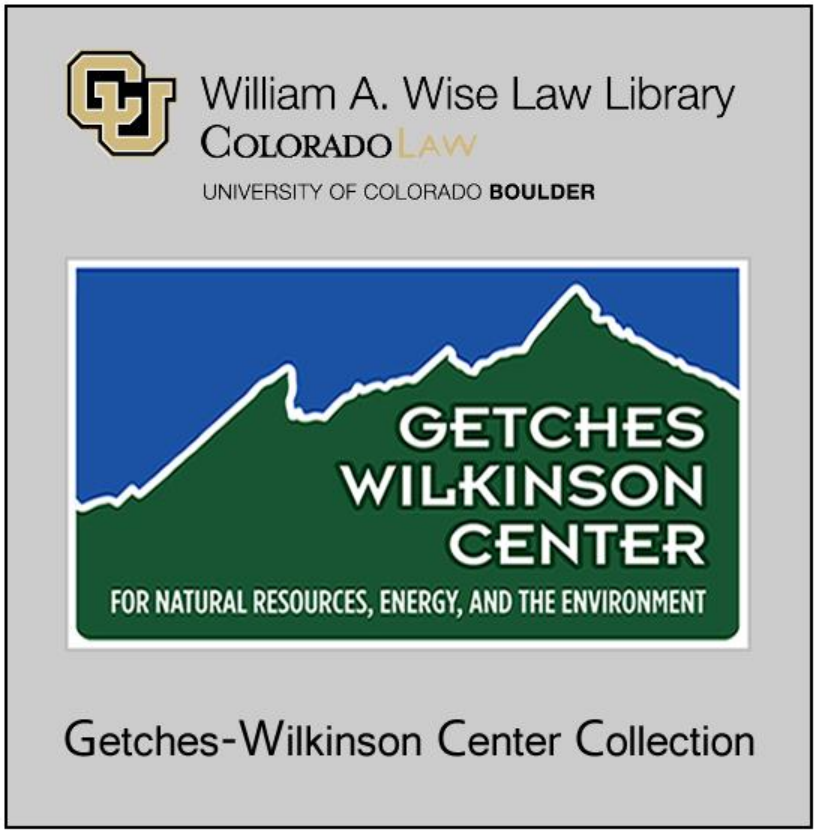
6-2-1997

The Pacific Northwest Governors' Comprehensive Energy Review: How Comprehensive?

Angus Duncan



Angus Duncan, *The Pacific Northwest Governors' Comprehensive Energy Review: How Comprehensive?*, *in* DAMS: WATER AND POWER IN THE NEW WEST (Natural Res. Law Ctr., Univ. of Colo. Sch. of Law, 1997).

The Pacific Northwest Governors' Comprehensive Energy Review:

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Dams: Water and Power in the New West

June 2-4, 1997

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The Pacific Northwest Governors' Comprehensive Energy Review:

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by Angus Duncan

I. INTRODUCTION

The Rivers and Harbors Act of 1925 directed the Corps of Engineers to survey the potential of the Columbia River for power, navigation, flood control and irrigation development. The Corps' response arrived in 1932, as the New Deal was searching for public works opportunities to put people to work. In other quarters there were reservations that the power output from large dams could ever be put to work in a region that was sparsely settled and largely agrarian, with little industry and that distant from most usable dam sites.

Nonetheless, construction work began in 1933. Bonneville Dam was completed in 1938; Grand Coulee in 1941. Today there are eleven large mainstem dams on the Columbia River below the Canadian border. Including the Snake and other major tributaries, there are 138 US dams, public and private, generating hydroelectricity as a principal or ancillary purpose. Sixty percent of the firm electric energy generated in the Pacific Northwest comes from hydroelectricity, and almost 70% of the capacity.

Of nearly equal importance, storage of water behind some of the dams allows power to be shaped to the fluctuating demands of customers. Storage backs up other sources of generation, producing a product that is higher quality and higher value because it is reliable and available on demand.

Under the terms of the Columbia River Treaty of 1961, a series of projects was constructed on the upper Columbia in Canada that altogether doubled the total available storage capacity of the system (including the Canadian portion of the Libby Dam reservoir, which extends 42 miles into Canada from the project site in northwestern Montana). Some 20 MAF was made available to the US for power generation and flood control, the two authorized uses of the stored water. With the added storage, more generators and power houses could be constructed on dams below the border.

The hydroelectric project construction boom lasted for forty years, ending with the

completion of Lower Granite Dam on the Snake River in 1975. In that period virtually every free-flowing stretch of the river from Bonneville to Columbia Lake in Canada was transformed into slack-water reservoir. The only exception, Hanford Reach, escaped the intrusion of the planned Ben Franklin Dam only by virtue of the security requirements of the government's Hanford Nuclear Reservation. There are still Ben Franklin boosters in the communities of central Washington that are prospering from irrigated agriculture.

This making and harnessing of the industrial Columbia River has contributed substantially to a prosperous regional economy, including low cost power for aluminum and pulp and paper processing, irrigated agriculture, and a barge transportation system that transships wheat from Montana and the Dakotas to markets across the Pacific.

The storage dams also drastically modified the Columbia River's hydrograph, shifting water forward from one summer into the following winter when power loads rise.

With construction of the Canadian storage facilities, Congress in 1964 authorized the sale of surplus power to the Pacific Southwest via high voltage transmission Intertie.

The linkage between the river, the power system and transmission was reinforced with Congressional passage of the Transmission Act of 1974.

Each installment of generating capability required and presupposed the transmission capacity to move power to customer loads. Without transmission capacity, the dams could not and would not have been built. This is an historical fact essential to reconciling the industrial Columbia River with the biological one.

II Utility Competition, Endangered Salmon and BPA

A. For half a century BPA-marketed power was the benchmark low cost electricity in the Pacific Northwest; and the region enjoyed the lowest power rates in the country. After 1980, three events combined to force BPA into a struggle to offer competitively-priced power, and even to survival

1. WPPSS

In the state of Washington, five nuclear plants were conceived in 1960's and brought under construction in the 1970's. Folding in the costs of three plants -- two unfinished shells and a completed, but hugely uneconomic, WPPSS II -- resulted in BPA's wholesale power rates rising some 600% in the early 1980's.

2. Endangered Salmon

The causes of the declines are many and complex, but two principally implicate the hydropower system.

The first is habitat. Dams and huge, warm slackwater reservoir pools have transformed the mainstem habitat of the fish. Critical needs for food, cool water, protection from predators, conservation of energy during migration, all have become far more difficult for the fish to obtain.

The second is institutional. BPA, the federal owners of most of the dams, and the utility owners of the rest, have historically operated river flows for flood control and power generation. Their objectives and authorities have been isolated from governance of the rest of the river's production and health. The hydropower system has locked in an operational status quo that is difficult to move or modify, and that is not integrated with either other uses of the river, or its conservation needs.

In 1991 and 1992 three populations of Snake River salmon were listed under the Endangered Species Act. While many parties shared recovery responsibilities, the largest portion has been carried by the federal hydropower system. Direct costs are in excess of $200 mm annually (from a budget of about $2.5 billion). BPA also counts as opportunity costs the flows that are diverted from its turbines to spill fish over dams, or that is moved from times optimum for power generation to times optimum for fish migration.

In 1996 a new scientific report altered the terms of regional engagement in salmon recovery. The Power Council's Independent Scientific Group (now the ISAB) issued its "Return to the River" paper (Williams et al, Return to the River. NPPC 1996). The paper carefully does not advocate particular measures, but projects the idea of the "normative" river: a river whose functions more closely approximate the undeveloped river, thereby more likely supporting the historical needs of indigenous species such as salmon. Given the massive modification of the normative river represented by hydropower development, the report has vast potential implications for BPA and the other river managers.

3. Competition Comes to the Electric Power Industry

A chain reaction of events that began with the first oil embargo in the early 1970's has led, among other outcomes, to far lower power industry entry barriers and far lower generating costs in the 1990's. Low-cost, modular gas-fired combustion turbines have driven the market cost of new electricity supplies down to two cents a kilowatt, less than half of the cost projected as recently as 1990. Some short-term deals have shaved another half-cent off the asking price. Non-traditional suppliers, brokers, futures traders, all have emerged to ride this fuel- and technology-led bow wave. They have combined with large industrial consumers of electricity to pry open the traditional closed, monopolized service territories of regulated utilities. Utilities are fighting back with whatever weapons they can lay their hands to: delay, mergers, stranded cost recovery rules.

BPA is more likely than most utilities to be left adrift by this industry restructuring. Historically its position had been impregnable. It had the lowest cost power. It controlled most of the transmission system (blocking BC hydro from the California market, for example). The only significant interconnection that might admit competition was the Southwest Intertie, the northern access to which it controlled.

Because of this position, BPA never needed the protection of a regulatory compact. It had an obligation to supply Northwest customers with wholesale power at cost. The customers had no obligation to buy from BPA, but neither had they the ability or the incentive to buy elsewhere. BPA could maintain fat staff and consultant payrolls, carry conservation and other public purpose costs, and provide an assortment of subsidies to customers. On behalf of its customers, it could take on obligations such as WPPSS and raise rates accordingly, protected by regional insularity and its price margin. The concern was never that BPA was too weak to enforce reciprocal obligations with its customers; but that it was so strong the customers needed leverage to control the agency, leverage they obtained through the region's Congressional delegation.

4. BPA In A Box

As the region approaches the expiration of the 20 year customer contracts signed in 1980, BPA finds itself exposed. It is vulnerable to competitors luring away its customers with offers designed to build market share at the agency's expense. WPPSS costs eat up 25%-30% of BPA'S annual budget, while selling the agency over-market-cost power from WPPSS II that must be resold at a loss. The WPPSS capital debt is not paid off until 2018.

Some of the customers for whom the WPPSS acquisitions were transacted have signaled they will move on to new suppliers at the earliest opportunity, cutting their costs but leaving BPA with stranded WPPSS costs to spread on fewer customers, thereby driving these remaining few away. While investor-owned utilities are succeeding in getting transition assistance from their regulators in the form of stranded cost charges that will follow customers who take their business elsewhere, BPA's options for such recovery are limited by its one-way deals with its customers.

If anything approaching a normative river is to be achieved, it will involve higher costs to BPA, and possibly loss of the output at one or more projects if reservoir drawdown proposals proceed.

Bonneville is in a box. It cannot hope to escape to easier times much this side of 2018, when the capital debt for the WPPSS plants is finally retired.

II The Governors' Comprehensive Review of the Northwest Energy System

A. In 1996 the Governors of Idaho, Montana, Oregon and Washington convened a panel of 15 persons representing utilities, customers, and public interest groups, to consider and recommend changes in the region's electric power system. It is significant that tribal representatives were conspicuously absent.

B. Defining the Problem

The group began by accepting the Governors' definition of the problem to be solved: a narrow definition that began with an outcome -- how to protect regional access to low-cost hydropower -- instead of the underlying problem -- how to redress problems of river overuse and fragmented management.

1. The "Industrial River" Definition

How do we redesign the "institutional structure of the region's electric utility industry" to conform to a coming competitive marketplace, take advantage of the market's efficiencies but protect parties from its rougher edges, at least for a transition period? Then, can we/should we continue to support the public purposes (conservation/renewable energy/fish and wildlife) that have historically been assigned to utilities? Finally, what does this mean, if anything, for the

river?

2. An Ecosystem Definition

Among the many roles and uses of the river, what are the priorities? Flood control? Commercial navigation? Irrigation? Power generation? Conservation of its biologic health? Are the rules and institutions we have in place likely to realize these priorities? If not, what changes should be made? How shall the modified river conservation-management system be made compatible with the most efficient and economical hydropower system, and with a competitive electric power industry? Is there a place for BPA in this redesign? Will BPA's operational role and financial condition allow it to take this place?

C. Agenda: Four Issues, One Omission

1. Consumer Access

How should the region's electric energy marketplace be opened to competition, giving customers access to a choice of suppliers? How should we deal with the equity issues raised by customers with, and without, market power? Who wins, who loses? Shall there be transition periods, cushions, new institutional protections for small consumers?

2. Transmission

What institutional arrangements can be designed for a transmission system that is independent of buyers and sellers, will assure the most efficient transactions, and maintain reliability standards? How does BPA's substantial control over regional transmission comport with this goal?

3. BPA Power Marketing

Is a government-owned and operated wholesale electric utility compatible with an open, competitive market? How can BPA rearrange its business, and its customer relationships, to generate sufficient revenue to fully meet its obligations, including WPPSS payments and fish recovery? Are some historical features of the regional system -- preference to publically-owned utilities; power at cost; subsidies; special arrangements with aluminum companies -- open to review and modification? Should historical customers reserve the right to leave BPA for

better near-term deals, then return when WPPSS costs are liquidated and BPA is competitive again? What cost exposure is borne by the US Treasury, as BPA's "shareholder?" Is there a stranded cost mechanism BPA can apply to departing customers, to assess them a "fair share" of the system costs BPA incurred -- especially WPPSS and fish recovery -- on their behalf?

4. Public Purposes

The region's historical support for energy conservation, renewable energy technology development, and consumer protection are at risk. What changes might mitigate this risk and still be compatible with a competitive market?

D. Missing from the Agenda

1. Columbia River Conservation and Governance

How should the river be managed and conserved; and for what objectives and purposes? How will river governance be affected by evolving power markets? By different conceptions of BPA's future role? How will BPA, and power markets, be affected by uncertainty over fish recovery costs and modifications of the hydropower system? Is an independent transmission system (including legal separation of BPA transmission from BPA power marketing) compatible with fish recovery?

IV. Accomplishments of the Comprehensive Review

A. Utility System Issues: Considerable progress on most issues, including an acceptable public purposes package (see the Comprehensive Review Final Report, NPPC 96-CR26, December 12, 1996).

1. Recommended legislatures provide open access for all customers by 1999, with consumer protections.

2. Recommended creation of an Independent Grid Operator to manage all traffic on the region's transmission grid, with responsibility for efficiency and reliability in dispatching power per bilateral supplier/customer agreements. Recommended BPA be "legally" separated, with transmission function performed independently of power marketing to avoid self-dealing or the appearance thereof.

3. Recommended that for ten years, 3% of the region's power sales revenues be applied to conservation, renewable energy projects, and low-income energy assistance. Distribution utilities would continue to have a central role in disbursing, and possibly collecting the funds. However, the Review left to the States and/or public utility boards the discretion to determine funding methods.

4. Recommended a "subscription" process for BPA to follow in marketing power. Traditional customers would exercise their preference to power-at-cost as now, but customers signing short (5 to 10 year) contracts would pay an option fee for the continuing right to power-at-cost. Interrupted service would come back only at market rates.

B. River Issues: Efforts by some participants forced river issues onto the table, but not to affirmative outcomes.

1. Governance

The Review concluded "that we cannot expect to achieve both the degree of cost stability the electric industry requires to maintain the benefits of the Columbia River power system . . . and achieve sustainable fish restoration unless we ensure predictability, accountability and effective governance for the fish and wildlife interests of the river." But many Review members did not want to bring river governance up in the Review, or make any recommendation.

2. Fish Settlement

Some fish advocates argued that they would resist regional power industry restructuring absent a comprehensive agreement, or settlement, of outstanding fish recovery issues: particularly, a decision to proceed to drawdown or dam breaching on the Snake River and at John Day Dam on the Lower Columbia. The proposition was never taken seriously in the Review, and the strategy of holding up regional restructuring has generally failed for want of political leverage.

V. Failures of the Comprehensive Review

A. Power System

The Review, having no authority except to make recommendations to the Governors who empaneled it, now must rely on state legislatures to implement many of the

regulatory and funding choices necessary to the power system redesign. Idaho and Washington have already determined not to act in their 1997 sessions. Montana and Oregon are open questions still.

Utilities and other customers are meeting to construct a subscription system, and to implement legal separation of BPA's transmission and power marketing functions. Both processes are compromised by the Review's failures to deal with fish costs (a) directly, and (b) through a stranded cost recovery mechanism as a tool for funding future costs (and aligning customer incentives).

B. Fish Recovery and Ecosystem Conservation

The larger failures of the Review have to do with leaving fish and river conservation issues ill-defined and undecided.

At the outset of the Review, the tribes were assured that only power system issues would be addressed, not fish. This was a preposterous fiction, given the region's reliance on hydropower and on the BPA transmission system. Nevertheless the Governors' offices maintained it and the tribes accepted it as convenient. The tribes have since realized that once again the needs of the power system and its customers have come first, the river second.

The fish representative was the sole dissenting vote, arguing the Review should have addressed:

1. Whether recommendations "improve the ability of the power system to meet its fish and wildlife obligations."

2. Whether other, neglected changes could improve that ability.

3. Whether recommendations "undermine the fish and wildlife obligations of the nation and the region (to the tribes, among others).

4. Whether the continued purchase of power "at cost" clearly includes the costs of fish and wildlife restoration.

5. Whether the benefits of the river will be shared fairly.

6. Whether "we can establish a system of power and river governance that will effectively change the operation of the power system in order to restore fish and

wildlife populations in the Basin."

7. Absence of "specific commitments to actions that will restore the biological health and productivity of the Columbia River."

These boil down to two critical issues: paying for fish recovery, and reforming river governance.

C. Paying for fish recovery

The Review did not propose any changes to existing regional/BPA budgets for fish recovery. These budgets do not contemplate any substantial reconfiguration of the hydropower system. Only limited changes are anticipated: continued reliance on barges to move ± 50% of fish downriver could be aided by new surface bypass facilities; gas saturation problems at spillways could be mitigated by flip-lip and other modifications. No significant changes in pool elevations, deep drawdowns or dam breaching are presently fundable.

A proposal to contemplate an additional $500 mm annually, contingent on Congressional appropriations, was considered but not included. In the end, the Review deferred fish funding issues. They are now under discussion in regional work groups implementing the subscription and transmission Review proposals.

There are four sources for increased fish funding: (1) Costcutting; (2) BPA power sales revenues; (3) BPA transmission services revenues; (4) stranded cost recovery by BPA (of WPPSS costs; of deferred fish costs); (5) deferring scheduled BPA payments of its debt to the US Treasury.

1. Costcutting

BPA has already reduced costs, especially personnel costs, substantially. The agency promises additional savings, trying to lower power rates to two cents per kilowatt hour by 2000. Can the agency come up with more savings still, to fund fish recovery? More likely are cuts in fish funding so BPA can reach its two cents goal.

BPA still supports subsidies to some users (e.g. irrigators; rural customers) that could be taken back, although this would be politically difficult and might require legislation.

2. Power Sales Revenues

To keep its historic utility customers, BPA cannot charge them more than market rates even if this means BPA revenues fall short of financial obligations. In turn, the utilities fear losing their customers -- especially their best, largest customers -- to predatory suppliers cream-skimming and seeking market share.

However, the market value of BPA power can be enhanced with incentives including resale rights, a BPA repurchase obligation, a customer option to reserve its power-at-cost rights for when WPPSS debt is gone, and offsetting power sales payments against any stranded cost obligation.

3. Transmission Revenues

BPA power sales and transmission revenues are collectively pledged to meet its full agency obligations. Many buyers and sellers in the new electricity marketplace want functions and revenues separated, to avoid cross-subsidies and self-dealing. Only transmission costs, they argue, should go into transmission rates. Fish costs are generation costs, and should stay on that side of the wall.

The power industry is especially concerned that BPA might use its position astride the region's transmission system to recovery stranded costs through a "wires" charge.

Fish advocates argue that transmission and generation are a single integrated system. Moreover, BPA statute requires the agency to apply its revenues to meet its full obligations, without regard to the origin of the revenues.

Practically, there are limits to how much added revenue BPA could pull from transmission before the market responded with bypass strategies.

4. Stranded Cost Recovery

There is no question BPA is hamstrung by costs -- for WPPSS; for fish -- that in the plain meaning of the term may be stranded in a competitive industry. However, these costs are not necessarily stranded as FERC has defined and narrowed the term. If BPA can meet its present obligations, including the costs of uneconomic nuclear plants averaged with low-cost hydroelectricity, it may not

meet the technical definition of a stranded costs.

But BPA's costs are WPPSS compounded with fish . . . and with potentially rising future fish costs. Can prospective (because they were deferred) costs be stranded? In California, PG&E is filing a proposal with the state PUC to recover just such prospective "transition costs."

There are other hurdles BPA and the region must surmount to devise a recovery mechanism that is sufficient but not open-ended, that is equitable, and that can be recovered by other means than a wires charge. Absent such a mechanism, BPA will have to set a wires charge at what the market will bear.

5. Deferring Treasury Payments

The last hand in BPA's pocket each year is Treasury, after WPPSS payments (first priority) and other capital and operating costs. BPA must repay debt incurred to build the dams and transmission system, conservation investments and other costs. Will Treasury accept slippage in repayments owed to it? Perhaps. Will it do so if BPA's customers are insisting on their right to power-at-cost when cost is below market, and their right to secede when it is above? Will it do so if customers are not subject to a plausible stranded cost recovery charge? When subsidies remain in place? When the region is not stepping up to its fish recovery costs? Maybe not.

D. Reforming River Governance

The Columbia, like other western rivers, suffers from a governance system that matches up poorly with ecosystem conservation needs, and does not efficiently manage cross-claims among economic users. Agencies, missions, jurisdictions, funding and most of all priorities are confused when they are not in outright conflict. Institutions for coordination and accountability are weak or flawed. Many observers have commented that there is no one in charge of salmon recovery; and anyone put in charge would be confounded by the contradictory authorities that fragment the basin.

The result is that a system which US District Judge Malcolm Marsh said "literally cries out for major overhaul" but is destined still for "small steps, minor improvements and adjustments . . . (and) minimum disruption" (See IDFG v. NMFS, US DIstrict Court for Oregon, Opinion issued March 28 1994).

Some utilities and other BPA customers participating in the Review acknowledged the linkage between unsettled fish recovery, ineffective river governance, and uncertainty over power costs for BPA customers. Most wanted to defer any discussion of fish costs or river governance. Deferral was equivalent to conforming the status quo, which for many economic users is preferable to a serious regional discussion of revising river priorities and the institutions to ensure their observance.

VI. Conclusion

The states of the Columbia Basin, and the economic users of the river, have defined their problem narrowly, and crafted a narrow solution to it. The problem, in the words of the Pacific Northwest House delegation, is how to "retain the benefits of the Columbia River basin's hydroelectric system for the region," while satisfying "the region's obligations to the United States Treasury" (See Letter of March 17, 1997, signed by seventeen Pacific Northwest House Members).

But narrow solutions will be durable ones only if the region is hardened to the loss of Columbia River salmon and steelhead, and to the declining biological health of the river. There are contradictions between those ecosystem values and functions, and the way the river is operated today for power and other economic uses.

As things now stand, BPA is unlikely to have a subscription process successful enough to generate revenues sufficient to pay fish costs. If such costs are forced by legal action -- Treaty rights litigation, for example -- the region is more likely than not to default on its Treasury debt. When that happens, when the region shows up on Treasury's doorstep, the rest of Congress and the country will not be sympathetic. There will be calls to sell off the dams, and to privatize the system under FERC licenses (which will do irreparable harm to any prospects for ecosystem conservation). If Treasury is to pay the bills, Treasury will capture the benefits whenever they materialize. The hydroelectric system will be lost to the region, because the region was unwilling to shoulder the responsibilities and pay the bills that go with it. And the river will be no better off for the abandonment of regional responsibility.

Yet the region persists in addressing hydropower system concerns as though they can be divorced from ecological ones. A revealing moment came toward the close of the Review, during intense debate over whether a stranded cost recovery mechanism should be recommended. Several alternatives were considered, and analyzed for impacts on users. The bar charts showed effects on large BPA customers and small; on customers who kept their loads with BPA, on customers who departed, and on the US Treasury. There was no bar on the charts to reflect the benefits to the region of recovered fish populations and a

biologically healthy river.

Proposals that included paying for significant changes in dams and hydropower operations to benefit fish were, unsurprisingly, the most costly. They involved missed payments to Treasury or stranded cost recoveries from customers, or both. The Review Chairman dismissed all these efforts with the sweeping statement that no proposal would survive that could not show positive benefits to all parties . . . by which he meant customers, utilities, and the Treasury. Positive benefits for the fish and the river were not the concern of this Review.

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A Discussion of Proposals for Restructuring the Pacific Northwest Power System

A Paper Prepared for General Distribution

by the

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Table of Contents

A Discussion of Proposals for Restructuring the Pacific Northwest Power System

Executive Summary

The ways we have managed the Columbia River and allocated its benefits over the last half century, for power generation and multiple other uses, stand to be radically transformed in the next several years.

Over the last year many regional voices have urged a comprehensive review of river and power system issues. The region's Congressional delegation and Governors have responded by establishing two parallel processes: a reconsideration of Columbia Basin governance structures under the aegis of the Power Planning Council; and a Governors' Comprehensive Review of the Northwest Energy System.

This paper consists of a model for the region's power system that begins with the same "givens" employed in the Review, but recasts and reprioritizes the goals. It then infers from these goals the industry structure that could be expected to deliver them. While political considerations may delay or deflect optimal solutions, that is all the more reason for understanding clearly what is optimal, and foregone.

Goals (in rough priority sequence)

1. Maintain the maximum long-term public benefit from the Columbia River as an environmental and economic public resource.

2. Achieve long-term energy sustainability.

3. Retain the benefits of the region's existing low cost resources for the region.

4. Assure affordable access to electricity for consumers with the least market power.

5. Substitute efficiently functioning competitive markets for regulated power industry activity wherever possible.

6. Assure adequacy of supply and reliability of operation.

7. Assure fairness.

8. Provide accountability.

Outcomes

1. The Federal hydropower generating system -- facilities ownership, and power marketing function -- should remain in public ownership. This is necessary to arrest and reverse the historical fragmenting of authority over the river's multiple uses; and to provide for conservation of its biological health as the primary management objective. Hydropower operations should be more closely integrated into river management, not further dispersed and not apportioned to users who do not share public stewardship responsibilities. The Regional Review and Basin Governance processes should be reconstituted as a single enquiry at the earliest possible juncture.

2. The value of the region's investment in the Federal power system should be reserved to the region and to the public interest. Actions taken to optimize this value should be consistent with river conservation. Existing subsidies and transfer payments should be phased out unless they are rejustified in terms of contemporary public policy objectives.

3. BPA's power marketing role needs to be redesigned to limit its influence in competitive power markets, while assuring that its products bring market-driven returns to the region.

4. BPA transmission assets should be detached from the agency's power marketing and other functions, and joined with all other available regional transmission facilities in an independently-operated ISO or TRANSCO. However, BPA and the region should receive and reserve for public use the full value of the region's equity investment in these assets.

5. BPA net revenues, if any, should be available to leverage longer investment horizons for energy efficiency and renewable resources.

6. There should be state-by-state policies applicable to all energy suppliers that assure a minimum level of affordable service accessible to all individual consumers.

7. Governance of Columbia River operations, including shared ownership of Federal hydroelectric system assets, watershed restoration and maintenance (and oversight of relevant Federal management and oversight agencies), and long-term power planning, should be the responsibility of a reorganized Northwest Power Planning Council that includes Federal, State and Tribal representation. The Federal Government should agree that any BPA net revenues generated are available for use within the region only.

A Discussion of Proposals for Restructuring the Pacific Northwest Power System

Introduction

The ways we have managed the Columbia River and allocated its benefits over the last half century, for power generation and multiple other uses, stand to be radically transformed in the next several years.

The Bonneville Power Administration has been with us in essentially its present form since 1939; it is already undergoing dramatic reshaping, and might not last out the decade. Public power and private utilities have skirmished over turf for years but with little real interest in upsetting 60 years of comfortable status quo. Both are seeing familiar ways of doing business upended.

It is less clear that the historic roles of the Corps of Engineers and the Bureau of Reclamation in the Pacific Northwest will be re-examined, but they should be.

Over the last year many regional voices have urged a comprehensive review of river and power system issues. The region's Congressional delegation and Governors have responded by establishing two parallel processes: a reconsideration of Columbia Basin governance structures under the aegis of the Power Planning Council; and a Governors' Comprehensive Review of the Northwest Energy System (the"Review").[1]

The Review commenced in January, 1996, with a notable and talented membership and an important but still loosely-defined agenda. After two months of labor the agenda has achieved greater clarity. More important, the substantive

[1] Among other issues, this paper will address the wisdom, and potential consequences, of separating these two enquiries.

approach adopted by the Review has begun to suggest -- and arguably influence -- its outcome. Now, before either this approach or its consequences have been set in hardened concrete, alternative ways of stating issues and approaching conclusions beg to be considered. Such alternatives may at the least illuminate the debate, forcing assumptions to be questioned before they are embedded.

This paper is intended to provide members of the Comprehensive Review of the Northwest Energy System, and other interested parties, with such an alternative view.

The Comprehensive Review Approach

The Review's approach, developed by its consultants, is a series of logical steps that proceed from the general to the specific and form a "template" for use by members in considering possible industry forms and structures. Here is that approach, summarized:

1. "Identify the '***givens***'; factors . . . beyond the control of the region;" (and therefore to be taken as assumptions).

2. "Identify the ***goals . . .***(for the) future power system."

3. "Identify . . . ***structural changes*** required by the givens and goals."

4. "Identify the desired ***structure*** . . . . Determine the degree to which and how ***public purposes*** might be maintained and identify the role, if any, of ***regional oversight and planning*** within that structure."

The Review chair made clear that this approach and the templates were to provoke thought and discussion, that it was not the only approach and was not to be taken as preemptive.

It is certainly plausible to reason from the general to the specific. However, the consultants selected, and the Review so far has concurred in, general factors that are largely power system attributes -- efficiency, reliability, low costs to customers, consistency with competitive market models. Other features -- public purposes, and regional oversight and planning, will then be fit ". . . within that structure." Presumably

either there is then a fit, or public purposes are modified to achieve one, or the structure is modified to accommodate the purposes deemed essential.

The approach invites the question whether the *order* in which factors are considered may influence or predetermine outcomes. How difficult might it be for public purposes to subsequently modify an agreed-to industry structure that meets desired power system criteria and has become a kind of new status quo for discussion purposes? Could one hypothesize a materially different outcome from the same set of factors if one *began* with public purposes, and designed around them the most efficient, etc. possible power system? Same ingredients, different mixing sequence.

Arguably this second approach was the one employed by our predecessors in the 1930's. Had they set about designing the most efficient and carefully calibrated power system then, it is unlikely they would have built Bonneville and Grand Coulee, or supported formation of a network of public utilities. But the objectives of public policy in the 1930's were jobs, rural electrification, irrigation water for family farms, public power as a check on private utilities. Public interest/public policy goals were asserted, and the power system architecture was developed around those goals.

The rest of this paper consists of an alternative model that accepts the "givens" from the Review template, but recasts and reprioritizes the goals. It then infers from these goals an industry structure that can reasonably be expected to deliver them. The structure will resemble in many ways concepts the Review is actively considering, but will depart in significant respects. The discussion is conceptual, and acknowledges that many details will need to be added, some of which may modify the design in significant ways. Our hope is that to the extent it provides contrasting features and tradeoffs, it may expand the range of the region's choices beyond what the Review presently is contemplating.

Givens

This paper largely accepts the "givens" provided by the template (Attachment A).

We anticipate, however, that the distinction between wholesale and "large

retail" customers of utilities is increasingly technical rather than real; and that demands for "increased access to the power market" combined with technology advances (e.g., fuel cells) will move customer choice of suppliers down the scale of customer size more rapidly than anticipated. The relative market power of customers will increasingly be a public issue, as those least able to afford higher costs see higher prices, reflecting not only the reality of costs of service but also market flaws (e.g. access to market information) that penalize such customers unfairly.

Goals

We propose to modify, and to rearrange the order of goals provided in the template (Attachment B), and stipulate a rough hierarchy (although the objective remains to accommodate all goals to the fullest extent possible). These should be thought of as public policy goals, which are distinct from private industry goals, although the two may and often will coincide.

1. Maintain the maximum long-term public benefit from the Columbia River as an environmental and economic public resource. Conservation of the river's health -- developing and respecting science-driven standards of hydrological and biological health -- should be established as the highest and best use of the river and as the primary management objective, with other uses accommodated equitably thereafter. Seek collaborative mechanisms for balancing local, regional, national and Canadian interests in the river.

2. Achieve long-term energy sustainability through a resource investment portfolio strategy. Such a strategy would give greater weight to long-term desired outcomes and risks than is likely to come from suppliers being driven largely or solely by near-term competitive market pressures. It would include a regional Research, Demonstration and Commercialization (RD&C) element. "Sustainability" is distinct from regional self-sufficiency in that it does not exclude imported supplies but discriminates as to sources. Equally it assumes an intermediate term mix of sustainable and depletable resources.

3. Retain the benefits of the region's existing low cost resources for the region.

4. Assure affordable access to electricity for consumers with the least market power.

5. Substitute efficiently functioning competitive markets for regulated power industry activity wherever possible, consistent with other goals. Achieve lower

power costs through improved efficiency of planning, development and operations. Assure the maximum ability for consumers to choose among power products, services and terms they desire.

6. Assure adequacy of supply and reliability of operation to the extent that the competitive market may fail to do so.

7. Assure fairness -- no one group benefits excessively at the expense of others.

8. Provide accountability for the legitimate costs of the power system and other river users. Users pay for their own uses of the river.

Outcomes

We will not attempt to cover all issues under discussion in the Regional Review. Some outcomes from this amended approach will be familiar to Review members, as they parallel panel discussions to date. We will begin, however, with those that are different in significant ways.

1. The Federal hydropower generating system -- facilities ownership, and power marketing function -- should remain in public ownership.

The rationale underlying this conclusion is simple and historical. Conflicts exist between different operational uses of the river, and the greatest conflicts are between power generation and sustenance of fish and other aquatic life. The shifting of the natural hydrograph from spring and summer forward into winter use for generation, combined with food-web impacts of transforming a free-flowing river into a series of slackwater pools, have altered biological systems profoundly[2]. The pressure to generate more power combined with the value to the power system of flexibility to meet demand and follow load, almost always operate adverse to the workings of the evolved ecosystem.

[2] The recent report of the Independent Scientific Group to the Power Council suggests that the key to restoring salmonid populations likely lies in restoring their environment -- headwaters, mainstem and estuary -- to conditions more closely resembling those to which the species evolved over several thousands of years. The additional costs of responding to this counsel are liable to be significantly in excess of current regional commitments.

The Bonneville Power Administration (BPA), the Bureau of Reclamation (BuRec) and the Corps of Engineers (COE) are three federal agencies among the many government entities charged with managing elements of the river's flow. Each has its own constituencies that pressure it to maximize the benefits it extracts from the river. At the same time, all three agencies are accountable to the Federal government (and to a much lesser extent, to the four Northwest states and to Native American tribal governments). As such, they must balance the public interest against the often conflicting counterclaims of their private interest constituencies.

What's most needed on the river is greater unification of purpose in river operations (associated with the often-heard demand that "someone should be in charge of salmon recovery"), and greater accountability of management actions to that purpose.

What's not needed is further fragmentation of authority. Particularly not needed is shifting hydropower generation -- or the marketing of that power -- to a private entity that has the principal goal of maximizing power revenues and no public body stewardship obligations, thereby escalating the conflict between water for power and water for biological sustainability.

This conclusion argues for preserving BPA or establishing a successor agency charged, as was BPA originally, with the marketing of federal hydropower, subject not just to a Power Council Fish and Wildlife Program but to a governance structure that can effectively balance off private economic uses of the river with the primary management objective of biological sustainability. The new BPA may, however, be far smaller than its present incarnation, and more passive as a marketplace participant (see #2 below).

Conflicts over river operations should be resolved within a single governance structure (such as a successor to the Northwest Power Planning Council) and executed within a single public agency. National and regional interests both need to be adequately represented in such policymaking; hence composition of the governance body must include federal, state, and tribal representation. It must act

consistent with legislated standards that assure conservation of the river's biology, then allocation to other uses.

The alternative has been proposed of shifting ownership of assets (facilities and/or marketing rights) to a private company or customer cooperative, and relying on superimposing regulatory constraints on its operations to protect the river. This is essentially the structure the region relies on today: weak enforcement tools to bring agencies into "consistency" with Power Council Fish and Wildlife Program.

A regulatory approach is not without merit if regulations can be modified periodically, to reflect new science or other circumstances, and if effective enforcement is provided for. But removing or minimizing the source of conflict is preferable to indefinite mediation between competing interests and authorities. Otherwise the parties that purchase power marketing rights will, quite rationally, seek maximum predictability from the river operators, while preserving to themselves maximum flexibility to respond to market conditions. One uncertainty is preferable to two. Any financing sources for such a private "BPA" will seek to fix fish operations costs or shift the risk elsewhere. Once the risk allocation was fixed, the private power marketers would have every incentive to induce hydroproject operators to maximize output.

Certainly a public agency with power marketing responsibilities will be impelled by the same calculation, as BPA showed last year by seeking a Congressional "cap" on its fish cost exposure. BPA in fact secured some *relief*, but the obligation remains with BPA (and the Treasury) that higher flows or other measures for fish survival could be called for and would have to be balanced against reserving the same water for power generation. BPA must manage both market risks and river conservation risks. So it should.

The wisdom of a separate regional process for exploring basin governance issues has to be questioned at this point. If the Regional Review decides to shift hydropower system assets into private hands, governance options are materially narrowed. If the governance deliberations insist nonetheless on public control and ownership, the industry structure devised by the Regional Review might have to be

dismantled and reconstructed to accommodate this. **The Regional Review and Basin Governance processes should be reconstituted as a single enquiry at the earliest possible juncture.**

Preservation of BPA in some modified form capable of marketing federal base system power (at least) will have consequences with respect to power industry designs and operations. These are discussed below.

2. The value of the public investment in the Federal power system should be guarded, enhanced and reserved to the region and to the public interest.

This proposition invites the question whether there is residual economic value in the system. Yet any number of analyses demonstrate that the underlying hydropower base is still very low cost and well able to compete in any foreseeable market conditions. Load following and other power quality services are likewise highly marketable. The region's equity interest in the transmission system has value, for which the region and federal government should insist on compensation in any transfer or alternate operating model.

There is general agreement that the federal hydropower system, exclusive of WPPSS and its debt, is a source of highly competitive power[3].

We are two decades away from liquidating WPPSS debt, at which time no other generating resource on the horizon will be able to undersell the hydropower system's output. A BPA free to meet the market and sell at market-driven prices is potentially a net revenue producer (after meeting its costs, including Treasury payments). Those net revenues can be preserved for regional public purposes, or they can be shifted to customers in the form of dividends or lower rates, or they can be captured by the federal government for other discretionary purposes. All parties should be interested

[3] Removing WPPSS debt from BPA's annual revenue requirement would likely result in power costs below 2¢/KwH. Annual costs to amortize the debt from WPPSS 1, 2 and 3 are between $500mm and $600mm through 2012, ramping down thereafter through 2018. This amount is between 25% and 30% of BPA's annual revenue requirement. The benefits of liquidating this capital debt will be partially offset by accumulations for decommissioning expenses.

in maximizing BPA's value so long as higher priority values are not adversely affected thereby.

Any proposal to privatize or otherwise dispose of such a valuable public asset must carry a substantial burden of proof. It must establish that the public is receiving the full value (including allocation of system risks) of the foregone revenue stream in exchange, and that other public values are not compromised in unacceptable ways (e.g., biological effects from river operations commitments included in a transaction). It must not succeed by leaving liabilities and costs with the Federal government while conveying income-generating assets at a discounted price to private parties (or parties with narrowly defined purposes, such as publicly-owned utilities).

For example, it has been suggested that the dams themselves carry fish recovery liabilities that make them difficult to sell, but there might well be buyers for a power marketing authority that was severed from these liabilities. Alternately, a deeply discounted front-end price for the federal assets could serve the same purpose: to leave fish recovery risks, or the cost of carrying those risks, with the government while moving the revenue-producing assets into private ownership.

Either such arrangement might well be attractive to private buyers and lenders. Either would provide the means for accelerated Treasury repayment, and would be a major step toward a largely privatized and competitive power market. But these gains would come at a price. Aside from the consequences for river management, the transaction would transfer a stream of potential future net revenues from public into private hands. Capital for future public investment in goals such as energy efficiency and renewable resource technologies would flow instead to the separate owners.

Arguably such a transaction could be justified economically if the government and region are receiving full economic value in exchange for the assets. However, most speculation involves transactions in which, for example, the system is acquired at a price that meets lenders' debt service coverage ratios (e.g., at a discounted price that assures debt will be serviced under conservative conditions of reduced output or revenues, while securing upside potential to buyers). Alternately, fish restoration

liabilities beyond a capped level are left to the Federal Treasury.

Even in the unlikely event of a transaction that resulted in the government receiving full value for hydropower system assets, the consequences for river management and protection of the river's biological integrity (discussed above) are sufficiently discouraging by themselves.

Whether the hypothetical net revenues ever develop, and how soon, depends on many factors, not the least of which is what additional burdens would remain with the hydropower system. Of these, the costs of mitigation of impacts on fish and wildlife are as intrinsic to hydropower operations as exhaust emissions are to fossil fuel plants, and should under no circumstances be detached.

Another factor of significance is the potential for the hydropower system to be displaced by new electrical technologies (e.g., fuel cells) that would render the old system uneconomic. Keeping the existing system in public hands is not without risk. However, there are no such technology trajectories threatening at present.

How such net revenues might be managed and distributed is discussed below (under "Governance").

The list of other costs, transfer payments, or risks is long and frequently controversial. WPPSS debt (and current above-market operating expense margins), irrigation and low-density discounts, residential exchange, regional and public preference, rural delivery subsidies, all contribute to pushing BPA base hydropower costs upward. BPA regional investments in conservation and renewable technologies that may be cost-effective long-term still shift costs back into today's short-term competitive markets.

In addition to BPA's ongoing internal cost-reduction actions, the agency and the region need to act to eliminate or, if appropriate, shift much of this cost overburden back to current beneficiaries.

WPPSS: All or some part of WPPSS nuclear plant debt might be assigned to the utility customers that participated in the net-billing arrangements for the plant; or it might be treated as a legitimate stranded investment and defrayed through a uniform wires charge (as has been proposed elsewhere). BPA has vacated any residual WPPSS obligations for its Direct Service Industrial (DSI) customers who execute new contracts; most have. It proposes similar immunity for its utility customers who sign new contracts. If these exemptions stand, spreading any WPPSS debt adjudged "stranded" becomes more difficult because it will have to be charged to fewer customers, particularly to residential and small business users with less market power and fewer market choices.

BPA and the region should consider whether a preference customer that declines to carry its proportionate share of this debt (by refusing to pay a stranded investment wires charge, or by reducing its load placed on BPA) whould not thereby forego its future rights to preference status and the access to post-WPPSS power costs that may obtain in the future.

Immediately, BPA and the region should revisit whether WNP2 is ever likely to produce competitive power, especially in light of the winter reliability exposure of 1100 MW of capacity in one resource. Despite recent performance improvements, the operating cost of power generated remains above market (capital debt costs are already sunk and must be liquidated independent of a termination decision). A managed shutdown would impose significant front-end costs on a BPA struggling to be competitive in the near-term, but could improve the agency's competitiveness thereafter. Recent BPA-sponsored analysis indicates these cost offsets approximately cancel each other out, suggesting that the case for termination has grown stronger.

Subsidies and Transfer Payments: Subsidies should be subject to "sunset" and rampdown except as, under reexamination, they are warranted for contemporary public policy reasons. These include power sales discounts, residential exchange costs, and continuing obligations to retire debt incurred for irrigation facilities (which should be carried by the beneficiaries).

Public Preference: The logic underlying public preference is not compelling today as it was fifty years ago. Public utilities in any event will be under considerable marketplace pressure to achieve efficiencies by any means including merger with other public bodies, or with private ones. Already that pressure has prompted the rational response of seeking other suppliers than BPA, although BPA is still held to its obligation to meet these customers' requirements at cost.

Proposals to modify or eliminate public preference will be controversial. It may be that no significant legislative changes are possible without compromising the push to market competition by preserving this institution in modified form. However, BPA must at least have reciprocity with its customers. An obligation to sell must be met with a commensurate commitment to buy. If customers can seek a market clearing price for purchases outside BPA, then BPA should be allowed the reciprocal right to sell at market rather than at cost. Preference customers that commit to BPA as their supplier in the near and intermediate terms might thereby secure their future preference status. In a competitive marketplace, however, preference should entitle purchases at a discount that reflects the value to BPA and the region of such reliable commitments, not the right to purchase at cost.

Rural Delivery Subsidies ("postage stamp" transmission rates): This is an issue for a TRANSCO successor to BPA (or for a "BTA"), not for a BPA engaged in power marketing. The applicable general principle for a privately-owned TRANSCO is that transmission pricing is a function of cost plus a reasonable rate of return, and therefore the price to any customer should not be less than the cost to provide service to that customer. The exception to this principle should be that a minimum level of electrical service should be available at an affordable cost to any residential consumer, on a "lifeline" rate if necessary. Such an exception may supplant a low density subsidy with another directed to low income consumers, irrespective of whether the customer is rural or urban, and whether the supplier is the Federal system or another supplier.

It is entirely possible that the effects of reconnecting transmission rates to cost-of-service will have uneven effects in rural areas. Rates may drop in areas near generation resources and rise elsewhere. Public policies to moderate and ramp in effects need to be developed.

3. BPA's power marketing role needs to be redesigned to limit its influence in competitive power markets.

All other things being equal, there is little rationale for a federally-owned power supplier competing in unregulated wholesale power markets. Neither BPA nor any other party in the region can untangle the web of special advantages (e.g., Treasury borrowing) and disadvantages (e.g., preference obligations). The obstacles to a "level playing field" are daunting at least.

But all other things were not equal in the 1930's when BPA was designed, and they are not today. The rationale for preserving BPA (albeit in modified form) is outlined above.

The Regional Review is considering different models for power sales transactions, including a central pooling arrangement, bilateral contracts, or a variation on these forms. If BPA remains a power marketing function, the bilateral approach is most likely to raise objections to the agency using market power -- for example, packaging ancillary services with bulk power supplies -- to acquire undue competitive advantages.

A pooling approach, whatever its perceived disadvantages to other suppliers, could be designed such that BPA "delivers" its power for sale to the pool, then takes the price derived by the pool in its subsequent sales transactions. While BPA still influences the market and price (by virtue of the size of its deliveries), it is not competing head-to-head for customers with other regional suppliers. The pool would have to be designed to assure that a large supplier such as BPA could not influence pool operations by timing its deliveries or otherwise distorting pool workings.

Alternately, BPA could be positioned to auction its available supplies and services in a format that allows distribution utilities, customer coops, direct purchasers and others to bid, with no restrictions on resale. This assumes distinctions between

wholesale and retail markets continue to blur. Under an auction approach, BPA would have to package most of its products in standard shapes and sizes that could then be repackaged by the market to meet the requirements of distribution utilities and large end users. Product terms and duration of sales would be established by the market into which BPA sells. The unbundling already underway at BPA leads in exactly the right direction. Short-term products could still be sold on spot markets as they are now.

An auction approach assumes also that the universe of available buyers of BPA power expands -- through open access, development of futures markets, etc. -- such that customers are less able to wait BPA out and force it to sell or spill.

The US Forest Service already uses this approach to sell merchantable timber from National Forest lands. The Service has proven over the years that an auction approach can be carried out efficiently or inefficiently, taking into account environmental effects or indifferent to them. The technique itself is neutral and accessible.

In both pool and auction approaches, BPA would become a price taker with a market role that is passive, although not without influence. This role assumes that through a combination of cost of service reductions, eliminating or reducing transfer payments and liabilities, and recapture of stranded investment if necessary, BPA can occupy this role. The assumption will be greeted with considerable skepticism, yet we believe further analysis will be able to describe the actions that make this approach feasible. We suggest several in this paper.

In a reduced supply role, there is no need for BPA to have either obligation or authority to acquire new resources to meet load (although an exception might be made to acquire resources that allow existing resources to be reshaped into higher-value products). BPA would have no obligation to meet any customer's requirements, which will instead be met through the actions of the power marketplace. Smaller publicly-owned utilities, most of which want the freedom today to buy elsewhere if BPA costs are not competitive, will be subject to the full discipline of the

market that comes along with its benefits. Such small customers can consolidate, or form purchasing cooperatives, or take other actions to increase their market power as necessary.

Preference customers that wish to retain their commitments of BPA power supplies (perhaps at a discount to a market-set price) could do so on a take-or-pay basis that is fully reciprocal (BPA gets an assured load, customers an assured supply, and both have greater price predictability than the market would offer).

Implicit in this new BPA role is the right for the agency to realize revenues from market-priced products, a departure from cost-based BPA pricing and ratemaking. The ability to realize net revenues from competitive products is essential to subsequent proposals to employ such net revenues, if any, to realize certain regional public purposes.

A market-passive BPA is also a much smaller BPA. Power marketing and rate case staffs would have far diminished roles. Energy services product lines would not be pursued. Other functions not essential to moving power to market should also be accessible to downsizing (see Transmission, below).

4. BPA should divest itself of its transmission assets, which should be joined with all other available regional transmission facilities in an independently-operated TRANSCO. However, BPA and the region should receive and retain full value of the region's equity investment in these assets.

There is no substantial public policy rationale for a Federal agency acting as a (or "the") regional transmission entity. There is no river to protect. Private ownership and operation of transmission facilities is the rule rather than the exception nationwide, and always has been. BPA was a convenient tool for financing the large regional investment in these facilities, and it was the only utility with sufficiently regional scope to operate the system.

But BPA's financing advantage no longer obtains, and in fact its transmission borrowing authority from the Federal Treasury is limited and unlikely to grow. A region-wide, privately-owned, FERC-regulated transmission company is easily conceivable. Such an entity would have the assets (including a captive market) against which to raise additional capital as needed for system growth and efficiency improvements.

Open access and the operational independence of a regional TRANSCO (or IGO) from its generating and consuming customers are critical features. Neither is very controversial anymore, although the task remains to shape these for optimum efficiency and for neutrality among the parties with interests at stake.

More important to the approach taken by this paper are the terms of the transaction under which BPA (and other owners) commit, and possibly convey, their transmission assets. Some of these assets have been substantially amortized; others may have limited equity and a large residual debt. Some are efficient and have low operating costs; others may impose large line losses, have higher operating costs, or be in line for substantial and costly maintenance. A transaction in which all assets were assigned the same value would be inequitable.

Instead, the different systems should be valued by an independent agent against common, agreed-to economic and technical standards. Shares in the TRANSCO should be awarded based on the values ascertained. Services from the TRANSCO would be priced on a cost-of-service plus reasonable rate of return, regulated by FERC. Dividends would be declared to distribute the return, in proportion to the shares (e.g., value contributed into the TRANSCO).

In this way BPA and other contributors with significant amounts of equity investment in transmission assets may be able to realize on some part or all of that value without compromising the independence of the TRANSCO. BPA obligations to the Treasury continue unaffected, secured by BPA's ownership share in the TRANSCO. The ability of BPA to generate net revenues for the benefit of the region is

commensurately improved (although to what degree depends on how FERC treats the assembled TRANSCO assets).

Valuations of transmission assets should occurr even if the assignment to the IGO is of operating responsibility but not ownership.

Nothing in this approach presumes that transmission assets transferred from BPA to a new entity are beyond reach of a stranded investment charge if this becomes necessary to address WPPSS debt. Federal generation and transmission facilities were developed as a system, not as stand-alone components, and as assets should continue to be so regarded during transition to open markets.

5. BPA net revenues, if any, should be available to leverage longer investment horizons for regional developers/suppliers of energy efficiency and renewable resources.

Conservation and renewable resource investments will operate at a disadvantage in short-term competitive energy markets. They are capital intensive and frequently have longer payback periods, creating stranded-investment risks (of default; of customers switching suppliers; of supercession by new technologies) unattractive to investors and lenders alike. Allocation of benefits and recovery of costs and returns are often complicated by diverse ownership and financing arrangements. Utility investments in these resources put upward pressure on near-term rates. Customer investment strategies face high discount rates for individuals and competition for scarce investment capital among businesses.

These are all real market factors that legitimately influence investment choices, and that must be either accepted or offset by market intervention. For the last 15 years, the region has relied on public policy determinations of what regional conservation investment level is cost-effective; and has used utility regulatory powers to induce conservation acquisition at that level. The spread between average power costs (low)

and marginal costs of new resources (high) permitted significant conservation investment levels, to the lasting benefit of the region.

Elements of that strategy remain valid (e.g., codes; design intervention), but as a whole it will have to be reconstructed to be consistent with changes in the power industry, and in cost/risk calculations. Both economic and environmental rationales for conservation acquisition need attention.

Substantial amounts of cost-effective conservation remain in the region, and are augmented as efficiency technologies advance. The Power Council staff draft 1996 Power Plan identifies 1575 aMW of regional conservation that is cost-effective on a 20-year investment horizon. At the same time the staff and most other observers acknowledge that only a fraction of this is likely to be acquired through utility programs.

Renewable energy suppliers relied initially on public policies (e.g., PURPA) to drive down unit costs of technologies and to open utility markets. The objective was stand-alone cost-effective renewables, an objective that has been frustrated by declines in market prices for power from conventional (gas) technologies that have undercut the cost reductions achieved by renewables developers.

New regional acquisitions of renewable resource projects are stopped cold. Projects already on utility books are being downsized, their costs reduced and spread, their prospects clouded.

This paper has assumed a public policy goal of "long-term energy sustainability through a near-term resource investment portfolio strategy". Such a strategy would accept longer payback periods and higher levels of technological risk in return for resource diversity, technological gains, operating experience, and the environmental and other attributes of renewable technologies and efficiency improvements. Such a strategy requires investment dollars and investment vehicles. Where are they to be found?

One option under discussion involves a non-bypassable "wires charge",

wherein all consumers remit a small sum tied to their energy use (or capacity; or simply a connection charge). The approach is promising despite numerous issues of administration, fuels coverage, investment (or grant) criteria, and so on which this paper will not address. The largest hurdle will be persuading the legislatures of the four states that such an assessment, in amounts sufficient to undertake a meaningful investment program, is politically attractive. Absent some external incentive or leverage, the political prospects are not encouraging.

Such leverage might be provided from the net revenues of a restructured BPA. A regional/Federal governing board (see Ownership and Governance, below) could allocate funding to a state in proportion to that state's commitment to raising and applying wires charge (or other) revenues to a conservation/renewables investment strategy consistent with regional standards. While available BPA funding might be limited initially and vary from year to year, its leveraging effect over time could be substantial.

Absent another identifiable source of funds for such leveraging investments, the region's near-term future is unlikely to contain any new renewable initiatives. Significant amounts (20% to 30% of the projected cost-effective total, per NPPC staff)) of near-term conservation resource may be acquired from market forces and residual utility actions. For the remaining 70% to 80%, few tools or incentives are easily identifiable if there is not a public policy commitment, backed up by funding, to mitigate the risks and longer investment horizons of these resources.

6. There should be state-by-state policies applicable to all energy suppliers that assure a minimum level of affordable service accessible to all individual consumers.

Low-income residential and rural customers may be shocked to discover how unforgiving a competitive electric power market can be after the insulated comfort of regulated monopoly markets. While many, perhaps most customers will benefit from lower rates and improved customer choice, those with the least market power may find

costs shifted dramatically in their direction. Some of this will be justified on a strict cost-to-serve basis; some part will be traceable to different capabilities among customers to make the market work efficiently for them. "Redlining" of services to certain neighborhoods and communities could occur.

Offsetting these effects could be aggregation services that emerge to intermediate between pools of small consumers and the market. "Distribution utilities" will likely evolve to the same market.

The issue is whether public policies ought to act to redress differences in market power, and to assure that a minimum level of affordable service is available to all; possibly some variation on lifeline rates and service; or authorizing, even sponsoring, consumer aggregation services. Such policies should be indifferent to a rural or urban address (rates that reflect cost-of-service in rural areas are already standard *distribution* utility policy in any event).

States adopting such policies should apply the obligations (or collect levies for redistribution) equitably from all energy suppliers. If assessments are imposed at the wholesale level, BPA should be treated as any wholesale supplier.

7. Governance of Columbia River operations, including shared ownership of Federal hydroelectric system assets, watershed restoration and maintenance (and oversight of relevant Federal management and oversight agencies), and long-term power planning, should be the responsibility of a reorganized Northwest Power Planning Council that includes Federal, State and Tribal representation. The Federal Government should agree that any BPA net revenues generated are available for use within the region only.

To whom does the Columbia River belong? Who is responsible for its maintenance? Who benefits from the wealth it generates? The answers to these questions are fundamental to determining governance architecture and authorities.

This paper argues that the river belongs not only to those who live in the lands it drains, but to the nation also, and to succeeding generations of Northwesterners, citizens of the United States, and of Canada. Those who live in the Columbia Basin -- tribal and non-tribal peoples -- should expect special deference from the two national governments, and the right to keep within the region the wealth produced by our investments (through Treasury repayment) in the river. In return our fellow citizens outside the Basin, and generations to come, are entitled to demand good stewardship practices and an accounting of our actions to conserve its integrity while we make use of its bounty.

This answer contains the basis for a different ownership and governance structure than the fragmented form which evolved over 150 years of Euro-American development. The full subject is beyond the scope of this paper, which will limit itself to discussing ownership and operations of the hydroelectric system.

Ownership: We have argued above the importance of hydropower system assets and marketing responsibilities remaining in public ownership. Presently those assets are 100% federally-owned. BPA is largely responsible for retiring the federal debt incurred to construct the projects and transmission system, as well as for system operating costs. BPA has been self-financing for many years, meeting its obligations (including debt payments) from power sales revenues. Dam maintenance and modification work undertaken by the COE and the BuRec is reimbursed from BPA (without adequate cost-control authority for BPA).

While some power sales revenues derive from sales outside the region, the preponderance comes from Northwest ratepayers. There is a case to be made that since regional ratepayers have shared with the Treasury the costs and risks of developing the system, they should also share ownership. If both ownership and river stewardship responsibilities are shared among federal, state and tribal sovereignties, a formal ownership and governance structure reflecting this is an easily supportable outcome.

As a long-term objective, we propose the shifting of hydropower system

ownership to a collaborative entity -- a joint ownership and operating agency (JOOA) -- comprising the federal government, the four states, and representation from the treaty and trust tribes of the region. Obligations, benefits, liabilities and risks of the system would be assigned to this entity. The federal government would participate in decisions over system operations and allocation of costs and benefits, but as a co-owner (rather than, as at present, non-resident sole proprietor). It would be agreed that any net revenues realized would be retained within the region and applied to mutually-acceptable public purposes (and not captured by the federal Treasury). Net losses would have to be treated similarly.

The COE and BuRec would continue to operate the projects, and BPA would market the power, but the agencies would do so subject to the operating plan adopted by the JOOA. Authority to maintain and to modify the projects would shift to the JOOA, along with responsibility to cover costs. Coordination and accountability would be greatly enhanced.[4]

As an interim step, the federal government could retain system ownership but execute an agreement with the states that assigned certain system benefits and liabilities to the JOOA with the representation described above.

Other uses of the river (e.g., flood control, transportation, irrigation) would continue under appropriate federal and state authorities, but should no longer be subsidized by the hydropower system. Such uses in any event ought to be paying their own way or receiving a clear and transparent subsidy from the federal treasury.

The federal government would retain its responsibility on behalf of the nation for conserving the environmental health of the Columbia River. The JOOA would be obligated to operate the hydropower system consistent with basin watershed health standards.

[4] It is a highly debatable proposition to place a political body in control of a commercial venture. No less debatable is the notion of putting a commercial venture in charge of a political/governmental process and a public value: the use and management of a river ecosystem. Clearly the JOOA would need to be designed to resist broadening the range of authorized public purposes it would support, in order to avoid duplicating exactly the layering of subsidies and transfer payments that accumulated at BPA over the years. This is still the lesser risk, when compared to the risks of commercial pressures on biological systems that have resulted in the damaged Columbia watershed we confront today.

Ideally those standards would be developed collaboratively also, by the JOOA acting as watershed management and conservation council. Each party to the JOOA would then be responsible for devising and carrying out activities within its purview that bring the watershed into compliance. Federal land and resource management agencies, along with state and tribal agencies, would be held accountable to their sovereigns, acting jointly, for failure to act consistent with the region's watershed management standards and program, or for conditions that are within their authority to correct but remain out of compliance with the standards.

Treaty Obligations: The federal government cannot under law assign elsewhere its treaty obligations, whether to a foreign government or to the treaty tribes. The actions of the JOOA, watershed standards and a watershed management and conservation program will need to be subordinate to and consistent with such obligations. Equally, any new treaty agreements entered into by the federal government will need to be consistent with regional system operating and watershed management programs, and should be entered into only after consultation between the federal government and its JOOA partners.

Compliance with treaty obligations would remain subject to judicial review.

The JOOA and the watershed governance council should at the earliest occasion seek joint development, with the governments of Canada and British Columbia, of institutional linkages that provide for trans-boundary coordination of basin watershed management.