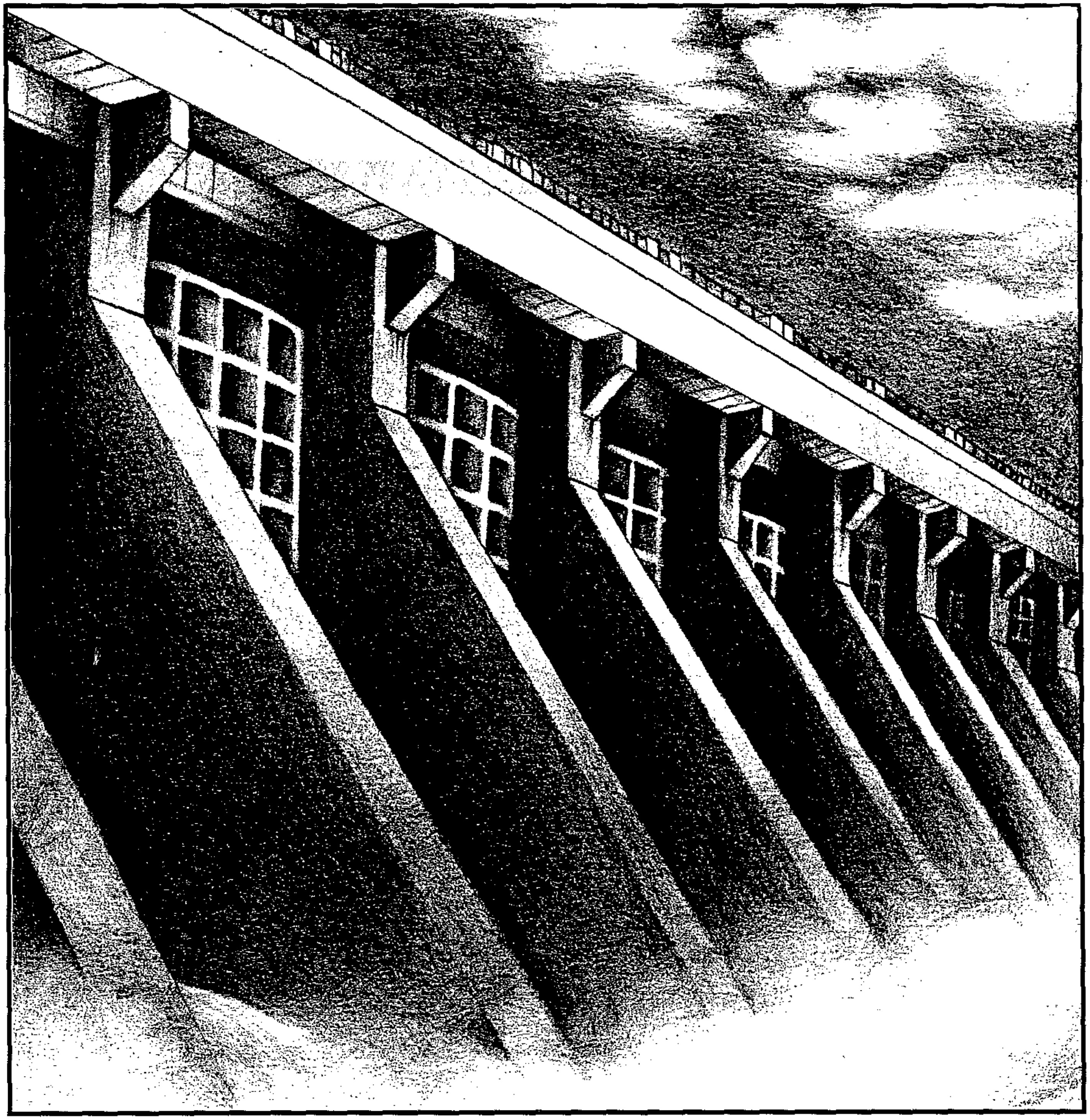
Staff Issue Paper on the Role of The Bonneville Power Administration in a Competitive Energy Market

95-14



Northwest
Power Planning
Council

July 28, 1995

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July 28, 1995

To interested parties:

The Council invites comment on the enclosed Council staff issue paper, "The Role of the Bonneville Power Administration in a Competitive Energy Market." The paper explores a number of issues regarding Bonneville's competitiveness, and raises questions about the public purposes underlying Bonneville programs.

Written comment may be submitted to Steve Crow, Director of Public Affairs, Northwest Power Planning Council, 851 S.W. Sixth Ave., Suite 1100, Portland, OR 97204-1348, or fax comments to (503) 795-3370. Opportunities for oral comment will be provided at the August and September Council meetings. Please call the Council's public affairs division at 1-800-222-3355 or (in Portland) 222-5161 to arrange a time for oral comment). All comment should be submitted by September 15, 1995. In addition to this paper, transcripts of a June 14 panel presentation discussing this subject are available (request document number 95-9).

The Council plans to compile the comments received on this paper, and use the comments to identify issues and options that merit further exploration. The Council welcomes reactions to this proposed process and whether other avenues should be used to foster an appropriate public debate on these issues.

Very truly yours,

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Staff Issue Paper:

The Role of the Bonneville Power Administration in a Competitive Energy Market

INTRODUCTION

This staff issue paper explores issues and alternatives confronting the Bonneville Power Administration in a competitive energy market. Bonneville is facing unprecedented challenges. This paper explores a number of alternatives for improving Bonneville's competitiveness, and raises questions about the public purposes underlying Bonneville programs.

By way of background, the paper discusses the history of the federal hydropower system and Bonneville's role in it. The paper first raises questions about the public purposes to which the federal power system should be devoted and Bonneville's role in that system. Next, the paper addresses the size of the competitive problem Bonneville appears to be faced with. The paper next enumerates various alternatives for cutting Bonneville costs and increasing the agency's revenues. The paper ends with a discussion of the broader changes that may be facing Bonneville and the region's energy system.

The Council has not taken a position on any of these issues and, in fact, is beginning a major revision of its power plan in which many of these matters will be addressed. The Council is publishing this staff issue paper to promote regional participation in the debate.

BACKGROUND

The Bonneville Power Administration and the federal Columbia River power system have for almost 60 years played a key role in the Northwest's electric power generation and transmission system. In important ways, Bonneville and the hydropower system have helped shape the region.

Major construction of federal hydropower dams on the Columbia River began in the 1930s. The federal dams, operated by the Army Corps of Engineers and the Bureau of Reclamation, were built to serve multiple purposes -- navigation, flood control and other purposes -- but power generation was a central purpose. This construction program was fueled in part by the perception that the electric power industry had been dominated by private utilities with monopoly power whose distribution of electrical power neglected many rural areas.

The Bonneville Project Act created the Bonneville Power Administration to sell the dams' surplus power at cost, to encourage the widest possible use of electricity, and to build and maintain a transmission system. At an early point, the agency determined to provide power at uniform, "postage stamp" rates, and to initiate an aggressive transmission construction program. The dams not only provided the cheapest electric power in the nation, they also became engines for economic development. War time demands for electricity were such that by the early 1940s, more than 90 percent of Bonneville's power was committed to industry.

Congress included a "public preference" clause in the Bonneville Project Act, i.e., Bonneville must give preference to "public bodies and cooperatives" in the sale of power. Contracts with private utilities were required to include five-year cancellation clauses. As new federal dams were constructed, similar public preference provisions were enacted. With the construction of major dams in Canada, the negotiation of the Columbia River Treaty, and the authorization of new transmission lines to California markets (the "intertie"), a second form of preference was created. The Northwest Preference Act of 1964 provided that Bonneville could export power outside the region only if it was unneeded in the region.

In 1974, Congress passed the Federal Columbia River Transmission System Act to establish a funding mechanism to "provide greater assurance that the needs of the region for transmission capacity will be met." That Act established a Bonneville Power Administration fund in the U. S. Treasury, authorized Bonneville to issue and sell revenue bonds and continued authority for the agency to charge "postage stamp" rates. In effect, Congress authorized Bonneville's activities to be financed by hydropower revenues and revenue bond, and freed it from reliance on federal appropriations.

In the 1960s and '70s, Bonneville was instrumental in the development of the "Hydro-thermal Power Plan." As part of the plan, Bonneville backed the construction of three of the Washington Public Power Supply System nuclear power plants. The prospect that Bonneville would be unable to ensure power for its public utility and direct service industrial customers was instrumental in the utilities' decisions to proceed with two more nuclear plants. Only one of the Supply System plants was completed, but Bonneville retains responsibility for approximately $500 million in annual debt payments for three of the plants.

In 1980, the Northwest Power Act authorized Bonneville to finance energy development and created a priority for cost-effective energy conservation, renewable and high-efficiency energy resources. The Act created a residential exchange mechanism to share Bonneville's low-cost power with residential customers of investor-owned utilities. Implicit in the Act was the assumption that Bonneville would finance most of the new energy development in the region. The Act also required Bonneville to address the needs of Columbia River Basin fish and wildlife that were adversely affected by development and operation of the hydropower system. The Northwest states were authorized to form the Northwest Power Planning Council to develop a power plan and fish and wildlife program to guide energy conservation and development and the protection, mitigation and enhancement of fish and wildlife.

Since 1980, the electric industry within which Bonneville operates has been fundamentally transformed. Technological advances have made it possible for highly efficient power generators to be built at costs that are well within the financial capability of many utilities and non-utility generators. Drilling technology improvements and more efficient gas markets have resulted in much lower natural gas prices.

At the same time, much of the regulatory structure that traditionally constrained electric utilities has been and is being rearranged, supplanted or marginalized by the Energy Policy Act of 1992. That statute authorized new electricity producers and brokers to supply electricity at the wholesale level. This had previously been the exclusive domain of Bonneville and other utility companies. A recent Federal Energy Regulatory Commission (FERC) proposal on open transmission access proposes another major step toward a fully competitive wholesale power market. The deregulation of the wholesale power market is likely to have a much greater effect on Bonneville than on other Northwest utilities. For most of the utilities in the region, wholesale transactions represent a small part of their total revenues, typically less than 10 percent. All of Bonneville's revenues come from wholesale transactions.

The combination of new technology, inexpensive natural gas and new energy suppliers has overturned many of the assumptions that were underlying the region's electric power system when the Northwest Power Act was enacted in 1980. With the technological developments of the 1990s, new large thermal power plants are no longer part of any utility's thinking; the federal hydropower system probably will not be the dominant financier of future energy development in the region; and regional preference, long a landmark in the region's energy policy, is being reconsidered.

While these changes in the competitive market were occurring, wild salmon populations were experiencing a precipitous decline. The Council's fish and wildlife program, already calling for substantial efforts in the 1980s, was significantly expanded in response to listings of Snake River salmon under the Endangered Species Act. Actions called for by National Marine Fisheries Service biological opinions have resulted in added costs and lost revenues. Moving the pattern of river flows toward a natural hydrograph has increased the quantity, duration and certainty of nonfirm power generation in the spring and summer months. This has helped competitors use Bonneville's nonfirm power to compete for Bonneville's firm loads.

These new pressures are having a palpable effect on Bonneville sales. Recently, Bonneville lost almost 500 megawatts of load as several of its utility and direct service customers turned to competing power suppliers. Other customers have said they may shift significant additional load to other suppliers. Bonneville's ability to resell its power is constrained by federal law.

For all of these reasons, there is genuine concern about Bonneville's ability to compete in the market, or to finance energy conservation, renewable energy development and fish and wildlife mitigation. For Bonneville to play a role in the long term, it must be able to maintain its competitiveness in the short term. Consequently, Bonneville is pursuing a number of initiatives to improve its ability to compete in the short term. The agency is stabilizing costs, for example, and developing competitive, five-year rates. Bonneville is also developing a strategy for managing a competitive transition through stranded investment measures or negotiated load-retention agreements with its customers.

Several members of the Northwest Congressional delegation are exploring legislative avenues for improving Bonneville's competitive position. Legislation could change regional preference to give Bonneville more flexibility to market its surplus power and could limit Bonneville's fish and wildlife expenses. Bonneville's rate proposals bring a number of other issues into play: the residential exchange, stranded investments and the irrigation discount rate, among others. Other parties have suggested additional ways for Bonneville to cut costs and increase revenues so it can compete in today's electricity market. Several such ideas were discussed by a panel of observers convened by the Council at its June 14, 1995 meeting in Seattle.

It is unlikely, however, that short-term legislation and the five-year rate case will address the long-term issues that face Bonneville and the region, many of which are the result of fundamental changes in the energy market. These developments signal the beginning of a fundamental reconsideration of the region's energy policy. Clearly, the debate over the future of Bonneville also implicates the role of the Power Planning Council.

PUBLIC COMMENT

The Council invites comment on the issues raised in this paper. Written comment may be submitted to Steve Crow, Director of Public Affairs, Northwest Power Planning Council, 851 S.W. Sixth Ave., Suite 1100, Portland, OR 97204-1348, or fax comments to (503) 795-3370. Opportunities for oral comment will be provided at the August and September Council meetings. Please call the public affairs division at 1-800-222-3355 or (in Portland) 222-5161 to arrange a time for oral comment). All comment should be submitted by September 15, 1995. In addition to this paper, transcripts of the June 14 panel presentation are available (request document number 95-9).

The Council plans to compile the comments received on this paper, and use the comments to identify issues and options that merit further exploration. The Council welcomes reactions to this proposed process and whether other avenues should be used to foster an appropriate public debate on these issues.

DISCUSSION

I. BONNEVILLE'S POSITION IN THE REGION.

Any discussion of changing Bonneville's activities to cut costs or increase revenues so it can compete in the new electricity marketplace requires consideration of certain fundamental issues:

- In view of developments in the electric power industry, does it still make sense to think of the Northwest electric power system from a regional perspective?

- Should Bonneville, with its unique advantages and disadvantages as a public agency, be a competitor in an open wholesale energy market? Can Bonneville be positioned to compete without imposing unfair burdens on other competitors?

- Are the public purposes traditionally served by Bonneville and the federal power system still valid? Is Bonneville best suited to meet these purposes? Would some of these purposes be served by a competitive power system in any event? For example, without Bonneville, would market forces make energy available at fair terms in rural areas? Would a market-driven system finance fish and wildlife and energy conservation measures? Without Bonneville, would market forces provide energy to large industrial customers at rates that account for their unique contribution to the regional system?

- If the region's goal is narrow -- for example, only to sell power from the hydropower projects -- is this purpose best served by a federal agency that competes against entities that lack the competitive advantages and encumbrances of the federal system?

- Are Bonneville's current responsibilities -- for example, paying the cost of mitigating the dams' impacts on fish and wildlife, financing energy conservation and renewable energy development -- suited to an agency that competes in a largely unregulated market? (Readers should note that these responsibilities have different implications. Whatever the structure of the industry, the responsibility to mitigate the environmental impacts of the hydropower system is likely to be borne by whoever benefits from the assets. On the other hand, the responsibility to finance conservation and renewables development will likely be approached differently now than in the 1980s, because the industry structure is different.)

- If broader responsibilities remain appropriate, can the agency's competitive position be improved while reaffirming its public responsibilities?

- As transmission moves to a common carrier (open access) model, should the transmission system become part of a Northwestwide or westwide transmission entity? What do the region and the federal government gain from public ownership of most of the transmission system, and what would they gain by selling it? Will national policy encouraging wholesale competition ultimately force divestiture of transmission assets?

- Will a broader restructuring of the electric industry, such as that being proposed in California, ultimately force a significant change in the role of Bonneville?

- Can Bonneville compete, even with reduced costs? Some believe energy will remain inexpensive for an extended time, and that Bonneville will be unable to compete even if Congress reduces the agency's existing obligations and restrictions. In short, is attempting to shore up Bonneville's competitiveness a futile exercise?

- What role, if any, should the nation's taxpayers play in ensuring that Bonneville continues to meet the public purposes it has served historically?

None of these questions stands on its own. The justification for reinforcing Bonneville's competitive position hinges on the agency's public functions; the agency's ability to carry out public functions depends on its ability to compete in the market. In this sense, the appropriate question is not how Bonneville can be preserved. Rather, the question is how we can best ensure an adequate, efficient, economical and reliable power supply, meet environmental goals, administer federal power sales, and maintain an efficient and equitable transmission system? None of these goals will necessarily be accomplished by a competitive energy market.

In the following section, Council staff surveys alternatives for cutting Bonneville's costs and increasing its revenues. These alternatives are meant to give commentors a sense of the steps that could be taken if the objective is a competitive Bonneville Power Administration. A number of parties have told the Council that these issues must be dealt with comprehensively; others insist that a quicker, incremental approach is appropriate. Clearly any changes should be considered in view of the broader public values at stake. A question for commentors is whether it is possible to fashion a package of changes that would keep Bonneville competitive without seriously compromising the agency's public functions, or whether other approaches would better serve the region. The Council hopes that public discussion will identify additional alternatives, improve the staff's analysis and promote a regionally acceptable solution.

II. PRELIMINARY ANALYSIS OF CUTTING BONNEVILLE COSTS AND INCREASING REVENUES

A. Is Bonneville competitive?

Bonneville's competitiveness depends both on rates and on other values such as reliability and certainty. To some extent, short-term rates can undermine these other values, and these considerations much be balanced.

How low do Bonneville's rates need to be to retain customers and be competitive? This rate level will define the scope of the competitiveness problem and help guide a discussion of the alternative strategies available to Bonneville. Council staff has approached this analysis from two directions: an analysis of the West Coast wholesale market and estimates of the rates Bonneville needs to compete.

The Council staff's preliminary analysis indicates a substantial West Coast market for power in the 20 mill per kilowatt-hour range for high load factor (loads that are constant throughout the day and throughout the year) purchases of power from California and the desert Southwest (excluding transmission). This has been confirmed generally by independent analyses by some Northwest utilities. The reduction in proposed project financing by independent power producers appears to confirm this further. The size and duration of this market are subject to some uncertainty. However, there appears to be enough low-cost power to pose a competitive threat to Bonneville over the next five years. Staff is continuing to refine its analysis and consulting with Bonneville, utilities, the California Energy Commission and others.

Based on conversations with Bonneville and utilities that are actively marketing power, it appears to staff that five-year rates in the mid-20 mill per kilowatt-hour range for the typical public utility load would be competitive. This price includes transmission, load shaping and reserves. Five-year rates in the low 20 mill range appear to be competitive for customers with high load factors, such as the direct service industries (DSI) and some utilities. The Council invites comments on these estimates.

Bonneville recently proposed rates for the five-year period 1997 to 2001. The proposed composite average firm rate for public utility purchases is 24.9 mills, including transmission purchases at 3.7 mills. The average DSI rate is 22.6 mills, including separately priced transmission of 2.6 mills. Bonneville believes these rates will be competitive, and that it will be able to retain almost all of its current customers.

Bonneville's most recent rate case analysis shows that these rates should result in a 71 percent probability of meeting full Treasury payments over the 5 year period. It is difficult to compare the probabilities calculated in the five-year rate case with the probabilities used in previous two-year rate cases. In previous rate cases, Bonneville could adjust rates every two years to accommodate changing circumstances.[1]

[1]. The five year probability is the result of the probabilities of meeting full Treasury payments in each year. Because outcomes from year to year are interdependent, the rate period result is evaluated with a simulation analysis. For a similar reason, the probability of making a payment in any given year of the rate period cannot be inferred from the probability for the rate period as a whole. Mathematically comparable total rate period values can be calculated, however. They are the following:

Reference Period	Probability over 2 Years	Probability over 5 Years
1993 Financial Plan	95%	88%
1994-95 Rates	85%	67%
1997-01 Rates	87%	71%

Bonneville's analysis contains a number of key assumptions. First, it has reduced exchange costs from about $200 million per year to about $60 million per year over five years. These proposed changes in the exchange are likely to be challenged. Second, it assumes a net additional load loss of only 75 megawatts. Built into this analysis are the assumptions that Bonneville loses half of the top quartile DSI sales and one large aluminum smelter. It also assumes the rest of the DSIs are at full production. If Bonneville loses additional load, the probability of Treasury repayment would go down. Third, Bonneville assumes that Tenaska Power Partners will not be successful in a lawsuit seeking $1 billion in damages for Bonneville's cancellation of the Tenaska power project. Fourth, the analysis assumes that Bonneville receives $60 million per year in credits under Section 4(h)(10)(C) of the Northwest Power Act (this provision is discussed on page 16). So far, the Administration has agreed to only $30 million per year. Finally, the analysis relies on significant budget cuts by Bonneville totaling $500 million.

If these key assumptions turn out to be too optimistic, Bonneville's probability of meeting its full Treasury payments could decline. As a rule of thumb, if Bonneville's costs go up $500 million over the five-year rate period without compensating increases in revenues, the probability of repayment falls to 50 to 60 percent. If Bonneville could cut costs or increase revenues by $500 million over the five-year rate period, the five-year repayment probability increases to about 90 percent.

Assuming no legislative action, but considering a range of adverse outcomes in the uncertainties described above, Bonneville recalculates the likelihood that it can make its Treasury repayments as follows[2]:

BASE CASE		**1000 MW LOSS**		**2000 MW LOSS**	
5-yr prob	5-year miss	5-yr prob	5-year miss	5-yr prob	5-year miss
55-71%	$116-366	50-71%	$116-501	39-71%	$116-661

B. Alternative Ways to Cut Costs or Increase Revenues

This section describes a preliminary analysis of ways to increase Bonneville's probability of meeting its Treasury payments over the next five years. The savings and additional revenues are summarized in Table 1. These are staff analyses. The Council has not taken a position on any of these alternatives.

[2] The new probabilities are calculated starting with the probability of making all Treasury payments over the 5-year rate period of 71 percent, used in the rate case. These are adjusted using a range of additional cost impacts of $0-$130 million, changing the initial probability to a range of 55-71 percent. In the two additional load loss cases, uncertainty about stranded cost recovery is incorporated, with ranges from $0-$50 million and $0-$100 million respectively. The $50 and $100 million values represent complete recovery of lost net revenues, thus keeping the high end of the range at the original 71 percent.

In this preliminary analysis, Council staff has reviewed alternatives that could cut Bonneville costs or increase revenues totaling $900 million to $1.6 billion over the next five years. If transmission assets could be sold for more than current net investment, the upper end of this range could be higher. In several cases there is a broad range of potential savings or revenues. The Council invites additional ideas and comment on these options.

The alternatives:

1. **Limit Bonneville's fish and wildlife costs?** Some parties believe that Bonneville fish and wildlife costs should hinge on Bonneville's revenues. Some parties believe that a cap on fish and wildlife spending would add financial discipline, sharpen the prioritization of fish and wildlife activities and increase the effectiveness of fish and wildlife expenditures. For example, the Council has seen the Columbia Basin Fish and Wildlife Authority and its members identify numerous potential efficiencies as they try to accommodate Bonneville's current financial constraints. A cap could also relieve financial pressure on Bonneville in the short term, address one of the major uncertainties about future Bonneville rates, and mitigate concerns that fish and wildlife investments will sap Bonneville's financial flexibility in the long term.

A bill introduced by Montana's Senator Max Baucus would limit fish and wildlife costs that Bonneville may incur annually to 20 percent of its gross annual power revenues (transmission revenues not included). Because Bonneville's power revenues in 1994 were about $1.7 billion, the cap would be set at $340 million, and future expenditures would depend on power revenues. The bill anticipates additional costs for salmon recovery being assumed by the federal government. The bill states explicitly that "compliance with this section shall not relieve the government of any responsibilities under the Endangered Species Act . . . ." The Baucus bill would also prohibit Bonneville fish and wildlife costs from being recovered through transmission rates

Bonneville usually calculates its fish and wildlife costs by adding its direct payments for fish and wildlife projects to an estimate of the effect flow augmentation and spill for fish will have on net power sale revenues. Bonneville's direct payments include the cost of implementing the fish and wildlife program (habitat projects, research, hatcheries and other measures). Bonneville also reimburses the U.S. Treasury for: the costs of the U.S. Corps of Engineers' salmon research, passage and transportation work; and the U.S. Fish and Wildlife Service's costs for the Lower Snake Compensation Plan. Finally, Bonneville's direct payments include repaying a share of the cost of fish screens, ladders and other construction projects at the dams.

Bonneville's calculation of fish and wildlife costs also usually includes lower power revenues and the cost of purchasing power due to salmon operations. Power sales are reduced when Bonneville stores water for flow augmentation or spills water at dams instead of generating electricity when power demand is greatest. In many years, because Bonneville uses water for salmon flows, it must also purchase power from other sources to meet its customers' demands. Although Bonneville can generate electricity when it releases water for fish (as long as the water is not spilled), the power usually goes on the market when prices are lower. This decreases Bonneville's revenues. Each year, Bonneville calculates the cost of energy purchases and the reduced revenues attributable to salmon operations.[3] These amounts are presented as the power system costs of fish operations. They are added to Bonneville's direct payments for fish and wildlife projects for a total estimated fish and wildlife cost.

Council staff has previously estimated the long-term regional cost of the current National Marine Fisheries Service's biological opinion at about $500 million in an average water year. Over the long term, full implementation of the Council's fish and wildlife program would carry similar costs.

Bonneville's average share of these costs is about $400 million to $450 million annually. This share could range from about $250 million in a very wet water year to nearly $700 million in low water years. The average savings for Bonneville from a $300 million cap could be $100 million to $150 million per year, for a five-year total of $500 million to $750 million.

There are several potential salmon protection measures that add to the concern that Bonneville's rates may not be competitive in the future. For example, the potential added cost of the various reservoir drawdown alternatives contributes to the uncertainty of fish and wildlife costs. The revenue requirement to repay the capital cost of the drawdown alternatives in the Council's 1994 Fish and Wildlife Program would peak at about $95 million per year, five to ten years after construction begins. If drawdown activities are implemented they are not likely to impose large costs during the five-year rate period, as most costs would be related to planning and design. In the long term, drawdown would result in additional generation and revenue losses. Similar considerations would apply to the Fisheries Service's plan if the Service calls for drawdowns. The added costs of surface bypass systems would also be due after the five-year rate period.

One issue regarding the cost cap is whether the federal government or other parties would cover fish and wildlife costs above the cap. In other words, would a cost cap merely limit Bonneville ratepayers' financial responsibility, or limit all fish and wildlife mitigation responsibilities associated with the federal dams? If the latter, fish and wildlife activities could be reduced by 25 to 33 percent in average water years and more than 50 percent in low water years. However, low water years are when many

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[3] To determine the cost of power purchases attributable to salmon operations, Bonneville takes the cost of power purchases and subtracts the revenue it gains when an equivalent amount of water is released in the spring and early summer. To estimate the extent to which power sales revenues are reduced by salmon operations, Bonneville takes what it would have earned in the absence of salmon operations and subtracts the power revenues it actually earns when the river is operated for salmon flows, along with other purposes (other important purposes served by river operations are: hydropower generation, flood control, irrigation, navigation and recreation).

fishery managers believe salmon need the most help. Can such a cap be reconciled with the requirements of the Northwest Power Act, the Endangered Species Act, and the Nation's treaty commitments to Indian tribes and Canada? Can a fish and wildlife cost cap be devised that gives ratepayers a degree of certainty, affords Bonneville financial relief, and yet does not undermine the region's efforts to rebuild fish and wildlife populations? Could a cap improve the biological effectiveness of recovery efforts by forcing a more serious examination of the relative merits of alternative measures?

Several utilities point out that they are subject to the regulatory jurisdiction of the Federal Energy Regulatory Commission, which imposes a variety of fish and wildlife mitigation obligations on the utilities' dams. They ask why Bonneville's obligations should be limited if other utilities' obligations are not? Should there be limits on the environmental costs associated with coal and gas-fired power plants that compete with hydroelectric dams?

There are also technical issues that would have to be resolved in accounting for fish and wildlife costs. If foregone power revenues are included, the actual amounts will be difficult to measure and will not be known until the end of an operational year. These amounts will have to be forecast. The region will need to understand the assumptions Bonneville uses to estimate foregone revenues and power purchases it attributes to salmon recovery. Another technical issue: uncontrollable maintenance and replacement costs for fish passage facilities -- replacing aging fish ladders, for example -- could crowd out recovery and mitigation measures.

Application of a cost cap could also influence the selection of operational strategies for fish. A flow-based strategy, for example, carries significant, immediate costs in terms of power purchases and foregone revenues. In contrast, the costs of a passage improvement strategy would not be incurred by the region immediately, as such investments are repaid over time, beginning after completion of the work.

In short, there are many issues relating to fish cap proposals: 1) Who will be covered under the fish cap? Bonneville? The Mid-Columbia participants, Idaho Power and other utilities? Navigation and irrigation interests? 2) What should be the level of the cap? 3) How do we calculate the level of the cap? 4) What fish costs should be included under the cap? Fish and wildlife program and/or Endangered Species Act expenses? Reimbursables? Foregone revenues? 5) How long would the fish cap last? One year, five years or permanent? 6) Would it be a cap and a floor? 7) Should "sufficiency language" be included? (i.e., statutory language stating that the fish and wildlife measures taken under the cap are deemed sufficient to fulfill the Bonneville administrator's responsibilities under the Endangered Species and Northwest Power Acts).

2. **Modify public preference?** Under current federal law, publicly owned utilities have first preference to power from Bonneville. Some parties have suggested that public utilities that remove load from the federal system should not be allowed to claim public preference if they return. Instead, they could buy power on the same terms

as investor-owned utilities. Others suggest a waiting period before returning public utilities could claim preference power. Such changes could discourage public utilities from taking load off Bonneville.

Modifying public preference would expand Bonneville's market. Council staff could not identify any estimates of the added revenues that could come from changes in public preference.

3. **Enhance marketing of Bonneville power?** Under current law, Bonneville can sell surplus firm energy outside the Northwest only if it retains the right to call it back with 60 days' notice. If these regional preference provisions were modified to allow a longer notice period, Bonneville could get higher prices for this power. This may be especially important for marketing the annual surplus caused by salmon flow operations. Bonneville estimates changing regional preference might increase revenues by as much as $20 million a year over the next five years, and possibly more later. Over five years, the savings could total about $100 million.

Some parties have suggested changing the two-month callback provisions to five years. They argue that current power sales rarely exceed five years so there would not be a penalty, and some callback provisions are prudent given the uncertainty in the industry. Is there a public interest in setting a callback limit on surplus Bonneville sales?

Council staff assumes Bonneville would still offer surplus power to Northwest utilities before making sales outside the region. If utilities decide to take load off of Bonneville, they could be limited in their access to Bonneville power in the future.

Bonneville is proposing to unbundle its power sales, and this would likely increase revenues. For many customers, Bonneville provides an exact amount of power at an exact time of day for a flat rate. The market value of selling capacity, shaping, reserves and other individual services may be significantly higher than what Bonneville currently charges.

4. **Limit, eliminate or buy out the residential exchange?** Under the Northwest Power Act, the residential exchange reduces electric rates for residential and small farm customers of utilities that have a higher system cost than Bonneville. It was originally intended primarily for investor-owned utilities, whose access to federal hydropower in the early 1970s was cut off by public preference.

Reducing or eliminating the exchange would reduce electric rates for most direct service industries and most public utilities, but raise rates for many residential customers. This year, four investor-owned utilities and 14 public utilities participate in the exchange. In the 1995 exchange, the largest consumer benefits will go to customers served by Portland General Electric ($57 million), Puget Sound Power and Light ($50 million), Utah Power and Light ($13 million), Pacific Power and Light ($6 million), Oregon Trail Cooperative ($2.5 million) and Central Electric Cooperative ($1.7 million).

Bonneville's current rate proposal would substantially reduce the benefits of the residential exchange. The proposal would leave only three or four utilities with any exchange benefits, reducing the net cost of the exchange to Bonneville in 1997 from close to $200 million to about $48 million.

This reduction would occur because of the rate test required by Section 7(b)(2) of the Northwest Power Act. The residential exchange provisions of the Act were meant to serve three contradictory goals:

- To allow exchanging utilities to pay the same wholesale power cost for their residential and small farm loads as Bonneville's public utility customers pay (and under more limited circumstances, Bonneville may purchase an equivalent amount of power from the exchanging utilities at their average system costs);

- To protect the public utilities from paying more than they would have paid in the absence of the Act; and

- To base the rates for the direct service industries on specific additions and subtractions from the rate paid by the public utilities.

The second of these goals is embodied in the 7(b)(2) rate test. The test, in conjunction with the third goal, requires that as Bonneville reduces the public utility rate based on competitive considerations, the increasing net cost to Bonneville be added back into the rates that the exchange provisions were intended to reduce. In effect, the exchange rate would actually increase rather than decrease. These proposed reductions, however, are likely to be hotly contested.

As an alternative to the Bonneville rate proposal, there are other ways to reduce the cost of the exchange:

The Act allows Bonneville to purchase power for these residential and small farm customers in lieu of exchanging power with participating utilities. Given the current energy market, this could significantly reduce the net cost to Bonneville. Under the current contracts with utilities, this provision can only be triggered with seven years' notice, or at the end of the contracts in 2001. Bonneville has given such notice.

Elimination of the exchange would require legislation. It may be possible to negotiate a cap, reduction, phase-out or buy-out of exchange costs over a period of years. If the cost of the exchange were reduced 10 percent per year, the five-year savings would be about $250 million. If the exchange were eliminated beginning at the end of the current contracts, Bonneville would save some portion of the estimated $257 million net cost of the exchange in 2001. If Bonneville could save one quarter of the 2001 costs, the savings could be about $60 million within the five-year rate period. (These estimates were made before the current rate proposal.) Any savings from a buy-out are speculative.

One regional utility has suggested that Bonneville negotiate a buy-out of the residential exchange. This, in the utility's view, would acknowledge the fact that the exchange was created to spread the benefits of federal power to the residential and small farm customers of investor-owned utilities. There is no reason why this purpose should be abandoned.

The state utility commissions would need to be involved in any discussions regarding reducing or eliminating the exchange.

5. **Cut Bonneville operating costs?** Bonneville has implemented several rounds of cost cutting. Recently, Bonneville announced an additional $250 million reduction for each of five years. These savings were assumed in Bonneville's analysis of its revenues and costs. Of these savings, some are at risk in pending litigation, and $30 million are from steps that have yet to be identified.

Some parties have suggested further cuts, noting that Bonneville staffing levels and other costs are still above industry averages. Bonneville staff has replied that Bonneville is reducing employees through attrition and early retirements; further reductions would require federal "reduction-in-force" procedures that would be disruptive to the agency. Council staff has not analyzed this issue. As a rule of thumb, a reduction of 500 full time equivalents (FTE) would reduce personnel costs by about $35 million per year; 1,000 FTE would be about $70 million per year (based on Bonneville estimates of the costs a contractor would charge). Five-year savings could range from zero, if no additional staff or other operating reductions are possible, to $350 million if staffing could be reduced by 1,000 FTE.

6. **Terminate WNP 2?** During the past year, the Washington Nuclear Project Number 2, operated by the Washington Public Power Supply System, produced power at about 30 mills per kilowatt-hour. In previous years, when the plant operated less reliably, the costs were much higher. These variable costs do not include any repayment of the debt on the plant. Given the current market, Bonneville is losing money on the power from this plant. Terminating the plant, however, would entail additional costs for termination and decommissioning.

The Council staff have not done an independent analysis of possible power system savings associated with termination of WNP-2. Rather, staff reviewed a Bonneville analysis of the cost of terminating WNP 2, which assumed: termination costs similar to those involved in closing the Trojan Nuclear Plant; as much delay in decommissioning as possible; and replacement of the plant with a 250 megawatt gas turbine and purchases. In the near term, it would probably be cheaper to rely entirely on purchases, although winter reliability concerns might require additional generation. The Council staff's review has focused on the five-year period 1996-2000 because of Bonneville's near-term cash flow problems. The viability of the WNP-2 should also be reviewed from both a short-run and a long-run perspective through a complete analysis of power system performance.

The major factors in determining potential savings are the performance assumed for WNP-2, the costs of operation, the price of gas, and the cost of purchased power (which correlates with the price of gas). Staff have reviewed the gas price and purchase power forecasts used in the Bonneville analysis. The Council staff's current draft medium natural gas price forecast is slightly higher (less than 10 percent) than the low gas price forecast used in the Bonneville analysis and much lower (more than 25 percent) than the medium gas price forecast used by Bonneville. The Council staff's low gas price forecast begins slightly lower than the low forecast used in the Bonneville analysis and stays flat in real dollar terms, while the Bonneville forecast increases at around 4 percent per year through the year 2000.

In Bonneville's analysis, the key findings were that if the Supply System met its performance targets (75 percent capacity factor) and medium or medium-low gas prices obtain, the additional costs of termination and decommissioning exceed the potential savings from closing the plant over the five-year period 1997-2001. If, however, the plant achieves only a 70-percent capacity factor, there are five-year net savings ranging from $0 to $100 million, with net costs of $50 to $60 million in the first year. If gas prices are at Bonneville's low level and power prices are five mills lower than Bonneville's base assumption, the five year savings could be as much as $140 million.

The Supply System has recently adopted a target for fiscal year 1996 operating costs that is approximately 19 percent lower than the target used in the termination analysis. This cost and a 75-percent capacity factor would lower the WNP-2 operating cost into the high 20 mills per kilowatt-hour range. If the Supply System is successful in meeting these targets, but, as appears likely, gas prices and power purchase prices are at the lowest levels used in the Bonneville analysis, it is estimated that there would be a modest five year savings ($20 to $30 million) from terminating WNP-2, with net additional costs in the first couple of years. However, at almost the same time the Supply System was lowering its cost target, Bonneville announced power rates that are on the order of 22 mills per kilowatt-hour. In other words, even if the Supply System is successful in meeting its performance targets, it would still be operating at a loss of several mills per kilowatt hour. Bonneville has said it will re-analyze this issue using the lower rates it has proposed.

If Bonneville were to lose load equivalent to the output of WNP-2, there would be no need to replace the power. There would, however, be no revenues to offset the termination and decommissioning costs, and the region would lose some resource diversity.

7. Adopt remedies for stranded investment? If Bonneville cannot sell power at a competitive price it will lose customers. If a significant number of customers leave the Bonneville system, costs of past investments made on their behalf may be "stranded," and be imposed on a smaller number of customers. In these circumstances, it could be difficult to recover enough revenue to meet Bonneville's fixed costs, and extra burdens may be imposed on customers unable to leave the Bonneville system. To avoid this situation, it may be necessary to make provision for customers for whom the investments were made to take responsibility for the unrecoverable costs of these investments. Several parties have identified the debt on the WPPSS plants, fish and wildlife costs, and investments in energy efficiency and renewable resources as potentially stranded investments.

This situation is not unique to Bonneville. The Federal Energy Regulatory Commission sees the disposition of stranded investment as one of the barriers that must be overcome to achieve a competitive wholesale power market. The FERC has proposed rules that would allow investor-owned utilities to recover stranded costs. Under these proposals, legitimate and verifiable stranded costs would be assigned to departing customers based on the extent to which the customer caused them. In the first instance, these charges would be negotiated, but in the absence of agreement the charge would be determined by the FERC. For non-investor-owned utilities like Bonneville, FERC has proposed the option of a customer-specific transmission charge for recovering stranded investments.

Bonneville has proposed several ways of dealing with stranded investments. In renegotiating the long-term power sales contracts, Bonneville has said it would discuss with customers ways of retaining load, but if it could not secure sufficient five-year purchase commitments, it would initiate a special process to recover stranded investment costs through a transmission surcharge. In the draft contract templates for the new long-term power sales contracts, Bonneville has also included provisions for capturing stranded investments in generating facilities, if customers add resources to serve their own loads in the third, fourth and fifth years of the contracts.

How significant might stranded costs be in the aggregate? To take one example: annual debt service on the WPPSS debt is almost $500 million. This debt is clearly uneconomic in today's market (much of it is for terminated plants) -- a potentially stranded investment. Spread over Bonneville's firm sales, this debt amounts to approximately 6.1 mills per kilowatt-hour. If 1,000 megawatts of load were to leave Bonneville with no stranded investment provisions, the remaining firm load customers would have to pick up approximately $50 million in stranded WPPSS debt, less the proportionate share of the revenues Bonneville would get from the sale of the surplus power. Alternatively, with a stranded investment charge, those leaving the system would take up to $50 million in WPPSS debt with them, less a share of revenues from surplus sales. If Bonneville were able to recover its full costs from surplus sales, the stranded investment charge would be zero. Depending on the market, the net stranded investment charge could be as little as two or three mills, and could be higher.

Are there ways to ensure that customers pay their obligations and also ensure that competition is not impeded? What role should recovery of stranded investment play in maintaining Bonneville's competitive position? Many parties consider recovering stranded investments a last resort to keep Bonneville solvent. Several commentors have said that Bonneville would not have stranded investments if it could be freed from some of the obligations it has under existing law. Others believe it is an issue of fairness -- those who imposed costs have a responsibility to pay them.

In view of the Federal Energy Regulatory Commission proposal, must this issue be addressed if Bonneville is to compete with other power suppliers? Should the issue of stranded investment be dealt with as part of any legislation affecting Bonneville, or is it a matter that can be handled by other means? If remedies for stranded investment were created, should they be in the form of exit fees charged to customers that leave the Bonneville system? A customer-specific transmission charge? A charge added to transmission fees charged to all utilities? Should it be some other mechanism?

8. Seek financial assistance from the federal government and beneficiaries of the dams? Under the Northwest Power Act, Bonneville can allocate fish and wildlife costs to non-hydroelectric purposes of the dams as credits toward Bonneville's payments to the Treasury. The Clinton Administration has agreed to allow credits of about $60 million in Fiscal Years 1995 and 1996 under section 4(h)(10)(C) of the Northwest Power Act.

The Administration has also committed to providing $30 million per year under 4(h)(10)(C) after Fiscal Year 1996. In its recent rate proposal, Bonneville assumes that another $30 million in credits per year will be allowed over the next five years. Other parties have suggested legislation that would require barge operators, irrigators and other beneficiaries of the dams to pay a portion of the non-hydroelectric power related fish and wildlife costs.

9. Make Bonneville a government corporation? Bonneville has proposed legislation to recreate itself as a government corporation. Bonneville believes that as a corporation it could eventually save $25 million to $30 million per year.

Bonneville has characterized most of the savings as "undistributed." Council staff has reviewed the waivers that Bonneville already received from the Clinton Administration and believes that many of the savings have already been achieved. Forming a corporation could help ensure that the savings continue.

Bonneville staff believe that corporate status could allow further employee reductions without going through reduction-in-force procedures. Several recent court decisions, however, appear to indicate that government corporations must still recognize veteran and other preferences in any reductions of staff.

10. Refinance Bonneville's debt to the Treasury? Congress is considering legislation to refinance Bonneville's debt for the appropriated capital investments in the federal Columbia River Power System. The debt totals about $6.7 billion and represents about 40 percent of Bonneville's current outstanding debt. In previous years, there have been proposals to increase Bonneville's payments significantly. The proposed legislation would remove a major source of uncertainty for Bonneville.

The proposed legislation contains a $100 million "premium" (payment from Bonneville to the U.S. Treasury) in connection with the refinancing. The impact of the legislation also depends on the interest rate available if the debt is refinanced. Bonneville estimates that refinancing could add from $50 million to $75 million in costs over five years.

11. Tailor the circumstances in which Bonneville customers may seek other suppliers? Until 2001, Bonneville customers cannot generally seek other energy suppliers without Bonneville's permission unless Bonneville has a deficit. Bonneville's direct service industrial customers may end their contracts with Bonneville on one year's notice, but until 2001 they are restricted from buying from Bonneville's public customers without Bonneville's permission. Several organizations have suggested that Bonneville could improve its competitive position by tailoring its permission according to its ability to resell or displace abandoned power at comparable prices. Others have argued that such limitations are not compatible with Bonneville's desire to be more customer focused. How much might Bonneville save through such a strategy?

12. Limit other lost-opportunity costs? If the lost hydropower value of using water for salmon flows instead of firm hydropower generation is considered a salmon recovery cost to be capped, should the lost-opportunity value of water used for other purposes -- irrigation, municipal and industrial uses, flood control, navigation, recreation, unauthorized water uses, and so forth -- also be considered (while acknowledging that some water uses involve property interests)? On more than one occasion the Council has suggested that the federal System Operation Review survey these opportunity costs generally. Unfortunately, there has been no comprehensive and systematic analysis and the available information is piecemeal. In 1993, for example, Bonneville estimated the lost hydropower value of water associated with Northwest irrigation at $150 million to $300 million per year, but provided no comparable information on other uses. Can these costs be estimated so the region has a fuller picture of lost hydropower or other opportunity values?

13. Limit or eliminate pumping rate contracts with irrigation districts? Under current federal law, the irrigation districts pay between 1 and 14 mills per kilowatt-hour for electricity to pump water at federal irrigation projects. The Bureau estimates that it uses about 480 megawatts for this pumping. If Congress authorized renegotiation of pumping rate contracts with irrigation districts to allow Bonneville to charge market rates for this power, it could increase revenues by about $32 million per year, as reported by the Task Force on the Bonneville Power Administration of the Committee on Natural Resources of the U.S. House of Representatives.

When Congress originally authorized the federal irrigation projects, some of the capital costs of the irrigation facilities were assigned to power revenues. Bonneville is required to pay these costs. To relieve Bonneville of this obligation and shift the costs to irrigators would require congressional action on each project and a revision of existing contracts between the irrigation districts and the Bureau of Reclamation.

Elimination of Bonneville's obligation under these congressional mandates would reduce Bonneville's costs by a total of about $200 million over five years. These expenses increase substantially in 2013.

14. Adapt Bonneville's ratemaking procedures? Another area of potential savings may be in Bonneville rate-making processes. The Northwest Power Act outlines detailed ratemaking procedures for Bonneville that may be more burdensome than those imposed on its competitors. Bonneville's rates, set in an elaborate and time-consuming process, are only for sales at wholesale. Bonneville's competitors may be able to get rates approved for a single transaction at wholesale in a simpler and speedier process. Under the procedures Bonneville has developed to implement section 7(i) of the Northwest Power Act, participation in a Bonneville rate case requires parties to commit significant time and resources involving data collection, technical analysis and legal review.

Rate-making procedures can have a direct effect on Bonneville's ability to compete. For example, if Bonneville sets a rate in a 7(i) process at 27 mills; its competitors know that a large amount of low-cost energy will be on the market in the spring and summer at 10-15 mills (or less) because of salmon flow requirements; the competitors buy the spring /summer energy and resell it at 25 mills. Could Bonneville improve its competitive position by reviewing and simplifying the procedures by which it implements section 7(i)? Section 7(e) of the Act, for example, envisions a diversity of rate forms. Bonneville relied on this section to develop the variable industrial rate for the direct service industries. Does the Northwest Power Act provide Bonneville with sufficient flexibility to address such situations?

15. Limit or eliminate Bonneville's obligation to meet net requirements? Under the Northwest Power Act, Bonneville must meet whatever loads customers choose to put on Bonneville. Competitors may supply customers' less costly loads, knowing that Bonneville must serve whatever remains. This has been characterized as "cherry picking." Should Bonneville's net requirements obligations be limited or eliminated to avoid such situations?

16. Sell Assets? When private businesses are not competitive they often sell assets to buy down debt or cover other costs. Bonneville's primary asset is its transmission system. There is some doubt whether it would make sense for Bonneville to sell what is arguably its most valuable asset. A sale would probably end up increasing the cost of transmission services for the region as a whole. Nevertheless, it is an option.

It is difficult to estimate a market price for Bonneville's transmission system. An extremely conservative price would only cover the remaining debt on the system. This would eliminate about $500 to $600 million per year budgeted for transmission debt service, operations and maintenance. Such a sale would reduce Bonneville's average rates by almost 4 mills per kilowatt hour, with an equivalent reduction in revenues (because Bonneville sets transmission rates only to cover transmission costs). If the system were sold for a higher price -- say the system's replacement cost -- the reduction in Bonneville's rates would be higher. On the other hand, customers purchasing power from Bonneville or competitors that need transmission over the former Bonneville transmission system would presumably pay more for that transmission service than they do now because a private buyer of the transmission system would earn a return on its investment (offset to some degree by elimination of risk reserves) and pay taxes. Since both Bonneville and its competitors would pay the same for transmission, the net effect should be that Bonneville's power products would compete on an equal basis with competitors' power products. The same effect can be achieved, however, by unbundling transmission services and charging comparable rates. Bonneville's current rate proposal would accomplish this without the problems of an asset sale.

If the transmission system were sold for more than the book value, then more money could be available to buy down other debt or cover other costs, depending on the sale price. However, would proceeds benefit Bonneville or the region, or would they be used to reduce the federal deficit? Moreover, the higher the sale price, the more customers would pay for transmission services. Using proceeds from the sale of transmission to buy down other debt would have the effect of redistributing the burden of the other debt to those who are more dependent on use of the transmission system. Overall, the results of selling the transmission system could range from no net effect (but a possibly improved competitive position for Bonneville) to several billion dollars in revenues to Bonneville. However, such a sale would increase costs to users of the system. In short, a sale might improve Bonneville's competitive position, but it probably would cost the region as a whole more for transmission services.

Bonneville has serious concerns about the idea of selling its most significant asset. The competitiveness problem may not be serious enough to warrant such action. Selling the transmission system could make it difficult for Bonneville to recover stranded investments. Bonneville suggests that the appropriate question is how the transmission system can be made more efficient, to reduce obstacles to a fully functioning bulk power market. In its current rate proposal, Bonneville has unbundled its transmission rates and charges all customers an equivalent rate. This should help it compete with alternative power suppliers.

On the other hand, many question the ability of any transmitting utility that owns or markets generation, including Bonneville, to provide comparable transmission services and pricing, which is the Federal Energy Regulatory Commission's objective. Some observers believe the nation will ultimately require utilities to divest themselves of their transmission assets to ensure a competitive wholesale market. Discussions are under way regarding the formation of a single owner/operator western transmission system. Proponents argue that such a system would offer efficiency benefits.

III. DEVELOPING A COMPREHENSIVE SOLUTION

It is important to keep these issues in perspective. The transition to a competitive wholesale power market is well under way. It is this transition that is at the root of many of Bonneville's immediate problems. The new, competitive electricity market has the promise of lowering electric rates in the Northwest. If properly structured, this new system will provide significant benefits for all consumers. The challenge is managing the transition from the old system to the new one.

The prior section lays out a number of alternatives to help Bonneville compete in the new wholesale electricity market. There appears to be significant interest in the region in addressing these issues comprehensively. Several parties have already made general recommendations that address various parts of the problem.

Many interests agree that Bonneville should seek additional assistance from the federal government, cut operating costs further and enhance the marketing of surplus power. These actions could close the competitiveness gap by $250 million to $550 million over five years.

Bonneville and many other interests focus on reducing the cost and uncertainty associated with fish and wildlife spending. They believe this option would solve most of the problem and that a comprehensive package that addresses Bonneville's other activities is not necessary.

Others have called for gradual changes in all of Bonneville's activities. This approach could keep Bonneville competitive, maintain portions of its current public policy functions and minimize the impacts on any single beneficiary of the current federal system.

Other organizations would manage the transition to the new market by limiting a customer's ability to leave the Bonneville system, imposing stranded investment charges and closing WNP-2. This approach would be intended to maintain Bonneville's current public purposes, including its obligations to fish and wildlife, energy efficiency and renewable resources.

Several parties favor a more rapid transition to a market-based system. This would involve the elimination of all subsidies and entitlements provided by Bonneville. Federal power would be available to anyone in the Northwest. Bonneville would have more flexibility to price its products in the market. These changes could make Bonneville competitive immediately and avoid the need for stranded investment charges.

Some utilities and others believe that a federal power marketing agency with broad social, environmental and economic development responsibilities is an anachronism in the emerging competitive power market. They favor a complete shift to a market system by transferring Bonneville's marketing and/or transmission functions on a competitive basis to a new commercial entity or entities. They would look to new mechanisms to carry out fish and wildlife and other responsibilities the region determined it was important to continue.

It is also important to recognize that the transition to a competitive wholesale power market may be only part of the power industry's transition. There may be further structural changes to expand competition to the retail level. Such changes would almost surely alter the roles of Bonneville and its customers.

The Council invites commentors to review the issues raised at the beginning of this paper, relating to the system's fundamental purposes, and consider how cost cutting and revenue enhancing alternatives may best serve these purposes. What should the goals of a restructured system be, and how could they best be achieved? Are the cost estimates described in this paper and in the following table appropriate.

The Council also welcomes ideas regarding process. A public review of a variety of proposals could lead to the development of a comprehensive regional solution that enjoys broad support. How should a discussion of these issues be structured?

TABLE 1: Preliminary analysis of potential competitiveness alternatives

Alternatives	Savings or Added Revenue Over Five Years
Limit Bonneville's fish and wildlife costs	$500 million to $750 million
Modify public preference	?
Enhance marketing of Bonneville surplus power	$100 million
Limit or eliminate the residential exchange	$60 to $250 million
Cut Bonneville operating costs	0 to $350 million
Terminate WNP 2	$100 million savings to $40 million added cost
Remedies for stranded investment	?
Seek financial assistance from the federal government and beneficiaries of the dams	$150 million
Bonneville Corporation	?
Refinancing Bonneville's debt to the Treasury	$50 to $75 million added cost
Limit waivers	?
Limit other lost opportunity costs	?
Limit or eliminate subsidies to irrigated agriculture	$200 million
Adapt ratemaking procedures	?
Limit obligation to meet net requirements	?
Sell Assets	$0 - several billion
Total potential savings or added revenues	**$900 million to $1.6 billion***

* Not including proceeds from sale of assets.