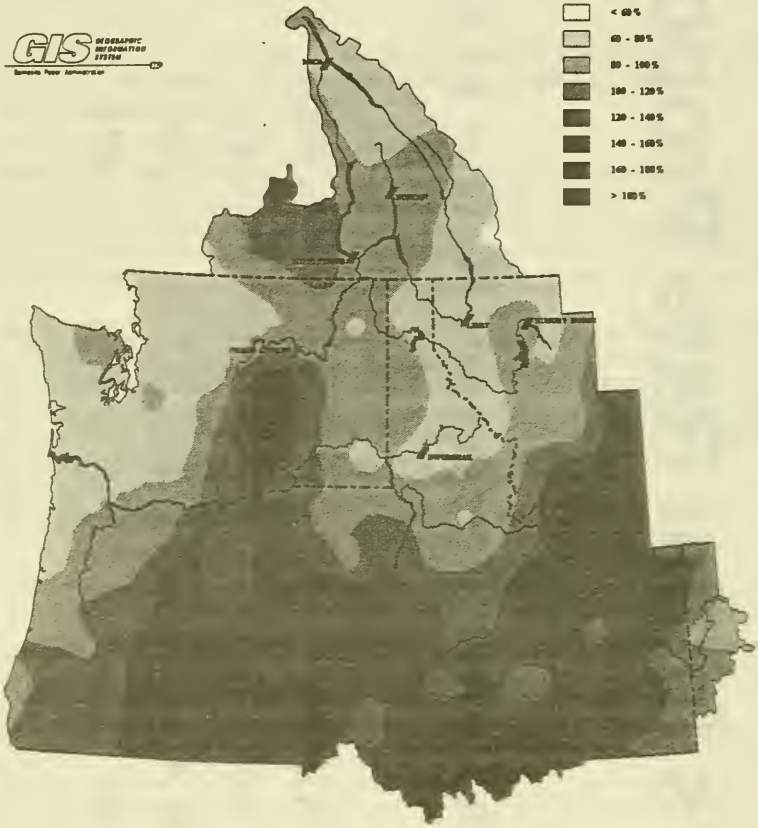
BPA's Initial Rate Proposal

Priority Firm Power Preference Rate = 11.6%

– Fish and Wildlife	4 - 5%
– Resource Acquisitions	3 - 4%
– Drought & Aluminum Prices	3%
– Other Costs	1%

Northwest Seasonal Precipitation to Date

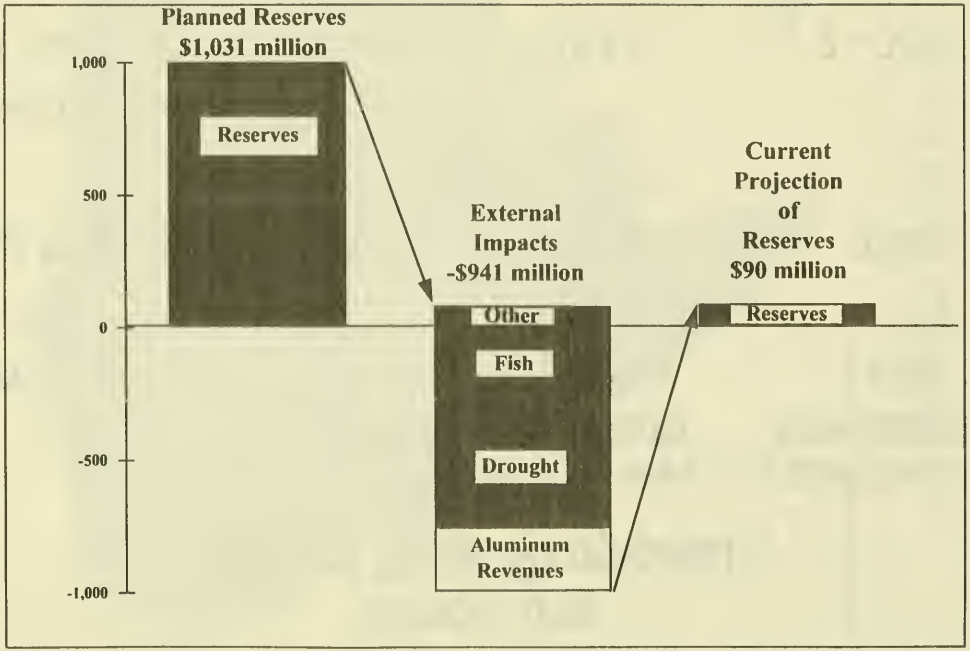
October 1, 1992 to April 1, 1993



Changes in BPA's Financial Condition Since the Initial Rate Proposal

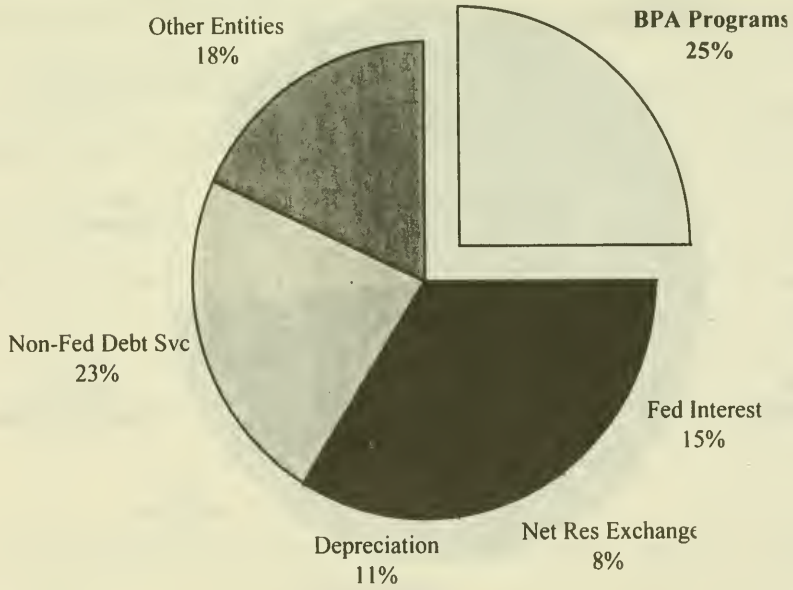
	($Millions/Year)		Additional
	FY 1993	FY 1994/95	Rate Impact
Drought	($227)	($95)	8%
Fish and Wildlife	($50)	($25)	2%
Aluminum Prices and Load	($42)	($45)	2 - 3%
Total Impacts	($319)	($165)	12 - 13%

Bonneville Financial Reserves
FY 1993*



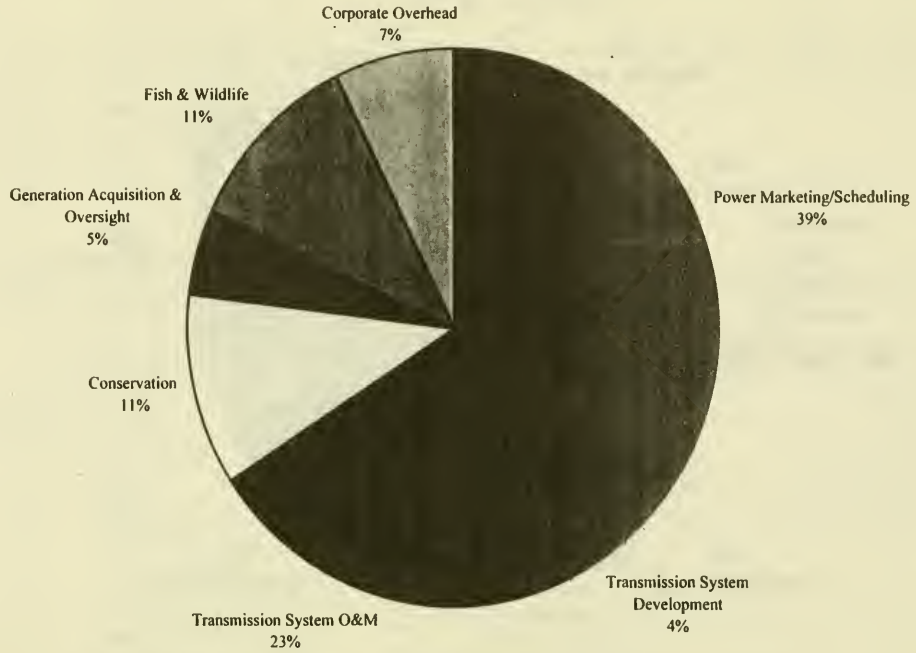
* = Projected End of Year Financial Reserves

Bonneville Annual Expenses



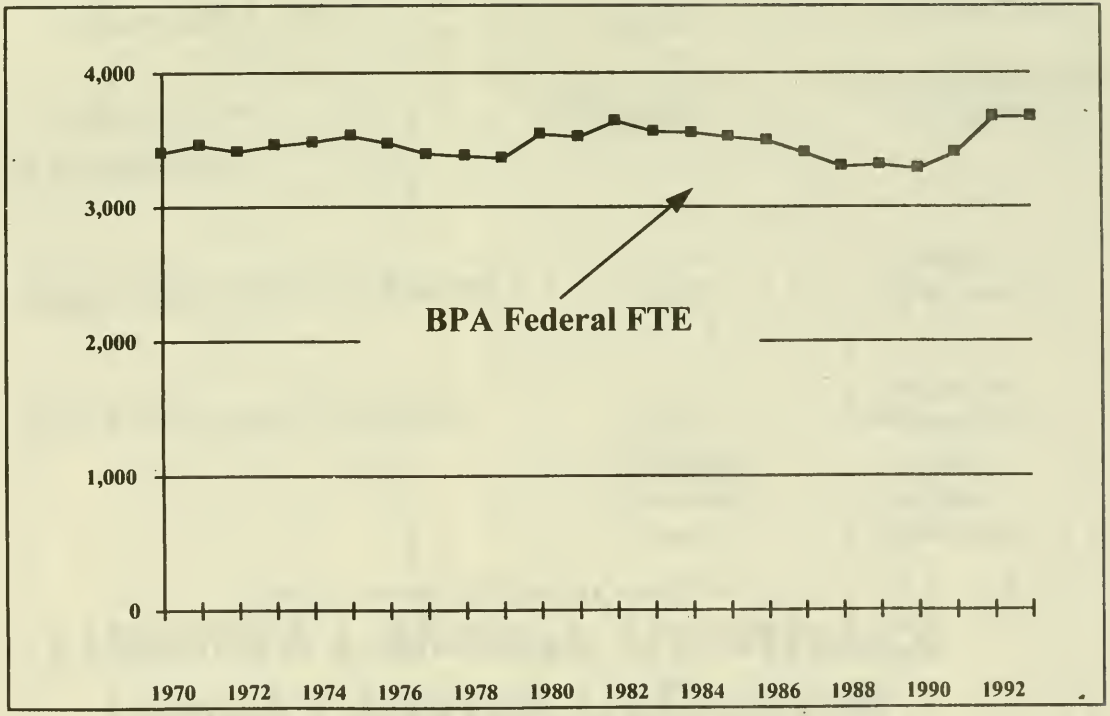
Total Annual Expenses
$2.4 billion

Bonneville Programs



BPA Current Operations
$560 million annual expense

Bonneville Federal Workforce



Policy Options Regarding Treasury Payment Assurance

Under Current Financial Conditions:

	Treasury Repayment Probability	Incremental PF Rate Effect
❒ Ten-Year Financial Plan	95%	Implementation Deferred
❒ 1993 Initial Rate Proposal	90%	-2.4 percentage points
❒ Alternatives:		
» Option #1; or	retain 90%	No change from Initial Proposal
» Option #2; or	85%	-1.7 percentage points
» Option #3	80%	-3.0 percentage points

Mr. HARDY. Bonneville faces probably the most extraordinary set of circumstances that it has ever had to deal with in its 55-year history. Basically, as a result of water condition changes in the last two to three months, our financial condition has deteriorated by over a quarter of a billion dollars. What I want to describe today, right now, are the near-term financial circumstances that we are having to cope with and our strategy for doing that.

Quite apart from the near-term circumstances, however, are a longer-term series of competitive issues. Mr. Chairman, you alluded to these in your remarks, and all I can say is, I fully agree that we have a series of mid- and long-term competitiveness issues that we have to successfully address if we are to remain a competitive supplier of low-priced electrical energy for our consumers in the Pacific Northwest. This near-term crisis simply highlights the need to take immediate action both in the near term and in the mid and long term to address those kinds of problems.

The first chart has to deal with the initial rate proposal that we made in early January of this year. We have a rate cycle of basically every two years. This rate increase will go into effect on October 1, 1993. The initial rate proposal was basically for an 11.6 percent rate increase. Its components were, as illustrated in the chart, basically fish and wildlife, resource acquisitions, conservation expenses, drought, and aluminum prices, and less than 1 percent being all other expenses. That is where we were as of early January.

In the months of January and February we had three things happen to us that dramatically changed our financial condition. First, we had a substantial drop-off in precipitation from the rest of the basin—John, if you could switch the chart.

This chart illustrates what has happened to us. This is as of April 1 for the water year which began on October 1, 1992. Basically, the legend here is: yellow and orange are below average rainfall; green and blue are above-average rainfall. So you can see that a good portion of the State of Oregon and southern Idaho are in reasonably good shape from a precipitation standpoint. But it just so happens that all of our major storage reservoirs, as illustrated on the chart—namely, Grand Coulee, Libby, Hungry Horse, Dworshak, Keenleyside, Duncan, and Mica—are all in the yellow or in the pink sections. Namely, those are all in areas that are well below average in terms of their precipitation.

We had the driest February of record in the Pacific Northwest. We have had the driest six consecutive water years of record, and the 1992/1993 water years are the second worst consecutive water years of record. Only 1944 and 1945 were worse, and the list of worsts or second worsts goes on and on relative to the set of circumstances in which we find ourselves today.

But low precipitation was only one of three things that happened to us in January and February. The second thing that happened was a dramatic cold snap in mid–January that both sent demand way up and dried up or froze up stream flows, so we had little or no inflow to the reservoirs.

Those three factors—dramatic drop-off in precipitation, dramatic drop-off in stream flows, and substantial increases in demand for

our product—caused us to make $170 million of unbudgeted power purchases in January, February, and early March.

In addition to those unbudgeted power purchases, we also suffered a revenue deterioration of about another $40 million because the snowpack was lower than we had predicted. Hence we would not have the same amount of revenues from surplus power sales to California and other utilities once the snow melted.

The net effect of those three actions—the increased demand and stream flow drop-off plus the low precipitation—was to have our revenue circumstances deteriorate by the quarter of a billion dollar figure that I just alluded to.

This next chart shows you, in a rate sense and in a dollar sense, what the effect of this change in circumstances was in January and February. These are all in addition to the numbers on the first page.

Basically, the drought, the dry water conditions, added 8 percentage points to the rate increase. Increased fish and wildlife expenses, primarily the increased cost of purchasing energy to provide storage for the 3 million acre-feet of water we are required to provide in the Columbia and the 1.4 million acre-feet in the Snake, cost a lot more because power prices went up. That added about another 2 percentage points to the rate increase.

Finally, worldwide aluminum prices deteriorated further, or the recovery looked like it was going to be postponed yet further. This added another 2 to 3 percentage points to our revenue shortfall. We receive about 25 percent of our revenues from our aluminum company customers.

The net effect of these three factors was to add 12 to 13 percentage points to the 11.5 percent initial rate proposal. Right now, if we were to do nothing, to take no other actions other than business as usual, we would be looking at a 23 to 25 percent rate increase.

When these numbers came together five weeks ago, I concluded that this level of rate increase was simply unacceptable for the region to accept and survive. So, we set about an exercise to go back and cut all of our budgets across the board to try to minimize the size of the rate increase.

What we have, I want to emphasize, is a revenue problem. Our expenses other than purchase power didn't change at all in the last three months, what changed was our revenue picture. That being said, the only tools we have to deal with this problem are on the expense side of the equation. So, we are using those tools to the maximum extent possible.

What I announced three weeks ago and what I directed the staff to do five weeks ago were three things: First, we are going to cut our administrative expenses by 50 percent for the duration of the fiscal year. Second, we are going to look to cut program expenses anywhere from 5 to 25 percent. Our basic programs are transmission, maintenance, fish and wildlife, conservation, and generation. Finally, we have started the process to terminate the two mothballed Washington Public Power Supply System plants, Plants 1 and 3, to realize the savings of some $10 million a year in preservation costs associated with those two plants.

I would now like to talk a little bit, given that we are moving in that direction, about what we have to deal with in our budget

so you get some feel for the order of magnitude of what is possible in terms of cutting the budget and its effect on the rate increase.

Next slide please, John.

I'm sorry, before we get to the pie charts, this graph simply illustrates in a graphic sense the sum of the previous two graphics.

A year and a half ago when I took over as Administrator, we had $900 million in reserves and were projecting that we would end fiscal year 1993 with over $1 billion worth of reserves. Today, given the circumstances that I have just described, we are projecting that we will end fiscal year 1993 with $90 million worth of reserves after we make our annual payment to the Treasury.

The significance of the $90 million figure is that that is working capital for us. Between the time that we make our annual Treasury payment on September 30 and the time utility power bills, which are our revenue source, start coming in the third week in October, the cash flow in those three to four weeks is $80 to $100 million in a typical October. So we are already in the cash flow range relative to making our annual Treasury payment.

I still remain confident that we can make that payment, but we do have exposures. If we have other unanticipated cost increases as a result of further worsening in weather conditions, further Endangered Species Act requirements, or other sorts of circumstances, that could impair our ability to do that. The graphic simply illustrates the causes of that deterioration in a graphic sense as opposed to a numbers sense in the $90 million reserve level.

Next slide, please.

This is the overall Bonneville budget. The point of this graph is, about 25 percent of our budget is our current expense budget. This is the controllable portion of our expense budget. I suspect our budget does not look unlike those that you have seen in the Federal Government.

We have a lot of fixed costs. The blue, which is 15 percent, represents Federal interest; that is the interest on the Federal debt from the dams and from the transmission system. The non-Federal debt service, which is 23 percent, is primarily WPPSS debt. Depreciation is 11 percent. The net cost of residential exchange is 8 percent. Finally, other entities, or basically Army Corps of Engineers and Bureau of Reclamation expenditures, over which we can request reductions but over which we have no realistic direct control, is 18 percent of our annual expense budget.

That leaves about 25 percent of our budget, that is what we call our current operations budget. That is the principal discretionary portion of our budget.

Let's go to the next slide, please.

This shows the current operations portion of our budget, some $560 million worth of expenses. Of this portion of the budget, 39 or 40 percent, the one labeled the green or orange segment—it is orange on the chart; I think it is green on your graphic; unfortunately, we have switched our colors here—is basically power purchases. This is weather driven. These are expenses, at least that I would argue, that are not discretionary. To the degree you start taking risks with these, you literally are taking risks with whether you are going to keep the lights on or not.

So, you have about 60 percent of our current operations budget that is the truly discretionary portion of our budget. That means we have about $340 million, give or take, to work with in terms of ability to cut our budget and have a meaningful impact on the rate increase.

Basically, on the expense side, $25 million equates to one percentage point on the rate increase. So the total budget is roughly equivalent 13 or 14 percentage points. A 50 percent cut in the current options budget would give you $170 million, or roughly 6 to 7 percentage points off the rate increase.

Next slide, please.

Mr. Chairman, this graphic shows permanent Bonneville Federal employment. There were a number of committee questions, about what our staffing levels have been. The point of this graph is that our overall employment has been roughly steady for the last 20 years. It has varied plus or minus 5 percent, around a median of about 3,500 employees, for the last 20 years. The low has been a little below 3,300; the high has been almost 3,700. Last year, in fiscal year 1992, we were at 3,667, and that is about the level that we expect to come in at this year. So, we have some fluctuations up and down, but basically we have stable staffing. That does not include contractor staffing or other kinds of staffing, and I suspect we will get into that in the questions.

Next slide, please.

The other principal tool, other than budget reductions, that we have to control the size of the rate increase is taking a somewhat greater risk on making our annual payment to the U.S. Treasury. Our long-term goal is to have a 95 percent confidence level of repaying Treasury. In the initial rate case proposal, we concluded it was too expensive to get there all in one rate case, so we lowered that to a 90 percent probability of repaying Treasury.

To decrease the size of the current rate increase, we could further lower that probability to 85 or 80 percent, and that gives you 1.7 and 3 percentage points worth of rate benefit, respectively. That is the other principal tool that we have. There are some others, like the level of working capital, but that pretty much runs out the tool kit of measures that we have to take this 24–25 percent rate increase and get it down into the range that is more acceptable. My goal is to definitely get it below 20 percent. The customers in the settlement discussions that you alluded to coalesced around a goal of 14 to 15 percent. We are working jointly to try to get to that goal. I am not sure whether we can make that much of a change, but we are clearly dedicated to getting as close to that goal as we can.

I might say one other thing, Mr. Chairman, anticipating a question, but drawing from your original opening statement. It is true, we did have settlement discussions with a number of the rate case parties two weeks ago. By the nature of the rate case process, only the parties to the rate case were allowed to be participants in those settlement discussions.

However, I would observe that those discussions included not just customers of Bonneville, but also included the Northwest Conservation Act Coalition, Northwest Environmental Defense Council, and other environmental groups. As a matter of fact, NCAC and

others made some quite constructive proposals around the concept of tiered rates and others. So, you had a larger spectrum of interest than just Bonneville's utility customers represented. That being said, it is true that by the nature of the rate case process only parties to the rate case were allowed to be participants in those settlement discussions.

That concludes my opening remarks, Mr. Chairman. I think it gives you a fair idea of where we are and our current financial circumstances. I would be happy to talk about that and talk about the longer-term competitiveness of Bonneville, or answer any other questions the committee may have.

[Prepared statement of Mr. Hardy follows:]

STATEMENT OF RANDALL W. HARDY

BONNEVILLE POWER ADMINISTRATION

UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE BONNEVILLE POWER ADMINISTRATION TASK FORCE

HOUSE COMMITTEE ON NATURAL RESOURCES

APRIL 28, 1993

Statement of Randall W. Hardy, Administrator,
Bonneville Power Administration
April 28, 1993

Chairman DeFazio, it is a pleasure to appear before the Bonneville Power Administration Task Force. In upcoming months, we look forward to a series of productive discussions on the challenges facing Bonneville today, and how we can work together towards meeting the Northwest's energy and environmental futures.

We face immediate and critical challenges. Our region is in the middle of one of the most critically dry water conditions in its history--a situation which will likely impact the Northwest for several years to come.

My testimony will focus on how this year's unprecedented events seriously eroded Bonneville's financial condition. I will also present the actions we are taking to restore Bonneville's fiscal health.

FINANCIAL SITUATION

Mr. Chairman, it has been an extraordinary year. When we put our 1992-93 rates in place, we anticipated having nearly $1 billion in reserves at the end of Fiscal Year 1993. At the present time, we are projecting a reserve level of about $90 million by the end of the fiscal year.

Recent developments are particularly troubling. In three months, our projected reserves eroded by over $250 million.

This dramatic decline has been driven by factors generally outside our control. Continued drought conditions, low aluminum prices, and Endangered Species Act costs have significantly reduced our net revenues compared to expectations when the rates were put in place in October, 1991.

The Northwest hydropower system is under its greatest stress ever. Streamflows between August and February were the lowest since 1925. The last two years have been the second worst consecutive water years in Bonneville's 55-year history. Only the years 1944-1945 were worse. Continuing drought conditions are causing severe reductions in the operating levels of Federal reservoirs. And, it is becoming increasingly expensive to store water to aid the spring juvenile migration of threatened and endangered salmon.

Drought conditions impact Bonneville in two key areas--reduced revenues from sale of nonfirm energy and surplus revenues and increased purchase power costs to cover our firm load and fish flow obligations. Both have contributed significantly to the decline of our forecasted net revenues.

Drought conditions are not the sole cause of our financial difficulties. The region's aluminum industry, which provides about one-fourth of Bonneville's revenues, is suffering from continued low aluminum prices. Because Bonneville's revenues from the smelters are tied to worldwide aluminum prices, we have been impacted as well.

As our contracts require, the drought forced us to restrict 25 percent of the interruptible portion of aluminum companies' loads in order to meet the firm power needs of all our region's customers. Regretfully, this put people out of work, damaging the region's economy.

The listing of three species of Snake River salmon as threatened or endangered has also had a deleterious effect on our net revenues. Much of the costs of measures to protect listed salmon is associated with changing the hydrosystem's operation to increase streamflows. The cost of implementing these measures is significantly increased in years when streamflows are low. For example, the cost of meeting our Columbia and Snake River flow obligations for these listed species is roughly $110 million in 1993.

Unfortunately, this year has illustrated our extreme sensitivity to weather conditions and aluminum prices. Our system planning incorporates flexibility and safety to ensure reliable system operation; however, the number of severe and unusual simultaneous events occurring this year is clearly unprecedented.

Should our projected revenues be hammered further by unanticipated events such as extended drought conditions, or the loss of a generating facility, this could seriously impact our ability to make a full Treasury payment this year.

Last year, as the potential for a large rate increase became clearer, Bonneville conducted it's public budget review process, Programs in Perspective. As a result of Programs in Perspective, we reduced costs by $270 million and were able to reduce an 18 to 20 percent projected rate increase to the 11.6 percent initial rate proposal announced in January.

The events of the last three months, however, have put us in a crisis situation. Due to the continued drought conditions and depressed aluminum market, we are now estimating our rate increase will be significantly higher--substantially in excess of 20 percent if no further action is taken. In addition, we are in the "danger zone" concerning our ability to make a full Treasury payment this year. These levels of Treasury payment risk and rate increase are simply not acceptable.

COST REDUCTIONS

Extraordinary measures are needed to meet this extraordinary situation. To meet this unprecedented situation, we are taking three immediate actions.

First, we will cut administrative costs by 50 percent for the remainder of fiscal year 1993. We will do this by:

- Limiting travel;
- Eliminating most training;
- Reducing use of overtime;

- Cutting office supply purchases;
- Limiting use of support service contracts; and
- Reducing temporary and on-site contractor employment

Second, we are examining reductions in our programs in fiscal years 1994 and 1995 ranging from 5 to 25 percent. The principal program areas affected would be transmission system development, operations and maintenance, energy resources (both conservation and generation), and fish and wildlife.

While we have not made any final decision, I have given Bonneville staff two guidelines. First, seek to reduce levels of program increases or flatten out these programs, but do not look for absolute reductions from fiscal year 1992 program levels. In a word, "cut, but do not gut" our principal programs. Second, try to achieve rough equity among our four major program areas.

Finally, we have already initiated efforts to terminate Washington Public Power Supply System Nuclear Plants 1 and 3. These plants are currently mothballed at an annual cost of roughly $10 million. Savings from their termination can probably start to be realized in fiscal year 1995. In addition to preservation cost savings, it is prudent to terminate these plants because their 40 mill cost to complete is substantially above the acquisition cost of plentiful conservation and gas-fired resources in the Northwest.

Presently, we do not know how much specific areas will be cut, especially from our fish and wildlife, resource acquisition, and transmission programs. However, I can assure you that across the board, we are taking a very close look and will be taking immediate actions. We will deliver final program decisions in June.

There are, however, limits to our ability to make significant cost reductions. Approximately 85 percent of our budget is either fixed costs or is controlled by entities other than Bonneville, or purely weather driven.

In identifying potential cost-cutting opportunities, we will continue to work closely with our customers, the Northwest Power Planning Council, and other regional parties. We would welcome the Task Force's input into establishing priorities for our cost-cutting activities.

PROGRAMS IN PERSPECTIVE

I want to take this opportunity to point out that Bonneville goes to great lengths to assure that its programs, which are ratepayer funded, serve Northwest interests. In 1987, we established Programs in Perspective to involve Bonneville's stakeholders in the agency's strategic directions and specific program planning. This annual process creates a forum for determining the priorities for spending regional ratepayer dollars.

Through Programs in Perspective, Bonneville has established a history of broad-based, regional, public participation. The process draws together all of Bonneville's planning processes into a single package of program descriptions and budgets. These discussions contribute significantly to our final program decisions. The budget which was submitted to the Congress reflects input from this regional process. It is a proven link involving over 500 regional parties. It has been a model program for others in both the U.S. and Canada.

The dialogue borne through Programs in Perspective will also assist in defining a new long-term goal of our highest priority--competitiveness.

COMPETITIVENESS

There is an immediate need to cut our programs given the fiscal crisis we face. But, we have also embarked on a new longer-term program to improve Bonneville's competitiveness. Our plan is to become more market-driven, customer-focused, cost-conscious, and results-oriented. While recognizing our unique social responsibilities, as a Federal agency, we will apply sound business principles to good government.

To achieve this, we are first looking at ways to become more efficient. We will seek out greater efficiencies in existing processes and programs. We will look for added value from new products and services. And, we are eliminating activities no longer needed.

We will also move to "unbundle" our power products and transmission services. Our goal is to provide greater variety and more customized services to better match customers' needs and the markets they serve. Possibilities will include different types of transmission for different voltages, load-shaping, storage, and transmission and integration services. Bonneville will also examine and consider multiple rates for multiple products—concepts such as tiered rates will be explored as well. Everything will be on the table.

CONCLUSION

We will continue to work closely with Congress, the region, our customers, and other parties to address these short-term financial difficulties—and more importantly, our long-term strategy to remain competitive in the changing Northwest energy markets. I am confident of our determination to regain Bonneville's fiscal strength and help stabilize the Northwest economy. We will work closely with you and the committee in defining Bonneville's role for the next decade.

This concludes my statement, I would be pleased to address your questions.

Mr. DEFAZIO. Thank you, Mr. Hardy.

I would first recognize Mr. Thomas if he has any opening remarks.

Mr. THOMAS. No, thank you, Mr. Chairman.

Mr. DEFAZIO. Thank you.

We will proceed to questions, and we will try and hold to the five-minute rules, and I would expect multiple rounds. I could fill up a lot of five-minute segments. So we will begin, and I will take the first five minutes on the settlement discussions.

The concern is that you formulate a two-year budget, the Council has put forward a program independent of that in but response. You develop a budget; the budget is cleared through, I guess, DOE and OMB. The concern and part of the reason for holding this hearing is that as you get into rate settlement—and, again, we are not going to discuss the pending rate case or your intentions therein—but the point is that it seems that policy is potentially made by financial decisions. I am just concerned that we don't break the link here between accountability outside of the agency to the Council or outside of the region to the Congress and to the administration in those sorts of discussions. I might just leave it at that. If you want to comment on that, you can. Otherwise, I will go on to other questions.

Mr. HARDY. I would say I agree with you, Mr. Chairman. I assume that that is one of the purposes of this hearing and of succeeding hearings.

I might also observe that in making these program reductions, particularly in the conservation, generation, and fish and wildlife area, we are working very closely with the Power Planning Council to try to make sure that we keep that linkage between policy and our current financial circumstances as tight as possible.

As a matter of fact, the Council is holding a hearing tomorrow on the Northwest on just this subject. I expect the hearing will be very well attended, and we will have a very spirited debate. We have encouraged the Council to do that, and they were, as a matter of fact, the first group that I sat down with once I concluded that I needed to do something of this nature to try to make sure that we, to the maximum extent possible, could go down this road together.

Mr. DEFAZIO. The airlines love us for scheduling these things this way. I assume a lot of the audience will be back there for that hearing tomorrow, although I guess you will be here for other hearings.

Mr. HARDY. Yes, sir.

Mr. DEFAZIO. Just a couple of comments before I get to my formal questions.

When you talked about your scope of control and you were talking about the pie chart and pulled out your 25 percent, which does, in fact, to some extent, mirror the Federal budget when we talk about entitlements, but I am curious on a couple of points. We have the other entities, the Corps and Bureau, and you said you could request reduction but you have no control. Have you anticipated or entered into any discussions with them to deal with that?

I don't know, are they that whole 18 percent, or does some of that 18 percent—where does WPPSS operations come in? We have

got non-Federal debt service, which is 23 percent. I understand that; residential exchange; Federal interest. Where do you put WPPSS operating costs? Is that on other entities, 18 percent? Is that in there? I am just curious. What is that 18 percent block?

Mr. HARDY. I believe WPPSS operating costs are part of that, along with the Corps and the Bureau, and those are the three principal factors associated with that.

Mr. DEFAZIO. Okay. Then I would just like to have a brief discussion of that. First off, have you thought about, considered, entered into discussions with the Corps or the Bureau regarding their share of that and seen whether or not there are any potential reductions there given the extraordinary circumstances that confront you?

Mr. HARDY. Yes, we have. We have both done that at the assistant administrator level and at my level, and I am anticipating we will get some reductions from both of those agencies. I don't expect it to be a huge amount, but they are trying their best. The Bureau in particular has been quite forthcoming in trying to present us with some savings. We have deferred at least one capital project that we otherwise would have directly funded at Hungry Horse. That I think will provide us with some savings, and we are looking for other savings as well.

Mr. DEFAZIO. Yes, I would urge you to be aggressive in dealing with your fellow agencies, and maybe I will get a look at some of their costs in more detail.

My understanding is that the Administrator does have a right of review of the WPPSS expenses. Do you agree with that statement?

Mr. HARDY. Yes.

Mr. DEFAZIO. You have a right of review and——

Mr. HARDY. We have a right of review of the Supply System expenses. We have made the same request of the Supply System, and we are actively working with them to try to identify those savings. They are in the process of doing that, and at least the figures I saw at the Supply System executive board meeting last week would indicate that there are several million dollars of savings in the current operating budget that are available. We are aggressively pursuing those with their cooperation.

Mr. DEFAZIO. In your formal responses you did note that WPPSS was at the high end in terms of single plant operating utilities in terms of their per-unit costs.

Mr. HARDY. That is correct.

Mr. DEFAZIO. What sort of scrutiny do you give to their budget? Do you have a detail of staff that goes over their budget, or how do you review their budget, their submission, their costs?

Mr. HARDY. We have about a 10- or 12-person staff that is permanently on site in Richland that not only reviews their budgets but basically is into all aspects of their operations. So we are working with them on a continuous, day-to-day basis. One of those Bonneville staff people is an auditor who participates with Supply System staff and with their independent commercial auditor to audit those expenses. We track and monitor that quite closely.

The Supply System has just hired a new managing director, and I am optimistic that he is the kind of turnaround manager that will help us produce even greater savings. I can tell you that in the few

interactions that I have had with him, his observation has been, at least on first blush, he thinks there are some significant staff savings available in the Supply System, and he intends to pursue that.

Mr. DEFAZIO. So he is going to earn his quarter of a million a year?

Mr. HARDY. I would hope he would and then some.

Mr. DEFAZIO. That is good.

Mr. HARDY. I guess his observation was, he ran a very similar utility in Texas where the staffing was considerably less than is at the Supply System, and I suspect he will pursue that aggressively. I expect him to, and the Supply System board expects him to.

Mr. DEFAZIO. Perhaps a good first step would be to say that you, in fact, given your extraordinary circumstances, find their request too high and ask them, since you—and I will get into this a little later—but since you are considering across-the-board cuts, that you recommend that they consider across-the-board cuts. I think it is $240-some-odd million, their operating expense.

Mr. HARDY. $242 million a year.

Mr. DEFAZIO. Right, and we have the figure that—what was it?—$25 million rates increase by 1 percent?

Mr. HARDY. Right.

Mr. DEFAZIO. So if we could get a 10 percent reduction there, we could pick up a percent. A percent here and a percent there, and pretty soon you have got real percents.

My time has expired, but I will get back to this. I want to recognize other people so that I don't carry on at too great a length.

Mr. Smith.

Mr. SMITH. Thank you, Mr. Chairman.

Mr. Hardy, I am interested in the irrigation discount as well as the heavy industry discount like you give to aluminum production folks. First, how much impact does the irrigation discount have on your budget?

Mr. HARDY. It is about a $13 million impact. That was the amount of the discount in 1992, I believe. That is about a half a percent.

Mr. SMITH. A half of 1 percent.

Mr. HARDY. Half of 1 percent; yes, sir.

Mr. SMITH. And the heavy industry discount?

Mr. HARDY. It is not a discount, it is what we call a variable rate.

Mr. SMITH. It is on the price of aluminum.

Mr. HARDY. Right. It varies not only with the cost of power but also with the price of aluminum. So it has a slope to it. The base rate floats up and down with the cost of power, but where you are on the slope depends on what the world price of aluminum is. Right now, because the world price of aluminum is so depressed, the industry's rate is 18 mills, which is the lowest it can get under the current rate structure.

Mr. SMITH. And what was it at its peak?

Mr. HARDY. At its peak, I believe it was in the range of 26–27 mills. Our priority firm rate is 23.5 mills. So it was considerably above that.

I guess the point I would make, Congressman Smith, is that in the five or six years since the variable rate was initiated we have about broken even. When aluminum prices were over a dollar a

pound in 1988 and 1989, we made a lot of money, a little over a quarter of a billion dollars. We basically now have lost that, if you want to look at it that way, and we are about even.

However, the rate has probably kept on line some plants that otherwise would have gone off line. In that sense we are probably, in a net sense, ahead for having instituted the rate.

Mr. SMITH. I want to get into this long-term competitiveness issue. I think you mentioned it, and I want to talk about it a minute, because we are faced here with not only your needs for revenue enhancement but also the question of how, with the Btu tax, we keep our aluminum industries competitive, and I notice that you have mentioned in an *Oregonian*-reported statement that the proposed energy tax on top of your proposed rate increases could force utilities to abandon energy conservation programs. Do you want to comment on that?

Mr. HARDY. I am a loyal member of the Administration, and I support the Btu tax. Honestly, I have gotten myself in some trouble because I have concerns, but I guess those are handled by forces that are beyond my control.

Mr. SMITH. I understand the OMB, and I know how it operates, and I understand your loyalty, and I am not trying to interfere with that, but am trying to get your expert opinion about the long-term competitiveness of rates in view of the increases that you have established here you need, plus the increase that may occur if there is a Btu tax.

Mr. HARDY. Let me describe to you in a factual sense, Congressman, what the compounding effect would be, and then everybody can make whatever value judgments they think are appropriate.

I have just described to you a rate increase that, if we do nothing, is 23 to 25 percent. We have described in these settlement discussions, which the chairman referred to earlier, an ability to get that down around 20 percent. Our customers want it to be in the 14–15 range. Absent any other things going bad, we are probably in that 15–20 percent range.

The Btu tax, if passed in its present form, would add 10–12 percentage points just in and of itself to Bonneville rates. In 1995, we will be looking at another rate increase. I can't project with any high degree of confidence what that rate increase will be, but it probably would be in the high single digits.

So you could look at a three-year period of time where you could easily draw up a scenario of a 40 percent or more increase in Bonneville rates as a result of forces that are already existent in our rate structure, be they water or Endangered Species Act or low aluminum prices or external forces in the form of a Btu tax or potentially repayment reform or other kinds of initiatives. I think it is a pretty factual statement that those would have a serious competitive impact not just on the aluminum industry, but on the irrigation industry and on a number of other Bonneville customers.

Mr. SMITH. I appreciate that.

This question of reservoir drawdown is something that is in the experimental stage at the moment, I understand, and there is questionable science about whether or not it saves salmon or doesn't. But what are your views on the drawdown issue, and what

are the costs that might be associated with the drawdown as we have known it has been discussed at least?

Mr. HARDY. We are not opposed to drawdown. We would like to see some form of biologic test before we commit to the large expenditure that would be involved. In fact, we, the Corps and the National Marine Fisheries Service are working with the recovery team and others to try to design just such a test. We are kind of a third party in this. It is much more the Corps and the National Marine Fisheries Service that have taken the lead. We have fully endorsed that effort, I think, that is potentially scheduled for 1994.

In any event, I think some test of the biologic validity would be extremely helpful, and we clearly think that issue needs to be addressed as part of the long-term recovery plan for salmon that the NMFS Recovery Team is currently working on. We need a yes or a no, or more likely, a biologic testing road map to get to yes or no on drawdown, and I am hopeful that will be the outcome.

The costs of the drawdown proposal, as currently laid out by the Corps, plus the power impacts would probably amount to another 5–10 percent rate increase for Bonneville. I should emphasize that that is a rate impact that doesn't occur until well after the turn of the century. I mean it takes you probably on the order of 14–15 years or more to actually do all of these things, so you don't feel the full impact of that in a rate sense until probably between the years 2005 and 2010. So it is not an immediate thing, but clearly it has competitiveness and other implications in the long term.

Mr. SMITH. In dollars, what are we talking about?

Mr. HARDY. I would have to answer that question for the record. The Corps has estimated that the dam modification costs alone range from $1.3 billion to $4.9 billion. There are also power impact costs in addition to those, and I would have to get those and answer that for the record.

Mr. SMITH. All right. Thank you. I wish you would. Thank you.

[The information follows:]

Power impact costs associated with operating all four lower Snake River projects to near spillway crest from April 15 to June 15 were analyzed for the 1992 Columbia River Salmon Flow Measures Options Analysis Environmental Impact Statement. Drawdown is to occur April 1 to 15 and refill by early July. The annual cost for lost firm energy is estimated to be $72 million per year and lost firm capacity is $32 million per year. Lost non-firm energy is estimated to range from $21 million to $55 million per year. The lost capacity may not affect the ability to serve Northwest peak loads, but may affect the ability to market capacity. These impacts are based on not operating turbines once the reservoir level is reduced below the point that turbine screens can no longer deflect the fish away from the turbines. If the turbines were kept in operation, BPA estimates that impacts would be in the neighborhood of about half of the above estimates.

Mr. DEFAZIO. I thank the gentleman.

I would like to recognize that we have been joined by two colleagues, but first our colleague from Washington State, who is not a member of the committee but asked permission to sit today, given the vital concern of Northwest Members, and we welcome him.

We are going through a round of questions, but if the gentleman had a brief opening statement we would take that now.

Mike, do you have one?

STATEMENT OF HON. MIKE KREIDLER

Mr. KREIDLER. Thank you very much, Mr. Chairman.

I do have an opening statement. What I would like to do is perhaps enter it into the record so that we might proceed with questions that are probably most germane to this committee's activities.

Thank you very much for allowing me to attend.

[Prepared statement of Mr. Kreidler follows:]

STATEMENT OF CONGRESSMAN MIKE KREIDLER

I'd like to thank Rep. DeFazio for allowing me the opportunity to sit in on this task force meeting. Obviously, the deliberations of this task force are important not only to the Natural Resource Committee members, but to all the members of the Pacific Northwest delegation. I appreciate Rep. DeFazio's acknowledgment of that fact, and look forward to attending and perhaps participating in future meetings of the task force.

I am pleased to be able to comment on Bonneville's current financial situation. I understand that the original intention of the task force was to address long-term issues affecting Bonneville's operations at the end of this century and beyond. However, if we do not mitigate this short-term crisis there may be no "long-term" issues for the task force to confront.

I, like others in the delegation, am very concerned about the combined impact of drought conditions, fish mitigation measures, lower aluminum prices, debt repayment, and possible energy taxes on Bonneville and its consumers. We have already seen some of the impacts reflected in Bonneville's need to increase its initial 1993 rate proposal.

I understand that Mr. Hardy is making efforts to keep the total rate increase below 20%, including cutting administrative costs in half, shutting down two "mothballed" nuclear plants, and reviewing all programs for an unprecedented second time. I support these general objectives, but am concerned about what this means when it comes down to specific numbers.

My main concern is that as part of this review, important programs in the Fish and Wildlife and Conservation sectors will be significantly cut. I understand that since there are not many discretionary programs from which Bonneville can make cuts this a very difficult issue to resolve. However, it makes little sense to make short-term cuts in programs that will cost us more in the long-run. In fact, making cuts in these programs now may incur additional costs in the future which would *not* have occurred had these programs been preserved.

I would like to explore methods by which Bonneville can lessen this additional rate increase request without damaging significantly its ability to meet its obligations to the Federal Government and others. At the appropriate time, I'd like to ask Mr. Hardy for his thoughts on alternative approaches to resolving this problem, including: drought surcharges; cutting back or eliminating irrigation assistance; allowing a rate increase of slightly more than 20%; turning more conservation responsibilities over to BPA's customers; reviewing and changing contracts that are not cost-effective; and cutting all acquisition and development of new, traditional power generation for a few years while focusing more on conservation and renewables.

In addition, I'd like your thoughts on whether a viable long-term solution to Bonneville's fiscal problems could include granting more financial oversight authority to the Northwest Power Planning Council to ensure that Bonneville's financial condition does not deteriorate further.

Again Mr. Chairman, I'd like to thank you for holding this hearing and I look forward to talking further with this witness.

Mr. DEFAZIO. Thank you.

We have been joined by another Northwest Member, Mr. Williams.

Mr. Williams, do you have opening remarks you would like to make at this time?

STATEMENT OF HON. PAT WILLIAMS

Mr. WILLIAMS. I, too, would like to get to questions, Mr. Chairman, but I can't help but visit with Randy just a little bit being as I have a minute.

I know that this is a very difficult time for BPA and that you have an extraordinary set of circumstances within which to operate the power system this year between the drought and efforts to maintain Northwest fisheries and the need to purchase additional power. I think you and Bonneville are between a rock and a hard place.

I want to commend the task force for having this hearing and commend you, Mr. Hardy, for accepting our invitation to be with us and would ask that an opening statement be put in the record and would conclude, Mr. Hardy, by just making this point. You and I have visited about this personally, and you have always been very generous with your time with me.

When it rains, those of us in the headwaters are expected to keep the water, when it rains a lot, in flood time. When there is a drought, we are expected to give it up. We have vital fisheries. When the fish downstream are in trouble, our fisheries, for the most part, are expected to suffer. I don't know that that is BPA's intention, I think it isn't, but our scientists tell us that is the result of what would happen given certain proposals if they were carried out.

We took the dams. I guess back then we were glad to have them. We gave up the land. We ruined a lot of the great and wonderful scenic waterways. We ended forever the scenic beauty of many of the canyons. We would like to know that in heavy drought years we can keep some of the water in payment for those things given up. We would like to know that the bull trout of Montana are on a par with the salmon downstream, and we are hopeful that this can be worked out by you, who, again, I know you are between a rock and a hard place. But from my part in Montana I make you this deal. If you will work out these problems and others that I will have in my opening statement—and I will send it to you, Randy—if you will work out those problems in Montana, we promise to make it rain. [Laughter.]

Thanks, Mr. Chairman.

Mr. DEFAZIO. I thank the gentleman.

Now, Mr. Sharp.

Mr. SHARP. Thank you very much.

Mr. Hardy, you indicated that while this is a hearing on the immediate financial situation that you are struggling to deal with, that you are open to discuss some of the longer-term problems, and I wonder if you would take a couple of minutes just to identify for us, those of us especially who are not recently very familiar with what has been happening, what you see over the next 5, 10, 20 years as the sort of key issues that you have to deal with.

Mr. HARDY. I would be delighted to, Mr. Sharp. Let me try to sketch this out. This has implications not just for Bonneville, but I think the picture I will sketch is pretty similar for the electric utility industry nationally.

I see us facing three factors that fundamentally affect our long-term competitiveness. Factor number one is what is going on here in Washington, DC. We are going to reinvent government, in the phrase of the day, and the conclusion that I have reached is, Bonneville had better reinvent itself in a way that is consistent with the objectives of the Clinton Administration to be a leaner, more

customer-focused organization, or we are going to have serious problems, and I think that is entirely appropriate.

But with repayment reform issues that affect us, btu taxes, federal FTE employment restrictions and reductions, all of those things are things that will affect us nationally, we have to restructure ourselves to be responsive to that set of governmental imperatives that are starting to move that affect us and affect all industries to a significant extent.

The second factor is one that is unique to the electric utility industry. This industry has been a series of regulated monopolies for its entire 100-year existence, and that is now going to fundamentally change. As a result of the bill the Congress passed last year to deregulate transmission access, we are already deregulated at the generation level. Deregulation at the transmission level is rapidly coming, and we only have to look to what the airlines and the gas companies and the banks and the phone companies went through in the 1980s to get some picture of the amount of competitive change that is going to occur in this industry as a whole in the 1990s.

Bonneville is not unlike any other major utility; we have to be equipped to respond to that kind of new and very different competitive challenge. Simply leveraging our monopoly power and our transmission system and our hydro system is no longer going to be sufficient to enable us to remain competitive in that kind of rapidly changing environment.

The third portion of this that is important is our customers' competitiveness. It is not just the aluminum companies, it is Boeing, it is Weyerhaeuser, it is major industrial customers and commercial customers of most of our retail utilities. Most of them are competing in a global marketplace. Whether it is paper or aluminum or airplanes or whatever other commodity or product you are talking about, there is much keener competition. That makes them much more sensitive to our price increases as a major segment of their operating costs. To keep them competitive in earning revenues that will basically pay our bills, we need to keep our rates as low as possible.

So I see those three factors all creating significant long-term pressures on Bonneville and, frankly, on most utilities across the Nation that we have to cope with.

In the past, Bonneville has tried to be all things to all people in the region. Our customers have an analogy that is pretty apt. They call us the punch bowl. Every customer and most of the interest groups have a straw, and he or she who has the biggest straw and sucks the hardest and the fastest gets the mostest.

Unfortunately, that has been all too true, and we have played that role. We have tried to please all parties and balance all interests. I have concluded we can no longer continue to do that and remain competitive. We need to move from being a kind of beneficiary-focused, process-oriented organization to being a more market-driven, customer-focused, cost-conscious organization. We need to make that movement towards a more businesslike posture without abandoning our social responsibilities for fish mitigation and environmental protection. We need to be more selective about the investments that we make, and we can't be all things to all people.

We have adopted a competitive statement and a strategy of about 10 or 15 pages that lays out a concept of where we want to go, but it basically involves two things. First, we have to become much more efficient. Not efficient in the sense we are describing here today of just squeezing the grape and cutting the budgets; we have to go through a fundamental structural change to look at making ourselves more efficient. That probably implies staffing reductions. It implies a lot more fundamental changes in how we deliver programs and our services. Secondly, to use the utility jargon, we have to unbundle our services.

Basically, we have one product right now. It is plain vanilla PF bulk power. We deliver it to everybody, and we load all of our costs under that one product. That is a little oversimplified, but not much. That may work for a small co-op in eastern Oregon or eastern Washington. It is not a particularly attractive product to a generating utility privately or publicly owned. We need to break apart our products and services; we need to market our storage, our load factoring, our other transmission integration services, shaping all of these different services that we are uniquely equipped to provide. We provide them now. Sometimes we charge for them, sometimes we don't, but we don't market them as separate products.

From my perspective, we don't collect nearly the value we should from those products, and we don't serve our customers very well because we are not marketing in a discrete sense to try to meet the individual needs of individual customers. We have to do that.

Probably the final thing that is implied in this is, we have to look at subsidies in our existing rate structure or things that are arguably subsidies—variable rate, irrigation discount, low-density discount. I am not saying we are necessarily going to do away with them, but we clearly have to examine whether those are still appropriate given this kind of competitive environment that we face.

Finally, we have to look at other rate structure changes. The chairman has expressed an interest in two-tiered rates at the wholesale level. We are going to actively investigate that concept. If we were to adopt a two-tiered rate, I believe we would be the first utility probably in the country to adopt a two-tiered rate at the wholesale level. There are significant equity and revenue stability questions involved in that, but I have concluded that we need to start moving in that direction so we have a combination of program incentives and price signals.

We need to do all of that, and that is what our competitiveness project is designed to do. Those are the challenges that I see in the strategy that we have tried to scope out to meet those challenges.

Mr. SHARP. My time is about up, but I appreciate that very concise overview and at some point will want to get a little better understanding of the interplay between the new transmission access requirements and BPA, which I think is actually treated somewhat differently than most of the rest of the country on that, as one who is very much involved in advocating that.

But I think what you are saying is very important for lots of people to hear, because that kind of change is oftentimes very upsetting, especially when you use the analogy—which I understand doesn't quite accurately fit—of the punch bowl, that what has, I assume, been brought more to the table, is who really benefits, who

doesn't, who is getting subsidized, and whether those are values today that we wish to go forward with.

I mean not everybody is going to want to get rid of every kind of subsidy that is in the system, but we are going to, in a sense, flesh out in the open, and that undoubtedly leads to some very difficult times for you folks and for the public at large as that gets sorted out again. But I appreciate your very concise view of things. Thank you.

Mr. DEFAZIO. I thank Mr. Sharp for his remarks.

The Administrator and I had some discussion of this in the interrogatory phase beforehand. What we agreed on was that this is a public entity and everything is going to be on the table, even if just by asking some of these questions I make people uncomfortable or other members of the committee make people uncomfortable.

You know, you have to learn to live with it because we want to make our decisions about the future with full awareness of all the implications for all the customers of the utility, and I think the Administrator is aware of that and, I think, in fact, supportive.

Mr. Thomas.

Mr. THOMAS. Thank you. Just a couple of questions.

Do you have criteria for to whom you sell power, as most of the other Power Marketing Agencies do? Are they nonprofits? Are they municipals? Are they co-ops? Or are they anybody that is in your area?

Mr. HARDY. We have several pieces of legislation, Mr. Thomas, that govern whom we sell power to and what kind of priority or preference they get. Like the other Power Marketing Agencies, public preference requires us to give first priority in power sales to publicly owned utilities, both municipals and co-ops. We also have long-term contracts to sell directly to 15 major industrial customers, primarily aluminum companies.

We don't make any significant wholesale power sales to the investor-owned utilities in our region. However, we do provide them with a variety of transmission services. We also make surplus power sales to California utilities and other out-of-region entities. Those are governed primarily by the Transmission System Act, what is called regional preference, where before we can make any sale to a California utility or an out-of-region utility we have to offer that same amount of power for purchase within the Northwest first.

Mr. THOMAS. Do you have an average wholesale rate?

Mr. HARDY. Yes. Our average wholesale rate is roughly 24 mills.

Mr. THOMAS. Compare that to the other Power Marketing Agencies.

Mr. HARDY. It is, I believe, lower than the other Power Marketing Agencies. I don't know what——

Mr. THOMAS. Quite a bit lower, isn't it?

Mr. HARDY. Yes, it is.

Mr. THOMAS. You don't know what the others are?

Mr. HARDY. I am not familiar with the exact rates of each one of them right now.

Mr. THOMAS. Who pays for the changes in both capital and operating for fish and wildlife? Does that come out of power revenues?

Mr. HARDY. Yes, sir, it does.

Mr. THOMAS. All of it?

Mr. HARDY. Most of it does. In the case of some fish enhancements that are done by the Corps and the Bureau, some portion of that, but usually a pretty small portion, comes out of appropriated funds, but typically anywhere from 70–90 percent comes from Bonneville funds, and then almost all the other fish program measures are ones that we directly fund. So probably 90-plus percent of all of it comes out of power revenues.

Mr. THOMAS. Do you have full supply contracts with all these people?

Mr. HARDY. Yes, we do.

Mr. THOMAS. If you were a regular commercial utility—of course, the drought is a problem, but you have more problems than drought—what would you be doing? In other words, you don't have the power supply now, do you, to meet the needs of all these customers?

Mr. HARDY. Right now we do, but we have interrupted the top 25 percent of the aluminum company loads, which contractually we are allowed to do to try to preserve our ability to serve the firm loads of all the rest of our customers. We have enough power to basically keep the lights on and meet the loads, but we have only been able to do that this year because of a significant amount of out-of-region spot market power purchases that we have made from California.

Mr. THOMAS. I guess I am interested philosophically in whether or not a public entity like Bonneville has an obligation to meet the needs of all these folks and whether or not over a period of time you are generally a hydro producer and that is what you sell, or do you intend to go back into coal generating and those kinds of things?

Mr. HARDY. We have the obligation to meet all of our customers' electric load low growth requirements, and in that respect we are fundamentally different from other Power Marketing Agencies.

Mr. THOMAS. Why do you?

Mr. HARDY. Because the Northwest Power Act that passed in 1980 gave us the obligation to meet the load requirements of all of our current customers, we are in the business of acquiring resources to meet those load requirements.

Mr. THOMAS. Have you acquired new customers since that happened?

Mr. HARDY. We have acquired a few minor new customers, some small public agency customers that have formed, but no significant new customers. Our typical customer base of our firm power customers is about 155 customers: roughly 120 public agencies, typically small utilities that take all of their power from us; 6 investor-owned utilities, which typically don't take a lot of bulk power from us but take a variety of transmission services; and, finally, 15 direct service industrial customers, primarily aluminum companies, that take all of their power directly from us.

Mr. THOMAS. I see.

As you know, we have just one of your customers in Wyoming, Lower Valley Power and Light, and they are interested in providing gas utility service to their area. Do you have any role in that?

Mr. HARDY. We potentially could have a role, and we are working with Lower Valley to try to see if there is a set of arrangements that can be mutually beneficial to Bonneville and to Lower Valley, and I am hopeful that those will work out.

Mr. THOMAS. Thank you.

I think you have a tough task, and one of them, it seems to me, for many of us, is to really define the role of a public power agency. It is different, and it is changing, as you have suggested, and it would seem to me that seeking to define that in fairly long-range terms is kind of the first step of where you go when you make major changes.

Mr. HARDY. If we could come out of these six hearings with some sense of direction on that, that would be extremely helpful to me.

Mr. DEFAZIO. I thank the gentleman.

If I could just address one of the questions you raised, which was about other PMAs, I chaired the hearings on WAPA for the chairman in the last Congress and took the lead in putting that portion into the energy bill, and my recollection is that WAPA has a rate that varies across the region by project, and it runs between 15 and 30 mills, so in some places actually their PF rate is lower than BPA's and in others it is higher. They don't blend it the same way BPA does and give everybody the same rate. I think mostly Mr. Thomas' people are subscribing to WAPA.

The second thing is that WAPA, with the Pick-Sloan project, has gone to tiered rates. I don't know whether it is a model or not, but it is certainly something to be aware of.

At this point, what I am going to do is run and vote. I am going to give the gavel to Mr. Williams, and it will be Mr. LaRocco's series of questions. I will be right back.

Mr. LAROCCO. Thank you, Mr. Chairman.

I think I can conclude before I have to go vote, too.

Just a couple of questions, Mr. Hardy. With regard to the chart that you had up there on the changes in BPA's financial condition, maybe you can help me understand with regard to increased costs and fish and wildlife that you have got delineated here. What has really changed here, other than no rain, since the initial proposal?

Mr. HARDY. That is the principal change, and let me describe to you why that has produced additional costs. We are not doing anything more. We are providing the same amount of flows that we were previously required to provide. It is just that the cost of providing those flows, the 3 million acre-feet in the Columbia and the 1.4 million acre-feet in the Snake, has gone up significantly, particularly in the Columbia.

To provide that three million acre-feet of water in a low water year, you basically have to purchase energy to assure refill of Grand Coulee, which is typically the reservoir that that water comes out of.

Mr. LAROCCO. So this cost is really for purchasing——

Mr. HARDY. It is purchase power cost, right, that is attributable not to keeping the lights on but to providing that additional 3 million acre-feet of water stored behind Grand Coulee. We purchase power to serve load rather than drafting Coulee to serve load. We keep that water behind the dam in Coulee, so in May and June when the fish flush comes we can provide that water.

Last year, that cost was pretty low; it was down around $10 million. This year, it is about $60–$70 million purely because of the change in the power market. It is also going to cost us more next year because none of the reservoirs are going to refill this year, and hence to refill the reservoirs next year, we will incur more purchase power costs than we originally anticipated when we adopted the Power Council's fish program a year and a half ago.

Mr. LAROCCO. So there have been no new requirements, no new programs.

Mr. HARDY. There have been no new programs. This is strictly the cost of providing the same basic program that we provided in 1992, but it is much more expensive because of the higher power purchase cost.

I don't know whether other new requirements may be levied or not. We are still in consultations with the National Marine Fisheries Service on this year's operations. The outcome of that process could be additional requirements, but right now that isn't certain. But those figures are simply higher costs to service already existing requirements that we adopted in late 1991 with the passage of the Power Council's program.

Mr. LAROCCO. Is there an argument to be made that it should go under the drought category here, or is it easier for the public to understand that it is in fish and wildlife? I mean there is no increase in any program and no new requirements. Shouldn't it be under drought instead of under fish and wildlife?

Mr. HARDY. We tried to do an intellectually honest job of dividing the cost. The 3 million acre-feet that we provide in the Columbia for fish is just that, it is a fish-related cost, it doesn't have anything to do with keeping the lights on. So we tried our best to attribute the costs associated with purchasing power to store that 3 million acre-feet to fish, and all the other power purchase costs were attributed to drought—namely, purchase power to keep the lights on. As you see, the majority of those expenses are still drought expenses, they are not fish expenses, but we thought that was the appropriate cost categorization of those costs.

Mr. LAROCCO. With regard to across-the-board cuts, do you anticipate any new requirements with regard to potential listings of any more endangered species? If there are anticipated listings, will that raise your budgets? Are you going to have to seek money to address those anyway? In other words, is fish and wildlife an area that maybe you shouldn't cut, or is it just easier to go across the board?

Mr. HARDY. We need to be sensitive to that. We don't want to make penny wise/pound foolish cuts in the fish program or any other program. As I believe I described in my opening statement, my general guidance to staff has been to cut but not gut the programs.

That is particularly applicable to the Fish and Wildlife Program. We are not seeking absolute decreases, we are seeking to lower the rate of increase. You will still see some increases in program costs in 1994 and 1995 over 1992 levels. We are going to try and gain efficiencies in those programs, but not do things that would either put us in jeopardy relative to already listed stocks or cause addi-

tional nonlisted stocks to become listed if we could take some preventative measure.

I am still anticipating that the expenditure levels for the Fish and Wildlife Program will continue to increase by some amount and that we will have some capability to try to step in ahead of time and address potential listings, whether they are bull trout or Kootenai sturgeon or whatever. Clearly if we can take a preventative measure early on, it almost invariably is less costly than if we get into a listing situation. None of the budget numbers contemplate additional costs that might come about as a result of additional listings. We have tried to preserve some capability to deal with those, and we will try to give priority, in terms of how we reduce our fish and wildlife budget, to listed stocks or potentially listed stocks to avoid that kind of result.

Mr. LAROCCO. With regard to the reserves that you have had, I don't have a historical perspective on that. Can you help me out in understanding the amount of reserves that you have normally had at BPA over the past decade or so, and were those reserves put aside to take care of situations like these, or do you normally——

Mr. HARDY. Well, over the past decade our reserves have typically varied from almost 0 to the high of $900 million that we had about 18 months ago. Our desired level of reserves to maintain the 95 percent probability of repaying Treasury as well as execute all of our other program requirements are probably in the $400–$500 million level. Part of what is driving the current rate increase is to try to rebuild our reserves. We calculate our reserves will now be down to $90 million, at the end of this fiscal year. We want to rebuild our reserves to the $400–$500 million over the 2-year rate period so we have an ability to withstand at least one bad water year and still not gut our programs.

Mr. LAROCCO [presiding]. Okay. The task force stands in recess until we see Mr. DeFazio or Mr. Williams, and I will go vote.

Thank you.

Mr. HARDY. Thank you, Congressman.

[Recess.]

Mr. DEFAZIO [presiding]. We are back in session, and I would defer to the gentleman from Washington State, if he has some questions, for five minutes.

Mr. KREIDLER. Thank you, Mr. Chairman.

The first question I have, Mr. Hardy, deals with how much of the current financial crisis is brought on by some of the problems that Bonneville has had with its contractors. It is my understanding that some of these contractors consider the money that Bonneville provides them with as more or less an entitlement and that they have not been very responsive when asked to account for the money that they have spent. It may be that some of Bonneville's fish and wildlife and/or conservation money could be more efficiently spent either by different contractors or by changes in the present contractors' methods.

What are your thoughts on that issue?

Mr. HARDY. I would say some of that is true. I don't think it is a first order problem, but it probably is a second-order kind of problem. One of the things that we are seeking to do as we go in and look at reducing our programs is try to both cut out some of

the administrative overhead associated both with our own staffing and contractor staffing; second, in some cases we have awarded sole source contracts, particularly in the fish and wildlife area at particular agencies because they are fish agencies; we are going to compete some of those contracts.

So I think this whole exercise will allow us to get at some of those problems and get much more of a performance-based criterion for delivery of services than we have had in the past. That is true in a variety of areas, but the fish and wildlife area, and conservation area, are two where we have suffered from the entitlement mentality and we need to correct that.

Mr. KREIDLER. I might add that I think sometimes it may not be, given the proportion of the discretionary section of your total budget, the largest issue, but sometimes these issues become very symbolic to the rate-paying public. A fair amount of distrust, anger and frustration can develop when the public sees indications of mismanagement. This generates the kind of broad publicity that overshadows the many good things that Bonneville is doing.

I think in the fish and wildlife area in particular some of the contractors, such as State agencies, have not been accountable as they could be because Bonneville monies are an additional revenue source for them. Some of those examples come to Members of Congress' ears, and undoubtedly are not going to be the only ears that are going to hear this, and at some point they could be rather broadly talked about—certainly in the media.

In addition, I would like to get your thoughts, in the context of the challenges that Bonneville faces right now and in the future, regarding a longer-term solution which would address the operation of Bonneville as it relates to its customers. One long-term solution would be to create a board of Bonneville's customers or to perhaps expand the authority of the Northwest Power Planning Council, to have more input, control and/or approval over Bonneville's finances. What is your response to that proposal.

Mr. HARDY. I think those are fair questions to be examined. I hope the committee will get into some of those questions.

If I understand the chairman correctly, I think one of the things the committee is intending to do is look at some of the repayment and other long-term structural financing problems that we have to deal with. Those are logical points of departure to getting at the governmental structure questions that you are talking about. I think everything is potentially on the table.

I guess I would observe relative to the ideas that you have mentioned in your question, whether it is a board of customers or the Power Planning Council, I think there are pretty substantial constitutional problems with going much farther than we already have gone with the Power Council. It is a State-appointed body, and we are a federal agency.

Now, that being said, it is logical to look at a TVA kind of model where you have a federally appointed board of directors. That is one model. Another model would be to look towards making Bonneville essentially a government corporation. We act like a government corporation now, but we are not, and that seriously constrains our ability to do business cost effectively in a number of areas. Those are only two of probably several different alternatives,

but I think it would be appropriate to explore all of those, and we are very open to exploring those with the task force.

Mr. KREIDLER. Very good. Thank you very much.

Mr. DEFAZIO. In response to the gentleman, we will be holding a hearing on the long-term perspective on Bonneville, and that will go to structural issues, because when you begin to look at debt restructuring it has implications under the Budget Act which could require a more independent agency and other constructs, and I have said to people we are going to look at all those things. So I will be certain and invite the gentleman back.

If I could return to where I left off, which is on WPPSS. I don't want to belabor this because I have many other questions, but you said you have a permanent staff of 12. I don't necessarily want to second guess management's judgment here, but I am concerned that when you permanently assign people to monitor another agency that ultimately they begin to develop a stronger alliance to the other agency where they are permanently stationed than to the agency which stationed them there to begin with, and institutional concerns begin to come into play.

I would urge the Administrator and senior staff, in conjunction with the new director or administrator of WPPSS, to take a very hard look at the operations of WPPSS and begin to exert pressure, holding out this ultimate tool you have, which is disapproval, if they are not following prudent utility practices and hewing to other concerns that you have. So I just want to make that point one more time.

I do have a question about mothballing since we are there. I appreciate the fact that you have finally, after many years of prolonged agony, decided to cut off the continued expenditure of funds for mothballing, but my understanding is that there will be mothballing costs in 1994. Is that correct? And what would the amount be?

Mr. HARDY. I don't expect, Mr. Chairman, that we will realize much of those savings in 1994. We have got a number of steps that we have to go through before we can formally reach the termination decision. Most of them are legal.

Probably the most significant of them is a declaratory judgment action that we will need to pursue as a result of agreements we made with the bond fund trustees for Plants 1 and 3 when we did the refinancing several years ago to make sure that termination does not constitute an event of default for purposes of sale of the assets of those two plants. That will also help us clarify some other questions relative to use of the construction fund for Plant 1 and some other issues.

So it is about six to nine months away from the point where we can actually reach a termination decision, per se, and I think if we start realizing savings in this rate period, it probably won't be until 1995, but if you don't get started you never finish these things.

Mr. DEFAZIO. All right.

Is it your understanding that the WPPSS board is now committed to termination?

Mr. HARDY. The Executive Board is strongly committed to it, but they are not the ones who make the decision. It is the WPPSS Full Board which, ironically, provides virtually no policy guidance for

the organization but does two things: They vote on members to the Executive Board, and they terminate plants.

I think if you put it to a vote of the Full Board today it would not be unanimous, but I am pretty sure you would have a majority that would favor termination, and I am confident that is the decision the Full Board will reach. But we will not be ready to present that decision to them until we have all of our legal ducks in a row, which is probably later this year or early next year.

Mr. DEFAZIO. Okay. And you don't expect any additional expenditure requests from WPPSS to undertake further study or other things regarding this subject?

Mr. HARDY. We don't need to study this subject any more. We know what the answer is; we have just got to do it.

Mr. DEFAZIO. Okay. I appreciate that. It has been a long time coming. I am glad to hear it. We may finally put a stake in the heart of the vampire here and keep it from rising again. That would be great.

You alluded to the $150 million in bond revenues in the construction fund, and I guess there is about $100 million in fuel and enrichment options or commitments. I assume that we will be hearing more about that as we move through this process, the potential uses to which that money could be applied after other obligations are satisfied.

Mr. HARDY. That is true. The figures are more like $100 million in the construction fund, and $100 million, give or take, from the potential sale of fuel and other assets, but we need to use the declaratory judgment action to clarify the purposes for which we can use both of those funds.

The bond fund trustee basically has to agree with how we will dispose of those or how we will use those funds in a way so that the bond holder's interest is protected. That will be a major purpose of the declaratory judgment action, to structure those so we will get the maximum amount of flexibility in how we use those funds.

Mr. DEFAZIO. We have made an awful lot of lawyers rich and kept a lot of judges really busy. Does everyone agree and believe that we need this declaratory judgment? Aren't there legal theories out there, looking at the agreements and otherwise, that perhaps that is not necessary?

Mr. HARDY. We have to address that question with both of the bond fund trustees. There are two different trustees. Seafirst is the trustee for Plant 3, and Morgan is the trustee for Plant 1. If both of them agree, perhaps we could short-circuit this, but that is a discussion we have yet to have with them. We did make a commitment when we did the refinancings to do a declaratory judgment action. That was necessary for them to give the approval to go forward with those refinancings. So if there is any way to short-circuit that, we certainly will do it, but we want to make sure we get the right answer here.

I share your desire not to have more folks earn more legal fees from what has already been a very profitable endeavor for much of the legal profession in this country at the expense of Northwest ratepayers. But I want to make sure we get the right answers be-

cause there is a significant amount of savings that is available if we do this thing right.

Mr. DEFAZIO. I appreciate that.

You answered my colleague from Washington on the question about contractors, and I asked some questions in the preliminary interrogatories about personnel and contractors, and I would like to spend a little time examining that. I can't say that I am fully able to decipher the chart that was provided, which I have here, in terms of the total staffing.

[EDITOR'S NOTE.—See "Questions and Answers Supplement to the Statement of Randall W. Hardy" in the Appendix.]

Mr. DEFAZIO. When I look at page 9 and your responses to the questions I submitted on April 7 and the categories—let's just use 1993 because it is on the chart, and we could use any of the years. Federal employees, as you stated, 3,667; I understand that. Then we go to contractors and cooperating agencies. There is a support services contractor staffing levels breakdown, but it seems to me there is a substantial portion where we don't have a breakdown between what are cooperating agencies and what are contractors.

Going back to the question about WPPSS, this doesn't include the WPPSS FTEs. They are not considered a coordinating or cooperating agency, are they?

Mr. HARDY. This is page 9, Mr. Chairman?

Mr. DEFAZIO. Yes.

Mr. HARDY. You are right, these do not includethe Supply System, the Corps or the Bureau. These include principally contractors that we have for basic support services in those respective areas.

Mr. DEFAZIO. It is puzzling me. So this does not include the Corps or Bureau.

Mr. HARDY. That is right. Your chart on page 8 includes all of the Corps. If you count the portion of Corps and Bureau employees that we finance, that is under the hydro generation and construction line on page 8. So the 1,630 number is mainly Corps and Bureau employees whom we pay for. The nuclear generation line on page 8 is basically all the Supply System activities that we pay for. The fish and wildlife line is basically all the fish and wildlife staffing that we pay for. So those are all contractors in a technical sense of that term.

I would say a more relevant chart for purposes of contractors that we use on a pretty much full-time basis to do tasks that otherwise we would use Bonneville permanent employees to do is what is on page 9, which are support services contractors.

Mr. DEFAZIO. Okay. So the estimates of support services contractor staffing levels are semi-permanent or more regularly occurring.

Mr. HARDY. Yes.

Mr. DEFAZIO. So we would add that to the BPA number.

Mr. HARDY. That is right.

Mr. DEFAZIO. And then the rest are other.

Mr. HARDY. That is correct.

Mr. DEFAZIO. As you would say, the nuclear generation number in there is for WPPSS or the Supply System, and fish and wildlife involves cooperative agreements with the State fish and wildlife agencies, such as for the program for predators and things like that.

Mr. HARDY. Predators, and a whole variety of research activity. As you see from that figure, we have got 900 fishery biologists and related people under contract to us.

Mr. DEFAZIO. Some of these, I would assume, are not intergovernmental contracts but are private sector contracts that are let competitively or, as you said, sole source.

Mr. HARDY. That is correct. I don't know what the breakdown is between competitive and sole source, but there are some of both in there.

Mr. DEFAZIO. Could we break this down a little further so we can get some grasp of the range of the contracts that we have ongoing, the duration, the expected termination, or whether they are permanent, reoccurring contracts, those sorts of things?

Mr. HARDY. We would be happy to provide the committee with a further breakdown of those contractor expenditures.

Mr. DEFAZIO. I am sure your staff feels the same way mine does when I say those sorts of things.

I thank you.

[The information follows:]

Staffing that BPA pays for among its contractors and cooperating agencies has annually been in the 7300 to 8400 FTE range during FY 1991 to 1993.

The Transmission System Design and Construction component includes architectural and engineering firms under direct contract to BPA for design services (approximately 90–170 FTE annually) and construction firms under direct contract to BPA (approximately 500–700 FTE annually).

The Transmission System Operation and Maintenance component includes non-electrical facilities maintenance contractors (principally right-of-way clearance and buildings maintenance) and electrical crew relievers under short-term, "Kelly-Temporary Services" type contracts (130–170 FTE annually); construction firms supporting heavy equipment replacement (approximately 50–70 FTE annually); and marketing/scheduling/dispatch support (approximately 10–50 FTE annually).

The Energy Conservation component includes utility, state, and local agency staff, and the contractors to these entities, who are engaged in the delivery of the BPA conservation programs (700–1200 FTE annually).

The Hydro Generation and Construction component includes Corps of Engineers employees (approximately 650 annually), Corps contractors (approximately 300–350 annually), Bureau of Reclamation employees The Nuclear Generation component includes Washington Public Power Supply System employees (approximately 1750–1780 FTE annually) and its contractors (approximately 580–630 FTE annually), plus 30 percent of the Trojan Nuclear Power Station workforce (approximately 340 FTE annually, prior to the planned shutdown) and 30 percent of Portland General Electric Company's contractor support of the plant (approximately 180–190 FTE annually, prior to the planned shutdown).

The Fish and Wildlife component includes firms under contract to BPA (approximately 120–160 FTE annually); and Federal, State and Tribal fish and wildlife agencies and their contractors (approximately 600–800 FTE annually).

The "Other" category includes contract support to BPA overhead functions, professional and technical services, and data processing (approximately 390–430 FTE annually); and operating employees at small-scale generating resources under contract to BPA, construction employees at plants under development for BPA power acquisition, and the staff and contractors of the Northwest Power Planning Council (approximately 100–250 FTE annually).

BPA's direct support services contracting has involved competitive procurement for 89–95 percent of the dollar volume during FY 1991 to 1993. Based on actual contract awards, 95 percent of $49.6 million was competitively let in FY 1991; 90 percent of $61.2 million was competitively let in FY 1992; and 89 percent of $29.7 million has been competitively let so far in FY 1993. We do not have the competitive/non-competitive splits by program.

Mr. DEFAZIO. You have implemented a limited hiring freeze. Does that mean you are going to seek to lower employee levels by

attrition, or does that mean you intend to hold where you are and replace people to remain at that staffing level?

Mr. HARDY. The former. We are already, as a result of the hiring freeze, reducing permanent staffing at Bonneville, and associated with the program cuts that we are now making, we will substantially reduce both contractor and temporary employee staffing.

What I have told our employees is, if we have staffing reductions, and I fully expect we will, that we will handle that to the maximum extent possible by attrition. I also intend to look seriously, as part of our long-term competitiveness project, at potential separation bonuses and other kinds of programs that would provide a maximum incentive so that, if we downsized, we could do that as humanely as possible. We would also do it in a way that, frankly, is a heck of a lot more efficient than trying to do the RIF process. Let me illustrate an example to you that may seem convoluted, but believe me, it is apt.

You identify a GM–14 middle manager whose position you no longer need. You institute a government reduction in force process to try to eliminate that position and several others. That manager exercises his or her reversion rights to the next lower position, and he bumps her, bumps who, bumps who, and the person that ends up going out the door is a GS–7 secretary who is probably the most productive person in the organization to begin with.

That is not a very productive process for us to engage in, so I am trying to think through that a little more carefully. In the meantime, we are taking significant reductions in contractor and temporary staffing because we can hire and fire at will there. With full-time federal employees, we are going to do that through attrition, but we are also going to look at these separation programs so we can target that to make sure we realize the benefit of any staffing changes we pursue.

Mr. DEFAZIO. So you do have more flexibility and you do expect to be addressing the contractor level substantially in these reductions.

Mr. HARDY. Absolutely.

Mr. DEFAZIO. Okay.

Mr. Williams, do you have questions?

Mr. WILLIAMS. Thank you.

Mr. Hardy, I thought there was real wisdom on BPA's efforts to have energy savings in the various sectors through an aggressive conservation effort, and I have followed that with some specificity through the years, the residential sector, commercial sector, industrial sector, and the agriculture sector.

Where, if in any of those sectors, are most of the savings occurring, and in which of the sectors do you think we have the most room for improvement?

Mr. HARDY. I would say the savings, in terms of dollar savings as opposed to megawatt savings—let me back up. Our goal is to retain the same megawatt acquisition targets that the Power Planning Council has laid out. They have identified a target of about 660 megawatts over the next 10 years. We think we can still attain that target even with significant reductions in cost.

I would say that the principal area that would come from is probably residential. Our existing residential weatherization retrofit

program is a pretty expensive program, in a pretty mature market and we have gotten all of the easy savings. Some reductions can be made there; potentially in the Super Good Cents program. A lot of cuts can be made in infrastructure supports and training and things like that. We have a pretty well-developed conservation infrastructure already, and there are potentially some savings in smaller commercial. Those are probably the areas we would be looking at.

Mr. WILLIAMS. Are you satisfied that the agriculture sector is practicing appropriate conservation?

Mr. HARDY. No. I think there is a lot more to be done in that sector. It tends to be probably our most expensive sector, but it also is one where the potential, from my perspective, is largely untapped, and we need to figure out a better way to do that.

I am uncertain, Congressman Williams, as to how these reductions would affect the agricultural sector. We are in the process of looking at those right now. The savings there are not huge, but I expect the bigger savings targets are in residential, both Super Good Cents and existing residential weatherization retrofit.

Mr. WILLIAMS. It is my understanding from the staff of the task force that you have been asked this question in writing, but let me perhaps rephrase it and see what your answer is publicly here. The task force tells us that the Washington Public Power Supply System pays its board members $500 a day plus expenses and that those costs are passed on to BPA's customers. Is that true?

Mr. HARDY. That is true.

Mr. WILLIAMS. How much does that cost BPA and therefore its customers, through, what, a 5-year period? 10-year period?

Mr. HARDY. We have got a chart that answers that for the committee, and I think the combination of both reimbursement and actual travel and related expenses is on the order of a couple of million dollars over the last 4 or 5 years. The chart is on page 20.

[EDITOR'S NOTE.—See "Questions and Answers Supplement to the Statement of Randall W. Hardy" in the Appendix.]

Mr. WILLIAMS. Your staff gave it to me as well, Peter. Thank you.

$2,415,262. So you have kept track of it. I suppose that is a small amount, but it is Ev Dirksen's quote about a million here and a million there. I also suppose this is the type of thing that, once it becomes exposed, just drives ratepayers crazy even though it is a very small part? What do you think we ought to do with that practice?

Mr. HARDY. I think it appropriate to reexamine that practice.

I would observe that the Washington State governor has it within his unilateral authority to change that compensation level. He has made several statements about his view of that, and I would expect that he would follow through on that. I would hope we would still retain some level sufficient to attract particularly out-of-state board members if we replace some board members, but I don't think that necessarily has to be $500 a day.

Mr. WILLIAMS. You say that is Washington's governor that has that authority?

Mr. HARDY. Yes, sir.

Mr. WILLIAMS. I remember Lowry from his days around here. I expect that practice will be ending soon.

Mr. HARDY. One might have that expectation; yes, sir.

Mr. WILLIAMS. Thank you, Mr. Hardy. I appreciate your being with us.

Mr. HARDY. Thank you, Congressman.

Mr. DEFAZIO. That was most illuminating. I was unaware that he had that unilateral authority, and I think I may correspond with him and urge that he use that unilateral authority.

Mr. Kreidler.

Mr. KREIDLER. Mr. Hardy, I would go back to some of the issues relating to BPA's short-term situation and get your thoughts on the viability of various options to limit any additional rate increase requests while retaining Bonneville's ability to meet obligations to the Federal Government and others. One option would be to charge a one-time drought surcharge on BPA customers as a means of more or less looking at this as a short-term crisis and not something that is ongoing, hopefully.

Mr. HARDY. I think the drought surcharge is kind of appealing. It has a clear conceptual linkage. The chart I showed you clearly shows that a significant portion of the costs are weather related, and that if we get average water next year it will go away. So having a higher level of rate for the first year and a base level of rate that you recede to may make some sense.

I must say, in the discussions we have had both in the rate case and in the settlement discussions with our customers, they have not favored that approach. Our public utility customers, in particular, for a variety of reasons that are still a bit of a mystery to me, are reluctant to proceed. I think they have to do with how many times you go back to your commission to get your rate changed and wanting to have some stability of some 2-year rate period rather than changing it every year or every 6 to 9 months.

I think they are also concerned somehow that the Direct Service Industries are going to be advantaged because they would be recovering in the second year just to take advantage of this while the public utilities would be penalized in the first year.

I must say, I don't find those arguments to be terribly persuasive, but that is one of the issues that will be considered in the rate case. We have left ourselves the flexibility to do that, and I simply need to look at the rate case record and make a decision, but I think there is a certain logic to that.

Mr. KREIDLER. What do you think of the more long-term option of turning more of the conservation responsibilities over to the BPA's customers.

Mr. HARDY. We are actively working with our customers to do just that. It is called third-party financing. They put up their bonding capability to finance conservation activities, and we pay the debt service.

We have a group of customers, about 7 or 8, with whom we are actively pursuing negotiating such arrangements with right now, the advantage being both at the federal borrowing that is shifted to them because they can borrow in the tax-exempt market and we have to borrow at Treasury rates; they can actually do it more cheaply. I am hopeful that we will be able to conclude some con-

tracts. That is not easy, but the advantage it has for our customers is that it gives them multi-year commitments.

If they sign such a contract with us, they have got basically a guarantee for 5–7 years that they have got stable program levels and conservation funding rather than being subject to our financial circumstances each year when we allocate our budgets. I am hopeful that we will be able to gradually shift some of that financing burden to our customers in exchange for giving them multi-year contracts, given that program stability.

Tacoma and Seattle, in particular, are two of the customers that we are attempting to negotiate such arrangements with. Eugene Water and Electric Board is another. We have a whole group of Washington utilities called the CARES group, which are some of the smaller PUDs, mid-sized PUDs, in Washington State, and the same thing with some of the Oregon munis. So we have quite a number of customers or groups of customers that we are attempting to negotiate such arrangements with.

Mr. KREIDLER. Do you have any estimate of what proportion of your discretionary spending on conservation, which I understand to be about 11 percent, could potentially be turned over to the customers?

Mr. HARDY. I don't have a precise estimate, and I will have to get that for your for the record. My guess would be that it is somewhere in the 10–20 percent range, maybe higher.

[The information follows:]

Current negotiations with utilities on third-party financing arrangements for FY 1994 and FY 1995 would turn over about 30 percent to customers.

Mr. KREIDLER. Another option would be to perhaps cut back on acquisition and development programs in favor of conservation, particularly over the next few years. Is that a viable?

Mr. HARDY. That is one of the issues we are actively pursuing in the current budget reduction exercise. I mean we are not just looking at our conservation budget, we are looking at our generation budget as well and seeking to bring both of those down. We are actually seeking to keep our conservation acquisition targets at the same level while making ourselves more efficient.

Our generation targets we are probably going to decrease by some amount, slip on-line dates and possibly even cancel some projects. So we are looking at delaying those acquisitions. The trade-off there tends to be how much can you do and what kind of additional short-term power purchase obligations would you incur, on average, over the number of water years.

I think it is fair to say we are trying to take some additional risk in that area, hoping we are going to have average water and thereby decrease the size of the rate increase. So you will see cuts in both those budgets, not just the conservation budget but the generation budget as well.

Mr. KREIDLER. Lastly, what are your thoughts on using the lump payments that are going to come to Bonneville in connection with the transmission lines to California for rate increase reduction purposes. I am asking about the potential of essentially postponing those lump payments to the Federal Government as a means of moderating the immediate impact in the short term.

Mr. HARDY. That is true. If you are talking about the $150 million, roughly, that we will receive from other utilities who would purchase their own ownership shares of the 50 percent of the third AC Intertie we have constructed.

Right now, the problem that we have is that we have committed to the Congress, the Appropriations Committees and to OMB that we will handle that money in a particular way; namely, we will take it in and use it to retire outstanding debt obligations. We have committed to that in this year's budget to both the Appropriations Committees and OMB.

That being said, what I have told the customers is, if they can prevail upon the forces that be in Congress and in the Administration to change the treatment of that, recognizing that this is an emergency kind of situation, we will do all we can to try to treat the money in that way.

I would tell you frankly, I am in a position of having made commitments to both the Congress and OMB that I feel I cannot unilaterally change. So that ball is squarely in the customers' court to take and run with and try to muster the political wherewithal to get those changes.

That being said, it is worth 3–4 percentage points on this year's rate increase if we were able to use the full $150 million that would make a significant difference. Now that would push the problem into 1996, which would affect next period's rate increase, but if we had good water and better aluminum prices and things like that, we might be in a little better position to deal with it at that time.

Mr. DEFAZIO. I thank the gentleman and go on to my next round and come back to him if he has more questions.

Just to reflect on some of the questions about conservation, I think I am supportive of the direction you are headed, which is that you want to keep the targets but look at something that may be driven in different ways, driven with different sorts of incentives. Are we looking at something a little more decentralized?

You know, one of the common complaints I have heard—and I think we will be looking into some of these things in future hearings and hearing from customers—is that some of your customers have developed what they consider to be credible and ambitious conservation plans, but the negotiation process with BPA was just so onerous that many of them ultimately abandoned those plans or otherwise curtailed or changed them undesirably.

Are we going to be looking at something perhaps that is driven a bit more by targets as opposed to process and bureaucracy?

Mr. HARDY. We are. Basically, we have done two things. When I first came to the agency a year and a half ago, we started to decentralize our conservation acquisition operation to give more responsibility to our area offices to acquire conservation. That has been a difficult process with a staff the size we have and with a fairly highly centralized mode of running conservation programs up to that time.

Now I think we have now pretty well defined for the area offices the so-called envelope within which they can operate. That is, if they can negotiate a contract with certain cost parameters and certain contractual provisions, the area manager has the authority to

make the decision within that envelope. I'm optimistic that that will lead to a less bureaucratic, more responsive kind of approach.

The second thing I would say is, part of the budget cutting that we are now doing is looking at further efficiencies in that operation and, in particular, our own administrative overhead costs which I think are excessive in those areas. I am convinced that we can significantly reduce those costs and probably make ourselves more responsive in the bargain.

All that being said, I think we need to distinguish between what we need to acquire the 660 megawatts in a more efficient fashion with probably lower program incentives but with a tiered rate or some other kind of price signal, and what a customer may want. I can't satisfy all the wants. The more you satisfy all the wants, the more this becomes an entitlement program, and we simply cannot succeed if that is the way it is viewed by ourselves and our customers. Our customers, I think, are aware of that and are actively working with us to try to change that.

I must say, however, that I often run into a world of difference between the theme that I hear from a utility general manager and that that I hear from the same utility's conservation manager about what we are doing and not doing. Some of our own utilities have a rather fundamental management inconsistency that they need to wrestle with before we are going to be successful in solving this problem.

Mr. DEFAZIO. Since you mentioned entitlements, I thought I would bring up Super Good Cents, which I think some look at as an entitlement.

Now that both Washington State and Oregon have adopted the model conservation standards and revised upward dramatically their residential building codes, do you believe it is time to revisit the amount of subsidy that is provided in the single family residential, and are you going to look at that?

Mr. HARDY. Yes.

Mr. DEFAZIO. Okay.

The power purchases, if we could just dwell on that for a moment. You talked about purchases, $170 million unscheduled in January, February, or early March. What are you projecting for fiscal year 1994 for power purchases? In looking at next year's budget, is one of the underlying factors driving the total cost of this budget an assumption that you will require similar purchases in the next winter that were unanticipated this year and came out of reserves, but are you now building those into your base budget?

Mr. HARDY. Not to that level, but let me describe to you the planning horizon we are using. I will answer for the record the precise number because I don't have it in front of me.

As a result of the fact that, given water conditions in this year, reservoirs will not refill this year, we will have to plan to purchase an amount of power based on average water assumptions for 1994 that will enable us to assure or give us a reasonable probability of reservoir refill in 1994. So we would be making purchases above what we would normally make if our reservoirs were full on July 31 of this year, but I am not going to budget $170 million of additional purchases because what we had this year was a 1-in-50-year event. It would not be prudent to collect that amount of money, but

we are planning, based on average water assumptions, to purchase an amount of water to make sure that under average water conditions we will refill on July 31 of 1994.

Mr. DEFAZIO. Okay. If you could provide that figure, I would appreciate it.

[The information follows:]

Power Purchases for FY 1994 are estimated at $126 million.

Mr. DEFAZIO. Is the budget predicated upon continued curtailment of the first quartile for the aluminum companies for next year, given the fact that you are anticipating additional——

Mr. HARDY. I don't believe so, but I need to check that, Mr. Chairman. I don't know right now what the answer to that question is. I think we have assumed that we would have a return to average water conditions and we would be able to serve that low. I need to check that; I am not certain.

Mr. DEFAZIO. Well, if on the one hand we are assuming that we need to have an additional budget allocation for power purchases to refill the reservoirs, and on the other hand, we are over here assuming that we can reinstate that quartile, it seems that that is not entirely contradictory. I understand there is a difference between storage and flow, but it still seems there is some overlap of concern with those two issues.

Mr. HARDY. I am not sure what assumption we are now using in the 1994 budget on that question. I need to get back to you on that.

Mr. DEFAZIO. Could you?

[The information follows:]

The FY 1994 estimate of $126 million assumes that the first quartile for the Direct Service Industries is restricted from October through December.

Mr. HARDY. I can tell you relative to what we are doing with the DSIs that this is a day-to-day kind of thing. We have recently made them an offer for the duration of 1993 that is a fixed price offer to try to give us some additional stability. Basically, they would pay for the first several months, from May 1 forward, a much higher price for energy than they otherwise would if they got it from surplus sales in exchange for a guarantee of replacement energy for the duration of the year. However, I don't know what specific planning assumption we have used for the 1994 budget, Mr. Chairman.

Mr. DEFAZIO. Is that a subject of the rate case?

Mr. HARDY. That is outside the rate case.

Mr. DEFAZIO. I would like to have some details on that, if I could.

Mr. HARDY. Certainly. I would be happy to provide you that.

[The information follows:]

The 1994 budget assumes service to the first quartile of the aluminum companies for 1994 when energy is available. The forecasts used in preparing the budget were the same as those used in BPA's Initial Proposal to the 1993 Rate Case. BPA uses a historical water period of 50 years in the forecast process. Whenever there is nonfirm energy available, the aluminum companies are given first priority to purchase it at the forecasted Variable Industrial rate. The expected value of the 50 water conditions is used in forecasting the service to the first quartile and becomes the basis for the budget.

In BPA's supplemental proposal, BPA had new information on streamflows for the spring and summer of 1993. With this new information, BPA adjusted its forecast of service to the aluminum companies' first quartile by projecting restriction through

December 1993. Recently, with newer information on forecasted stream flows, BPA felt that it could be in a position to offer special service to the first quartile through that period.

The planning assumptions used in preparing the 1994 Budget and the Initial Proposal of the Rate Case do not become operational standards. They are only forecasts of operations based upon the most current information. In the Rate Case, BPA is not stating what will happen during the rate period; instead, BPA is only trying to estimate what revenues and costs would be, based on the most recent input.

Mr. DEFAZIO. At least in my recollection, the last major problems we had was some time in the mid-1970s. My recollection is McCall was governor, or maybe it was Straub, but I think it was McCall. There was a great outcry in Oregon for voluntary curtailment of energy use. There was a big debate about car lots, over whether they should be required to turn off their lights at night because it was a security issue, because people might steal the cars, and about outdoor advertising, and other calls for curtailment. I am a little puzzled as to why we didn't ask for some voluntary curtailment this year.

I think the people of the Northwest are extraordinary and unusual in this country, exhibiting a different spirit than I see in the East in terms of neighborliness and cooperative sorts of responsibility that I think people in the know now would respond well, and I'm curious why we didn't call for some voluntary curtailment while we are in this huge deficit situation and purchasing so much power.

Mr. HARDY. That is an excellent question, Mr. Chairman. Let me try to explain why we didn't.

In terms of when we proceed to call for voluntary curtailment, we have reached an agreement with the region's utilities to do that, and it is the governors that do that. It is not Bonneville or the region's utilities; the governors have to make that call and make that request. We have agreed to do that only when we have a genuine power supply emergency as opposed to a severe revenue problem. Right now, we don't have a power supply emergency; we have a severe revenue problem.

If we would have gone out in mid-January when the cold snap hit and called for region-wide curtailments, we would have exacerbated our revenue problem. The reason that would have happened is just what you have alluded to—the people of the Northwest are very conservation conscious. They would have responded just like they did in 1977, and we would have had about 5 or 10 percent typically less kilowatt hour sales. We would have had the same amount of fixed costs spread over a smaller kwh sales base, and rates would have been forced up even more.

That is exactly what happened to utilities like Seattle City Light in 1977 when we had region-wide curtailments. We had them in 1977 because we had a genuine power supply emergency. City Light and others had a 50 percent drought surcharge. The citizens did their duty, they conserved, and they got hit with a 50 percent surcharge on their power bill. You can imagine the public reaction in Seattle and other places when that became manifest. The conclusion that we reached here was that unless we had a genuine power supply emergency we would simply make an already bad revenue problem even worse if we did that, so we have stopped short of doing that.

That being said, had we had one or two more events in mid-January, we would have been to the governors requesting regional curtailment. Had two more things happened, we probably would have been at that point. Had the cold snap lasted another week or two and had WPPSS II continued off line for more than it did, we might very well in early or mid-February been to the governors asking for that, because we simply would not have been able to purchase enough power to serve load. That is what the regionwide curtailment plan is set up to address, that kind of power supply emergency as opposed to the severe revenue problem which we currently have.

Mr. DEFAZIO. What was your average price for your purchase power versus your average wholesale rate, or maybe even looking at your blended rate with the lower rate to the——

Mr. HARDY. If I recall correctly, our average purchase power price for January, February, March, is about 28 mills. Our wholesale rates for public utilities is 24, and the rate for the aluminum companies is 18.

Mr. DEFAZIO. I can't quite understand that then. Okay, let's say we sold one kilowatt hour less through conservation, we have lost 24 mills of revenue; but if we had to purchase that kilowatt hour it would have cost 28 mills; so we lost 4 mills. I don't quite understand. If you are buying it for a higher price and selling it for a lower price, if you didn't have to sell it, do you get it? I'm puzzled.

Mr. HARDY. Our calculations were that we had a significant risk of being worse off as a result of that in a financial sense, and we are, by virtue of the obligations under the regionwide curtailment agreement, responsible for those lost revenue costs of the utilities. That is the only way we could get them to agree to sign up.

Mr. DEFAZIO. Oh, so you are saying it isn't your wholesale rate that is relevant to me, it is the retail rate, and so we have a rate system in effect where, even if expensive, costs you more to purchase than to generate. When you are in a deficit situation you will go out and purchase because your avoided cost is actually higher because it is the difference between your wholesale rate to those utilities and their retail rate that you have to make up. So we are subsidizing consumption at the retail rate level even in periods of economic crisis. Is that in the rate case that you have to reimburse them for those costs?

Mr. HARDY. No. It is part of the Share the Shortage agreement that we have negotiated with the utilities.

Mr. DEFAZIO. And that is the long-term power sales agreement with the utilities?

Mr. HARDY. No. It is a separate curtailment agreement that basically regulates a series of progressive steps associated with calling for curtailments to address a power supply emergency.

Mr. DEFAZIO. It doesn't sound to me like they are sharing much. They are saying, "We want to be made whole for the power that we might have sold," and I mean I would say that is something to be looked at very carefully, particularly if we beginning to look at tiered rates. I mean we have got a problem with that kind of an agreement because you are going to go out and purchase at higher cost, which is a 4 mill loss to you, in order to avoid the higher mill cost to reimburse these utilities for foregone revenues.

Mr. HARDY. I would have to refer back to the agreement. I don't believe we reimbursed our total amount, but we reimbursed some amount. But the nature of this agreement is that the power system is all interconnected, and if we can't get unanimous consent to go forward, one utility can lean on the system at the expense of another utility. Absent trying to exercise the police powers of the State to compel them to do certain things, and audit that and enforce that, the best way to try to do this is to reach some collective voluntary agreement where you share the costs that you incur when you have to do a power supply sort of voluntary curtailment. That is what the attempt has been with the Share the Shortage agreement.

Mr. DEFAZIO. Right, but they aren't voluntarily making up the difference in your wholesale costs at this point in time; I mean your purchase costs. They aren't helping you pay that 4 mill difference. That is coming out of your reserves, which of course they contributed to because they are customers, but then that drives the rate case.

I would just say, this seems to me something that warrants a lot of scrutiny in looking at the two-tiered or multi-tiered rates. We shouldn't be driven by the lowest common denominator. If we have got a bad utility out there that is not going to ask its people to conserve in these periods of common concern, then rather than them driving everybody else in the wrong direction, maybe they need to pay a little extra if they want to stay at that high rate of consumption. I just urge you to look carefully at that.

I am not sure this meets the overarching mandate of the Northwest Power Act of driving us toward conservation and renewables. It doesn't send a conservation signal to me and apparently didn't send one to the utilities. Anyway, I think that is something that warrants some more scrutiny.

I have gone on for quite some time. Let's see if Mr. LaRocco has some questions. I don't have too many more. I told you it would take about two hours, Randy, and probably we will get you out of here in another 15 minutes.

Mr. LaRocco.

Mr. LAROCCO. Thank you, Mr. Chairman.

I just have one question for you. The Northwest Power Planning Council has produced a graph showing a drop in BPA preference rates in real dollars from 1983 to 1992. If BPA had adjusted rates since 1983 to keep pace with inflation, what would your current cash reserve situation be? Do you have any estimates on that, Randy?

Mr. HARDY. Basically, our rates have declined by about 23 percent in real terms. We would have needed a rate increase of about that amount over that 10-year period, 23–25 percent probably, to keep our cash reserves level at the $400–$500-million level that would have been our planning criterion.

So if we would have done that, I think our cash reserves would have come in, rather than at the $90 million that I showed you in the chart, would probably be in the $500 million, give or take, range, which is about what our planning estimate is for what we think an appropriate level of reserves is.

Mr. LAROCCO. You would have to raise them by 23 percent now just to catch up to real terms?

Mr. HARDY. We would have to have raised them by a total of 23–25 percent over that 10-year period. We would probably have to raise them by a little more than that now, probably on the order of 27 or 28 percent would be my guess, to get back up now, today, to the point where we started out at 10 years ago.

I should probably also point out, Congressman, that while it is true that our rates have declined in real terms over the last 10 years by about 20 percent, if you extend that period to the last 15 years with all the run-up in WPPSS costs in the early 1980s, they have actually tripled in real terms in that longer time frame. So it depends a lot on what time frame you pick.

Mr. LAROCCO. Okay.

Mr. Chairman, I think that is all the questions I have.

Mr. DEFAZIO. Thank you.

Just one more question on the conservation issue and the Super Good Cents. It seems to me that in some areas where alternatives are available at the curb in terms of gas for single-family residences that we are, in fact, encouraging construction of single-family all-electric homes which, as efficient as they may be, is building load. I wonder to what extent that is going on.

I mean, is there any discrimination in Super Good Cents on whether gas is available at the curb, or is it just up to the discretion of the utility? In fact, in some cases we may have utilities that are not unified utilities so they aren't going to be making a choice. I mean we have got an electric utility, and the gas utility may be private, say, in the case of my home town. Are you looking at that issue?

Mr. HARDY. Yes, Mr. Chairman, pursuant to our changes in our fuel switching policy, that is one of the areas that we are reviewing and that we had actually committed to review before the current budget crisis came upon us.

It is clear to me that there have been abuses of that program to build load rather than to conserve energy. While I don't think those are universal or even a majority of the cases, they are significant enough that they are troubling. So we are clearly looking at that along with reducing the incentive levels in the Super Good Cents program, and I expect that we will conclude that within the next month or so and that you will definitely see, at a minimum, some changes in incentive levels, lowering of incentive levels, in those programs and perhaps curtailment of some of the programs altogether, depending upon what other alternate fuel choices are available in particular areas.

Mr. DEFAZIO. Right. It seems to me the key is if there is alternative available. Certainly in a lot of rural areas and other places there is no alternative.

Mr. HARDY. Right.

Mr. DEFAZIO. So there should be some distinction made.

On fish and wildlife, Congressman Smith touched a little bit on the potential for John Day drawdown. I have seen a price tag that says that, you know, for less than $100 million that facility could be modified to a minimum operating pool which would increase flows, as I have seen, for migrating fish, between half a day and

a day through that reservoir and apparently may incur much lower costs than some attempt to flush from higher points on the system. Is this something that the BPA is going to be looking at as a potential option?

Mr. HARDY. Yes, we have had a meeting with fishery public interest group leaders about three weeks ago. I committed to do that. Since it is a Corps project, it has been more in the Corps' court. The same people in my staff that will be looking at that I presently have got fully occupied right now with the current biologic opinion and some of the ongoing river operations, but we will take a look at that. It does offer some interesting potential. It has some risks associated with it that we have to evaluate. I believe that part of this is, you have got capacity losses and other things that we have to evaluate.

All that being said, if it does offer those kinds of improvements in travel time for something around that kind of cost, it is something that we ought to give some consideration to. I think the real trick here is getting a good evaluation of just what are all the costs, and it is not just power costs. We have issues with the Umatilla hatchery and wildlife preservation and other kinds of things that are affected by the water table and water level as you vary that reservoir. So we need to be confident that we can address those questions satisfactorily, and we are committed to taking a look at that.

I would say the other issue is this: If you did something like the John Day drawdown, is that in lieu of providing additional flows in that part of the Lower Columbia or in addition to? If it is in lieu of, that becomes a much more attractive proposition. If it is simply one more measure that is in addition to amount of flows that you will have to provide, that is much less attractive. So we need to look at all of those issues.

Mr. DEFAZIO. In response again to the interests of the Member from Idaho, I would expect that later this year, probably after we have the recovery team proposal, we will devote an entire session to our finned friends and related issues. So we will have more opportunity to explore this then.

I would like to ask another question. This one just sticks out. You know, once when I was a county commissioner I got a hostile editorial written by a local paper saying that I was counting pencils at Lane County. Of course, this was at a time when the entire staff of the county was on two-thirds time and we had major revenue problems because of a downturn in the industry, and I thought, in fact, it behooved us to look everywhere and anywhere to save money. I think it is also an example to the organization. If there is something that sticks out like some of the earlier questions about the WPPSS board of directors either to the ratepayers or to the internal organization as a sore point, it sends a message, and it sends the wrong message.

I am a little puzzled and concerned at the numbers I see on this squawfish program, and I just wonder where all the money is going. I see a total figure of around $8,000,000 and I see $700,000 in bounties, and I wonder where the other 90 percent of the money went. Could you illuminate that issue for me a little bit?

Mr. HARDY. I can illuminate it. I am not sure it will be a very satisfactory answer. That program has very high administrative costs which we intend to cut significantly.

Mr. DEFAZIO. What do we do? Go out and name every fish and then keep track of them?

Mr. HARDY. That is a good example of a program with a sole source contract with a particular set of State agencies. That is one problem.

Mr. DEFAZIO. Who got the contract?

Mr. HARDY. The State does, ODF&W and Oregon State University, if I am not mistaken. We have done things like evaluating the socioeconomic impacts of this; can you create a food consumption market for squawfish.

Mr. DEFAZIO. People eat whiting these days; we are fighting over whiting. Ten years ago it was called hake, and no one would touch the stuff. So you never know. My cats would like it, if no one else.

Mr. HARDY. You never know, and that is a significant portion. From my perspective, that was something that maybe was an interesting and potentially attractive question when we designed and implemented the program two years ago. That probably is something that we can't afford in this day and age. So we are going to go back and look at those kinds of costs, Mr. Chairman, because I would heartily agree with you that that level of cost over the actual bounty is just grossly out of proportion.

Mr. DEFAZIO. I would suggest that maybe we raise the bounty a little bit. I will just put ads in the local paper for you down in my district for unemployed mill workers and loggers. A lot of them like to fish, and I think they would be happy to go up there and pull them in for a little less.

But that just sort of stuck out. It sends a message. And I don't mean to belittle you or the administration, and I realize new programs are problematic, but I am glad to hear you are going to address it, because I think it does stick out.

I will give an observation, which maybe I shouldn't, but I am often doing things like this. I wanted to look at the Willamette Basin, because I had concerns over the operation of a flood control reservoir which also had recreational value, which wasn't an allowed use at the time it was constructed. In dealing with the Corps of Engineers, they came up with a phenomenal price tag to just study the system, which hadn't been studied as an integral whole. It had been built one dam at a time, and the last modeling they did was in the 1930s before any of the dams were built, so I said I think maybe it is time to update this. So they gave me this very big price tag, and reluctantly I paid it, and of course 3 years later I am still waiting for the result.

Then I asked them to look at another study, and this time they came in with another phenomenal price tag, and I said to them, "I'll tell you what. You go back and you justify everything in this. Detail me the budget. You show me where all this money is going, and I'll look at getting the money"—I learned something from the first example—and suddenly the price tag for the second study dropped rather dramatically. I still didn't get the detailed breakout and, in fact, still thought it was too high.

The point is, in dealing with these State agencies or anyone else, sole contracts, you know, they are going to rip you off if they can. I mean they have got Measure 5 in Oregon and they have got everything else going on, and if they can pick up some money from you they don't have to get it out of the licenses or somewhere else. That is just a concern with your sort of general contracting procedures when you get to sole source contracts. I think we should only use sole source contract when there is some very unique attribute, and that still doesn't mean we let them bargain like a monopoly; we can hold them to some reasonable accountability.

Maybe we could close on a couple of general questions. I think we have got a pretty good picture of where we are headed this year, and we are looking at out years in the budget, but I am concerned that there is ongoing litigation. I would think we know pretty well where we are headed with water this year and other potential problems, and it looks as though the Treasury payment is not imperiled, in my opinion, at this point in time for this year, which I think is very desirable in the current climate in Washington, DC.

I just can't follow all this stuff, but it seems to me that Judge Marsh is our Judge Dwyer of fish, and there are some cases pending before him that might have some impact on the system or system operations.

Could you briefly comment on that and what the potential implications of those are possibly—best case/worst case?

Mr. HARDY. To speculate on the state of mind of a federal district judge is probably a little beyond my purview.

There is a hearing before Judge Marsh tomorrow which could fundamentally change things. I don't know if it will or not. It is on the permit that National Marine Fisheries gave the Corps to transport fish by barge from the upper part of the Snake down below Bonneville Dam. That has been challenged by a group of intervenor, tribes and environmental groups—in particular, American Rivers and the Sierra Club.

When the judge held his initial hearing on that last Thursday, what the Department of Justice argued was that this was a fairly narrow issue associated with a strategy that has been in place for 20 years and that it should be treated that way. The judge indicated, as I understand it—I was not in the courtroom—that he was not inclined to treat it that way. He swore in several experts who happened to be there in the courtroom and basically went through four hours of trying to understand how the river system ran. He had significant questions about increased spill, about potentially more flows, about other hydro system measures, and he indicated he would reconvene everybody tomorrow. He asked for a couple of specific witnesses to appear before him and potentially make some kind of a ruling.

If he were to uphold the permit and allow the barging to continue, our revenue situation would be basically unchanged, and from my perspective, this is a question really that the MNFS recovery team should address in a comprehensive fashion as opposed to singling out one issue.

But if the judge were to decide to take control of this situation, it is unclear what the implications would be. But any more flows or increased spill would have significant revenue implications and,

depending upon what the magnitude of those were, could very well put the Treasury payment in jeopardy.

Mr. DEFAZIO. But you are at this moment committed to making the flows—to meeting the Council's program?

Mr. HARDY. That is right. We are meeting the Council's plan with some added flows that we committed to as a result of our 1992 consultation with the National Marine Fisheries Service. We are currently in consultations with NMFS this year, and I think it is safe to say that we will probably end up providing even more flows in 1993, although we haven't finally resolved those issues.

What Judge Marsh may do, however, is a total unknown and could be well beyond anything that we have contemplated so far. If it is, it could have significant revenue implications, and I would be hesitant to speculate on what those could be because I just don't know.

Mr. DEFAZIO. But you have at this point no intention of not meeting the goals that were set in cooperation and coordination with the Council and consultation with NMFS.

Mr. HARDY. That is absolutely correct. We have met the Power Council's goals and our 1992 operational commitments to NMFS to the letter, and we intend to do that in 1993, whatever the result of those consultations ends up being.

Mr. DEFAZIO. Okay.

Just two things to put this all in perspective. This was touched on before, and I realize that I may have to ask this in a different manner, which has to do with your operating reserves. Having come from county government, I am familiar with the concept of revenue anticipation notes, tax anticipation notes, commonly used, and obviously in the case of BPA we have a stable and predictable customer base and can predict with some accuracy, absent generating problems, but at least on the consumption side, what our revenues will be given a rate.

When BPA bills a utility, how often do you bill your customer utilities?

Mr. HARDY. Monthly.

Mr. DEFAZIO. Monthly. And then how long do they have to pay that bill?

Mr. HARDY. We require payment 20 days.

Mr. DEFAZIO. And are they all billed on the same date, or are they billed on different dates?

Mr. HARDY. The large customers are billed at the beginning of the month and the smaller ones are billed throughout the month.

Mr. DEFAZIO. At the beginning of the month. So if there were to be a critical cash flow problem next fall after you make your Treasury payment, that would occur in the initial weeks of the month of October.

Mr. HARDY. It is a little more complicated than that. Let me just talk about the problem generally without reference to the specific proposal that the customers have made in the rate case.

Mr. DEFAZIO. I am certainly not raising a specific proposal, I am investigating your billing practices, because my utility doesn't give me three weeks to pay the bill, do you, Bill?

Mr. KITTREDGE. No.

Mr. DEFAZIO. No, I didn't think so. In fact, last month, with my travel schedule, I was in arrears and I got a notice.

That isn't set by contract, is it, the length of time which they have to pay? Is it set by contract?

Mr. HARDY. Yes, it is set by contract.

Mr. DEFAZIO. Oh, it is. The 20 days?

Mr. HARDY. Yes, sir.

Mr. DEFAZIO. Is it set by long-term contract or——

Mr. HARDY. I believe it is set by their power sales contract, if I am not mistaken, but I would have to check to make sure.

Mr. DEFAZIO. Okay. It is?

Mr. HARDY. It is the power sales contract, so it is a long-term obligation The power sales contract requires payment in accordance with our rate schedules which set the payment date.

Mr. DEFAZIO. So given current contractual obligations, we have given them the 20 days.

Mr. HARDY. For your information, we are renegotiating the power sales contracts over probably the next 18 months to 2 years, and that could well be one of the provisions that could be changed, and as I say, the customers have made a specific proposal to change that or to agree to a so-called prompt payment in the rate case, and we are evaluating that.

Let me talk a little bit about what we have got to deal with here. We have got two sets of problems. One is the immediate cash flow problem to get through that three-week period, and as I mentioned in my opening statement, typically to get through that three- to four-week period we would typically have $80–$100 million worth of cash flow in the month of October.

What we proposed initially, back before we entered the rate case, was to carry a $100 million reserve level. We have now lowered that in our initial rate case proposal to $50 million to try to garner the rate benefit of that.

What the customers are asking is to reduce it to 0 or 5 or some other number that is fairly low. We are looking at that proposal. We are also looking at other proposals that would have the same effect. But we have got two problems. One is the immediate problem, but the other is a problem that goes on for several months.

Typically, even with $100 million of reserves, our expenditures exceed our cash receipts for a 3- or 4-month period from October 1 until about the end of the year. So if that is the pattern and you don't have a fairly high level of reserves to begin with, you are running to catch up, and what you need from the customers if you are down near 0 in reserve levels is not just that one-time prompt payment, you need a stream of revenues that is going to help you get over a 3- to 4- to 6-month period before you are evened out again, and that complicates the problem beyond just the immediate prompt payment problem.

All that being said, we are looking at trying to find a way to do what the customers want, which is to get that $50 million number down. It may or may not involve the kind of prompt payment mechanism that they have suggested.

Mr. DEFAZIO. Okay. Just for reference, when was the last wholesale rate increase?

Mr. HARDY. It was in 1991, October 1 of 1991.

Mr. DEFAZIO. And how much was that one?

Mr. HARDY. About 2.5 percent.

Mr. DEFAZIO. Okay.

Do you have any model for measurable economic impacts? I noted one of my local utilities usually uses a period of rate increase by BPA to piggy-back. Is that common?

Mr. HARDY. That is not an uncommon phenomenon, Mr. Chairman.

Mr. DEFAZIO. Is this measurable long-term—if you go 2.5 percent or you go 5 percent, the inflationary impact in terms of cost of electricity throughout the region is x, is there any model out there? When we are talking about rate increases of the magnitude you are talking, I am just curious about what the total economic impact is.

Mr. HARDY. It is very difficult and dangerous, frankly, to speculate about what the ripple effect of our wholesale rate impact is at the retail level because utility circumstances are so different. A rule of thumb that some use is, if you are a total requirements customer you buy all your power from Bonneville. A 10 percent Bonneville rate increase would equal about a 5 percent retail rate increase absent any other factors. Now you crank in inflation, and you crank in the cost of a utility's distribution system. Typically I think a number of our customers do use the occasion of our rate increase to increase rates not just to accommodate our increased wholesale power bill but for their own needs it is convenient to do that. The costs can vary significantly anywhere from 90 percent to 10 percent of our wholesale rate increase passed through to retail, just depending upon the individual circumstances of an individual customer.

Mr. DEFAZIO. When we were talking earlier about your power purchases and the concerns about consumption, it seems to me there must be some elasticity with consumption which will be driven by the rate increase, particularly for marginal businesses or other large consumers of power, et cetera. So at some point, after you raise the rates to a certain amount, you must be assuming that your consumption falls off a certain amount. Is that factored in?

Mr. HARDY. It is factored in, in terms of how we evaluate the load impacts of any rate proposal. I don't have those numbers right at my fingertips, but I would be happy to give you some illustrative examples for the record.

Mr. DEFAZIO. Okay.

[The information follows:]

BPA accounts for the effects of electricity rate increases on electricity load. In general, as the electricity rate increases, load decreases. In addition, with any given rate increase, marginal businesses or large electric energy-intensive industrial consumers will be affected the most, relative to residential or commercial consumers.

We reflect the effects of rate increases in our load forecasts used for rate projections and for long-term resource planning. The electricity rate is a significant factor influencing electricity consumption, along with other factors, such as employment and variations in weather. We describe the responsiveness of electricity loads to electricity rates by the term elasticity. Our near-term forecasting models, used to forecast one to five years out, have relatively low elasticities of less than −0.1, indicating that a 10 percent increase in average retail electricity price would result in a public utility load decrease of less than 1 percent. This is a short-term elasticity, intended to reflect only near-term changes in retail electricity usage.

In our near-term forecasting, we have also included a small amount of additional load losses from marginally viable industrial firms that we believe will be especially had hit by rare increases. This is because the general models used for near-term

forecasting do not fully capture the effects of price increases on some firms. Elasticities in our long-term load forecasting models are higher (about −0.3) reflecting the fact that consumers will show a greater response to price increases when they have more time to react (i.e., acquire more efficient buildings and equipment and/or substitute alternative fuels for electricity).

Unfortunately, several factors complicate the assessment of load responses to price increases outlined above. First, at the wholesale level, our utility customers will consider alternative sources of bulk power (generation resources or possibly non-BPA power purchases) that are competitive with the price of BPA's power. We presently believe that this rate threshold is between 35 and 40 mills/kVh depending upon the utility and resource being considered, assuming that utilities can acquire generation resources at a price comparable to BPA's acquisitions. This level is still significantly above our expected wholesale rate level, but the gap is narrowing.

Second, our analysis for the initial rate proposal considered BPA wholesale rate increases in the range of 15 to 17 percent. Significantly higher wholesale rate increases in the range of 20 percent or hither were not incorporated in the initial rate proposal, but sensitivity analyses with respect to higher rate increases have been conducted. Our current assessment based on work done to date is that most firms and industries will respond to higher rates consistent with the elasticities described above. We are continuing to review and assess likely responses to rate increases and will reflect the results of such review when we prepare our final rate analyses of loads.

Third, at the retail level, industrial consumers could be made temporarily or permanently unprofitable if their production costs increase significantly as a result of our rate increase relative to the market price for their products. At some point, are "thresholds" are reached, such that the load responses by individual consumers will be "lumpy." These response thresholds differ by individual firm and industry because individual economic and market circumstances differ. We focus analysis on those firms and industries most apt to hit "thresholds" and believe we have a reasonable assessment of likely load responses, but this sort of firm and industry level analysis is inherently complicated and difficult given the myriad factors that influence firms' decisions about operations and investments in plant and equipment.

Two large Northwest industries in particular, primary aluminum and pulp and paper, have sufficiently high electricity costs as a fraction of total production costs that significant load reductions are plausible. For example, a rate increase in excess of 25 percent would result in an aluminum smelter production cost increase of over 5 cents per pound of aluminum, which, at currently forecasted aluminum prices, could cause an additional load loss of 150 average NW beyond currently forecasted smelter curtailments, an amount equivalent to a small regional smelter.

At retail rates of 35 to 40 mills per kWh, pulp and paper mills would begin to consider installation of cogeneration facilities to decrease their reliance on purchased electricity. Even large (40 percent) wholesale rate increases do not result in industrial retail rates for most public industrial electricity consumption that approach 35 mills per kWh, however, Therefore our current analyses do not indicate that large reductions in pulp and paper loads will be triggered by the BPA rate increases currently being considered.

Mr. DEFAZIO. One other last, last point. Just an observation from my years in public service and government is that I realize that you are making some extraordinary efforts in terms of your administrative costs, and I was very pleased to hear that we are going to look at the contractors and WPPSS and their administrative and operating costs, et cetera.

But when you look at your major program areas, I guess I would say I am not certain that across-the-board cuts are most desirable, that in the case there may be some parts of the organization that haven't seen reductions or cuts or pressures as much as other parts of the organization; some parts of the organization are more essential than other parts of the organization; some parts are mandated, some parts are not.

I just want to express that general concern when you are looking at those sorts of constraints, and again, you are the administrator and you have got to make these calls, but it is just a general observation. It goes to the concern that I opened with and I'll close with,

which is to say that at any and all costs, not wasting money or anything else, but we have to avoid getting into a situation where our federal system is being run out of the courts.

It is just not desirable for anybody to get to that point in time, and if there are certain measures that some may even find objectionable in a difficult budget year, we have got to remember that, you know, fish, according to the Northwest Power Act, are not nice to have, they are something we have to have and we have to attempt to perpetuate. We really need to avoid in any areas of the budget untoward cost cutting. You know, in the case of the Forest Service, they did some things under the direction of John Crowell that the industry applauded greatly at the time and thought, "Boy, this is great, we are going to get more timber harvest." Well, it turns out, in fact, they began the long downward spiral to catastrophe and virtually no timber harvest or sale program and very little timber harvest because of what people thought was very beneficial to them at the beginning.

So I realize you have customer pressures, and I think, from the hearing, that you have expressed some things that I am very supportive of in terms of taking some tough looks at basically everything and putting everything on the table. I really applaud you and support that. I realize that you are under a multitude of pressures out there, but we have got to keep the long-term view in mind, too, as we make some of these short-term decisions. Maybe we are not going to be comfortable with it, but on the other hand, if it is a choice between an essential program that is going to avoid future huge costs, those are judgment calls you will have to make.

But I just want to applaud what I see as your willingness to consider anything and everything and let you know that I will support you in those efforts and continue to push you on a number of those points I raised.

I think you got the points about WPPSS and the contractors and some of the other things I raised. I think those are stones to be turned over in addition to some of these other things you are already doing, and I appreciate your willingness to be here and share so much of your time, your opinions, and be open with your responses. I hope that your customers appreciate it too because I think you are representing them well.

So thank you very much. I appreciate it.

Do you have any closing comments?

Mr. HARDY. I guess I would like to say two things, Mr. Chairman. One is, I appreciate, as I have expressed to you before, your chairing this task force and convening these series of oversight hearings. It helps to have someone, both you and the other task force members, taking a comprehensive look at what we do and the trade-offs we have to make.

I must say, what I suffer from most in this job is people coming in selectively on this issue or that issue and then they disappear for the 99 percent of the rest of the issues that I have to deal with. Taking a comprehensive look is very helpful to let us know whether, in your judgment, I am making the right judgments or we are making the right judgments about these trade-offs between the size of the rate increase and funding essential programs.

The other thing I would say is, when we talk about across-the-board cuts, I don't mean to imply equal percentage cuts for each program. We are talking about a range of 5–25 percent. What I mean to imply is, every program is going to take some level of cuts, but I am going to be highly selective in how I do this. When I say "cut, not gut," what I mean to try to express by that is, we are not going to sacrifice the long term for the short term, and we are not going to single out fish and wildlife and conservation programs to be the only programs that are going to be cut.

Unless I miss my guess, our transmission program will probably bear the single biggest share of the cuts of any of our programs. The others will span somewhere in between that 5–25 percent range with fish and wildlife probably being in the middle somewhere, but with making those reductions in areas like the squawfish program and other things, where we frankly can and should make them, but hopefully not sacrificing long-term objectives. I appreciate your support in trying to do that.

Mr. DEFAZIO. I will look forward to our series of hearings and meetings over the year. In the future you won't have to carry the entire burden yourself. We will have witnesses from the region, utilities and other interested parties at the future hearings, and I am looking forward to that.

Thank you. I appreciate it.

Mr. HARDY. Thank you, Mr. Chairman.

Mr. DEFAZIO. The hearing is adjourned.

[Whereupon, at 3:41 p.m., the task force was adjourned.]

APPENDIX

APRIL 28, 1993

ADDITIONAL MATERIAL SUBMITTED FOR THE HEARING RECORD

Questions and Answers Supplement
to the
Statement of Randall W. Hardy
Administrator of the
Bonneville Power Administration
United States Department of Energy
before the
Bonneville Power Administration Task Force
House Committee on Natural Resources
April 28, 1993

Responses to Congressman DeFazio's Pre-Hearing Questions
Bonneville Power Administration (BPA) Task Force

QUESTIONS FROM CONGRESSMAN DEFAZIO

Please note that the figures expressed in this document do not reflect revisions which will come about as a result of FY 1994 Rate Case settlement discussions and from BPA's ongoing cost cutting actions.

OVERVIEW

Question 1: Please indicate what percentage of the BPA FY 1994 budget is spent on the following:

- WNP 1, 2, 3 debt service
- WNP 1, 2, 3 operations and mothballing
- WNP 4, 5 settlement costs
- non-WNP energy resources
- federal/interest principle
- transmission
- residential exchange
- non-WNP operations
- conservation
- fish and wildlife

Answer: Percentages of the BPA FY 1994 budget are reflected in the following Table:

1994 Congressional Budget Obligations for FY 94

	Gross	Net 4/
	FY 1994	**FY1994**
WNP-1, 2 & 3 debt service	12.8%	17.2%
WNP-1, 2 & 3 operations & mothballing	5.8%	7.8%
WNP 4 & 5 settlement costs	N/A	N/A
Non-WNP energy resources 1/	8.2%	11.0%
Federal Interest/Principal 2/	19.8%	26.6%
Transmission	10.1%	13.6%
Residential Exchange 3/	29.6%	5.4%
Non-WNP operations (miscellaneous)	5.5%	7.4%
Conservation	5.4%	7.3%
Fish & Wildlife	2.7%	3.7%
TOTAL	**100.00%**	**100.00%**

1/ Includes short-term power purchases.

2/ Includes $156 million as an unscheduled amortization payment connected with funds from the non-Federal participants in the Third AC Intertie transmission line, and will be made only if these funds are received in a timely manner.
3/ The 1980 Northwest Power Act established the residential exchange in order to extend the benefits of the Federal Power system to all residential and small farm electric customer in the Pacific Northwest. The gross cost of the Exchange is offset by revenues of $1,055.2 million, resulting in an estimated net cost of program to BPA customers in FY 1994 of $166.6 million.
4/ For budgetary purposes BPA must obligate the gross costs of the residential exchange program. The only difference between the gross and net cost is a factor of the residential exchange program where the gross cost of the Exchange is offset by revenues of $1,055. million as noted in footnote #3. This column is provided for discussion purposes only.

OPERATIONS

Question 1: The amount of the BPA operations budget per year from FY 1980 to FY 1993 and proposed budget for FY 1994, with a breakdown of operations expenses by function per year.

Answer: The following Table 1 provides the data requested.

Question 2: A list of the number of FTE positions, including seasonal or temporary workers, at BPA by fiscal year from FY 1980 to FY 1993 and proposed FTE for FY 1994. Please provide a numerical breakdown for each fiscal year of the following:

- number of FTE at each GS, GM, or SES level;
- staff function by program (for example--power operations, transmission, conservation, public affairs, etc.), and;
- number of FTE slots actually filled.

Answer: **TO BE PROVIDED LATER** (Answer to Question #2 follows chart)

FY 1980 through FY 1994 Actuals and Projections

($ in thousands)

	FY 1980 Actuals	FY 1981 Actuals	FY 1982 Actuals	FY 1983 Actuals	FY 1984 Actuals	FY 1985 Actuals	FY 1986 Actuals	FY 1987 Actuals	FY 1988 Actuals	FY 1989 Actuals	FY 1990 Actuals	FY 1991 Actuals	FY 1992 Actuals	FY 1993 Projections	FY 1994 Projections
Expense															
Operation & Maintenance	84,049.0	94,884.0	102,050.0	106,257.0											
System Operations					25,822.0	27,937.0	24,860.0	22,778.0	24,580.0	24,972.0	25,112.0	20,865.0	34,456.0	34,400.0	37,000.0
System Maintenance					57,808.0	66,516.0	70,406.0	64,351.0	72,626.0	78,825.0	83,241.0	103,744.0	116,827.0	113,100.0	119,600.0
Power Scheduling					3,483.0	3,734.0	3,176.0	4,059.0	33,630.0	105,376.0	18,284.0	30,047.0	157,572.0	226,000.0	110,100.0
Power Marketing					6,470.0	11,707.0	10,361.0	13,098.0	41,182.0	41,214.0	46,427.0	48,736.0	49,322.0	65,800.0	69,500.0
Planning Council					4,904.0	6,196.0	5,888.0	6,368.0	8,716.0	7,373.0	7,117.0	7,289.0	7,873.0	8,700.0	8,030.0
Transmission System Development									25,114.0	27,468.0	21,896.0	21,068.0	32,597.0	25,100.0	25,000.0
Fish and Wildlife					10,553.0	15,018.0	19,580.0	26,368.0	12,083.0	26,649.0	25,232.0	42,188.0	68,867.0	64,800.0	65,000.0
Resource Planning, acq. & envt.	187,419.0	377,277.0	612,786.0	728,081.0	921,636.0	950,327.0	870,872.0	886,383.0							
Energy Conservation			1,283.0	18.0	1,571.0	1,109.0	5,550.0	13,208.0							
Energy Resources									876,700.0	831,226.0	831,298.0	752,271.0	839,484.0	815,600.0	884,500.0
Interest Expense	35,235.0	49,698.0	85,520.0	113,833.0	120,904.0	104,335.0	107,803.0	148,164.0	155,967.0	171,300.0	154,638.0	306,096.0	304,260.0	358,000.0	366,300.0
Residential Exchange			418,500.0	563,117.0	836,787.0	1,080,838.0	1,046,360.0	1,013,101.0	976,747.0	789,303.0	820,961.0	892,067.0	844,178.0	817,500.0	1,221,800.0
Associated Project Costs	58,452.0	73,672.0	78,873.0	87,896.0											
Bureau of Rec.					40,367.0	42,804.0	53,639.0	45,038.0	48,570.0	28,872.0	36,716.0	33,029.0	38,781.0	39,600.0	76,450.0
Corps of Engineers					60,689.0	60,335.0	80,363.0	71,974.0	83,600.0	64,785.0	84,987.0	68,839.0	78,023.0	76,900.0	78,000.0
U.S. F&W Service					2,931.0	2,845.0	2,922.0	3,428.0	6,146.0	7,356.0	8,296.0	9,633.0	10,189.0	11,500.0	13,200.0
System Planning & Construction			17,708.0	7,844.0	11,786.0	11,101.0	29,278.0	35,781.0							
Reimbursable	90,729.0		96,270.0	81,619.0	74,046.0	77,083.0	51,531.0	33,754.0	33,507.0	50,328.0	20,404.0	25,109.0	64,781.0	104,300.0	89,000.0
Misc. adjustment to actuals											7,384.0				
TOTAL EXPENSE	455,904.0	594,532.0	1,311,120.0	1,645,040.0	2,149,970.0	2,490,978.0	2,431,987.0	2,388,687.0	2,375,287.0	2,357,503.0	2,191,988.0	2,376,031.0	2,630,021.0	2,942,200.0	3,272,780.0
Capital															
Construction	129,130.0	189,190.0													
Energy Conservation			63,399.0	223,600.0	89,646.0	138,365.0	90,583.0	52,672.0							
Energy Resources									33,566.0	40,237.0	45,783.0	50,877.0	71,213.0	126,400.0	149,700.0
System Planning & Construct.			181,830.0	159,927.0	206,452.0	136,187.0	166,017.0	142,386.0							
Transmission System Development									48,499.0	55,436.0	106,263.0	128,979.0	212,608.0	181,700.0	148,300.0
System Maintenance									35,180.0	48,363.0					
System Replacements											63,050.0	57,169.0	90,168.0	97,900.0	97,400.0
Capital Equipment							12,506.0	11,721.0	6,478.0	7,256.0	8,964.0	8,346.0	12,156.0	16,200.0	16,000.0
Fish and Wildlife						10,224.0	8,015.0	5,863.0	9,864.0	8,138.0	17,997.0	11,815.0	15,781.0	21,800.0	34,900.0
Capitalized Bond Premium													28,025.0		
Misc. adjustment to actuals											(7,384.0)				
TOTAL CAPITAL	129,130.0	189,190.0	255,229.0	383,727.0	296,110.0	284,776.0	277,121.0	213,652.0	134,557.0	159,517.0	237,583.0	264,986.0	430,981.0	473,900.0	434,300.0
TOTAL OBLIGATIONS	585,014.0	783,722.0	1,566,348.0	2,028,767.0	2,445,080.0	2,665,547.0	2,709,088.0	2,602,344.0	2,509,844.0	2,517,020.0	2,434,561.0	2,641,057.0	3,060,002.0	3,416,100.0	3,707,000.0

Source: Congressional Budget Program & Financing Summaries

DRB01D7

4A

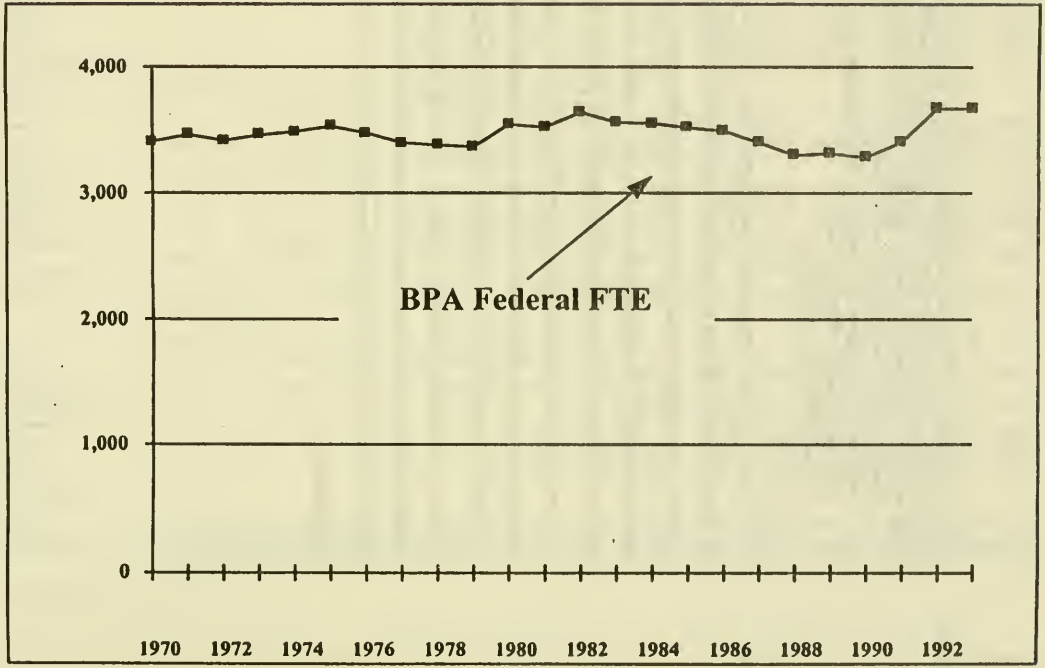
Question 2: A list of the number of FTE positions, including seasonal or temporary workers, at BPA by fiscal year from FY 1980 to FY 1993 and proposed FTE for FY 1994. Please provide a numerical breakdown for each fiscal year of the following:

- number of FTE at each GS, GM, or SES level;
- staff function by program (for example--power operations, transmission, conservation, public affairs, etc.), and;
- number of FTE slots actually filled.

Answer: BPA's Federal FTE ("full-time equivalent" employment level, or "worker-years") has been at a steady 3,500 plus or minus about 5 percent for the past 20 years (Figure 1). We estimate, however, that the regional workforce BPA pays for numbers about 12,000. So, BPA accomplishes most of its mission to deliver the benefits of the Federal Columbia River Power System to the people of the Pacific Northwest by and through other parties. Many of these parties are contractors of various stripes--construction firms in the building of our transmission facilities, retail utilities in the delivery of our conservation programs, the States and Indian Tribes in the enhancement of fish and wildlife, etc. Nearly all of the great expansion of BPA workload that came with the passage of the 1980 Pacific Northwest Electric Power Planning and Conservation Act has been accommodated by contracting.

Figure 1

Bonneville Federal Workforce



4B

The following chart (Figure 2) represents the actual number of BPA FTE at the GS/GM, SES, and hourly levels for fiscal years 1985 through 1992. Each FTE number represents all BPA positions including seasonal and temporary workers. Projected FTE at the GM/GS, SES, and hourly levels for fiscal years 1993 and 1994 is not available. However, FTE program levels for fiscal years 1993 - 1995 were projected in BPA's 1993 Initial Rate Proposal and are detailed in Figure 3.

Figure 2

Actual FTE Levels at Each GM/GS/SES/Hourly Level								
Grade	1985	1986	1987	1988	1989	1990	1991	1992
SES	12.51	12.81	11.85	13.69	16.13	15.44	14.37	14.17
GS 1	.68	.31	.03	0	0	0	.89	.59
GS 2	4.67	3.38	2.23	2.26	1.45	0	2.18	.55
GS 3	28.71	24.78	16.88	14.39	10.37	6.33	6.90	4.12
GS 4	184.17	164.28	123.56	116.48	100.16	71.67	60.79	43.68
GS 5	261.54	235.55	207.71	197.43	206.99	184.52	177.54	176.66
GS 6	129.88	125.98	120.63	114.69	113.91	111.59	125.46	144.71
GS 7	200.90	204.75	191.38	175.98	192.22	190.70	200.97	233.95
GS 8	71.01	64.20	62.62	59.30	52.73	45.66	49.39	51.51
GS 9	209.85	231.10	214.67	190.91	179.39	182.71	172.83	199.99
GS 10	28.01	22.17	20.62	18.04	21.07	16.68	17.29	23.80
GS 11	377.31	350.69	354.61	344.73	334.20	350.14	370.71	372.13
GS 12	586.08	603.76	595.84	594.30	621.96	632.58	651.83	716.18
GM/GS 13	345.66	343.76	344.81	341.69	362.08	375.92	399.01	436.12
GM/GS 14	122.23	126.09	130.06	118.08	117.61	116.76	130.58	155.16
GM/GS 15	50.51	49.70	52.56	48.08	45.00	48.73	50.12	51.87
Hourlies	1077.58	1011.55	950.58	947.70	936.61	931.15	968.62	1042.02
Totals*	3691.31	3574.86	3400.64	3297.75	3311.88	3280.58	3399.48	3667.21

*The official DOE totals may differ slightly from the above totals due to rounding.

Actual FTE at GM/GS, SES, and hourly levels is <u>not</u> available for years prior to 1985.

4C

The next chart (Figure 3) shows FTE by program, and includes projections for fiscal years 1993-1995.

Figure 3

Actual, Estimated, & Proposed Federal Staffing Levels By Program:
1993 Initial Rate Proposal
FTE

	FY 1990 1/	FY 1991 1/	FY 1992 1/	FY 1993 2/	FY 1994 3/	FY 1995 3/
Trans. System Development	418	440	540	506	494	465
Trans. System Operations, Maintenance & Reimbursable	1031	1031	1067	1092	1115	1116
Trans. System Replacements	226	249	247	249	255	283
Power Marketing and Scheduling	240	246	280	292	295	295
Energy Resources	309	347	380	385	390	390
Fish and Wildlife	49	54	64	72	75	75
Support Services & Information Resource Management	450	479	507	516	520	520
General & Administrative and Residential Exchange	558	553	582	555	561	561
TOTAL	3281	3399	3667	3667	3705	3705

1/ Actuals 2/ Estimated 3/ Proposed in rate case

Question 3: The total amount budgeted in FY 94 for purchases of equipment, including, but not limited to, computers, vehicles, furniture, and a list and description of these proposed expenditures.

Answer: For FY 1994, BPA has budgeted approximately $12,770,000 for capital tools and equipment. This includes $7,600,000 for power system tools and equipment, and $5,170,000 for capitalized general purpose Automated Data Processing equipment, and capitalized office equipment and furniture.

Descriptions of these categories are provided below. In addition to these amounts, BPA makes expenditures for transmission system equipment such as transformers, circuit breakers, microwave, etc., which are purchased as part of the capital investment for transmission system development and maintenance and replacement programs.

Note: Please note that the following discussion does not yet include the effects of current cost-cutting efforts.

Power system capital tools and equipment:

Capitalized tools and equipment - portable generators, electronic survey equipment, chemical sprayers, electric welders, cable and conductor handling equipment, saws, metal fabrication equipment, etc. - $532,000.

Motor vehicle equipment - Line trucks, trailers, crawlers, tractors, truck-mounted cranes and manlifts, material handlers and all-terrain cranes, etc. - $2,432,000.

Laboratory and field test equipment - Video probes, electronic digital hydrometers, digital circuit-breaker timers, portable digital fault recorders, D.C. ground detectors, 500-kv standard resistor, etc. - $2,812,000.

Power systems control equipment - Communications test, voice, and data equipment, baseband spectrum analyzers, noise-load test equipment, circuit board testers, signal disturbance monitors, network analyzers, etc. - $1,292,000.

Special purpose ADP equipment - engineering image processing , stereo plotters, etc. - $532,000.

General Purpose Automated Data Processing Equipment:

Personal Computers - Personal computers , soundboards and system cards, anc PC printers - $965,000.

WAN/LAN Equipment - Wide Area Network and Local Area Network computer systems servers, hubs, modems, cabling, etc. - $1,140,000.

Scientific and technical equipment - workstations, VAX's, VAX disk storage, IBM disk storage, etc. $1,740,000.

Telecommunication equipment - telephone switch, televideo conferencing equipment, etc. $410,000.

Office Furniture and Systems Equipment. - Systems furniture, filing and records storage equipment, and printing, photographic, and reproduction equipment - $915,000.

Question 4: BPA contractor expenditures from FY 1991 to FY 1993 and proposed expenditures for FY 1994. Please provide a numerical breakdown for each fiscal year of the following:

- number of contractor employees;
- amount of contractor funding by program;
- contractor equipment purchases paid for by BPA.

Answer: BPA does not measure directly the staffing levels of its contractors. We have made rough estimates, nevertheless, from funding levels and information provided verbally by the contractors. The numbers in Figure 1 are FTE for which BPA bears the cost.

Figure 1

TOTAL STAFFING IN BPA BUDGET
FTE

	1991	1992	1993
BPA Federal Employees	3399	3667	3667
BPA Contractors and Cooperating Agencies			
Trans. System Design and Construction	607	694	864
Trans. System Operation & Maintenance	224	230	281
Energy Conservation	700	900	1200
Hydro Generation & Construction	1680	1680	1630
Nuclear Generation	2901	2901	2808
Fish and Wildlife	757	823	924
Other	490	670	681
TOTAL	10,758	11,565	12,055

Two subsets of this contractor and cooperating agency workforce are directly engaged by BPA management--transmission system construction contractors, and support services contractors. Expenditures for the latter are estimated by program in Figure 2.

FIGURE 2*
SUPPORT SERVICES CONTRACTING

PROGRAM	FY 1991	FY 1992	FY 1993[1]
Trans. System Development	$4,815,500	$5,785,300	$10,885,000
Trans. System Operations, Maintenance & Reimbursable	10,843,700	8,007,000	8,968,000
Trans. System Replacements	0	3,005,100	4,795,000
Power Marketing and Scheduling	1,227,800	2,348,000	4,070,000
Energy Resources	12,134,600	18,223,900	13,445,000
Fish & Wildlife	265,700	313,400	300,000
Support Services & Information Resource Management	15,273,500	14,192,800	12,160,000
General & Administrative and Residential Exchange	7,726,800	8,166,500	11,128,000
TOTALS	$52,287,600	$60,042,000	$65,751,000

[1] Source: Post-Programs In Perspective Decisions, September 1992. The impact of the recent administrative and program cuts are not reflected in this data.

*(Estimates from operating plan projections at start-of-year. Projections not yet available for FY 1994).

Estimates of the FTE that have been or will be engaged in BPA support services contracting are presented by program in Figure 3.

Figure 3

Estimates of Support Services Contractor Staffing Levels:
FY 1994-95 Post-PIP Decisions
By Program Areas
FTE

	FY 1990 1/	FY 1991 1/	FY 1992 1/	FY 1993 2/	FY 1994 3/	FY 1995 3/
Trans. System Development	128	107	94	163	140	141
Trans. System Operations, Maintenance & Reimbursable	270	155	135	185	193	193
Trans. System Replacements	/4	54	62	78	74	79
Power Marketing and Scheduling	17	15	33	56	53	48
Energy Resources	144	151	112	136	136	136
Fish and Wildlife	6	6	11	8	8	9
Support Services & Information Resource Management	243	258	263	292	296	295
General & Administrative and Residential Exchange	112	132	157	192	192	193
TOTAL	920	878	867	1110	1092	1094

1/ Actuals 2/ Planned 3/ Proposed 4/ Included In Trans. System Operations, Maintenance & Reimbursable

BPA does not have a tracking system in place to track purchases of equipment for contractors.

On contractor equipment purchases paid for by BPA, BPA generally retains the title on the equipment. If the useful life of the equipment is over when the contract expires, BPA may abandon the property in place or transfer the title. If the useful life is not over by the time the contract expires, the equipment either comes back for utilization or disposal or, in a few cases, BPA allows the contractor to retain the equipment if they could use it on another contract for BPA or for some other Federal agency.

Question 5: It is my understanding that at the most recent "Programs In Perspective" BPA engineers agreed that in certain cases local utilities can design and construct power lines below 500 kv more cost-effectively than BPA. Is this an accurate statement? If so, how much money could be saved from FY 1994 to FY 1998 if BPA turned this responsibility over to the local utilities? Are there other areas relating to transmission that BPA could transfer work to local utilities to achieve more cost-effective results?

Answer: The statement is not accurate. In the last Programs in Perspective BPA stated that in some cases local utilities can build 115 kv transmission lines less expensively. The comment did not include facilities above 115 kv and did not extend to the construction of 115 kv substation facilities or the operation and maintenance of facilities. The primary reason for BPA costs being higher than some customer costs is related to the Federal requirement for complying with environmental planning studies and securing of transmission line right-of-way. The added right-of-way costs are attributable to width requirements to comply with reliability criteria. We can build short 115 kv lines and rebuild 115 kv lines to 230 kv more cost effectively than other utilities by using our area Transmission Line Maintenance crews. However, this practice detracts from our maintenance program.

Periodically, BPA conducts intensive detailed comparisons of its design criteria and unit costs for various transmission facilities with a number of U.S. utilities. In these comparisons, the cost of BPA facilities at 500 kv and 230 kv have been some of the lowest in North America.

We believe very little savings could be accomplished between FY 94 to FY 96 by turning over construction to local utilities for 115 kv facilities. In years past, BPA has built a significant number of 115 kv lines. The BPA system has a total of approximately 3,300 miles of 115 kv. However, during the last five years, BPA has completed only 2 miles of new 115 kv line. For FY 1994 to 1998 we anticipate building only 15 miles of new 115 kv line as part of a larger construction program involving 500 kv construction.

At the present time, we are unaware of other areas related to transmission that could be transferred to local utilities. As part of the competitiveness initiative we will however, continue to look at all areas of transmission line and substation design and construction at voltages of 115 kv and above to determine how, all things considered, these projects can be built in the most cost effective manner.

Question 6: Has an independent entity conducted a top to bottom review of the efficiency of BPA operations? If not, does BPA intend to initiate such an independent review?

Answer: BPA has not had an independent entity review its operations. However, BPA has initiated an internal (function-by-function) review of the entire agency's operating efficiency. This will be a customer-based, quality-based review. It will focus on what the customers need, what BPA produces to meet that need,

and how efficiently and effectively BPA produces it. Customers will be represented on each of the functional review teams. At the present time, BPA does not intend to contract outside the agency for such a review.

Question 7: BPA has announced that cuts will occur in the administrative budget, including employee training, travel, supplies and support services. What level of reductions will you take from current levels in these and other administrative areas? What cuts will be taken in FY 94 and FY 95 from budgeted levels?

Answer: On April 9, 1993, BPA announced cuts of up to 50 percent in the remaining fiscal year 1993 budgets for administrative costs. The purpose of these cuts is to conserve maximum cash in FY 1993 so that BPA can make its annual payment of approximately $700 million to the U.S. Treasury on September 30, 1993. Examples of the administrative cuts BPA is making include limiting travel, eliminating most training, reducing office supply purchases, restricting overtime, limiting use of support service contracts, increasing charges for employee services, and placing a moratorium on work station and equipment moves. The actual savings from these cuts is still being identified by BPA managers.

At the same time, BPA is undertaking an agency-wide function-by-function review to identify all possible cost-savings and efficiencies that can be gained on a permanent basis. BPA customers have been invited to participate in this review.

Simultaneously, BPA is reviewing its FY 1994 and FY 1995 program levels, in an effort to minimize the rate increase slated to go into effect on October 1, 1993. BPA program managers have been asked to look at the impacts of cuts ranging from 5 to 25 percent. Over the next several weeks, customers, key

constituent groups, and Congressional committee members will be solicited for ideas on how we can achieve these cuts in a balanced and equitable fashion.

Revenues

Question 1: An estimate of the amount of revenues foregone per fiscal year since the irrigation discount was implemented in 1984, and an estimate of the revenue increase per year from FY 1994 to FY 1998 if it is eliminated. Is there any statutory basis for the irrigation discount?

Answer: The irrigation discount has been available since 1985 and the participating utility must pass through the entire amount to the end-user irrigator.

The annual amount of the irrigation discount since 1985 is as follows:

Year	Irrigation Discount Amount ($ Millions)
1985	6.050
1986	11.976
1986	11.976
1988	17.468
1989	14.043
1990	13.025
1991	11.883
1992	13.236

Concerning the amount of revenue deficiency for future years, in BPA's initial rate proposal BPA forecasted the revenue deficiency for the upcoming 2-year rate period (FY 1994 and 1995) to be a total of $27.018 million. No forecast for years beyond 1995 has been performed.

BPA regrets that it must refrain from addressing the question pertaining to the statutory basis for the irrigation discount due to the prohibition on ex parte communications that applies to issues pending resolution in rate hearings conducted pursuant to section 7(i) of the Northwest Power Act. Please refer to the explanation (Enclosure 1) at the end of this document.

Question 2: An estimate of the amount of revenues foregone per fiscal year since the low-density discount was implemented, the revenue increase per year from FY 1994 to FY 1998 if the discount is eliminated, and an estimate of the revenue increase, if any, if the discount is modified in accordance with the proposal submitted by the Northwest Conservation Act Coalition.

Answer: By fiscal year, the amount of low-density discount is reflected in the following table.

Year	Low Density Discount* ($)
1982	5,502,559
1983	7,660,127
1984	9,490,116
1985	12,471,338
1986	11,876,838
1987	11,852,888
1988	13,993,768
1989	15,190,906
1990	18,625,482
1991	18,363,652
1992	18,859,375
Forecasted	
1994	21,336,000
1995	21,619,000

*Numbers exclude residential exchange.

The amount of the low-density discount for FY 94 and FY 95, as forecast in BPA's initial rate proposal is $21,336,000 and $21,619,000, respectively. No forecasts for years beyond 1995 have been performed.

BPA regrets that it must refrain from addressing the question concerning the proposal submitted by the Northwest Conservation Act Coalition due to the prohibition on ex parte communications that applies to issues pending

resolution in rate hearings conducted pursuant to section 7(i) of the Northwest Power Act. Please refer to the explanation (Enclosure 1) at the end of this document.

Question 3: It is my understanding that certain BPA customer utilities have advanced a proposal to increase BPA's short-term cash flows by paying their BPA obligations earlier than they presently do. Please describe the benefits that might accrue to BPA if this approach was adopted. Does BPA plan to implement this proposal?

Answer: BPA regrets that it must refrain from addressing this question due to the prohibition on ex parte communications that applies to issues pending resolution in rate hearings conducted pursuant to section 7(i) of the Northwest Power Act. Please refer to the explanation (Enclosure 1) at the end of this document.

While ex parte restrictions prevent BPA from discussing this specific proposal, the agency has lowered its level of working capital (which this proposal was designed to address) from $100 million to $50 million in its initial rate case proposal. It is possible that this level may be lowered further, with associated rate savings, as the rate case progresses. This lower level of working capital might result from adopting a form of the customer prompt payment suggestion, or from other financial approaches.

Question 4: An estimate of the effect on revenues in FY 1994 and annually thereafter if BPA sold 1350 megawatts of Third AC capacity to participants instead of the 725 megawatts of capacity BPA currently plans to sell.

Answer: BPA regrets that it must refrain from addressing this question due to the prohibition on ex parte communications that applies to issues pending

resolution in rate hearings conducted pursuant to section 7(i) of the Northwest Power Act. Please refer to the explanation (Enclosure 1) at the end of this document.

Washington Public Power Supply System (WPPSS)

Question 1: An estimate of the savings per year from FY 1994 to FY 1998 if the "mothballing" of WNP 1 and 3 was terminated.

Answer: The current cost to preserve the two projects is approximately $10.5 million per year, of which about half is funded from BPA revenues (which is included in the current rate case) and half from the WNP-1 construction fund. The savings from discontinuing preservation may be offset by other costs. The most significant is site restoration. BPA and the WPPSS are working to resolve a number of legal and financial issues in order to maximize the potential savings from a termination decision. These issues must be resolved prior to making a termination decision.

Question 2: An estimate of the revenues that would result if WNP 1 and 3 fuel was sold following the termination of mothballing.

Answer: The current market value of the WNP-1 and WNP-3 fuel and enrichment is approximately $100 million. Depending on market conditions and the approach used to sell the fuel, that amount could be recovered over the next several years following a termination decision. It should be noted that short term disposition of these quantities could depress the market price for the commodity and reduce the net gain from the sale. There are unresolved legal issues that could restrict the potential uses of revenues from fuel and other asset salvage sales. Resolution will likely require a declaratory judgment in state or federal court.

Question 3: Please provide an estimate of the payment the BPA will make to WPPSS for the operating costs of WNP-2 in FY 1994. How do WNP-2 operating costs compare to the nuclear industry average? Does BPA have a mechanism for auditing WNP-2 operating expenses? Has BPA ever refused to pay any WNP-

2 expenses? If so, please state the amount of payment refused and the rationale [or] doing so.

Answer: The payment BPA will make to the WPPSS for the FY 1994 (July 1-June 30) WNP-2 operating costs is estimated to be $242 million. This figure includes operating and maintenance, capital and fuel. Verifiable industry cost data is difficult to obtain. However, in our opinion, WNP-2 operating costs (37.0 mills/kwh - 12 month rolling average as of March 1993) are within the cost range experienced by other Single Nuclear Plant Utilities and on the high end of the industry average cost for Single Nuclear Plant Utilities. BPA does not currently audit WNP-2 operating expenses but does have an oversight staff at the WPPSS and a member of BPA's internal audit staff is a part of this group. The oversight staff, working in conjunction with BPA headquarters staff, is responsible for exercising BPA's contractual authorities including approval of annual budgets and contract awards greater than $500,000. Any BPA disapproval must be based solely on whether the item is consistent with the standard of prudent utility practice. BPA has not formally disapproved any WNP-2 expenses. However, the WPPSS has been responsive to BPA's requests regarding outage scheduling and reducing expenditures whenever prudent.

Question 4: It is my understanding that WPPSS currently pays its board members $500 per day of service. Does BPA reimburse WPPSS for these expenses? If so, please provide an estimate of the total funding BPA has provided WPPSS since 1980 for this purpose.

Answer: The WPPSS currently pays its board members $500 plus expenses per day of service. BPA reimburses the WPPSS for these expenses. Below are the totals for the fiscal years 1987 through 1993. Earlier data is not readily available because it is archived at the WPPSS.

WPPSS Board Member Expenses

WPPSS/Fiscal Year (July-June)**	Expenses $ [1]	Fees $ [2]	Total $
1987	87,283	279,217	366,500
1988	56,943	216,550	273,493
1989	86,603	275,100	361,703
1990	139,606	331,450	471,056
1991	119,772	267,950	387,722
1992	100,338	246,650	346,988
1993	104,800	233,000	338,000
TOTAL	651,745	1,763,517	2,415,262

*1993 - Total FY 93 budget.
**WPPSS fiscal year is July-June

Question 5: Please provide an estimate of WPPSS administrative expenses that will be reimbursed by BPA in FY 1994.

Answer: The WPPSS administrative and general expenses are estimated to be $15 million in its FY 1994 budget. BPA will reimburse 99 percent of these expenses.

Question 6: A list of the number of FTE positions at WPPSS, including contractor, temporary and seasonal employees by fiscal year from FY 1980 to FY 1994 and proposed FTE for FY 1994. Has the number of WPPSS staff declined as WPPSS responsibilities have declined? How does the number of WPPSS staff who are responsible for the operations of WNP-2 compare to the nuclear industry average?

Answer: The table below lists the approximate number of WPPSS staff including contractor and temporary employees. Seasonal employees are not included in these figures. These employees are hired for and during the spring outage and number approximately 300 per year. Contractor figures for FY 1989 are not available. Data prior to FY 1987 is not readily available because it is archived at WPPSS.

[1] Expenses: Includes travel, per diem, car rental, etc.
[2] Fee: Stipens authorized per Washington State Legislature.

Please note that WPPSS fiscal year runs from July 1 to June 30.

WPPSS Staff

WPPSS Fiscal Year (June - July)	Total Average Staff*
1987	2326
1988	1838
1989	1710
1990	1898
1991	1876
1992	2042
1993**	1946

* Includes contractor staff, except in 1989
**1993 - As of February 28, 1993

* WPPSS staffing levels for WNP-1 and 3 have decreased drastically since FY 1980. In FY 1987, approximately 575 staff were charged to projects other than WNP-2. As of February 1993, all but approximately 190 staff were being to charged to WNP-2.

Verifiable industry staffing data is difficult to obtain. However, in our opinion, WNP-2 staffing levels are higher overall than the industry average for Single Plant Nuclear Utilities on a FTE basis. They are within the range of other Single Plant Nuclear Utilities, though on the high side of that range. FTE staffing in Operations, Maintenance, Training, and the Engineering disciplines is about average and the Administration and Operations Support disciplines are higher than the industry average. Industry data is difficult to analyze for administrative and support functions. To address the staffing level, the WPPSS commissioned an independent organizational efficiency study in 1991. The results indicated that 110-160 WNP-2 positions could be eliminated due to efficiency improvements. The WPPSS has committed to reducing total organization staffing by 160 positions by FY 1997.

Question 7: Please provide WNP-2 operations and maintenance (O&M) expenditures per year from FY 1985 to the present and estimated O&M expenditures for FY 1994. What percentage of these O&M expenditures have been reimbursed by BPA under the net billing agreement from FY 1985 to the present? How do WNP-2 O&M expenditures compare to the nuclear industry average?

Answer: Operations and Maintenance (O&M) expenditures presented below include capital and other costs with the exception of FY 1987 and 1988. Capital/Other costs are not readily available for those years. Data prior to FY 1987 is also not readily available.

WNP-2 O&M Expenditures
($ in millions)

WPPS Fiscal Year (June - July)	O&M	Capital/Other	Total
1987	129.3	NA	129.3
1988	137.4	NA	137.4
1989	152.6	11.3	163.9
1990	170.3	30.0	200.3
1991	171.0	27.9	198.9
1992	168.5	59.6	228.1
1993	191.3	79.5	270.8

*1993 - Year End Estimate

BPA reimburses 100 percent of the WNP-2 O&M costs. Verifiable industry cost data is difficult to obtain. However, in our opinion, WNP-2 O&M costs are on the high end of the industry average cost for Single Nuclear Plant Utilities.

Question 8: Portland General Electric recently concluded that it was more cost-effective to permanently shutdown the Trojan reactor than to continue to operate it. Has BPA conducted any analysis of the long-term cost-effectiveness of continuing to operate the WNP-2 reactor? If so, what are the results of this analysis?

Answer: Although WNP-2 is not facing a large capital investment as Trojan Nuclear Plant was, BPA has analyzed the cost-effectiveness of continuing to operate

WNP-2 but on a lesser scale than done by PGE for Trojan. BPA maintains a continuous dialogue with WPPSS about WNP-2's performance to date and long term strategic targets for WNP-2. The targets include increasing capacity factor and limiting cost growth to achieve a total cost of power of 26 mills/kwh in 1990 levelized costs. Most recently, in October 1992, BPA formally presented to WPPSS managers a comparison of WNP-2's cost of power with BPA's competitive acquisition results and with Trojan. The comparison showed that WNP-2 needed to meet its strategic targets to be competitive with BPA's new acquisition opportunities (1990 levelized costs of 34 mills/kwh). BPA has notified the WPPSS that achievement of the strategic targets for cost of power is critical to the future of WNP-2. Failing to reach a 65 percent capacity factor and not holding the line on costs would cause WNP-2 to not be competitive with other resources and could result in WNP-2 meeting the same fate as Trojan. The WPPSS has committed to and is progressing towards reaching those targets.

Conservation

Question 1: In a letter to Chairman Miller dated March 24, 1993, the Northwest Power Planning Council stated that BPA "has not been aggressive in reducing program administrative costs" for conservation programs. Please identify potential savings, if any, per fiscal year from FY 1994 to FY 1998 from reducing administrative costs of conservation programs.

Answer: Conservation is a resource for which quality control is essential. This requires administrative costs at both the level of BPA and the individual utility. Many of these costs are fixed in absolute terms, and others depend on the level of activity. BPA has committed itself to an agency-wide review of every function, including conservation and generation acquisition activities. We have been examining the issue of administrative cost in detail over the last four months, and are looking for efficiencies in both direct and indirect administrative costs. The challenge is to acquire more megawatts for approximately the same or slightly increased administrative support. BPA programs have already shown this type of improvement from FY's 1991 to 1992 as our "dollars-out-the-door" went up by about 40 percent without an appreciable increase in direct or indirect administrative costs. Just as in all other program functions we are reviewing and will be cutting costs in our conservation programs. Program budgets for FY 1994 through FY 1998 are projected to grow, however, we will be reducing FTE, and support service contracts. These costs can vary with the level of activity and will not increase at nearly the rate of the incentive budgets.

We are striving for continuous improvement, but do not have an estimate of administration-cost savings for the FY 94 to FY 98 period.

Question 2: Please provide an estimate of the total expenditures to date of the "Super Good Cents" program in areas where natural gas service is currently available. Please estimate the budget savings that would result from a termination of the Super Good Cents program in areas currently served by natural gas per fiscal year from FY 1994 to FY 1998.

Answer: It is difficult to estimate the expenditures for areas in which gas is available, because expenditures are done by utility and gas is not equally available within each utility, even when gas is available to a part of the service area. Nevertheless, we estimate that between FY 1985 and FY 1992, BPA paid incentives of $8.4 million for new construction where gas is currently available.

The Super Good Cents Program covers both single family and multifamily construction. We estimate that, if the Super Good Cents Program were terminated in the areas served by natural gas, BPA expenditures would be reduced by $3 to $5 million in each of the fiscal years 1994 through 1998, and 2.0 average megawatts of electrical efficiencies would be lost in multifamily construction in those areas.

Question 3: It is my understanding that a study has been conducted which compares the costs of BPA conservation programs per unit of energy saved to the costs incurred by certain Northwest utilities per unit of energy saved. Please provide a copy of this study and explain the differences in conservation costs, if any, between BPA and regional utilities.

Answer: We have not conducted such a study, nor were we aware of any such study. Further, the Northwest Power Planning Council, in preparing its "Green Book", did not discuss the issue of cost/kilowatt hour. Such comparisons are extremely sensitive with regard to whether the "achieved" savings are

rigorously evaluated, and exactly what specific costs are included in the analysis.

Question 4: To date BPA's conservation programs have focused primarily on producing energy savings in the residential sector. Please provide an estimate of the current cost per unit of energy saved from residential, commercial and industrial conservation programs respectively.

Answer: The most current cost estimates are those for FY 1992. The costs listed below are real levelized costs in order to account for the varying measure lives. We are providing both the BPA cost and the Pacific Northwest Regional cost for all of the sectors from which BPA acquired conservation resources in FY 1992.

	BPA cost	Regional cost
Residential Sector	17 mills/kWh	22 mills/kWh
Commercial Sector	21 mills/kWh	24 mills/kWh
Industrial Sector	8 mills/kWh	9 mills/kWh
Agricultural Sector	37 mills/kWh	46 mills/kWh

The residential sector includes appliance efficiency, residential weatherization, manufactured housing, Super Good Cents, and the Northwest Energy Code Programs. The commercial sector includes Targeted Acquisitions, Commercial Model Conservation Standards, and Energy Smart Design. The Industrial sector does not include Conservation/Modernization (aluminum industry program), which did not acquire new efficiencies in FY 1992.

Question 5: Please provide an estimate of BPA expenditures to date on the Manufactured Housing Acquisition Program (MAP) per fiscal year. What percentage of these expenditures were administrative costs? Please provide an estimate of the percentage of MAP homes that are sited in areas currently served by natural gas.

Answer: As background, the MAP program includes a feature in which BPA pays the manufacturers for each qualifying home. The region's investor owned utilities (IOUs) reimburse BPA on a dollar-for-dollar basis for each home sited in their service territory. Because BPA is reimbursed for these costs there is a natural lag between BPA expenditures, creating a situation where BPA costs always appear greater at any one time than they actually are.

BPA paid about $8 million dollars to manufacturers in FY 1992, and $22 million in FY 1993, as of April 1, 1993. We have received reimbursements from the IOUs of $5.2 million, with another $7 million in process.

Administrative costs for FY 1992 and 1993 were $1.1 million annually, including support to the states to help with the program. This is less than 4 percent of the total program expenditures in these two fiscal years.

Even in utility service territories that also receive gas service, the rural sections of the utility (where the MAP homes are likely to be sited) do not usually have accessible gas service. Based on a BPA survey of gas and electric utilities, we estimate that for the region as a whole, 20 percent of the MAP homes will be sited in areas where gas would be available.

Question 6: How much electric water heating and space heating load does BPA currently serve? How much of this load is in areas currently served by natural gas? What is the relative efficiency of burning natural gas in a turbine to produce electricity which is used for water and space heating vs. burning gas on site for this purpose?

Answer: BPA currently serves about 1,600 aMW of electric space and water heating load. About half of the homes using electric space and water heat are in areas

where gas is available. Another 25 percent of these homes could be served with gas if natural gas mains were extended.

For a large fraction of these homes, conversion to natural gas is technically feasible. However, BPA has concerns about whether a fuel switching program can be designed to be cost effective. We intend to test this question through our fuel switching pilot program.

A combined cycle gas combustion turbine (CT) on average provides 38 Btu's in the home for every 100 Btu's of gas put in a pipeline and delivered to the powerplant. On the other hand, direct gas combustion for space and water heat on average provides 68 Btu's in the home for every 100 Btu's put in a pipeline and delivered to a home or building.

Question 7: Please describe the scope of BPA's activities regarding fuel switching.

Answer: BPA has several fuel switching activities under way at this time. These activities are discussed in the 1992 Resource Program.

BPA has been working with staff from the Northwest Power Planning Council (Council), Oregon Public Utility Commission, Association of Northwest Gas Utilities, and Northwest Natural Gas to develop a natural gas option for the region's MAP manufactured home efficiency program. MAP currently provides payments to manufacturers to offset the costs of building more energy efficient electrically heated manufactured homes. The goal is to determine

what additional efficiency investments are economically justified for gas heated homes and to support efforts by the Council, gas companies, and other parties to modify MAP to include a gas efficiency option.

In the 1992 Resource Program, BPA recognized the need to review its electricity conservation programs and incentive payments for unintended fuel choice effects. The goal of BPA's programs is to acquire cost-effective conservation, not to inadvertently induce consumers to choose electricity over natural gas or induce consumers to stay with electric space or water heat when they would have switched to natural gas absent BPA's programs. We have scheduled review of all of our programs where fuel choice/fuel switching is an issue. Results of our initial reviews of the Long Term Super Good Cents and MAP programs will be available in June, 1993. Results for other programs will follow in summer and fall 1993.

BPA is working with its customers on three or four customer-initiated projects to develop better information on fuel choice costs, benefits and policy options. In the 1992 Resource Program, BPA determined that it had insufficient basis for specific fuel choice actions beyond those noted above. We are now pursuing three customer initiated projects that will provide us with better information for developing sound fuel choice policy options for the 1994 Resource Program. These projects also provide specific economic or information benefits to sponsoring customers.

BPA is continuing work to develop information and policy options for the 1994 Resource Program. These activities include data development and analysis, participation in the Council's Natural Gas Advisory Committee, and

participation in Washington Natural Gas' Least Cost Plan update. BPA has established an internal "Fuel Choice" team to oversee and coordinate all BPA fuel choice/fuel switching activities.

Question 8: Please provide an estimate of the amount of energy that would be saved per year if the two-tiered rates and low density discount adjustment recommended by the Northwest Conservation Act Coalition were implemented (growth adjustment and no-growth adjustment model). What is the earliest possible date that BPA can implement tiered rates? Has BPA initiated an EIS on tiered rates?

Answer: BPA has initiated an Environmental Impact Statement (EIS) on tiered rates. The Federal Register notice of intent for the rate design EIS is scheduled for publication late this spring.

BPA regrets that it must refrain from addressing the Northwest Conservation Act Coalition's proposal due to the prohibition on ex parte communications that applies to issues pending resolution in rate hearings conducted pursuant to section 7(i) of the Northwest Power Act. Please see Enclosure 1 at the end of this document.

However, status reports and communications related to matters of procedure are excluded from the prohibition on ex parte communications. As such, BPA is able to report that on April 18--the last day of settlement negotiations in BPA's 1993 rate case--it responded favorably to the settlement proposal of the Northwest Conservation Act Coalition (NCAC) to consider tiered rates in a separate public process and 7(i) rate case. This proposal, made for settlement purposes only, recognized that there is a need to (a) synchronize tiered rates with customers' ability to capture conservation savings, (b) initially give full consideration to many variables and viewpoints outside the adversarial 7(i)

format, (c) assure tiered rates will not be put off in the future because of the complexity of the 1995 rate case, and (d) perform necessary Environmental Impact Statement work. NCAC specifically proposed for settlement purposes only that (a) a formal study group be formed to consider tiered rate proposals, (b) a final report be issued in early 1994, (c) the tiered rates proposals inform and affect rate principles in the power sales contract negotiations, and (d) BPA hold a separate 7(i) on tiered rates, possibly in 1994. Additional time will be spent by the rate case parties prior to commencement of cross-examination (May 10) to determine if a workable settlement can be fashioned along the lines suggested by NCAC. BPA staff is currently evaluating what a realistic timetable is for a separate tiered rates process, including formal study groups and a tiered rates 7(i) hearing. The Administrator is desirous that a separate 7(i) on tiered rates be commenced and concluded in FY 1994.

Capital Investment

Question 1: The amount of the BPA capital investment budget per year from FY 1980 to FY 1993 and proposed budget for FY 1994 with a breakdown of expenditures by function per year.

Answer: Please refer to the Table 1 provided in the answer to Question 1 of the Operations section for the data requested.

Question 2: It is my understanding that BPA is currently considering a number of proposals for customer capital financing of conservation activities. Please describe each of these proposals, including the amount and terms and conditions of such financing, and the amount of energy that would be saved. Does BPA plan to utilize these proposals to reduce its dependence on Treasury borrowing?

Answer: BPA may utilize certain conservation proposals to reduce its dependence on Treasury borrowing. Currently, proposals from various utilities are being evaluated for conservation program cost-effectiveness for the amount of conservation savings proposed. There are presently seven utilities/organizations with proposals in various stages of development that have the potential for customer capital financing of conservation activities. They include Tacoma Public Utility District (PUD), Seattle City Light, Grant PUD, Emerald PUD, Eugene Water and Electric Board (EWEB), Conservation and Renewable Energy System (CARES), and Oregon Municipal Electric Utilities (OMEU). Preliminary estimates of proposed conservation programs, for BPA's Fiscal Years 1994-95 only, are identified below.

Because the exact terms and conditions, and feasibility of each financing is not clearly defined at this point, the budget still assumes that these investments would be financed through Treasury borrowing. However, discussions are

underway with some of the utilities and as opportunities for customer capital financing are further defined, assumptions in the budget may be revised.

Utility/ Organization	BPA FY 1994-95 ($millions) Proposed Conservation Program	Energy Savings (amw) 1994-95
1. Tacoma PUD	$26.5	6.30
2. Clark PUD*	$15.4	9.86
3. Seattle City Light	$51.5	22.30
4. Grant PUD	$5.1	5.60
5. Emerald PUD	$4.0	0.80
6. EWEB	$16.8	6.16
7. CARES	$30.6	8.90
8. OMEU	$13.8	3.98

* Proposal withdrawn

Question 3: Which capital financing methods have the least impact on electric rates over the short term? Over the long term?

Answer: Capital investments may be financed either through long-term borrowing or directly through revenues generated from current rates. When capital investments are financed through long-term borrowing, the impact on near-term rates is minimized through annual debt service payments of principal and interest that are spread over a number of years. Because funding of capital investments through long-term borrowing involves the payment of interest charges on the funds borrowed, over the long-term, total payments are higher than they otherwise would be if financed directly through revenues. Thus, over the long-term, investments funded through revenues will tend to lower the upward pressure on electric rates due to the fact that the accumulation of interest charges is avoided.

BPA is pursuing the use of cost-effective third-party financing sources to the greatest extent feasible to provide capital financing. Feasibility is determined

by the overall economics of a resource proposal such that the net benefits are greater to BPA than borrowing from the Treasury. Priority is given to tax-exempt third-party sources. Implementation of third-party financing will reduce pressure on BPA's Treasury borrowing cap and, to the extent that tax-exempt sources are used, help minimize interest costs. It is important to note that implementing third-party financing is complex due to structuring, legal, and tax considerations. Tax-exempt third-party financing is particularly complicated due to IRS regulations.

Question 4: Please provide projections of net borrowing authority use from FY 94 to FY 2000. When will your current borrowing authority for transmission and conservation be fully utilized?

Answer: The following table outlines the status of BPA's borrowing authority usage from FY 1994 to FY 2000.

According to current projections, the borrowing authority for the transmission system and fish & wildlife investments will be fully obligated in FY 1996. The borrowing authority for conservation and renewable resources will be fully obligated in FY 1999. It is likely these borrowing trends will change measurably as a result of present cost reduction efforts.

	FY 1994	FY 1995	FY 1996	FY 1997	FY 1998	FY 1999	FY 2000
Capital Obligations	434.3	551.7	585.9	570.2	653.0	643.6	648.9
Bond Amortization	-303.5	-218.1	-255.8	-254.0	-199.1	-185.6	-180.0
Net Borrowing Auth.	130.8	333.6	330.1	416.2	453.9	458.0	468.9
Total Remaining B.A.	1,020.1	686.5	356.4	-59.8	-513.7	-971.7	-1,440.6

Question 5: Please provide the bill and report language that authorized the three separate increments of borrowing authority totaling $3.75 billion. Also provide any BPA documents that clarify what type of capital investments each increment of borrowing authority can be used for.

Answer: The Federal Columbia River Transmission System Act of 1974 (Transmission Act) was the initial act authorizing BPA borrowing authority. The Pacific Northwest Electric Power Planning and Conservation Act of 1980 specifically amends the SEC. 13, subsection (a) of the Transmission Act. The Energy and Water Development Appropriations Act of 1984 also specifically amends the Transmission Act.

Enclosure 2 contains copies of the relevant pages from the three legislative acts that govern the amount and intended uses of BPA borrowing authority with the U.S. Department of Treasury.

Question 6: How much electric water heating and space heating load does BPA currently serve? How much of this load is in areas currently served by natural gas? What is the relative efficiency of burning natural gas in a turbine to produce electricity which is used for water and space heating vs. burning gas on site for this purpose?

Answer: BPA currently serves about 1,600 aMW of electric space and water heating load. About half of the homes using electric space and water heat are in areas where gas is available. Another 25 percent of these homes could be served with gas if natural gas mains were extended.

For a large fraction of these homes, conversion to natural gas is technically feasible. However, BPA has concerns about whether a fuel switching program can be designed to be cost effective. We intend to test this question through our fuel switching pilot program.

A combined cycle gas combustion turbine (CT) on average provides 38 Btu's in the home for every 100 Btu's of gas put in a pipeline and delivered to the powerplant. On the other hand, direct gas combustion for space and water heat on average provides 68 Btu's in the home for every 100 Btu's put in a pipeline and delivered to a home or building.

Fish and Wildlife

Question 1: BPA staff have stated that fish and wildlife spending amounts to about $300 million per year. Please provide an accounting by year for expenditures and estimates of foregone revenue for fish and wildlife measures since 1978. For each year, provide costs of the net effects of the water budget and the additional flow augmentation provided by the Northwest Power Planning Council phase two amendments; repayment for bypass improvements, reimbursements to other federal agencies and their purpose, and the fish and wildlife program expenses.

Answer: The following tables and notes reflect the data requested above. It should be noted that Council Phase Two expenses are included under "BPA Fish and Wildlife Program." Repayment to the Treasury for bypass improvements at Corps of Engineers dams is included under "Associated Projects" and under "Program Related Fixed Expenses." BPA repays the Treasury for costs incurred by other federal agencies that are part of the Federal Columbia River Power System. Repayment does not go to the individual agency.

BONNEVILLE POWER ADMINISTRATION
Fish and Wildlife Investments -- Notes

General

These notes support three separate tables that display, from a rate making, revenue requirement perspective, the Pacific Northwest electric utility ratepayers' investment in fish and wildlife activities within the Columbia River Basin. The three tables cover the Fiscal Years (FY) 1978 to 1995. The expenses shown in the tables are based on budget outlays for the year shown. Where audited actuals are not available for the period FY 1978 to FY 1992, estimates of actuals are used. The title "Capital Investments," shown at the top of each table, is presented for information. The annual expense (interest, amortization, and depreciation) associated with these investments is shown under the title "Program Related Fixed Expenses"

The three tables cover the following years: Table One FY 1978 to FY 1984, Table Two FY 1985 to FY 1990, and Table Three FY 1991 to FY 1995.

Footnotes -- General

(A) Power purchases and foregone revenues estimated for FY 1993 to FY 1995 could be significantly higher depending on water conditions. The power purchase estimate for FY 1993

FWOC16
4/12/83

BONNEVILLE POWER ADMINISTRATION
FISH AND WILDLIFE INVESTEMENTS
($ in Millions)

TABLE 1

	First Funded By:	FY 1978-1980	FY 1981	FY 1982	FY 1983	FY 1984	FY 1978 - 1984
CAPITAL INVESTMENTS							
FISH AND WILDLIFE1/	BPA	0	0	0	0	0	0
ASSOCIATED PROJECTS (FEDERAL HYDRO) 2/	COE	30.0	17.9	85.7	55.1	9.0	177.7
TOTAL CAPITAL INVESTMENTS		30.0	17.9	85.7	55.1	9.0	177.7
PROGRAM OPERATING EXPENSES							
BPA FISH AND WILDLIFE PROGRAM							
NON-E S A ACTIVITIES 3/	BPA	2.3	2.3	4.0	9.1	19.0	37.9
E S A ACTIVITIES	BPA	0.0	0.0	0.0	0.0	0.0	0.0
SUBTOTAL		2.3	2.3	4.0	9.1	19.0	37.9
BPA POWER PURCHASES FOR FISH ENHANCEMENT							
EXISTING WATER BUDGET 4/	BPA	0.0	0.0	0.0	0.0	12.0	12.0
E S A IMPLEMENTATION 5/	BPA	0.0	0.0	0.0	0.0	0.0	0.0
SUB TOTAL		0.0	0.0	0.0	0.0	12.0	12.0
ASSOCIATED PROJECTS (FEDERAL HYDRO)							
NON - E S A RELATED							
O & M LOWER SNAKE RIVER HATCHERIES	USFWS	0.0	0.6	1.0	2.2	3.6	7.2
O & M CORPS (w/bypass eff. FY 1982)	COE	16.0	6.4	7.0	9.1	10.0	47.1
O & M BUREAU (hatchery eff. FY 1982)	BOR	0.0	0.0	0.0	0.0	0.0	0.0
E S A - STUDIES 6/	COE/BOR	0.0	0.0	0.0	0.0	0.0	0.0
SUBTOTAL		16.0	5.0	8.0	11.3	13.6	54.4
OTHER (NW POWER PLANNING COUNCIL)	BPA	0.0	0.2	2.0	2.0	2.4	6.6
TOTAL PROGRAM OPERATING EXPENSES		17.3	8.4	19.1	23.3	47.0	112.7
PROGRAM RELATED FIXED EXPENSES							
INTEREST EXPENSE 6/	BPA	15.0	8.4	9.2	12.1	12.7	55.4
AMORTIZATION EXPENSE 6/	BPA	0.0	0.0	0.0	0.0	0.0	0.0
DEPRECIATION EXPENSE 6/	BPA	9.0	2.4	3.2	3.8	3.9	22.3
TOTAL PROGRAM FIXED EXPENSES		24	8.8	12.4	15.9	16.6	77.7
GRAND TOTAL PROGRAM EXPENSES		41.3	17.2	20.5	39.2	64.2	190.4
FOREGONE REVENUES							
SPILL (at Federal dams)	BPA	0.0	3.0	14.0	1.0	8.0	26.0
ESA Drawdown - Minimum Operating Pool 7/	BPA	0.0	0.0	0.0	0.0	0.0	0.0
		0.0	3.0	14.0	1.0	8.0	26.0
TOTAL - PROGAM EXPENSE & FOREGONE REVENUES		41.3	20.2	42.5	40.2	72.2	219.4

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF THIS TABLE.

FWOC18
4/12/93

BONNEVILLE POWER ADMINISTRATION
FISH AND WILDLIFE INVESTEMENTS
($ In Millions)

TABLE 2

	First Funded By:	FY 1993	FY 1994	FY 1995	FY 1996	FY 1997	FY 1998	FY 1995 - 1998
CAPITAL INVESTMENTS								
FISH AND WILDLIFE 1/	BPA	10.2	0	4.7	7.7	9.3	16.2	15.1
ASSOCIATED PROJECTS (FEDERAL HYDRO) 2/	COE	49.4	9.1	78.6	7.6	13.9	7.6	103.1
TOTAL CAPITAL INVESTMENTS		59.6	17.1	83.3	15.3	23.2	23.7	219.2
PROGRAM OPERATING EXPENSES								
BPA FISH AND WILDLIFE PROGRAM								
NON-E S A ACTIVITIES 3/	BPA	15.9	19.9	22.2	19.9	23.0	32.8	137.3
E S A ACTIVITIES	BPA	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SUBTOTAL		15.9	19.9	22.2	19.9	23.0	32.8	137.3
BPA POWER PURCHASES FOR FISH ENHANCEMENT								
EXISTING WATER BUDGET 4/	BPA	17.0	74.0	11.0	40.0	40.0	40.0	222.0
E S A IMPLEMENTATION 5/	BPA	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SUB TOTAL		17.0	74.0	11.0	40.0	40.0	40.0	222.0
ASSOCIATED PROJECTS (FEDERAL HYDRO)								
NON - E S A RELATED								
O & M LOWER SNAKE RIVER HATCHERIES	USFWS	6.4	4.0	6.0	6.1	7.0	9.3	37.1
O & M CORPS (w/bypass off, FY 1992)	COE	11.4	16.0	20.7	10.6	12.3	11.6	52.2
O & M BUREAU (hatchery off, FY 1992)	BOR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
E S A - STUDIES 6/	COE/BOR	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SUBTOTAL		19.0	20.7	26.6	16.0	19.9	12.0	119.3
OTHER (NW POWER PLANNING COUNCIL)	BPA	3.1	3.0	3.2	3.4	3.7	3.9	20.0
TOTAL PROGRAM OPERATING EXPENSES		52.0	117.3	62.0	77.0	96.6	96.2	493.6
PROGRAM RELATED FIXED EXPENSES								
INTEREST EXPENSE 6/	BPA	15.3	17.1	22.2	24.3	24.5	28.0	129.4
AMORTIZATION EXPENSE 6/	BPA	0.1	0.6	0.8	1.1	1.7	2.4	6.8
DEPRECIATION EXPENSE 6/	BPA	4.4	4.0	5.6	6.7	6.9	9.1	22.3
TOTAL PROGRAM FIXED EXPENSES		19.8	22.2	28.6	31.1	32.1	39.1	160.3
GRAND TOTAL PROGRAM EXPENSES		73.8	139.8	91.5	109.0	118.7	130.7	653.9
FOREGONE REVENUES								
SPILL (at Federal dams)	BPA	27.0	19.0	9.0	10.0	15.0	15.0	85.0
ESA Drawdown - Minimum Operating Pool 7/	BPA	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		27.0	19.0	9.0	10.0	15.0	15.0	85.0
TOTAL - PROGAM EXPENSE & FOREGONE REVENUES		99.8	158.5	100.5	119.0	133.7	145.7	738.9

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF THIS TABLE.

FWOC16
4/12/93

BONNEVILLE POWER ADMINISTRATION
FISH AND WILDLIFE INVESTEMENTS
($ in Millions)

TABLE 3

	First Funded By:	FY 1991	FY 1992	FY1993 (EST.)	FY 1994 (EST.)	FY 1995 (EST.)	FY 1991 - 1995	ALL YEARS FY 1978 - 1995
CAPITAL INVESTMENTS								
FISH AND WILDLIFE 1/	BPA	17.7	11.2	20.6	37.4	33.8	121	178.1
ASSOCIATED PROJECTS (FEDERAL HYDRO) 2/	COE	38.1	67.4	85.9	68.1	71.3	327.8	676.6
TOTAL CAPITAL INVESTMENTS		56.8	78.6	116.7	101.5	105.2	450.8	854.7
PROGRAM OPERATING EXPENSES								
BPA FISH AND WILDLIFE PROGRAM								
NON-E S A ACTIVITIES 3/	BPA	32.7	59.4	38.0	41.8	43.0	210.0	386.2
E S A ACTIVITIES	BPA	0.3	7.6	22.3	24.1	24.8	79.2	79.2
SUBTOTAL		33.0	67.0	81.3	68.0	67.8	295.2	465.4
BPA POWER PURCHASES FOR FISH ENHANCEMENT								
EXISTING WATER BUDGET 4/	BPA	40.0	40.0	40.0	40.0	40.0	200.0	434
E S A IMPLEMENTATION 5/	BPA	0.0	19.0	80.0	28.0	30.0	163.0	163
SUB TOTAL		40.0	59.0	120.0	68.0	70.0	363.0	597.6
ASSOCIATED PROJECTS (FEDERAL HYDRO)								
NON - E S A RELATED								
O & M LOWER SNAKE RIVER HATCHERIES	USFWS	8.7	11.2	11.6	13.2	13.8	58.4	102.8
O & M CORPS (w/bypass eff. FY 1992)	COE	11.8	13.3	14.0	14.0	14.0	67.1	190.4
O & M BUREAU (hatchery eff. FY 1992)	BOR	0.0	0.8	1.2	1.3	1.3	3.8	3.8
E S A - STUDIES 6/	COE/BOR	0.0	17.0	17.0	12.0	12.0	58.0	58
SUBTOTAL		20.6	41.5	43.7	40.6	41.1	187.3	361.0
OTHER (NW POWER PLANNING COUNCIL)	BPA	3.8	3.8	4.4	4.4	4.5	21.0	48.4
TOTAL PROGRAM OPERATING EXPENSES		97.3	171.4	235.4	178.8	183.6	866.5	1472.8
PROGRAM RELATED FIXED EXPENSES								
INTEREST EXPENSE 8/	BPA	28.2	31.4	40.0	48.4	57.6	206.6	381.4
AMORTIZATION EXPENSE 8/	BPA	3.6	4.8	6.3	8.3	10.0	31.9	38.6
DEPRECIATION EXPENSE 8/	BPA	6.3	7.0	8.1	8.8	9.8	39.8	94.4
TOTAL PROGRAM FIXED EXPENSES		38.1	43.2	54.4	65.4	77.2	278.3	514.3
GRAND TOTAL PROGRAM EXPENSES		136.4	214.6	289.8	244.2	260.7	1145.8	1990.1
FOREGONE REVENUES								
SPILL (at Federal dams)	BPA	15.0	15.0	5.6	5.6	3.6	44.8	105.6
ESA Drawdown - Minimum Operating Pool 7/	BPA	0.0	8.0	5.5	5.5	3.6	22.6	22.8
		15.0	23.0	11.1	11.1	7.2	67.4	188.4
TOTAL - PROGRAM EXPENSE & FOREGONE REVENUES		151.4	237.6	300.9	255.6	267.9	1213.2	2180.5

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF THIS TABLE.

have been adjusted and updated to reflect the poor water conditions now affecting the operations of Federal hydroelectric system.

(B) The tables represent a "revenue requirement" view of BPA's fish and wildlife funding responsibilities. All expenses in these tables are paid for by BPA's ratepayers.

(C) Estimates for FY 1993 to FY 1995 are generally based on information contained in BPA's FY 1994 Budget Submission to Congress or the 1993 Initial Rate Case documentation.

Footnotes -- Specific

1/ Based on outlays.

2/ Based on Plant-in-Service.

3/ Includes costs for environmental analysis that are forecasted in BPA's Power Marketing Program.

4/ "Existing Water Budget" has been incorporated in BPA's load/resource balance. The water budget is included under "Program Expenses" for ease of display. In years when there is a firm surplus of power, the water budget is a foregone revenue. In years when there is no firm surplus of power, the water budget is an expense for power purchases.

5/ These figures are based on operational implementation of salmon measures, 3.0 million acre feet on the Columbia River and 1.3 million acre feet from Dworshak Dam for FY 1992. Beginning in FY 1993 Snake River flow augmentation is in firm planning, Columbia flow augmentation reflects 50-year planning (instead of 5-year), and the costs of implementing the National Marine Fisheries Service Biological Opinion are included in these estimates. These estimates also include some foregone revenues associated with flow augmentation.

6/ Estimate, subject to revision as updated information becomes available from these agencies.

7/ This "drawdown" includes operations near minimum operating pool elevations as in 1992. Other drawdown proposals being studied include physical changes to the Lower Snake River dams. These proposals would result in significantly higher costs and are not included in the table.

Question 2: What percentage of the FY 1992, 1993 and proposed FY 1994 budget are/were devoted to the implementation of Council program measures and what amount are/were spent for other purposes? Please provide a list of all non-program measures in these budgets, including the rationale, cost and purpose of each measure.

Answer: In FY 1992, 1993, and proposed 1994 about 99 percent of BPA's direct Fish and Wildlife costs were devoted to Council Program measures. No more than about 1 percent of the Fish and Wildlife direct costs were spent on measures not called for in the Council's Program. BPA's budget historically has been used to implement the Council's total program annually.

Though not initially identified by the Council, BPA has implemented certain projects that have benefited implementation of the overall Program. Program-Related, Non-Measure Projects were undertaken in response primarily to support measures already approved and in the Program. These projects expanded the scope of effort, provided needed supporting information, or addressed project components not included in the original proposals.

Following are nonprogram measures, budgets, and the rationale for each measure.

Project Title	FY92	FY93	FY94
Resources for the Future	$300K	$390K	$450K

Rationale - These projects were initiated to collect biological data from existing data bases throughout the region and then to determine the cost effectiveness of the various approaches to implementing the work being done within the fish and wildlife program. While the Council does not call for specific measures or projects to be completed within their program, they are on record as saying that program measures should be carried out in a cost-effective manner. See answer to Question 4 for more detail.

Project Title	FY92	FY93	FY94
Biological Analysis/NMFS Recovery Plan.	$0	$496K	$0

Rationale - The National Marine Fisheries Service (NMFS) currently has a Recovery Team working on a recovery plan to address the needs of listed species in the Snake River Basin. BPA will be called upon the address certain measures that will be specified in the Recovery Team's plan. This contract is for the purpose of performing preparatory analysis to address these measures. The analysis will review the results of the ongoing actions now being undertaken by BPA. BPA's intention is to be able to have data available to discuss the Recovery Team's plan when it is released.

Project Title	**FY92**	**FY93**	**FY94**
Model Coordination	$150K	$0	$250K

Rationale - The purpose of this contract is to fund various parties to review the various anadromous fish data modeling activities being undertaken in the region and to understand the various modeling approaches being used. Those parties being funded are staff at the state resource managing agencies of Oregon, Washington, and Idaho, the Columbia River Intertribal Fish Commission representing the region's tribes, and the Northwest Power Planning Council. While this is not a specific Council program measure, the Council did participate in making the final decision.

Question 3: It is my understanding the BPA is currently reducing program budgets throughout the agency. Do you intend to defer implementation of the Northwest Power Planning Council's Strategy for Salmon? If so, in what areas and what savings would result in FY 1994? Do you intend to defer any non-program measures? If so, in what areas and what savings would result in FY 1994?

Answer: In an effort to minimize the rate increase slated to go into effect on October 1, 1993, all BPA program managers are examining impacts of cuts ranging from

5 to 25 percent in FY 1994 and FY 1995 program levels. All programs will be examined, including conservation, and fish and wildlife -- BPA's fastest growing programs. BPA believes that efficiencies in these programs can be achieved without sacrificing overall goals. BPA is committed to meeting its fish and wildlife obligations and to achieving all the cost-effective conservation in the region.

To date, specific program cuts have not been selected. BPA is requesting that customers and other interested parties help in identifying how program goals can be achieved at minimum cost.

Question 4: It is my understanding that BPA has a contract relating to salmon with Resources for the Future. What is the purpose of the contract? How much has BPA spent on this contract to date and how much does BPA plan to spend in FY 1994?

Answer: The purpose of BPA's original contract with Resources for the Future (RFF) was to identify research and modeling needs for analysis of the Fish and Wildlife Program. BPA wanted to develop analytical tools that would allow better evaluation of proposed mitigation actions and provide a way to track the progress of the mitigation efforts. The total expenditure under the contract was $754,099, covering 3 years of research planning and initial biological and economic model development. The effort culminated in the final report *Design of Studies for Development of BPA Power Administration Fish and Wildlife Mitigation Accounting Policy, Volumes 1 and 2* published in August 1988, and a *Workshop Series Background Report: The Use of Cost-Effectiveness Analysis in Planning for Increases in Sustainable Run Sizes of Anadromous Fish* published in March 1989.

Subsequent to the original effort, BPA contracted with RFF for further development, application, and documentation of biological and economic models of anadromous fisheries in the Columbia Basin. BPA also called upon RFF to participate in regional forums to present the analytical approach, and to provide opportunities for regional understanding of and participation in the analytical approach. More recently, RFF has applied the analytical approach to system-level cost-effectiveness analysis. Total expenditure to date (over 4 years) is $1,570,555. Published reports resulting from this contract include:

1) Lee, D.C. *The Use of Production Indices in Planning and Evaluating Fisheries Management Programs.* August 1990.

2) Paulsen, C. M. and D. C. Lee, *Cost-Effectiveness Analysis of the Columbia River Basin Subbasin Plans: Methods and Results.* October 1990.

3) Lee, D. C. and C.M. Paulsen. *Improving System Planning in the Columbia River Basin: Scope, Information Needs, and Methods of Analysis.* December 1990.

4) Lee, D. C. and J. B. Hyman. *The Stochastic Life Cycle Model (SLCM): A Tool for Simulating The Population Dynamics of Anadromous Salmonids.* May 1991 updated May 1992.

5) Paulsen, C. M., et. al. *Mid-Columbia Propagation and Passage Cost-Effectiveness Analysis.* September 1991.

6) Paulsen, C.M., J. B. Hyman, and K. Wernstedt. *Above-BPA Propagation and Passage Cost-Effectiveness Analysis.* January 1993.

7) Wernstedt, K. *Overview and Assessment of Analytical Tools Used to Support Fish and Wildlife Planning Within the Columbia River System.* January 1993.

8) Hyman, J. B. *Multiple Stock Dynamics, Risk, and Monitoring in Mitigation Planning for Salmon: Critical Issues and Proposed Models.* January, 1993.

Continuing development of analytical methods for cost-effectiveness will focus on analysis of actions for ESA stocks, model modifications to allow dynamic analysis of both biological effects and costs, and developing additional capability to apply cost effectiveness to multiple objectives, including maintenance of biological diversity. The current budget for FY 1993 is $386,240. The planned budget for FY 1994 is $450,000. Placing this cost in context, BPA is spending about 0.1 percent of its annual investment in Fish and Wildlife mitigation on analysis of the cost-effectiveness of mitigation alternatives.

Question 5: How many biologists currently work for BPA either directly or under contract? Is the role of BPA's biological staff to implement the recommendations of the National Marine Fisheries Service and the Council or to come up with alternatives?

Answer: The current staff level of BPA's Division of Fish and Wildlife is 60.7 FTE. The Division is currently staffed at an authorized level as follows: 9 managers and supervisors, 24 biologists, 3 engineers, 1 economist, 7 project managers, 3 policy analysts, 3 computer specialists, 1 budget analyst, 2 contract administrators, 5 secretaries, and 2 administrative technicians.

In 1992, BPA conducted a survey to determine how many contractor FTE were being supported by the Fish & Wildlife Program. The survey reflected that 50 percent of the program dollars supported 456 FTE. If

that FTE figure was applied to 100 percent of program dollars, the number of contractor FTE supported by the program would be approximately 900 FTE.

The current role of the Fish & Wildlife Division is to implement the Council's Fish & Wildlife program and to respond to those actions called for by the NMFS. It would also be reasonable to assume that BPA would have alternative proposals to discuss with both the Council and NMFS at various times. BPA has proposed alternatives to both parties that have either been added or implemented in lieu of projects that were proposed. All parties are constantly striving to ensure that the right projects are implemented.

Question 6: Has BPA contracted with the University of Washington to do a modeling effort that is similar to one already conducted by the Northwest Power Planning Council? If so, what is the purpose of this contract and how much will it cost?

Answer: BPA has a current cost-reimbursable contract with the Center for Quantitative Sciences at the University of Washington for the development of models that address both downstream passage of juvenile salmonids and the complete life cycle of salmonids. These models complement rather than duplicate other extant models due to different scope, time scale, accessibility, and ease of use. The contract was awarded in FY 1990 and runs through FY 1994. Authorizations through FY 1993 total $2,809,130. Expenditures through February 1993 total $2,432,249 with expected exhaustion of funds by the end of FY 1993. Planned funds for FY 1994 total $768,000

The question implies that the Council modeling effort has been completed. That is not the case. The development of the Council's Passage Analysis

Model (PAM) and BPA's Columbia River Salmon Passage Model (CRiSP) has been essentially contemporaneous, beginning about 1989. Both models have evolved and continue to evolve, incorporating advancements in computer technology and in our understanding of pertinent physical and biological processes, in an attempt to address evolving resource management issues. In general, CRiSP has a much finer temporal resolution than PAM (e.g. daily average flows in CRiSP vs. annual average in PAM), and includes separate submodels for many processes that are simply lumped together in PAM (e.g. dissolved gas generation and associated mortality). CRiSP is calibrated for spring and fall chinook and for steelhead whereas PAM considers only spring chinook. CRiSP is also stochastic in order to represent the highly variable nature of passage conditions. PAM considers only mean conditions. It is our opinion that these and other differences between the models make CRiSP better suited to investigate impacts of modifications to the operation of the Columbia-Snake hydrosystem. While we prefer the CRiSP model, both models are complimentary.

Question 7: It is my understanding that BPA has contracted for a "shadow" biological opinion similar to the one conducted by the National Marine Fisheries Service. It this correct? If so, what is the purpose of this contract and how much will it cost?

Answer: We assume this question refers to the NMFS Salmon Recovery Plan.

BPA is developing a Technical Analysis document that will address a range of issues we view as pertinent to the salmon recovery effort, including the NMFS Recovery Plan. Several examples of these issues are: (1) habitats of weak salmon stocks of the Snake River Basin and feasible recovery measures, (2)

flow augmentation and reservoir drawdown - strategies for recovery for ESA listed stocks in the Snake River Basin and (3) ocean carrying capacity. The purpose of the work is to anticipate the scope and content of the NMFS Plan and prepare BPA to integrate the plan in our operations when appropriate. We consider the Technical Analysis an internal working document but we are seeking input from recognized experts and have contracted for portions of the Technical Analysis. The cost of the contracted portion of the work is approximately $500,000.

Question 8: How much has BPA budgeted for the squawfish program in FY 1994? Of this amount how much will go directly for the payment of bounties to fishermen? Please describe the status and results of research on the effectiveness of the squawfish program.

Answer: For FY 1994 BPA is currently budgeting $8.4 million for the squawfish management program. Approximately 9 percent of this budget ($750,000) is allocated to rewards associated with the sport-reward fishery.

The squawfish management program is an experimental effort to significantly reduce losses of juvenile salmonids to northern squawfish predation. It is also a regional effort, implemented through a multi-agency team of state and federal fishery agencies, Indian Tribes, universities, and the private sector. The cost for the program falls into five categories: (1) squawfish harvest (includes the cost of rewards), (2) biological evaluation, (3) socio-economic evaluation, (4) disposition/utilization, and (5) research.

Over the three years of the program, 1990 through 1992, approximately 450,000 squawfish have been harvested. At this time, it is too early to draw

conclusions about the results of this program. Existing information indicates that the exploitation rates in both 1991 and 1992 were about 12 percent system-wide, ranging from 0 to 20 percent on a reservoir-by-reservoir basis. This is within the range of exploitation on which the research hypothesis is based. The hypothesis is that a sustained annual exploitation of 10 to 20 percent of squawfish may reduce predation mortality by 50 percent or more within 10 years.

We are making efforts to increase harvest of squawfish to ensure timely evaluation.

Question 9: Please describe the so called "lease back/buy back" fish program. How much will this program cost in FY 1994?

Answer: The leaseback/buyback program is a Council measure calling for payments to the commercial fisherman in lieu of their harvest income. Estimated cost of this program could be as high as $6 million. Since the program is experimental in nature, the payment would be one-time to cover a 2-year period. BPA began negotiating in 1992 with all concerned parties. To date, no agreement has been reached with the parties.

Explanation of Ex Parte

In Central Lincoln Peoples' Utility Dist. v. Johnson, 735 F.2d 1101 (9th Cir. 1984), the United States Court of Appeals for the Ninth Circuit held that the Administrative Procedure Act's prohibition on ex parte communications applies to BPA ratemaking because it is formal rulemaking required to be made on the section 7(i) hearing record after opportunity for an agency hearing. Accordingly, BPA must avoid ex parte communication concerning issues pending resolution in ongoing rate hearings.

The recent case of Portland Audubon Society v. The Endangered Species Committee, No. 92-70436 (9th Cir. April 1, 1993) strongly counsels that BPA avoid possible ex parte communications concerning rate case issues. In the Portland Audubon Society case, environmental groups challenged the decision of the Endangered Species Committee (the "God Squad") to grant an exemption from the requirements of the Endangered Species Act to the Bureau of Land Management for thirteen timber sales in western Oregon. The groups based their challenge on ex parte contacts that were alleged to have occurred between the White House and Committee members. The Court first held that the APA's ban on ex parte communications applied to the Committee's deliberations, stating that the "result is similar to the one we reached in a case involving formal rulemaking," the Central Lincoln case involving BPA. The Court then determined that the President and his staff were subject to the APA's ban on ex parte communications since the "provision's history makes it clear that the ex parte communication prohibition was meant to include public officials." (Note in this regard that the application of ex parte prohibitions to Congressional communications has been expressly recognized in the Ethics Manual of the United States House of Representatives.) The Court remanded the matter for an evidentiary hearing before an administrative law judge on the questions of whether any improper communications with the White House had in fact occurred during the Committee's decision-making process, and, if so, what remedy is required. Quite understandably, this case causes BPA to very cautiously evaluate for ex parte problems any inquiries that happen to involve issues pending in BPA's 7(i) process.

BPA would be remiss not to also point out that a number of the Task Force's other questions bear on program and program level issues that BPA had argued to the rate case Hearing Officer should be excluded from the rate case. BPA had argued that inclusion of these type of issues in the rate case would undermine BPA's program planning processes and responsibilities, and interfere with the Federal budget process. BPA also argued that Presidential and Congressional authority over BPA budgets could be compromised, and the Constitutional doctrine of separation of powers would be violated were the judiciary called upon to review budget decisions approved by Congress. However, the Hearing Officer concluded over BPA's objections that the program and program level materials were relevant to BPA's rate case revenue requirement and should therefore be allowed in the rate case. Despite the Hearing Officer's action, BPA does not regard communications regarding program and program level issues to be subject to the rate case's ex parte prohibition. The reason for this is that BPA's rate case procedures (51 Fed. Reg. 7611 (1986) exclude from the ex parte ban a matter "which relates to a topic that is only secondarily the object of a hearing, for which BPA is statutorily responsible under provisions other than Northwest Power Act section 7, or which is eventually decided other than through a section 7(i) hearing." BPA believes that communications concerning programs and program levels meet the quoted criteria.

Enclosure 2

Source: The Federal Columbia River Transmission System Act of 1974

wholly owned Government corporations named in section 101 of such Act (31 U.S.C. 846), but nothing in the proviso of section 850 of title 31, United States Code, shall be construed as affecting the powers granted in subsection (b)(11) of this section and in sections 2(f), 10(b), and 12(a) of the Bonneville Project Act (16 U.S.C. 832 et seq.).

16 USC 832a, 832i, 832k.

(d) Notwithstanding the provisions of sections 105 and 106 of the Government Corporation Control Act, the financial transactions of the Administrator shall be audited by the Comptroller General at such times and to such extent as the Comptroller General deems necessary, and reports of the results of each such audit shall be made to the Congress within 6-1/2 months following the end of the fiscal year covered by the audit.

Audit, report to Congress. 31 USC 850, 851.

SEC. 12. (a) If the Administrator determines that moneys in the fund are in excess of current needs he may request the investment of such amounts as he deems advisable by the Secretary of the Treasury in direct, general obligations of, or obligations guaranteed as to both principal and interest by, the United States of America.

16 USC 838j.

(b) With the approval of the Secretary of the Treasury, the Administrator may deposit moneys of the fund in any Federal Reserve bank or other depository for funds of the United States of America, or in such other banks and financial institutions and under such terms and conditions as the Administrator and the Secretary of the Treasury may mutually agree.

SEC. 13. (a) The Administrator is authorized to issue and sell to the Secretary of the Treasury from time to time in the name and for and on behalf of the Bonneville Power Administration bonds, notes, and other evidences of indebtedness (in this Act collectively referred to as "bonds") to assist in financing the construction, acquisition, and replacement of the transmission system, and to issue and sell bonds to refund such bonds. Such bonds shall be in such forms and denominations, bear such maturities, and be subject to such terms and conditions as may be prescribed by the Secretary of the Treasury taking into account terms and conditions prevailing in the market for similar bonds, the useful life of the facilities for which the bonds are issued, and financing practices of the utility industry. Refunding provisions may be prescribed by the Administrator. Such bonds shall bear interest at a rate determined by the Secretary of the Treasury taking into consideration the current average market yield on outstanding marketable obligations of the United States of comparable maturities, plus an amount in the judgment of the Secretary of the Treasury to provide for a rate comparable to the rates prevailing in the market for similar bonds. The aggregate principal amount of any such bonds outstanding at any one time shall not exceed $1,250,000,000.

Sale and issuance. 16 USC 838k.

Terms and conditions.

Interest rate, determination.

Limitation.

(b) The principal of, premiums, if any, and interest on such bonds shall be payable solely from the Administrator's net proceeds as hereinafter defined. "Net proceeds" shall mean for the purposes of this section the remainder of the Administrator's gross receipts from all sources after first deducting trust funds and the costs listed in section 11(b)(2) through 11(b)(7) and 11(b)(11), and shall include reserve or other funds created from such receipts.

"Net proceeds."

(c) The Secretary of the Treasury shall purchase forthwith any bonds issued by the Administrator under this Act and for that purpose is authorized to use as a public debt transaction the proceeds from the sale of any securities

Bonds, purchase.

31 USC 774.

Source: The Pacific Northwest Electric Power Planning and Conservation Act of 1980

4.(h)(8)(B) Consumers of electric power shall bear the cost of measures designed to deal with adverse impacts caused by the development and operation of electric power facilities and programs only.

4.(h)(8)(C) To the extent the program provides for coordination of its measures with additional measures (including additional enhancement measures to deal with impacts caused by factors other than the development and operation of electric power facilities and programs), such additional measures are to be implemented in accordance with agreements among the appropriate parties providing for the administration and funding of such additional measures.

4.(h)(8)(D) Monetary costs and electric power losses resulting from the implementation of the program shall be allocated by the Administrator consistent with individual project impacts and system-wide objectives of this subsection.

4.(h)(9) The Council shall adopt such program or amendments thereto within one year after the time provided for receipt of the recommendations. Such program shall also be included in the plan adopted by the Council under subsection (d).

Fish and wildlife, protection.

4.(h)(10)(A) The Administrator shall use the Bonneville Power Administration fund and the authorities available to the Administrator under this Act and other laws administered by the Administrator to protect, mitigate, and enhance fish and wildlife to the extent affected by the development and operation of any hydroelectric project of the Columbia River and its tributaries in a manner consistent with the plan, if in existence, the program adopted by the Council under this subsection, and the purposes of this Act. Expenditures of the Administrator pursuant to this paragraph shall be in addition to, not in lieu of, other expenditures authorized or required from other entities under other agreements or provisions of law.

16 USC 839 note.

4.(h)(10)(B) The Administrator may make expenditures from such fund which shall be included in the annual or supplementary budgets submitted to the Congress pursuant to the Federal Columbia River Transmission System Act. Any amounts included in such budget for the construction of capital facilities with an estimated life of greater than 15 years and an estimated cost of at least $1,000,000 shall be funded in the same manner and in accordance with the same procedures as major transmission facilities under the Federal Columbia River Transmission System Act.

Allocation of funds

4.(h)(10)(C) The amounts expended by the Administrator for each activity pursuant to this subsection shall be allocated as appropriate by the Administrator, in consultation with the Corps of Engineers and the Water and Power Resources Service, among the various hydroelectric projects of the Federal Columbia River Power System. Amounts so allocated shall be allocated to the various project purposes in accordance with existing accounting procedures for the Federal Columbia River Power System.

4.(h)(11)(A) The Administrator and other Federal agencies responsible for managing, operating, or regulating Federal or non-Federal hydroelectric facilities located on the Columbia River or its tributaries shall—

4.(h)(11)(A)(i) exercise such responsibilities consistent with the purposes of this Act and other applicable laws, to adequately protect, mitigate, and enhance fish and wildlife, including related spawning grounds and habitat, affected by such projects or facilities in a manner that provides equitable treatment for such fish and wildlife with the other purposes for which such system and facilities are managed and operated;

Source: The Pacific Northwest Electric Power Planning and Conservation Act of 1980

8.(d)(1) The first sentence of subsection (a) of section 13 of such Act is amended by inserting after the word "system," the following: "to implement the Administrator's authority pursuant to the Pacific Northwest Electric Power Planning and Conservation Act (including his authority to provide financial assistance for conservation measures, renewable resources, and fish and wildlife, but not including the authority to acquire under section 6 of that Act electric power from a generating facility having a planned capability greater than 50 average megawatts).". 16 USC 838k. Ante, p. 2697. Ante, p. 2717.

8.(d)(2) The fourth sentence of such subsection (a) is amended by inserting the following before the period at the end thereof: "issued by Government corporations".

8.(d)(3) Such subsection (a) is further amended by inserting the following before the period at the end thereof: "prior to October 1, 1981. Such aggregate principal limitation shall be increased by an additional $1,250,000,000 after October 1, 1981, as provided in advance in annual appropriation Acts, and such increased amount shall be reserved for the purpose of providing funds for conservation and renewable resource loans and grants in a special revolving account created therefor in the Fund. The funds from such revolving account shall not be deemed State or local funds".

8.(d)(4) Such subsection (a) is further amended by inserting the following after the fourth sentence thereof: "Beginning in fiscal year 1982, if the Administrator fails to repay by the end of any fiscal year all of the amounts projected immediately prior to such year to be repaid to the Treasury by the end of such year under the repayment criteria of the Secretary of Energy and if such failure is due to reasons other than (A) a decrease in power sale revenues due to fluctuating streamflows or (B) other reasons beyond the control of the Administrator, the Secretary of the Treasury may increase the interest rate applicable to the outstanding bonds issued by the Administrator during such fiscal year. Such increase shall be effective commencing with the fiscal year immediately following the fiscal year during which such failure occurred and shall not exceed 1 per centum for each such fiscal year during which such repayments are not in accord with such criteria. The Secretary of the Treasury shall take into account amounts that the Administrator has repaid in advance of any repayment criteria in determining whether to increase such rate. Before such rate is increased, the Secretary of the Treasury, in consultation with the Administrator and the Federal Energy Regulatory Commission, must be satisfied that the Administrator will have the ability to pay such increased rate, taking into account the Administrator's obligations. Such increase shall terminate with the fiscal year in which repayments (including repayments of the increased rate) are in accordance with the repayment criteria of the Secretary of Energy.". Rate increase. Termination.

8.(e) Clause (2) of section 1(b) of the Act of August 31, 1964 (78 Stat. 756) is amended to read as follows: "(2) any contiguous areas, not in excess of seventy-five airline miles from said region, which are a part of the service area of a rural electric cooperative served by the Administrator on the effective date of the Pacific Northwest Electric Power Planning and Conservation Act which has a distribution system from which it serves both within and without said region.". 16 USC 837. Ante, p. 2697.

ADMINISTRATIVE PROVISIONS

Section 9.

9.(a) Subject to the provisions of this Act, the Administrator is authorized to contract in accordance with section 2(f) of the Bonneville Project Act of 1937 (16 U.S.C. 16 USC 839f.

Source: Energy and Water Development Appropriations Act of 1984

ity, generate fission products within the reactor, discharge cooling water from nuclear operations directly or indirectly into Steel Creek, or result in cooling system testing discharges which exceed the volume, frequency and duration of test discharges conducted prior to June 28, 1983.

42 USC 4321 note

Consistent with the National Environmental Policy Act of 1969, and in consultation with State officials of South Carolina and Georgia, the preparation and completion of the Environmental Impact Statement called for in the preceding paragraph shall be expedited. The Secretary of Energy may reduce the public comment period, except that such period shall not be reduced to less than thirty days, and the Secretary shall provide his Record of Decision, based upon the completed Environmental Impact Statement, not sooner than December 1, 1983, and not later than January 1, 1984.

Public comments

Departmental Administration

For salaries and expenses of the Department of Energy necessary for Departmental Administration and other activities in carrying out the purposes of the Department of Energy Organization Act (Public Law 95-91), including the hire of passenger motor vehicles and official reception and representation expenses (not to exceed $35,000); $366,056,000, all of which is available for fiscal year 1984 and shall remain available until expended, plus such additional amounts as necessary to cover increases in the estimated amount of cost of work for others notwithstanding the provisions of the Anti-Deficiency Act (31 U.S.C. 1511 et seq.): *Provided*, That such increases in cost of work are offset by revenue increases of the same or greater amount, to remain available until expended: *Provided further*, That moneys received by the Department for miscellaneous revenues estimated to total $209,619,000 in fiscal year 1984 may be retained and used for operating expenses within this account, and may remain available until expended, as authorized by section 201 of Public Law 95-238, notwithstanding the provisions of 31 U.S.C. 3302. *Provided further*, That the sum herein appropriated shall be reduced by the amount of miscellaneous revenues received during fiscal year 1984 so as to result in a final fiscal year 1984 estimated appropriation estimated at not more than $156,437,000.

42 USC 7101 note

42 USC 5821 note; 31 USC 3302 note

Power Marketing Administrations

Operation and Maintenance, Alaska Power Administration

For engineering and economic investigations to promote the development and utilizaton of the water, power, and related resources of Alaska, and for necessary expenses of operation and maintenance of projects in Alaska and of marketing electric power and energy, $3,410,000, to remain available until expended, of which not to exceed $200,000 to be available only upon a determination by the Secretary that such amounts are required to ensure continuity of service in the case of an emergency.

Bonneville Power Administration Fund

Expenditures from the Bonneville Power Administration Fund, established pursuant to Public Law 93-454, are approved for official reception and representation expenses in an amount not to exceed

16 USC 838i note

$2,500; and for continuity of financing the construction program, as well as financing new programs, an additional $1,250,000,000 in borrowing authority is made available, under the Federal Columbia River Transmission System Act (Public Law 93-454) to remain outstanding at any given time: *Provided*, That the obligation of such additional borrowing authority shall not exceed $123,400,000 in fiscal year 1984. 16 USC 838 note

During fiscal year 1984 and within the resources and authority available, gross obligations for the principal amount of direct loans shall not exceed $40,000,000; during fiscal year 1984, commitments to guarantee loans may be made only to the extent that the total loan principal, any part of which is to be guaranteed, shall not exceed $20,000,000.

Operation and Maintenance, Southeastern Power Administration

For necessary expenses of operation and maintenance of power transmission facilities and of marketing electric power and energy pursuant to the provisions of section 5 of the Flood Control Act of 1944 (16 U.S.C. 825s), as applied to the southeastern power area, $20,594,000, to remain available until expended.

Operation and Maintenance, Southwestern Power Administration

For necessary expenses of operation and maintenance of power transmission facilities and of marketing electric power and energy, and for construction and acquisition of transmission lines, substations and appurtenant facilities, and for administrative expenses connected therewith, in carrying out the provisions of section 5 of the Flood Control Act of 1944 (16 U.S.C. 825s), as applied to the southwestern power area, $36,229,000, to remain available until expended.

Construction, Rehabilitation, Operation and Maintenance, Western Area Power Administration

For carrying out the functions authorized by title III, section 302(a)(1)(E) of the Act of August 4, 1977 (Public Law 95-91), and other related activities including conservation and renewable resources programs as authorized, including the purchase of passenger motor vehicles (not to exceed nine for replacement only), purchase, maintenance, and operation of one aircraft, $194,630,000, to remain available until expended, of which $163,430,000 shall be derived from the Department of the Interior Reclamation fund and $1,004,000, shall be derived from the Colorado River Dam fund for power marketing and transmission expenses of the Boulder Canyon Project. 42 USC 7152

Emergency Fund, Western Area Power Administration

For the "Emergency Fund", as authorized by the Act of June 16, 1948 (43 U.S.C. 502), to remain available until expended for the purposes specified in that Act, $500,000, on a continuing basis to be recovered from the Reclamation Fund against receipts for the transmission and sale of electric power and energy which are deposited

SUBMITTED BY HON. LARRY LAROCCO

QUESTIONS FOR BPA TASK FORCE HEARING
APRIL 28, 1993

FISH AND WILDLIFE/SALMON RECOVERY

1) Does BPA plan on cutting its current Fish and Wildlife program? If so, can you give this Task Force an approximate amount of cuts in the Fish and Wildlife program? Will it be necessary to maintain current Fish and Wildlife staff levels to administer less money? Further, will there be an equal decrease in Fish and Wildlife administrative staff commensurate with cuts in Fish and Wildlife programs?

2) With many salmon stocks currently listed as threatened or endangered species on the Columbia/Snake River system and the nearly certain listing of more salmon stocks, is this a prudent time for BPA to cut its Fish and Wildlife program?

3) Earlier this year, BPA made a rate proposal of 11.6%, with 4% ascribed to fish and wildlife costs. Now BPA is stating that there have been additional costs since the initial rate case which will require a higher rate increase. $28 million of this additional increase is ascribed to increased fish and wildlife costs. Specifically, what accounts for the increased costs for fish and wildlife since the initial rate proposal?

4) There have been proposals made to modify John Day and Lower Granite dams to operate in a drawdown mode. According to these proposals, at most these modifications would cost $200 million. Does BPA concur with these modification cost estimates? If not, what does BPA estimate modification of these two dams to cost? What would the annual preference rate increase be if this project was amortized over fifty years like other capital construction costs?

5) If the above modifications were made to Lower Granite Dam, what is BPA's latest estimate of the annual costs of a ten week drawdown of Lower Granite Dam to spillway crest? Please provide a breakdown for the various components such as firm power, secondary power, etc.

6) What is BPA's latest estimate of the annual costs for a drawdown of the four lower Snake River dams (i.e. the "Idaho Plan")? Please use the definition of drawdown used in the Huppert Report and include the appropriate dam modification costs released by the Army Corps of Engineers earlier this year. Please provide a breakdown for the various components such as firm power, secondary power, etc.

7) What is BPA's latest estimate of the annual costs of the Power Council's current flow augmentation plan? Again, please provide a breakdown for the various components such as firm power, secondary power, etc.

8) Please explain the different impacts of these two plans on BPA rates.

9) Currently many entities such as the states, the tribes, the U.S. Fish and Wildlife

Service, National Marine Fisheries Service, and the Power Planning Council all have teams of fish biologists partially funded by BPA. BPA also has their own team of approximately 60 fish biologists. Is this approach to funding fish biology efficient?

10) BPA has been forced by the Endangered Species Act, as well as the 1980 act, to provide certain flows for endangered salmon in the Columbia/Snake River System. In its budgets, BPA classifies these mandated fish flows as "foregone revenue" and attributes it to the Fish and Wildlife budget. Many observers (including Justice Marsh) have questioned this accounting practice. Is this practice appropriate? What river management baseline does BPA use to estimate "foregone revenues"? Did the 1980 Act, or the enforcement of the Endangered Species Act, change this baseline?

11) With regard to the potential endangered species listing of the Kootenai River Sturgeon in North Idaho, what are the revenue impacts of providing varying flows for the sturgeon. Specifically, what would the revenue impact be on BPA for providing a 20, 25, 30, and 35,000 cubic feet per second flow for the sturgeon?

REVENUES, EXPENDITURES, AND CONSERVATION

1) The Northwest Power Planning Council has produced a graph (attached) showing a drop in BPA Preference rates in real dollars from 1983 to 1992. If BPA had adjusted rates since 1983 to keep pace with inflation what would BPA's current cash reserves be? Further, what rate increase would it take to return BPA's rates to 1983 rates in real dollars?

2) In fiscal year 1993, what projected costs will have the greatest impact on BPA's revenue situation in percentage terms: 1) the lower world price of aluminum; 2) decreased snowpack and drought; 3) closing the Trojan nuclear plant; or 4) increased flows for fish.

3) Please provide a schedule on a monthly basis of the following items for the first two quarters of fiscal 1993:

   a) out of region power purchases (volumes and price); and
   b) sales (volume and price) to the aluminum smelters; and

   c) power purchases made on behalf of the aluminum smelters to meet their 1st quartile needs; and

   d) a monthly schedule of fees from aluminum smelters for transmission services

4) What was the upward impact of those wheeling purchases on the price of power on the spot market? How much did that increased spot market price increase the cost for spot purchases for acquisition of the other three quartiles of smelter load?

   Is BPA obligated to make such wheeling purchases, and if so, what obligates them to do this?

- What was the actual average price paid to BPA of all power purchased by the aluminum smelters, both wheeling and firm, in the first two quarters of fiscal 1993?

5) The credit to the smelters for the ability to interrupt service is based on two things: 1) the 1985 costs of building new capacity, discounted at an interest rate of 14%; and 2) the 1288 megawatt credit of forced outage reserves.

Today, interest rates for new power sources are nearly half that. Further, BPA stated in the "1992 Pacific Northwest Loads and Resources Study" (the White Book) that the smelters actually provide approximately 600 megawatts of forced outage reserves.

Has BPA taken steps to adjust the forced outage reserve credit to reflect current conditions? When does BPA plan to adjust the forced outage reserve credit to reflect current conditions?

6) In its 1988 "Resource Program" document, BPA stated that they had departed from the "least-cost path" in obtaining conservation resources. To quote the document, "Bonneville recognizes there is an economic risk in not being on the least-cost path, and that getting back to the least-cost path may result in higher costs to ratepayer. However, these risks are judged to be acceptable, in view of the importance of the financial targets."

In light of its departure from the "least-cost path" causing BPA to lose opportunities to acquire low-cost conservation resources (i.e. home weatherization during construction), and the current need for BPA to make expensive out of region power purchases, was this action fiscally prudent? If BPA had followed the "least-cost path" how much out of region power purchases could have been avoided in fiscal 1992 and the first two quarters of fiscal 1993? What impact would this action have on the current rate increase?

WASHINGTON PUBLIC POWER SUPPLY SYSTEM

1) BPA is currently on a schedule for making its principal and interest payments on the WPPSS 1 & 3 debt. Could you provide this task force with an amortization schedule of principal and interest payments on an annual basis for the current debt, not including possible future refinancing?

2) What is the projected operating life of WPPSS 2? What is the projected cost of decommissioning WPPSS 2 now, and what is the projected cost of decommissioning WPPSS 2 at the end of its operating life? How much money is currently in the sinking fund to pay for decommissioning of WPPSS 2?

What are the projected costs of removal for WPPSS 1 & 3 in light of Washington State reclamation standards to return the site to its original condition?

3) Overall, rate the success of BPA's nuclear program. What has been the cost per year for BPA's portion of the region's nuclear facilities (both operating and not) since

- acquiring nuclear resources? Considering operating and non-operating nuclear facility construction, operation and maintenance, what would the per kilowatt hour cost be from the nuclear resource program?

END OF QUESTIONS

Department of Energy
Washington, DC 20585
August 13, 1993

The Honorable Larry LaRocco
U.S. House of Representatives
Washington, DC 20515

Dear Congressman LaRocco:

On April 28, 1993, Randall Hardy, Administrator, Bonneville Power Administration, testified before the Committee on Natural Resources, Bonneville Power Administration Task Force, regarding the proposed Fiscal Year 1994 budget for that program.

Enclosed are the answers to 17 of the 20 questions that you submitted. The remaining three responses will be forwarded to you as expeditiously as possible.

If we can be of further assistance, please contact our Congressional Hearing Coordinator, Valerie Howard, on (202) 586-2032.

Sincerely,

William J. Taylor, III
Assistant Secretary
Congressional, Intergovernmental
and International Affairs

Enclosures

Question 2: With many salmon stocks currently listed as threatened or endangered species on the Columbia/Snake River system and the nearly certain listing of more salmon stocks, is this a prudent time for BPA to cut its Fish and Wildlife program?

Answer: BPA is faced with falling revenues and rising costs. These facts are forcing us to take a hard look at the way BPA operates and examine the proposed funding levels for all our programs, including the Fish and Wildlife Program. If forecasts of revenues and expenses had not changed dramatically from the close of Programs in Perspectives (PIP) in October 1992, to the present, it is uncertain whether BPA would be conducting such a broad review of its planned program budgets as it is now performing Under current circumstances and in an effort to keep the proposed rate increase below 20 percent, it is necessary to reevaluate all program levels for FY 1993, 1994, and 1995.

Decisions on specific program level reductions have yet to be made. In our decision making process, BPA will carefully evaluate all components of the fish and wildlife program before any reductions in funding are approved. BPA recognizes its' significant and important role it has in fish and wildlife protection, mitigation, and enhancement within the Columbia River Basin.

BPA further recognizes that its responsibilities under the Endangered Species Act are sigificant and will increase should additional species be listed. These responsibilities include implementing the National Marine Fisheries Service's Recovery Plan for threatened and endangered salmon in

the Snake River Basin and for ongoing coordination and consultation on Federal Columbia River Power System operations. Decisions on revised program funding levels are expected in June. We do not expect to make any cuts which would reduce our ability to carry out, in future years, the measures described in the 1993 National Marine Fisheries Service Biological Opinion relating to hydrosystem operations.

Question 3: Earlier this year, BPA made a rate proposal of 11.6%, with 4% ascribed to fish and wildlife costs. Now BPA is stating that there have been additional costs since the initial rate case which will require a higher rate increase. $28 million of this additional increase is ascribed to increased fish and wildlife costs. Specifically, what accounts for the increased costs for fish and wildlife since the initial rate proposal?

Answer: The $28 million fish and wildlife cost relates to the FY 1994 forecast of power purchases for fish enhancement resulting from Endangered Species Act activities. These costs are included in BPA's power scheduling program, and refer to changes in the forecast of power purchases for fish enhancement, not to changes in the fish and wildlife program. The higher forecast is due to poor water conditions in FY 1993 that impact the cost of power purchases in both 1993 and 1994.

Question 5: If the above modifications were made to Lower Granite Dam, what is BPA's latest estimate of the annual costs of a ten week drawdown of Lower Granite Dam to spillway crest? Please provide a breakdown for the various components such as firm power, secondary power, etc.

Answer: The losses we estimate would occur from operating Lower Granite to spillway crest for a 10-week period would be similar to those operating at elevation 710 feet (about a 30 foot draw down). A similar scenario was analyzed in the 1992 Columbia River Salmon Flow Measures Options Analysis Environmental Impact Statement(OA/EIS). The OA/EIS analyzed a 12-week draw down period from April 1 through June 30 with 2 weeks required at the outset to bring the reservoir to the draw down elevation, 8 weeks at the draw down elevation, and 2 weeks required at the end of the period to refill reservoir levels back to their previous elevation. These losses amounted to $18 million per year of lost firm energy and $11 million of lost firm capacity. Non-firm losses are estimated to be in the range of $11 - $20 million. Therefore total annual operational losses for this 12-week draw down at Lower Granite is in the range of $40 - $49 million. BPA assumes that the 10-week draw down would have similar cost impacts assuming it too has a ramp-up and ramp-down period.

The annual capital cost for Lower Granite is estimated to be about $5 - $7 million. This is based on a low range estimate of $60 million in total capital costs and a high range estimate of $86 million amortized over 50 years (current practice for Corps of Engineers plan investments) financed at a 7.25 percent Treasury borrowing rate.

Combining the annual capital costs of about $5 to $7 million at Lower Granite, (derived from the modification costs identified in the previous answer) with the

operating costs described above yields an overall annual cost of $ 45 to $56 million. This could produce an upward rate impact of .5 to .6 mills/kwh, or roughly 2 to 3 percentage points from present levels.

Question 6: What is BPA's latest estimate of the annual costs for a drawdown of this four Lower Snake River dams ([i.e.] the "Idaho Plan")? Please use the definition of drawdown used in the Huppert Report and include the appropriate dam modification costs released by the Army Corps of Engineers earlier this year. Please provide a breakdown for the various components such as firm power, secondary power, etc.

Answer: BPA has not conducted an independent analysis of this four Lower Snake River draw down. However, the Corps 1992 Options Analysis EIS looks at a draw down scenario similar to that in the Huppert Report. The Idaho Plan analyzed in the EIS calls for the four lower Snake projects to be operated at near spillway crest from April 15 through June 15. Drawdown is to occur April 1-15 and refill by early July. Annual cost for lost firm energy is estimated to be $72 million per year and lost firm capacity is $32 million per year. Lost non-firm is estimated to range from $21 - $55 million per year. Total annual losses for this plan of operation are estimated to be in the range of $125 to $159 million. The Huppert Report defines a different drawdown period. It would begin the draft on April 7 to be near spillway crest in 2 weeks (April 21) and refill would take 16 days to be completed by June 15. This operation was analyzed two ways in an attempt to provide a minimum and maximum impact. As reported by the Corps, costs to make modifications are from $1.3 to $4.9 billion.

The estimated annual capital costs for the four lower Snake projects based on amortizing the modification costs of $1.3 - $4.9 billion over 50 years at a 7.25 percent Treasury borrowing rate is $97 - $366 million. Combining the annual capital cost of $97 - $366 million with the annual operating costs of

$125 - $159 million, described above, yields an overall annual cost of $222 - $519 million.

Question 7. What is BPA's latest estimate of the annual costs of the Power Council's current flow augmentation plan? Again, please provide a breakdown for the various components such as firm power, secondary power, etc.

Answer: The Council's original Water Budget of 3.45 MAF has been estimated to cost $40 million per year. Updated estimates would probably show a higher cost since the region no longer has firm power surplus. On average the annual cost of the Power Council's Columbia River Phase II flow augmentation plan is estimated to be $20 million. In years when there is ample water supply, no action is required and there would be no cost. In the lowest runoff years net costs could be as high as $90 million. This year these operations cost about $33 million. This cost is comprised of either foregone non-firm sales, power purchases, or a combination of the two

BPA does not have a current breakdown of these costs into energy and capacity components However, the Power Council's Phase II flow plan for the Snake River was reviewed in the 1992 Columbia River Salmon Flow Measures Options Analysis/EIS (OA/EIS). That study shows that the impact on firm energy would cost $25 million and there would be a gain in the production of non-firm of $3 to $7 million. This gain in non-firm results from shifting energy production from the winter into the spring when there is generally more energy being produced than there is a demand for firm load This comports with BPA's estimate of expected Snake flow augmentation costs of about $16 million. Capacity impacts were not analyzed in the OA/EIS.

Thus, the total annual average impacts for the original water budget, and Phase II Columbia River flow augmentation and Snake River flow augmentation is in the range of $75 to $80 million and up to $155 million

in poor water years. Since the original water budget was absorbed into BPA rates in the early 1980s, the portion that is reflected in the 1993 rate case is about $50 million.

In addition to the measures listed above, the Council's Phase II program also calls for operating the four lower Snake River projects to near minimum operating pool and John Day dam at near minimum irrigation pool. The expected cost of these operations for John Day are about $5 million in lost capacity and non firm energy. The costs associated with operating the four lower Snake River projects at near minimum operating pool are about $20 million in lost capacity and lost non firm. Phase II also calls for spill at several projects costing an estimated $20 million.

Endangered Species Act requirements for listed Snake River stocks have resulted in more water being provided from the Snake and Columbia Rivers than was called for by the Power Council's Phase II program. The requirements for flows under ESA added about $10 - $15 million in 1993. Thus, the estimated 1993 operational costs for fish including original water budget, Phase II measures and ESA requirements totals about $144 - $149 million. On an expected basis these operations will average $120 - $210 million, depending on NMFS ESA flow targets.

In addition to these operational costs associated with the Power Council's flow augmentation plan and ESA, there are additional non-power costs included in BPA's FY 1994 to 1995 Wildlife Program of $18 million for implementation activities (increased law enforcement, squawfish, monitoring and evaluation, and additional fish screening). Combining the

expected operating costs (not including $40 million for the original water budget) with the non-power costs results in a range of $80 to $170 million with a corresponding Priority Firm (PF) rate increase of about .8 to 1.7 mills/kwh, or roughly 3 to 7 percentage points from present levels.

The water budget portion of these flows was absorbed in BPA rates in the mid-1980s. The Phase II and ESA measures described above are reflected in BPA's proposed 1993 rate increase and represent about 4 to 4.5 percentage points of that increase. None of the impacts described above include pre-Phase II fish program measures mandated by the Power Council (roughly $50 million annually) or BPA payments to the Treasury for Lower Snake hatchery operations and fish mitigation measures funded through the Corps of Engineers (roughly $40 million annually).

Question 8: Please explain the different impacts of these two plans on BPA rates.

Answer: BPA prepared a preliminary estimate of the rate impacts of the drawdown of the four lower Snake River dams (i.e., the "Idaho Plan") shortly after release of the Army Corps of Engineers cost estimates for 2 drawdown options. We estimated that BPA's Priority Firm (PF) rates would increase by about 4 to 5 percent (from rates without drawdown) in FY 2009 for the Spillway Crest alternative once the modifications are completed after a 14-year construction period. The analysis assumed a $900 million (1992 dollars) capital investment amortized over 50 years and an $85 million (1992 dollars) annual power cost. We also estimated a PF rate increase of about 11 to 12 percent (from rates without drawdown) in FY 2012 for the Natural Riverbed alternative once the modifications are completed after a 17-year construction period. The Natural Riverbed analysis assumed a $3.2 billion capital investment (1992 dollars) amortized over 50 years and a $200 million (1992 dollars) annual power cost. We also estimate that the Northwest Power Planning Council's flow augmentation plan could increase BPA's PF rate by about 4 to 8 percent in the FY 1994 to 1997 time period. The ranges were developed using a variety of different alternative power cost estimates intended to incorporate uncertainties related to both an operational approach which rely on power purchases and storage, and a firm planning approach which rely on firm resource acquisition. Much of the information used to develop these rate impacts are based on judgment or preliminary estimates.

Question 10: BPA has been forced by the Endangered Species Act, as well as the 1980 [act], to provide certain flows for endangered salmon in the Columbia/Snake River System. In its budgets, BPA classifies these mandated fish flows as "foregone revenue" and attributes it to the Fish and Wildlife budget. Many observers (including Justice Marsh) have questioned this accounting practice. Is this practice appropriate? What river management baseline does BPA use to estimate "foregone revenues"? Did the 1980 Act, or the enforcement of the Endangered Species Act, change this baseline?

Answer: We wish to point out that BPA has not been forced to provide flow, but, rather has been required to provide certain amounts of storage in upstream reservoirs that is used by fisheries interests to augment lower river stream flows. BPA considers the baseline for river operations to be prior to the 1980 Act. The Act created the mitigation requirement for Fish and Wildlife. All new programs which benefit fish and wildlife and have a cost to BPA ratepayers are included in BPA's estimate of fish and wildlife costs.

Changing hydrosystem operations to benefit fish does have a cost, generally, in terms of power purchases and foregone revenues, which must be recovered from BPA ratepayers. BPA includes this cost in its budget because we consistently deal with questions about what causes rate increases.

Water Budget and flow augmentation are not reflected in the Division of Fish and Wildlife budget. To the extent that flow augmentation is met, the purchases are out of the Power Purchase budget. BPA uses Pacific Northwest Coordination planning as its baseline. From the planning process rule curves are developed for reservoir operations. The Federal Hydro system uses these rule curves as it baseline for operations.

With the passage of the Northwest Power Act, the Water Budget (3.45 MAF) was included as part of the annual planning process thereby changing BPA baseline rule curves. These rule curves are the baseline used to estimate costs (or benefits) such as foregone revenues. Flow Augmentation (3 MAF) is handled operationally, therefore it is outside of the coordination planning process and is provided as water above the operating rule curves.

Question 11: With regard to the potential endangered species listing of the Kootenai River Sturgeon in North Idaho, what are the revenue impacts of providing varying flows for the sturgeon. Specifically, what would the revenue impact be on BPA for providing a 20, 25, 30, and 35,000 cubic feet per second flow for the sturgeon?

Answer: Providing flows for sturgeon in the Kootenai River will have direct revenue impacts to BPA as well as to other regional parties which could result in additional indirect revenue implications for BPA. The flows being requested will result in a devaluation or loss of generation power at Libby and downstreams, and will necessitate power acquisitions to replace lost firm power. Lake Kookanusa, behind Libby Dam, will not refill to the extent occurring in current operations resulting in head loss (reduced generating capability per unit of water) through the summer and fall and adversely impact recreation and resident fish

The following table quantifies a range of costs to BPA associated with the varying flow levels requested:

BPA AVERAGE ANNUAL COSTS FOR DEVALUED FIRM POWER, FIRM POWER REPLACEMENT AND HEAD LOSSES

Flow Level	Low Cost in $millions	High Cost in $millions
35 kcfs	22	46
30 kcfs	19	36
25 kcfs	15	26
20 kcfs	10	20

The Kootenai River downstream from Libby Dam passes through British Columbia, Canada where it joins with the Columbia River. On its way, it passes through several hydro projects owned by Canadian parties the power

from which is marketed by B.C. Hydro. Increased flows for sturgeon will result in significantly increased spill (shows in excess of generating capacity) at these Canadian projects. B.C. Hydro may be understandably displeased with Libby's altered operation resulting in losses for them. This could also impact ongoing negotiations between BPA and B.C. Hydro over power purchases, flow augmentation storage and the return of Canadian Entitlement Power, thus resulting in indirect revenue impacts to BPA. The requested change in the operation of Libby could result in serious adverse impacts to recreational interests in British Columbia as well. The table below estimates a range of revenue impact to B.C. Hydro from these flows:

BCH COSTS DUE TO
SPILL ON KOOTENAY RIVER IN BRITISH COLUMBIA

Flow Level	Low Cost in $millions	High Cost in $millions
35 kcfs	10	14
30 kcfs	8	12
25 kcfs	7	9
20 kcfs	5	7

Non-federal parties owning hydro projects on the Columbia River downstream from Grand Coulee Dam will also be affected by increased discharges from Libby Dam for sturgeon. The table below shows a range of power impacts to these project owners:

MID-COLUMBIA NON-FEDERAL PARTIES COSTS FOR DEVALUED NON-FIRM POWER AND FIRM POWER REPLACEMENT

Flow Level	Low Cost in $millions	High Cost in $millions
35 kcfs	6	13
30 kcfs	5	10
25 kcfs	4	7
20 kcfs	3	6

Finally, there may be additional indirect impacts to BPA by virtue of obligations under the 1980 Northwest Power Act. The Northwest Power Planning Council in its 1987 Columbia River Basin Fish and Wildlife Program states that draw downs of Lake Kookanusa of more than 90 to 110 feet for power purposes must be mitigated by BPA for effects to recreation and resident fish. With the higher levels of requested sturgeon flows draw downs of this magnitude are likely to occur in low water years. It is open to interpretation if these draw downs, which did not occur for power purposes, must be mitigated by BPA. Recreation interests in Montana and British Columbia would have an interest in not having Lake Kookanusa drafted to this extent.

REVENUES, EXPENDITURES, AND CONSERVATION

Question 1: The Northwest Power Planning Council has produced a graph (attached) showing a drop in BPA Preference rates in real dollars from 1983 to 1992. If BPA had adjusted rates since 1983 to keep pace with inflation what would BPA's current cash reserve be? Further, what rate increase would it take to return BPA's rates to 1983 rates in real dollars?

Answer: It is not possible to determine what BPA's cash reserves would be if rates had kept pace with inflation since 1983. This hypothetical assumes BPA would abandon cost based rates and carry cash reserves far in excess of those needed for prudent risk mitigation. Also, an implied assumption is that this very different financial situation for BPA would have no effect on financial policy decisions, such as the expense/capital ratio for new resources and programs. Additionally, this scenario presupposes no reductions in customer loads due to the higher rates.

We have, however, estimated the revenue impacts had BPA's rates kept pace with inflation, assuming no changes in load. The total revenue accumulation for BPA since late 1983, when rates set in 1983 would be in force, would be $2,035 million more than the actual revenues earned, based on BPA rates in force during that time period.

The rate increase necessary for BPA to return to the real level of rates set in 1983 is 30 percent. That is, the FY 1994 Priority Firm (PF) rate would have to be 30 percent higher than the current FY 1993 PF rate in order to return to the real level of rates set in 1983. Since the actual increase for FY 1994 will be far lower than a 30 percent increase, FY 1994 rates will be well below the real level of rates set in 1983.

Question 2: In fiscal year 1993, what projected costs will have the greatest impact on BPA's revenue situation in percentage terms: 1) the lower world price of aluminum; 2) decreased snowpack and drought; 3) closing the Trojan nuclear plant, or 4) increased flows for fish.

Answer: Of the four impact areas identified, decreased snowpack and drought have had the greatest impact on net revenues in fiscal year 1993.

The drought impact will exceed $200 million while the impact of low worldwide aluminum prices will exceed $60 million. The impact of increased flows for fish will affect Bonneville in the $120 million to $140 million range. Closure of the Trojan Nuclear Plant had a positive impact of about $20 million on BPA's revenues This is a result of budget savings for Trojan operators and maintenance, plus reduced residential exchange costs which offset additional purchase power purchase costs

Assuming net revenues of approximately $2 billion, the drought would result in a decrease of about 7 percent, aluminum price impacts are about 2 percent, increased flows for fish reflecting about 4 to 4.5 percent, and closure of Trojan Nuclear Plant offsetting these decreases by about .5 percent.

Question 3: Please provide a schedule on a monthly basis of the following items for the first two quarters of fiscal 1993:

a) out of region power purchases (volumes and price); and
b) sales (volume and price) to the aluminum smelters; and
c) power purchases made on behalf of the aluminum smelters to meet their 1st quartile needs; and
d) a monthly schedule of fees from aluminum smelters for transmission services

Answer (a): The following are power purchases (both spot and block purchases) that BPA considers out of region, that is from the Pacific Southwest and from BC Hydro. These values include Industrial Replacement Energy (IRE) that the smelters purchased to meet their top quartile load.

Out of Region Power Purchases

Month	Purchase	Cost	Mills/kwh
October, 1992	134,150 mwh	$ 3,138,395	23.39
November,1992	146,681 mwh	$ 3,366,599	22.95
December,1992	571,511 mwh	$16,286,628	28.50
January, 1993	1,305,540 mwh	$41,303,909	31.64
February, 1993	667,290 mwh	$17,769,710	26.63
March, 1993	848,505 mwh	$24,973,857	29.43

Please note that all the energy reports are not yet final, so these values are to be considered draft.

Answer (b): Since this portion of the question and the next portion of the question differentiate between sales to the smelters and sales to only the first quartile, we assume you are requesting sales of energy (including transmission) to all four quartiles by BPA and other utilities. The energy to serve the restricted top quartile load (Industrial Replacement Energy) noted in portion (c) below are energy purchases from utility sources other than BPA. The other three quartiles are served by BPA as part of BPA's firm load. The data below is the sum of energy provided by BPA and energy provided by other utilities.

Aluminum Smelter Sales

Month	Sale	Cost	mills/kwh
October, 1992	2,290,588 mwh	$36,893,837	16.1
November, 1992	1,789,539 mwh	$36,409,291	20.4
December, 1992	1,534,655 mwh	$36,159,661	23.6
January, 1993	1,819,315 mwh	$34,243,481	18.2
February, 1993	1,431,783 mwh	$28,110,969	19.6
March, 1993	1,544,544 mwh	$29,519,531	19.1

Please note that all the energy reports are not yet final, so these values are to be considered draft.

Answer (c): The following Industrial Replacement Energy purchases include the wheeling costs.

Power Purchases on Behalf of Aluminum Smelters
to Meet First Quartile Loads

Month	Purchase	Cost	mills/kwh
October, 1992	302,183 mwh	$8,333,838	27.6
November, 1992	355,299 mwh	$9,990,291	28.1
December, 1992	279,527 mwh	$7,887,661	28.2
January, 1993	72,403 mwh	$3,896,481	53.8
February, 1993	80,391 mwh	$3,034,969	37.8
March, 1993	64,728 mwh	$2,283,531	35.3

Please note that all the energy reports are not yet final, so these values are to be considered draft

Answer (d): The smelters pay transmission only on the energy that they purchase from non-BPA sources to meet their top quartile loads Industrial Replacement Energy (IRE) during periods when BPA is restricting service to this load, not on the energy BPA provides on a firm basis to their other three quartiles. This top quartile load is a nonfirm load on BPA. The following transmission charges reflect the total revenue from all the applicable transmission rates that BPA would charge for such purchase (incidental wheeling, northern intrtie wheeling, and southern intertie wheeling.)

Monthly Schedule of Fees From Aluminum Smelters for Transmission Services

Month	Cost
October, 1992	$577,600.99
November, 1992	$763,131.49
December, 1992	$611,502.47
January, 1993	$ 80,026.61
February, 1993	$127,346.81
March, 1993	$114,551.90

Please note that the reports are not all final so these values are still an estimate.

Question 4: What was the upward impact of those wheeling purchases on the price of power on the spot market? How much did that increased spot market price increase the cost for spot purchased for acquisition of the other three quartiles of smelter load?

Is BPA obligated to make such wheeling purchases, and if so, what obligates them to do this?

What was the actual average price paid to BPA of all power purchased by the aluminum smelters, both wheeling and firm, in the first two quarters of fiscal 1993?

Answer: We understand the question to ask how the transmission charges impacted the price of spot market energy. The rate charged for wheeling is based on providing a service. The rate charged for energy in the spot market is a function of the cost of the resource used to produce the energy and the type of market (buyer's or seller's), not on the cost of transmission. As such, the cost of transmission did not impact the spot market price of energy. There was a period of time this past winter when there was a transmission bottleneck in California that didn't allow as much nonfirm energy from the Southwest to flow to the Northwest This situation produced more of a seller's market and possibly contributed to higher prices, however this situation was based on a transmission limitation not on the rate charged for transmission. Steps have been taken to fix the bottleneck and energy deliveries are no longer reduced. The other three quartiles of smelter load is firm and is served by BPA through its firm resources.

BPA is not obligated to make the wheeling purchases. The purchases are made on the behalf of the Direct Service Industries to provide them with a greater reliability of importing their industrial replacement energy.

We interpret the final question to mean the average price paid by the smelter for nonfirm energy (IRE) and transmission to meet its restricted top quartile load and for firm energy to meet its other three firm quartiles. The average price of energy that the aluminum smelters paid in the first two quarters of FY 93 is 19.34 mills per kilowatthour. Not all the reports for that period have been finalized, so this value is estimated. It should be noted that the price the smelters would be paying during this period, if they purchased all four quartiles of their energy from BPA, would be 17.9 mills per kilowatthour. Therefore, their average rate increased only 1.44 mills per kilowatthour higher due to the purchases they made for their restricted top quartile

Question 5: The credit to the smelters for the ability to interrupt service is based on two things: 1) the 1985 costs of building new capacity, discounted at an interest rate of 14%; and 2) the 1288 megawatt credit of forced outage reserves.

Today, interest rates for new power sources are nearly half that. Further, BPA stated in the "1992 Pacific Northwest Loads and Resources Study" (the White Book) that the smelters actually provide approximately 600 megawatts of forced outage reserves.

Has BPA taken steps to adjust the forced outage reserve credit to reflect current conditions? When does BPA plan to adjust the forced outage reserve credit to reflect current conditions?

Answer: BPA has not recently taken steps to adjust the Value of Reserve (VOR) credit. In our rate design, the VOR is incorporated in the IP-PF link. The IP-PF link is the Premium or Standard margin, less the VOR credit, both determined in the 1985 rate filing. The 1985 values are escalated by the rate of inflation for use in subsequent rate proceedings. Following a formal rate proceeding in 1990 the link has been extended and would not expire before June 30, 1996. BPA is planning to examine the general reserve issue with its customers in the Resource Program and Contract Renegotiation Process. Because of the complexity and contentiousness of reestimating the various types of reserves provided by the Direct Service Industries, the cost basis for developing a credit, and the linkage to these other processes, BPA has not determined when the reserve credit will be examined in a Rate Case 7(i) process.

Question 6: In its 1988 "Resource Program" document, BPA stated that they had departed from the "least-cost path" in obtaining conservation resources. To quote the document, "Bonneville recognizes there is an economic risk in not being on the least-cost path, and that getting back to the least-cost path may result in higher costs to ratepayer. However, these risks are judged to be acceptable, in view of the importance of the financial targets."

In light of its departure from the "least-cost path" causing BPA to lose opportunities to acquire low-cost conservation resources ([i.e.] home weatherization during construction), and the current need for BPA to make expensive out of region power purchases, was this action fiscally prudent? If BPA had followed the "least-cost path" how much out of region power purchases could have been avoided in fiscal 1992 and the first two quarters of fiscal 1993? What impact would this action have on the current rate increase?

Answer: In the 1988 Resource Program, BPA decided to deviate from the Least Cost Path in response to budget constraints At that time, this decision was expected to result in a savings loss of 55 aMW through the end of 1992. A return to the least-cost path was, at that time, projected to occur in 1995.

However, BPA ramped-up its conservation efforts in 1990 and again in 1992. It is not clear exactly how much more conservation would have been obtained had BPA ramped up from its 1988 least cost path, but for analytical purposes, 55 aMW will be used to represent additional savings that might have been obtained (and, therefore, the power purchases that could have been avoided).

To assess the financial impact of deviating from the least cost path, it is necessary to compare the revenue requirements for the conservation which was not acquired with the cost of purchases required to cover the 55 aMW of need for FY 1992 and the first two quarters of FY 1993. For all but two months of this period, purchase power was relatively inexpensive. The purchases to meet the extra need resulting from not following the least cost path totaled $19.4 million. By contrast, $25.4 million would have been

required to support acquisition of the additional consrvation over the same period.

These results indicate that following the Least Cost Path over this period would have resulted in higher costs, and accordingly would not have helped BPA's current financial situation. Prices of natural gas used in thermal resources proved considerably lower than was anticipated at the time of the 1998 Resource Program, and purchase power accordingly proved more attractive than forecast in the late 1980s.

WASHINGTON PUBLIC POWER SUPPLY SYSTEM

Question 1: BPA is currently on a schedule for making its principal and interest payments on the WPPSS 1 & 3 debt. Could you provide this task force with an amortization schedule of principal and interest payments on an annual basis for the current debt, not including possible future refinancing?

Answer: BPA scheduled principal and interest payments for WPPSS 1 & 3 cash requirements for debt service to be funded by BPA are attrached. These schedules are on a BPA fiscal year basis and are included in BPA's 1993 Final Rate Proposal.

Question 2: What is the projected operating life of WPPSS 2? What is the projected cost of decommissioning WPPSS 2 now, and what is the projected cost of decommissioning WPPSS 2 at the end of its operating life? How much money is currently in the sinking fund to pay for decommissioning of WPPSS 2?

Question 2b: What are the projected costs of removal for WPPSS 1 & 3 in light of Washington State reclamation standards to return the site to its original condition?

Answer: WNP-2 is currently scheduled to operate until the expiration of its Operating License in the year 2024. However, the industry is planning on extending the life of nuclear plants The Supply System is taking appropriate actions for that option to be available.

The cost to decommission WNP-2 is approximately $373 million (1993 dollars), whether it is decommissioned in 1993 or 2024. The estimate is based on SAFESTOR (long-term storage before decommissioning) for 30 years prior to radiological decontamination and site restoration. Decommissioning WNP-2 in 1993 would require more ratepayer revenue than waiting until 2024, when accumulated earnings on the sinking fund will pay a greater share of the costs. The current sinking fund balance is approximately $19.2 million.

The Supply System has estimated the cost of restoration of WNP-1 and 3 in the Long Range Forecast of its FY 1994 Budget. If it is assumed that the sites must be returned to their original condition, it would entail removal of all temporary buildings and structures, burial of the reactor and related buildings, and recontouring and revegetating the site. This is estimated at

$114 million (1992 dollars) per project. If Washington State will consider something less than full restoration to original conditions, the cost could range from about $50 million to $114 million per project.

Question 3: Overall, rate the success of BPA's nuclear program. What has been the cost per year for BPA's portion of the region's nuclear facilities (both operating and not) since acquiring nuclear resources? Considering operating and non-operating nuclear facility construction, operation and maintenance, what would the per kilowatt hour cost be from the nuclear resource program?

Answer: Bonneville would describe its situation as disappointing, but fairly typical of that experienced by the majority of the nuclear industry. The attached table shows costs for WNP-2, Trojan and WNP-1/3.

	WNP-2 Program[1/]		Trojan Program[2/]		WNP-1/3 Program[3/]	
Year	Program Cost	Mills per Kilowatt Hour Cost	Program Cost	Mills per Kilowatt Hour Cost	Program Cost	Mills per Kilowatt Hour Cost
1976			$19,553,975	40.5		
1977	$26,390,810		$29,031,213	14.9		
1978	$61,280,490		$23,725,058	47.5		
1979	$81,377,000		$26,305,825	16.7		
1980	$86,918,000		$36,887,224	20.3		
1981	$90,232,000		$44,782,587	23.2	$72,124,000	
1982	$135,725,000		$36,654,775	25.4	$124,578,000	
1983	$221,000,000		$34,202,321	27.9	$297,443,198	
1984	$407,089,000		$36,599,710	25.8	$351,078,000	
1985	$172,200,000	67.4	$57,107,715	27.5	$414,002,000	
1986	$317,800,000	72.8	$62,295,539	29.3	$346,720,767	
1987	$328,700,000	59.5	$65,593,064	50.3	$339,979,442	
1988	$337,600,000	56.8	$71,723,433	37.7	$291,502,345	
1989	$357,600,000	59.3	$74,688,933	45.0	$291,231,458	
1990	$373,100,000	57.4	$75,810,133	41.6	$208,674,779	
1991	$338,900,000	59.8	$92,783,216	211.2	$43,164,662	
1992	$330,200,000	86.9	$83,942,220	61.2	$113,376,634	

1/ Data supplied by the Washington Power Supply System and includes debt service.
2/ Data supplied by Eugene Water and Electric Board and includes debt service.
3/ Data supplied by the Washington Power Supply System. Non-operating plants; Mills per Kilowatt Hour not applicable.

Prepared by:	Steve Wright
Office:	AC
Office Phone:	(202) 586-5640
Date:	May 11, 1993
Coordinated with:	
Asst. Sec. Initials:	

Department of Energy
Washington, DC 20585
August 17, 1993

The Honorable Larry LaRocco
U.S. House of Representatives
Washington, DC 20515

Dear Congressman LaRocco:

On April 28, 1993, Randall Hardy, Administrator, Bonneville Power Administration, testified before the Committee on Natural Resources, Bonneville Power Administration Task Force, regarding the proposed Fiscal Year 1994 budget for that program.

Enclosed are the answers to two of the three remaining questions that you submitted. The one remaining response will be forwarded to you as expeditiously as possible.

If we can be of further assistance, please contact our Congressional Hearing Coordinator, Valerie Howard, on (202) 586-2032.

Sincerely,

William J. Taylor, III
Assistant Secretary
Congressional, Intergovernmental
and International Affairs

Enclosures

Questions for Bonneville Power Administration Task Force Hearing
April 28, 1993

QUESTIONS FROM CONGRESSMAN LAROCCO

FISH AND WILDLIFE/SALMON RECOVERY

Question 1: Does BPA plan on cutting its current Fish and Wildlife program? If so, can you give this Task Force an approximate amount of cuts in the Fish and Wildlife program? Will it be necessary to maintain current Fish and Wildlife staff levels to administer less money? Further, will there be an equal decrease in Fish and Wildlife administrative staff commensurate with cuts in fish and Wildlife programs?

Answer As is the case with all of BPA programs, we are considering a reduction in our fish and wildlife program in the range of 10 to 25 percent of the post-Programs in Perspective (PIP) levels (or by approximately $10 - $20 million) For example, assuming an annual program level in the range of $80 million, BPA would have approximately 60 total employees with 30 additional employees involved in the contracting effort. This level of staff would reflect salaries and benefits of $1.8 million or about 2.2 percent of an $80 million program An FY 1993 management analysis of Division of Fish and Wildlife staffing needs revealed that 86 employees (an increase of 26) would be required to fully address all current responsibilities.

It should be noted that BPA's responsibility for implementation of the Fish and Wildlife Program clearly involves more than administering contracts. A majority of the BPA "contracting" staff have biological backgrounds that enable project scoping and leadership beyond that routinely found in contracting offices. Additionally, BPA has initiated a monitoring and evaluation program to effectively examine project benefits and results. This

regionally directed program has been initiated with BPA staff and will continue to be staffed within existing allocation levels. Due to ongoing staffing constraints, the Fish and Wildlife Program has staffed many administrative functions with contract employees. The Fish and Wildlife Program is decreasing this administrative contract support by an amount commensurate with the program reduction.

Question 9: Currently many entities such as the states, the tribes, the U.S. Fish and Wildlife Service, National Marine Fisheries Service, and the Power Planning Council all have teams of fish biologists partially funded by BPA. BPA also has their own team of approximately 60 fish biologists. Is this approach to funding fish biology efficient?

Answer: BPA's Division of Fish and Wildlife has 60 staff, of which only 24 are biologists. The balance includes engineers, project managers, policy analysts, computer, budget and contract specialists, administrative support, and managers. In addition, there are 30 contractor employees involved in implementing the Fish and Wildlife Program working directly for BPA.

BPA implements the Northwest Power Planning Council's Fish and Wildlife Program primarily through contracts with other entities including State, Federal, and Tribal fish and wildlife agencies. This implementation method is due in large part to the framework called for in the Council's Fish and Wildlife Program and the fact that BPA is not a fish and wildlife management agency. The management responsibilities for fish and wildlife lie with other Federal and State agencies and Tribes. BPA shares in the accountability for implementing the Council's Program. BPA technical experts, including biologists, are required to develop and administer the contracts and ensure the supplies and services requested meet the technical requirements contained in the contract. Federal regulations stipulate that technical experts must determine the acceptability of all contracted supplies and services.

BPA's fish and wildlife technical experts are also responsible to assist BPA in making decisions that fulfill the requirements under the Endangered Species Act for listed Snake River salmon. These requirements include compliance

with the National Marine Fisheries Service's 1993 Biological Opinion and the Recovery Plan, due in late summer.

BPA's contract activity with State and Federal fish and wildlife agencies and Tribes results in funding that directly supports the work of other fish and wildlife biologists. BPA is in the process of the identifying the number of technical experts, including biologists, that are supported by BPA contracts as part of the Function by Function Review that is currently in progress.

Department of Energy
Washington, DC 20585
September 2, 1993

The Honorable Larry LaRocco
U.S. House of Representatives
Washington, DC 20515

Dear Congressman LaRocco:

On April 28, 1993, Randall Hardy, Administrator, Bonneville Power Administration, testified before the Committee on Natural Resources, Bonneville Power Administration Task Force, regarding the proposed Fiscal Year 1994 budget for that program.

Enclosed is the answer to the one remaining question that you submitted.

If we can be of further assistance, please have your staff contact our Congressional Hearing Coordinator, Valerie Howard, on (202) 586-2032.

Sincerely,

William J. Taylor, III
Assistant Secretary
Congressional, Intergovernmental
and International Affairs

Enclosure

Questions for Bonneville Power Administration Task Force Hearing
April 28, 1993

QUESTIONS FROM CONGRESSMAN LAROCCO

Question 4: There have been proposals made to modify John Day and Lower Granite dams to operate in a drawdown mode. According to these proposals, at most these modifications would cost $200 million. Does BPA concur with these modification cost estimates? If not, what does BPA estimate modification of these two dams to cost? What would the annual preference rate increase be if this project was amortized over fifty years like other capital construction costs?

Answer: BPA has not made an independent analysis of the construction and mitigation costs for any of the drawdown alternatives. Relying on the Corps' estimate, it is expected a one pool drawdown of Lower Granite will cost between $60 and $86 million (depending upon whether or not a new collection and holding facility is included). For Lower Granite, the Corps estimates include: $15 million for low level juvenile collection facility, $14 million to upgrade collection and holding facilities, $5 million for modification of adult ladders, $29 million for bank stabilization, $1 million for miscellaneous dam modifications, $18 million for engineering and design and $4 million contract supervisors and administration.

To lower John Day to an elevation of 257 feet, the Corps estimates modification costs to be $75.9 million which breaks down as follows: $12.2 million to modify the existing pumping stations, $1.9 million to modify adult ladders and navigation facilities, $18.9 million for a replacement wildlife refuge, $25.5 million to restore recreation sites to their present level of service, $16.1 million modify municipal water supply for the city of Umatilla and to install a water reuse system for the Umatilla and Irrigon fish hatcheries, and $1.3 million for miscellaneous

modifications. (These cost estimates include the construction costs as well those for Engineering and design, supervision and administration, and contingencies.).

When analyzing the impacts on preference rates, power impacts must be added to the modification costs. For a 10-week drawdown of Lower Granite to 710 feet elevation, the annual costs are about $18 million for energy, $11 million for capacity and $11 - $20 million for foregone nonfirm revenues for an annual total of about $40 - $49 million. For a 5-month drawdown of John Day to 257 feet elevation, the annual costs are about $5 million for energy, $5 - $20 million for capacity and $2 - $5 million for foregone nonfirm revenues for a total of $12 - $30 million. The annual capital cost for Lower Granite and John Day are estimated to be about $5 - $7 million each. The combined annual impact of the two projects totals roughly $62 - $93 million which would produce an upward rate impact of roughly .8 to 1.0 mills/kwh or about 4 to 6 percentage points from current levels.

We would like to take this opportunity ot present BPA's 1993 costs for fish enhancement activities. The costs reflected in the table below are discussed in greater detail in our responses to questions 5, 6, and 7.

BPA ANNUAL EXPENDITURES FOR FISH

During 1993, BPA will spend about $306 million for fish. Expenditures breakdown as follows:

ACTION	COST
1. Council Water Budget	$40 million
2. Council Phase II Volumes - Columbia River	33 million
3. Council Phase II Volumes - Snake River	16 million
4. Additional ESA Flow Requirements	10-15 million
5. Drawdown of 4 Lower Snake Projects • to Minimum Operating Pool and John Day to Minimum Irrigation Pool	25 million
6. Phase II Spill	20 million
7. Pre-Phase II Council Fish and Wildlife Program Measures	37 million
8. Phase II Council Fish and Wildlife Program - ESA	20 million
9. Lower Snake Hatchery Funding to Corps/BOR O&M	44 million
10. Program Fixed Expenses (Including interest, amortization, and depreciation on capital additions for bypass, screens, hatcheries, wildlife trusts, etc., and Council budget)	59 million
TOTAL:	$304 - 309 million

SUBMITTED BY HON. MIKE KREIDLER:

Questions for BPA Administrator Randy Hardy
regarding Bonneville's current financial condition

April 28, 1993

1. What cuts are going to be proposed or are being considered as part of the second review of program budgets? If these numbers are not yet available, when will they be available?

2. What is the expected impact on Fish and Wildlife and/or Conservation programs?

3. How much of the current financial crisis has been brought on by problems with Bonneville's contractors? It is my understanding that some of these contractors view the money they receive from Bonneville as an entitlement, and that they are not very responsive when asked to account for the money they have spent. It may be that some of Bonneville's Fish and Wildlife and/or Conservation money could be more efficiently spent either by different contractors or by changes in the present contractors' methods. What are your thoughts on this issue?

4. What are your thoughts of the viability of the following options to help limit the additional rate increase request while retaining Bonneville's ability to meet obligations to the Federal government and others?

   * One-time drought surcharge on BPA customers;
   * review of the irrigation assistance program;
   * allowing a total rate increase of more than 20% (in other words, can we prevent deep cuts in the Fish and Wildlife and Conservation programs if we allow a rate increase of 20.5 or 21%?);
   * turning more conservation responsibilities over to BPA's customers; or,
   * cutting acquisition and development programs in favor of conservation for a few years.

5. As a longer term solution, what are your thoughts on the possibility of creating a board of Bonneville's customers (or perhaps expanding the authority of the Northwest Power Planning Council) which would have more input or control over BPA's finances?

Department of Energy
Washington, DC 20585
August 2, 1993

The Honorable Mike Kreidler
U.S. House of Representatives
Washington, DC 20515

Dear Congressman Kreidler:

On April 28, 1993, Randall Hardy, Administrator, Bonneville Power Administration, testified before the Committee on Natural Resources, Bonneville Power Administration Task Force regarding the Bonneville Power Administration's proposed Fiscal Year 1994 Budget.

Enclosed are the answers to the five questions that you submitted.

If we can be of further assistance, please contact our Congressional Hearing Coordinator, Valerie Howard, on (202) 586-2032.

Sincerely,

William J. Taylor, III
Assistant Secretary
Congressional, Intergovernmental
and International Affairs

Enclosures

cc: The Honorable Peter A. DeFazio

Responses to Congressman Kreidler's Questions by Letter of April 28, 1993

QUESTIONS FROM CONGRESSMAN KREIDLER

Question 1: What cuts are going to be proposed or are being considered as part of the second review of program budgets? If these numbers are not yet available, when will they be available?

Answer: BPA is reviewing all programs for greater efficiency and potential reductions. We note, however, that no single program is expected to bear an undue burden as a result of BPA's present financial difficulties. We are committed to keeping our rates as low as possible without impairing the reliability of the regional power system or compromising long-term goals, including conservation and meeting our fish and wildlife responsibilities.

For Fiscal Years 1994 and 1995, BPA will cut at least $250 million from program spending. This will be accomplished through a combination of reductions and deferrals. Specific program cuts will be announced in early July when the Draft Record of Decision for the current rate case is released. We will forward this information to your office.

Question 2: What is the expected impact on Fish and Wildlife and/or Conservation programs?

Answer: Proposed funding for BPA's FY 1994 and 1995 Fish and Wildlife Program is under review as part of the agency's cost reduction effort. Reductions in program funding could fall within the range of 10 to 25 percent of the levels included in the FY 1994 Congressional Budget Submission. This translates to cuts ranging from $10 to $20 million each year.

The likely reductions include research measures not mandated under the Endangered Species Act for fish health and artificial propagation. Proposed cuts could also include the law enforcement program to curb illegal harvest, and a potential 33 percent cut in the squawfish management program. Reductions also are expected in the administrative area such as contractor support, staff training, and travel. A decision on the overall program level will be announced early July

BPA's Conservation Program funding for FY 1994 to 1995 is also under review for possible cost reductions. As is true with all programs, reductions in program funding could fall within the range of 10 to 25 percent of the levels included in BPA's FY 1994 Congressional Budget Submission. For the Conservation Program, this translates to cuts ranging from $15 million to $50 million each year.

Energy Resource's Programs are being redesigned to reduce infrastructure support and overhead. Because of the long-term benefits of acquiring energy conservation, BPA has not reduced its 10-year targets for conservation acquisitions, but is looking for more efficient ways to acquire the equivalent megawatt savings. Some

support services are likely to be reduced such as advertising, technical assistance, research, training, and on-site data collection. Combined cuts in support services and research are expected to be in the range of $6 million to $8 million. BPA is working with its customers to review a range of options to improve program efficiency and reduce costs.

One specific conservation effort which will be redesigned is the Long-Term Super Good Cents Program. The program is being redesigned to make it more efficient, cost effective, and mitigate any fuel switching problems. The program provides incentives to builders to construct new homes to standards which exceed existing building codes with respect to insulation levels and other house tightening measures. Budget reductions for this program, from advertising, administrative costs, and incentives are expected to reach $3 to $4 million in FY 1994. This would represent about 25 percent of the Long-Term Super Good Cents Program's overall budget.

Question 3: How much of the current financial crisis has been brought on by problems with Bonneville's contractors? It is my understanding that some of these contractors view the money they receive from Bonneville as an entitlement, and that they are not very responsive when asked to account for the money they have spent. It may be that some of Bonneville's Fish and Wildlife and/or Conservation money could be more efficiently spent either by different contractors or by changes in the present contractors' methods. What are your thoughts on this issue?

Answer: Problems associated with BPA's contractors are not a substantial factor in the current financial situation. While some contractors perform better than others, or are more responsive than others to perceived shortcomings, our overall experience with contractors has been quite positive. With respect to the role of contractors in BPA's Fish and Wildlife Program, as well as the Conservation Program, this issue will be closely examined during the "Function-by-Function" reviews currently being conducted by BPA and its customers.

Question 4: What are your thoughts of the viability of the following options to help limit the additional rate increase request while retaining Bonneville's ability to meet obligations to the Federal government and others?

a. One-time drought surcharge on BPA customers;
b. review of the irrigation assistance program;
c. allowing a total rate increase of more than 20 % (in other words, can we prevent deep cuts in the Fish and Wildlife and Conservation programs if we allow a rate increase of 20.5 or 21%);
d. turning more conservation responsibilities over to BPA's customers; or
e. cutting acquisition and development programs in favor of conservation for a few years.

Answer a: The issue of a one-year surcharge for FY 1994 is pending in the current rate proceeding, a formal, on-the-record, quasi-judicial hearing. At the conclusion of the hearing, the BPA Administrator is required to determine this issue, among others, based on the evidence in the record. The Administrator is precluded by law from determining issues pending in the rate case before it is concluded and therefore cannot yet state what the Administrator's position or decision will be on this issue.

BPA staff, however, state that a surcharge would reduce the overall relative rate increase for the two-year rate period. A rate surcharge would assign risk coverage funds to the year in which they are needed. This would reduce the overall relative rate increase compared to a rate design where risk coverage is levelized over the 2-year rate period. BPA's customers universally oppose the surcharge concept, arguing that the first year rate would be too high and disruptive.

A number of other proposals aimed at reducing the rate increase have also been made by parties to the case. These are under review as well.

Answer b: Since this issue is pending in the current rate proceeding as well, the Administrator is precluded by law from determining issues pending in the rate case before it is concluded and therefore cannot yet state what the Administrator's position or decision will be on this issue. BPA staff, however, states that the cost of the irrigation discount does not affect the level of BPA's revenues. This is because the cost of the discount is made up by BPA's other customers. Therefore, lowering the amount of the discount or elimination of the discount merely shifts part of the rate increase to irrigators from all other power purchasers.

Answer c: BPA has stated on record that a 20 percent or more rate increase at this time would be unacceptable for the region. We believe that program costs, including the costs of fish and wildlife and conservation efforts, can be reduced without harming long-term program objectives. With the program cuts being taken, and other possible action, we expect to bring the rate increase below 20 percent. If we did not make any program reductions, the rate increase would be 2.5 to 3 percentage points higher.

Answer d: BPA's Conservation Acceleration Project (decentralization), implemented 2 years ago, was designed to place more conservation acquisition responsibilities in the hands of customers by allowing more latitude in making conservation acquisition decisions. The current investigation of opportunities for conservation program efficiencies will examine strengthening decentralization. Utilities are continuing to take progressively more responsibility for their conservation results, as they have jointly worked with BPA in developing Conservation Action Plans for their individual service territories.

BPA is also examining alternative delivery systems for acquiring conservation. One of the alternatives being discussed is tiered rates, which BPA will consider in its next rate case. If BPA were to adopt tiered wholesale rates, in which the first block of power sold costs less than additional blocks, utilities could be induced to institute tiered retail rates or run other conservation programs. Tiered retail rates should promote investments by customers in cost-effective conservation in order to avoid purchasing energy in the higher rate tiers. This could reduce the need for BPA-financed conservation programs.

Finally, BPA is currently conducting negotiations with several utilities for 'third party financing' arrangements. Under this concept, the utility would issue bonds to finance the conservation activity in their utility service territory. This would allow BPA to avoid having to borrow from the U.S. Treasury for that activity, and it would provide lower-cost financing since public utilities would be able to utilize their tax-exempt status. Since these arrangements would provide funding for at least two years of conservation activity, for the utility it would provide a degree of budget certainly and stability that does not currently exist through BPA's traditional budgeting process.

Answer e: BPA's 1993 Resource Program calls for aggressive acquisition of both generation and conservation resources over the next 10 years in order to meet the needs of our customers. Our analysis show that over the next 10 years, available cost-effective conservation will be inadequate to meet these needs, and will require development of generation resources. Generation resources take a substantive time to develop and by planning now, we can meet these needs Generation resource acquisition projects now under way will have no significant impact on FY 1993 through 1995 rates.

Question 5: As a longer term solution, what are your thoughts on the possibility of creating a board of Bonneville's customers (or perhaps expanding the authority of the Northwest Power Planning Council) which would have more input or control over BPA's finances?

Answer: The Northwest Power Planning Council was created under the Northwest Power Act as a compact agency responsible for developing a Regional Energy Plan with which certain BPA actions must be consistent. While such an arrangement has been found constitutional by the Ninth Circuit Court of Appeals, making the Council the executive authority of BPA in the form of a Board of Directors would raise serious constitutional issues under the Appointments Clause of the U.S. Constitution An Appointments Clause issue would also arise with a Board of BPA's customers, unless members of such Board were federally appointed. See. Seattle Master Builders v. Northwest Power Planning Council, 786 F.2d 1359 (9th Cir. 1986).

In Seattle Master Builders a group of home builders sued to strike down as unconstitutional the Council and its Energy Plan. Before BPA may acquire major resources, BPA and the Council are required to determine whether the proposed acquisition is consistent with the Energy Plan. The home builders also challenged the reasonableness of certain provisions of the Energy Plan. The Court concluded that the Council was a compact agency whose members were not Federal officers under the Appointments Clause.

U.S. House of Representatives
Committee on
Natural Resources
Washington, DC 20515-6201

May 25, 1993

Administrator Randy Hardy
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208

Dear Administrator Hardy: Randy

As a follow-up to the Bonneville Power Administration Task Force's April 29 hearing, I would like you to answer the following questions.

1.) During the hearing, we discussed the reasons you chose not to call for voluntary curtailment earlier this year. You stated that a contractual agreement between BPA and its customers would require BPA to reimburse its customers for any revenues lost during a period of voluntary curtailment. Please provide the Task Force with copies of the contract provisions requiring such reimbursement and the statutory basis for those provisions. In particular, I would like to know how such a contractual agreement is consistent with the Northwest Power Act's mandate to promote conservation and the efficient use of energy.

2.) In your answer to my written questions, you estimated that the irrigation discount will cost BPA $27 million in lost revenues in FY 1994 and FY 1995. Does the BPA's estimate of the costs of the irrigation discount include the cost of lost power generation due to water withdrawals? If not, would you estimate for me the cost attributable to lost power generation due to water withdrawals?

3.) Setting aside the issues in the pending rate case and whatever decisions you must make in the case, does BPA have any plans for a process to review or develop wholesale tiered rates? Is the BPA willing to consider an interim rate case limited to a multi-level rate proposal?

Mr. Randy Hardy
May 25, 1993
Page 2

Thanks again for your cooperation. I look forward to our work together.

Sincerely,

PETER DeFAZIO
Chairman
Task Force on the Bonneville Power Administration

cc: The Honorable Bob Smith

Department of Energy
Washington, DC 20585
July 22, 1993

The Honorable Peter A. DeFazio
Chairman
Committee on Natural Resources, Bonneville
Power Administration Task Force
U.S. House of Representatives
Washington, DC 20515

Dear Mr. Chairman:

On April 28, 1993, Randall Hardy, Administrator, Bonneville Power Administration, testified before your Task Force regarding the Bonneville Power Administration's proposed FY 1994 Budget.

Enclosed are the answers to three questions that you submitted.

If we can be of further assistance, please contact our Congressional Hearing Coordinator, Valerie Howard, on (202) 586-2032.

Sincerely,

William J. Taylor, III
Assistant Secretary
Congressional, Intergovernmental,
and International Affairs

Enclosures

Responses to Congressman DeFazio's Questions by Letter of May 25, 1993
Bonneville Power Administration (BPA) Task Force

QUESTIONS FROM CONGRESSMAN DEFAZIO

Question 1: During the hearing, we discussed the reasons you chose not to call for voluntary curtailment earlier this year. You stated that a contractual agreement between BPA and its customers would require BPA to reimburse its customers for any revenues lost during a period of voluntary curtailment. Please provide the Task Force with copies of the contract provisions requiring such reimbursement and the statutory basis for those provisions. In particular, I would like to know how such a contractual agreement is consistent with the Northwest Power Act's mandate to promote conservation and the efficient use of energy.

Answer: "Conservation" and "curtailment" measures attempt to balance loads and resources by cutting loads rather than building new resources. They do so, however, in very different ways.

"Conservation" is defined in the Northwest Power Act as "any reduction in electric power consumption *as a result of increases in the efficiency of energy use, production, or distribution.*" (Section 3.(3), P.L. 96-501; emphasis added). Conservation is intended to be long-term and dependable, making resources available for service to other customers. It assumes the same jobs can be done, or the same comforts enjoyed, but with a reduced use of electricity.

In the Regional Curtailment Plan for Electric Energy (Portland: Northwest Power Pool, 1992), the term "curtailment," as defined in accordance with standard utility practice during a protracted electric energy shortage is: "load reduction, irrespective of the means by which that reduction is achieved." (Section III.D). Curtailment is brought on by unexpected near-term or mid-term loss of a major resource, or loss of a major transmission facility which

otherwise could have been used to import energy purchases. Curtailment can also refer to those measures used to bring resource output in balance with load when there is an operating year energy shortage on a system.

Curtailment results in an organized "shut down" to avoid failure of an electric system, or to assist in its re-establishment. If loads exceed resources, all components of the electric system -- generators, transmission, motors, lights, and other equipment -- try to operate at frequencies and voltages beyond their design. After a period of time, they either shut down or burn out. Unlike the long-term nature of conservation, curtailment is short-term and is used to avoid system failur and emergencies.

Section 11 of the Power Sales Contract is the contractual agreement between BPA and most of its customers except Washington Water Power, Montana Power Co., Portland General Electric Co., Pacific Power & Light Co., Puget Sound Power & Light Co., and Tacoma City Light that provides for the reimbursement of lost revenues during a period of voluntary curtailment. BPA has the authority to make such reimbursement under Sections 2(f) and 5(a) of the Bonneville Project Act and Section 5(b) of the Northwest Power Act. A copy of Section 11 is attached.

In anticipation of the winter-spring energy shortfalls of 1992 to 1993 related to drought conditions in the summer and fall of 1992, BPA's Division of Power Supply examined the utilization of Section 11(b) to determine whether curtailment could serve as a "resource" to meet load.

The two reasons for choosing purchases over curtailment are price and flexibility.

Price: The Power Sales Contract requires that, if BPA requests curtailment, then BPA shall pay the curtailing party for lost revenues. Customers to whom Section 11 applies, for the most part, are totally dependent upon BPA for power resources. Their expenses may be fixed within the short-term horizon of weeks or months between notice of the need for curtailment and the time when it would have to commence. If BPA and a State Governor call for curtailment, voluntary or otherwise, those utilities would be unable to adapt total revenues to cover expenses in a timely fashion to meet the income lost by reduced electricity sales. This would place them, because of a request for curtailment, in a position of reduced ability to meet their revenue requirements When the Power Sales Contracts were negotiated in 1981 to 1982, this situation was recognized, resulting in Section 11. Section 11 requires BPA to reimburse utilities for costs incurred during a voluntary curtailment. In effect, this regionalizes the localized, negative impact of a curtailment on utility systems. Costs are defined in the contract as the difference between utility retail prices and BPA's energy portion of the priority firm rate.

In early 1993, additional energy was needed on certain dates, for fixed periods of time, often only on certain hours of the day, and at the lowest possible price The projected cost of the curtailment "resource" was approximately 4 cents per kilowatthour (kwh). This figure is derived by taking the average utility retail rate of 5.5 cents per kwh, minus the average of the energy charge of BPA's 1991 priority firm energy charge of 1.7 cents per kwh. Purchased energy was available for purchase at a price of about 2.7 cents per kilowatthour.

Flexibility: To "turn on" the curtailment "resource," utilities must engage in lengthy marketing efforts, notifications, public service requests, and other actions. Voluntary curtailment in Oregon during the early 1970's only gained an estimated energy savings of between 3 percent to 5 percent after 3 to 6 months of effort. Mandatory curtailment, usually imposed only after voluntary efforts have not produced enough savings, takes additional time to implement.

If a resource is needed only for certain peak times, days, or months, then purchases can be made only for those times. Curtailment does not have this flexibility. Once the curtailment "resource" has been turned on, it cannot be immediately turned off. If the crisis requiring curtailment has ended, recovery by a utility system of its original load takes a period of time.

Section 11 of the Power Sales Contract is designed to protect the operational integrity of BPA's electrical system in the short term through curtailment, and has no connection with the Regional Act's long-term conservation goals.

Amendatory Agreement No. 2 to
Contract No. DE-MS79-818P

8/10/82

AMENDATORY AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through

BONNEVILLE POWER ADMINISTRATION

and

_____

This AMENDATORY AGREEMENT, executed _____, 19__, by the UNITED STATES OF AMERICA (Government), Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Bonneville), and _____ _____ (Purchaser), a _____,

W I T N E S S E T H :

WHEREAS Bonneville offered a power sales contract to the Purchaser on August 28, 1981, and the parties hereto have executed such power sales contract (Contract No. DE-MS79-818P, which as amended is hereinafter referred to as "Power Sales Contract") providing for the sale and delivery of firm power and energy to the Purchaser; and

WHEREAS the parties hereto have agreed to the following amendments to the Power Sales Contract offered August 28, 1981; and

WHEREAS Bonneville is authorized pursuant to law to dispose of electric power and energy generated at various Federal hydroelectric projects in the Pacific Northwest, or acquired from other resources, to construct and operate transmission facilities, to provide transmission and other services, and to enter into agreements to carry out such authority;

NOW, THEREFORE, the parties hereto mutually agree as follows:

1. Effective Date of Agreement. This amendatory agreement shall be effective on the later of 2400 hours on the date of execution or the effective date of the Power Sales Contract.

2. Amendment of Power Sales Contract. The Power Sales Contract is hereby amended as follows:

(a) Section 2 is amended by adding a new section 2(b) as follows:

"(b) This contract may be terminated by the Purchaser upon (i) 7 years' prior notice to Bonneville; (ii) concurrent submission by the Purchaser to Bonneville of a Firm Resource Exhibit reciting zero demand upon Bonneville as of the proposed date of termination; and (iii) a determination that termination will cause no adverse economic impacts on Bonneville's other customers."

(b) Section 4 is amended by deleting Exhibit C and replacing it with a new Exhibit C attached hereto and by this reference made a part of this contract in accordance with the specific provisions of this contract relating to Exhibit C.

(c) Section 11 is deleted and replaced by a new section 11 as follows:

"11. Compensation Program for Regional Curtailment of Firm Loads.

"(a) The parties agree to commence negotiations as soon as practicable to develop a comprehensive agreement among utilities in the Pacific Northwest to buy and sell electric energy made available due to

curtailments in consumption or from resources on a party's system during a period when governmental bodies having the authority to do so have so ordered such curtailments or sales.

(b)(1) If the Bonneville Power Administrator and the governor of the State encompassing the Purchaser's service area publicly appeal for curtailments of electric power consumption or if mandatory curtailments of electric power consumption in the Purchaser's service area are ordered by governmental bodies having the authority to so order, Bonneville shall compensate the Purchaser as provided in this section for any reduction in Bonneville's obligation to supply Firm Power to the Purchaser. If the Purchaser's service area extends into more than one State and all of such States do not participate in the curtailments described above, the procedures of this section shall be applied only to those loads in service areas in the participating States.

"Compensation under this section shall not be available to the Purchaser during any Operating Year that the Purchaser is purchasing Firm Power from Bonneville on a Planned Computed Requirements or Contracted Requirements basis. The compensation under this section may be reduced partially or in its entirety as described in paragraph (4) or paragraph (5) below. The reductions described in paragraph (4) below shall be made after the adjustments described in paragraph (5) below.

"Compensation shall begin with the first full month following such appeal for curtailment or ordered curtailment. Compensation shall end with the month during which the Bonneville Power Administrator and the appropriate State political leaders publicly indicate that a need for curtailment no longer exists or such State officials rescind an order for curtailment.

(2) Bonneville shall pay the Purchaser each month an amount equal to the product of the rate set forth in this paragraph and the amount of load curtailment determined in paragraph (3) below unless such amount of load curtailment is reduced partially or in its entirety as set forth in paragraph (4) below. Such rate shall be the amount in mills per kilowatthour by which the Purchaser's average revenue from retail sales of electric energy exceeds the wholesale firm power rate the Purchaser would have paid Bonneville for the increment of energy determined pursuant to paragraph (3) below.

(3) The amount of regional load curtailment on the Purchaser's system during a month shall be deemed to be the amount, if any, by which the Purchaser's Estimated Firm Energy load, after adjustment as specified below, exceeds the Purchaser's Actual Firm Energy load for such month after adjustment, if any, as set forth below. If the Purchaser does not regularly publish an Estimated Firm Energy Load, such Purchaser's Estimated Firm Energy Load for purposes of this section shall be the Purchaser's component of Bonneville's latest published estimate of its firm energy loads.

The Purchaser's most recently published Estimated Firm Energy Load shall be used herein to determine amounts of regional load curtailment in conjunction with information submitted by the Purchaser to Bonneville as soon as possible following the end of each month in which a regional load curtailment program is in effect. Such information shall be provided for each such month and for the three most recent, but not necessarily consecutive, months in which a regional load curtailmemt program or a load curtailment program pursuant to section 17(e) was not in effect. Such information shall include: (A) the Purchaser's Actual Firm Energy Load

for such months; and (B) detail on any separately identifiable significant changes in the Purchaser's Actual Firm Energy Load from its Estimated Firm Energy Load which were not the result of a regional load curtailment program, a load curtailment program pursuant to section 17(e), or an interruption of load for the purpose of providing economic operation of the Purchaser's system including its Firm Resources.

The Purchaser's Actual Firm Energy Loads for all months used for calculations herein shall be adjusted to reflect only those loads in the Purchaser's service area which are in States participating in the regional curtailment program. Such adjustments shall be made by subtracting the portion of the Purchaser's Actual Firm Energy Load in States which are not participating in the regional curtailment program from the Purchaser's Actual Firm Energy Load for such month. Such adjustment may be changed monthly to reflect changes in the States which are participating in the regional curtailment program.

The Purchaser's Estimated Firm Energy Load for all months for which information was requested above shall first be adjusted to reflect separately identifiable changes in load which were not the result of a regional load curtailment program, a load curtailment program pursuant to section 17(e), or an interruption of load for the purpose of providing economic operation of the Purchaser's system including its Firm Resources. The Estimated Firm Energy Load shall then be adjusted in the manner specified for Actual Firm Energy Loads above to reflect only those loads in the Purchaser's service area which are in States participating in the regional curtailment program. An adjusted Estimated Firm Energy Load for each month in which a regional load curtailment program is in effect shall then be determined by multiplying the Estimated Firm Energy Load for

such month, as adjusted above, by the ratios of the Purchaser's Actual Firm Energy Load, as adjusted above, to its Estimated Firm Energy Load, as adjusted above, for the three most recent, but not necessarily consecutive, months in which a regional load curtailment program or a load curtailment program pursuant to section 17(e) was not in effect.

(4) If regional curtailment has been requested after July 1, 1983, because Bonneville is unable to acquire sufficient resources to meet its firm obligations, Bonneville shall reduce the amount of load curtailment determined in paragraph (3) above during any month if the Purchaser's load growth as specified in subparagraph (A) below exceeds the amount of resources which the Purchaser dedicated to its own load or made available to Bonneville as specified in subparagraph (B) below. Such amount of load curtailment for each month shall be reduced partially or in its entirety by the amount which (A) exceeds (B) below:

(A) the excess of the Purchaser's Actual Firm Energy Load in average megawatts over the Purchaser's Actual Firm Energy Load in average megawatts for the same month during the Operating Year prior to the first Operating Year for which Bonneville's load growth notice provided in section 10(e) of this agreement is effective; and

(B) the annual firm energy capability in average megawatts of (i) resources acquired by Bonneville from the Purchaser under P.L. 96-501; and (ii) the portion of the Purchaser's Firm Resources which are included as 5(b)(1)(B) resources in its Firm Resources Exhibit. Such resources shall not include conservation programs to the extent such programs have been reflected in the Purchaser's Actual Firm Energy Load in subparagraph (A) above.

(5) If the Purchaser purchases Firm Power from Bonneville on an Actual Computed Requirements basis, the amount of load curtailment determined in paragraph (3) above for any month shall be determined after the following adjustments:

(A) The amount of load curtailment determined in paragraph (3) above shall be reduced to provide compensation only for the portion of the Purchaser's Actual Firm Energy Load served by Bonneville. Such reduction shall be made by increasing the Purchaser's Actual Firm Energy Load used to determine the amount of load curtailment in paragraph (3) by the amount of load curtailment attributable to the Purchaser's Firm Resources. Such increase in the Purchaser's Actual Firm Energy Load shall be deemed to be the amount determined in the manner specified in section 17(e)(5) even if the Purchaser has not implemented a load curtailment program pursuant to section 17(e).

(B) If the Purchaser initially purchased Firm Power from Bonneville on a Metered Requirements basis, but is purchasing Firm Power from Bonneville on an Actual Computed Requirements basis at the time regional curtailment is requested hereunder, subparagraph (A) above will apply only if the Purchaser has implemented a load curtailment program pursuant to section 17(e). This subparagraph (B) shall no longer apply if the Purchaser was offered the opportunity to be a party to a comprehensive agreement among utilities in the Pacific Northwest described in subsection (a) above after it commenced purchasing on a Computed Requirements basis."

(d) Section 17(b) is deleted and replaced by a new section 17(b) as follows:

"(b) On or before the effective date of this contract, and thereafter, as provided in paragraph (1) below, the Purchaser may request in writing to purchase on the basis of Contracted Requirements by submitting the data and proposed schedule of Contracted Requirements purchases of peak and energy pursuant to paragraph (2) below.

(1) The Purchaser may request that it begin to purchase on a Contracted Requirements basis at the time of submittal of any revised Firm Resources Exhibit. Such request shall become effective, in accordance with this subsection (b), for the seventh Operating Year of such exhibit, or for an earlier Operating Year if Bonneville is expected to have an excess of firm load over its firm resources in the first Operating Year for which the Purchaser requests to purchase on a Contracted Requirements basis. Bonneville's expected firm load-resource balance and the priority of competing requests for purposes of allocating the availability of this subparagraph of paragraph (1) shall be determined in the manner described in section 12(b)(7) above.

The Purchaser may elect to cease purchasing on a Contracted Requirements basis at the time of submittal of any revised Firm Resources Exhibit. Such election shall become effective for the seventh Operating Year of such exhibit, or for an earlier Operating Year if Bonneville is expected to have an excess of firm resources over its firm load in the first Operating Year for which the Purchaser proposes to cease purchasing on a Contracted Requirements basis. Bonneville's expected firm load-resource balance and the

priority of competing requests for purposes of allocating the availability of this subparagraph of paragraph (1) shall be determined in the manner described in section 12(b)(9) above.

(2) If the Purchaser requests to purchase on the basis of Contracted Requirements, it shall submit to Bonneville in the Purchaser's initial Firm Resources Exhibit in addition to data required in section 12(a), the Purchaser's annual Estimated Firm Peak Load, the annual average of Purchaser's Estimated Firm Energy Load, the estimated Assured Capabilities of the Purchaser's Firm Resources corresponding to the time period of such loads, and a schedule of annual Contracted Requirements purchases of peak and energy for each of the first seven Operating Years. If the Purchaser's Contracted Requirements peak purchase amount for any such Operating Year is based on its Estimated Firm Peak Load for the months June through November, such amount shall be the Purchaser's Contracted Requirements peak purchase amounts for June through November and the Purchaser shall also submit a lower amount which is based on its Estimated Peak Load for the months December through May. With each revised Firm Resources Exhibit submitted in accordance with section 12(b), such Purchaser shall submit a new schedule deleting the amounts of Contracted Requirements peak and energy purchases for the current Operating Year and adding the amounts to be purchased in the seventh succeeding Operating Year together with Purchaser's annual Estimated Firm Peak Load and annual average Estimated Firm Energy Load in the seventh Operating Year, and new information on the estimated Assured Capability of all Firm Resources and Estimated Firm

Question 2: In your answer to my written questions, you estimated that the irrigation discount will cost BPA $27 million in lost revenues in FY 1994 and FY 1995. Does the BPA's estimate of the costs of the irrigation discount include the cost of lost power generation due to water withdrawals? If not, would you estimate for me the cost attributable to lost power generation due to water withdrawals?

Answer: BPA's estimate of the 2-year amount of the irrigation discount does not include "the cost of lost power generation due to water withdrawals.At this time, we do not have a methodology for calculating the impact of water withdrawals. Such estimates are complicated by a variety of factors including water returned to the river, price elasticity in the irrigation sector, and varying amounts of annual precipitation

BPA will reconsider the need for the irrigation discount in the context of developing tiered rates over the next two years, as a part of the 1995 rate case. Utilities that currently qualify for the irrigation discount are also those that have slow growth. Thus, they may benefit from a tiered rate structure in the form of lower rates, offsetting the need for the irrigation discount

Question 3: Setting aside the issues in the pending rate case and whatever decisions you must make in the case, does BPA have any plans for a process to review or develop wholesale tiered rates? Is the BPA willing to consider an interim rate case limited to a multi-level rate proposal?

Answer: BPA is currently preparing to initiate a public process, to begin this summer, to consider the development and implementation of tiered rates. BPA will establish a working group to identify the problems and concerns to be addressed by a tiered rate, look at tiered rate objectives and principles, and develop tiered rate alternatives. The alternatives will then be evaluated, the completion of which will be no later than July 1994. BPA may, if it is appropriate at that time, hold an interim rate case on the tiered rate methodology.

April 27, 1993

The Honorable Peter DeFazio
House of Representatives
1233 Longworth House Office Building
Washington, D.C. 20515

Dear Congressman DeFazio:

The Public Power Council (PPC) and its member utilities take this opportunity to respond to your questions of the Bonneville Power Administration (BPA).

PPC intends to provide additional information on these questions and other matters the Task Force will review. We believe that your airing of these issues will help to contribute to their resolution.

We would like to emphasize these key points for this first Task Force hearing:

- BPA is in a financial crisis and it needs to cut its costs;
- BPA's customers, the ones who pay those costs and are among the beneficiaries from BPA's programs, have identified areas where costs can be cut without undermining BPA's mission or responsibilities; and
- BPA's customers want to work with BPA to accomplish these efficiency improvements.

Thank you for the opportunity to provide these responses. If you need any additional information, please call me.

Sincerely,

William K. Drummond

William K. Drummond
Manager

Responses to DeFazio's Questions

OPERATIONS

(p.2,Q6)
Has an independent entity conducted a top to bottom review of the efficiency of BPA operations? If not, does BPA intend to initiate such an independent review?

- **The customers welcome the opportunity for an objective and independent review of BPA operations.**

- **The Programs in Perspective (PIP) process was initially designed to provide increased involvement in BPA's decision making.** Its incremental review is, however, unlikely to produce the coherent agency-wide review that mechanisms like the Customer Review Group (CRG) can.

(p.2,Q7)
BPA has announced that cuts will occur in the administrative budget, including employee training, travel, supplies and support services. What level of reductions will you take from current levels in these and other administrative areas? What cuts will be taken in FY 94 and FY 95 from budgeted levels?

- **PPC believes that cuts in BPA's administrative costs, as well as its other costs, are necessary for BPA to remain a competitive power supplier.**

- **We believe that BPA's utility and industry customers can help BPA to deal with its current financial situation.** BPA's customers have faced similar financial difficulties in managing their own operations and have reduced their costs to remain competitive. Because they have faced these difficult issues themselves, the customers are uniquely positioned to assist BPA in making decisions about the kinds and amounts of any cuts.

- **PPC is supporting the "conceptual" agreement that occurred during recent rate settlement discussions.** Through that decision PPC agreed to work with BPA staff to reduce administrative costs. BPA customers recommend that, in light of the current financial crisis, BPA hold its costs to 1992 actual levels.

- **Expenditure levels may need to be reduced much further, but it is most important that BPA's expenditures should support the BPA mission.**
  This mission includes:
  - firm electric power and capacity;
  - transmission services;
  - exchange coordination and backup services;
  - economy and replacement energy; and
  - fulfill its fish and wildlife responsibilities.

REVENUES

(p.2,Q3)
It is my understanding that certain BPA customer utilities have advanced a proposal to increase BPA's short-term cash flows by paying their BPA obligations earlier than they presently do. Please describe the benefits that might accrue to BPA if this approach was adopted. Does BPA plan to implement this proposal?

BPA's customers have proposed a voluntary prompt bill payment program whereby, upon notification by BPA, the utilities would pay their power bills upon receipt of the bill from BPA, instead of at the end of the period during which the bill may be paid. Also, some investor-owned utilities participating in the Residential Exchange Program would agree to receive their Exchange payments at the end of the period in which they may receive these payments. This cash flow modification would assist BPA in meeting its U.S. Treasury payments and other payments in years when BPA's working capital declines below levels needed to make these payments while maintaining adequate cash balances.

¢ONSERVATION

(p.4,Q1)
In a letter to Chairman Miller dated March 24, 1993, the Northwest Power Planning Council stated that BPA "has not been aggressive in reducing program administrative costs" for conservation programs. Please identify potential savings, if any, per fiscal year from FY 1994 to FY 1998 from reducing administrative costs of conservation programs.

- **Reducing the administrative costs of delivering conservation resources is a high priority with PPC.** It is important, however, to differentiate between program administrative costs and corporate administrative costs because the corporate costs are beyond the control of BPA's conservation staff. The preliminary numbers indicate that program overheads average approximately 14% of program costs and corporate overheads average approximately 26%.

- **PPC believes that significant savings are possible by employing innovative strategies for delivering conservation resources.** Third party financing of conservation and placing greater control of conservation expenditures at the local utility level are examples of these innovations. For example, an organization of Washington Public Utility Districts has been formed to develop conservation and renewable resources. These approaches rely more on local than centralized decision-making.

- **Given the state of knowledge about conservation performance in the Northwest, a more reasonable approach to program evaluation would also help to lower BPA conservation program administrative costs.** The issues are how much certainty we need and how much can we afford.

- **BPA's corporate overheads are somewhat more difficult to analyze and understand.** We understand that BPA is reviewing the impacts of corporate overheads on conservation programs. We will be examining the components of these overheads as soon as the assessment is complete and we expect to be working with BPA to address the issues of corporate overheads as they contribute to BPA's conservation program costs.

(p.4,Q2)
Please provide an estimate of the total expenditures to date of the "Super Good Cents" program in areas where natural gas service is currently available. Please estimate the budget savings that would result from a termination of the Super Good Cents program in areas currently served by natural gas per fiscal year from FY 1994 to FY 1998.

- **The intent of the Super Good Cents program is to promote energy efficiency in new electrically heated homes.** No reliable statistics are available from PPC's members about the programs's effect in areas served by natural gas. Informal evidence from PPC's members, however, indicates that in areas where natural gas is available its market share is approaching 90%.

- **The Super Good Cents program is designed to educate the construction trades, manufacturers, suppliers and consumers about the importance of quality materials and workmanship in the efficiency of new homes.** It was developed to prepare the market to accept the Northwest Power Planning Council's Model Conservation Standards (MCS).

- **Significant savings might be accomplished by reducing the cost components of the Super Good Cents program.** For example, regional advertising could be lowered along with certain program support items. PPC is participating in BPA's program-by-program review of all of its residential programs and we expect to identify significant savings through these efforts.

(p.4,Q3)
It is my understanding that a study has been conducted which compares the costs of BPA conservation programs per unit of energy saved to the costs incurred by certain Northwest utilities per unit of energy saved. Please provide a copy of this study and explain the differences in conservation costs, if any, between BPA and regional utilities.

- **PPC is unaware of any published study comparing the cost per unit of energy saved in BPA programs and the cost per unit of energy saved of other Northwest utilities.** PPC has repeatedly expressed its concern about BPA making appropriate conservation investments and keeping its administrative and overhead costs as low

as possible; however, some comparisons between BPA programs and those of other utilities might be unfair. Frequently, the utility programs compared are less comprehensive and less aggressive than BPA's conservation programs. This does not mean that BPA's conservation programs cannot be improved; there is ample evidence that improvement is possible. We just need to decide what is broken before we try to fix it.

(p.4,Q5)
Please provide an estimate of BPA expenditures to date on the Manufactured Housing Acquisition Program (MAP) per fiscal year. What Percentage of these expenditures were administrative costs? Please provide an estimate of the percentage of MAP homes that are sited in areas currently served by natural gas.

- **Historically, very few manufactured homes have used gas.** Each year, over 11,000 manufactured homes are sited in the region. More than 90% of these homes are electrically heated. It is difficult to accurately estimate the number of these manufactured homes that are located where natural gas is available.

- **The regional benefits of MAP are significant.** With energy savings of approximately 6,000 kWh per year per house, the new homes leaving the factory will add another 7.5 average megawatts of conservation savings. The MAP is expected to save Northwest consumers approximately $38 million over the term of the four year contract.

(p.4,Q7)
Please describe the scope of BPA's activities regarding fuel switching.

Bonneville and its customers reviewed the fuel choice policy as part of the 1992 Resource Program. The conclusions drawn from this review were threefold.

Fuel switching is a potentially cost-effective resource but the method and rate of acquisition are unclear. Bonneville identified approximately 200 aMW of fuel switching resource potential not expected to be captured by current market forces in the service areas of its customer utilities. What was not clear from the analysis was how, if at all, this resource could be

captured in a programmatic effort. In order to improve its information base regarding fuel switching, Bonneville initiated the following efforts.

Review of current policies and programs to assess their impacts on fuel switching. Bonneville will determine if any of its existing programs, policies or regulations provide inappropriate market signals with regard to fuel choice. Bonneville, in cooperation with its customers, will move over time to make changes in program design if necessary.

Provide assistance for customer initiated projects. Bonneville will consider financial and other assistance for fuel switching projects endorsed by the local utility. Projects must be regionally cost-effective and be structured so that the electric and gas utilities along with the switching consumer all contribute to funding the cost of program.

(p.4,Q8)
Please provide an estimate of the amount of energy that would be saved per year if the two-tiered rates and low-density discount adjustment recommended by the Northwest Conservation Act Coalition were implemented (growth adjustment and no-growth adjustment model). What is the earliest possible date that BPA can implement tiered rates? Has BPA initiated an EIS on tiered rates?

Potential energy savings from implementing NCAC's tiered rate proposal are unknown, for several reasons.

- NCAC's definition of tiered rates is incomplete and there are many definitions of tiered rates.
- Numerous definitional and allocation issues remain to be resolved under anyone's tiered rates scenario.
- Customer responses to tiered rates will, undoubtedly, change depending on the decisions that are made about tiered rates and how they are implemented.
- No one is certain how DSI or residential exchange loads will be addressed under possible tiered rates scenarios but the public agencies believe DSI loads and residential exchange must be included in BPA tiered rates.
- Tiered rates may significantly affect the manner in which conservation is delivered especially in fostering conservation transfers.

FISH AND WILDLIFE

(p.5,Q2)
What percentage of the FY 1992, 1993 and proposed FY 1994 budget are/were devoted to the implementation of Council program measures and what amount are/were spent for other purposes? Please provide a list of all non-program measures in these budgets, including the rationale, cost and purpose of each measure.

The unspoken implication is that program measures deserve the top priority and non-program measures need special rationale to justify their inclusion in BPA's budget. We think other priorities are important, and deserve BPA's attention, such as: does the measure offer a direct benefit to fish and wildlife, especially weak or listed stocks and is it cost effective? The Council's program is not the only authority on fish programs, and some elements may actually harm listed stocks. It is critical that threatened or endangered fish not be harmed by BPA's measures.

(p.6,Q3)
It is my understanding the BPA is currently reducing program budgets throughout the agency. Do you intend to defer implementation of the Northwest Power Planning Council's Strategy for Salmon? If so, in what areas and what savings would result in FY 1994? Do you intend to defer any non-program measures? If so, in what areas and what savings would result in FY 1994?

Savings are possible in several areas that would not detract from the Strategy For Salmon, for example a reduction of the overhead for the squawfish program. In other areas, such as O&M, wildlife, and habitat, deferral of program measures is acceptable. Some program elements may be harmful to potential endangered species and should be reconsidered for that reason.

(p.6,Q4)
It is my understanding that BPA has a contract relating to salmon with Resources for the Future. What is the purpose of the contract? How much has BPA spent on this contract to date and how much does BPA plan to spend in FY 1994?

The purpose of the Resources for the Future (RFF) contract is to help develop tools that can be used to manage the fish and wildlife program in a cost-effective manner. RFF has used available information and developed analyses that can help the region decide which measures in the Council's Fish and Wildlife Program are cost-effective and which are not. Preliminary results are available on a system-wide basis, which indicate that we are not on a least-cost path toward fish enhancement. This information should be used to redirect the Fish and Wildlife Program and as part of the NMFS Recovery Plan. There is no other available comprehensive source on the cost-effectiveness of the region's expenditures in this area. Two recent GAO reports note that there is currently no evidence of the cost-effectiveness of either past or proposed future actions. The analysis by RFF is one critical component of a least-cost fish enhancement and recovery plan.

(p.6,Q6)
Has BPA contracted with the University of Washington to do a modeling effort that is similar to one already conducted by the Northwest Power Planning Council? If so, what is the purpose of this contract and how much will it cost?

The BPA modeling effort is important because it is an alternative to, not a duplication of, the Council and state models. BPA's model is more comprehensive than the Council's model, allows for consideration of alternative measures and answers different questions; it goes far beyond the Council's model. Also, the other models were not developed in the same open arena as the BPA model.

(p6,Q8)
How much has BPA budgeted for the squawfish program in FY 1994? Of this amount how much will go directly for the payment of bounties to fishermen? Please describe the status and results of research on the effectiveness of the squawfish program.

PPC supports predator control as part of a comprehensive program of salmon recovery. We are concerned that administrative costs appear to comprise a disproportionate share of program costs.

(p.6,Q9)
Please describe the so called "lease back/buy back" fish program. How much will this program cost in FY 1994?

This proposal is apparently dead for this year due to a failure to ensure the fish not harvested in the lower river would pass through tribal fishing areas. There are pros and cons to the concept. Basically, the best, if not only, way in near term to make additional adults available for spawning is to stop or reduce the harvest. The concept is that BPA would pay for adults through this program and be compensated by NMFS in terms of river operation (giving credit for fish). It is expensive per fish, but compared to the cost and uncertain benefit of changes in river operations, it may be cost-effective. The program is designed to increase the number of listed wild adult Snake River salmon, but would likely help other runs as well.

PAT WILLIAMS
MONTANA

MAJORITY DEPUTY WHIP

2457 RAYBURN BUILDING
WASHINGTON, DC 20515
(202) 225-3211

Congress of the United States
House of Representatives
Washington, DC 20515-2601

COMMITTEES:
EDUCATION AND LABOR
AGRICULTURE
NATURAL RESOURCES

SUBCOMMITTEES:
LABOR-MANAGEMENT RELATIONS
CHAIRMAN
POSTSECONDARY EDUCATION
GENERAL COMMODITIES
NATIONAL PARKS AND PUBLIC LANDS
NATIVE AMERICAN AFFAIRS

April 28, 1993

Mr. George Eskridge
Montana District Manager
800 Kensington
Missoula, Montana 59801

Dear George

Thank you for coming to Northwest Montana to hear the concerns of my constituents about the lake and about Bonneville's operations.

I know this is a difficult time for BPA, and that you have an extraordinary set of circumstances within which to operate the power system this year. Between the drought, efforts to maintain northwest fisheries, and the need to purchase additional power, Bonneville would seem to be very close to the rock and the hard place.

As you know, today is the first hearing of the U.S. Congress task force on the BPA. This task force has been formed for the purpose of both reviewing BPA's water and power programs, and to begin the discussion about what we want Bonneville to look like in ten or twenty years. As the custodians of much of the region's water storage capacity, we Montanans have very serious concerns about how this water is used, and about the cost to Montana's fish, wildlife, and recreation of policies benefitting these same resources downstream.

I'm committed to work through the task force to resolve some of the following issues, and I'm willing to work with the residents of this county and the state on other issues of concern as well.

From our top state officials at the Power Planning Council, to the marina operators and fishermen on Lake Koocanusa, Montanans are weary of the drawdown process. We Montanans deserve a full accounting of why our reservoirs are drawn to such low levels that our fisheries cannot thrive, residents and visitors can't get their boats in the lake, and the Tobacco Valley is choked in dust.

Mr. George Eskridge
April 28, 1993
Page 2

We want an accounting of our reservoirs' contribution to the efficient production of power, to the recovery of sturgeon on the Kootenai and the salmon in the Columbia.

Montanans are willing participants in our nation's quest to restore the salmon, but we must be assured that our contributions are based on science and have a good chance of success.

And finally - but importantly - our Northwest Montana economy is very sensitive to electric rates. Columbia Falls Aluminum and our timber mills most likely cannot absorb large rate increases. We encourage Bonneville to continue to do all it can to keep its costs down, and to improve conservation so that we avoid expensive new power purchases.

Now, George, if you'll do those things, we'll try to make it rain.

Best regards.

Sincerely,

Pat Williams

Pat Williams

U.S. House of Representatives
Committee on
Natural Resources
Washington, DC 20515-6201

February 16, 1993

The Honorable Charles A. Bowsher
Comptroller General of the United States
U.S. General Accounting Office
441 G Street, N.W.
Room 7000
Washington, D.C. 20548

Dear Mr. Bowsher:

I recently announced my intent to establish within the Committee a Task Force on the Bonneville Power Administration to review the many critical issues confronting BPA and the Northwest region, including electric power resource acquisition, water management, endangered salmon, and financial reform. As part of this review, I request that GAO prepare a summary of all the work it has done regarding BPA and other federal agencies involved in the operations of the BPA system subsequent to the passage of the Pacific Northwest Electric Power Planning and Conservation Act of 1980. If possible, I request that this summary be completed before March 31, 1993, so that the Task Force can utilize it prior to holding its first hearing.

Thank you for your assistance.

Very truly yours,

George Miller

George Miller
Chairman

GAO

United States
General Accounting Office
Washington, D.C. 20548

Resources, Community, and
Economic Development Division

B-252738

March 31, 1993

The Honorable George Miller
Chairman, Committee on Natural Resources
House of Representatives

Dear Mr. Chairman:

This letter with enclosures responds to your February 1993 request that we summarize our work on the Bonneville Power Administration (BPA) since the enactment in 1980 of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). You asked that we include our relevant work on other federal agencies involved in the operations of the BPA system. These include the U.S. Army Corps of Engineers and the Bureau of Reclamation, which operate dams on the Columbia River; the Department of Energy, BPA's parent agency; and the U.S. Fish and Wildlife Service and the National Marine Fisheries Service, which are responsible for protecting the Columbia River's endangered and threatened fish species.

To respond to your request, we searched GAO's automated database to identify products on BPA and the related agencies issued from December 1980, when the Northwest Power Act was enacted, to the present. For those products in which we had recommended that an agency or agencies take action, we retrieved from other GAO automated files the documentation indicating whether and how the agency or agencies had responded to the recommendation(s). We reviewed each of the identified products for content and relevance. As agreed with your office, we categorized the products according to the issues identified in your letter and several related issues.

Each of the eight enclosures to this letter summarizes our work on one of these issues, as follows:

Enclosure I - Financial Management
Enclosure II - Endangered Species
Enclosure III - Resource Acquisition
Enclosure IV - Irrigation
Enclosure V - Electricity Transmission

B-252738

Enclosure VI - Administrative Matters
Enclosure VII - Washington Public Power Supply System (WPPSS)
Enclosure VIII - Power Marketing Administration (PMA) Rates/Repayment

For each of the identified issues, the summary includes our conclusions and recommendations and the action(s) taken by the agency or agencies in response to our recommendations. We have also included within each enclosure a complete list of our relevant products.

If you have any questions, please contact me at (202) 512-3841.

Sincerely yours,

Jim Wells

for Victor S. Rezendes
Director, Energy and
Science Issues

FINANCIAL MANAGEMENT

BACKGROUND

Federal law requires the Bonneville Power Administration (BPA) to repay the federal investment in the Columbia River Power System --about $8.5 billion as of 1987--and to set electric power rates at the lowest possible level consistent with sound business practices. The Federal Columbia River Transmission System Act of 1974 placed BPA on a self-financing basis, giving it authority to fund its operations from the revenues of power and transmission service sales and to borrow from the U.S. Treasury. This law also provided that BPA apply revenues to pay for, among other things, the costs of (1) operation and maintenance, (2) purchased and exchanged power, and (3) transmission service.

BPA made repayments on the federal investment from 1939 through 1965, using a cost-based method that incorporated fixed annual repayments. In 1965, BPA switched to a "repayment study method," under which annual repayments are not required; BPA need only repay the federal investment within its repayment period (usually 50 years).

GAO WORK

In June 1981, we concluded that BPA's repayment study method was unacceptable and recommended that BPA replace it with a cost-based (mortgage-type) approach. We found that since BPA had adopted the repayment study method, its repayments of the federal investment had fallen far behind levels that would have been expected if annual schedules had been maintained. We based our recommendation on a number of factors that we believed BPA should consider in evaluating its policies and alternatives, including the requirements of the 1980 Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) and the principles of good government. We found that the repayment study method made it virtually impossible for BPA to (1) adequately meet some of the requirements of the Northwest Power Act, such as the requirement that BPA allocate costs among its various customers, and (2) conform to principles of good government, such as those calling for the establishment of credible and reliable processes, the encouragement of economy and efficiency, and the prevention of unsanctioned burdens on the taxpayer.

In testimonies before the Congress in August and September 1983 and in a report issued in October 1983, we continued to recommend that BPA adopt a repayment method based on costs with fixed annual payments. Our October 1983 report cited the fixed repayment requirement that the Congress had placed on the Tennessee Valley Authority to suggest that a cost-based approach was

practicable. Our October report also included two additional recommendations. First, we recommended that BPA stop its practice of first paying the highest interest-bearing obligations, rather than repaying debts in the order in which they were incurred. We concluded that the practice of first paying high-interest obligations reduces BPA's payment to the Treasury. As a result, the Treasury has to borrow more money at interest rates that usually exceed those paid by BPA, thereby costing the taxpayer more.

The report also recommended that the cost-based method contain a provision that late or missed repayments incur interest costs at the higher of the project's interest costs or the Treasury's current cost of borrowing. In response to our recommendations, the Department of Energy (DOE) stated that (1) BPA's repayment study method was appropriate but that DOE and BPA were continuing to study alternative methodologies, including the cost-based method that we had recommended; (2) imposing an interest penalty on missed repayments was not legally permissible; and (3) paying the highest interest-bearing capital obligation first was consistent with sound business principles.

In a September 1989 report, we reviewed the authority of several federal agencies, including BPA, to borrow funds when this authority was not provided in advance in annual appropriations acts. At the time, agencies with authority to borrow were financing a large portion of their programs with debt and were repaying their debt with appropriations or new borrowing rather than collections. We recommended that those agencies that would, in all likelihood, be able to repay their borrowings entirely with collections be granted authority to borrow. We concluded that, since BPA had not received appropriations to reduce debt and since BPA had attempted to set its rates at a level sufficient to recover its costs, it was reasonable to expect that BPA would be able to repay its $1.8 billion in borrowings with collections.[1]

Our 1990 report reviewed BPA's Residential Exchange Program, which was created by the Northwest Power Act. The purpose of this program was to reduce the disparity in electric rates paid by residential and small farm customers of the region's utilities by having BPA "exchange" its relatively low-cost power with Northwest utilities that had higher-cost power. We found that, although the program reduced the disparity in rates, this reduction stemmed mostly from significant increases in BPA's rates over the period rather than from reductions in rates attributable to utilities' purchases of lower-cost BPA power. After finding that BPA had not

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[1]The report noted that BPA was also required to pay $6.7 billion in debt resulting from appropriations.

been conducting the reviews necessary to ensure that utilities were passing on lower costs to residential and small farm customers, we recommended that the BPA Administrator initiate such reviews. BPA adopted our recommendations, including procedures to verify that customers' rates are adjusted by Northwest utilities to account for purchases of BPA's lower-cost power.

GAO PRODUCTS

Federal Electric Power: Bonneville's Residential Exchange Program (GAO/RCED-90-34, Feb. 6, 1990).

Budget Issues: Agency Authority to Borrow Should Be Granted More Selectively (GAO/AFMD-89-4, Sept. 15, 1989).

Nuclear Science: Effect of Conversion of Washington Nuclear Plant No. 1 on Debt and Electric Rates (GAO/RCED-89-88FS, Mar. 9, 1989).

Federal Electric Power: Development of Bonneville Electricity Rates for the 1988-89 Period (GAO/RCED-88-126, June 7, 1988).

Bonneville Power Administration's Repayment of Federal Investment in Columbia River Power System (GAO testimony, 125176, Sept. 13, 1984).

Implementation of the Pacific Northwest Electric Power Planning and Conservation Act's Fish and Wildlife Provisions (GAO/RCED-84-166, Aug. 17, 1984).

Policies Governing Bonneville Power Administration's Repayment of Federal Investment Still Need Revision (GAO/RCED-84-25, Oct. 26, 1983).

Bonneville Power Administration's Repayment of the Federal Investment (GAO testimony, 122327, Sept. 14, 1983).

Federal Investment in the Columbia River Power System: Status of Repayment (GAO testimony, 122041, Aug. 3, 1983).

Bonneville Power Administration's Capability and Preparations to Implement the Regional Power Plan (GAO testimony, 121651, June 13, 1983).

Actions by the Bonneville Power Administration to Implement the Long-Term Contracting Provisions of P.L. 96-501 (GAO/EMD-81-140, Sept. 4, 1981).

Policies Governing the Bonneville Power Administration's Repayment of Federal Investments Need Revision (GAO/EMD-81-94, June 16, 1981).

Bonneville Power Administration's Efforts in Implementing the Pacific Northwest Electric Power Planning and Conservation Act (GAO/EMD-81-67, Apr. 8, 1981).

ENDANGERED SPECIES

BACKGROUND

Hydropower facilities in the Columbia River Basin have contributed to an estimated 80-percent decline in the numbers of salmon and steelhead trout that migrate to the ocean as young fish and return as adults to spawn. Dams have been built by the Department of the Interior's Bureau of Reclamation (Bureau), the U.S. Army Corps of Engineers (Corps), or public utility districts.

The Pacific Northwest Electric Power Planning and Conservation Act, enacted in 1980, established the Pacific Northwest Electric Power and Conservation Planning Council (Council) and directed it to develop a program for enhancing, mitigating, and protecting fish and wildlife affected by the Columbia River Basin power-generating facilities. The Council's program was first adopted in 1982 and was revised in 1984 to include a 5-year action plan that put primary emphasis on enhancing fish resources. The action plan also included measures for protecting and enhancing the habitat of the basin's nonmigratory fish and wildlife.

The Department of Commerce's National Marine Fisheries Service (NMFS) listed the Snake River sockeye salmon as an endangered species in 1991 and the Snake River fall chinook salmon and spring/summer chinook salmon as threatened species in 1992.

GAO WORK

In 1984, we reviewed the Council's compliance with the act's requirement to develop a fish and wildlife program and found that the Council had developed a program according to the procedures and standards specified in the act. In 1987, we again reviewed the Council's program and found that the Bonneville Power Administration (BPA) and other responsible agencies appeared to be making progress in carrying out the Council's program. BPA and the Corps have responsibility for implementing roughly one-half of the action items included in the program, and, as of 1985, BPA and the Corps had spent more than $100 million on implementing these items. All expenditures for the program are funded by BPA through its power sales revenues. We noted, however, that it was too early to determine the success of the overall program in protecting and restoring the region's fish and wildlife resources. We also noted that both the Council and BPA had instituted programs to inform the public of, and elicit their views on, plans and activities related to fish and wildlife programs.

In 1990, we examined the efforts made by the Corps to determine the most effective method for assisting fish migration past certain Columbia and Snake River dams. We found that the

Corps had excluded several factors from calculations used to determine that the costs of constructing bypasses at two dams outweighed the benefits and that the inclusion of these factors could have led to the opposite conclusion. In addition, we found that the Corps did not adequately involve fish and wildlife agencies or other groups, as its regulations require, in making its decisions. We determined that the Corps was not obligated to restore the numbers of migrating fish to a specific level and therefore had no benchmark to assess the need for additional fish migration projects.

On the basis of these findings, we recommended that the Secretary of the Army direct the Corps, in consultation with other interested groups, to establish a mitigation objective and determine which measures, such as bypass facilities, were necessary to meet the objective. We also recommended that, in performing future cost-benefit analyses, the Corps take such steps as using validated models to project impacts on fish stock and consulting with other agencies and other parties involved in resource management. In response, the Army stated that the Corps was developing mitigation objectives and expected to have a detailed analysis in 1993 or 1994. In addition, the Corps agreed to adopt our recommendations regarding cost-benefit analyses.

In 1992, we reviewed past actions taken to address declines in salmon runs, together with the costs of these actions. We also reviewed the results of studies and research that evaluated the effectiveness of the salmon recovery measures undertaken. We found that, since 1981, federal agencies and regional organizations had spent over $1.3 billion (in 1991 dollars) to construct and operate fish hatcheries, construct fish ladders and other facilities to assist salmon in their migration to and from the sea, improve salmon habitats, and conduct research to learn more about salmon or to assess and improve salmon runs. The effectiveness of the actions taken has varied by the type and location of the action. For example, hatcheries have been successful, but problems have resulted from mixing wild and hatchery-bred salmon; facilities to assist salmon in their migration, such as bypass screens and fish ladders, have also had differing results, depending on the location of the dams and the type of salmon.

A 1993 follow-up report identified the potential economic costs and effectiveness of future actions that could be taken to further protect endangered and threatened salmon stocks. We found that a preliminary estimate of the impacts of additional salmon protection measures on employment would not be available until mid-1993 at the earliest. Preliminary estimates of the direct net economic costs of some potential salmon protection measures range from $2 million to $211 million annually (in 1990 dollars). These protection measures would alter stream flows to improve the

survival of fish migrating downstream; more definitive estimates of economic impact cannot be determined until NMFS identifies the specific measures to be taken. We found no conclusive evidence to indicate how effective any of the salmon protection measures proposed to date would be in sustaining populations of threatened or endangered salmon.

GAO PRODUCTS

Endangered Species: Potential Economic Costs of Further Protection for Columbia River Salmon (GAO/RCED-93-41, Feb. 23, 1993).

Endangered Species: Past Actions Taken to Assist Columbia River Salmon (GAO/RCED-92-173BR, July 13, 1992).

Hydroelectric Dams: Issues Surrounding Columbia River Basin Juvenile Fish Bypasses (GAO/RCED-90-180, Sept. 6, 1990).

Electric Power: Issues Concerning Expansion of the Pacific Northwest-Southwest Intertie (GAO/RCED-88-199, Sept. 14, 1988).

Federal Electric Power: A Five-Year Status Report on the Pacific Northwest Power Act (GAO/RCED-87-6, Feb. 19, 1987).

Matters for Consideration When the Columbia River Basin Fish and Wildlife Program Is Revised (GAO letter, 124359, May 2, 1984).

RESOURCE ACQUISITION

BACKGROUND

The Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) was enacted in 1980, in part, to alleviate regional concerns about future power shortages. Its primary objectives included (1) establishing a regional power planning process with participation from all interested parties and (2) encouraging cost-effective energy conservation and development of renewable energy resources. The act strongly emphasized conserving electricity and developing renewable resources by making these activities the first and second priorities of the Bonneville Power Administration (BPA) when acquiring new resources. In addition, the act also authorized BPA to borrow up to $1.25 billion to finance energy conservation investments. Under the act, BPA was authorized to acquire conservation and renewable resources consistent with the Pacific Northwest Electric Power and Conservation Planning Council's (Council) power resource plan, and the Council was authorized to review BPA's acquisitions for consistency with the plan.

GAO WORK

In an April 1981 report, we found that, to implement the act successfully, BPA should consider (1) developing an expertise in demand forecasting, (2) including provisions in power contracts allowing BPA access to customers' records to verify conservation investments, (3) developing conservation programs for BPA's industrial customers, (4) completing the acquisition procedures and guidelines for renewable resources, and (5) examining BPA's organizational structure in light of new legislative responsibilities.

During congressional testimony in November 1981, we reported that BPA's efforts to carry out the act's provisions had proceeded too quickly in some instances (signing contracts) and too slowly in others (formulating conservation policies and developing renewable energies). This testimony reiterated most of the suggestions of our April 1981 report.

In a 1987 review of BPA's implementation of the Northwest Power Act, we found that the regional power planning process instituted under the act had provided a positive framework for evaluating and planning for the development of the Pacific Northwest's future electric power resources. We concluded that, through the planning process, BPA had identified the types of power resources that should be developed and the timing of their development under differing future conditions. However, we noted that, until regional conditions called for utilities to acquire

major resources, the workability of the act's resource acquisition process, including whether resources would be acquired in a manner consistent with the Council's plan, would not be certain. We also concluded that both the Council and BPA had instituted programs to inform the public of, and elicit their views on, plans and activities related to regional power planning.

In 1991, we reviewed the potential savings in electricity from utility energy efficiency programs, as well as the progress made by states, utilities, and federal power agencies to encourage more efficient electricity use. We found that BPA was promoting the conservation of electricity by (1) providing financial and technical assistance to consumers of electricity, (2) encouraging states and local jurisdictions within its service areas to develop energy-efficient building codes, and (3) transferring energy-efficient technologies. We noted that, with an explicit legislative mandate and authority to charge more for its power unless customer utilities implemented demand-side management (DSM) programs, BPA was a recognized DSM program authority.

GAO PRODUCTS

Electricity Supply: Utility Demand-Side Management Programs Can Reduce Electricity Use (GAO/RCED-92-13, Oct. 31, 1991).

Federal Electric Power: A Five-Year Status Report on the Pacific Northwest Power Act (GAO/RCED-87-6, Feb. 19, 1987).

Implementation of the Pacific Northwest Electric Power Planning and Conservation Act by DOE's Bonneville Power Administration (GAO testimony, 116852, Nov. 10, 1981).

Bonneville Power Administration's Efforts to Implement the Conservation Provisions of Public Law 96-501 (GAO/EMD-81-99, June 8, 1981).

Bonneville Power Administration's Efforts in Implementing the Pacific Northwest Electric Power and Planning and Conservation Act (GAO/EMD-81-67, Apr. 8, 1981).

IRRIGATION

BACKGROUND

The Department of the Interior's Bureau of Reclamation (Bureau) and the U.S. Army Corps of Engineers (Corps) are the principal federal agencies that build and operate multipurpose water projects. The Bureau constructs and operates projects for storing, diverting, or developing water resources to reclaim land in the arid or semiarid areas of the country. The Corps constructs and operates water projects associated with rivers, harbors, and waterways. Both agencies build and operate multipurpose reservoirs that provide municipal and industrial water supplies, hydroelectric power generation, irrigation, fish and wildlife enhancement, flood control, outdoor recreation, and river regulation and control.

The Bureau has been primarily responsible for the development of irrigation projects in the Pacific Northwest. The Reclamation Project Act of 1939, as amended, authorized the Secretary of the Interior to undertake projects to provide water not only for irrigation but also for other purposes, such as flood control and power generation. The act provides that the construction costs associated with the various purposes of such projects are to be recovered from the parties receiving the benefits.

In general, users of irrigation water repay their share of a project's costs without interest. These interest-free payments generally are required to be made within 50 years, on the basis of the irrigator's ability to pay as determined by the Bureau's economic analysis of the specific project. Irrigation costs above the water user's ability to pay are to be repaid by revenues from surplus hydroelectric power sales and other miscellaneous project revenues, again without an interest charge.

GAO WORK

In October 1985, we testified on the development of hydroelectric and federal water projects in the Pacific Northwest. Among other issues, we assessed whether the Bonneville Power Administration (BPA) should be required to repay the costs of constructing irrigation projects from its power sales revenues (irrigation assistance). We concluded that the Reclamation Project Act of 1939 does not authorize the use of power revenues for irrigation assistance but that a substantial number of individual project authorizations either require or allow irrigation assistance. For irrigation projects in the Pacific Northwest, Bureau documents indicate that about $2.7 billion in irrigation assistance is to be provided from revenues received by BPA from federal power sales.

In a July 1985 report, we noted that the Congress, in a 1966 law (P.L. 89-561), had limited BPA's authority to provide irrigation assistance, as well as the amount of the assistance. We noted that the law represented an attempt by the Congress to balance the somewhat conflicting interests of power users and irrigators. The law provides that (1) irrigation assistance may be paid only from net revenues (defined by the act as revenues not required to repay project costs allocated to power and irrigation assistance authorized before the passage of Public Law 89-561; (2) construction of irrigation projects after 1966 will be scheduled so that any irrigation assistance provided to those projects, together with already authorized irrigation assistance, will not require an increase in BPA rates; and (3) the total amount of irrigation assistance may not average more than $30 million per year in any period of 20 consecutive years.

We found that, according to the legislative history of the 1966 law, the key to balancing the interests of power users and water users is the scheduling of construction of post-1966 irrigation projects. The Congress reasoned that the repayment of the irrigation costs of any project authorized after 1966 would not be necessary until 2026 at the earliest, and probably not until 2030 or 2035. By that time, the Congress reasoned, BPA should have substantially reduced its power-related costs and could shift its revenues to the repayment of irrigation-related costs without having to increase power rates.

In a 1986 review of a proposed expansion of irrigation facilities in the Columbia Basin Project, we examined who would repay the costs of constructing the facilities and what share of the total costs each group would pay. We found that the main difference between the Bureau's analysis and the other two analyses that we reviewed was that the Bureau's analysis did not take into account the interest subsidy granted to users of federal irrigation. According to the two studies that took the subsidy into account, the U.S. Treasury would pay 74 percent or 82 percent of the total cost of the project. In contrast, the Bureau's study, which did not consider the interest subsidy, showed that irrigators would pay the largest share (46 percent) of the total cost and the Treasury would bear no expense in the project.

GAO PRODUCTS

Water Resources: Issues Concerning Expanded Irrigation in the Columbia Basin Project (GAO/RCED-86-82BR, Jan. 31, 1986).

Hydroelectric Development at Federal Facilities in the Pacific Northwest (GAO testimony, 128095, Oct. 8, 1985).

Recovering a Portion of Federal Irrigation Project Construction Costs Through Revenues From Department of Energy Electric Power Sales (GAO/RCED-85-128, July 26, 1985).

ELECTRICITY TRANSMISSION

BACKGROUND

The Bonneville Power Administration (BPA) owns and operates some 14,000 miles of high-voltage electricity transmission lines. Two regions--the Pacific Northwest and California--are joined by three high-voltage transmission lines (intertie), which allow for an exchange of electricity between the two regions. BPA owns about 80 percent of the Northwest segment of the intertie. The intertie, completed in 1970, also made Canadian power available through the Northwest into California. The regions benefit from the exchange because of the difference in the costs of generating electricity--the Northwest uses relatively low-cost hydropower, while California relies on higher cost oil- and gas-fired generation.

GAO WORK

In 1980, we found that the intertie should be expanded so that California could save roughly 4 million barrels of oil per year, while the Northwest could earn additional revenues from the sale of surplus energy. We recommended that the Secretary of Energy take a more active role in facilitating the proposed expansion. In a November 1983 follow-up review, we again recommended that the Secretary of Energy ensure that BPA continue to facilitate negotiations to expand the intertie. We also recommended that the Secretary direct BPA to resolve several outstanding concerns among BPA and participating utilities. The Department of Energy (DOE) concurred with our recommendations and stated that it would work to resolve outstanding issues. In addition, the 1985 DOE appropriations legislation contained authorization for BPA to upgrade portions of the existing intertie and to expand the intertie.

In 1988, we assessed, among other things, both the economic justification for a proposed $883 million expansion of the intertie and the relationship of the expansion to Canadian power imports. We found the economic rationale for the expansion inadequate and determined that Canadian power imports could increase as a result of the expansion. We recommended that BPA clarify the economic justification for the proposed expansion. BPA later performed the supplemental economic analysis, as recommended.

GAO PRODUCTS

Electric Power: Issues Concerning Expansion of the Pacific Northwest-Southwest Intertie (GAO/RCED-88-199, Sept. 14, 1988).

Expanding the Pacific Northwest/Southwest Intertie--Benefits and Impediments (GAO/RCED-84-38, Nov. 4, 1983).

Potential for Expanding Electric Power Transmission Between the Pacific Northwest and California (GAO testimony, 121900, July 11, 1983).

Analysis of Bonneville Power Administration's Estimate to Bury Segments of Transmission Line in Montana (GAO/EMD-82-80, May 7, 1982).

Oil Savings From Greater Intertie Capacity Between the Pacific Northwest and California (GAO/EMD-80-100, Sept. 24, 1980).

ADMINISTRATIVE MATTERS

BACKGROUND

In 1983, we issued several reports on the management by the Bonneville Power Administration (BPA) of its automatic data processing systems development activities. These reviews were based, in part, on our 1978 review of BPA's management of automatic data processing systems development activities and on a 1981 audit conducted by the Department of Energy.

GAO WORK

In March 1983, we reviewed computer security at BPA's control system computer center. We found that BPA had made strides in implementing a computer security program but that more could be done. Identified weaknesses included lack of written computer security procedures, inadequate site security, and lack of a fully developed contingency plan in the event of a computer failure. We recommended that BPA develop an action plan to correct these weaknesses and that the Chief Auditor periodically review the computer center's security program. BPA took corrective action in response to our recommendations.

Our February 1983 report reviewed BPA's electricity billing processes to assess the actions planned by BPA to improve the timeliness of its billings. We found that more than $3.2 million in interest expenses could be avoided annually if BPA were to change its customer billing processes. Specifically, BPA could achieve significant savings by (1) charging certain customers monthly rather than quarterly and (2) requiring federal agency customers to pay their bills promptly or be charged interest on late payments.

GAO PRODUCTS

Bonneville's ADP Resource Management Controls Show Improvement, but More Needs to Be Done (GAO/AFMD-83-63, June 22, 1983).

Bonneville Power Administration Control System's Computer Security --More Needs to Be Done (GAO letter, 122958, Mar. 18, 1983).

Changes in BPA Billing Practices Could Reduce Interest Costs and Improve Cash Flow (GAO/RCED-83-64, Feb. 28, 1983).

Federal Agencies Still Need to Develop Greater Computer Audit Capabilities (GAO/AFMD-82-7, Oct. 16, 1981).

BPA Management of ADP Systems Development Activities (GAO letter, 092132, May 30, 1978).

WPPSS

BACKGROUND

Created in 1957, the Washington Public Power Supply System (WPPSS) was a municipal corporation and a joint operating agency of the state of Washington. It consisted of 19 operating public utility districts and four cities in the state of Washington. WPPSS had the authority, among other things, to acquire, construct, and operate plants and facilities for the generation and transmission of electric power and energy. In 1969, WPPSS agreed to construct three nuclear-powered electric generating stations, and the Bonneville Power Administration (BPA) agreed to participate in financing these facilities (plants 1, 2, and 3).

In 1972, BPA's ability to assist in the financing of additional generating units was halted because of (1) rising construction costs for power plants 1, 2, and 3 and (2) a change in U.S. Treasury regulations. In spite of BPA's lack of financial participation, WPPSS decided to build two additional nuclear plants (plants 4 and 5) that would be financially backed by participating utilities (participants). Between 1976 and 1981, WPPSS continued to construct plants 4 and 5. Construction delays and dramatic cost increases at plants 4 and 5 led eventually to WPPSS' decision, in 1982, to terminate the construction of both plants because the financial market was not able to absorb the bond financing. However, by this time, WPPSS had sold $2.25 billion in bonds that required the participants to pay off the bonds in the amount of their proportionate share, regardless of whether the plants were ever completed or operated. A number of participants and ratepayers filed lawsuits contesting the validity of these obligations.

GAO WORK

We issued two reports in 1982 on BPA's involvement in WPPSS' nuclear plant projects. One report, issued on July 2, reviewed the potential impacts from default or successful legal challenge by participants in the financing of plants 4 and 5 on the Pacific Northwest's ability to raise funds for public works and other programs. We found that a default on the bond obligations by the participants would probably have adversely affected the economy of the region and its ability to raise capital in the bond market. Also, participants that defaulted could expect to pay higher interest rates for future bond sales.

Our other 1982 report, issued on July 30, examined, among other things, the role of BPA in the development and termination of plants 4 and 5. We found that BPA had (1) helped small regional utilities forecast the demand for electricity, (2) endorsed the

need for additional generating units, (3) supported utilities' participation in the financing of the plants, and (4) acted to indirectly facilitate the termination of the plants.

In testimony before the Congress in March 1984, we assessed both the impact of the costs of nuclear plants 1, 2, and 3 on BPA's rates and on BPA's responsibilities for project oversight. We found that BPA's ratepayers were responsible for almost $1 billion annually in costs related to plants 1, 2, and 3 and that costs from the projects represented about 30 percent of BPA's total projected revenue requirements for 1985. We also found that BPA's oversight staff and management staff were uncertain of BPA's oversight objectives and staff responsibilities. We identified means by which BPA could better exercise its existing contractual authorities for oversight, including conducting more comprehensive audits and budget reviews and participating in project-related meetings.

In our August 1984 report, we recommended to the Secretary of Energy that BPA take several steps to strengthen its oversight program, including defining its organizational roles and policies, adopting procedures for implementing its oversight objectives, outlining its intent to implement its contractual oversight authorities, and reviewing its oversight staffing and organizational format to ensure their adequacy and appropriateness to support a comprehensive oversight program. The Department of Energy (DOE), in commenting on a draft of our report, agreed with the general thrust of our recommendation that BPA improve the effectiveness of its oversight. However, DOE believed that recent changes in BPA's oversight structure had overcome many of the problems and therefore believed that no further action was needed to address the specific problems identified in our report.

Our 1989 report reviewed several issues involving DOE's possible acquisition and conversion of a partially completed commercial nuclear power plant (plant 1) to a nuclear materials production facility. We found that if DOE acquired the plant, it would probably complete the power-generating capability of the plant, thus making it a dual-purpose--production and power--reactor. We reviewed, among other things, whether a DOE acquisition and conversion of plant 1 through condemnation could lead to a default on bonds for the plant, and what effect such an acquisition would have on BPA's liability for BPA's share of debt in the plant. We also examined the rate that DOE would charge for electricity generated by the converted reactor.

We found that DOE could acquire the plant either through voluntary sale or condemnation. We determined that selling the plant for less than the amount of the outstanding bonds (roughly $2.1 billion) could cause a default. Condemnation, however, would

not lead to default or make the bonds immediately due and payable because the condemnation would be considered a transfer of the reactor "through the operation of the law." In addition, we found that although many factors could be expected to influence the rate charged for electricity from the plant, the cost of electricity from plant 1 would probably be lower than the cost of electricity produced from the most economical power-generating alternative.

GAO PRODUCTS

Nuclear Science: Effect of Conversion of Washington Nuclear Plant No. 1 on Debt and Electric Rates (GAO/RCED-89-88FS, Mar. 9, 1989).

Status of Bonneville Power Administration's Efforts to Improve Its Oversight of Three Nuclear Power Projects (GAO/RCED-84-27, Aug. 3, 1984).

The Bonneville Power Administration's Oversight Activities Related to Washington Public Power Supply System (GAO testimony, 123637, Mar. 12, 1984).

Bonneville Power Administration and Rural Electrification Administration Actions and Activities Affecting Utility Participation in Washington Public Power Supply System Plants 4 and 5 (GAO/EMD-82-105, July 30, 1982).

Financial Community's Perceived Impacts Which Could Result From Default or Successful Legal Challenge by Participants in Washington Public Power Supply System Nuclear Project Nos. 4 and 5 (GAO/EMD-82-106, July 2, 1982).

PMA RATES/REPAYMENT

BACKGROUND

The Bonneville Power Administration (BPA) and the Department of Energy's four other power-marketing administrations (PMA)--Alaska, Southeastern, Southwestern, and Western--sell wholesale power from hydroelectric facilities built and operated by the Department of the Interior's Bureau of Reclamation (Bureau) or by the U.S. Army Corps of Engineers (Corps). These projects are financed largely by the federal government. Project costs properly allocated for irrigation, power generation, and municipal and industrial (M&I) water supplies must be repaid in accordance with repayment policies and contract terms established by the Congress and through Bureau and Corps administrative decisions made over a long period of time. In general, repayment provisions for irrigation users require water users to repay the federal construction costs, without interest, over a period of time (usually 50 years).

Federal laws and regulations require power-marketing administrations to establish power rates at levels necessary to ensure that revenues from power sales are sufficient to recover all power-related costs. BPA and Western are also required to recover some costs for certain Bureau irrigation projects through power sales revenues (irrigation assistance). Generally, irrigation assistance is not repaid in annual installments; usually, it is deferred until the end of the payment period (usually 50 years).

GAO WORK

In March 1981, we reported that the price of irrigation water is much lower than the federal government's cost of producing the water. To show policymakers the direct economic value of producing more irrigation water, we recommended that, as part of the congressional authorization and appropriations process, the Secretary of the Interior provide estimates of (1) the federal government's full cost of providing irrigation water, including the cost of borrowing at the then-current rate of interest for federal borrowing; (2) the increases in crop yield expected for acres receiving federal water, and (3) the change in net income on the acres to receive federal water at full cost.

In August 1981, we recommended that the Secretaries of the Interior and of the Army change certain policies to, among other things, (1) require that all reservoir users share equitably in cost recovery, (2) include interest expense in all M&I water sales prices, and (3) accumulate all unrecovered operations and maintenance costs and consider such costs in future price determinations.

In our October 1981 report, we concluded that interest-free financing for irrigation projects and future M&I water supply costs had become a costly burden on the U.S. Treasury. We calculated that the interest subsidy for only four reviewed projects would cost the Treasury more than $667 million. We recommended that the Congress (1) amend the appropriate federal laws to ensure that M&I water users would fully repay their share of interest costs and (2) require the Secretaries of the Interior and of the Army to (a) use interest rates, developed by the Treasury, that would more appropriately reflect the Treasury's costs of borrowing funds and (b) revise the method of computing interest on construction. The Treasury concurred with our recommendations.

In 1985, we reported that revenues to the U.S. Treasury could be increased if irrigation assistance were to be repaid in annual installments over the life of the repayment period instead of being repaid in a lump sum at or near the end of the repayment period. For example, we calculated that this change would result in a net benefit to the Treasury of about $8.7 million for one project for which BPA provides irrigation assistance. We noted that the benefits might not be realized if BPA deferred power cost repayments to compensate for accelerated irrigation assistance payments.

In our September 1986 report, we analyzed several alternatives for determining federal power prices and concluded that certain changes could more fully identify and recover the government's costs or, in some cases, produce revenues in excess of costs. Alternatives based on the existing cost-of-service objective (which generally requires that the costs of providing electric service be recovered through rates) included options for (1) computing a power project's interest costs and (2) scheduling payments to the Treasury to repay the federal investment in constructing the power projects and financing their costs. We concluded that these alternatives would generally reduce or eliminate the under-recovery of costs and result in pricing methods that were more consistent with those of nonfederal electric utilities. In addition, we analyzed alternatives based on criteria other than the cost of service, including alternative methods for recovering some irrigation project costs through power sales revenues, marginal cost pricing, market pricing, and user fees. We concluded that the use of these methods could produce revenues in excess of costs.

GAO PRODUCTS

Federal Electric Power: Pricing Alternatives for Power Marketed by the Department of Energy (GAO/RCED-86-186BR, Sept. 30, 1986).

Federal Power: Additional Information on Repaying Federal Investments in Electric Power Facilities (GAO/RCED-86-44FS, Nov. 12, 1985).

Additional Information Concerning Irrigation Project Costs and Pricing Federal Power (GAO/RCED-86-18FS, Oct. 10, 1985).

Reforming Interest Provisions in Federal Water Laws Could Save Millions (GAO/CED-82-3, Oct. 22, 1981).

Changes in Federal Water Project Repayment Policies Can Reduce Federal Costs (GAO/CED-81-77, Aug. 7, 1981).

Federal Charges for Irrigation Projects Reviewed Do Not Cover Costs (GAO/PAD-81-07, Mar. 3, 1981).

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April 15, 1993

TO: House Natural Resources Committee
The Honorable George Miller, Chairman
Attn: Dan Adamson

FROM: Amy Abel (x7-7239)
Analyst in Energy Policy
Environment and Natural Resources Policy Division

SUBJECT: Bonneville Power Administration Task Force Briefing Book

As you requested, CRS has prepared a two-volume briefing book on the Bonneville Power Administration (BPA). This document contains the legal authorities and selected court cases involving BPA and the Northwest Power Planning Council. Summaries and some complete journal articles, CRS material, law review articles, and agency material are provided as background for salmon, water management, and power issues. When only a summary or abstract is included in the briefing book, we are providing the Committee with a copy of the entire document.

Additionally, we are providing copies of a legislative history of the Pacific Northwest Electric Power Planning and Conservation Act. Material for this document was compiled by Amy Abel (electricity), Betsy Cody (water management), and Eugene Buck (salmon), of the Environment and Natural Resources Division, and Robert Poling (legal issues) of the American Law Division.

Volume One

Volume 1 of the Bonneville Power Administration (BPA) Task Force Briefing Book includes sections on BPA's legal authorities, court cases involving BPA, and electric power issues. In addition to an indexed copy of the Pacific Northwest Electric Power Planning and Conservation Act (P.L. 96-501), the first section contains relevant annotated code. A selection of eighteen court cases provides an overview of legal issues.

The remaining sections in Volume 1 contain material on electric power issues. The section titled *Pacific Northwest Electric Power and Conservation*

Act–General includes a CRS report, journal article, and law review articles, describing the Act's implementation and BPA's general responsibilities.

BPA's resource plans are presented in the next section. BPA was the source for most of this information. Two journal articles are included that describe perceived inefficiencies in the planning and operation of BPA. In addition, an article produced by the Oak Ridge National Lab is included which compares the costs and benefits between construction of short-lead-time power plants and conservation.

The third electric power section, *Resource Planning: Conservation*, includes a description of how conservation is addressed in BPA's resource modeling process. A law review article describes BPA's statutory obligations to implement conservation. Finally, an article is included which describes the results of one residential conservation program.

The section on debt repayment and the proposed BTU tax includes President Clinton's plan for restructuring BPA's debt. Opposing views on BPA's debt to the Federal Government are expressed in two journal editorials. A CRS memo is included that estimates the impact of the proposed BTU tax on residential electric rates. The final section of this volume provides an overview of the Northwest Power Planning Council's functions.

Volume Two

Volume 2 provides background on the Columbia River Basin salmon and water management. The first section, *Salmon*, begins with a CRS Issue Brief describing the background and issues associated with the decline of wild salmon stocks in the Columbia River Basin. The issue brief is followed by articles on the history, threats, scientific uncertainty, and listing controversy of Columbia River salmon.

The second section, *Federal Agency Responsibilities and Actions*, includes articles related to Federal agency responsibilities for fish and wildlife management under the Pacific Northwest Electric Power Planning and Conservation Act, as well as responsibilities related to the listing of salmon species under the Endangered Species Act (P.L. 93-205).

The third section is *Water Management: Conflicts and User Concerns*. This section includes articles from various water users' perspectives, as well as some independent economic analyses of competing interest in the Columbia River Basin. The section also includes articles on water rights issues and potential legal and institutional implications of the salmon listings.

Proposals and Alternatives for Pacific Northwest Salmon Recovery and Water Management is the final section of this volume. The lead document in this section is a summary of the Northwest Power Planning Council's "Strategy for Salmon." There are many other proposals, including one from the State of Idaho, based on drawdown of key reservoirs to flush salmon smolts to sea. In

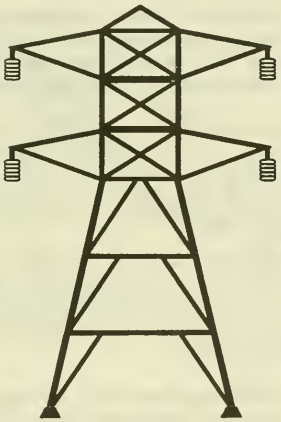
interest of keeping this volume to a manageable proportion, we have included only the Council's strategy in this section, along with broad proposals for the general enhancement of Pacific Northwest salmon populations. Also included are selected articles on the potential economic impacts of various proposals.

We hope this information is useful to the Bonneville Power Administration Task Force. Please call us if we can offer further assistance to the Committee or the BPA Task Force.

Bonneville Power Administration Task Force

Briefing Book, Volume 1

Power Issues, Legal Authorities and Court Cases



Prepared by the Congressional Research Service

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The remaining sections in Volume 1 contain material on electric power issues. The section titled Pacific Northwest Electric Power and Conservation Act–General, presents a CRS report, journal article and law review articles, describing the Act's implementation and BPA's general responsibilities.

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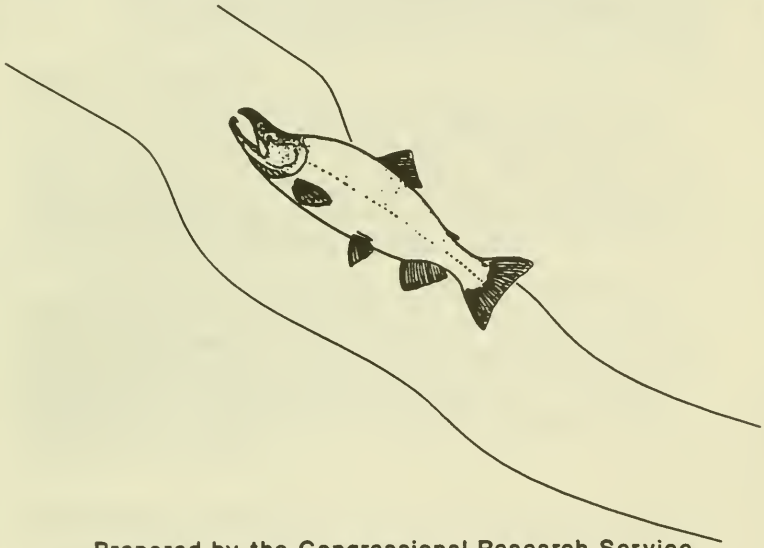
Bonneville Power Administration Task Force

Briefing Book, Volume 2

Salmon and Water Management



Prepared by the Congressional Research Service

COLUMBIA RIVER BASIN SALMON & WATER MANAGEMENT

I. Salmon: History, threats, scientific uncertainty, listing complications

II. Agencies: Review of Federal agencies' fish and wildlife authorities and responsibilities, and agencies' descriptions of activities related to salmon listing

III. Water Management: User conflicts and concerns

IV. Proposals: Alternatives for future management of resources within the Columbia River Basin

U.S. House of Representatives
Committee on
Natural Resources
Washington, DC 20515-6201

April 23, 1993

MEMORANDUM

TO: Committee on Natural Resources, Bonneville Power Administration Task Force, Majority Members

FROM: Majority Staff, Committee on Natural Resources

RE: Task Force Hearing on the Bonneville Power Administration's Fiscal Year 1994 Budget, April 28, 1993, 1:00 p.m., Room 1324 Longworth House Office Bldg.

Purpose of the Hearing

BPA is currently experiencing a financial crisis due to a wide variety of factors, including low aluminum prices ("DSI" power rate is linked to the price of aluminum), increased electric demand, the closure of the Trojan nuclear plant, a series of extremely dry years, failure to increase rates in the past, and modifications in power operations to reduce harm to endangered salmon. As a consequence BPA may have to increase power rates by more than twenty percent. This rate increase will be permanent even if weather conditions improve.

In order to reduce the amount of the rate increase the Administrator of BPA, Randy Hardy, plans to cut the BPA budget in a number of areas. The budget choices that BPA makes in the context of the current crisis will not only affect BPA's near-term financial viability, they will also involve important policy decisions relating to its energy resource mix, energy efficiency, the protection of salmon and many other issues. The purpose of this hearing is to identify areas where BPA can cut its budget and reduce the proposed rate increase without compromising important policy goals.

Background on BPA Task Force

The Task Force will convene for the first time at this April 28th hearing and pursuant to Democratic Caucus rules will

conclude its hearing activity no later than October 28, 1993. The Task Force will be chaired by Representative Peter DeFazio and composed of Members of the Committee on Natural Resources.

The mission of the Task Force is to conduct oversight of BPA and of implementation of the Pacific Northwest Electric Power Planning and Conservation Act and the Federal Columbia River Transmission Act of 1974. The Task Force will consider a wide range of issues, including BPA's proposed energy resource acquisitions, efforts to save the endangered salmon, Columbia Basin water management and the long-term financial status of BPA.

The Task Force will consist of the following Members:

Majority	Minority
Peter A. DeFazio, Chair	Robert F. Smith
Philip R. Sharp	Barbara Vucanovich
Pat Williams	Craig Thomas
Richard H. Lehman	John Doolittle
Larry LaRocco	Don Young (ex officio)
Karen Shepherd	
George Miller (ex officio)	

BPA Background

BPA was originally established within the Department of Interior in 1937 to market and distribute power from federal hydroelectric projects in the Pacific Northwest. Over time the responsibilities of the agency have grown to include the acquisition of new energy resources, the protection of fish and wildlife and regional energy planning.

In 1977 BPA was transferred to the Department of Energy. The agency presently markets and distributes power generated at 30 Corp of Engineer and Bureau of Reclamation dams, the WNP-2 nuclear power plant, and other generating facilities. BPA also funds and implements demand-side management programs and fish and wildlife restoration activities. BPA provides services in Oregon, Washington, Idaho, western Montana and small parts of Nevada, Wyoming, California and Utah. Approximately one-half of the electrical energy consumed in the Pacific Northwest is provided by BPA. BPA also dominates the electrify transmission system in the Northwest, it owns and operates approximately 15,000 miles of transmission lines and provides about eighty percent of the region's transmission capacity.

The Administrator of BPA is a political appointee who serves at the pleasure of the Secretary of Energy. Under the reorganization plan recently issued by Secretary O'Leary, the BPA

Administrator will report directly to the Deputy Secretary of Energy. During the Bush Administration the Administrator reported to the Assistant Secretary for Conservation and Renewable Energy.

Status of the Rate Case

BPA is in the process of developing electric rates for the next two years beginning in October 1993. BPA rates are set by the Administrator following an adjudicative ratemaking process that is presided over by an administrative law judge. After the Administrator has set the rates they are then reviewed by FERC before they go into effect.

In January 1993 BPA proposed increasing the priority firm rate by 11.6 percent. Since that time BPA's financial condition has worsened significantly due to low aluminum prices, cold weather, low streamflows and other factors. BPA now believes that it may have to raise rates by more than twenty percent.

BPA is currently conducting settlement discussion with the parties to the rate case. It expects to make a new rate proposal in June 1993.

Rate Case Ex Parte Rules

Because the rate case is considered through a formal adjudicative hearing process it is unlawful for BPA staff to engage in any ex parte communications relating to the rate case. The purpose of the ex parte rule is to prevent BPA from being influenced by "back door" private communications that the public and parties to the rate case are unaware of.

Section 1010.2(d) of BPA's hearing procedures defines an ex parte communication as follows:

> ... an oral or written communication regarding the merits of any issue pending in a hearing conducted pursuant to Northwest Power Act section 7(i) which is not on the record and with respect to which reasonable notice has not been given, but it shall not include requests for status reports on any hearing.

In a letter dated April 14, 1993 BPA notified the parties to the rate case that the BPA Task Force hearing "may also consider issues and potential budget savings and efficiencies that may have been raised as issues in the rate case." Because BPA has provided notice to the parties the most likely outcome of any ex

parte communication by a Member of the Task Force at the hearing is that BPA will notify the Administrative Law Judge of the communication and he will give the parties to the rate case an opportunity to respond on the record to the communication.

If you have any questions about the ex parte rules please contact the Majority Staff.

BPA Budget Cuts

On April 9, 1993 Administrator Hardy announced a series of actions to improve BPA's near-term financial status and reduce the amount of the proposed rate increase. Hardy announced that BPA would "move to terminate" two uncompleted nuclear plants, WNP-1 and WNP-3 that were built by the Washington Public Power Supply System (WPPSS). For the past ten years these plants have been preserved and maintained so that the option of completing construction was available. The current cost of this "mothballing" is about $10 million per year. BPA expects that termination of these plants will bring significant savings by the mid-1990s.

Hardy also plans to cut BPA administrative costs by 50 percent by reducing expenditures for travel, training, office supplies, overtime, and reducing temporary and on-site contractor employment. BPA also will continue a "limited" hiring freeze and is considering closing one or more field offices.

Finally, BPA has reopened their budget process for FY 1994 to consider reductions of up to twenty-five percent.

Overview of BPA's Proposed FY 1994 Budget

The proposed FY 1994 Budget that BPA has submitted to Congress is based upon assumptions made in January 1993. These assumptions are no longer valid and BPA has reopened its budget process as part of its effort to limit the rate increase. Consequently, the numbers in FY 1994 Budget are now only reference points for BPA's ongoing review of its budget and do not even include the budget cuts recently announced by Administrator Hardy.

The following table summarizes BPA's proposed FY 1994 Budget.

DEPARTMENT OF ENERGY
FY 1994 CONGRESSIONAL BUDGET SUBMITTAL
BONNEVILLE POWER ADMINISTRATION
CURRENT SERVICES
(in thousands of dollars)

EXPENSED OBLIGATIONS/OUTLAYS

	FY 1992	FY 1993	FY 1994
	Obligations	Obligations	Obligations
1 Residential Exchange	844,179	897,500	1,221,800
2 System Operations	34,466	34,400	37,600
3 Power Marketing	49,322	65,800	69,500
4 Power Scheduling	157,572	226,000	110,000
5 Planning Council	7,873	8,700	9,000
6 Interest	304,350	358,900	366,300
7 Associated Project Costs	110,913	128,000	167,400
8 Energy Resources	839,484	915,600	984,500
9 Transmission System Development	32,592	25,100	25,900
10 System Maintenance	115,827	113,100	119,600
11 Fish & Wildlife	68,662	64,800	65,000
12 TOTAL EXPENSED OBLIGATIONS/OUTLAYS	2,565,240	2,837,900	3,176,700
13 TOTAL REIMBURSABLE OBLIGATIONS/OUTLAYS	64,781	104,300	96,000

CAPITOL OBLIGATIONS/OUTLAYS

	FY 1992	FY 1993	FY 1994
	Obligations	Obligations	Obligations
14 Energy Resources	71,713	136,400	149,700
15 Transmission System Development	212,608	191,700	146,300
16 System Replacements	90,168	97,800	87,400
17 Fish & Wildlife	15,291	31,800	34,900
18 Capitol Equipment	12,156	16,200	16,000
19 Capitalized Bond Premiums	29,025	0	0
20 TOTAL CAPITAL INVESTMENTS	430,961	473,900	434,300
21 BORROWING AUTHORITY TO FINANCE CAPITOL OBLIGATIONS	430,961	473,900	432,700
22 BORROWING AUTHORITY TO FINANCE OTHER OBLIGATIONS		144,197	1,500
23 TOTAL BORROWING AUTHORITY	430,961	618,097	434,200

Potential Budget Savings

Representative DeFazio, the Chair of the Task Force, has submitted a series of questions regarding the proposed FY 1994 Budget for BPA's response prior to the hearing. The purpose of these questions (copy attached) is to identify potential areas where BPA can produce budget savings and efficiencies. BPA's responses will be provided to your office as soon as they are received.

What follows is a summary of the major budget issues raised in the questions submitted by Representative DeFazio:

Personnel:

Some BPA customers have suggested that BPA could operate more efficiently, and at a lower cost, with fewer personnel. The proposed FY 1994 Budget allocates 3,483 FTE positions to BPA. This FTE number does not include contractor or temporary FTE, overtime, holiday and seasonal workers.

Contractor Expenses:

Like most federal agencies, BPA spends a significant amount on outside contractors.

Washington Public Power Supply System (WPPSS):

BPA reimburses WPPSS for the expense of operating the WNP-2 nuclear power plant and the "mothballing" expenses for the incomplete WNP-1 and WNP-3 plants. BPA recently announced its intent to terminate mothballing of WNP 1-3. Critics of WNP-2 operations claim that the plant's operating expenses are considerably higher than the nuclear industry average and that BPA should exercise stricter oversight over WNP-2 expenditures.

Conservation:

According to the Northwest Power Planning Council, BPA has not been aggressive in reducing the administrative costs of its conservation programs. Many BPA customers complain that the BPA process for approving and implementing conservation programs is cumbersome and bureaucratic and that local utilities with independent programs are able to achieve conservation savings cheaper than BPA. Finally, BPA's conservation efforts have focused primarily on the residential sector even though less expensive conservation opportunities exist in the commercial and industrial sectors.

Fuel Switching:

BPA's "Super Good Cents" program provides a $2,500 subsidy toward the construction of energy-efficient all-electric homes. These subsidies are provided throughout the BPA service territory, including areas that are currently served by natural gas. This has the effect of subsidizing increased demand for electricity which is counter to the purpose of energy conservation.

Ironically, BPA intends to meet part of the increased demand for electricity in the Northwest by purchasing the output of natural gas turbines. In 1992 BPA signed a letter of intent to purchase 248 megawatts of output from a natural gas turbine to be built in Washington State. It must be noted that direct gas use in the home produces 2.5 times more energy than burning the same gas in a turbine to produce electricity that is subsequently used for space or water heating purposes.

Capital Investment

A number of BPA customers have expressed a willingness to provide capital financing for energy conservation activities. This could significantly reduce BPA borrowing. BPA is currently considering these proposals.

Fish and Wildlife

Most of the expenses that BPA attributes to fish and wildlife are the costs of power purchases to firm energy supplies in low water years, when flow restrictions to improve salmon migration reduce the available hydropower. In large part, these power purchase costs cannot be eliminated because they are governed by salmon transport requirements mandated under the Endangered Species Act. The purchase costs could be reduced, however, by aggressive energy conservation; since the replacement energy costs more than hydropower generation, higher cost conservation measures are justified to avoid the energy purchases.

In addition, BPA plans to reduce the cost of its other fish and wildlife programs by $10-12 million. Some of these programs have been criticized for yielding little benefit for the fish, or for addressing obsolete goals to increase overall fish numbers without regard to the impact on wild salmon stocks. For example, certain hatchery operations financed by BPA may actually contribute to the decline in wild salmon runs.

If you or your staff have any questions please contact Dan Adamson (5-1911) or Liz Birnbaum (6-0200) of the Committee Staff or Jeff Stier of Representative DeFazio's staff (5-6416).

Attachment #1 - Major Statutes Relating to BPA
Attachment #2 - Committee on Natural Resources - BPA Task Force Pre-Hearing Questions, April 7, 1993

Attachment #1

Major Statutes Relating to BPA

Bonneville Project Act of 1937:

Established BPA and directed it to build and operate transmission lines to deliver power from federal dams and to market the power at a rate that would recover the Federal investment in a reasonable period of time. BPA was directed to make this power available to publicly owned utilities in the Northwest prior to any sales to investor-owned utilities. This is known as the "preference" clause.

Act Authorizing the Third Powerplant at Grand Coulee Dam (enacted June 14, 1966):

BPA's method of repayment of its obligations to the U.S. Treasury was discussed in the legislative history of this Act. BPA has interpreted this legislative history as follows:

- repayment of capital investments within 50 years;

- investments bearing higher interest rates are paid first; and,

- interest payments must be paid on schedule, BPA may adjust the schedule for the repayment of principle.

Federal Columbia River Transmission Act of 1974:

Provided BPA with the authority to use revenues from ratepayers to directly fund its programs and provided borrowing authority for BPA to sell bonds to the U.S. Treasury to finance transmission construction. A total of $1.25 billion in borrowing authority was authorized.

P.L. 95-91, Department of Energy Organization Act of 1977

Transferred BPA from the Department of the Interior to the Department of Energy.

Pacific Northwest Electric Power Planning and Conservation Act of 1980:

- Made BPA responsible for meeting the electricity loads of its customers and authorized BPA to purchase new electricity resources to meet these needs.

- Established the Northwest Power Planning Council, a regional energy and fish and wildlife planning agency. The Council has two members from the States of Oregon, Washington, Montana and Idaho. The Act requires that BPA resource acquisition and fish and wildlife activities be "consistent" with the recommendations of the Council.

- Required BPA and the Council to give priority to energy conservation resources when acquiring new energy resources.

- Modified the "preference" clause, which requires to make firm power resources available to publicly-owned utilities prior to sales to any investor-owned utilities, to require BPA to be responsible for meeting all future requirements of its preference customers.

- Further modified preference through the "residential exchange" program which provides the benefits of firm federal power resources available to residential and farm customers of investor-owned utilities.

- Directed the Council to establish a program to protect and enhance the fisheries resources of the Columbia River basin. BPA provides funding for this program through its rates.

- Authorized $1.25 billion in borrowing authority for conservation and renewable resources.

P.L. 98-50 Energy and Water Development Appropriations for 1983:

Authorized an additional $1.25 billion in BPA borrowing authority.

ATTACHMENT #2

COMMITTEE ON NATURAL RESOURCES- BPA TASK FORCE
PRE-HEARING QUESTIONS
April 7, 1993

Overview

1. Please indicate what percentage of the BPA FY 1994 budget is spent on the following:

- WNP 1,2,3 debt service
- WNP 1,2,3 operations and mothballing
- WNP 4,5 settlement costs
- non-WNP energy resources
- federal/interest principle
- transmission
- residential exchange
- non-WNP operations
- conservation
- fish and wildlife

Operations

1. The amount of the BPA operations budget per year from FY 1980 to FY 1993 and proposed budget for FY 1994, with a breakdown of operations expenses by function per year.

2. A list of the number of FTE positions, including seasonal or temporary workers, at BPA by fiscal year from FY 1980 to FY 1993 and proposed FTE for FY 1994. Please provide a numerical breakdown for each fiscal year of the following:

- number of FTE at each GS, GM or SES level;
- staff function by program (for example-- power operations, transmission, conservation, public affairs etc.), and;
- number of FTE slots actually filled.

3. The total amount budgeted in FY 94 for purchases of equipment, including, but not limited to, computers vehicles, furniture, and a list and description of these proposed expenditures.

4. BPA contractor expenditures from FY 1991 to FY 1993 and proposed expenditures for FY 1994. Please provide a numerical breakdown for each fiscal year of the following:

- number of contractor employees;
- amount of contractor funding by program;
- contractor equipment purchases paid for by BPA.

5. It is my understanding that at the most recent "Programs In Perspective" BPA engineers agreed that in certain cases local utilities can design and construct power lines below 500 kv more cost-effectively than BPA. Is this an accurate statement? If so, how much money could be saved from FY 1994 to FY 1998 if BPA turned this responsibility over to the local utilities? Are there other areas relating to transmission that BPA could transfer work to local utilities to achieve more cost-effective results?

6. Has an independent entity conducted a top to bottom review of the efficiency of BPA operations? If not, does BPA intend to initiate such an independent review?

7. BPA has announced that cuts will occur in the administrative budget, including employee training, travel, supplies and support services. What level of reductions will you take from current levels in these and other administrative areas? What cuts will be taken in FY 94 and FY 95 from budgeted levels?

Revenues

1. An estimate of the amount of revenues foregone per fiscal year since the irrigation discount was implemented in 1984, and an estimate of the revenue increase per year from FY 1994 to FY 1998 if it is eliminated. Is there any statutory basis for the irrigation discount?

2. An estimate of the amount of revenues foregone per fiscal year since the low-density discount was implemented, the revenue increase per year from FY 1994 to FY 1998 if the discount is eliminated, and an estimate of the revenue increase, if any, if the discount is modified in accordance with the proposal submitted by the Northwest Conservation Act Coalition.

3. It is my understanding that certain BPA customer utilities have advanced a proposal to increase BPA's short-term cash flows by paying their BPA obligations earlier than they presently do. Please describe the benefits that might accrue to BPA if this approach was adopted. Does BPA plan to implement this proposal?

4. An estimate of the effect on revenues in FY 1994 and annually thereafter if BPA sold 1350 megawatts of Third AC capacity to participants instead of the 725 megawatts of capacity BPA currently plans to sell.

Washington Public Power Supply System

1. An estimate of the savings per year from FY 1994 to FY 1998 if the "mothballing" of WNP 1 and 3 was terminated.

2. An estimate of the revenues that would result if WNP 1 and 3 fuel was sold following the termination of mothballing.

3. Please provide an estimate of the payment the BPA will make to WPPSS for the operating costs of WNP-2 in FY 1994. How do WNP-2 operating costs compare to the nuclear industry average? Does BPA have a mechanism for auditing WNP-2 operating expenses? Has BPA ever refused to pay any WNP-2 expenses? If so, please state the amount of payment refused and the rationale or doing so.

4. It is my understanding that WPPSS currently pays its board members $500 per day of service. Does BPA reimburse WPPSS for these expenses? If so, please provide an estimate of the total funding BPA has provided WPPSS since 1980 for this purpose.

5. Please provide an estimate of WPPSS administrative expenses that will be reimbursed by BPA in FY 1994.

6. A list of the number of FTE positions at WPPSS, including contractor, temporary and seasonal employees by fiscal year from FY 1980 to FY 1994 and proposed FTE for FY 1994. Has the number of WPPSS staff declined as WPPSS responsibilities have declined? How does the number of WPPSS staff who are responsible for the operations of WNP-2 compare to the nuclear industry average?

7. Please provide WNP-2 operations and maintenance (O&M) expenditures per year from FY 1985 to the present and estimated O&M expenditures for FY 1994. What percentage of these O&M expenditures have been reimbursed by BPA under the net billing agreement from FY 1985 to the present? How do WNP-2 O&M expenditures compare to the nuclear industry average?

8. Portland General Electric recently concluded that it was more cost-effective to permanently shutdown the Trojan reactor than to continue to operate it. Has BPA conducted any analysis of the long-term cost-effectiveness of continuing to operate the WNP-2 reactor? If so, what are the results of this analysis?

Conservation

1. In a letter to Chairman Miller dated March 24, 1993, the Northwest Power Planning Council stated that BPA "has not been aggressive in reducing program administrative costs" for conservation programs. Please identify potential savings, if any, per fiscal year from FY 1994 to FY 1998 from reducing administrative costs of conservation programs.

2. Please provide an estimate of the total expenditures to date of the "Super Good Cents" program in areas where natural gas service is currently available. Please estimate the budget savings that would result from a termination of the Super Good Cents program in areas currently served by natural gas per fiscal year from FY 1994 to FY 1998.

3. It is my understanding that a study has been conducted which compares the costs of BPA conservation programs per unit of energy saved to the costs incurred by certain Northwest utilities per unit of energy saved. Please provide a copy of this study and explain the differences in conservation costs, if any, between BPA and regional utilities.

4. To date BPA's conservation programs have focused primarily on producing energy savings in the residential sector. Please provide an estimate of the current cost per unit of energy saved from residential, commercial and industrial conservation programs respectively.

5. Please provide an estimate of BPA expenditures to date on the Manufactured Housing Acquisition Program (MAP) per fiscal year. What percentage of these expenditures were administrative costs? Please provide an estimate of the percentage of MAP homes that are sited in areas currently served by natural gas.

6. How much electric water heating and space heating load does BPA currently serve? How much of this load is in areas currently served by natural gas? What is the relative efficiency of burning natural gas in a turbine to produce electricity which is used for water and space heating vs. burning gas on site for this purpose?

7. Please describe the scope of BPA's activities regarding fuel switching.

8. Please provide an estimate of the amount of energy that would be saved per year if the two-tiered rates and low-density discount adjustment recommended by the Northwest Conservation Act Coalition were implemented (growth

adjustment and no-growth adjustment model). What is the earliest possible date that BPA can implement tiered rates? Has BPA initiated an EIS on tiered rates?

Capital Investment

1. The amount of the BPA capital investment budget per year from FY 1980 to FY 1993 and proposed budget for FY 1994 with a breakdown of expenditures by function per year.

2. It is my understanding that BPA is currently considering a number of proposals for customer capital financing of conservation activities. Please describe each of these proposals, including the amount and terms and conditions of such financing, and the amount of energy that would be saved. Does BPA plan to utilize these proposals to reduce its dependence on Treasury borrowing?

3. Which capital financing methods have the least impact on electric rates over the short term? Over the long term?

4. Please provide projections of net borrowing authority use from FY 94 to FY 2000. When will your current borrowing authority for transmission and conservation be fully utilized?

5. Please provide the bill and report language that authorized the three separate increments of borrowing authority totalling $3.75 billion. Also provide any BPA documents that clarify what type of capital investments each increment of borrowing authority can be used for.

Fish and Wildlife

1. BPA staff have stated that fish and wildlife spending amounts to about $300 million per year. Please provide an accounting by year for expenditures and estimates of foregone revenue for fish and wildlife measures since 1978. For each year, provide costs of the net effects of the water budget and the additional flow augmentation provided by the Northwest Power Planning Council phase two amendments; repayment for bypass improvements, reimbursements to other federal agencies and their purpose, and the fish and wildlife program expenses.

2. What percentage of the FY 1992, 1993 and proposed FY 1994 budget are/were devoted to the implementation of Council program measures and what amount are/were spent for other purposes? Please provide a list of all non-program measures

in these budgets, including the rationale, cost and purpose of each measure.

3. It is my understanding the BPA is currently reducing program budgets throughout the agency. Do you intend to defer implementation of the Northwest Power Planning Council's Strategy for Salmon? If so, in what areas and what savings would result in FY 1994? Do you intend to defer any non-program measures? If so, in what areas and what savings would result in FY 1994?

4. It is my understanding that BPA has a contract relating to salmon with Resources for the Future. What is the purpose of the contract? How much has BPA spent on this contract to date and how much does BPA plan to spend in FY 1994?

5. How many biologists currently work for BPA either directly or under contract? Is the role of BPA's biological staff to implement the recommendations of the National Marine Fisheries Service and the Council or to come up with alternatives?

6. Has BPA contracted with the University of Washington to do a modeling effort that is similar to one already conducted by the Northwest Power Planning Council? If so, what is the purpose of this contract and how much will it cost?

7. It is my understanding that BPA has contracted for a "shadow" biological opinion similar to the one conducted by the National Marine Fisheries Service. Is this correct? If so, what is the purpose of this contract and how much will it cost?

8. How much has BPA budgeted for the squawfish program in FY 1994? Of this amount how much will go directly for the payment of bounties to fishermen? Please describe the status and results of research on the effectiveness of the squawfish program.

9. Please describe the so called "lease back/buy back" fish program. How much will this program cost in FY 1994?

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