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Draft

Fourth Northwest Conservation and Electric Power Plan

Northwest Power in Transition
Opportunities and Risks

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NORTHWEST POWER IN TRANSITION: OPPORTUNITIES AND RISKS

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CHAPTER 1

EXECUTIVE SUMMARY

The electricity industry in the United States is in the midst of significant restructuring. This transformation will move the industry from the regulated monopoly structure of the past 50 years to a more competitive model.

There is much to be gained in this transition. Electricity consumers are already benefiting from competition in a number of significant ways. Competition in the natural gas industry has helped lower the cost of electricity from gas-fired generating plants. Competition among manufacturers and developers of combustion turbines has contributed to less expensive, more efficient, shorter lead time power plants. Broad competition in the electricity industry could result in lower prices for consumers and more choices about the sources, variety and quality of their electrical service. This is good news. The opportunities are great.

But, there are also risks inherent in the transition to more competitive electricity services. Merely declaring that a market is competitive will not necessarily achieve the full benefits of competition or ensure that they will be broadly shared. It is entirely possible to have deregulation without true competition. How competition is structured is important.

It is also important to recognize the limitations of competition. Competitive markets are about efficiency, not fairness or other social goals. To the extent that the citizens of the Northwest want their electricity system to deliver certain social benefits, such as low-cost electricity to rural areas or fish and wildlife recovery, special attention will be required to accomplish those goals during and after the industry's transition.

Similarly, markets are never perfect. For example, prices rarely reflect the environmental consequences of resource development and operation. Inadequate information and related market barriers also inhibit the market for energy efficiency. Again, if the citizens of the Northwest value environmental quality and energy efficiency, special care will be required to ensure that these values are upheld while the region captures the benefits of a more competitive electricity industry.

To seize the opportunities and moderate the risks inherent in the transition to competitive electricity markets, the governors of the four Northwest states convened a "Comprehensive Review of the Northwest Energy System." The governors appointed a broadly representative steering committee to study that system and make recommendations about its transformation. Each governor has also appointed a representative to make certain the public is educated about and involved in the Comprehensive Review.

In establishing the review, the governors stated:

> *"The goal of this review is to develop, through a public process, recommendations for changes in the institutional structure of the region's electric utility industry. These changes should be designed to protect the region's natural resources and distribute equitably the costs and benefits of a more competitive marketplace, while at the same time assuring the region of an adequate, efficient, economical and reliable power system."*

This is not the first time the Northwest states and stakeholders within the region have come together to address the future of the region's power system and related issues critical to the economy and environment of the Northwest. For more than 15 years, Idaho, Montana, Oregon and Washington have worked cooperatively to protect the resources of the Columbia River Basin, which is the source of the region's vast hydroelectric system and its largest and most complex ecosystem.

Through the Northwest Power Act of 1980, these states formed a compact and established the Northwest Power Planning Council to help plan for the future of the power system, and inform and involve citizens of the region in the planning process. Congress and the four Northwest states identified and embraced a set of long-term goals in the Power Act:

- To achieve cost-effective conservation;
- To encourage the development of renewable energy resources;
- To establish a representative regional power planning process; and
- To assure the region of an adequate, efficient, economical and reliable power supply.

Since the creation of the Council, utilities, businesses, local governments and others in the region have saved more than 1,200 average megawatts of electricity, enough to power a city the size of Seattle. These savings cost utilities an average of 2 cents to 2.5 cents per kilowatt-hour. That's about half the cost of power from the lowest-cost new generating resources available at the time. The environmental benefits of foregoing new generating resources in favor of conservation have not been calculated, but it is likely that they are substantial.

The four states, utilities, local governments, businesses and citizens have also worked together to promote wind and geothermal demonstration power plants, which are now in various stages of development. These are accomplishments of which the Northwest can be proud. No other region in the nation has worked so successfully as a team to manage so vast and complex a resource as the Northwest power system.

The goals of the Northwest Power Act were the product of a different era, an era of regulated monopoly utilities and large, capital-intensive resources. Nonetheless, many of these goals are still relevant in the increasingly competitive utility world. The industry transformation could challenge or help further those goals, depending on how the transformation is structured and how successful the region is in fashioning mechanisms to achieve those goals.

THE FOURTH NORTHWEST POWER PLAN

This Draft Fourth Northwest Conservation and Electric Power Plan was begun as fulfillment of the Power Act mandate to prepare and adopt "a regional conservation and electric power plan" and review that plan at least every five years. The Council's last plan was adopted in 1991.

The timing of this draft plan, in light of the governor's review, requires a different approach than that taken in previous Council power plans. Consequently, this draft contains few recommended actions or policy decisions. It is instead a reference tool, containing background on the industry and its current restructuring, as well as analysis of some of the major issues that must be addressed as the Northwest advances toward its new energy future. Because the Bonneville Power Administration, which markets about half the electricity generated in the Northwest, and the Council itself will be profoundly affected by the transformation of the industry, issues related to their futures are also explored.

The goal of this draft plan mirrors and supports the governors' goal in setting in motion the Comprehensive Review. The key issues and findings are summarized in the following pages.

THE EVOLVING NORTHWEST ELECTRICITY INDUSTRY

The electricity industry in the Northwest is evolving rapidly in the direction of increased competition. This trend is the product of the interaction of a number of developments. Prices for natural gas have fallen dramatically. And the technology of gas-fired electricity generation has been advanced to the degree that new combined-cycle gas power plants are relatively low-cost, flexible resources. These changes have broken down the financial barriers that once blocked entry into the electricity generation business.

These forces have been amplified by important policy changes at federal and state levels. Federal policies encouraging competition in generation began with the Public Utilities Regulatory Policy Act of 1978 (PURPA) and have been advanced by the National Energy Policy Act of 1992. The Federal Energy Regulatory Commission is in the process of adopting new rules to ensure competitive wholesale power markets. Progress toward competition at the retail level has been left to the states to determine and shape. In many states, the prospect of lower-cost power is driving consumers of large amounts of electricity to seek access to the competitive market or at least to market prices.

While rates in the Northwest are generally lower than elsewhere in the country, the pressure for retail competition is evident here as well. The Bonneville Power Administration, which markets electricity from the federal power system, is a power wholesaler and, as such, is already fully exposed to competition. Bonneville's size and importance in the regional power system mean that wholesale competition will have dramatic effects in the Pacific Northwest regardless of actions at the retail level. This plan reviews the evolution toward increased competition and the forces driving it in Chapter 2.

CAPTURING THE BENEFITS OF COMPETITION

Competition in the electricity industry has been promoted because it is considered to be more effective than regulation in fostering improved productivity, greater innovation, increased choice and lower costs to consumers. However, while the Pacific Northwest could benefit greatly from more open competition in the utility industry, the region shouldn't assume that deregulation alone will ensure these benefits. Without a market structure that fosters effective competition, the industry could simply replace regulated monopolies with deregulated oligopolies — where a few large companies have near-monopoly power.

There are generally recognized conditions that need to be met to foster effective competition. For example, an effective market requires an adequate number of sellers, and market access by buyers and sellers to ensure that no individual has the power to influence prices in the market. The Federal Energy Regulatory Commission (FERC) is pursuing policies intended to satisfy these conditions at least partially, by expanding access to electricity markets through transmission systems.

An effective market also requires that sellers cannot subsidize their competitive position by shifting costs to customers in a monopoly part of their business. This condition could be met by separating companies into their competitive and monopoly components.

Even if effective competition is achieved in the utility industry, market imperfections and other barriers could keep the industry from functioning efficiently. For example, if environmental costs and benefits are not taken into account, the utility industry will fall short of environmental goals. Other market barriers can limit the amount of energy conservation that is secured. Consequently, continued attention to market imperfections may still be required even in competitive markets.

There are also some things that competitive markets simply can't do. In the Northwest, for example the utility system supports social goals, such as economic development in remote rural areas or promotion of irrigated agriculture, generally by offering lower rates for these purposes. In a competitive electricity market, it may be difficult to include the costs of providing low rates to some in the prices charged to others. If supporting such social goals is to continue, new avenues and sources for the support may need to be identified.

Finally, how the transition from the regulated utility industry to a more competitive market is structured is critical. The transition requires reconciling decisions and actions made in the regulated environment with the new realities of competition.

Stranded investment — the inability to recover the full costs of past utility decisions at current market prices — is the most contentious issue in this area. While stranded investment in this region is small compared to other regions, it may still be an issue. Where legitimate stranded costs exist, the allocation of those costs between utility stockholders and utility customers will need to be negotiated.

For some Northwest utilities with existing low-cost resources, the ability to charge market prices could lead to windfall profits. These gains also need to be divided between investors and consumers. The Council offers some guiding principles and cautions for a competitive electricity industry in Chapter 3.

THE EXISTING NORTHWEST POWER SYSTEM

The foundation for the transition to more competitive electricity markets is the existing regional power system. This system is still dominated by hydroelectric power. Today, hydropower accounts for about 66 percent of the region's annual electricity supply. Since the Council's 1991 Power Plan, the region added 2,470 average megawatts of generating resources and conservation. Natural gas accounted for 57 percent of these additions, while conservation made up 21 percent of the new resources. Renewable resources, largely small hydropower and some biomass, accounted for about 17 percent of the additions. The preponderance of natural gas-fired resources in the recent additions to the system has raised concerns, but overall, the power system today embodies more resource diversity than did the system of 1991.

During the same period, the region also lost some electricity resources. The closure of the Trojan nuclear plant decreased energy supplies by about 725 average megawatts.

In addition, changes in how the hydropower system is operated, designed to protect endangered salmon and other fish and wildlife, have reduced the annual firm energy capability and limited the flexibility of the system to meet seasonal and hourly variations in electricity loads. The fish and wildlife protections reduced the firm energy capability of the region's hydroelectric system by about 850 average megawatts. The availability of low-cost electricity from the Southwest has helped the region offset the loss of energy from the increased flows for fish. This draft plan devotes Chapter 4 to a description of existing regional energy resources.

FORECASTS AND RESOURCE TRENDS

The opportunities and risks inherent in the transition to a more competitive Northwest electricity industry must be analyzed in the context of certain key factors. These include: future electricity use, the price and availability of natural gas, the amount of and cost of electricity in the West Coast power market, the availability and cost of new resources, and uncertainties regarding the Northwest hydroelectric system.

In the midst of the changes in the electricity industry, growth of the region's economy and the reliance of that economy on affordable and reliable electricity continue. Because future economic growth and electricity requirements are inherently uncertain, the Council prepares a range of economic and demand forecasts rather than a single point prediction. The mid-range of that forecast anticipates electricity use will grow by 1.3 percent per year, or approximately 280 average megawatts annually. This figure reflects an expectation that the region will experience relatively stable and even slightly declining electricity prices in real dollar terms as a result of lower gas prices and transactions on the West Coast power market.

Future gas prices are a major factor in the demand for electricity and the cost of the options to supply that demand. The emergence of a competitive natural gas market has resulted in declining prices and the expectation of ample supplies at comparatively low prices for the future. Again, because future gas prices are uncertain, the Council prepares a range of forecasts intended to encompass that uncertainty. The mid-range forecast suggests a real growth rate of 0.4 percent per year for residential and commercial gas prices, 1.1 percent for industrial use and 1.6 percent for electric generation. The lower end of the forecast range reflects expectations that future gas prices may be constant in real terms or even decline slightly.

Falling natural gas prices, the opening of transmission access and the availability of substantial excess generating capacity in California and the Southwest have combined to create a vigorous West Coast market for electricity. The availability of relatively low-cost power in this market makes it an attractive alternative to the Northwest's meeting demand growth entirely with the construction of new resources.

The Council's analysis finds that the West Coast market is likely to have substantial supplies of electricity costing around 2 cents per kilowatt-hour well into the next decade. Taking into account transmission constraints, if the Northwest were to rely on that market for as much as 3,000 annual average megawatts, the future cost of electricity to the region could be reduced by an average of $3 billion, compared to a strategy of building new resources to meet Northwest load.[1] The level of reliance on the West Coast market would be considerably greater than 3,000 average megawatts in some months and much less in others.

When new generating resources are required, the Northwest has numerous options. Natural gas-fired combined-cycle combustion turbines are the most likely choice. The Council estimates there are sites available that are capable of supporting an additional 7,400 megawatts of gas-fired capacity. These sites could supply 6,800 average megawatts of energy at costs of 2.7 to 3.3 cents per kilowatt-hour under the medium gas-price forecast.

The other generating alternatives analyzed in this draft plan include industrial cogeneration, coal-fired generation, forest thinning residue-fired generation, geothermal, wind, hydropower, land-fill gas recovery, mixed wood residue burning, nuclear and solar. Currently, there are few generating alternatives that are cost-competitive with combined-cycle combustion turbines — only some industrial cogeneration, small amounts of new hydropower and a few biomass applications. However, there is a significant amount of cost-competitive conservation available. In the long run, coal-fired generation, some additional hydropower and biomass, wind generation at good sites and fuel cells are expected to become competitive. Gas-fired combined-cycle plants maintain their cost advantage even if a small carbon tax is assessed. If a large carbon tax is implemented, non-fossil fuel burning resources become cost-effective.

The region continues to face uncertainty with respect to the degree to which the operation of the hydropower system might be further constrained to protect fish or wildlife. The Council analyzed three alternative hydropower operations in comparison to the current system operation. Depending on the alternative, the capability of the hydropower system could be increased somewhat or it could experience substantial further losses in energy and capacity.

These changes are uncertain. There is no way to be certain if, when and to what extent new fishery recovery measures might be implemented. The important question is whether the region would make different resource choices in the near term in the face of this uncertainty. The Council believes the answer is no. The flexibility of the resource choices available to the region are such that, given sufficient lead time, the power system could adapt. However, some hydropower system changes could come at a significant cost. These issues are analyzed in Chapter 5.

RESOURCE ISSUES IN COMPETITIVE MARKETS

The advent of competitive electricity markets raises new issues with respect to the development of conservation, renewable resources and the consideration of environmental costs and benefits. These issues are explored in detail in Chapter 6 and described in the following paragraphs.

Cost-Effective Conservation

An objective of the Northwest Power Act is “to achieve cost-effective energy conservation.” Despite the region’s success in conservation development, significant cost-effective energy savings remain. This plan identifies 1,535 average megawatts of electricity savings that could be obtained over the next 20 years at an average levelized cost of 1.7 cents per kilowatt-hour. These savings are equivalent to the electricity generated by seven typical combustion-turbine power plants, and on average, they cost about two-thirds as much.

If this conservation is developed, the region’s consumers would save $2.3 billion on their future electricity bills.[2] Consumers on their own will make some of the efficiency improvements identified in this plan. The region’s utilities have indicated they will secure more. Together, consumers and utilities in the region will probably capture about a third of the available and cost-

[1] These present value savings include estimates of costs and benefits that accrue beyond the 20-year planning horizon because many of these resources have lifetimes that extend beyond 2015. See Appendix H for more detail.

[2] See footnote 1.

effective savings over the next 20 years. But, unless the remaining two-thirds of the savings are secured,, the region will pay $1.7 billion more in power system costs and natural resource impacts than it needs to.

There are significant uncertainties inherent in any long-term look at the benefits of conservation. In addition to evaluating the conservation over a wide range of demand and fuel price forecasts, the Council looked at a wide range of alternative scenarios to determine how robust conservation's value was to the region. These scenarios included a reduction in the estimate of the available conservation, a dramatic improvement in the cost of generating technologies, and the sudden loss of 3,000 average megawatts of load. In the worst case, the value of conservation dropped as low as $830 million.

On the other hand, there is the risk that growing scientific evidence that global climate change is occurring could result in the imposition of measures to reduce emissions of carbon dioxide and other greenhouse gases thought to contribute to this climate change. If a carbon tax between $10 and $40 per ton of carbon dioxide were implemented in 2005, the value of the conservation would grow to between $3.2 and $6.1 billion.

In even extreme scenarios, the development of further cost-effective conservation is a positive long-term investment for the region. In the shorter term, however, conservation requires that the region incur somewhat higher costs today compared to buying electricity off the West Coast market. For conservation to be successfully developed in the future, the near-term costs must be weighed against its longer-term benefits.

Bonneville and the region's utilities have been the dominant forces behind the success of conservation efforts in the past. However, their role is changing because competitive pressures are making some utilities reluctant to spend money on conservation programs when some of their competitors do not make such investments. As a result, utilities will be unable to secure all the remaining conservation that is cost-effective.

Consumers are expected to save some electricity on their own, but there are significant market barriers that will likely limit this activity. Most Northwest utility resource plans include significant amounts of conservation acquisitions over at least the next four years. As a result, the region has some time to think through potential actions that might be appropriate for the long run.

In light of the potential benefits that may be at risk, the Council suggests that the Comprehensive Review and the states evaluate the costs and benefits of potential mechanisms to acquire conservation beyond what will naturally be developed in the market. The goal should be a competitive market that preserves as much of the conservation benefit as possible.

Some options include: waiting during this transition period to see what happens in the market; instituting a system benefits charge similar to the charge on phone bills that pays for the 911 emergency line; granting utilities distribution monopolies only if they offer conservation opportunities to their customers; or requiring that a certain amount of load growth be met by conservation. The last suggestion would result in efficiency trading, similar to emissions trading, which is already in practice in the electricity industry. Important qualifications for any mechanism are:

- That it be competitively neutral and not interfere with the market pricing of electricity;
- That it complement the emergence of competitive markets for energy-efficiency services;
- That it provide some symmetry between who pays and who benefits;
- That it be administratively efficient;
- That it use competitive mechanisms to the greatest extent possible; and
- That it incorporate mechanisms to ensure performance.

Renewable Resources

Renewable energy projects — those powered by the sun, wind, biomass, water and geothermal energy sources — are valued because they have generally favorable environmental characteristics, they offer diversity and flexibility, and they help ensure the long-term sustainability of the power system. An objective of the Northwest Power Act is "to encourage the development of renewable energy resources within the Pacific Northwest."

Renewable projects producing more than 420 average megawatts of energy have been developed since the 1991 Power Plan. These were primarily hydropower and biomass resources. This represents about 17 percent of all resources developed during this period.

Encouraging progress has also been made on the renewable resource confirmation agenda of the 1991 Power Plan. The confirmation agenda incorporates research, demonstration and development activities necessary to test renewable resources under Northwest climate conditions. However, declining wholesale electricity prices have resulted in near-cessation of the development of additional generating resources. This is consistent with the surplus of generating capacity on the Western electrical system, but it raises the question as to what type and level of renewables activity, if any, is desirable in this environment.

Analysis presented in Chapter 6 shows that, for the reasons noted above, few renewable resources are cost-effective in the near term. Even over the long-term, the large inventory of undeveloped renewable resources available to the Northwest has little expected economic value. However, the potential value of these resources would increase substantially if mitigation of carbon dioxide production were required to control global climate change. Such controls could raise the cost of competing resources.

But, even if carbon dioxide controls were needed in the future, there appears to be little economic value in developing renewables in advance of need and cost-effectiveness. Such projects would require a substantial cost premium, they preclude the benefits of later technological development and are unlikely to produce significant economic benefit. This finding holds even with consideration of uncertain fuel prices, water conditions, demand growth and with adoption of relatively high carbon taxes.

Renewable resources are unlikely to be selected by utilities in a competitive market in the near term because they are not cost-competitive. However, key development and demonstration activities conducted now will help the region integrate such resources into the power system in the future.

Based on this analysis, a renewable resource strategy for the Northwest should focus on:

- Ensuring that the restructured electric power industry provides equitable opportunities for the development of cost-effective renewable resource projects;

- Ensuring that the renewable resource potential of the Northwest is adequately defined and that prime undeveloped renewable resources remain available for future development. This will require completion of key demonstration projects and additional resource assessment activities that are already under way;

- Supporting research and development efforts to improve renewable technology;

- Offering green power purchase opportunities; and

- Monitoring fuel prices, the global climate change issue and other factors that might influence the value of renewable resources. More aggressive preparation for the development of renewables could be initiated if changes in these factors indicate that accelerated development of renewables is desirable.

Environmental Considerations

The Northwest Power Act requires quantifiable environmental costs and benefits of the power system be taken into account. While there are a number of these costs, for this draft plan, the Council has focused on the implications of possible global climate change.

There is increasing scientific concern that global climate change may be caused by emissions of greenhouse gases, most notably carbon dioxide. Carbon dioxide is produced in large quantities by power plants (and other energy equipment) that burn fossil fuels. Global climate change is a particularly difficult issue to address in power planning for several reasons. First, while the uncertainty regarding global climate change is narrowing, there remain questions regarding the existence, causes and magnitude of that climate change. The consequences of global climate change are also not well understood.

Second, global climate change is largely "external" to the Northwest. While the Northwest would experience the effects of any climate change that occurs, actions taken unilaterally by the region could not, in and of themselves, significantly affect the degree of climate change experienced by the region. Third, because of the large hydroelectric resources of the Northwest, the electric utility industry is not the most significant producer of greenhouse gases in the Northwest. Reductions in greenhouse gases might be accomplished at less expense in other sectors of the economy or in other parts of the world.

Still, the possibility that emissions of greenhouse gases might someday need to be controlled poses a financial risk. For example, a carbon tax could significantly increase the cost of electricity from fossil fuel power plants. If the type, magnitude and timing of possible carbon dioxide regulations were better known, certain near-term resource choices or, alternatively, investing in carbon offsets (e.g., tree planting) might be good hedges against carbon regulation. However, because of the lack of sufficient information, the Council cannot evaluate strategic responses to global climate change with the level of sophistication that it can bring to, for example, gas price uncertainties or future electricity requirements of the region.

Instead, however, the Council estimated the potential impacts of carbon dioxide control measures on the overall cost of providing electricity to the region, as well as on the relative costs of alternative resources. A range of possible carbon tax rates was used to represent the cost of carbon dioxide control measures. A carbon tax would raise the Northwest's total electricity bill and increase the value of energy-efficiency improvements, renewable resources and nuclear power plants. The value of efficient natural gas-fired resources would also increase relative to other fossil-fuel resources.

Until the uncertainty regarding climate change is resolved by scientific consensus, and national and international policies respond to that consensus, the region can reduce its exposure to risk by:

- Avoiding investments in generating resources that are heavy emitters of greenhouse gases;
- Securing cost-effective conservation;
- Gaining experience with measures to offset greenhouse gas emissions, such as reforestation; and
- Considering the carbon dioxide offset value of the region's only operating nuclear plant.

THE ROLE OF THE BONNEVILLE POWER ADMINISTRATION

The transition to a competitive electricity industry raises many issues for the Bonneville Power Administration. The reasons for this are several. First, as a wholesale utility, competition is already here for Bonneville and will probably become more intense. Second, Bonneville markets the output of a public resource, the Federal Columbia River Power System. Third, Bonneville plays an extremely large role in both generation and transmission in the region. And fourth, Bonneville is responsible for a number of public purposes besides power production, including discounts for rural customers, energy-efficiency programs, fish and wildlife recovery, and research and development.

As the region thinks about the role of Bonneville in a more competitive power industry, the questions raised by the principles for effective competition (in Chapter 3) must be asked and answered for Bonneville, just as for any other actor in the market. Does Bonneville have undue market power in transmission or generation? If so, how is that market power most effectively mitigated? More fundamentally, what is the appropriate role for a federal agency in a competitive market? Can it be a full competitor or must its role be somehow limited? Are there alternatives for ownership of Bonneville's assets or marketing rights that might be preferable, and, if so, what are some of the key issues that must be resolved? How should the benefits and risks of the system be allocated? How should the products of the system be marketed and priced? And how should the public purposes currently carried out by Bonneville be fulfilled? None of these questions has easy or clear answers.

Many argue that the Bonneville Power Administration, as currently configured, violates several of the principles for a competitive electricity market. It combines generation and transmission in one entity. It has substantial market power. It is not in a good position to deal with market risk. And it carries out several public purposes that may be difficult to support in a competitive wholesale power market, at least in the ways they have been supported in the past. At the same time, Bonneville is at the heart of the regional power system and embodies many of the values of the region.

Deciding the future role of Bonneville is a key task of the Comprehensive Review. A successful resolution of Bonneville's role is necessary to set the stage for an efficient and competitive regional power system that maintains the benefits of the Federal Columbia River Power System for the Northwest. Some of these considerations are explored in more detail in Chapter 7.

THE FUTURE ROLE OF THE NORTHWEST POWER PLANNING COUNCIL

Just as the role of the Bonneville Power Administration may be different in the future, the role of the Council in power planning is also in question. The Council's role of establishing a power plan to guide the resource acquisitions of the Bonneville Power Administration is moot if Bonneville is no longer acquiring resources. More generally, the role of a long-term regional power plan in an open market environment is questionable.

The Council's planning responsibilities were not intended as an end in themselves. These were intended to serve the overall purposes of the Northwest Power Act:

- To encourage conservation and efficiency in the use of electric power;
- To encourage the development of renewable resources;
- To assure the Pacific Northwest an adequate, efficient, economical, and reliable power supply;
- To provide for the participation and consultation of the states; local governments, consumers, customers, users of the Columbia River system and the public at large in:
  - the development of regional plans and programs related to energy conservation, renewable resources, other resources, and protecting, mitigating and enhancing fish and wildlife resources;
  - facilitating the orderly planning of the region's power system;
  - providing environmental quality; and
  - to protect, mitigate and enhance the fish and wildlife, and their habitat, of the Columbia River Basin.[3]

Through the Comprehensive Review, the region will be re-evaluating many of these goals and identifying mechanisms that can accomplish many of the key goals in a new utility context. A number of activities that the Council currently carries out in the course of developing and encouraging the implementation of its plans could be useful to the region, both during the transition to a more competitive utility industry and beyond. These activities include:

- Providing up-to-date information on future electricity demands, new generating and efficiency technologies, system operations and market forecasts;
- Serving as a broker for information exchange among utilities and others;
- Working at federal and state levels to resolve legal and institutional barriers to accomplishing regional goals;

[3] 16 USC §839 (1)-(6).

- Providing impartial analysis of issues with a long-term regional perspective;

- Serving as a focus for analysis of the interactions between power and fish;

- Representing the interests of states and the public in power issues; and

- Being a regional convener of forums to resolve issues.

The restructuring of the Northwest's electricity industry may result in new roles that are appropriate for the Council. On the other hand, some of the existing and potential new roles might also be performed by others. There may still be a need for strategic thinking about the directions the electricity industry might take and the implications for the region. The Comprehensive Review will need to explore these and other possible Council roles. This draft plan elaborates on this question in Chapter 8.

STRUCTURING THE COMPETITIVE MARKETPLACE

This draft power plan is long on analysis and short on conclusions. That is deliberate. It is designed to provide supporting information and analysis for the Comprehensive Review of the Northwest Energy System that was inaugurated in January 1996 by the governors of Idaho, Montana, Oregon and Washington. If this draft plan offers any advice, it is this: a deregulated electricity industry will not automatically deliver benefits to all consumers. Deregulation without attention to how competition is structured will not secure the low-cost and reliable electricity that has long been a mainstay of the Northwest's economy. Nor will competition necessarily secure the societal and environmental values this region has come to expect from its power system.

To achieve the full benefits of a competitive electricity market — lower power costs, innovation in both services and technologies, more choices for consumers, and attention to societal and environmental values — the Northwest will need to design its own structure for that market. No region in this country is more capable of doing that than the Pacific Northwest.

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CHAPTER 2

THE EVOLVING NORTHWEST ELECTRICITY INDUSTRY

The Northwest's electric power industry is constantly evolving. That is nothing new. However, the pace of that evolution is new — a pace many believe is more rapid than at any time in memory. What has been a regulated monopoly, is increasingly becoming a competitive market. The three interacting factors driving change in the electric utility industry are:

1. Wholesale electricity markets have become competitive due to regulatory changes that opened the industry to new players. This opening of the wholesale market, combined with lower overall prices for new sources of electricity, has resulted in significant pressure to open retail markets to competition as well.

2. The availability of adequate supplies of low-cost natural gas has driven down the marginal cost of new generating resources. In addition, low gas prices have made it economical to operate at very low costs older gas-fired generating plants already in the West Coast system. This has created an abundance of low-cost electricity in the West.

3. Finally, gas turbine technology has improved, resulting in a low-cost, efficient resource that can be built quickly and in relatively small increments to meet growing loads. This has significantly lowered the barriers to entering the power generation business, thus contributing to increased competition.

2-A. COMPETITION IN ELECTRICITY MARKETS

Probably no change is more important to the electricity industry and, by inference, to this draft power plan and the goals of the Northwest Power Act, than the evolution toward open competition among electricity producers and distributors. The principal benefits of opening an industry to the pressures of competition are to bring down prices and increase customer influence over the variety, quality and price of services the industry delivers. That has been the clear goal of the federal government's restructuring of both the natural gas and telecommunications industries. It is also the goal of restructuring in the electricity industry. A key lesson of restructuring in other industries is that *how* restructuring occurs and how regulation changes to accommodate increased competition are important.

The Traditional Regulatory Environment

The electric utility industry, until relatively recently, was made up of regulated monopolies — businesses that were, to a large extent, protected from competition. There was always some competition between electricity and competing fuels for such applications as heating and industrial processes, and even competition among electric utilities to attract new loads. But, historically, there was little competition from non-utility generators of electricity, and almost no one competed to sell electricity within a utility's service territory. The utility's franchise was protected.

The traditional regulatory environment reflected the realities of the industry as it existed years ago. It was an industry that required the construction of large, capital-intensive power plants and the rapid expansion of transmission and distribution systems. The regulatory system that evolved was a cost-based system that offered utilities the financial stability associated with a protected customer base. In return, utilities accepted an obligation to serve all customers in their service territory and regulation that prevents the exercise of monopoly power in the prices they charge. This regulatory framework generally holds true today for both the investor-owned utilities, which are regulated by state utility commissions, and the local public utilities, which are regulated by locally elected boards or commissions.

In the Pacific Northwest, the Bonneville Power Administration is a special case in that it is a federal marketer of wholesale power. Bonneville sells the electricity generated at federal Columbia

River hydroelectric dams and one nuclear plant, the Washington Public Power Supply System's WNP-2, to retail utilities and to some industrial and government customers that are served directly rather than through utilities. The federal power marketer is required by law to sell to its public agency customers at cost. Because Bonneville markets the power generated at the federal Columbia River dams, those costs were, until recently, well below the cost of alternative power supplies. This meant Bonneville had a secure market for its inexpensive electricity. Furthermore, most of Bonneville's customers are "full requirements" customers, that is, Bonneville supplies all their power needs.

Regulatory Policy — Wholesale Competition

In 1978, the utility industry's near-monopoly on power generation began to crumble. Congress passed the Public Utility Regulatory Policies Act (PURPA) to promote renewable resources and cogeneration and to reduce utility reliance on imported oil. PURPA created a class of non-utility generators that had the right to sell the output of their power plants to utilities at the price the utilities would have to pay to develop their own resources — their so-called "avoided cost." This was an attempt to mimic market-based economics, and it encouraged developers to compete to supply utility resources. While these provisions stimulated wholesale competition, the law was very specific in prohibiting these new producers from selling to retail customers.

The next major federal regulatory change occurred in the National Energy Policy Act of 1992 (EPAct). This legislation created a class of wholesale generators that are exempt from the legal and financial requirements of the Public Utilities Holding Company Act of 1935. Exempt wholesale generators have the ability to structure themselves any way they want, although they are still subject to rate-regulation by the Federal Energy Regulatory Commission when they sell their power in interstate commerce. The 1992 Act further eased entry into the wholesale generation business, but prohibited these exempt generators from making sales to retail customers.

The drafters of the 1992 legislation recognized that transmission access was a necessary condition for a fully competitive wholesale power market. If there is to be true competition in generation, generators need to have a way of getting their power to market under terms and conditions that do not discriminate among the owners of generating resources. EPAct gives the Federal Energy Regulatory Commission the ability to require owners of transmission systems to provide access to others wishing to use the transmission system. Again, the legislation was clear that it was addressing transmission access for wholesale transactions only, and that the Commission did not have the authority to require wheeling to retail customers.

In March 1995, the Commission released what has come to be known as the electricity "mega-NOPR" — its notice of proposed rulemaking implementing the open access provisions of EPAct. Although the rules are not yet final, they give a relatively clear picture of the Commission's intent. They require utilities under the Federal Energy Regulatory Commission's jurisdiction owning both generation and transmission to "unbundle" these functions — separating decisions about generation and transmission within the corporate structure and charging separately for these products.

The utilities are also to adopt transmission tariffs that guarantee "comparability," i.e., charges, terms and conditions for transmission services that are comparable to what the utility applies to itself for these services. The intent is to frustrate the ability of transmission owners to use their transmission to give their own resources an advantage.

The anticipated Federal Energy Regulatory Commission rules will also require establishment of sophisticated information networks that can provide real-time information on the availability and price of transmission capacity. Some industry observers have suggested that functional unbundling and requirements for comparability will not be sufficient to ensure non-discriminatory open transmission access, and that pressure will build for utilities to divest themselves of their transmission assets.

Opening access to the transmission system fosters the need for coordination in the planning and operation of regional transmission grids. The Commission has proposed the formation of regional transmission groups, composed of the users, suppliers and the state regulators of transmission in given regions, to coordinate the planning, expansion and operation of transmission capacity. Many utilities in the Northwest are members of the Western Regional Transmission Association (WRTA) and the Northwest Regional Transmission Association (NRTA).

The Federal Energy Regulatory Commission also indicated its intent to address what it perceives to be a transition issue that will have to be resolved — the so-called "stranded investment" problem. Wholesale stranded investments are those that were made to serve wholesale customers who then take advantage of open transmission access to get service from another supplier. If the investing utility cannot recover its investment from its remaining sales, that investment will be stranded.

There are few examples of potential wholesale stranded investments in the Pacific Northwest. One example could be the investment in the Washington Public Power Supply System nuclear power plants, two of which are uncompleted and have never produced power, and another that is operating, but which produces electricity at above the current market price. Fiscal Year 1995 operating costs of the Supply System's WNP-2 were about 3.5 cents per kilowatt-hour, which are higher than the cost of power from new gas-fired combustion turbines, and much higher than current wholesale power prices. The Supply System has set ambitious targets for reducing operating costs. It remains to be seen how successful they will be.

The financing of these plants was backed by the Bonneville Power Administration to meet what was then perceived to be the need for new resources to serve public agency and direct service customers. The capital costs of these plants were melded with Bonneville's low-cost hydropower, causing rates to climb by about 500 percent. Even so, until the advent of competitive pressures, Bonneville could recover its costs, and until recently, keep its rates below the avoided cost of new resources. However, Bonneville's ability to recover those costs fully in today's low-cost wholesale market *and* fully carry out its other public responsibilities is far from clear.

The changes in the wholesale market brought about by the forces described above have been dramatic. Independent power producers have become the important developers of new generation. More than 100 power marketers have been licensed by the Federal Energy Regulatory Commission. These marketers may not own any generating resources, but they can purchase supplies from a number of producers and put together packages of power products to meet the needs of their customers.

An active spot market has evolved, with spot prices at COB/NOB (the reference point for West Coast power transactions at the California/Oregon border and the Nevada/Oregon border) published daily in *The Wall Street Journal*. Some utilities have established power trading floors, and the New York Mercantile Exchange is moving toward establishing a futures market for electricity.

The most compelling effect of the competitive changes in the utility industry is that the market price of electricity has fallen. There is clear evidence from the results of various competitive bidding processes that competition among potential developers and marketers has driven down prices. To some extent, this is the consequence of surplus capacity on the West Coast that can be priced at the operating cost plus a small markup. In the past, that surplus capacity might not have entered the market because it was too expensive. Low gas prices and open transmission access are making that capacity a major factor in today's wholesale power market. Many of these developments parallel the experience in the restructured natural gas market.

The development of the wholesale electricity market has been particularly problematic for Bonneville. Because it is exclusively a wholesale utility, it is fully exposed to wholesale competition. Its heavy debt burden for nuclear plants, high operating costs on the one operating nuclear plant and increased costs of salmon recovery efforts are colliding with the falling prices in the wholesale market. The result is that many of Bonneville's direct service industrial and public agency customers are seeking or have obtained power from other suppliers.

In its 1996 Initial Rate Proposal, Bonneville appears to have been successful in putting together a competitive five-year rate proposal. To do so required extensive cost-cutting efforts and efforts to pare back or eliminate some of its other responsibilities. To many, the apparent conflict between Bonneville's public agency responsibilities and the requirements of the competitive market raise questions about Bonneville's continued existence in its historic form. This is discussed more fully in Chapter 7.

Retail Competition

The availability of low-cost power in the wholesale power market is creating pressure for retail competition, i.e., a situation in which individual factories, businesses and even homes might choose who generates their electricity and what power products they buy. Electricity would be distributed to consumers over the same power lines as serve them today, but one consumer might be served by one utility, while his or her neighbor might be served by a different utility, an independent power producer or a marketer. Many believe that the full benefits of a competitive industry will only be realized when retail customers have full access to power markets.

The authority to allow retail competition lies with state and local regulators — legislatures, state utility commissions and the governing bodies of consumer-owned utilities. Not surprisingly, the pressure for retail competition is greatest where retail rates are highest. California embarked on an ambitious effort to restructure its electricity industry to allow retail access first to large customers and then to all customers within a few years. Although not yet complete, it appears almost certain that some form of retail competition will come about in that state.

California is the most ambitious example of competitive restructuring, but there are other states in which retail competition is also being actively considered. Michigan has an experiment in retail wheeling under way. Massachusetts has recently adopted a goal of providing retail customers with the choice of suppliers. The state also adopted principles for the restructured industry and for the transition to it, and has set a schedule for implementation, as has Wisconsin. Rhode Island also has adopted a set of principles for industry restructuring.

While these examples are perhaps the most prominent, regulatory commissions and legislatures across the country are beginning to address the issue, even in areas that do not have particularly high rates. At least 12 states outside the Northwest are investigating the introduction of retail competition.

Given the relatively low electricity rates in the Northwest, this region would seem an unlikely place for pressures for retail access, but even small reductions in price for large customers can translate into significant monetary savings. As a result, some industrial customers in the Northwest are using their market power to obtain the benefits of low wholesale prices. These relatively few large customers are causing much of the electricity industry, even in the Northwest, to act as if retail access were a given.

Puget Sound Power and Light in Washington has customers that have been granted revised rate structures as a result of their attempt to get direct access to the power market through other suppliers. A major customer of Seattle City Light also has sought direct access to the power market. While these are the most public examples, it is likely there are numerous other instances in the region in which utilities and their customers are wrestling with the trade-offs between opening up retail access or making special rate accommodations to retain major customers. Two state utility commissions, Washington's and Montana's, have undertaken inquiries on competition, and the Washington commission has published "Guiding Principles for an Evolving Electricity Industry."[1]

The effects of anticipation of competition are also evident. Utility efforts to "right-size" and cut costs are prevalent. Mergers and acquisitions are under way in the region and across the country, as utilities try to reduce costs through economies of scale and otherwise achieve competitive advantages. At least two major Northwest utilities have been public in expressing their concerns that they would face stranded investments if retail competition develops. Most utilities have expressed concerns about regulatory pressures to undertake conservation, renewable resource

[1] Washington Utilities and Transportation Commission, "Guiding Principles for an Evolving Electricity Industry," Docket No. UE-940932, December 13, 1991.

development and accommodation of environmental concerns that might raise their rates if their potential competitors — independent power producers, marketers and so on — are not subject to such pressures. They fear such rate increases will mean customers move to other suppliers.

2-B. Restructuring of the Natural Gas Industry

Changes in the natural gas market have been a major factor in the competitive evolution of the electricity industry. In fact, changes in the gas industry may have far more implications for the future of the electricity industry than any other recent development. Not only do low natural gas prices affect future demand for electricity and the cost and characteristics of electricity supply, but the development of a restructured natural gas commodity market may foreshadow similar changes for the electricity market.

In the early 1970s, natural gas was regulated from the wellhead to the end user. Consumers' gas needs were met by their local distribution company, much as electric utilities serve their customers' needs now. The local distribution company had its gas supplies delivered to the city gate by natural gas pipeline companies that acquired the gas supply, transported it to the city gate, and shaped it to meet demand.

Today, pipeline companies do not own or purchase any gas. They provide transportation and shaping services on an unbundled basis. Local distribution companies and many individual customers now purchase their own gas supplies, transportation, and other services as needed. There is now a fully developed natural gas commodity market. Financial instruments, such as natural gas futures, allow local distribution companies and customers to manage the risk of natural gas price fluctuations. A whole new industry of natural gas marketers now exists to help customers acquire gas supplies, transportation and other services on a bundled or separate basis to fit individual customer needs.

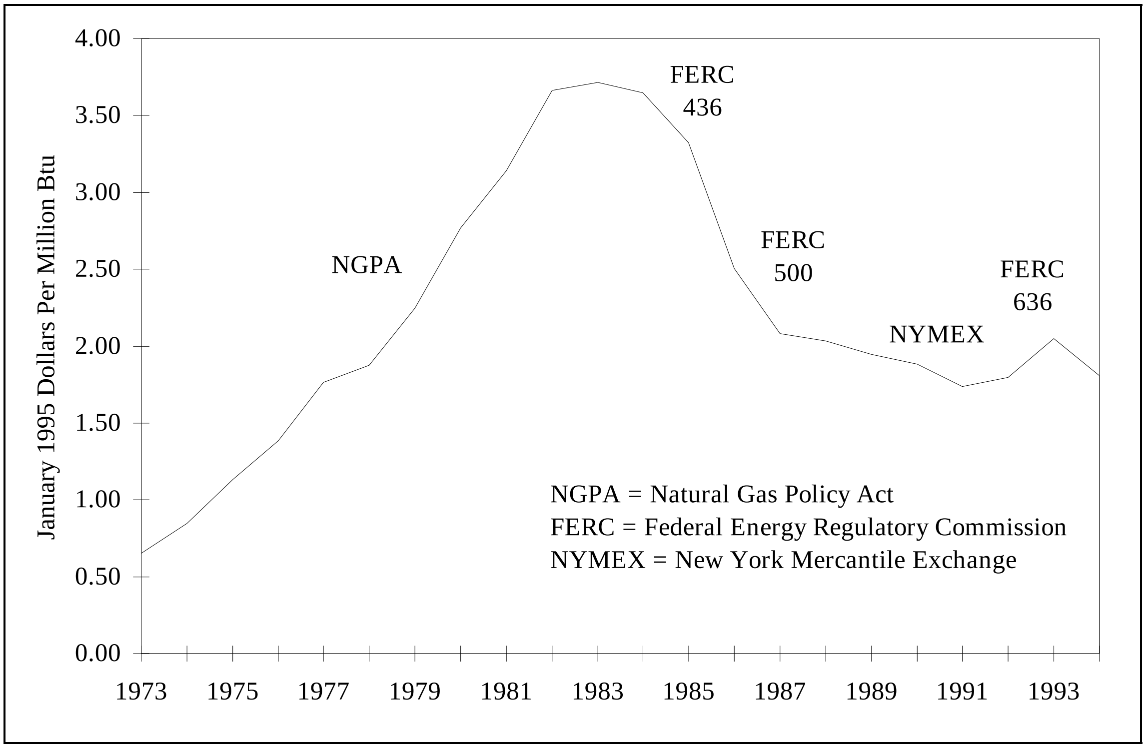
These dramatic changes occurred through a series of restructuring initiatives beginning with the Natural Gas Policy Act of 1978 and culminating in Federal Energy Regulatory Commission Order 636 in April 1992. (See Figure 2-1.) The regulatory changes gradually deregulated natural gas prices at the wellhead (Natural Gas Policy Act, 1978 and Natural Gas Wellhead Decontrol Act, 1989), opened up pipelines for use by anyone wanting to transport gas (FERC Order 436, 1985 and Order 500, 1987), and eliminated the purchase and sale of natural gas by pipeline companies (FERC Order 636, 1992). Order 636 also put into place pricing principles that provided incentives to utilize pipeline capacity more efficiently.

In April 1990, the New York Mercantile Exchange (NYMEX) began trading natural gas futures contracts, signaling the beginning of a complete natural gas commodity market. Finally, legislated restrictions on the use of natural gas for electricity generation contained in the Powerplant and Industrial Fuels Use Act were repealed.

Taken together, these changes have put into place the necessary elements for an economically efficient natural gas market. These elements include direct access to markets by both users and suppliers, a larger number of buyers and sellers participating in the market, proper pricing structures in the regulated portions of the industry, and price discovery and risk mitigation mechanisms provided by the spot and futures markets for the natural gas commodity.

The results have been dramatic decreases in natural gas prices and growing estimates of natural gas supply. Between 1983 and 1987, average wellhead real natural gas prices in the United States fell from $3.70 to $2.08 (both in January 1995 dollars), a drop of 44 percent. Since 1987, natural gas prices have averaged $1.89, while displaying price cycles that typify a competitive commodity market. Figure 2-1 illustrates natural gas price trends and restructuring actions over the past 24 years.

Figure 2-1
Restructuring Benchmarks and Natural Gas Prices



Until very recently, these lower price levels were considered unsustainable. Such low prices were not expected to garner sufficient new supplies of gas to meet growing demands. However, the establishment of a more competitive market has led to adoption of new technologies that have greatly increased the success, and reduced the cost, of natural gas exploration and development. In only 10 years, the estimates of ultimate potential gas resources have increased five fold.[2]

The theories and models of natural gas supply that were developed during the energy crisis of the 1970s and early 1980s have proven to be far too pessimistic. As a new understanding of the nature of natural gas supplies and markets is being developed, forecasts of future natural gas prices have been falling every year for the last dozen years. It is no longer conventional wisdom that natural resource prices will necessarily rise in real terms over time as those resources are produced. This change is reflected in the Council's forecasts of natural gas prices, described in Chapter 5.

Lower gas prices have meant that gas-fired steam generating plants, primarily used by California utilities to meet peaking needs, can now be run economically with gas. These existing generators are already available, they simply have not been used extensively in the past due to the high price of their fuel. The availability of low-cost gas for these plants has meant that the West Coast market has a significant amount of inexpensive electricity at its disposal right now. The extent of that market is described in Chapter 5.

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[2] For an excellent discussion of the changing views on oil and gas supplies see, William L. Fisher, "How Technology has Confounded U. S. Gas Resource Estimators," Oil and Gas Journal, Oct. 24, 1994, pp. 100-107.

2-C. GAS TURBINE TECHNOLOGY

Changes in the structure of the gas industry coincided with improvements in gas-fired power plants. Gas turbine technology has benefited from military and aerospace research and development. This has resulted in improved efficiency and reliability. New gas-fired power plants also are smaller than conventional thermal power plants, so more of their components can be assembled in factories. This makes their onsite construction faster. These two effects combine to reduce their overall costs. In addition, natural gas-fired combined-cycle combustion turbines have greatly reduced local and global environmental impacts. Consequently, they are easier to permit and require less permitting lead time. The dramatic benefits of today's low-cost gas-fired generation and the key characteristics of a gasified coal plant, as described in the 1991 Power Plan, are compared in Table 2-1.

In addition to the direct effect of providing electricity that is inexpensive and less-polluting, the characteristics of gas-fired combustion turbines have also lowered the barriers for entry into the power generation business. It is no longer necessary to undertake the risks associated with very large, long lead time, capital-intensive generating resources to enter the generation business. Thus, one of the conditions for a competitive generation market — ease of market entry — is within reach.

Table 2-1

Marginal Resource Comparison: Draft Plan Compared to 1991 Power Plan

Resource Characteristics	1991 Plan Gasified Coal	Draft Plan Gas-Fired Turbine	Change
Size (MW Capacity of Typical Plant)	420	228	46% Smaller
Lead Time (years)	7	4	43% Shorter
Capital Cost ($/kW)	$2,520	$684	73% Lower
Availability (%)	80	92	15% Greater
Efficiency (%)	36	47	30% Greater
Levelized Cost (cents/kwh)	6	3	50% Lower
Particulates (T/GWh)	0.07	0.03	57% Less
SO_2 (T/GWh)	0.04	0.02	50% Less
NO_X (T/GWh)	0.50	0.07	85% Less
CO (T/GWh)	0.02	0.02	similar
CO_2 (T/GWh)	985	497	50% Less

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CHAPTER 3

CAPTURING THE BENEFITS OF COMPETITION

The introduction of competition into the Northwest electricity industry is the overarching consideration motivating the Comprehensive Review of the Northwest Energy System. Both the reality of wholesale competition, with much of its focus on the Bonneville Power Administration, and the anticipation of retail competition have captured the attention of the electricity industry and those interested in its effects on the region. Competition in some form will happen. However, how competition evolves in the region will certainly influence how fully the potential benefits of competition are achieved; how the benefits and costs are distributed; the cost and reliability of our power supply; the effects on the environment; and the future role of current institutions, including public and investor-owned utilities, the Bonneville Power Administration and the Council. In the words of one authority on electricity industry restructuring, "You don't just say 'We're going to have a competitive market.' You have to think very carefully about how the pieces fit together with different mixes of regulation and deregulation."[1]

3-A. Benefits of Competition

A fully competitive market for energy services has the potential to create tremendous benefits for the electricity consumers of the Northwest. Competition drives producers to become more efficient, thus lowering prices. It also spurs the creation of new products tailored for specific market niches, providing a greater range of choice to consumers. There are indirect benefits of competition that are equally significant. Historically, low electricity costs have been a major factor in the economic growth of this region. Competition promises to continue that trend and sustain the expansion of the Northwest economy. Competition in electricity markets will result in more transparency of electricity prices and of what is included in these prices. For example, it will be much easier to tell how much of an electric bill is paying for kilowatt-hours, how much is for distribution services, how prices are different at different times and so on. This should lead to greater efficiency. For all these reasons, competition should be embraced. The tricky part will be restructuring the current electric power industry so that effective competition, not just deregulated oligopolies, emerges to benefit all consumers.

3-B. Principles for a Competitive Electricity Market

A well-accepted definition of a perfectly competitive market is a market where no individual participant is large enough to influence the market price of the product.[2] Although we in the United States like to think of ours as a competitive economy, in reality we have a mixed economy. This is because the conditions for perfect competition are seldom met in an industry. Some industries are inherently monopolistic and have traditionally been subject to regulation. For other industries, there is antitrust legislation, enforced in the federal courts, to ensure that a reasonable degree of competition is maintained.

This draft assumes that the portion of the electric utility industry that is opened to competition will be governed by antitrust laws. However, these laws do not apply to federal agencies. This creates a unique issue for the Northwest because more than half the power generated in the region comes from federal sources.

As the Comprehensive Review progresses, it is important to remember that the act of deregulating does not guarantee that adequate competition will result. Without adequate competition, the region will not see the benefits expected from deregulation. The proposed new

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[1] Hogan, William, "It's all in the Structure," *The Electricity Journal*, November 1995, p. 60.

[2] Samuelson, Paul A., Economics, Seventh Edition, p. 41.

structure of the electric utility industry should foster and protect competition where it is feasible, and separate competitive markets from non-competitive markets that require continued regulation. In addition, the inherent limitations of fully competitive markets need to be acknowledged.

Absence of Market Power

The absence of dominant market power is the key to fair and effective competition. That is, no player has the ability to control prices and profits. Excessive market power can arise from several factors, all of which require consideration in the course of any restructuring. The sources of market power are: too few sellers; restricted access to markets; mixing of regulated and unregulated activities; and, more generally, situations in which not all participants are subject to the same rules and requirements.

Many Sellers

Market power exists when there are so few sellers that those sellers are able to manipulate prices.[3] Where there are too few sellers, deregulation may just trade regulated monopolies for unregulated oligopolies. Many critics of the results of privatization/industry restructuring efforts in the United Kingdom point to the fact that too much of the generating capacity was held by very few producers, allowing those companies to manipulate prices

In efficiently functioning competitive markets, producers are no longer "price givers," who can set prices to recover costs and, in the case of investor-owned entities, earn an assured rate of return. Producers must accept the prices set by the interplay of supply and demand, or choose not to operate. Those prices will trend toward the marginal operating cost of the most expensive unit to operate in a given time period. From the standpoint of economic efficiency, this is what society wants to see. Consumers get to trade-off the benefit they derive from their marginal unit of consumption against the producer's cost of supplying that marginal unit.

It is also important to recognize that electricity is not a homogenous product. There are many other products associated with the sale of electricity, such as load following capability and reserves. There may be many sellers of some services, but too few for others. Similarly, the market may have many sellers generally, but transmission constraints can limit market entry in some areas. The problem is just as severe if there are many sellers, but a few dominate the market due to their size or other advantages.

Market Access

For a market to function efficiently, suppliers must have access to the market; suppliers must be able to deliver products to consumers. When the Federal Energy Regulatory Commission mandated open, nondiscriminatory, electricity transmission access and functional unbundling, it intended to put this market principle in place by assuring suppliers equal access to potential wholesale customers. The intent of functional unbundling is to separate the generation and transmission functions within a utility's organization to minimize the opportunity or temptation to use control of transmission to the advantage of one's own generation.

Functional unbundling and open access tariffs might provide nondiscriminatory market access. Open access tariffs require an owner of transmission to provide access to others under terms and conditions comparable to those the owner applies to itself. However, leaving generation and transmission under the umbrella of a single organization runs the risk of that organization using its transmission branch to benefit its own generation. It may be very difficult, moreover, for regulators or competitors to demonstrate that anti-competitive behavior actually took place. Many utilities in the Northwest have expressed concern, for example, that Bonneville, which owns so much of the region's high-voltage transmission system, could exercise subtle restraint on transmission access, to benefit its own generating resources.

There are at least three preventative steps beyond those described above that might be taken. Each offers increased certainty that nondiscriminatory open access will be achieved, but each is increasingly complex. The first step is

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[3] Newberry, David M., "Power Markets and Market Power," *The Energy Journal,* Vol. 16, No. 3, 1995, pp. 39-66.

to spin off generation or transmission to an affiliate. While this further separates the two functions, it does not guarantee that transmission decisions would not be influenced by the interests of the generating affiliate.

The second step is to vest decisions over transmission operation in an independent operator with no financial interest in generation. Ownership in the transmission system would not necessarily change hands, only responsibility for operation of the system would change. Many restructuring proposals being considered across the country feature an independent grid operator who would run the transmission systems of multiple owners as a single system. An independent grid operator may offer some operational efficiencies, as well. The independent grid operator could also be responsible for transmission system expansion decisions.

The third, and most certain, but also most difficult step is divestiture, i.e., selling off the generation or transmission assets. Divestiture is certain because the new owner of the transmission would have no interest in generation. It is most difficult because of the legal and financial transactions involved in divestiture. What are the assets worth? How are the proceeds to be allocated? How will the transaction be taxed? These and a host of other issues complicate divestiture, but do not make it impossible. While these difficulties are complex, this alternative would result in a lower ongoing regulatory burden than that associated with continued common ownership of generation and transmission.[4]

Consumer Choice

Consumer choice is the ability of consumers to choose among different products and different suppliers. Choice is a basic requirement for efficient competitive markets in that it is a corollary of having many suppliers with open, nondiscriminatory market access. Consumer choice drives competitive markets. In the case of wholesale competition, it is the ability of wholesale customers to choose among suppliers. In the case of retail competition, it is the ability of retail consumers to choose their supplier directly. In either case, it is consumer choice that forces suppliers to bring down their costs and make innovations in their products and services. Without consumer choice, regulation is needed to substitute for the discipline of the market and protect consumers from the abuse of monopoly power.

Separation of Regulated and Unregulated Activities

If a supplier were able to subsidize its competitive position by shifting costs to its regulated activities, it would unfairly gain market power. For example, there is a consistent complaint from the Bonneville Power Administration that its investor-owned competitors are able to recover the fixed costs of their resources from their regulated retail business and compete for Bonneville’s wholesale customers on the basis of variable operating costs alone. Whether this is entirely true is not known, but it does illustrate the concern.

A second concern arising from the mix of regulated and unregulated functions is that the regulated function will take second place in the internal competition for scarce capital resources. Given the choice between investing scarce capital in an unregulated business that can earn an unregulated rate of return and investing it where it can only earn a regulated return, most businesses will be drawn to the higher return. If that is true, the consequence could be that investment needed to ensure the reliability and efficiency of transmission or distribution will go begging. In the telecommunications industry, which is further along in the deregulatory process, recent experience has raised concerns about the quality of local phone service, the part of the business that remains a regulated monopoly.

There are arguments to be made in favor of continued vertical integration of regulated and unregulated activities. In addition to the transaction costs involved in divesting, there is the possibility that the increased transaction costs between the now-separated portions of the business, (e.g., the need to contract for transmission services) could outweigh the competitive benefits achieved by limiting the

[4] Zeigler, Belton, “Affiliate Transactions and Electric Industry Restructuring,” *The Electricity Journal,* October 1995, pp. 20-27.

market power associated with vertical integration.[5] However, the principle of minimizing market power is, in the opinions of many people, so important that the burden of proof should rest with those opposing divestiture.

Consistent Rules

Relative market power can also be affected if different competitors are subject to different ground rules. For example, different regulatory regimes, different tax liabilities, different costs of capital and other factors can affect relative competitiveness. The Northwest, with its mix of federal, investor-owned, and local publicly owned entities, has significant potential for these kinds of market distortions.

3-C. Characteristics of Competitive Markets

Although perhaps not as fundamental as the principles discussed above, there are also some characteristics of competitive markets that should be kept in mind in the course of any restructuring process.

Risk and Reward

Competitive markets imply the possibility of business failure and capital loss. A positive return on capital investment can only be guaranteed by substantial market power (historically, monopoly power for utilities). In the regulated monopoly environment, investors trade low risk (the relatively assured recovery of capital investment from franchise customers) for relatively low regulated rates of return. In the competitive environment, investors have no assurance that costs can be recovered. Competitive markets, however, also imply the possibility of success and profit. Investors take on risk in return for the possibility of a higher, unregulated rate of return.

The structure, rules and institutions of a competitive electricity market have to accommodate the possibility of both market success and market failure. Is there the ability to absorb loss? If there is a "profit," how and to whom is it to be distributed? The answers to these questions are fairly clear for investor-owned utilities. Stockholders should realize that their stock might go up or down. The issue is potentially most difficult for the publicly owned part of the industry — Bonneville and the consumer-owned utilities that don't have stockholders to take profits and losses.

Markets are Dynamic

It is tempting to think we know the conditions competition will bring and that if we can adjust the existing legal and regulatory system to fit those conditions, everything will be fine. In reality, however, we can't know what future conditions will be. The interplay of markets and technological advances can stimulate changes that alter the competitive landscape. For example, continued improvements in the cost and performance of small-scale generation and energy storage could result in a very different picture of the competitive future than the one that seems likely today. On the other hand, unforeseen resource constraints or environmental restrictions could turn the market in entirely different directions. In considering the restructuring of the industry it is important to put in place structures and systems that are consistent with the overall principles of competitive markets, not the specifics of the electricity market as we foresee it today.

3-D. Limitations of Competitive Markets

Competitive markets are not without limitations. These limitations also have to be kept in mind as restructuring is considered.

Markets are Rarely Perfect

Markets do a wonderful job of allocating society's resources when *all* relevant costs are reflected in prices and when market barriers are minimal. However, there frequently are environmental costs that are external to the

[5] Kaserman, David L. And John W. Mayo, "The Measurement of Vertical Economies and the Efficient Structure of the Electric Utility Business," *The Journal of Industrial Economics,* V XXXIX, N. 5, September 1991, pp. 483-502.

market process. For example, the health and environmental costs of sulfur dioxide pollution were external to the power industry until federal emissions standards and caps were established.

In addition, customers often lack complete knowledge of their alternatives. Poor information about the cost, performance and reliability of some conservation measures, for example, makes it difficult for them to compete against better understood resources. Some firms also might have a degree of market power in some part of their customer base.

These are imperfections that are not resolved now and can never be resolved fully. They exist to various degrees in most markets. It would be erroneous to assume that by moving from a regulatory environment to a market environment, all misallocations of resources would be eliminated. The move to competitive markets requires continued attention to issues of market externalities and other market imperfections.

Efficiency Not Equity

Markets, even when they perform well, are about efficiency, not equity. There may be societal goals, such as addressing low-income consumers, providing rate relief to groups or areas that would otherwise experience higher costs, or providing stimulus to a socially desired economic activity that may not be met by the competitive market. These can be entirely legitimate policy goals.

This region, and in particular, the Bonneville Power Administration, has frequently used power system revenues or rates to support these kinds of goals, including reducing irrigation and river transportation costs. This type of implicit subsidy was possible in a regulated monopoly. Competitive markets, however, cannot sustain cross-subsidies. One customer's subsidy is potentially another customer's greater-than-market price. With choices among alternative suppliers, a customer will usually find a way to undercut such prices.

This does not mean that revenues from the power system cannot be used to address non-market purposes. If, for example, the Bonneville Power Administration is allowed to charge market prices, and those prices exceed costs, the net revenues can be used for whatever purposes are deemed appropriate — a rebate to customers, low-income services or other purposes. But delivering the dividend in the form of subsidized prices puts the subsidizer at a competitive disadvantage and sends an inefficient price signal as well.

3-E. The Transition Matters

The transition to competitive markets will be neither instantaneous nor easy. Much of the difficulty of the transition has to do with reconciling the consequences of past decisions, made in an era of regulated monopolies, with the new competitive market. Competition has much to offer in the form of lower costs and better products and services. However, it will be difficult to make the transition if some groups — investors or customer groups — believe they would be made worse off because of competition. In addition, the timing of the transition for various customer groups will be important. For example, with an unstructured transition, large industrial customers will likely gain access to lower market prices sooner than individual residential customers.

The debate about this transition has focused primarily on the issue of stranded investment. Stranded investment is investment that cannot be fully recovered at competitive market prices. Most, but possibly not all, of that investment is in generating resources. If some customers can purchase electricity from the competitive market, instead of from their historic supplier, they may "strand" their "share" of the unrecoverable portion of the utility's investment, leaving it with those customers who don't have access to alternative suppliers, with the utility's investors or both.

Stranded investment could occur at the wholesale level, as a result of open transmission access, or at the retail level as a result of opening up retail competition. Even without actual retail wheeling, the special accommodations that are likely to be made for large customers who can threaten to leave the system can effectively strand costs on customers with less market power.

The stranded investment issue tends to generate a great deal of heat and not very much light. Customers who think they can take advantage of the competitive market brand suggestions for some kind of stranded cost recovery as “anti-competitive.” Customers who believe they will have less ability to take advantage of the market fear they will have to pay an unfair share of stranded investments. Utility stockholders, arguing that investments were made in good faith expectation of continued utility monopoly and obligation to serve, see failure to provide for stranded investment recovery as unfair to them.

The challenge is to get beyond these polarized positions to a competitive market. Some observations that may help move the debate:

- The amount of potentially stranded generation investment depends on the difference between the cost of existing generation and the market price. In the Northwest, the amount of stranded generation investment is presently thought to be small relative to other parts of the country.

- The amount of stranded investment cannot be figured on an individual resource basis, but rather on the basis of an owner’s entire system. Where utilities have been averaging the cost of their high-cost and low-cost resources in determining their regulated rates, stranded investment must be determined on the same basis. One cannot just pick out the high-cost resources and recover stranded investment for those resources, while at the same time receiving market prices for (and making windfall profits from) existing low-cost resources.

- Any stranded investment recovery mechanism should build in incentives to minimize stranded investments. For example, if owners must share in the stranded investment, there is an incentive to work hard to minimize stranded investments. Similarly, stranded investment recovery should not reward inefficient operation. Recovering fixed costs is necessary to some degree. Subsidizing above-market operating costs is neither prudent nor necessary.

- It is difficult to make an argument that all stranded investments should be recovered from customers (although that is what the Federal Energy Regulatory Commission has recommended for wholesale stranded investments).[6] The decisions made in a regulated monopoly environment were perceived to have relatively low risk, but certainly not zero risk. Stranded investment recovery should be shared between customers and investors. The fact that Bonneville does not have investors in the usual sense makes this more difficult, but not necessarily impossible.

- Virtually every electricity industry restructuring process in this country has recommended some level of stranded investment recovery. It is the norm, not the exception.

It should also be recognized that there is a flip side to stranded investment. Stranded investment occurs when total costs are greater than market prices. But for many utilities in this region, existing system costs are well below market prices or could be in a few years. The transition to competitive markets and market prices means that unless some provision is made for existing customers to share in the return, the benefits will all go to investors — a windfall profit. Stranded investment recovery is based on the principle of equity. Investors who received a near-certain, but low rate of return in the regulated environment may be entitled to some level of stranded investment recovery. If existing customers are also to be treated equitably, they are also entitled to some share of the windfall profits. They, after all, helped pay for the below-market resources and accepted the risks associated with those resources.[7]

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[6] Bradford, Peter, “A Regulatory Compact Worthy of the Name,” *The Electricity Journal,* November 1995, pp 12-15.

[7] Cearley, Reed and Lance McKinzie, “The Economics of Stranded Investment -- a Two-Way Street,” *The Electricity Journal,* November 1995, pp. 16-23.

CHAPTER 4

THE EXISTING NORTHWEST POWER SYSTEM

The makeup of the Northwest's electric power system continues to evolve in response to a variety of forces and trends. The existing system and its capability are described in detail in Appendix A. Figure 4-1 shows the composition of generating resources in the region. Generating resources in the Northwest amount to more than 17,000 average megawatts.

The majority of regional generation, about 66 percent, comes from the hydroelectric system. Coal resources are the next largest component, representing 18 percent of all generating resources, followed by natural gas, nuclear and biomass resources.

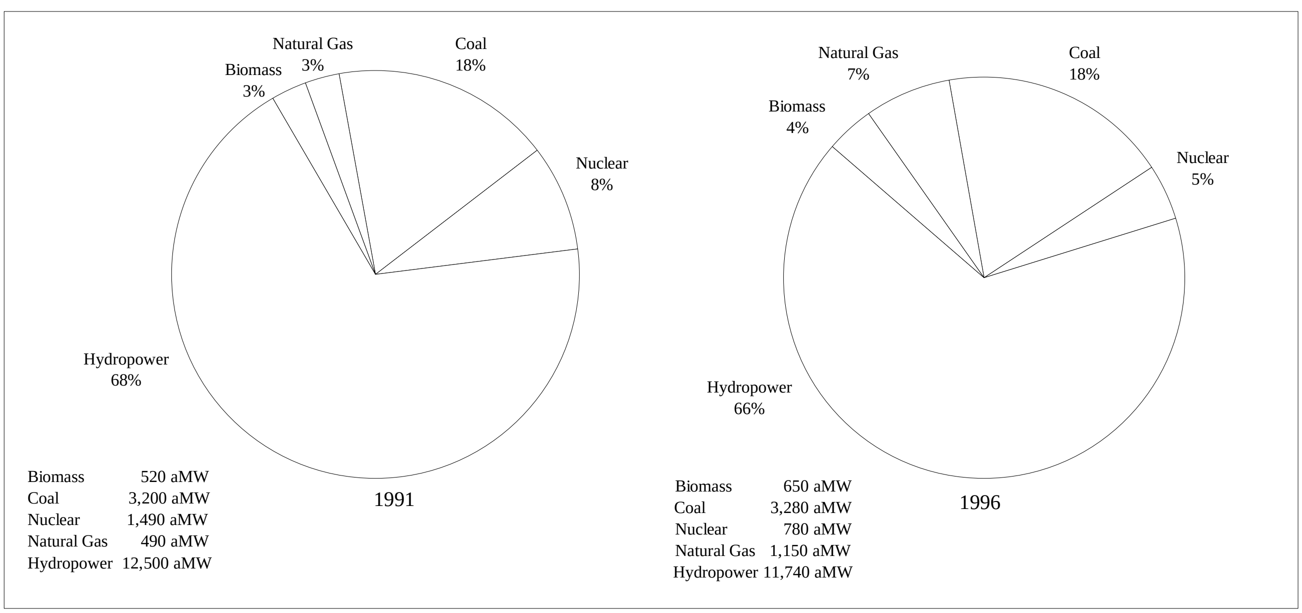
4-A. RESOURCES ADDED SINCE 1991

Beginning in the late 1980s, increased economic activity and accompanying electrical load growth initiated a period of active resource acquisition in the Northwest. For most of this period, utilities relied on competitive bidding, conservation activities and the development of utility-owned projects for meeting growing resource needs. Competitive bidding appeared well-suited both to secure low-cost generating resources and to account for environmental externalities, resource diversity objectives and other non-market societal objectives.

Some conservation also was acquired through competitive bidding, but utility programs, building-and appliance-efficiency standards, market transformation initiatives and other efforts were generally more effective for securing conservation. Since 1980, the Northwest has secured more than 1,200 megawatts of electricity savings. About 520 megawatts of that total have been saved since 1991.

Figure 4-1
Generating Resources of the Northwest Power System

(Firm Energy Basis)

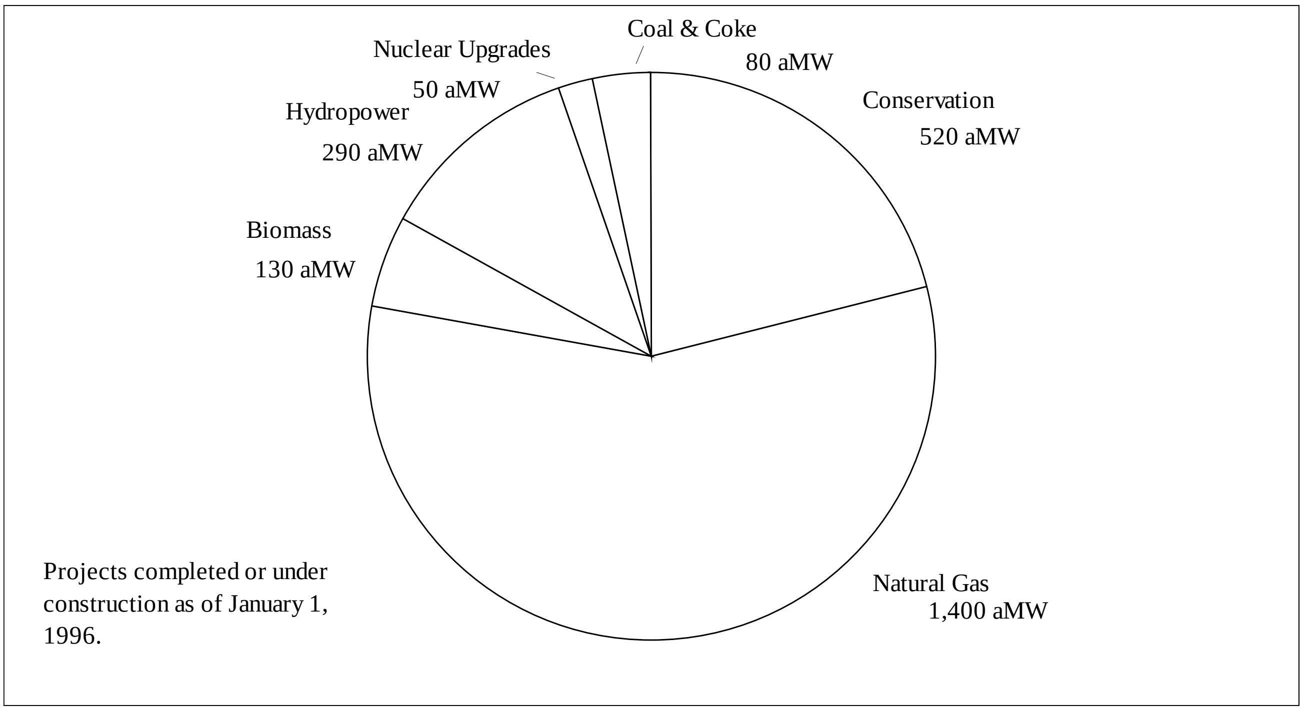


Conservation and generating projects totaling about 2,470 average megawatts of energy were secured during the 1991 through 1995 period (Figure 4-2). Declining natural gas price forecasts, improving combustion turbine technology, declining capital costs, and relative ease and speed of construction continued to improve the attractiveness of gas-fired combined-cycle power plants. Natural gas-fired projects providing about 1,400 average megawatts of energy were acquired during this period, comprising about 57 percent of total acquisitions on an energy basis. About 520 average megawatts of conservation were acquired since 1991, representing about 21 percent of total new acquisitions. Renewable energy projects, primarily hydroelectric and projects using biomass residue fuels, provided about 420 megawatts of resources that were committed to during this period. The balance of acquisitions include upgrades to existing thermal projects and projects using coal or petroleum coke.

Natural gas resources have increased the most in the last five years, from 3 percent in 1991 to 7 percent in 1996, primarily due to the fact that natural gas is among the least expensive and most flexible new generating options available. Although concerns have been expressed about what some have termed an "over-reliance" on gas-fired new generating resources, overall resource diversity is probably greater than it ever has been because of the new gas-fired resources. Furthermore, because of the increasing importance of the Western wholesale electricity market, resource diversity in the Pacific Northwest will probably be of lesser significance than West Coast resource diversity. The Northwest and California systems combined provide significant resource diversity.

Figure 4-2

Resource Acquisitions: 1991 through 1995 (average megawatts)[1]



[1] Projects completed during the 1991 through 1995 period, or under construction at the close of 1995. Planned projects for which construction has not commenced are not included in Figure 4-2.

Although regional electrical load growth continues, there have been no solicitations for new power plants within the past year. Declining natural gas prices and an increasingly active wholesale market have made the surplus of capacity on the interconnected Western system less expensive, more evident and more accessible. Utilities and large consumers are purchasing inexpensive wholesale power produced by existing plants on the Western system rather than building or purchasing the output of new power generating facilities. Low-price wholesale power has even led to suspension of construction for several projects, most notably the 248-megawatt Tenaska Washington II gas-fired combined-cycle plant.

Conservation activities, too, have declined. Conservation acquisitions in 1996 are expected to amount to only 70 average megawatts, about 60 percent of the region's 1995 acquisitions.

The Northwest power system has also lost resources over the last five years, including:

- Reduction of the operational flexibility and generating capability of the Columbia River Basin hydroelectric system as a result of changes in the pattern of reservoir storage and water releases intended to improve the survival of anadromous and resident fish. This has resulted in an estimated reduction of 850 average megawatts of firm energy capability;

- Closure of the Trojan nuclear power plant in the face of a requirement for significant additional capital investment to remedy problems encountered at the plant. This has meant the loss of 725 average megawatts of energy.

The changes in Northwest electricity resources since 1991 have probably resulted in a net increase in the emissions of carbon dioxide, a gas implicated in global warming. Factors that would increase carbon dioxide production include the closing of the Trojan nuclear power plant and the loss of hydroelectric generation due to spilling water to enhance fish passage.

Fish mitigation activities that shift power production seasonally or from firm to nonfirm periods do not necessarily increase carbon dioxide production. Power produced during fish flow periods, for example, may displace carbon-dioxide emitting fossil-fuel plants in the Southwest. But, foregone hydropower during other seasons and the lost power from Trojan will be replaced by higher carbon-dioxide emitting generation, except to the extent the losses are replaced by conservation, hydroelectricity or biomass generation. The net effect of emissions from new gas-fired combustion turbines is difficult to ascertain because the turbines may displace the operation of power plants that emit even more carbons, such as coal-fired plants.

The remainder of this chapter describes the major electricity resources in use in the Northwest.

4-B. The Hydroelectric System

The Northwest's hydroelectric system, although reduced in its capability and flexibility, is still an adaptable and low-cost resource. It produces more than two-thirds of the electricity in the region. In the near term, the region's advantageous position with respect to gas markets and the relative flexibility of gas-fired generation are important complements to the hydroelectric system. The flexibility of the hydroelectric system may also prove valuable when intermittent renewable resources are integrated into the power system. The challenge is to maintain and enhance the value of the hydroelectric system, while at the same time providing for non-power uses such as flood control, irrigation, recreation, transportation and fish and wildlife.

The hydroelectric system differs from thermal generating resources in that its instantaneous generating capacity far exceeds the amount of energy it can produce over the course of a year. This is because reservoirs cannot store enough water to keep turbines running at full capacity all year. Consequently, Northwest utilities have traditionally focused on meeting annual average energy needs as opposed to daily peak electricity demands.

The Columbia River hydroelectric system's sustained peaking capacity[2] is about 25,000[3]

[2] Sustained peaking capacity is the power system's ability to meet electricity demands during the peak hours of the day for

megawatts, but limitations on the storage capacity of the system result in significant variations in the system's energy output from year to year, depending on annual rainfall and snowpack accumulation. In the driest years, the hydroelectric system produces only about 11,700 average megawatts of energy. Utility planners can expect at least that much energy in any given year, so it is considered guaranteed or “firm” energy. In the wettest years, the hydroelectric system produces about 20,000 average megawatts. In average water years, the dams generate approximately 16,500 average megawatts.

Generation in excess of what can be guaranteed is commonly referred to as “nonfirm” or “secondary” energy. Nonfirm energy is sold on the spot market or under short-term contracts at lower prices than is obtained for firm energy. It is used to serve interruptible loads or to displace more expensive resources both in and out of the region.

Accommodating Fish and Power

The Columbia River historically supported one of the world’s largest salmon populations. Over the years, however, the number of salmon and steelhead in the river has decreased dramatically. Several Columbia River Basin salmon species are now extinct. Others have declined nearly to the point of extinction. Hydroelectric development has been an important factor in that decline. The natural flow of the Columbia River peaks in spring and early summer, when the snowpacks melt. Energy production from the hydroelectric system depends on this flow of water. If reservoirs were not available to store water for later use, the energy derived from the hydroelectric system would rise and fall with the natural flow of the river. This would not be a very reliable or valuable source of electricity because peak river flows (in spring) do not coincide with peak electricity demands (in winter). Figure 4-3 illustrates the monthly pattern of river flows under natural conditions, before hydroelectric development, and under current conditions, which include changes in dam operations to protect salmon and other fish and wildlife.[4]

By building dams to hold back some of the spring runoff for use the following winter, the output from the hydroelectric system can better meet the seasonal fluctuations in electricity use in the Northwest. Although this shifting of river flows makes the hydroelectric system a more valuable source of power, it also creates a more hostile environment for migrating juvenile salmon. Inundation of spawning and rearing habitat and hazards created at the dams themselves have also affected salmon production and survival.

But the dams were not built for electricity alone. They also help control flooding, provide water for irrigation and industrial use, improve navigation on the river and expand recreational opportunities in the Pacific Northwest. All these uses can have adverse impacts on both fish and power. In addition, salmon populations have been affected by commercial and sport fishing, ocean conditions, hatcheries and hatchery-bred fish, habitat destruction caused by logging, grazing and other developments, and a host of other factors that are not well understood. The Council’s Columbia River Basin Fish and Wildlife Program addresses all of these impacts.

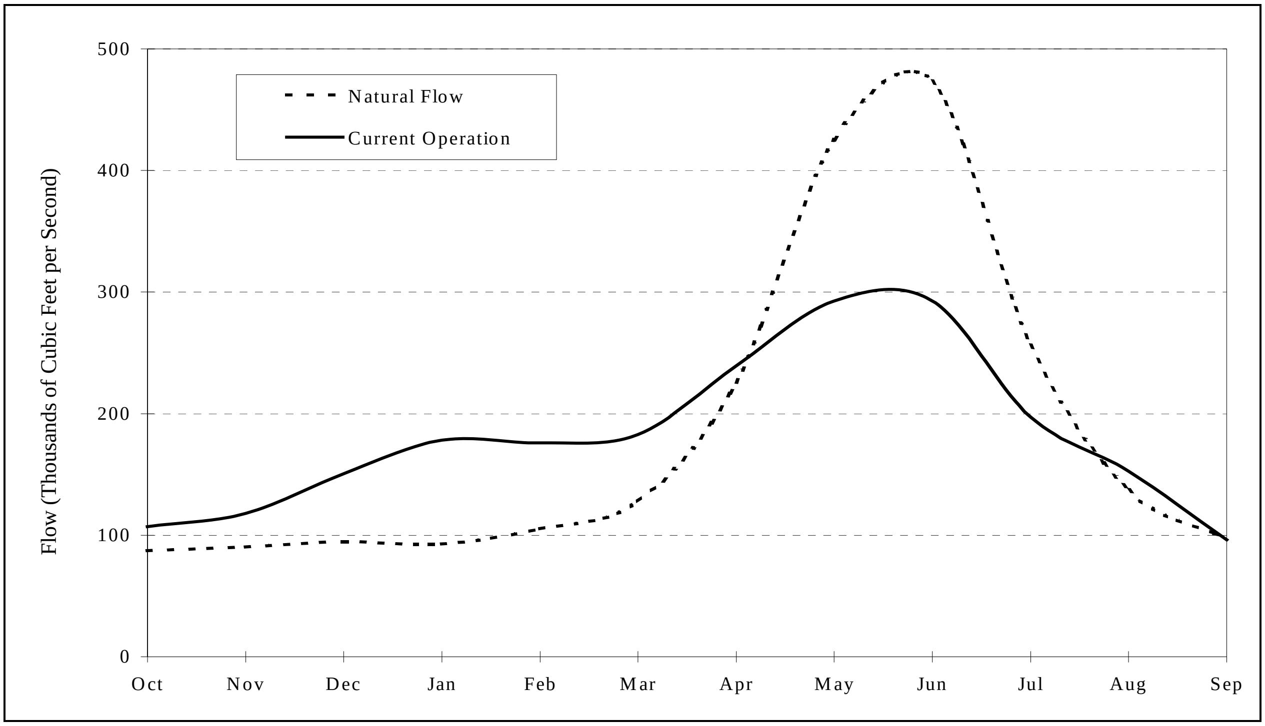
Because the hydroelectric system is one of the important factors affecting fish and wildlife survival, its operation has been modified since the early 1980s in an attempt to create a better balance between the generation of electricity and protection for fish and wildlife. As at-risk fish stocks have weakened, further constraints on the operation of the hydroelectric system have been implemented. The effect of most of these changes is to shift the release of water back toward the spring and early summer to more closely approximate the natural flows of the river. By releasing less water from headwater storage projects during the winter months, more is available for later release during the spring smolt migration period.

a sustained period of time, usually the five working days of the week. The peak demand period per workday typically lasts 10 hours.

[3] 1995 Pacific Northwest Loads and Resources Study, Bonneville “*The White Book*,” December 1995.

[4] Natural flow data was obtained from the Bonneville Power Administration’s document “Seasonal Volumes and Statistics, Columbia River Basin 1928-1989,” July 1993.

Figure 4-3
Average River Flows at The Dalles Dam



However, this action reduces the amount of energy available from the hydroelectric system during the winter months and forces the production of energy during a time when it is not in great demand. This effectively reduces the firm energy generating capability of the hydroelectric system. During dry years, lost winter energy must be replaced if all firm energy demands are to be served.

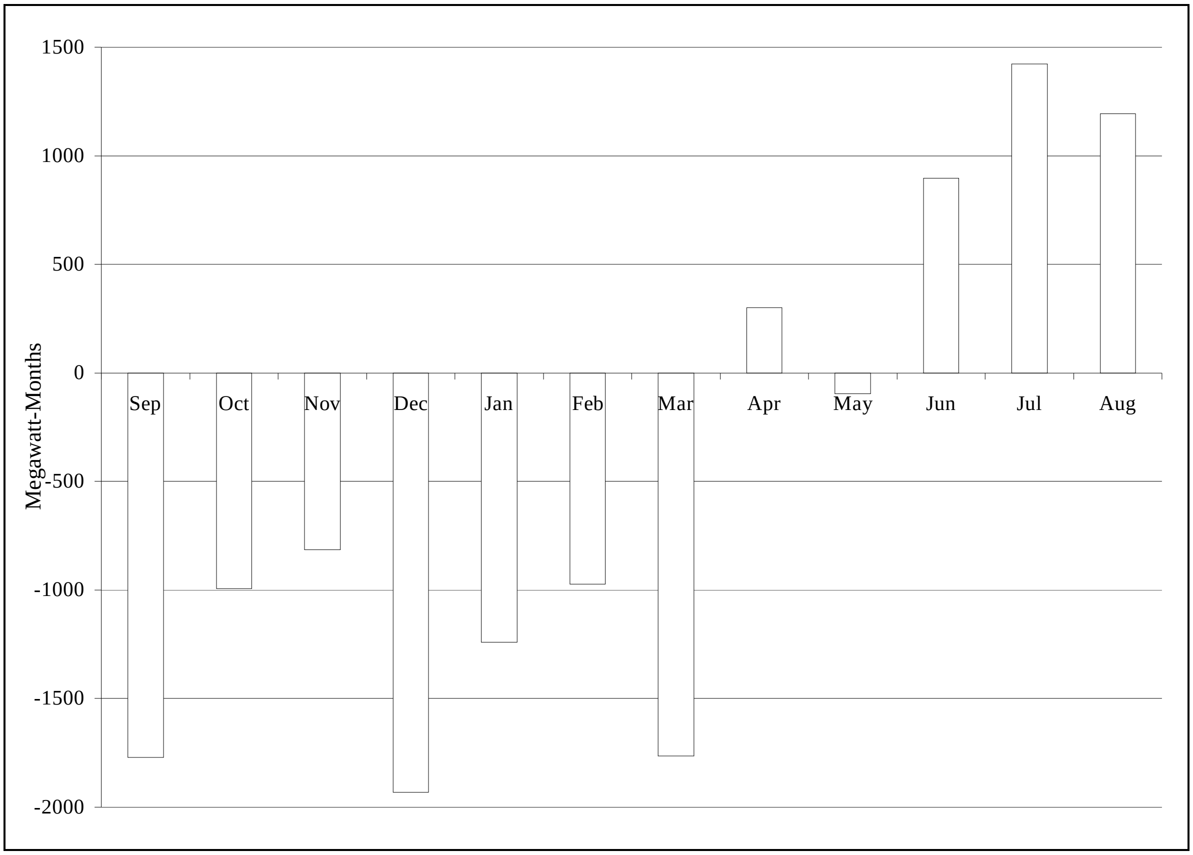
The Council's 1982 Fish and Wildlife Program included measures that reduced the firm energy generating capability of the hydroelectric system by an estimated 300 average megawatts. In addition, water laden with juvenile salmon was spilled over dams to divert the young fish from the turbines. The spills further reduced the firm energy generating capability of the system by about 50 average megawatts. This was the river operation that was used as the basis for resource analysis in the 1991 Power Plan.

Since 1991, more fish and wildlife protection measures have been implemented. Changes in river operations since 1991, including those enacted by the National Marine Fisheries Service to protect endangered Snake River salmon, have reduced the firm generating capability by an additional estimated 850 average megawatts (about a 7-percent loss). Consequently, the total reduction in firm energy generating capability of the hydroelectric system since the Council adopted its first fish and wildlife program amounts to approximately 1,200 average megawatts, representing a 10-percent loss. Figure 4-4 illustrates the average monthly change in hydroelectric generation due to fish and wildlife measures.

Under current operations, the hydroelectric system produces an average of nearly 10,000 megawatt-months less energy in the fall and winter compared to 1991 operations. About 4,000 megawatt-months are shifted into spring and summer months, and nearly 6,000 megawatt-months of energy are spilled or lost due to efficiency losses.[5]

[5] Efficiency losses occur when power is generated at lower reservoir elevations. Reservoirs are operated at lower elevations in order to increase the velocity of the river.

Figure 4-4
Changes in Hydroelectric Generation by Month Since 1991



In some fall or winter months, it can be necessary to purchase electricity from outside the region to provide adequate water for spring flow augmentation and serve firm Northwest electricity demands. The total cost to the power system of operations to protect fish and wildlife are calculated by combining power purchase costs, lost revenues due to reductions in firm power production and changes in the amount and value of nonfirm power.

A more constrained operation of the mainstem Columbia and Snake river reservoirs also results in capacity losses. For example, prior to the 1980s, the elevation of the lower Snake run-of-river projects varied five feet or more on a daily basis. These dams are drafted during the peak-demand hours of the day and refilled during the light-load hours of the night. If these reservoirs are now constrained to fluctuate only about a foot to benefit various fish populations, they lose much of their ability to meet daily peak-demand swings. This limited operation may also result in the loss of nonfirm energy. If reservoirs are not allowed to fill completely during the lightly loaded hours of the night due to elevation limitations, some water may have to be spilled, resulting in lost generation.

4-C. Other Generating Resources

In addition to the hydroelectric system, other sources of bulk electric power in the Northwest include large coal-fired power plants, the Washington Public Power Supply System's WNP-2, and simple-cycle and combined-cycle natural gas combustion turbines. Electricity is also produced by industrial cogeneration plants, small biomass plants and numerous small hydroelectric projects. A table and map of individual Northwest power generating projects is provided in Appendix A.

Coal-fired Power Plants

Following the development of the Columbia River hydroelectric system, coal and nuclear power were viewed as the most economical new sources of electricity. Abundant supplies of low-cost, low-sulfur coal are available from the Rocky Mountain states and western Canada fields, and more limited supplies of lesser quality from Washington fields. Accordingly, between 1968 and 1986, 14 coal-fired power units at six sites were brought into service by Northwest utilities. These large plants can serve about 6,660 megawatts of winter peak load, of which about 3,990 megawatts are currently dedicated to Northwest loads. These plants can produce about 5,520 average megawatts of energy, of which 3,395 average megawatts are dedicated to Northwest loads. Because the minemouth units have low operating costs, they are operated under nearly all conditions. Units that use coal supplied by rail are more expensive to operate and currently compete with natural gas combined-cycle power plants and off-peak power from Southwestern plants.

Nuclear Power Plants

Concurrent with the development of the region's large coal-fired power plants, regional utilities initiated construction of 10 nuclear plants. Only two, Trojan, in Oregon, and WNP-2, in Washington, were eventually completed.[6] Two partially completed plants, WNP-1 and WNP-3, were preserved for many years for completion, if needed. With the continuing decline in gas prices, they have been terminated. Nuclear plant operating costs have generally been higher and plant availabilities lower than anticipated when these plants were ordered.

Trojan was permanently shut down in 1993, when it was concluded that the cost of a needed steam generator replacement would result in production costs barely competitive with the cost of power from new resources. WNP-2, upgraded from its original peak capacity, can now serve about 1,170 megawatts of winter peak load. The plant produced 822 average megawatts of energy in Bonneville's 1995 Fiscal Year and was available to produce 890 average megawatts. WNP-2 currently has operating costs that are above market prices. The Washington Public Power Supply System, owner and operator of the plant, has established aggressive cost reduction targets. However, continued low market prices pose a risk for the continued operation of WNP-2.

Natural Gas-Fired Combined-Cycle Power Plants

The abundant gas resources of Western Canada and the Rocky Mountain states are accessible to the Northwest by two interstate pipelines. Declining natural gas prices and improving combustion turbine technology have made gas-fired combined-cycle power plants the least-costly new resource for bulk power production. Most of these projects consist of one or two combined-cycle combustion turbine units, and many serve modest cogeneration loads.

Six gas-fired combined-cycle projects were in service in the Northwest by the end of 1995. Two additional projects are under construction.[7] Projects in service or under construction at the end of 1995 will serve about 1,900 megawatts of winter peak load and can produce about 1,460 average megawatts of energy. Some of these projects are owned by independent developers and others by utilities.

Additional projects totaling about 930 megawatts of capacity are currently permitted for construction. One of these projects is partially constructed, but further construction has been suspended. Construction on the other projects is not scheduled. License applications for additional projects of about 2,700 megawatts total capacity are being considered by licensing agencies. Developers have indicated that they will apply for licenses for several additional projects.

Three of the projects for which licenses are being sought are part of Bonneville's Resource Contingency Program. This program responded to the 1991 Power Plan's call for obtaining "options" on the development of 2,450 average megawatts of new generating resources. By taking projects

[6] Trojan was completed in 1976 and WNP-2 in 1984. The Hanford Generating Project operated on steam from the N-reactor, a Hanford Production Reactor, until 1988, when it was shut down upon termination of plutonium production operations at Hanford.

[7] Combined-cycle power plants in operation in the Northwest by the end of 1995 include Beaver, March Point, Sumas Energy, Tenaska Washington I, Encogen and Coyote Springs 1. Hermiston Generating Project is scheduled for service in 1996. Construction of the River Road project commenced in February 1996. Additional information regarding these projects is supplied in Appendix A.

through the siting and licensing process, but delaying the actual construction until the market for the power is clear, it is possible to reduce the risk of investing in generation in advance of need. The options concept was devised primarily for long lead time resources and a regulated generation market. The value of options with resources that have much shorter lead times and a competitive generation market may not be as great as it was under those earlier conditions. On the other hand, siting and licensing some projects in advance of market demand may continue to provide some benefits for both prospective developers and the public.

Industrial Cogeneration

Industrial cogeneration in the forest products industry has long been a component of Northwest electric power generation. These plants include chemical recovery boilers in the pulp and paper industry, and power boilers fired by wood residues, fuel oil and gas in both the pulp and paper and lumber and wood products sectors. More recently, gas-fired combustion turbines have been installed as industrial cogeneration units.

Because of the many mill closures of recent years, and because many industrial cogeneration plants do not sell power offsite or generate power only when fuel costs are favorable, a precise inventory of operating industrial cogeneration plants is difficult to obtain. There are estimated to be approximately 70 plants in operation. These total in excess of 770 megawatts of capacity and are capable of producing in excess of 600 average megawatts of energy. Most industrial cogeneration plants in the Northwest are owned by the host facility, but recently several have been developed by utilities.

Other Renewable Resource Projects

Biomass: Many of the cogeneration plants described above use wood residues, spent pulping liquor and other biomass fuels. The number and diversity of small biomass plants has expanded in recent years and now includes plants using pulping liquor, wood residues, landfill gas, municipal solid waste and wastewater treatment plant gas.

Hydroelectric: Many hydroelectric projects have been developed on coastal streams, tributaries of Puget Sound and tributaries of the Columbia River. Most suitable large-scale sites have been developed, and recent development has focused on headwater diversion projects, projects on irrigation systems and upgrades of older hydroelectric projects.

Geothermal: There has been no commercial development of the potentially abundant geothermal resources of the Northwest for electric power generation.[8] Pilot projects are being developed at Newberry Volcano, in Oregon, and Glass Mountain, in Northern California, to explore the cost and feasibility of using these resources for power generation. Though it is unlikely that these projects will be competitive with the near-term wholesale power market, geothermal may prove to be an important source of renewable power in the long term.

Wind*:* Four commercial-scale wind projects are being developed to explore the cost and feasibility of using this resource for power generation in the Northwest. Though more expensive than electricity from new gas-fired combined-cycle power plants, wind power is the least-costly renewable alternative for producing large quantities of energy.

Solar: Solar photovoltaic power is often cost-effective for small, remote loads. Applications of this type continue to increase.

Other Projects

Several gas and oil-fired combustion turbines serve peak loads and may generate bulk power when gas prices are low. Other gas or oil-fired small combustion turbines, older steam plants and engine-generator sets provide emergency electricity service.

4-D. CONSERVATION

Conservation is the first-priority electric power resource in the Northwest Power Act, where it is defined as "any reduction in electric power consumption as a result of increases in the efficiency of energy use, production, or

[8] Small demonstration projects operated briefly at Raft River, Idaho, and Lakeview, Oregon. Numerous direct applications of geothermal energy for space or process heating are found in the region.

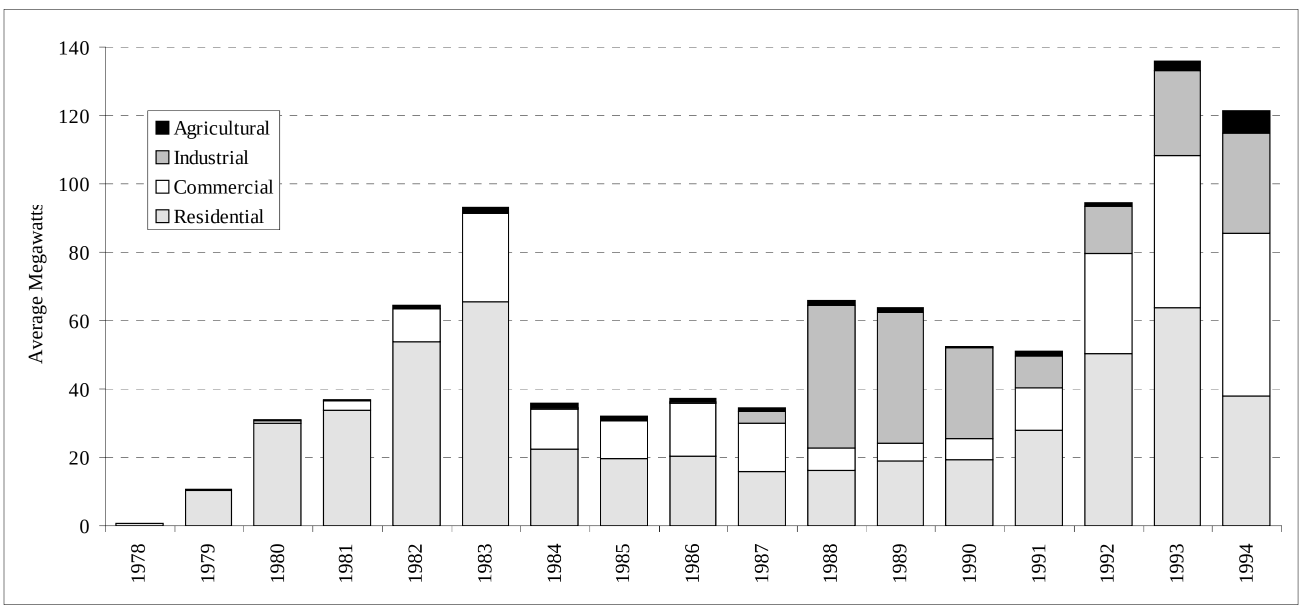
distribution." As a result of utility-supported conservation efforts undertaken since the passage of the Act in 1980, the cumulative conservation savings enjoyed by the region's electricity consumers in 1996 amounts to about 1,000 average megawatts. This level of annual savings is equivalent to the power output of five average-sized gas-fired combustion turbines. Utility-funded energy conserved since the passage of the Act amounts to nearly 60 billion kilowatt-hours, with a retail value to consumers of $2.5 billion.

An additional 200 average megawatts are estimated to have been saved through programs, codes and standards at local, state and national levels. Figure 4-5 depicts the annual utility-sponsored first-year conservation savings by sector from 1978 to 1994. This information comes from Nutrak, the Council's Northwest Utility Conservation Tracking System.

To accomplish these savings, the region has weatherized more than half a million homes or apartments, replaced thousands of showerheads with efficient models, installed efficiency measures for a quarter-million irrigated farm acres, produced several hundred thousand new high-efficiency site-built homes and 65,000 high-efficiency factory-built homes, upgraded the residential and commercial energy codes across the region, made conservation modifications to the aluminum refining plants, and developed a thriving energy-efficiency industry. These accomplishments have required perseverance, commitment, fresh thinking and hard work. They also required an estimated outlay of more than $2 billion. The Council has estimated that these savings were acquired at an average real levelized utility cost of about 2 to 2.5 cents per kilowatt-hour, about half the cost of the next most costly resource available at the time.

The pattern of conservation acquisition over time demonstrates some of the flexibility of the resource. After a period of surplus generating capacity in the mid-1980s, the 1991 Power Plan forecast a need for new resources and called for the region to acquire at least 1,500 average megawatts of energy savings by the end of the decade.

Figure 4-5
Regional Summary of First Year Conservation Savings by Sector, 1978-1994



This meant a shift in emphasis from conservation "capability building" to conservation resource acquisition.[9] From 1991 through 1994, the region's electric utilities acquired about 400 average megawatts of energy savings, exceeding the expectations of the 1991 plan. Since 1980, the region's public utilities, including Bonneville, have delivered about 56 percent of the total savings, and the investor-owned utilities delivered about 44 percent. The figure below charts the public/investor-owned utility split.

The ups and downs of annual conservation efforts shown in Figure 4-6 are due to the fact that the region was in need of electricity in the late 1970s and early 1980s, and conservation efforts were accelerated. In the early to middle 1980s, the region was in a period of surplus capacity, and conservation efforts were slowed. In the early 1990s, there was again a need for resources, and the region responded once again by increasing conservation efforts. In the mid-1990s, conservation is again being slowed, as utilities see an uncertain future, and inexpensive energy is abundant in the West Coast market.

Fuel Choice

The issue of fuel choice is related to electricity efficiency. The specific issue raised for the Council has been direct use of natural gas in homes and businesses as an alternative to the use of electricity generated by burning natural gas. In 1994, the Council studied the direct use of natural gas in homes. The study found that, although in many cases direct use of natural gas is more *energy* efficient than electricity use, the most *economically* efficient resource is very application-specific.

In general, conversion to natural gas is most cost-effective in homes that use a lot of energy. Thus, large homes, poorly insulated homes, or homes in colder climates tend to be the most promising conversion candidates. The Council estimated there might be 730 average megawatts of cost-effective residential fuel conversion savings available in the region. This was primarily from conversions of electric water heaters or electric forced-air furnaces to natural gas. Just as lower avoided electricity costs have reduced the potential amount of cost-effective electricity conservation, so would it reduce the amount of cost-effective fuel conversions.

The Council adopted a policy of considering direct use of natural gas as an alternative to conservation or electricity generation. The policy further stated that market-based approaches were the preferred method of pursuing cost-effective direct gas use. The primary methods of implementing this policy were thought to be encouraging the efficient pricing of electricity and ensuring that conservation incentive payments were not distorting market decisions away from direct use of natural gas where that is the more cost-effective option.

Both of these market-distorting problems are being substantially solved by the restructuring of the electricity industry. Low-priced natural gas generation alternatives have reduced the marginal cost of electricity to near the average cost-based electricity price. As a result, much more accurate price signals are evolving in the electricity market. Electricity market restructuring may also substantially eliminate the ability of electric utilities to make incentive payments for increased electric efficiency. Even before these changes, the market penetration of natural gas had been quite strong in areas where gas is available. With the restructuring of the electricity industry, there is no longer a convincing need to intervene in the fuel-choice market, nor is there really any effective way to do so.

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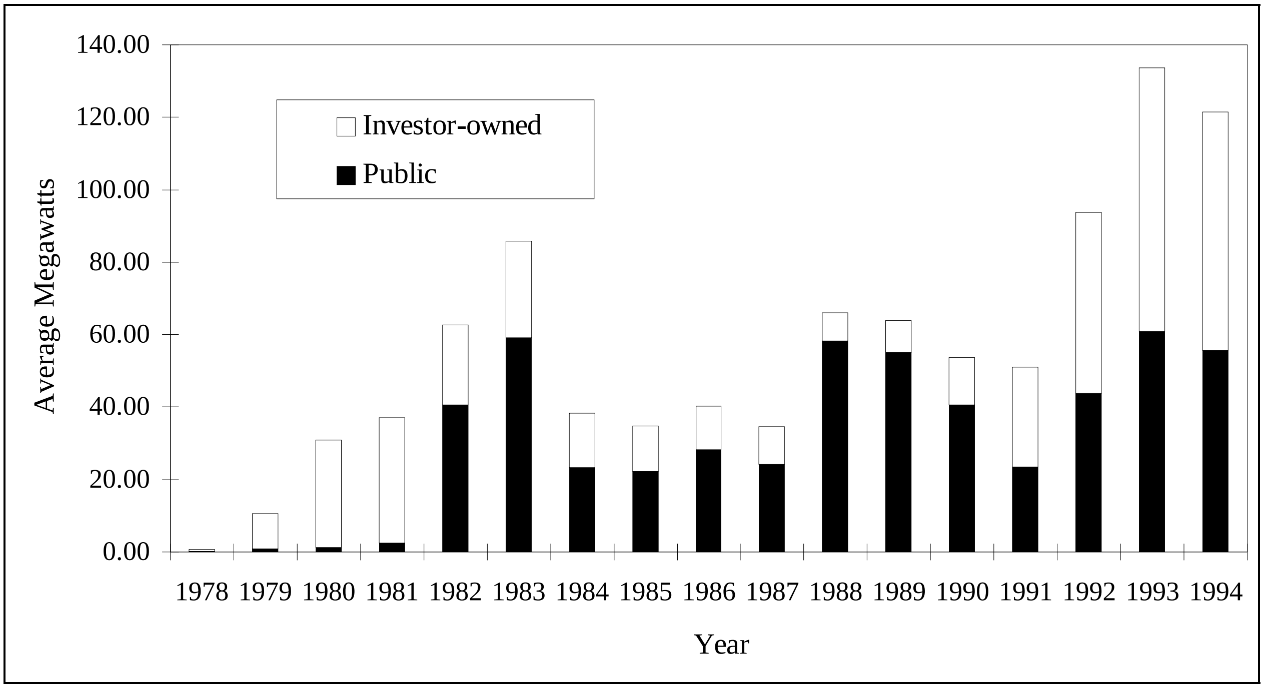
[9] Conservation capability building in the mid to late 1980s was directed at maintaining a viable conservation infrastructure and carrying out experimentation to identify viable strategies for conservation acquisition. The major exception to this was the Conservation/Modernization project carried out with the aluminum companies in the late 1980s. The purpose of this project was as much or more to maintain the viability of the aluminum industry in this region in a period of depressed world aluminum prices as it was to acquire conservation savings.

Figure 4-6
First Year Conservation Savings by Utility Type (Public/Investor-Owned)



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CHAPTER 5

FORECASTS AND RESOURCE TRENDS

This chapter describes the Council's forecasted range of electricity growth and its forecast of natural gas prices. These forecasts help indicate the potential level of increases in electricity use the region might experience. This lays the foundation for looking at what potential resource options are available to fill those growing needs.

This chapter also describes the outlook for the West Coast power market and assesses the amount and cost of electricity available from this market over the long run. As the current surplus in this market is depleted, construction of new generating capacity may resume. Brief descriptions of the estimated cost and quantity of generating resource alternatives that are available for development in the Northwest if new capacity is needed are also included in this chapter. This chapter ends with a description of the uncertainties and future capability of the hydroelectric system and their implications.

5-A. GROWING DEMAND FOR ELECTRICITY

In the midst of all of the changes in the electric power industry, the region's economy continues to grow, and businesses and consumers continue to rely on electricity and other forms of energy as an important component of their activities. It is this growth in economic activity and its changing composition that is the primary determinant of the region's increasing demand for electricity, although that increasing demand is also affected by changing prices for electricity and other fuels.

Economic Patterns

The economic outlook for the Pacific Northwest continues to be strong, although there is always significant uncertainty about the amount of economic growth the region will experience. Recent economic growth in the region has continued to outstrip the nation as it has on average for the last 30 years or more.

Two major categories of business activity are typically distinguished in analyzing regional economic growth. Manufacturing industries are engaged in the transformation of substances or materials into new products. Electricity consumed in these activities is assigned to the industrial electricity demand sector. The second major category of business economic activity, non-manufacturing, includes activities such as services, construction, wholesale and retail trade, mining, agriculture and government. Electricity consumed in these activities is assigned to the commercial demand sector. The electricity used by individual consumers makes up the residential demand sector.

In the past, the region's manufacturing sector has been dominated by natural resource-dependent activities. Lumber, paper and food products accounted for half of the region's manufacturing employment in 1970. Although these industries are still significant, their relative importance is declining. Currently, the largest manufacturing industry in the Northwest is electronics, which is composed of machinery, electrical equipment and professional instruments. The second largest manufacturing industry is transportation equipment, primarily The Boeing Company in Washington. Transportation surpassed lumber and wood products as the largest manufacturing sector in 1989. The historically dominant lumber and wood products industry now makes up the third largest manufacturing industry.

Although receiving far less media attention, the non-manufacturing sector dominates regional employment. These activities account for 85 percent of regional jobs, having grown from an 80-percent share 25 years ago. The largest non-manufacturing sectors are services, retail trade and government. Recent growth has been fastest in business services, health services, engineering services, legal services and restaurants.

The most likely range of economic forecasts shows that the region could add between 1.2 and 2.5 million employees by the year 2015, with 1.7

million added in the medium case. Nearly all of this additional employment occurs in non-manufacturing industries. By 2015, the non-manufacturing share of total regional employment could grow to nearly 89 percent.

Electricity Demand Forecast

The composition of economic growth is an important determinant of the growth in electricity demand because different sectors have significantly different energy requirements. On average, the region's businesses required about 22 megawatt-hours of electricity per employee in 1994. However, the manufacturing sector requires about nine times as much electricity per employee as the commercial, or non-manufacturing, sector. Therefore, the more rapid growth of the non-manufacturing sector tends to gradually reduce the electricity intensity of the region's economy.

Even within the manufacturing sector, there are dramatic differences in the electricity intensities of various subsectors. Four of the 20 subsectors in manufacturing account for about 80 percent of the electricity use. These four are metals, paper, lumber and chemicals. The same four industries, however, account for only 27 percent of the manufacturing sector employment. These large electricity users are generally among the slowest growing industries in the economic forecast, and this tends to further reduce the electricity intensity of the regional economy.

However, there is a new electricity-intensive sector projected to show very rapid growth over the next several years. This is a portion of the electronics industry engaged in the manufacture of silicon wafers, computer chips and microprocessors. The large number of these plants that are expected to come on line over the next several years has the potential of adding about 250 average megawatts of industrial electricity demand.

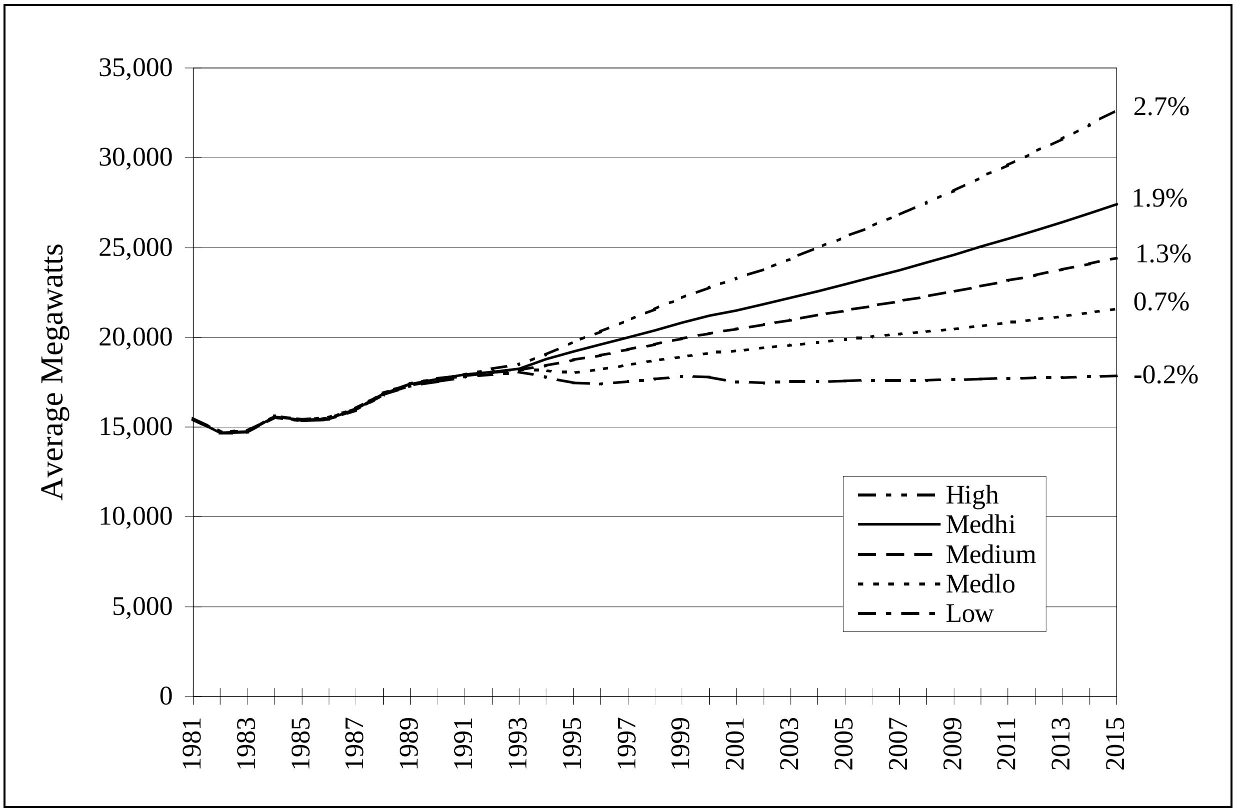
Personal consumption of electricity occurs in the residential sector. The amount of electricity used per household in the Northwest has been gradually trending downward since 1980 in response to several factors. These include a large electricity price increase around 1980, regional conservation programs and declining natural gas and oil prices starting in the mid-1980s. The medium forecast shows a continued downward trend in residential electricity intensity.

The medium forecast of electricity demand shows that the region could add about 5,920 average megawatts of firm demand between 1994 and 2015. This amounts to an additional 282 average megawatts per year and an average annual growth rate of 1.3 percent.

The demand for electricity is, however, inherently uncertain. For this reason, the Council produces a range of demand forecasts. With resources that are less capital intensive and have shorter lead times, and the emergence of a West Coast surplus power market, the risks associated with demand uncertainty are less than in the past. Nonetheless, it is still worthwhile to consider the implications of demand uncertainty.

The current electricity demand forecast projects growth rates to be between 0.7 percent and 1.9 percent per year, with equal and relatively high probability. This amounts to a difference of approximately 7,000 average megawatts over the 20-year planning horizon. It is possible, although much less likely, for growth, in the low and high cases, to be as little as negative 0.2 percent or as much as 2.7 percent per year, respectively. This is a difference of more than 14,000 average megawatts over the 20-year planning horizon. Figure 5-1 illustrates the forecast range in a long-term historical context.

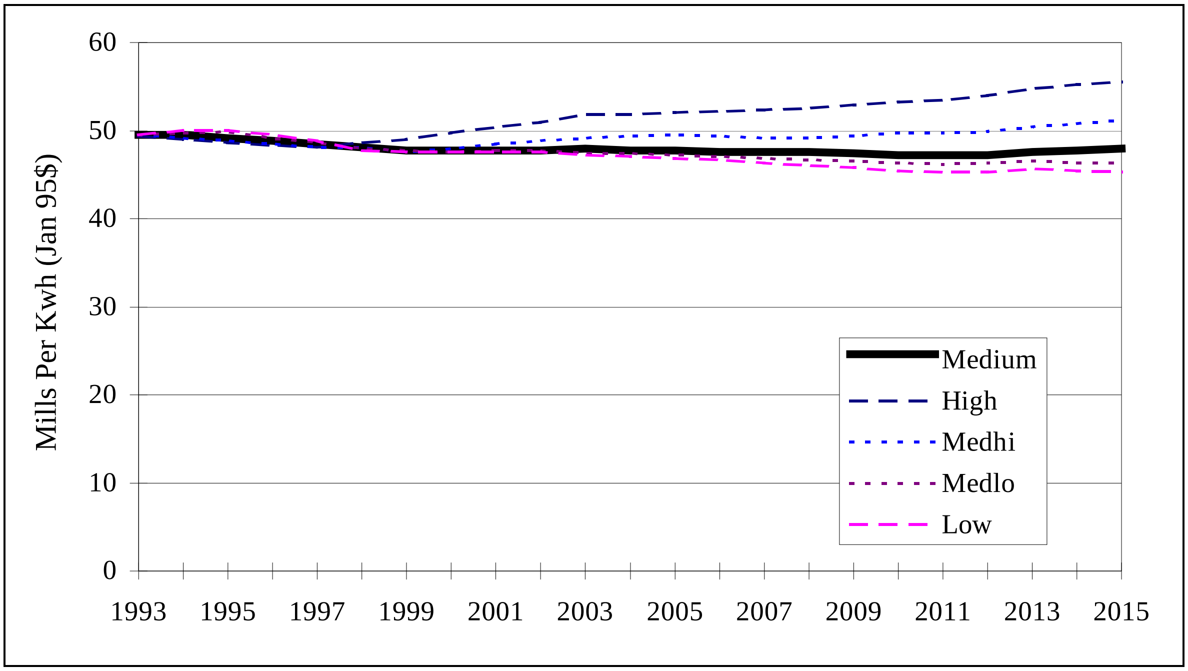
Figure 5-1
Demand Forecast Range in a Long-Term Historical Context



The composition of the forecasted use of electricity changes very little between 1994 and 2015. Residential and irrigation shares decrease by 1 percent each with the industrial sector gaining the 2 percentage points. Within the industrial sector, there is a shift away from Bonneville's direct service industries and toward other industrial customers.

The demand forecasts reflect an expectation that the region will experience generally stable electricity prices that will probably decline slightly in real terms in the medium and lower demand forecasts. This is illustrated for the residential sector in Figure 5-2. These are average rates per kilowatt-hour, including all fixed and variable costs.

Figure 5-2
Forecast of Average Residential Rates



Electricity prices are forecast simultaneously with electricity demand. In past forecasts, electricity price growth was very sensitive to the rate of growth in electricity demand. This is no longer the case for two reasons. First, the cost of new electricity generating capacity is no longer substantially greater than the cost of the existing regional power resources. This is primarily due to the lower forecasts of natural gas prices and the technological advancement in combined-cycle combustion turbines. Second, there is substantial opportunity to improve the use of electricity generating capacity throughout the West Coast power system. The opening up of the wholesale power market will facilitate that improvement. As a result, fewer new resources will be required, and those that are required will be less costly than in the past. The average regional electricity price forecasts are shown in Table 5-1.

Table 5-1
Average Regional Real Retail Electricity Price Forecasts

(1995 Cents Per Kilowatt-hour)

Forecast Case	1994	2005	2015	Growth Rate 1994-2015
Low	4.2	3.92	3.76	-0.5 %
Medium Low	4.2	3.87	3.80	-0.5 %
Medium	4.2	3.89	3.91	-0.3 %
Medium High	4.2	4.05	4.19	0.0 %
High	4.2	4.30	4.65	0.5 %

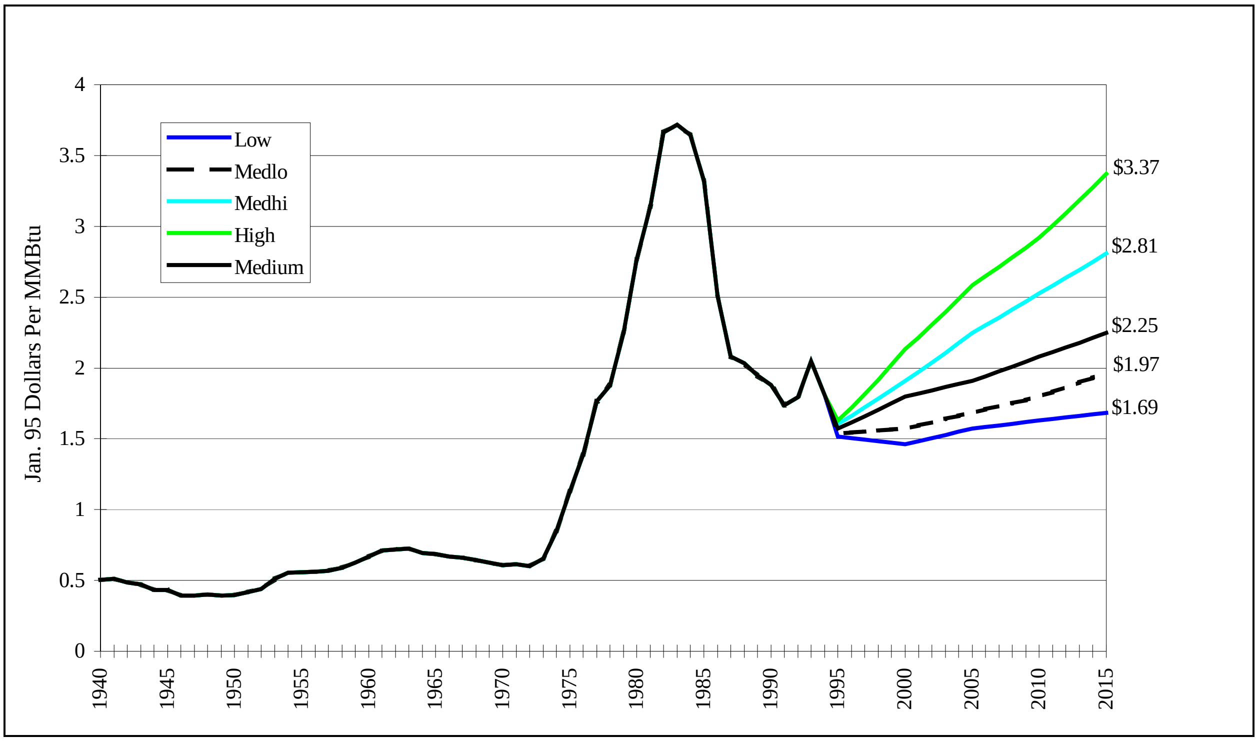
5-B. NATURAL GAS PRICE FORECASTS

Natural gas prices have two significant impacts on electricity consumption. First, natural gas prices relative to electricity prices help determine which fuel consumers will select for key pieces of energy consuming equipment, such as space and water heaters. Second, the price of natural gas significantly determines the cost of gas-fired combustion turbines, which in turn is a key resource for new electricity generation. As a result, natural gas prices influence both the amount of electricity consumed and the cost of supplying new resources.

As described later in this chapter, the restructuring of the natural gas industry has resulted in a vibrant market, producing dramatic decreases in natural gas prices and a growing estimate of natural gas supply. Ranges of natural gas and other fossil fuel price assumptions have been declining and becoming narrower since the Council developed its 1991 Power Plan.

Based on several national gas price forecasts and advice from the Natural Gas Advisory Committee, the medium-case forecast assumes that average real U.S. gas prices will grow at about 1.0 percent annually, increasing from the 1994 level of $1.84 to $2.25 by 2015. The lower cases recognize that real prices may remain flat or even decline slowly over time, and the higher cases explore the possibility that we have become too optimistic about the natural gas future as a result of recent patterns. However, even in the high forecast, gas prices reach only $3.37 compared to a high case of $6.00 contained in the Council's

Figure 5-3
Average U.S. Wellhead Natural Gas Prices: Historic and Forecast Range



forecast of natural gas prices in October 1992. Figure 5-3 illustrates the historical average U.S. wellhead price and the Council's forecast.

While national trends in natural gas prices are usually indicative of regional trends, they are not a good indication of actual gas prices in this region. The Pacific Northwest gets most of its gas supplies from Canada and the U.S. Rocky Mountains. These are the two lowest-cost natural gas producing regions in North America. As a result, prices of natural gas delivered into the pipelines serving the Pacific Northwest are substantially lower than prices in most of the country. For example, on October 2, 1995, gas delivered into the U.S. Pacific Northwest from Canada was about $.90 per million Btu, and gas delivered into the pipeline serving the Pacific Northwest from the U.S. Rocky Mountains was $1.04 per million Btu. At the same time, at the Henry Hub in Louisiana, the pricing point for NYMEX gas futures contracts, gas was $1.65 per million Btu. The Northwest's pricing advantage fluctuates with market conditions, but a $.50 advantage is fairly typical.

The low price for Canadian natural gas, which is primarily produced in Alberta and British Columbia, results from the large relatively less-developed gas resources, limited pipeline capacity to move gas out of Canada, and long distances to major gas markets outside the Northwest. These conditions are expected to continue to benefit the Pacific Northwest with relatively low gas prices for the forecast period, although the advantage relative to national prices is expected to decline to some degree in most forecast cases.

The prices of natural gas to final users depends on the cost of transporting and distributing the gas to the point of use. For smaller customers, these costs are a larger share of the delivered cost of natural gas. Because pipeline and distribution costs are not expected to escalate rapidly in real terms, the growth rates of prices to residential and commercial customers are moderated. The medium forecast used for this draft plan is summarized in Table 5-2. The complete range of forecasts may be found in Appendix C.

Table 5-2
Medium Case Forecast of Natural Gas Prices Delivered to End Users
(January 1995 Dollars per Million Btu)

Case and Sector	1994	2005	2010	Growth Rate 1994-2015
Residential	5.21	5.28	5.62	0.4 %
Commercial	4.43	4.49	4.83	0.4 %
Industrial	2.30	2.57	2.88	1.1 %
Electric Generation	1.82 (est.)	2.14	2.52	1.6 %

5-C. THE WESTERN POWER MARKET

The electricity forecasts indicate that loads could grow by about 5,920 average megawatts by the year 2015, if medium economic growth occurs. There are a number of resources that could be used to meet this load growth, including the West Coast power market, which currently has an abundance of low-cost resources.

The Northwest has traditionally thought of itself as an island of cheap electricity with links to the rest of the West. These Western connections can be used to increase reliability; to dispose of surplus nonfirm hydropower (which was the primary purpose for constructing the Intertie lines between the Northwest and Southwest); and to make exchanges that do not involve net sales of firm energy (e.g., transactions where the Northwest supplies peak capacity and the buyer returns the energy in its off-peak hours or season). Such exchanges were exempted from restrictions under the Northwest Preference Act, which was passed with the initial construction of the Intertie, because they were consistent with the concept of an island of cheap electricity. The closest these ideas came to being challenged were calls for increased reliance on gas-fired combustion turbines or purchases from California gas generation, which could be extensively displaced by nonfirm energy to meet firm Northwest loads. Until very recently, these notions were basically intact.

Several things have dramatically changed this perspective in the last few years. The first is the general assumption that the fall in gas prices in the mid-1980s, described earlier in this chapter, was not an anomaly. The second is the still-unfolding consequence of the Energy Policy Act of 1992 (EPAct), which allowed the Federal Energy Regulatory Commission (FERC) to require open access to the nation's transmission systems and legitimized major non-utility power suppliers, marketers and brokers as players in the nation's power markets. These factors are driving the industry toward a wide-open wholesale power market.

The Western Generation and Transmission System

To estimate how much electricity could be brought into the Northwest from Southern and Southwest markets, the Council analyzed how much transmission was available. To exclude indigenous Northwest resources, the analysis left out the Northwest Power Pool Area of the Western Systems Coordinating Council (WSCC), leaving in only California, the Inland Southwest and the southern Rocky Mountain area. (See map.) This area's generating resources, as of January 1995, are shown in Figure 5-4. Figure 5-5 shows the forecast load and resource balances for the next nine years. Data for both figures are from the WSCC's 1995 planning documents.

Figure 5-4
1995 WSCC Winter Generating Capability
(Excluding Northwest Power Pool Area)

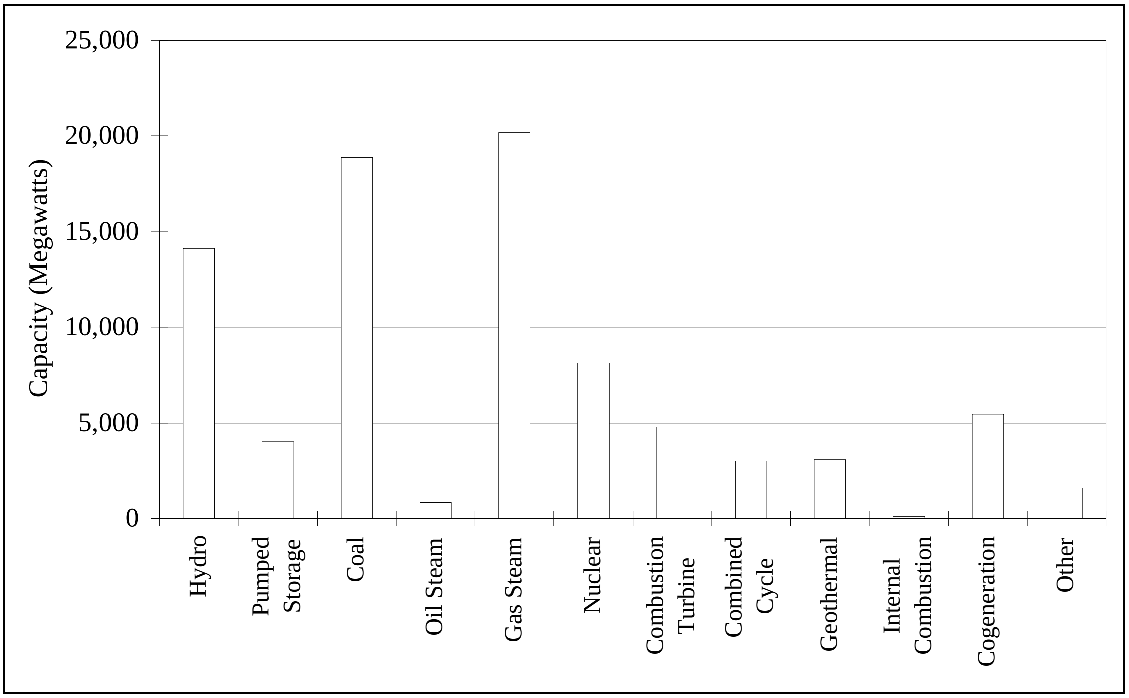
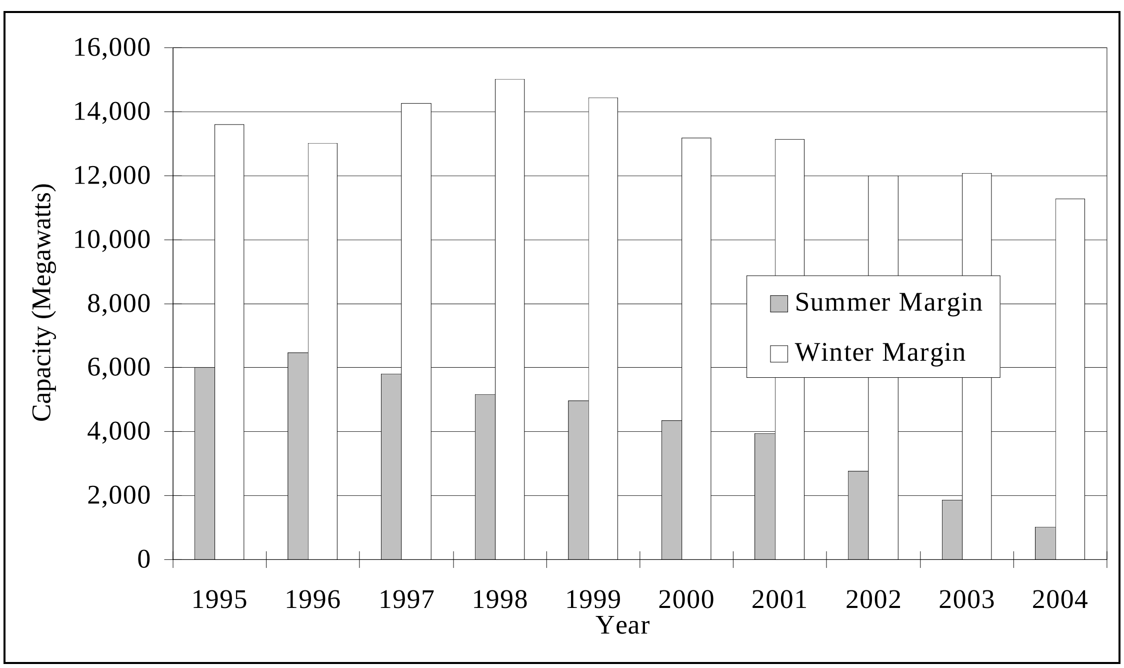


Figure 5-5
WSCC Surplus Above Required Reserves
(Excluding Northwest Power Pool Area)



There are three major points to be drawn from these figures. The first is that there is a substantial amount of gas-fired steam generation in this area, when gas prices are low. The second is that there is a surplus during the summer, which is the WSCC's peak period, that extends past the year 2000, although there are important qualifications about the plants that make up the surplus and their marketability. Third, and most importantly, the surplus during the winter, which is the Northwest's peak period, is larger and is likely to extend indefinitely until it is either contracted away to the Northwest or is limited by, for example, air quality concerns at the generation sites.

Transmission Constraints

The Northwest is currently connected to California and the Inland Southwest by two major interties, the AC Intertie to Northern, and to a lesser extent, Southern California, and the DC Intertie directly to Southern California. Southern California is in turn connected to the Inland Southwest, the site of large portions of its own generation, by major 500-kilovolt lines. The ability to import from the Southwest and Southern California to Northern California on the AC Intertie can be limited to as little as 1,300 megawatts under some load and generation patterns. The AC Intertie capability from Northern California into the Northwest is capable of delivering approximately 3,700 megawatts. However there is typically far less electricity available in Northern California, except during good runoff conditions in the spring. At that time, the California hydropower competes with Northwest hydropower on the market.

The DC Intertie can generally be loaded to its full rating, approximately 2,900 megawatts south-to-north, without impinging on reliability criteria based on the stability of the transmission system. However, heavy and long-term reliance on imports on the DC Intertie, which is a single line in a single right of way, to meet loads could incur the risk of not having an alternative contractual pathway in the event of an outage on the line. In recent years, prolonged outages have occurred because of a fire and an earthquake in Southern California.

An additional high voltage line, the Southwest Intertie Project, connecting the Southwest with the Northwest, is in the advanced subscription stage. This line would likely mitigate some of these concerns. Nonetheless even with the completion of a project like the Southwest Intertie, transmission capacity, not prices or generating availability, will be the major constraint on the ability of the Northwest to meet its load growth through purchases from the West Coast market.

West Coast Resource Availability and Price

After accounting for general reliability needs and potential transmission constraints, it would be reasonable for the Northwest to rely on imports of up to 3,500 to 4,500 megawatts in most months, depending on the desired reliability of delivery. This is consistent with the Northwest Power Pool's analysis of the Northwest's reliability for winter 1995/1996, which concluded that up to 4,500 megawatts of imported power on the AC and DC Interties could be safely relied on in the event of extreme winter weather. This is higher than the 3,500 megawatts used in the analysis for winter 1994/1995 because hydropower conditions improved in 1995/1996 in Northern California. For the long-term analysis conducted in this plan, it was assumed that imports would be constrained to 5,000 megawatts in any given month.

The Council's analysis further indicates that prices that might be offered for Northwest imports will be heavily dependent on natural gas prices, which are expected to remain at low levels. Based on the Council's medium natural gas price forecast, electricity delivered to the Northwest borders should generally remain in the low 20-mill range, with increases for on-peak prices likely in the early 2000s. On-peak refers to the daily, and particularly, the seasonal peak periods.

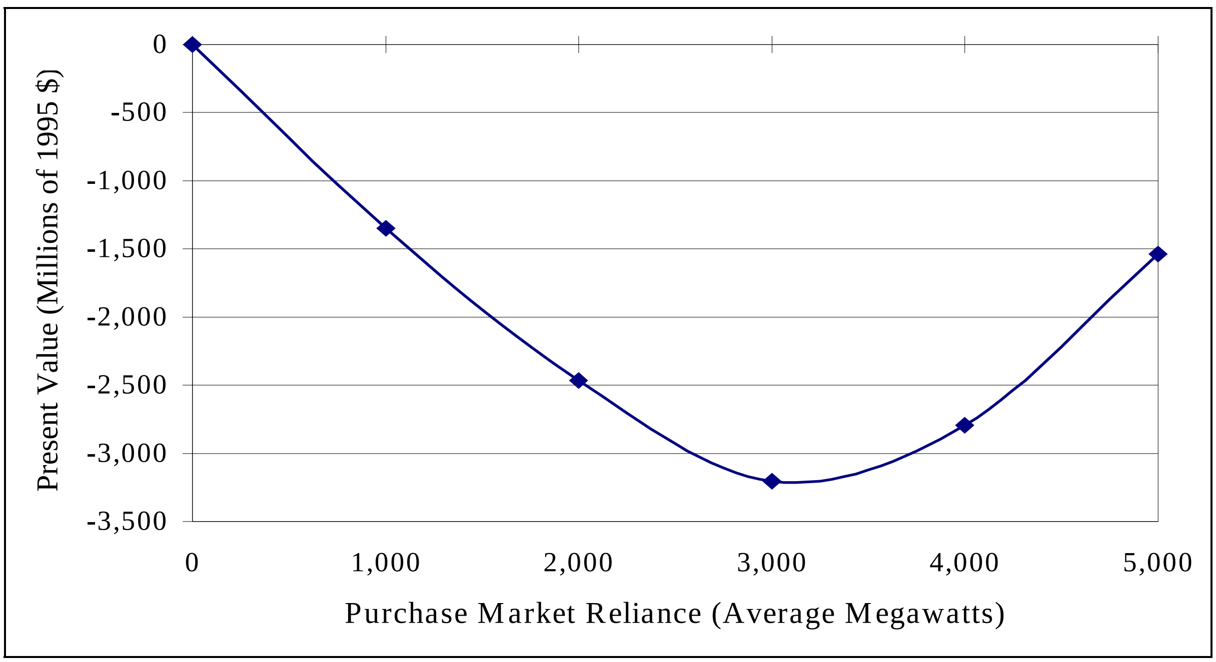
Summer peak-daytime prices could become quite high as Western generating surpluses are worked off and added air-quality constraints are imposed in Southern California air basins, thus reducing the output of gas-fired generating units in the air basin. High prices in summer on-peak periods would provide a market for Northwest nonfirm energy and that would bring in additional capital investment to meet peak loads. However, off-peak prices, particularly in off-peak months, when the Northwest would be most interested in purchasing power, are likely to remain moderate (in the low 20-mill range in 1995 dollars) well into the next decade, given gas prices that track the medium forecast. The analysis, including significant uncertainties and limitations, is described in more detail in Appendix E.

Estimated Level of Reliance on the West Coast Market

If the California and Inland Southwest wholesale power market can be used to maintain reliability and deliver electricity to the Northwest at a price lower than that of new generation, it is likely that the Northwest will develop some level of reliance on wholesale power purchases from the Western power market.[1] This is particularly likely given the estimated price and depth of the out-of-region bulk power market and the strong Northwest interconnections to this market. As a result, these markets significantly affect future resource avoided costs and the value associated with continued implementation of conservation and renewable resources.

Before assessing the cost-effectiveness of developing additional conservation and renewable resources, the Council needed to account for the large amount of inexpensive electricity that could be purchased from the West Coast market. To this end, the Council compared meeting load growth with the construction of new gas-fired combined-cycle power plants in the region to meeting load growth with increasing levels of out-of-region purchases on the market. The results of these studies are summarized in Figure 5-6.

Figure 5-6
Market Reliance Impact on the Present Value of System Costs



[1] Reliance on the spot market for significant amounts of energy will represent a move away from the traditional critical water planning criterion historically used in the Pacific Northwest power system. Critical water planning is a system planning criterion that sets targets for construction of new generation resources such that demand could be met under the worst historical drought conditions.

This chart shows the change in future power system costs (expressed as present value dollars) as a function of the level of reliance on out-of-region markets. The market level of zero means that all new resources are in-region combined-cycle gas plants.

The present value of future power system costs for this approach is about $30 billion. As market reliance increases, combined-cycle plant development is displaced by an equivalent amount of purchases. In this study, the expected present-value cost to the region is minimized if the region uses the West Coast market to meet about 3,000 average megawatts of demand growth. The expected cost reduction to the region is about $3.2 billion compared to constructing combined-cycle gas power plants. The mean annual cost savings approach $250 million per year.

The 3,000-average megawatt reliance does not imply a flat 3,000-megawatt purchase year round. In any given month, purchases could be as high as 5,000 megawatts, depending on the long-term transmission capacity constraints described above. Yearly purchase levels will be strongly influenced by demand patterns, available hydropower generation and natural gas prices.

Purchases will generally be greater in the fall and winter and will fall off sharply in the spring and summer, as reservoir storage is used to meet salmon flow targets, and more hydropower is available to meet in-region loads. One of the largest benefits of the spot purchase strategy comes from its ability to adapt to changing hydropower generation patterns. Spot purchases can be used heavily when there are constraints on hydropower generation, but they can be backed off in good hydropower conditions, without incurring the fixed costs of new construction. Thus, spot purchases become another form of the hydropower-firming strategy recommended by the Council in the 1991 Power Plan.

The expected values on the curve in Figure 5-6 represent mean values over 100 future scenarios for the power system. There is significant uncertainty around these points because the future is unknown. The 100 scenarios include a range of low to high load growth, low to high natural gas prices, and uncertainty in the amount of Northwest hydropower generation.

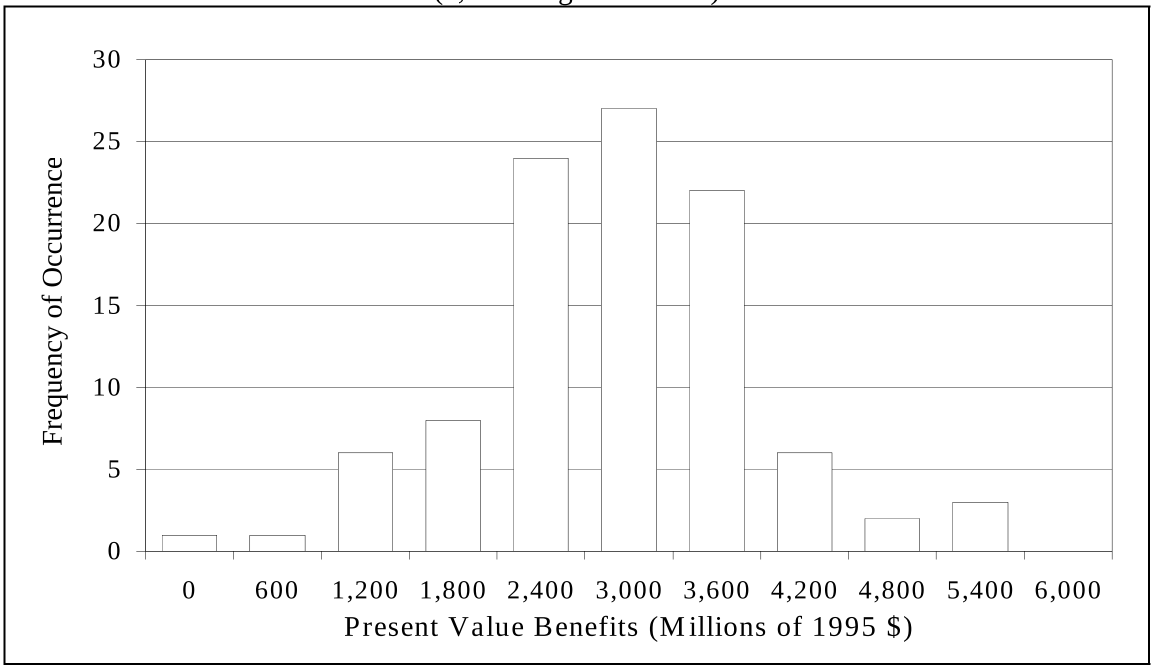
At the 3,000-average megawatt purchase level, the average savings relative to building power plants in the Northwest amount to $3.2 billion. However, in a case with low demand growth, where there is not much need for new construction, the relative savings would be much less. Continually poor hydropower conditions would also produce lower benefits, because it would allow less displacement of purchases and realize less of the flexibility benefit described above. Conversely, higher levels of demand growth, or continually favorable hydropower conditions would produce larger benefits.

Given the uncertainties incorporated in this analysis, the distribution of potential benefits at the 3,000-average megawatt reliance level ranges from $250 million to more than $5 billion. This is illustrated in Figure 5-7. More than 70 percent of the observations fall within the range from $2.4 billion to $3.6 billion. While the range is very large, at this level of market reliance there are no cases where the market purchase strategy doesn't produce some economic benefit relative to the full combined-cycle power plant strategy. Even over a wide range of potential futures, relying on purchases from the West Coast market produces savings.

The results of this analysis should not be construed as a recommendation by the Council that the region immediately abandon its historic critical water planning criteria and move to complete reliance on out-of-region markets to meet demand growth for the next several years. The Council will have little influence over this process. Decisions to meet load growth through short-term transactions will be made incrementally by individual utilities, based on the economics and reliability of proposed transactions. However, the potential economic benefits to the Northwest appear to be large, and it is the Council's judgment that reliance on the market needs to be incorporated into the analysis of the cost-effectiveness of conservation and renewable resources. To that end, a long-term market reliance level of 3,000 megawatts was incorporated into the analysis of the cost-effectiveness of conservation and renewable resources. For conservation or renewable resources to be found cost-effective, their costs to the region

Figure 5-7

Distribution of Benefits from Reliance on the West Coast Market
(3,000-Megawatt Level)



had to be lower than reliance on purchases from the market.

5-D. New Generating Resource Potential

A supply curve showing the estimated cost and quantity of new resource alternatives available for development in the Northwest is illustrated in Figure 5-8. Table 5-3 contains the corresponding data. Capsule descriptions of the generation supply alternatives follow. Further information regarding conservation potential is provided in Chapter 6 and in Appendix G. Additional information regarding generating resource potential is provided in Appendix F.

Coal: A practically unlimited supply of low-cost, low-sulfur coal is available to the Northwest. Gasification and other advanced technologies have improved the efficiency and reduced the environmental impacts of coal-fired generation. Additional coal-fired generation could supply 5,000 average megawatts, or more, of energy at costs of 3.7 to 4.2 cents per kilowatt-hour. These costs are expected to remain relatively stable, but they would be sensitive to carbon dioxide control measures. Constraints to the development of additional coal-fired power plants include public resistance to transmission line construction, cooling water supplies at arid sites, local air-quality impacts, environmental impacts of mining and transporting coal, and the risk that carbon dioxide emissions will be taxed.

Forest thinning residue: Some proposals for restoring degraded east-side forests involve selective removal of trees. These thinnings would be marketed as saw logs or pulping chips where possible. Unmerchantable materials could be chipped and distributed on-site or, alternatively, used as a power plant fuel. About 300 to 1,000 average megawatts could be generated using forest thinnings, at costs ranging from 5.1 to 6.2 cents per kilowatt-hour. These megawatt estimates are fairly uncertain. The cost estimates allocate the full cost of the forest thinning process to power production (i.e., including no subsidy from forest restoration programs). Costs are expected to decline slowly as biogasification technology is introduced. Development of this resource would require resolution of the controversy regarding the appropriate approach to east-side forest restoration.

Figure 5-8
New Resource Costs and Availability

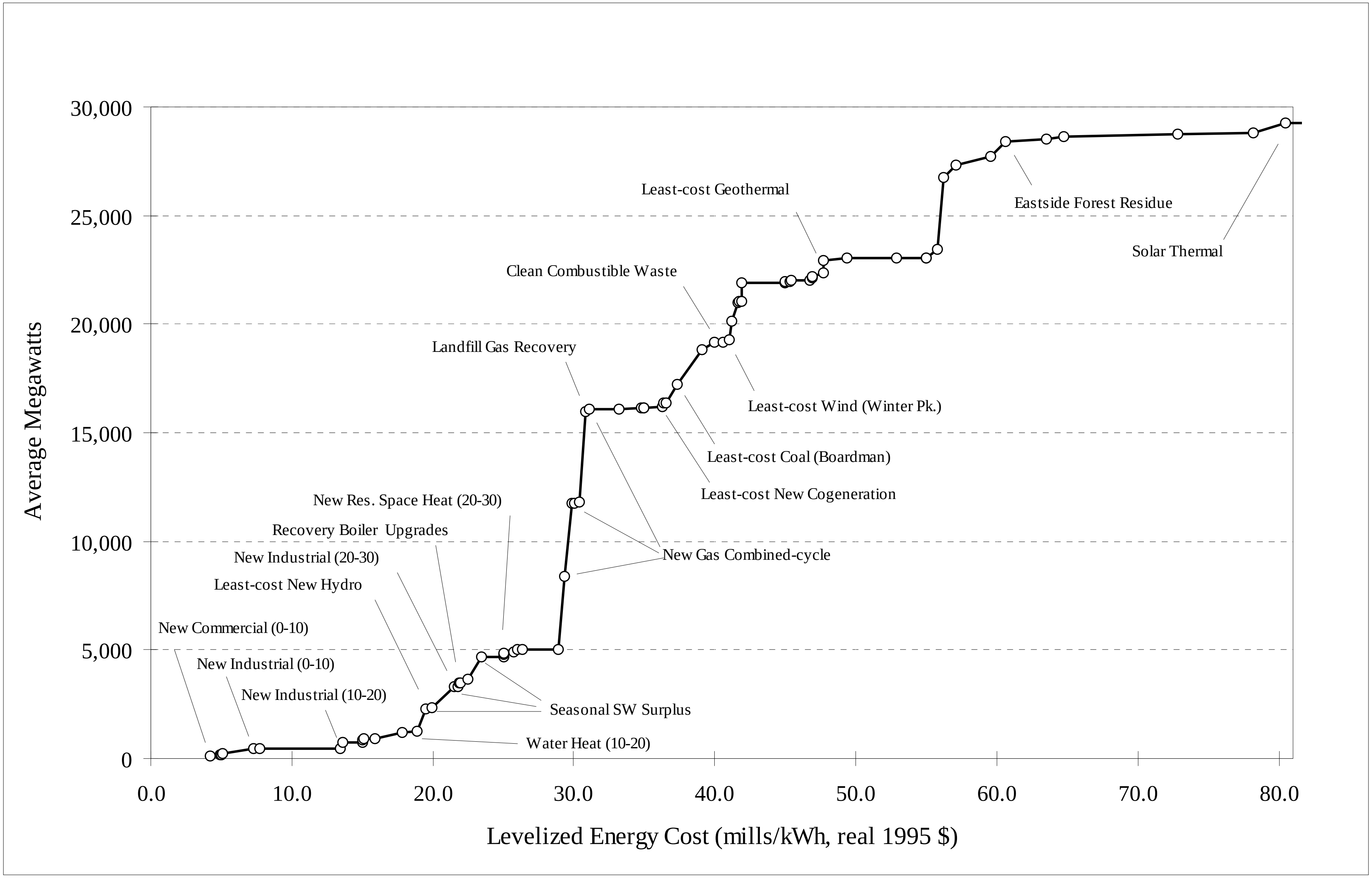


Table 5-3
Conservation and Generating Resource Supply Summary

Resource Name [2]	Levelized Cost (Real, 1995 mills/kWh) [3]	Average Megawatts
New Commercial 0-10 m/kWh	**4.2**	**123**
Commercial Remodel & Retrofit 0-10 m/kWh	4.9	39
Existing Residential Space Heat 0-10 m/kWh	5.0	9
New Residential Space Heat 0-10 m/kWh	5.0	1
Existing Commercial 0-10 m/kWh	5.1	46
New Industrial 0-10 m/kWh	**7.3**	**260**
Irrigation 0-10 m/kWh	7.7	2
Irrigation 10-20 m/kWh	13.5	5
New Industrial 10-20 m/kWh	**13.7**	**264**
Existing Residential Space Heat 10-20 m/kWh	15.0	17
New Residential Space Heat 10-20 m/kWh	15.0	97
Existing Commercial 10-20 m/kWh	15.1	42
Freezers 10-20 m/kWh	15.9	17
Water Heat 10-20 m/kWh	**17.9**	**291**
New Commercial 10-20 m/kWh	18.9	48
New Small Hydropower - Least-cost	**19.9**	**64**
Irrigation 20-30 m/kWh	21.8	6
New Industrial 20-30 m/kWh	**21.9**	**126**
Commercial Remodel & Retrofit 10-20 m/kWh	22.0	15
Chemical Recovery Cogeneration Upgrades	**22.5**	**195**
Existing Residential Space Heat 20-30 m/kWh	25.0	1
New Residential Space Heat 20-30 m/kWh	**25.0**	**129**
Compact Fluorescent Lighting 20-30 m/kWh	25.1	47
New Commercial 20-30 m/kWh	25.8	70
Refrigerators 20-30 m/kWh	26.0	88
Water Heat 20-30 m/kWh	26.4	22
Irrigation 30-40 m/kWh	28.9	8
New Natural Gas Combined-cycle, Permitted Sites	**29.3**	**3356**
New Natural Gas Combined-cycle, New Sites	**29.9**	**3356**
Commercial Remodel & Retrofit 20-30 m/kWh	30.0	22
Existing Commercial 20-30 m/kWh	30.4	49
New Natural Gas Combined-cycle (Dry Cooling)	**30.8**	**4140**
Landfill Gas Energy Recovery	**31.1**	**126**
New Industrial 30-40 m/kWh	33.2	13
New Commercial 30-40 m/kWh	34.8	25
Existing Residential Space Heat 30-40 m/kWh	35.0	20
New Residential Space Heat 30-40 m/kWh	35.0	10
Existing Commercial 30-40 m/kWh	36.3	42
New Industrial Cogeneration 40 m/kWh and less	**36.4**	**156**
Irrigation 40-50 m/kWh	36.6	8
New Boardman Coal Gasification	**37.3**	**867**
New Colstrip Coal Gasification	39.1	1627
Clean Combustible Industrial and Municipal Waste	**40.0**	**300**
Commercial Remodel & Retrofit 30-40 m/kWh	40.6	8
Wind - Least-cost Winter Peak	**41.0**	**117**

[2] The mill ranges appearing in the resource names (e.g. “0-10 m/kWh”) designate resource blocks and may only approximate the actual cost of resources in the block. The actual average cost of the resource block is shown in the Levelized Cost column.
[3] These levelized costs assume investor-owned utility financing, 15-year amortization of capital costs for generating resources. Levelized costs for conservation resources are based on the average of investor-owned and public utility financing, with the amortization life being 15 years or the life of the conservation measure, whichever is shorter.

New Valmy Coal Gasification	41.2	841
New Centralia Coal Gasification	41.6	867
Existing Commercial 40-50 m/kWh	41.8	68
Water Heat 30-40 m/kWh	41.9	12
Thousand Springs Coal Gasification	41.9	852
Existing Residential Space Heat 40-50 m/kWh	45.0	2
New Residential Space Heat 40-50 m/kWh	45.0	11
New Industrial 40-50 m/kWh	45.0	11
Freezers 40-50 m/kWh	45.3	16
New Commercial 40-50 m/kWh	45.4	42
Wind - Least-cost Spring - Summer Peak	46.7	32
New Small Hydropower - Medium Cost	46.9	89
New Commercial Cogeneration 50 m/kWh and less	46.9	84
New Industrial Cogeneration 40-50 m/kWh	36.4	156
Geothermal - Least-cost	**47.7**	**576**
Wind - Medium Cost Winter Peak	49.4	116
Commercial Remodel & Retrofit 40-50 m/kWh	52.9	13
Existing Residential Space Heat >50 m/kWh	55.0	2
New Residential Space Heat >50 m/kWh	55.0	4
Wind - High Cost Winter Peak	55.8	358
New Industrial Cogeneration 50-60 m/kWh	56.2	3339
New Commercial Cogeneration 50-60 m/kWh	57.1	552
Geothermal - Medium Cost	59.6	414
Eastside Forest Thinning Residues	**60.6**	**692**
Wind - High Cost Spring - Summer Peak	63.5	79
Water Heat >50 m/kWh	64.7	152
Geothermal - High Cost	72.8	86
New Small Hydropower - High Cost	78.2	45
Central Station Solar Thermal	**80.5**	**467**
Existing Commercial >50 m/kWh	82.6	11
* New Commercial >50 m/kWh	125	11
* Commercial Remodel & Retrofit >50 m/kWh	146	4
* Rooftop Solar Photovoltaics, Eastside	192	30
*** Not shown in Figure 5-8**		

Geothermal: The Northwest is thought to have large geothermal resource potential, but the feasibility of commercial generation of electricity from the resource has yet to be demonstrated. An estimated 400 to 3,900 average megawatts could be secured from geothermal resources in the Northwest and neighboring areas at costs of 4.9 to 7.3 cents per kilowatt-hour. Both quantity and cost estimates are highly uncertain. Costs are expected to decline slowly with the introduction of improved technology. Technology development will, to some extent, be driven by the petroleum industry because of developments in well drilling and other subsurface exploration techniques. Issues associated with geothermal generation include environmental impacts (noise, hydrogen sulfide, geothermal fluids and disposal of drilling materials), effects on hydrothermal systems, and conflicts with ecologically sensitive areas and recreational sites. Projects intended to demonstrate the feasibility of geothermal electric power generation are under development at three Northwest resource areas.

Hydropower: About 170 average megawatts could be secured from new hydropower resources at costs ranging from about 1 cent to 6.5 cents per kilowatt-hour. This estimate includes expansions to existing hydropower projects, addition of power generation to non-power water control structures and development of high-head, small-scale headwater sites. This estimate does not include efficiency upgrades at existing hydropower projects, additions to existing facilities for the primary purpose of securing capacity, or pumped-storage projects. Hydropower is a mature technology, and costs are expected to remain relatively stable. Habitat modification, stream-flow and water-quality effects, erosion and sedimentation, and land and water use conflicts are issues limiting development.

Industrial cogeneration: Cogeneration plants can supply industrial electricity, space and process heating, and cooling loads. Surplus electricity can be sold back to the electrical grid. The enhanced overall thermal efficiency of cogeneration can reduce the cost and environmental impact of supplying overall energy needs. Fuels used for industrial cogeneration include natural gas, fuel oil, spent pulping liquor, wood residues and coal. Many technologies are available for cogeneration, including reciprocating engines, combustion turbines and steam boilers. Installations are often sized ("thermally matched") to the thermal load of the facility. In theory, thermal matching produces the greatest efficiency and environmental benefits. Alternatively, the power plant can be constructed and operated primarily for power generation, and a relatively small amount of steam could be bled to an adjacent industrial plant.

Cogeneration is common in industries with large thermal loads and on-site production of residue fuels. In the Northwest, these include the pulp and paper, wood products and petrochemical industries. As much as 4,600 megawatts of additional industrial cogeneration could be developed in the Northwest, primarily in the food processing, wood products, pulp and paper, petrochemical, rubber and plastic, primary metals and transportation equipment sectors. The potential would be smaller if the plants were built to be thermally matched.

The cost of electricity from these plants would range from about 2.5 cents to 6.0 cents per kilowatt-hour, with most above 4.0 cents. Improvements in generating technology should help stabilize industrial cogeneration costs. Impediments, in addition to cost-effectiveness, include competing investment opportunities, short payback criteria, and uncertainties regarding the long-term viability of some plants. Benefits include improved reliability of power and steam supplies, and reduced air emissions and water consumption.

Renovation of existing cogeneration installations may present special opportunities for cost-effective cogeneration in the near-term. For example, additional power generation can be secured by upgrading older pulping chemical recovery boilers or by adding generating capability to units. The regionwide potential of chemical recovery plant upgrades and additions is estimated to be as much as 195 average megawatts. A representative cost of energy from projects of this type is 2.3 cents per kilowatt-hour. The cost of specific projects will vary because of the unique circumstances at each facility.

Landfill gas energy recovery: Anaerobic decay of landfilled materials produces a gas containing high concentrations of methane. In most cases, this gas is collected and flared. Another alternative is to use this gas to fuel engine-generator sets or small combustion-turbine power plants. Energy recovery from landfill gas could provide about 125 additional average megawatts at an incremental cost of about 3.1 cents per kilowatt-hour. Landfill gas recovery uses relatively mature technology, and costs are not anticipated to decline significantly. There are few impediments to the development of this resource.

Mixed wood residues: Because of public concerns regarding transportation, air-quality impacts and impacts on recycling programs, it is unlikely that new power plants burning unsorted municipal solid waste will be developed in the foreseeable future. However, clean combustible materials sorted from the municipal solid waste stream and combined with wood residues from industrial sources could be used to fuel new power plants or augment the fuel supply for existing plants.

Energy recovery from clean combustible wastes could provide about 300 average megawatts at costs of 4 to 5 cents per kilowatt-hour. Resource availability is uncertain and may decline as higher-value uses for combustible residues develop. Cost is sensitive to plant size, fuel transportation requirements and the value of cogenerated steam. These costs are expected to decline as biogasification technology is introduced. Biogasification technology will also permit use of agricultural residues, expanding the supply of potential fuel. Impediments include competing higher-value uses for residues, fuel transportation costs and land use conflicts.

Natural gas - bulk power generation: An abundant supply of inexpensive natural gas is available from western Canada and Rocky Mountain fields. Declining gas prices, surplus gas transportation capacity, natural gas price risk-hedging instruments, improvements in combustion turbine performance, decline in equipment and construction prices, and apparent ease of project permitting have resulted in gas-fired combined-cycle combustion turbines emerging as the least-cost alternative for new bulk power generation. Sites capable of supporting 7,400 megawatts of additional combined-cycle combustion turbine capacity appear to be available. These could provide 6,800 average megawatts of energy at 2.7 to 3.2 cents per kilowatt-hour (medium gas price forecast). Some of these plants could provide steam to nearby industries.

Technology improvements are expected to offset slowly escalating natural gas prices, while capital costs are likely to remain at current levels. This should lead to stable or slowly escalating electricity costs. Gas-fired combined-cycle power plants can be developed quickly, and have low capital costs and excellent operating flexibility. Issues include long-term gas price stability, nitrogen oxide emissions, consumption of water for cooling and the environmental impacts of natural gas production and processing. The potential effect of carbon dioxide controls is unclear. Because gas-fired combined-cycle plants produce less carbon dioxide than other fossil fuel plants, new gas-fired combined-cycle plants might be substituted for older fossil units.

Natural gas - commercial building cogeneration: Cogeneration plants can supply the space heating and cooling, hot water and electrical needs of commercial buildings. Surplus electricity can be sold back to the electrical grid. The enhanced overall thermal efficiency of cogeneration can reduce the cost and environmental impact of supplying energy requirements. Natural gas is the preferred fuel for commercial cogeneration, and many technologies are available including reciprocating engines, combustion turbines and steam boilers. Packaged fuel cell cogeneration plants have recently appeared on the market. Existing applications are typically confined to relatively large thermal loads such as college campuses.

About 640 megawatts of new commercial cogeneration is estimated to be available for development, primarily in the hospital, military and correctional sectors. The cost of electricity from these plants would range from about 4.5 to 6.0 cents per kilowatt-hour. Though high compared to current market prices, commercial cogeneration costs may be partially offset by transmission and distribution cost savings. The cost of commercial cogeneration is expected to remain stable as improvements in generating technology offset fuel cost escalation. Production-driven improvements in fuel cells could lead to substantial improvements in the cost-effectiveness of commercial cogeneration. In addition to cost, impediments to commercial cogeneration include interconnection issues, competing investment opportunities, short payback criteria, and air quality and other local environmental impacts.

Nuclear: The partially completed WNP-1 and WNP-3 nuclear plants were preserved for many years in case they were needed in the future. However, Bonneville terminated preservation funding as the cost of alternative sources of power declined. Although the units remain intact, completion of either is unlikely unless it is federally financed as a plutonium disposal project.

Advanced, passive-safety, modular plant designs have been developed to counter public concerns regarding plant safety and to reduce costs to competitive levels. The first advanced, passive-safety plant was intended to be in service by 2003. However, no plants of advanced design are currently planned for construction. The design goals for advanced passive-safety plants would result in energy costs of about 4.3 cents per kilowatt-hour. Experience with other new technologies suggests that target costs are unlikely to be achieved. Nuclear plants could produce large quantities of base-load energy without significant carbon dioxide production. However, the capital-intensive nature of nuclear technology, public concerns regarding plant safety and nuclear waste disposal, and performance uncertainties associated with new nuclear technologies are major constraints.

Ocean energy: Limited wave power potential may be present along the outer coast. Because of immature technology, environmental concerns and high costs, the development of this resource is not anticipated in the foreseeable future.

Solar: Southeastern Oregon and southern Idaho have relatively good solar insolation and large areas suitable for the installation of solar generating equipment. But the resource is diurnal and intermittent and seasonally non-coincidental with most Northwest loads. The least-cost central-station solar generation technology currently available is parabolic trough with supplemental natural gas boiler. The estimated cost of electricity from a hybrid gas/solar parabolic trough at prime Northwest solar resource sites is about 8 cents per kilowatt-hour.

Small-scale photovoltaic applications, at current costs of 20 to 25 cents per kilowatt-hour may be cost-effective in locations that are difficult to serve with grid power. Photovoltaic costs are expected to continue to decline at a relatively rapid rate, and small-scale applications providing distributed system benefits are expected to become increasingly common. Central-station solar generation would first become competitive in the Southwest, where good temporal and geographic coincidence between insolation and loads is present.

Wind: The Northwest possesses numerous wind resource areas suitable for electric power generation. The aggregate potential is in the thousands of megawatts, but the greater portion is in north-central Montana, remote from the region's load centers. The best wind sites have a potential of yielding about 700 average megawatts (in addition to current projects) at costs ranging from 3.6 to 7.5 cents per kilowatt-hour. This assumes only limited development of the prime Blackfoot wind resource area of north-central Montana, because of transmission constraints. The quantity estimate is subject to uncertainties regarding wind resource area quality, extent, developable area and turbine array density. The cost estimate excludes the federal production incentive, scheduled to expire for projects placed in service after 1999.

Technology improvements and production economies are expected to provide continued cost reduction. Impediments include transmission constraints, avian mortality and aesthetic impacts. The resource is intermittent, and the winds of some otherwise favorable resource areas are not seasonally coincidental with regional loads. Four commercial-scale wind power projects are under development in the Northwest.

General Prospects for Development of New Generating Resources

Though electrical load growth in the Northwest is expected to continue at rates comparable to the past several years, few new generating projects are scheduled for development. Rather, utilities (and some consumers) are meeting new loads by wholesale power purchases. Northwest peak period (fall and winter)wholesale prices reflect the variable cost of operating existing generating plants located in the Southwest. Many of these are older dual-fuel (natural gas or fuel oil) steam-electric units in California. These plants were not economical to operate for other than peaking purposes for many years because of high fuel prices. The decline in natural gas prices has enabled the operators of these plants to produce competitive base-load power. Moreover, the variable costs of many of these units are lower than the fully allocated costs of new combined-cycle plants, the least-costly new bulk generating resource.

The flexibility of wholesale purchases is attractive in a time of uncertainty and change in the industry. Wholesale contracts require little lead time, require no capital investment and are available for short durations.

Wholesale prices are forecast to gradually rise because of natural gas price escalation and the cost of implementing more stringent nitrogen oxide emission controls on older gas-fired power plants.[4] Even considering these costs, off-peak power from the Southwest is expected to remain highly competitive with new generation. As wholesale power prices rise toward the fully allocated cost of new resources, construction of new plants will eventually resume.

Because of their low cost, an abundance of suitable sites and favorable technical and environmental characteristics, natural gas-fired combined-cycle power plants are the most likely new bulk power generating resource alternative. Continuing technical improvements are expected to partially offset increases in natural gas prices. A few new hydropower projects, upgrades of existing hydropower and thermal plants, and a few new plants using biomass residues will likely be competitive with new gas-fired combined-cycle combustion turbines in the near-term. Technological improvements and production

[4] The latter can be achieved by acquisition of emission offsets, addition of nitrogen oxide controls to existing plants or by repowering or replacing existing steam-electric plants with new combined-cycle technology.

efficiencies are expected to improve the competitive position of many renewable resources and coal-fired power plants (Figure 5-9).

Absent controls on greenhouse gas emissions, new resource needs for the next decade, or longer, will mostly be met with off-peak operation of Southwestern plants, new gas-fired combined-cycle plants, and, possibly, continuing conservation activities (Figure 5-10a). Greenhouse gas controls (such as a carbon tax) could significantly affect this picture. The competitive positions of conservation, renewables and nuclear options would improve relative to existing and new fossil-fuel alternatives (Figure 5-10b). The role of natural gas in this situation is somewhat unclear. Because of their high thermal efficiency and low carbon-content fuel, gas-fired combined-cycle plants might be economic substitutes for older coal or gas-fired steam plants.

Figure 5-9
Resource Cost Trends [5]

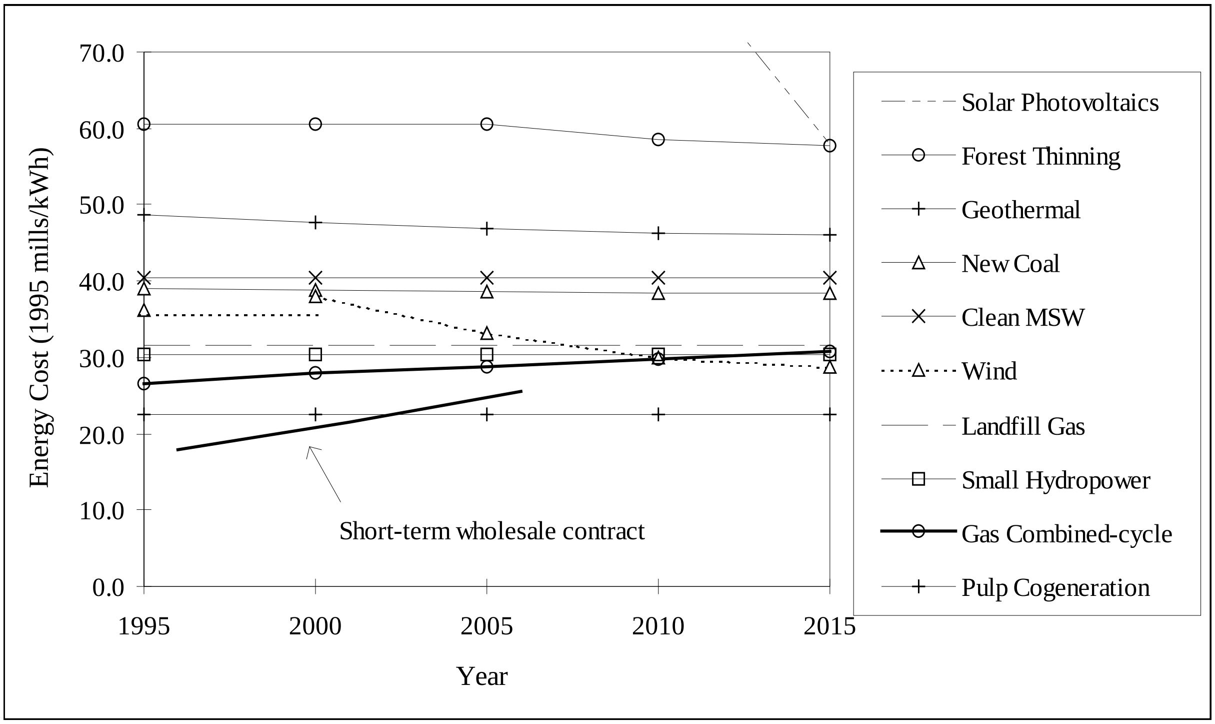
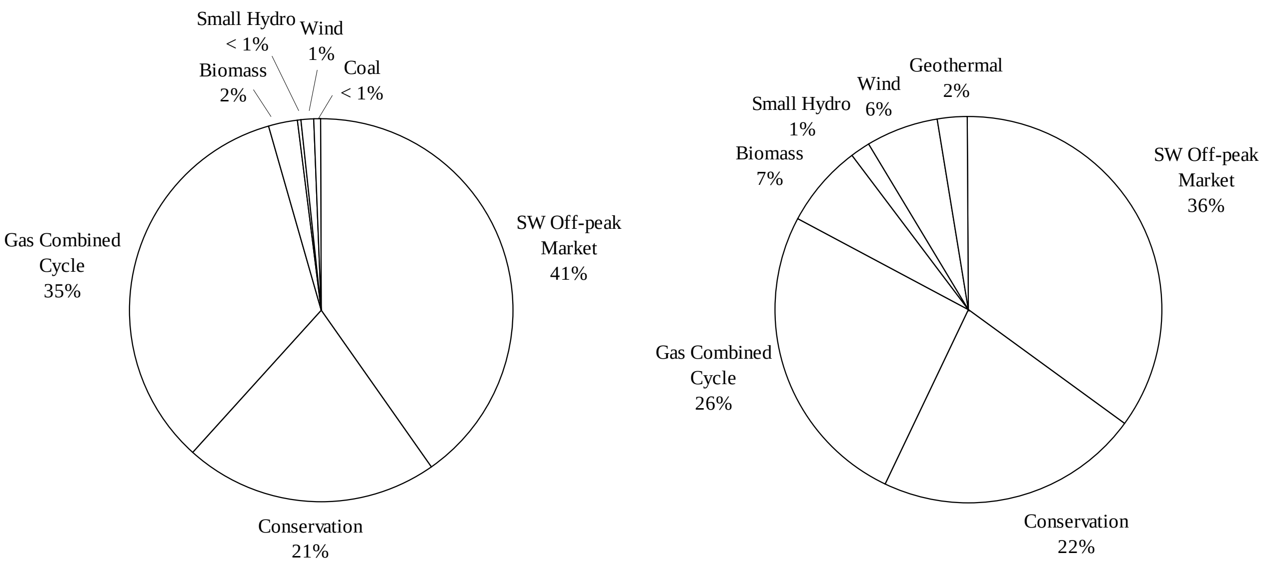


Figure 5-10
Effect of a Carbon Tax on the Mix of New Resource

[5] The increase in the cost of wind-generated electricity shown for year 2000 is due to scheduled expiration of federal production incentives. The mid-term increases in the cost of forest thinning biomass is due to the near-term availability of several retired biomass power plants that can be refurbished.



a. No Carbon Tax through 2015

b. $25/Ton Carbon Dioxide Tax in 2005

5-E. HYDROPOWER SYSTEM UNCERTAINTIES

Another uncertainty the Northwest is facing is how much of the hydroelectric system will be available to generate electricity given operational changes to the system intended to increase fish survival. The existing hydroelectric system and current operations are described in Chapter 4. This section outlines the types of energy and capacity impacts that could occur from changing the operation of that system in an attempt to aid fish.

Congress has recently implemented a budget limitation on Bonneville's expenditures for salmon restoration, including actual program costs and costs for fish-related power purchases and lost revenues. This could provide an adequate budget to maintain current river operations. However, as more information is gathered and more research is conducted, the operation of the river may be further modified. This could lead to more or fewer constraints, depending on the results of the research. This uncertainty is similar to the possibility of a future carbon tax. It may happen, but the timing, magnitude and likelihood is unknown.

It is not now known what set of fish and wildlife recovery measures the region will eventually implement. The Council's Columbia River Basin Fish and Wildlife Program,[6] the National Marine Fisheries Service's biological opinion[7] and the Columbia River Anadromous Fish Restoration Plan[8] have all been proposed as salmon recovery plans. Each suggested operation is different and affects the hydroelectric system's capability to produce electricity in different ways. Each scenario would change, to varying degrees, the hydroelectric system's ability to provide both firm energy and peaking capacity. Each scenario could lead to a different set of resource actions for the region.

The current analysis uses an estimate of the availability of hydroelectricity based on the

[6] Document #94-55, *Columbia River Basin Fish and Wildlife Program*, December 14, 1994, Northwest Power Planning Council.
[7] *Proposed Recovery Plan for Snake River Salmon*, March 1995, U.S. Department of Commerce, National Oceanic and Atmospheric Administration.
[8] *Wy-Kan-Ush-Mi Wa-Kish-Wit - Columbia River Anadromous Fish Restoration Plan of the Nez Perce, Umatilla, Warm Springs and Yakama Tribes*, Vol. 1, June 15, 1995, Columbia River Inter-Tribal Fish Commission.

National Marine Fisheries Service's biological opinion. To provide an idea of the size of changes that could be faced, three additional scenarios were analyzed and are described below. They span a range of potential river operations with impacts that are between a gain of 500 average megawatts to a loss of 3,000 average megawatts compared to the biological opinion. Table 5-4 summarizes the impacts of the base case and three additional scenarios relative to current operations. The energy figures shown are the net energy losses. No attempt was made to determine the change in the firm energy load carrying capability (FELCC) of the system.

Water budget operation: This scenario assumes river operations as they were in 1991. It represents an operation with energy and capacity gains compared to current operations. It was the operation in place for the 1991 Power Plan.

Drawdown proposal: This scenario reflects a hypothetical operation that produces both higher energy and capacity losses than current operations. It includes a drawdown of the four lower Snake River dams to natural river elevations year round. All of the energy and capacity from those projects is lost. It should be noted that this is not the same river operation as is contained in the Council's Columbia River Basin Fish and Wildlife Program's Strategy for Salmon.

Tribal proposal: This scenario represents an operation that reduces both the firm energy and capacity of the system well beyond current levels. The operation proposed in the Columbia River Anadromous Fish Restoration Plan is used for this case. This operation calls for higher flow augmentation in both the Snake and Columbia rivers and a drawdown to natural river elevations year round at the four lower Snake River dams and at the John Day Dam.

Table 5-4

Hydroelectric Energy and Capacity Gains or Losses Relative to the 1995 Biological Opinion[9]

Case	Water Budget	Drawdown Proposal	Tribal Proposal
Energy Impacts (average megawatts)	+500	-1,300	-3,000
Capacity Impacts (megawatts)	+800	-2,700	-5,200

[9] This table reflects only the gain or loss of generating capacity compared to operation under the Biological Opinion. It does not reflect shifting hydrogeneration to other months, when it is not lost, but it may have less value. Calculated losses to firm generating capacity (FELCC) include both factors. The effect on electricity generation from the base case used here -- the Biological Opinion -- is discussed more fully in Chapter 4.

The issue for this draft power plan is whether these potential hydropower changes would lead to different resource choices. In general, the answer is no. The availability of additional market purchases in the near term, plus relatively short lead time resources like combined-cycle combustion turbines mean the region could adapt to further losses of hydroelectric capacity, albeit at a cost. Losses on the order of either the Drawdown Proposal or the Tribal Proposal scenarios would require lead time to build replacement resources or increase transmission capability to maintain reliable service. Replacement resources, for example, require from two to five years to bring into service. If needed, intertie expansions might require additional lead time because of the controversy that often accompanies the construction of new, or expansion of existing, transmission lines. On the other hand, were hydroelectric system restrictions to be eased, thus increasing hydroelectric capability, the region would generally be able to reduce more expensive short-term purchases from the Western market.

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CHAPTER 6

RESOURCE ISSUES IN COMPETITIVE MARKETS

There are some resource issues that present a particular challenge in a competitive market. These include developing cost-effective conservation resources, maintaining progress on renewable resources and incorporating environmental considerations in resource decisions. Each of these is discussed in this chapter.

6-A. COST-EFFECTIVE CONSERVATION

One of the goals of the Northwest Power Act is to achieve cost-effective energy conservation. However, conservation faces a radically different environment today than it did in prior Council power plans:

- The alternative resource costs avoided by conservation are substantially lower, leaving fewer conservation measures cost-effective by comparison.
- Retail prices for electricity can be expected to move closer to marginal costs, reducing or eliminating one of the economic arguments for utility funding of conservation.
- Competitive pressures make it difficult for utilities to spend money on conservation programs.

These changes, taken together, mean that utilities, including the Bonneville Power Administration, will be unable to secure all the remaining cost-effective conservation as they did in the past. Bonneville is a special case. The agency has long supported efficiency efforts through its public utility customers. As Bonneville began to redesign its approach to conservation, it asked its public utility customers to underwrite more of their own programs. Bonneville at first agreed to provide back up if the utilities were unable to secure enough energy savings to meet regional goals set in the 1991 Power Plan. However, because the public utilities can purchase electricity in a market where other providers do not finance conservation, the Council doesn't expect Bonneville to continue supplementing public utility efforts to meet regional conservation goals.

Nonetheless, cost-effective conservation is still an important resource, and the region must be open-minded and creative in finding new ways to capture the economic and environmental benefits conservation can provide. The Council suggests that the Comprehensive Review and appropriate state forums evaluate the costs and benefits of new mechanisms to acquire conservation beyond what will naturally be developed in the market. The goal should be a competitive market that preserves as much of the conservation benefit as possible.

This section assesses how much cost-effective conservation is available, its benefits and risks, how much will likely be adopted by the market, and what kinds of conservation measures will be a challenge to secure without some extra-market effort. If additional mechanisms for acquiring energy savings are needed, can they be cost-effectively implemented without interfering with the operation of a competitive electricity market?

How Much Conservation has the Region Achieved?

The Northwest has made great strides toward improving the efficiency of its electricity use. As described in Chapter 4, during the 15 years following the passage of the Northwest Power Act in 1980, the region's consumers secured nearly 1,000 average megawatts of energy-efficiency improvements through utility conservation programs. Utilities paid about half as much for these energy savings as they would have had to pay for alternative electrical resources available during that period.

In addition, there were substantial efficiency gains from improved residential and commercial energy codes. The two most populous states in the region, Oregon and Washington, and several local jurisdictions in Idaho and Montana, adopted energy codes for new residential and commercial buildings that meet the Council's original model conservation standards. These codes, among the most rigorous in the nation, have already resulted in significant savings. They will continue to add hundreds of megawatts of cost-effective savings over the next 20 years and beyond. The work of state energy offices and local governments, combined with Bonneville and utility support, has been critical to the adoption and implementation of these codes.

At the federal level, minimum efficiency standards were established for major residential appliances. The federal energy standards for new manufactured homes were also revised for the first time since 1976. And the National Energy Policy Act of 1992 established new efficiency standards for some lamps, lighting equipment, electric motors, commercial heating, ventilating and air conditioning equipment, and shower heads. These standards will result in savings that do not have to be sought through utility programs.

How Much Remains to be Done?

The amount of conservation that is cost-effective to develop depends upon how fast the demand for electricity grows, future alternative resource costs and year-to-year variations in water conditions.[1] Figure 6-1 shows the amount of conservation that would be cost-effective to develop across a wide range of future electricity use patterns, gas prices and hydropower availability. The amount ranges from a low of about 800 average megawatts, when demand growth and gas prices are low, to a high of about 2,300 average megawatts, corresponding to a future of high demand and high gas prices. The average amount of regionally cost-effective conservation the Council has identified is approximately 1,535 average megawatts.[2]

[1] For example, if economic growth follows the Council's medium-low forecast, the region will need to add approximately 145 average megawatts of new resources each year. However, if regional economic growth is at the Council's medium-high forecast, nearly 425 average megawatts of new resources will be needed each year.

[2] This is the total amount of conservation achievable, given sufficient economic and political resources, over a 20-year period in the medium forecast. The 1,535 average megawatts of cost-effective potential identified in this plan is very different than the 1,500 average megawatts referenced in the 1991 plan. In this draft plan, the 1,535 average megawatts is the average amount of conservation developed in a 20-year period across all potential futures (such as low and high gas prices or load growth). In the 1991 plan, the 1,500 average megawatts was cost-effective achievable conservation over a 10-year period assuming medium-high load growth.

Figure 6-1
Distribution of Energy Savings Developed in Alternative Futures

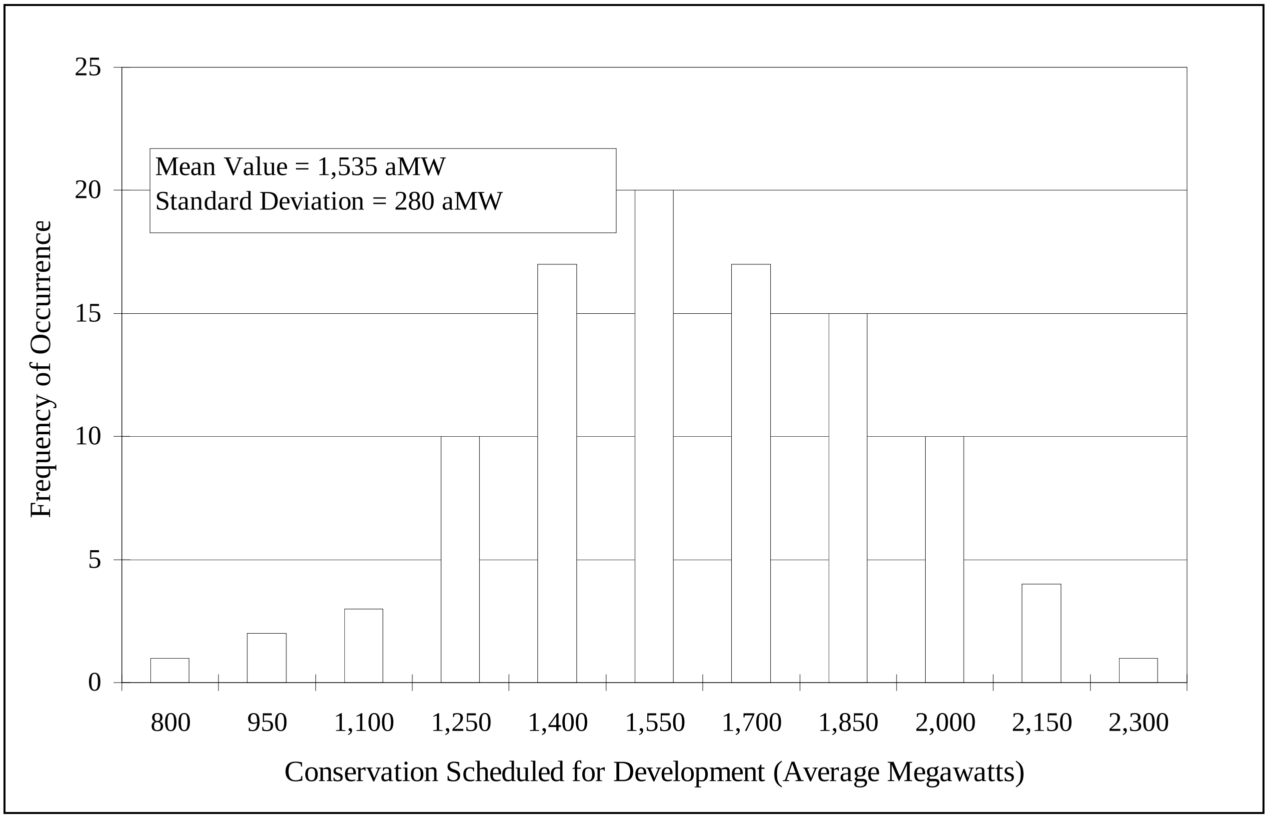


Table 6-1 shows the conservation savings potential by sector and end-use. Approximately one third of this potential is in new and existing non-aluminum-industry facilities. The Council has not estimated the amount of conservation that may be available in the aluminum industry, but there is undoubtedly some additional potential in that sector as well. The next largest source of potential savings is in residential water heating and laundry equipment, which represents about one-fifth of the total potential. New residential and commercial buildings make up about one-quarter of the cost-effective potential. The remaining potential is spread among existing residential buildings and appliances, existing commercial buildings and irrigated agriculture. The average levelized cost of these resources is approximately 1.7 cents per kilowatt-hour.[3] This is roughly two-thirds of the cost of new generating resources.

[3] These levelized costs do not include the 10-percent credit given to conservation in the Northwest Power Act.

Table 6-1

Average Achievable Conservation Potential by End Use or Sector

End Use or Sector	Average Megawatts	Average Levelized Cost (Cents/kWh)
Freezers	15	1.9
Refrigerators	45	2.9
Water Heating	335	2.0
Residential Lighting	30	2.6
New Residential Space Heating	140	2.1
Existing Residential Space Heating	25	1.8
New Commercial	230	1.3
Existing Commercial	95	1.4
Commercial Renovation/Remodel	50	1.3
New Non-Aluminum Industrial	225	1.5
Existing Non-Aluminum Industrial	335	1.5
Direct Service Aluminum Industrial	Not Estimated	Not Estimated
Irrigated Agriculture	10	1.8
TOTAL	1,535	1.7

Conservation's Benefits, Uncertainties and Risks

The development of cost-effective conservation is the highest priority electricity resource in the Northwest Power Act. To be considered "cost-effective," conservation must be less costly than the next similarly available and reliable generating resource. The goal of each Council power plan has been to find the mix of conservation and new power supplies that produces the lowest total present-value cost of meeting the region's energy service needs. In the near term, to be cost-effective, the levelized cost of a conservation resource must be less than the estimated levelized cost of market purchases from out of region. Once the transmission system cannot accommodate further purchases from outside the region, conservation must have a lower levelized cost than new natural gas-fired combustion turbines.

The Council has historically viewed the costs and benefits of investing in the region's energy future from a long-term perspective. It has tried to weigh the costs of investments made in new resources over the 20-year planning horizon against the benefits they could return to the citizens of the Northwest over the resources' useful lives. The fact that people tend to place greater weight on near-term costs and benefits than those that might occur far in the future is accommodated by discounting future costs and benefits.[4]

Conservation investments have three characteristics that must be taken into consideration in this sort of long-term perspective. First, the costs of conservation are virtually all capital. This means there are no operating costs that can be avoided if, for example, demand grows less quickly than expected or fuel prices fall. Second, for this analysis we have assumed that all energy savings are amortized over 15 years, even though some savings have much longer useful lives. This means the costs are front-loaded, while the benefits are frequently spread out over a longer period. Finally, some of the conservation is very long-lived. As a result of all these factors, a long-term perspective exposes conservation investments to uncertainty and risk.

Countering these characteristics is the fact that the investment in conservation is made incrementally. On average, the pace of acquiring

[4] For this plan, a base discount rate of 4.75 percent was used.

all 1,535 average megawatts of cost-effective conservation would be about 75 average megawatts per year. This means that the region can (and should) regularly revisit the economic merits of further investments in conservation. This limits the risk of potential over-investment. In the following paragraphs, the analysis of the long-term value of conservation is described along with the effects of key uncertainties and risks.

Analysis of the Long-Term Benefits of Conservation

The analysis was structured to estimate first the conservation that is likely to be developed as a result of the momentum of current utility programs and what consumers acting on their own are expected to secure in the longer term. This amounts to 515 average megawatts of conservation available at an average cost of 1.9 cents per kilowatt-hour. This conservation was assumed to be implemented on a fixed schedule: 70 average megawatts per year the first two years, 60 average megawatts per year the next two years, 30 average megawatts the fifth year and 15 average megawatts per year thereafter. The levels and schedule were estimated from a survey of current utility plans, and by identifying those resources that consumers would be more likely to adopt on their own, such as those that increase productivity in an industrial plant.

The remaining conservation was grouped into levelized cost increments of between 1.0 cent per kilowatt-hour and 4.0 cents per kilowatt-hour. These resources were assumed to be developed to meet loads as needed. The most cost-effective resources were developed first.

Table 6-2 shows the average present-value benefit to the region of developing each of the conservation resources. Also shown are the total tons of carbon dioxide offset by the conservation. This could become important should a carbon tax be required to mitigate global climate change.

Table 6-2

Regional Benefit of Conservation Resource Development [5]

Conservation Block	Average Present Value ($ Millions)	Average Megawatts	Carbon Dioxide Offset (Millions of Tons)
Utility Momentum Plus Market Driven	$ 570	515	27
Less than 1.0 Cents/kWh	$ 760	310	16
More than 1.0 and less than 2.0 Cents/kWh	$ 830	525	27
More than 2.0 and less than 3.0 Cents/kWh	$ 140	185	10
Total	$ 2,300	1,535	80

[5] The present-value benefits shown in Table 6-2 do not include the 10-percent credit provided conservation in the Northwest Power Act.

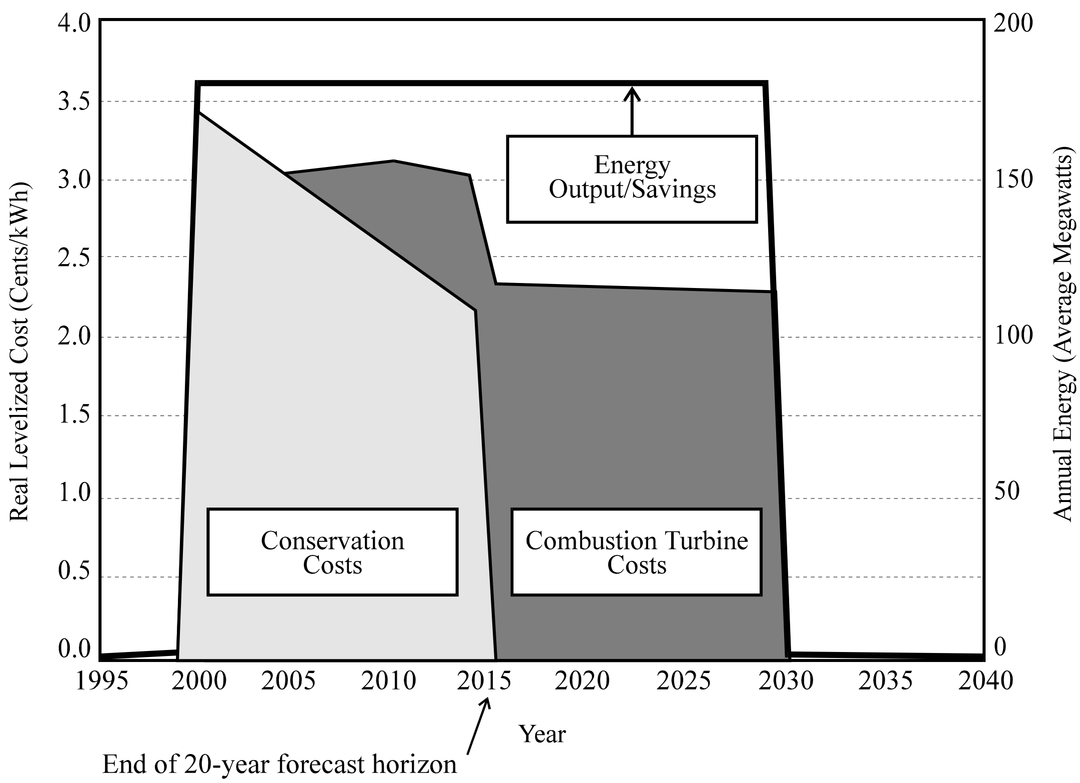
As can be seen in Table 6-2, the average total present-value benefit of developing the region's remaining cost-effective conservation potential is $2.3 billion. Investments in conservation, beyond those anticipated to be made by utilities and consumers, could secure $1.7 billion in benefits ($2.3 billion minus $570 million). To place these values in perspective, the estimated present-value cost for all resources, except conservation, needed to meet the region's electricity load growth over the next 20 years is $27.7 billion. By making these cost-effective investments in conservation, this "bill" could be lowered to $25.4 billion.

It is important to acknowledge that the majority of the benefit shown in Table 6-2 occurs over the long term, beyond the 20-year planning horizon. The power plan looks at the value of resources developed over 20 years to meet load growth. However, for a resource built in any given year that has a longer lifetime than the 20-year forecast horizon, the costs and benefits of that resource for its entire lifetime are counted. Consider, for example, either a combustion turbine or an equivalent amount of conservation developed in 2000. Both are financed over 15 years, both have 30-year lifetimes and both will produce or save kilowatt-hours well beyond the 2015 forecast horizon. Figure 6-2 shows the cost profile for these two resources over time.

If these two resources were evaluated only up to the year 2015, all of the costs of the conservation would be included, but the fuel and maintenance costs of the combustion turbine after 2015 would be missed. Until the year 2015, the two resources are fairly comparable in total costs, and both resources produce an equal amount of benefits (i.e., energy). But after 2015, conservation continues to produce savings for the region at very minimal cost. The turbine produces value after 2015, too, but at much higher cost. To capture the benefits and costs of resources acquired by 2015, the costs and benefits over their entire lifetimes need to be incorporated. The effects of uncertainty regarding future electrical generation costs have been addressed in the Council's analysis and are discussed below.

Figure 6-2

Resource Costs and Benefits Valued Over Their Productive Lifetimes



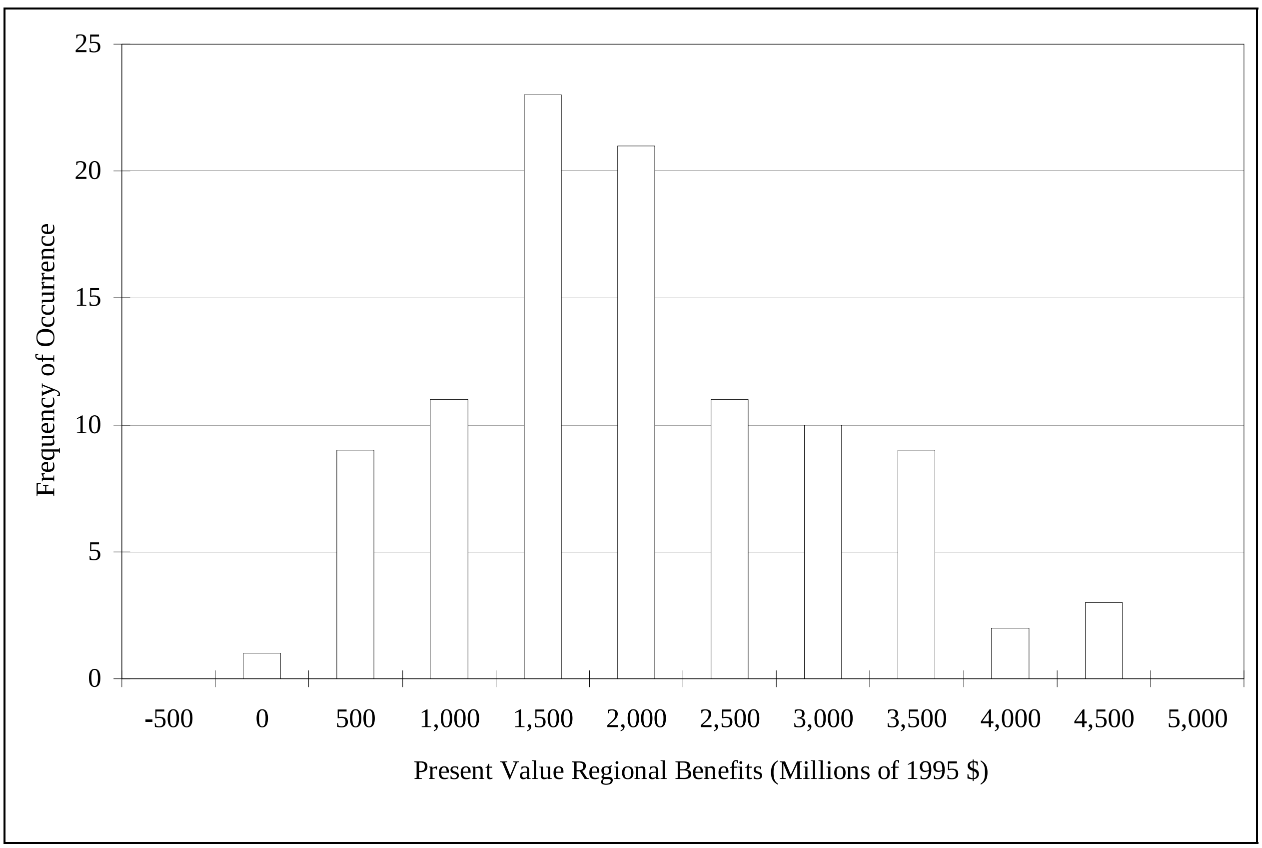
Effect of Fuel Price, Demand and Hydropower Uncertainty

While the average present value of the conservation is of interest, it is important to have a sense of how that value might change with respect to the uncertainty in fuel prices, demand growth and hydropower conditions. Figure 6-3 shows the distribution of present-value benefits produced by the investments in conservation. The acquisition of this additional conservation produces a benefit to the region of between $0 and $4.5 billion over the next 20 years, with an average of $2.3 billion, as reported above. The range of values is a result of the specific combination of economic growth, fuel prices and hydroelectric availability the region experiences over the next 20 years.

On a long-term basis, the conservation investment is robust, with the region always being better off if it invests in conservation. The reason conservation remains valuable over the wide range of futures modeled here is because the conservation is relatively low cost and the cost-effectiveness of additional investments in conservation are continually assessed as the region invests over time. In futures in which low load growth and/or low gas prices occur, the region slows its investments and develops much less than 1,535 average megawatts. The range of conservation development due to such factors is shown in Figure 6-1. Conservation's characteristic of being developed in increments over time is valuable, because decisions about additional development can be deferred until the savings are needed. If the region were to commit today to developing exactly 1,535 average megawatts over the next 20 years, without adjusting for load growth or other factors, there would be a significant number of cases in which present-value costs exceed the benefits.

Figure 6-3

Distribution of Present-Value Benefits of Conservation Over Full Resource Life



Additional Risks and Uncertainties

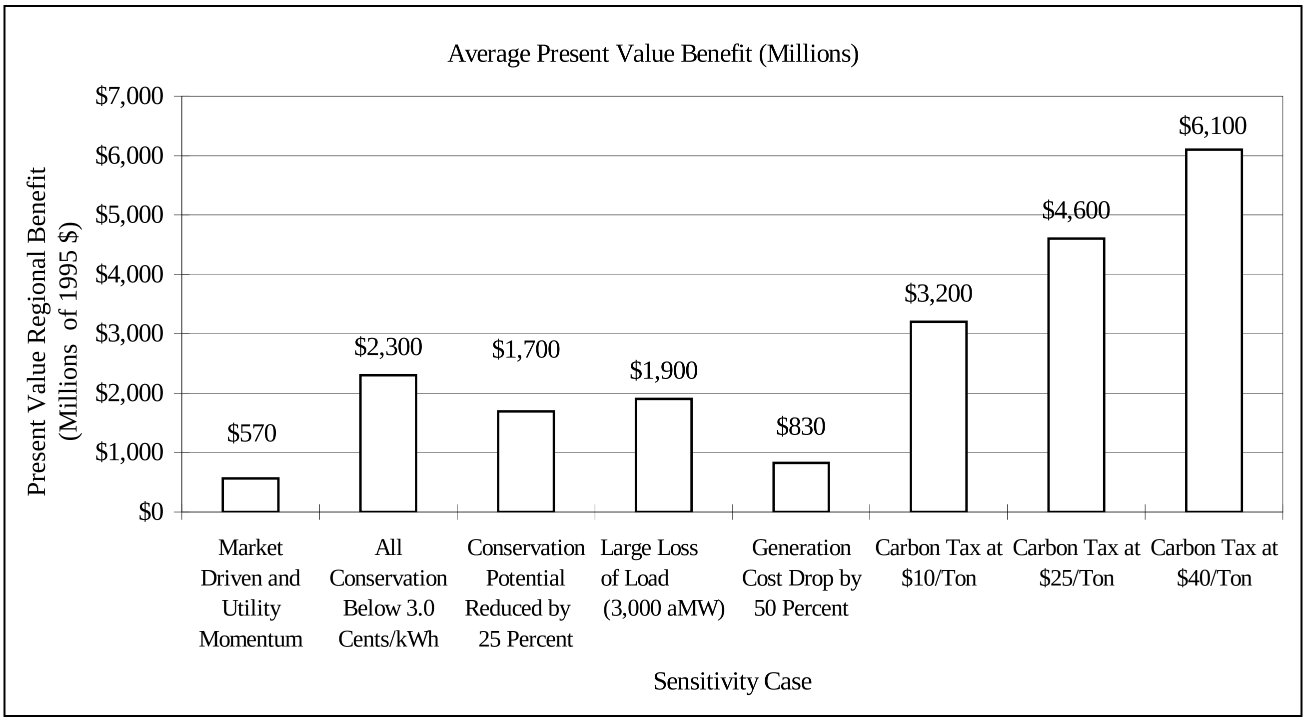
The Council's base-case analysis accounts for much of the uncertainty associated with fuel prices, demand and hydroelectric conditions. However, there are additional uncertainties and risks to which conservation investment is exposed. While some of these risks reduce the average value of the conservation, in all cases there remains significant value. There are also risks that significantly *increase* the value of conservation. Many would argue that these risks are at least as likely as those risks that reduce the value of conservation.

Figure 6-4 illustrates the base-case analysis and multiple sensitivity analyses that were conducted.

Market driven and utility momentum: The first bar in Figure 6-4 illustrates average present-value savings to the region if conservation is developed through utility momentum and the market. This is not all the cost-effective savings that could be acquired over the 20-year forecast horizon.

All conservation below 3.0 cents per kilowatt-hour: The second bar shows average present-value savings if all cost-effective conservation is developed. The remaining sensitivity cases in the figure are described next.

Figure 6-4
Summary of Conservation Sensitivity Study Results



Conservation potential reduced by 25 percent: The Council relies on the best information and analysis it can produce in estimating the amount of conservation available for development. However, those estimates are subject to some uncertainty. Some parties have criticized the analysis for estimating too much conservation, others for estimating too little. To evaluate the risk associated with overestimating the conservation potential, the analysis was re-run using the proposed lower estimates of achievable potential — a reduction of about 25 percent. This reduces the average present value of conservation from $2.3 billion to $1.7 billion.

Large loss of firm load: The primary risk the region takes in purchasing conservation is that once the capital is invested it can no longer be used for some other purpose. Virtually all of the cost of conservation is a fixed, up-front capital cost, which is repaid in savings over many years. Once the capital is spent on a conservation measure, there is no simple way to recover its value, other than to wait for the savings to accrue. If the region were to suddenly lose a large amount of load, some of the conservation investment would not be needed.

This possibility was investigated by assuming that the region loses 3,000 average megawatts of electrical load in the year 2005 as a result of industrial plant closures or economic downturn. In this scenario, the development of cost-effective conservation still provides the region with $1.9 billion in present-value savings, compared to $2.3 billion in the base case. This is a result of three factors. First, because the region is already relying heavily on market purchases to meet its needs, it can respond to rapid changes in loads by curtailing purchases. Second, less than 10 percent of the conservation that is typically developed by the year 2005 has a levelized life-cycle cost to the region of more than 2.0 cents per kilowatt-hour. Since it is less expensive than continued market purchases, it retains its value to the region. Third, because the conservation is implemented incrementally at about 75 average megawatts per year, further conservation investment can be reduced when the loss of load occurs.

Cost drop by 50 percent: Another way in which conservation investment could be at risk is if there were some dramatic and unanticipated improvement in generation technology that would reduce the value of conservation savings. This was tested by assuming that some technological breakthrough reduces the cost of new generation by nearly 50 percent (to 1.5 cents per kilowatt-hour) in the year 2005 and that this source of power is immediately available to serve all regional loads. The costs of this resource were assumed to be all variable costs, and thus it would have complete flexibility to be turned on and off to meet load fluctuations. Should this occur, it would reduce conservation's average present-value benefit to the region to approximately $800 million.

Carbon tax added: Not all the risks the power system faces are adverse to conservation. As is discussed later in this chapter, there is the risk that measures might be imposed to reduce emissions of carbon dioxide and other greenhouse gases thought to be contributing to global climate change. This risk was simulated by assuming a tax of between $10 and $40 per ton of carbon dioxide is implemented in 2005. Such measures could increase the value of conservation to the region by between $3.2 and $6.1 billion.

Net Annual Expenditures for Conservation Over Time

As noted above, conservation requires more money up front than purchasing electricity from the West Coast market in the near term. In the longer term, however, conservation reduces yearly expenditures for power purchases and defers new power plant additions. The Council compared the yearly cost of developing conservation versus buying power from the market in the near term and developing gas-fired generation in the longer term to assess the magnitude of the near-term risk created by purchasing conservation. Figure 6-5 shows the annual net cost to the region of acquiring conservation by the year 2015 under three different acquisition schedules.

The first schedule shows the annual net cost of acquiring the 515 average megawatts of conservation utilities are already planning to acquire plus the conservation the market might accomplish on its own. This is labeled "Market Driven and Utility Momentum." The second schedule, labeled "Market Driven and Utility Momentum Plus Conservation Below 3.0 Cents per Kilowatt-Hour" adds the annual net cost of capturing the remaining cost-effective conservation to the 515 average megawatts developed in the first schedule. The third schedule, labeled "Least-Cost Acquisition Schedule of Conservation Below 3.0 Cents per Kilowatt-Hour" develops all conservation in least-cost order. The "zero" line represents the cost of relying on market purchases and new gas-fired generation in lieu of capturing any conservation. A positive figure represents net cost to the region, while a negative figure represents a net savings.

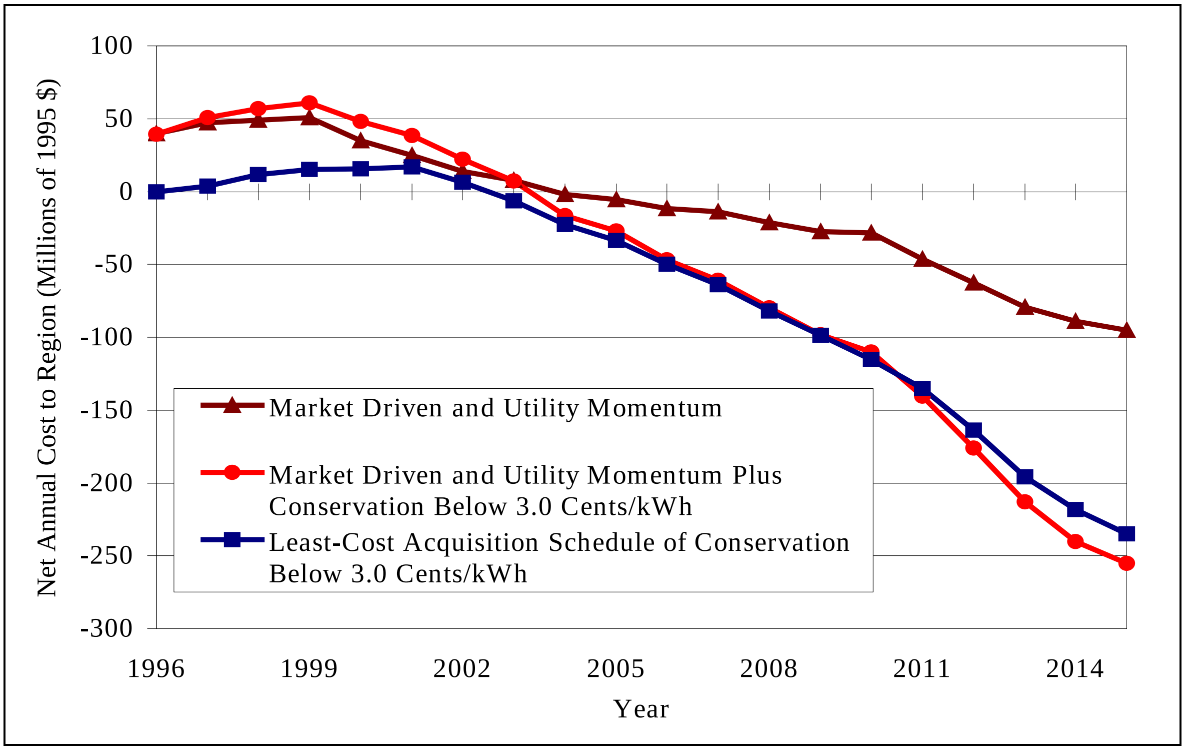
As shown in Figure 6-5, the combination of utility program momentum and consumer actions, results in a pace of conservation acquisition that will require an investment of about $40 million annually more than the cost of relying on alternative resources through the year 2003.[6] Developing the additional conservation needed to meet load growth would add only approximately $7 million per year in "new" investments beyond those anticipated to result from current utility plans and market expenditures.[7]

Net costs are higher in the early years because so much of the conservation results from utility programs and contract commitments that have not been fully adjusted to the lower avoided costs the region is now seeing. As a result, some of this conservation is more expensive than that which would be acquired on a least-cost basis. However, if the region's consumers and utilities are able to develop lower-cost conservation first, roughly the same amount of conservation is acquired, but at about one-third of the annual net cost. This can be seen by comparing the line labeled "Least Cost Acquisition Schedule for Conservation Below 3.0 Cents per Kilowatt-Hour" to the other two lines in Figure 6-5.

[6] Of the 700 average megawatts of conservation needed to meet load growth through the year 2003, approximately 335 average megawatts are anticipated to be developed by utilities and consumers without further market intervention.

[7] It should be noted that actual utility expenditures are expected to be only a portion of this amount due to consumer cost-sharing.

Figure 6-5
Annual Net Cost of Conservation Resource Acquisitions
Compared to Reliance on Power Purchases and New Generating Resource Acquisitions



Will the Remaining Cost-Effective Conservation Be Achieved?

It appears that the region could secure significant economic benefits by developing its remaining cost-effective conservation. In the past, Bonneville and the region's utilities were positioned both economically and institutionally to acquire all cost-effective conservation. Competition is changing that. Before discussing whether there is a need for new alternatives, this section discusses how much conservation the region might reasonably anticipate being developed by utilities, consumers and the energy service industry in response to the evolving competitive market.

Utility-Funded Conservation

Historically, Bonneville and the region's utilities have served as the primary agents for conservation resource development in the Northwest. In the near term, the Council's survey of electric utilities indicates that they intend to continue to acquire approximately 250 megawatts of energy savings by the year 2000, or about 60 to 70 megawatts per year.

Among public utilities, informal surveys indicate that many want to continue to offer energy saving opportunities to their customers both as a service and to achieve conservation at lower utility costs. Many of these utilities are augmenting Bonneville funds, carried forward from previous years, to continue conservation over the next few years.

The investor-owned utilities are operating under least-cost planning orders from their regulators. While many of these utilities have reduced their expenditures on conservation, in large part because of the declining avoided cost, they have still committed to developing fairly large

UTILITIES AND CONSERVATION: A NEW PARADIGM

In the 1970s and 1980s, the costs to build new generating resources were generally higher than the costs of existing resources. Electricity prices were usually based on average costs, so the revenue from new loads did not cover the costs of building new resources to serve new loads. Serving new loads raised everyone's prices. Utilities became vehicles for spreading the costs of new resources (of whatever type — generation or conservation) among customers, whether or not the customers contributed to load growth. Customers who shared the cost of other customers' service tolerated the situation because their energy bills would have been higher yet if they left the utility to self-generate.

In that world, it was reasonable for utilities to have an important role in acquiring conservation. They were already in the business of spreading new-load costs among all customers. Sharing the cost of conservation, while more contentious than sharing the cost of new generation, was not fundamentally different. If a conservation measure reduced the total cost of meeting load growth, it was *possible* (though not simple) to make all customers better off. Because self-generation was unattractive compared to utility service, and transmission access was restricted, utilities' monopoly franchise was relatively safe, and utilities could impose some cost-shifting on their customers without disastrous effects on their stockholders.

The world today is much different. Lower natural gas prices, better generating technologies and the opening of transmission and, possibly distribution, access have or will combine to make it attractive for some customers to leave utilities for independent suppliers or self-generation. Utilities are beginning to respond to this threat by offering these customers prices that approach the marginal cost of service. If competition develops fully, utilities will not be able to allocate to these customers any part of other customers' costs of service (generation or conservation).

To the extent that customers do not share others' costs of generation, much of the rationale for sharing the costs of conservation disappears, along with the utility's ability to do so. In a competitive world, new-load revenues cover their own costs, except for environmental externalities. Other customers are mostly indifferent to the efficiency of use by new loads, since new loads pay their own way. As a result, a fully competitive utility cannot sustain cost transfers among customers for investments in conservation, even if the conservation is cheaper than generating alternatives.

The utility industry as it stands today is not fully competitive. For example, utilities still have monopoly franchises, and marginal retail prices for some customers do not equal marginal costs. Most utilities, however, are anticipating competition, if not already experiencing some of its manifestations. As a result, the exact role of conservation in the changing world is unclear. Many utilities are taking a cautious attitude toward the further development of conservation as a resource during this current period of uncertainty. Investments in conservation, mostly up-front capital investment, run the risk of becoming stranded investments in a competitive marketplace.

Many utilities will continue to pursue conservation because their customers and governing boards want them to do so. But it is unlikely that the part of the electricity business that is competitive will have an interest in, or be able to sustain, large investments in conservation over the long run, unless that conservation is directly funded by the customer who installs the measures.

amounts of the conservation resource in the next few years.[8] Many of the investor-owned utilities have indicated that their plans to carry out conservation programs in the near-term are designed to help position them for a more competitive world in the long-run. This includes reducing the cost of utility conservation programs, focusing on markets where competition could cause the loss of customers, and favoring consumer information and loans over rebates.

As competitive pressures increase, both public and investor-owned utilities are expected to further reduce their efficiency efforts.

Consumer-Developed Conservation

Consumers will continue to develop some conservation on their own, regardless of the actions of utilities or other parties. Consumers invest in conservation for many reasons in addition to the fact that efficiency improvements save them money. These reasons include comfort, productivity enhancements, environmental concerns and so on.[9]

How much conservation consumers will develop depends on how well the market for energy efficiency functions. One criterion for a well-functioning market is prices that accurately reflect the cost of the next increment of consumption. In the past, consumers' power rates were much lower than the marginal cost of electricity. In the more competitive environment, the price consumers pay for electricity will likely converge with the marginal cost of electricity supply.[10] If this occurs, then one of the two key elements of a functioning market will be in place; marginal prices will approximate marginal costs.[11]

However, there is another, equally essential element of a functioning market: that buyers and sellers can make well-informed choices. Good information implies that: 1) the decision-maker has timely and accurate knowledge; and 2) the decision-maker has enough confidence in that knowledge to base decisions on it.

The lack of good information in electricity and conservation markets takes the following forms: low awareness of how energy and efficiency could be applied in homes and businesses; lack of adequate and quality information that gives the end-user a clear-cut, reliable course to follow; lack of access to capital and conflicting uses for capital; and a disconnect between the decision-maker contemplating efficiency choices and the consumer who pays the electricity bill. An example of this latter "split-incentive" problem is a home builder who builds a house on speculation and wants to minimize first cost, and the eventual homeowner who will ultimately pay the utility bill and has little understanding of long-term energy costs. The lack of good information in its various forms constitutes a barrier to the functioning of the market for energy efficiency.

There is an old joke about the economist who passes by a $20 bill on the sidewalk. When asked why he passed it by, he replied that it can't be a real $20 bill because somebody would already have found it and picked it up. Despite economic theory, the experience of the past 15 years of conservation implementation is full of examples of $20 bills left on the sidewalk and in homes, offices and factories because of market barriers. Market barriers make it unlikely that consumers will take advantage of all cost-effective energy-efficiency improvements.

An example is the fact that many consumers pass up opportunities to buy more efficient

[8] Avoided costs have come down dramatically since the early 1990s, and as a result, less conservation is cost-effective. This means that the yearly amount of conservation that is targeted by utilities is less than it once was, but in the next few years it is still significant.

[9] Consumers will also adopt energy-efficiency measures that, if evaluated solely from their electricity benefits, are above the regional cost-effectiveness limit because these measures have significant non-energy value, such as comfort, productivity or product quality improvements. The Council has not attempted to estimate the size of this conservation resource, and it is not included in the estimates of cost-effective conservation discussed in this plan.

[10] We expect competition to result in a trend toward unbundling of electricity rates – separating the costs of the kilowatt-hours delivered from the fixed costs of delivering the electricity and lowering the price of the kilowatt-hours. Only through such unbundling can consumers compare their supply alternatives on an apples and apples basis. Lower prices and unbundling will reduce the disincentive utilities experience when conservation cuts into their recovery of fixed costs. It will also reduce the consumer's economic incentive to conserve.

[11] Marginal costs are unlikely to reflect all environmental costs of electricity production, so there will not be a completely accurate price signal.

appliances, even when the energy saved by the more efficient appliances, evaluated at the consumers' cost of electricity, would offset the extra capital cost of the appliance in a matter of months. Interpreted as investment opportunities, these efficient appliances can be very attractive to consumers; they might return 30 percent to 50 percent or more on the initial investment. But relatively few consumers evaluate their purchases in those terms. Similar patterns of consumer choice show up in residential and commercial buildings and in the industrial sector.

Conservation Developed by the Competitive Market

There are certain types of activities that utilities and energy service companies are likely to pursue as the emerging industry structure becomes more apparent.[12] Utilities and energy service companies are interested in providing consumer information to overcome the market barriers described above to the extent that it allows them to make a profit.

The types of products and services that will promote conservation and align with the business interests of utilities or energy service companies are those that promote customer loyalty and satisfaction, or that can be offered at a profit. In a competitive market, the cost of kilowatt-hours from different suppliers will vary only slightly. As a result, conservation services might be one tool in an arsenal of options to differentiate one supplier's product from another's and create customer loyalty.

Manufacturers of efficient products will also have an interest in promoting their products. For example, Honeywell wants commercial building managers to adopt Honeywell's energy management system. However, efficiency is usually just one feature in a whole host of features that consumers are searching for in a particular product. As a result, the market niche for efficient products is usually small, unless it is packaged with key additional features.

[12] "Energy service companies" are companies that offer demand-side management services, including conservation. The term appears to be evolving, and is now used to denote companies that are interested in general energy services, including choice of fuels and load shifting.

The common thread in these approaches to conservation is that they will increase the viability and/or profitability of the company providing the service by offering superior and/or differentiated products that are desired by customers. Mostly they are products or services that can be charged directly to the benefiting customer, and the customer values them enough to pay a price premium. These services cannot be supported by other customers, because the benefits do not accrue to all customers, but to the customer that directly installs the conservation. They are primarily market-driven efficiency services.

The following are the types of conservation services that are likely to be developed in a more competitive electricity market.

Customer retention services: Energy companies that want to build customer loyalty may help the customer find ways to reduce the cost of electricity use. For example, in an effort to retain their business, Puget Sound Power and Light recently included conservation services in a package to one of its larger customers who was investigating alternative power suppliers.

Enhanced services: Some energy companies may elect to offer services rather than energy sales (kilowatt-hours) to their customers. An example might be selling air compression to an industrial firm. Rather than charging for the electricity used to energize the air compressor, the energy service company would charge for the amount of compressed air used. In this situation, it is in the interest of the energy service company to produce the compressed air at the lowest possible cost. If the cost of improving efficiency is lower than the energy cost, they will have an incentive to improve efficiency.

Fees for expertise: Energy companies will sell their ability to help customers reduce their costs, increase their comfort and productivity, or both. The fee represents a sharing of the cost savings between the customer and the energy service company. For example, Western Montana Generation and Transmission Company is considering opportunities such as charging for audits of homes heated with electricity or natural gas.

Differentiation from competitor's products: Some energy providers may try to capture a market niche based on environmental or societal values. These companies will promote “green pricing” or the fact that they are a “green” company, offering energy-efficiency services to secure particular customers. Working Assets Long Distance is an example of this strategy in the telephone industry. A number of electric utilities around the nation, including Portland General Electric and Salem Electric in the Northwest, have tried various approaches to offering green services, with mixed success.

Efficient use of the distribution system: In either a competitive or regulated environment, it will make sense for utilities owning distribution systems to utilize those systems fully. This means reducing power losses on the distribution system itself, as well as load management and load reduction on customers’ facilities that might otherwise require more costly system upgrades.

Community values: A number of utilities in the Northwest, particularly some of the public utilities, have offered conservation programs because their customers viewed it as the right thing to do. To the extent that the conservation ethic persists, some utilities will continue to pursue conservation that satisfies their customers.

Conservation Development Experiences in More Competitive Markets

The electricity industry in the Northwest is not the first to undergo major restructuring. The Council reviewed the experience in other countries and industries to assess the probability that conservation’s apparent benefits to the region will be secured in a more competitive energy service market. This review revealed the following:

- Experience in all five countries where the electricity industry has been opened to competition shows that the acquisition of conservation tends to decrease in newly competitive markets, and that private conservation companies have not emerged as strongly or as quickly as predicted. [13]

- Experience from the U.S. gas industry, which has been deregulated for 10 years, indicates that niche markets have developed for conservation, but it has not been widespread.

- Very recent experience of a few energy service companies indicates that those that do not rely on shared savings and/or utility financial support, but instead provide a building with specific end-use services (e.g., lighting, space conditioning, etc.) for a fixed annual fee (with adjustments for inflation and weather) may successfully penetrate a limited market niche (e.g., large office buildings).

Conservation Program Evaluations and their Estimation of Market Effects

Evaluations of previously operated conservation programs are also a source of information on what the market might accomplish. In some of these evaluations, the utility tried to ascertain how much of the savings might have occurred in the market even without the utility program.[14] For the Northwest, evaluations from the industrial sector provide the most information on what the market would have done without the program. The evaluations indicate that approximately 5 percent to 15 percent of the savings from various programs would have been done anyway, even without the utility’s help. This indicates that without some sort of information, or financial help, or both, the market will achieve some, but not all, cost-effective conservation on its own.

Additional Opportunities for Conservation Development

The types of conservation that are most at risk of being bypassed in a competitive market are those that do not align with the business interest of a provider, such as an energy service company. Utilities and energy service companies may not have much business interest in intervening if the

[13] Lance Hoch and Linton Parker, “Sustainable Energy Policy in Competitive Electricity Markets: What’s Been Tried, What Works and What Doesn’t,” Proceedings of the Fourth International Energy Efficiency & DSM Conference: The Global Challenge, Berlin, Germany, October 1995, pp. 503-511.

[14] The evaluation community has used the term “free-rider” to denote the portion of participants in a utility program that would have done the conservation on their own. This is an estimate of what the market would have accomplished without the utility program.

conservation resource is small and widely dispersed in thousands of facilities, and the profit margin to pursue each of these individually is small. For example, more efficient refrigerators save individual consumers about $4 per year. This is too little to overcome the high administrative costs of pursuing these savings on a customer-by-customer basis. However, if the savings can be achieved in the aggregate, for example, through the manufacturer, they are significant.

There are several types of conservation resources that may be difficult to secure in a competitive environment. These include:

- State energy codes
- Federal appliance efficiency standards
- Demonstration of emerging technologies and systems
- Market transformation efforts
- Instances in which the conservation decision is not made by the energy bill payer, such as rentals.

Options for Conservation Development in the Long-Term

Of the $2.3 billion in savings that can be expected if all cost-effective conservation is developed, approximately $1.7 billion falls into the category of savings that seem unlikely to be produced through near-term utility commitment or, in the long run, by a competitive electricity market. What follows is a discussion of alternative ways the Northwest can secure the remaining energy savings.

Give the Market a Chance

The Northwest could focus its efforts on developing more competitive electricity markets and wait to see what the effect is on conservation acquisition. Because many utilities still intend to pursue conservation development for various reasons, and some government programs also will garner energy savings, acquisition over the next three to four years is likely to be substantial.

New/Revised Mechanisms

The region could focus on activities that would encourage development of the most cost-effective conservation during the transition to a more competitive electricity market. This might include providing appropriate regulatory signals for existing investor-owned utilities and focusing on resources that might be lost during the transition from the current regulatory compact to any new market. Potential forms of new and revised mechanisms might include the following:

Require conservation as a "public good" in exchange for a monopoly franchise at the distribution level: Even in a competitive electricity market, distribution companies are likely to remain monopolies. They will have no incentive to pursue conservation as a least-cost resource. However, if regulators for investor-owned utilities, and the public for public utilities, think that conservation has benefits that should not be lost, then some level of conservation services on the part of the distribution company might be required in exchange for the monopoly franchise. To make this work, the distribution company should have its profits disconnected from its sales of kilowatt-hours.

System benefits charge: A frequently discussed option to raise funds for conservation resources that might not be captured by the open market is a "system benefits charge." The system benefits charge is a fee assessed broadly across the electricity system that is non-bypassable and is used to develop conservation. Exactly how these funds are raised and how they would be spent would need to be fully explored.[15] The idea, however, is similar to the levy on phone bills to provide 911 emergency calling and universal service for low-income and physically impaired customers. Almost every active restructuring process in the United States is calling for a system benefits charge or something very similar to maintain some level of energy-efficiency services. The same is true of many international restructuring decisions, such as those in the United Kingdom, Norway and New Zealand.

Conservation as part of meeting load growth or developing new generating resources: Another option that might be used to encourage conservation development would be a requirement that a certain percentage of load growth be met

[15]For example, PacifiCorp has initiated a discussion on how to develop conservation in the more competitive world, which looks into exactly these questions. Two white papers have been developed by PacifiCorp to aid in the discussion.

through conservation efforts. Investments beyond the required offset could be banked or sold on an open market. Utilities, generation resource developers and others could obtain, bank and sell conservation offsets. The system would be similar to the market developed around sulfur-dioxide emissions.

Recommendation

Council analysis indicates that there is a substantial amount of cost-effective conservation available for acquisition in the region. Approximately 20 to 30 percent of this conservation will likely be acquired in the restructured electricity industry through market forces and momentum from existing utility action. If the remaining 70 to 80 percent of the savings are not acquired, the result would be higher power system costs than would be the case if the total amount of cost-effective conservation was acquired.

In the regulated utility paradigm, mechanisms to acquire conservation were available that resulted in relatively little disruption of the market. The new utility structure, especially in generation and supply markets, is much more competitive. Competitive markets are sensitive to factors such as cross subsidies or incorrect price signals and will tend to exploit these factors where they occur.

The Council suggests that the Comprehensive Review and appropriate state forums evaluate the costs and benefits of potential mechanisms to acquire conservation beyond what will be developed in the market. The goal should be a competitive market that preserves as much of the net conservation benefit as possible.

These mechanisms should reflect the principles outlined below.

- Any intervention should be competitively neutral, and not give one electricity or other energy resource provider an advantage relative to another. Intervention should not interfere with the market pricing of electricity and the operation of a competitive electricity market. For example, use of a non-bypassable charge on distribution minimizes the ability for competitive electricity suppliers to avoid the charge. At the same time, the magnitude of the charge must not upset the competitive balance between electricity and natural gas or other fuel suppliers.

- Any intervention should complement the competitive market for energy services that might emerge. This might include a strategy for those types of conservation actions that need a kick-start, but that can eventually be handed over to the competitive market. In this case, the strategy should include signals for when to cease the intervention.

- Any intervention should provide some symmetry between those who pay for the intervention and those who receive its benefits.

- Any intervention should be administratively efficient to gain the greatest net benefits possible.

- Any intervention should use competitive mechanisms to the greatest extent possible when acting to secure the conservation resource.

- Any intervention should incorporate performance assurance mechanisms to secure the savings.

CONSERVATION: WHAT TO DO NOW

During the transition to more competitive electricity markets, the Council has identified 10 things utilities, regulators, end-users, governments and the conservation industry can do to help maximize conservation benefits, minimize conservation costs and smooth the transition.

1. Take advantage of the conservation momentum and the near-term resource surplus to reconsider and perhaps redesign conservation programs and strategies.

2. Identify and market the non-energy benefits of efficiency, including increased industrial productivity, comfort, environmental compliance and enhanced property value.

3. Share conservation ideas, plans, successes and failures. With more than 100 utilities and many governments in the region putting conservation programs together, there are bound to be plenty of new ideas.

4. Continue the development of cost-effective lost-opportunity resources. These are resources that if not acquired now will become either physically impractical or uneconomical to pursue in the future.

5. Support market transformation efforts to achieve cost-effective electricity conservation at lower costs. Market transformation efforts target decision-makers, such as manufacturers and retail chains.

6. Provide ongoing accessible consumer information about cost-effective electricity conservation.

7. Explore changing rate structures so that fixed costs are recovered in fixed charges, and energy rates reflect the utilities' marginal cost. For example, utilities may increase their monthly service charge to recover fixed costs and set kilowatt-hour rates at or close to marginal costs. Reducing the recovery of fixed costs through marginal sales could eliminate the "lost revenue" problem associated with conservation and permit utilities to pursue conservation that costs them less than short-term marginal costs. This will, however, tend to reduce the consumer's economic incentive for conservation.

8. Explore ways to reduce the direct cost of utility conservation.

9. Explore ways to reduce the financial risk from conservation. Some utilities are seeking to accelerate amortization or to expense, rather than capitalize, the cost of new conservation, both of which reduce the cost of conservation financing. Although expensing rather than capitalizing intensifies the rate impact of conservation in the short run, these actions reduce the longer-term risk of stranded assets.

10. Consider a focus on customers that can seek electricity alternatives. Larger commercial and industrial customers are usually those most sensitive to price. They are also customers who have the resources to seek alternative power suppliers in a deregulated retail market, and their industries appear to contain the largest, low-cost conservation potential. Utilities that are already increasing their focus on these customer classes for business reasons, can offer conservation services as part of an overall strategy. Moreover, because the retail rates for these customers are typically closer to short-run marginal costs, the lost-revenue impact of conservation investments in their facilities is less. Utilities implementing this strategy must address the possibility that these loads will not necessarily be the utility's customers in the long term.

6-B. A RENEWABLE ENERGY STRATEGY

An objective of the Northwest Power Act is "to encourage the development of renewable energy resources within the Pacific Northwest." Renewable resource-based generating projects producing more than 420 average megawatts of energy have been developed since adoption of the 1991 Power Plan. This represents about 17 percent of all resources developed during this period. Encouraging progress has also been made on the renewable resource confirmation agenda set forth in the 1991 Power Plan. However, declining wholesale electric energy prices have resulted in near-cessation of additional generating resource development, and few new renewable projects are expected to be cost-effective in the near-term. This is consistent with the surplus of generating capacity on the Western electrical system, but raises the question of what type and level of renewables activity, if any, is desirable in this environment.

In developing this draft plan, the Council has assessed the value of the renewable resources available for development in the Northwest. This analysis considered load growth, hydropower and fossil fuel price uncertainties in an attempt to capture the resource diversity benefits of renewables. The analysis also considered the possibility of a carbon tax, should aggressive measures to reduce greenhouse gas production be needed. The values of several accelerated renewable resource development strategies, including sustained development, were also assessed and compared to developing renewables only as they become needed and cost-effective.

Based on its analysis, the Council has concluded that few renewable resources are cost-effective in the near-term. Unless carbon dioxide control measures increase the cost of other resources, the large inventory of undeveloped renewable resources available to the Northwest has little expected economic value if current forecasts of technology cost and performance, fuel price, water availability and load growth uncertainties hold. However, the potential value of renewable resources increases substantially if mitigation of carbon dioxide production is required to control global climate change.

A possible strategy of maintaining a set level of sustained renewables development was also analyzed. This analysis also suggests that there is little economic value in a strategy of sustained development of renewables. Projects developed in advance of cost-effectiveness would require a substantial cost premium, they would preclude the benefits of later technological development, and they are unlikely to produce significant economic benefit. This finding holds with consideration of fuel price, water availability and load growth uncertainties and with adoption of relatively high carbon taxes.

Nonetheless, because of the potential value of renewables in the event of control measures on carbon emissions, it is important to improve our understanding of the region's renewable resource potential and to ensure that the better resource areas remain available for development, if needed.

These findings suggest that a renewables strategy for the Northwest should focus on:

- Ensuring that the restructured electric power industry provides equitable opportunities for the development of cost-effective renewable projects;

- Ensuring that the renewable resource potential of the Northwest is adequately defined and that prime undeveloped renewable resources remain available for possible future development. This will require completion of key demonstration projects and resource assessment studies already under way;

- Supporting research and development efforts to improve renewable technology;

- Offering green power purchase opportunities; and

- Monitoring fuel prices, the global climate change issue and other factors that might influence the value of renewable resources. More aggressive preparation for the development of renewables could be initiated if changes in these factors indicate that accelerated development of renewables is desirable.

Renewables Activities - 1991 to the Present

About 700 to 800 megawatts of renewable resources, primarily hydropower and biomass cogeneration, were identified by the Council in the 1991 Power Plan as potentially cost-effective for development during the 10-year period following adoption of that plan. That plan called for development of these low-cost renewable resources. Since that plan was adopted, renewable projects providing more than 420 average megawatts of energy have been developed, and additional projects remain to be completed. Hydropower and projects using biomass residue fuels provide the bulk of this energy.

Recognizing that the cost of most renewables, though declining, was still higher than alternatives, the Council in its 1991 plan recommended a renewable resource confirmation agenda. The confirmation agenda is a set of coordinated research, development and demonstration activities intended to foster the efficient development of geothermal, solar and wind resources at sites in the Northwest. Confirmation activities include resource assessment, resolution of development constraints and renewable demonstration and pilot projects. These are described in Appendix K.

Many of the confirmation agenda actions have been initiated, though few have been completed. Most successful have been long-term wind and solar resource assessment, geothermal and wind pilot projects, and niche applications of solar photovoltaics. Less progress has been made on actions intended to secure improved resource information at specific sites, with the exception of environmental assessment at sites proposed for demonstration or pilot projects, and solar resource monitoring.

Prospects for Development of Renewable Energy Resources

As discussed in Chapter 5, technology improvements and production economies are expected to continue to reduce the cost of electricity from renewable resources. However, because of declining gas prices and continuing improvement in gas turbine technology, energy from most renewable resources is expected to be more expensive than new gas-fired combined-cycle power plants over the near term. Moreover, most renewables require large capital investments, which must be amortized over a lengthy operating period in order to secure competitive power costs. This is a disadvantage in the currently uncertain and changing utility industry where financial flexibility and minimal long-term capital investment are prized. The intermittent energy production of some renewables further reduces the value of their energy, and may increase the cost of delivering power from remote renewable resources because of the resulting low transmission capacity factor. Finally, though renewables (biomass excepted) are free of fuel price risk, they are susceptible to technology performance risk; the generating equipment must operate reliably over a long lifetime to recover the initial capital investment.

Given these economic handicaps, and absent major shifts in resource economics, such as would result from unexpectedly rapid increases in natural gas prices or adoption of carbon dioxide control measures, few renewable resources are likely to be cost-effective in the near term. Exceptions might include hydropower upgrades, upgraded chemical recovery cogeneration at pulp mills and projects developed primarily for non-power benefits (such as generation using landfill gas).

In the longer term, technology development is expected to improve the competitive position of some renewable resources. Costs should continue to decline for currently immature technologies, such as gasification of solid biofuels; technologies that stand to further benefit from economies of production, such as photovoltaics; and technologies that may benefit indirectly from research and development in other industries, such as geothermal exploration and drilling. The performance of fossil-fuel technologies is also expected to improve, but the effects of these improvements may be offset by escalating gas prices.

WHY PEOPLE SUPPORT RENEWABLES

The chief arguments that have been advanced by supporters of renewable resource development include:

Favorable environmental characteristics: Long-term and broadly dispersed environmental impacts, such as those linked to nuclear waste disposal, fossil-fuel extraction or atmospheric pollutants, are rare with renewable resources. In many cases, the environmental effects of renewable energy development are limited to the vicinity of the project and are relatively manageable.

Improved air quality and few greenhouse gas emissions: Wind, solar and hydropower resources have no atmospheric emissions and contribute no greenhouse gases to the atmosphere. Geothermal plants release comparable or fewer atmospheric pollutants and much less carbon dioxide than fossil-fuel combustion. Biomass combustion releases more pollution than natural gas for generation of an equivalent amount of power. However, controlled burning of biomass residues for power generation is less polluting than the uncontrolled burning of these materials that might otherwise occur, and the carbon dioxide released by combustion of biomass will eventually recycle if sustainable forestry and agricultural practices are followed.

Energy cost stability: A diverse resource portfolio, including renewable resources, offers resiliency against fuel price, technology and environmental risks and uncertainties.

Local economic benefits: Renewables development can provide long-term employment, royalty and tax benefits to local communities that may not otherwise benefit from power system investments.

Regional self-sufficiency: Indigenous renewable resources reduce the need for energy imports and provide protection from fuel or transmission interruptions.

Development of products for export: An active domestic renewables industry can create products and services for overseas markets.

Non-power direct benefits: Some renewable energy projects, such as landfill gas energy recovery, offer important non-power benefits.

Promote a sustainable energy supply: A sustainable society is one in which humans can thrive without progressively degrading the natural environment and for which the living standards of future generations are not diminished by actions of the present. Renewable energy resources appear to constitute an important component of a sustainable energy supply.

Public support: Although the development of specific renewables projects may be locally controversial, renewables in general enjoy broad public support.

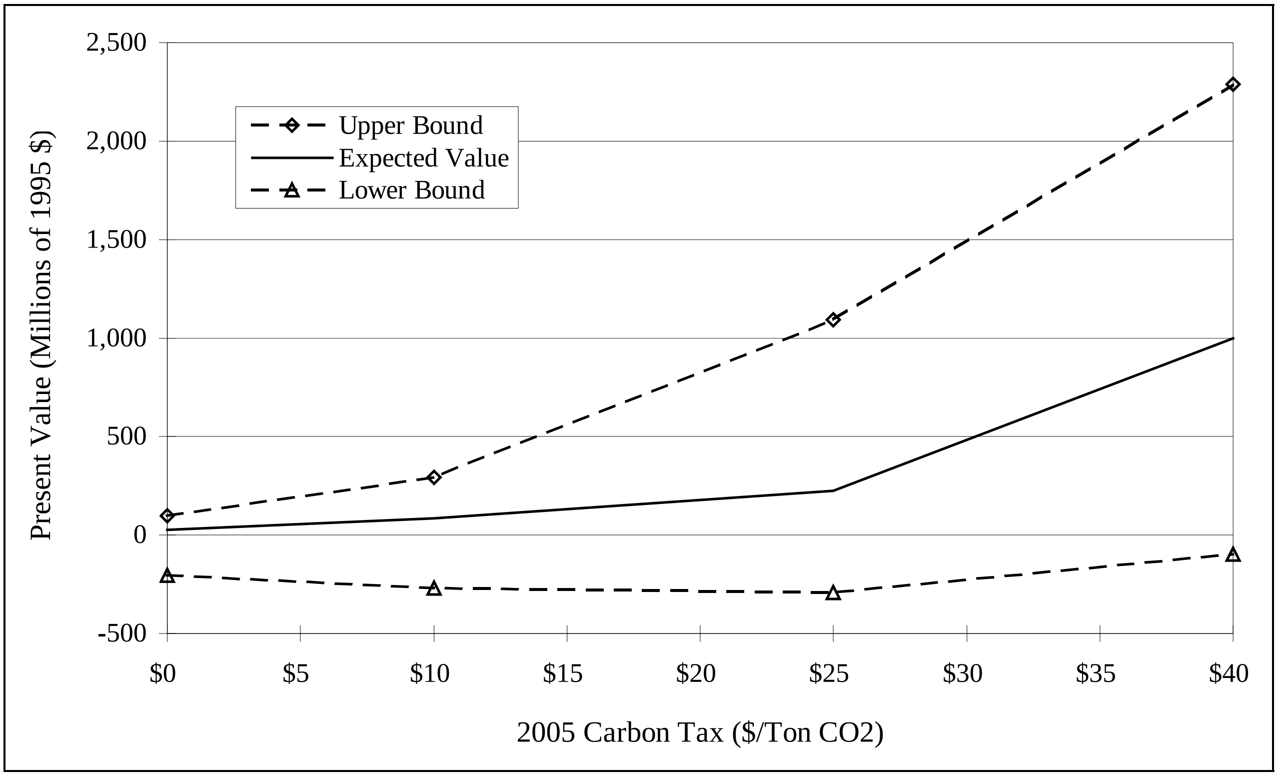
Value of Renewables Available for Development

Though few renewables are cost-effective in the near-term, having renewable resources available for development, in case they are needed, may have appreciable economic value. Considering only the uncertainties of water availability, load growth and fossil fuel prices, the expected value of renewables likely to become cost-effective over the 1996 to 2015 period is $28 million. This is compared to a present-value system cost of approximately $26 billion. The range of possible outcomes resulting from water availability, load growth and fossil fuel price uncertainty is not large.

The prospect of greenhouse gas control measures greatly increases the amount and value of cost-effective renewable resources. In this analysis, a carbon tax is used as a proxy for greenhouse gas controls. The tax rate range of $10 to $40 per ton of carbon dioxide emitted that is assumed for this analysis is consistent with fuel tax rates thought to be necessary to induce significant reductions in carbon dioxide production. This analysis assumes that a firm schedule for implementing a carbon tax is agreed to in 2000, and the tax is assessed beginning in 2005. This would provide time to initiate development of carbon dioxide offsets, conservation and renewable resources, and otherwise prepare for the tax. This approach is consistent with the phasing approach for pollutant reduction used in the Clean Air Act amendments of 1990.

The increase in the net-present value of the renewable resource inventory for the range of possible carbon tax levels is shown in Figure 6-6. As expected, carbon taxes result in more, and earlier, development of conservation and renewables. Electrical production cost savings occur by meeting new loads with resources that don't release carbon dioxide and by displacing the operation of existing projects that are sensitive to carbon taxation, such as coal-fired power plants. The expected net-present value of the renewables inventory increases to $86 million, $226 million and $997 million with carbon tax levels of $10, $25 and $40 per ton of carbon dioxide, respectively.

Figure 6-6
Net Present Value of Renewables Available for Development



Value of Accelerated Renewables Development

Because the societal benefits put forth by supporters of renewables development (see Box) are not necessarily incorporated in market-based resource decision-making, the level of renewables development that will be achieved purely on the basis of market prices may be less than the level that would occur if all societal values were considered. Some have argued that the gap between market-driven renewables development and this "societally optimal" level could be closed by establishing a target rate of renewable resource development. Market-driven levels of renewable resource development could be accelerated using resource portfolio standards or system benefit charges.

To assess the value of accelerated renewables development, three levels of developing renewable resources in advance of their need or cost-effectiveness were analyzed:

- Development of 27 average megawatts of renewable energy in advance of need and cost-effectiveness over the period 1999 to 2004. For the analysis, one 30-megawatt geothermal project was assumed to be developed. This level of project development is representative of a modest extension to the current renewables pilot and demonstration program.

- Development of 89 average megawatts of renewable energy in advance of need and cost-effectiveness over the period 1999 to 2004. For the analysis, two 30-megawatt geothermal projects and two 30-megawatt wind plants were assumed to be developed during the period. This level of project development is representative of an aggressive renewables pilot and demonstration program.

- Development of approximately 30 average megawatts of renewable energy per year in advance of need and cost-effectiveness between 1999 to 2004 for a total of 129 average megawatts. For purposes of the analysis, a mix of biomass, geothermal, solar and wind resources was assumed to be developed, including (relatively) low-cost projects that are added to sites already having pilot projects and pilot development at new areas. This rate of development would be representative of moderate-level sustained renewables development.

As in the previous analysis, an attempt was made to incorporate the societal benefits of renewables that may not be reflected in the resource decisions of a competitive wholesale electricity market. In addition to the energy contribution, much of the diversity value of renewables was included by considering hydropower, load growth and fossil-fuel price uncertainty. Fuel carbon tax cases of $0, $10, $25 and $40 per ton of carbon dioxide, levied as described above, help set a value for the carbon-free characteristics of renewables. Accelerated development was assumed to shorten lead times for subsequent development of additional projects at sites that have significant resource potential and to accelerate geothermal cost reductions.[16] Projects were assumed to accumulate credit for carbon offsets between 2000 and 2005.

The analysis does not reflect possible costs or benefits of non-carbon environmental effects, economic development issues, non-power direct benefits or contribution to a long-term sustainable energy supply. These effects appear to be generally offsetting (e.g., the local environmental effects of renewables development versus the residual air-quality impacts of fossil-fuel development); subject to non-energy policy (e.g., economic self-sufficiency); or do not appear to be compromised by any of the courses of action considered (e.g., long-term energy sustainability).

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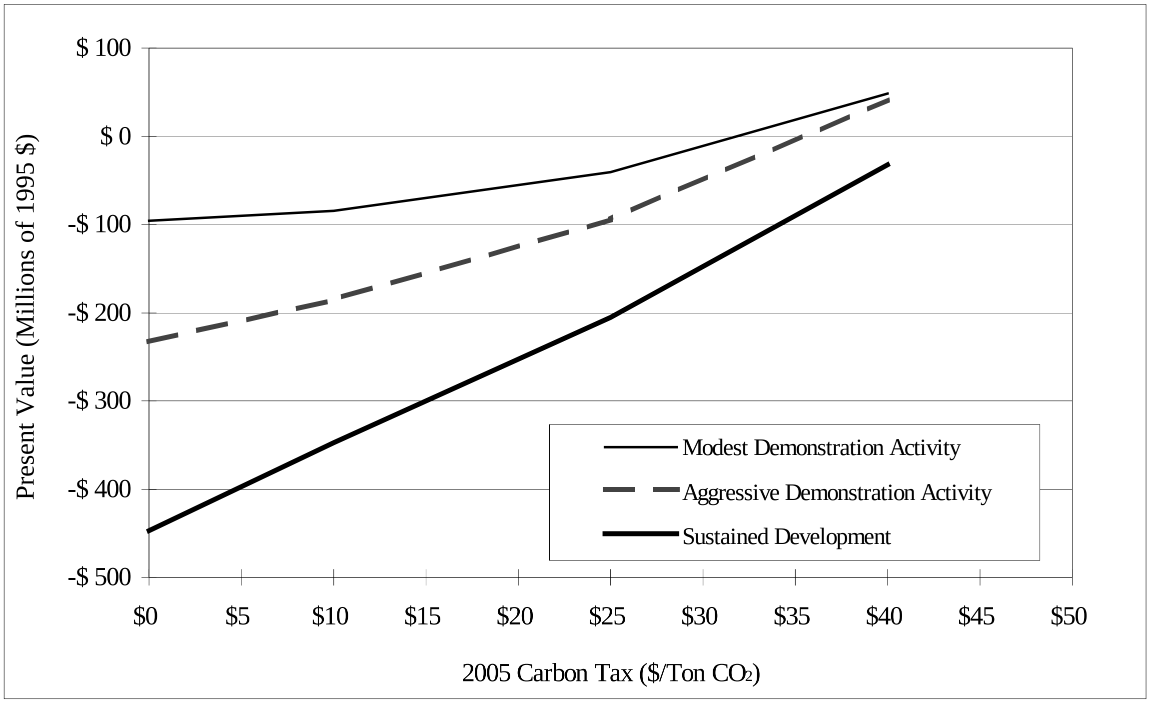
[16] Because of the site-specific characteristics of geothermal resources, advanced development at Northwest sites could accelerate cost reduction for subsequent geothermal development beyond the rates illustrated in Figure 5-8. The levels of accelerated development considered in this analysis would be unlikely to stimulate reductions in biomass, wind and solar photovoltaics beyond the rates shown in Figure 5-8.

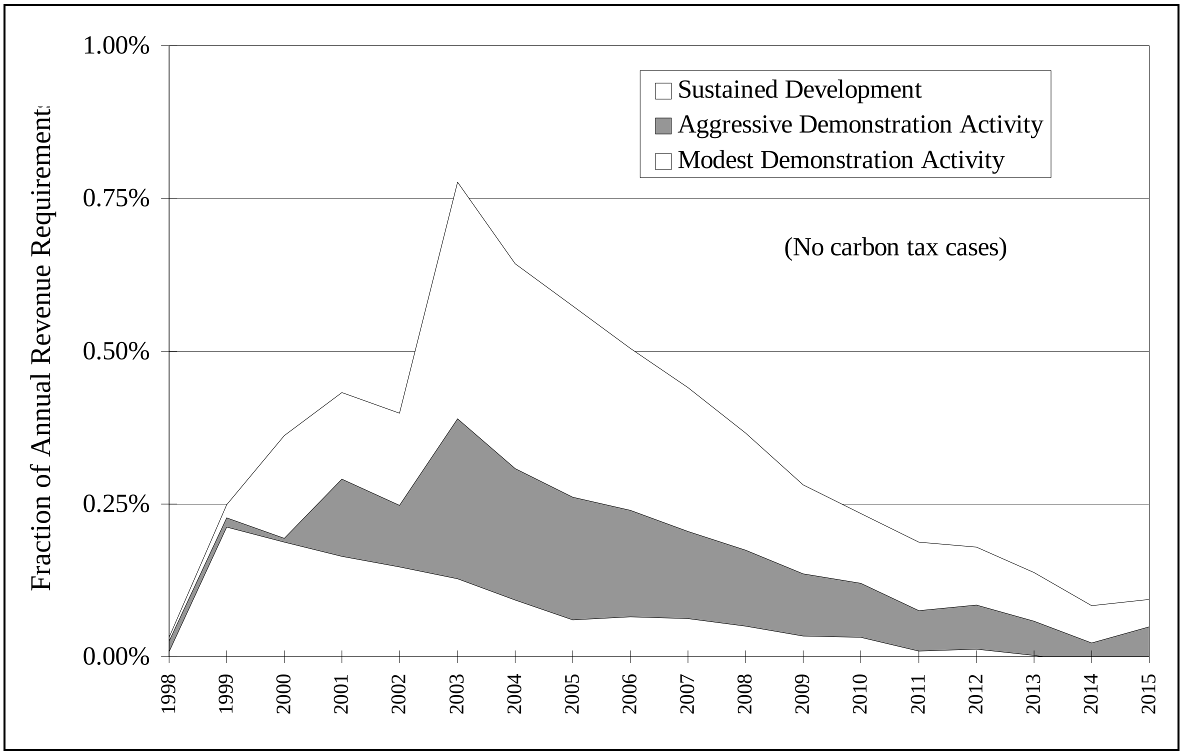
Figure 6-7
Net Present Value of Accelerated Renewables Development



As illustrated in Figure 6-7, the expected net present values of the three levels of accelerated renewable development are negative except for the cases of high carbon taxes. The moderate and aggressive pilot and demonstration programs result in positive net present value for carbon taxes between $30 and $40 per ton, or greater. The net present value of the five-year sustained development program is negative across the full range of carbon taxes examined.

The generally negative expected values of accelerated renewables development result from: 1) the development and operating costs of the renewables are high compared to other alternatives during the period of accelerated renewables development; 2) early development of prime resource areas precludes later development of these sites using improved and less-costly technology; 3) the value of pilot projects in reducing the lead time for subsequent step-out development has been reduced by the availability of surplus power on the wholesale market and by the assumption that the coming of a carbon tax will be known several years in advance. Advance notice of a forthcoming carbon tax would provide time for aggressive efforts to prepare promising large renewable resource areas for development.

Figure 6-8
Impact of Accelerated Renewables Development on Revenue Requirements



The effect of accelerated renewables development on annual regional electricity revenue requirements was also assessed. (See Figure 6-8.) The results are roughly indicative of the impact on rates, assuming that the net costs are evenly spread on the basis of energy consumption. Costs of the current renewables confirmation activities are excluded.

By the fourth year (2003), the net cost of the five-year sustained development program peaks at 0.78 percent of regional revenue requirements ($71 million). In following years, net costs decline because of the combined effects of load growth (which increases regional revenue requirements) and the increasing cost of wholesale power and combined-cycle resources (because of fossil fuel price escalation and the cost of complying with increasingly stringent California nitrogen oxide control requirements). Over the 10-year period 1996 through 2005, net costs of the 2000 to 2004 sustained-development program average about $31 million annually.

The other two development strategies are less costly. By the fourth year (2003), the net cost of the five-year aggressive pilot and demonstration program peaks at 0.39 percent of regional revenue requirements (about $36 million). The modest pilot and demonstration program peaks at 0.21 percent of regional revenue requirements (about $21 million) in its first year. Over the 10-year period 1996 through 2005, the annual net costs of aggressive and modest pilot and demonstration programs average about $18 and $9 million, respectively.

Because the resource costs used to model accelerated development were representative of adding new projects to existing sites and not pilot project development, actual costs would likely be somewhat higher than shown here.

Findings Regarding a Near-Term Strategy

The analyses described above lead to the following findings regarding a near-term renewable resource strategy:

First, the inventory of undeveloped Northwest renewable resources has little quantifiable potential economic value unless carbon dioxide controls are eventually required. However, the expected value of these resources increases from $86 million to $1 billion across a range of possible carbon taxes (see Figure 6-6).

Second, the development of renewable resources in advance of need and cost-effectiveness has little quantifiable economic benefit except in high carbon-tax cases. This results from the relatively high cost of most renewable resources and the following:

- The benefits of pilot projects in shortening the lead time for project development appear to be less valuable than in the past. The flexibility of the wholesale market, and the likelihood that greenhouse gas control measures, if adopted, would be phased in over a period of several years erode the benefits of shortened lead time.

- Near-term development of renewable resources foregoes the benefit of expected longer-term technology improvements for the resources developed. This effect is significant for renewables because of the limited supply of prime resources, the capital intensity of most renewables development and the expectation of relatively rapid technology improvements.

Third, the net cost of sustained development of renewables in advance of need would quickly approach 1 percent of regional electricity revenue requirements. The annual cost of a sustained development program would then decline if further acquisitions were terminated, and decline more rapidly if a carbon tax were adopted. The net cost of renewable development rates in excess of about 30 average megawatts per year or continuing for more than about five years would exceed 1 percent of revenue requirements. A modest five-year renewables research and development program consisting of, for example, a 30-megawatt demonstration project and slight expansion of resource assessment projects would require less than 0.25 percent of regional revenue. These figures exclude the net costs of the renewable confirmation activities that are under way.

Finally, continued technology development will improve the position of renewables. But, geothermal excepted, it seems unlikely that renewable development efforts by the Northwest could contribute significantly to the advancement of renewable resource technologies or the viability of renewable resource companies. A robust global market and public support for basic research and development are probably necessary to ensure that technology development continues and that equipment vendors and developers remain in business. In the case of geothermal, development efforts at Northwest sites might accelerate the optimization of technologies for these applications.

Conclusions: Justifiable Elements of a Renewable Resource Strategy

The findings described above suggest that the actions described below might be justifiable elements of a near-term (5 to 10 year) renewable resource strategy.

Ensure that the restructured electric power industry provides equitable opportunities for development of cost-effective renewable projects: Open access transmission at comparable rates, for example, will provide equitable opportunities for remotely situated renewable projects to access markets. Better understanding of the cost of transmission and distribution to specific loads will reveal the system benefits that might be provided by projects including remote solar photovoltaic applications.

Ensure that the renewable resource potential of the Northwest is adequately defined and that prime undeveloped renewable resources remain available for possible future development. This will require completion of key demonstration projects and additional resource assessment activities already under way: Continuation and completion of the resource assessment and demonstration activities of the renewable resource confirmation agenda of the 1991 Power Plan will provide much needed information. These activities, fully described in Appendix K, include completion, operation and monitoring of geothermal projects at Newberry Volcano, in Oregon, and Glass Mountain, in Northern California, and commercial-scale wind demonstration projects. Also included are long-term wind and solar resource monitoring, and further characterization of prime wind and solar resource areas. These projects are revealing the feasibility, cost and environmental implications of developing the geothermal, solar and wind resources of the Northwest, thereby providing guidance for management and future development of the best resource sites.

Support research and development efforts to improve renewable resource technology: While renewable resources my not be cost-competitive today, they are likely to be needed in the long-term, and further research and development will bring their costs down. Unfortunately, with a weak near-term market for renewables, research and development may be limited. Consequently, the region should make a special effort to support these activities. One approach might be to continue support for research and development at the national level, for example, through the activities of the Electric Power Research Institute. Research and development support should also extend to demonstration of new technology applications for renewable resources of regional importance, such as improved hydropower efficiencies and distributed solar applications.

Offer green power purchase opportunities: "Green power"[17] purchase opportunities are of value to consumers who believe that the benefits of renewable resources are not fully reflected in market-driven resource development decisions. Green power sales will also foster markets for renewable technologies and maintain renewables development capability. Project development serving green power sales should focus on cost-effective renewables, to the extent that these are available, and additional projects at existing sites with the potential of synergistically improving the economics of both existing pilot projects and the added projects.

Monitor fuel prices, the global climate change issue and other factors that might influence the value of renewable resources: Initiate more aggressive preparation for the development of renewables if changes in these factors indicate that accelerated development of renewables is desirable.

6-C. Environmental Considerations

The Power Act gave the Council responsibility to take environmental effects of electricity generation and use into account in its planning. As further guidance to the Council in administering its environmental responsibility, the Act included priorities to be used in choosing among resources that are equally cost-effective. These priorities generally favor environmentally benign resources.[18] The Act also specifies a 10-percent advantage for conservation in comparing the cost-effectiveness of conservation with that of other resources.

In past plans, the Council has taken a number of actions based on its consideration of environmental effects of the power system:

1) In 1988, the Council specified 44,000 miles of stream reaches as protected areas. These reaches were judged to be unsuitable for siting of hydroelectric generating plants, because of the unavoidable effects on fish and wildlife habitat and migration.

2) In the 1991 Power Plan, the Council set the cost-effectiveness cutoff for conservation (the upper limit on the cost of conservation measures judged cost-effective) higher than the avoided direct cost of new fossil-fueled generating plants. The extra margin was included by the Council to reflect the environmental advantages of conservation as a resource, compared to fossil-fueled generation.

3) In the 1991 Power Plan, the Council also recommended that the region plan to build

[17] The term "green power" is commonly used to describe a wholesale or retail power product consisting of power from renewable sources.

[18] The priorities are: first, conservation; second, renewable energy; third, high-efficiency resources; and fourth, conventional fossil generation.

gasified coal generating plants if coal generation was chosen. Gasification technology was thought to be marginally higher in direct costs, but the Council judged that its environmental advantages, in addition to its potential for staged development, made it preferable to conventional pulverized-coal generating plants.

Environmental Mitigation in Competitive Electricity Markets

In a world of regulated utility monopolies, the mitigation of environmental effects of electricity production can be addressed by the utility itself. Of course, there are difficulties in measuring environmental effects and reaching agreement between utilities and regulators as to how best to mitigate them. When agreement is reached, however, extra direct costs resulting from environmental mitigation can be spread among customers by the monopoly utility. Nonetheless, even monopoly utilities face some level of competition because some customers can choose other energy forms or alternative locations, so the ability of a utility to pass on environmental mitigation costs is limited.

In a world with increasingly competitive electricity markets, the ability to pass on costs will be limited. A utility undertaking environmental mitigation that is not required of its competitors will incur costs its competitors do not incur. Beyond some point, this utility risks losing customers if it must require higher power rates.

It is difficult to predict the net effect of a more competitive electricity market on environmental quality. It is plausible to imagine competition leading to the substitution of more efficient and more environmentally benign natural gas generation for older fossil-fuel fired generation. In such cases, more competitive markets could improve environmental quality. In the near term, competition and low gas prices may result in older, less efficient, less environmentally benign plants being run. The balance between the use of newer versus older plants depends on relative production costs. To the extent that environmental effects are externalities[19] to producers and users in competitive markets, there will be continued reason for concern about the level of attention utilities will pay to these effects.

In a competitive world, the desirable level of environmental mitigation will need to be the responsibility of all competitors. This might be accomplished by regulation of technologies, emission trading, pollutant taxing or other means. Whatever means are used, they will need to be applied equitably across competing energy producers, across competing energy forms and across regulatory jurisdictions.

This will tend to move policy decisions regarding environmental mitigation from the level of individual utilities and state and local regulators to the national or international level. A regional organization such as the Council is likely to find itself increasingly responding to environmental policies determined at the national or international level, instead of making environmental policy decisions itself. This draft plan focuses most of its environmental analysis on an issue that fits this description: global climate change.

Global Climate Change

The possibility that global climate change is occurring, driven by emissions of "greenhouse" gases[20] and other human activity, has received increasing attention in recent years. The potential effects of such climate change include higher temperatures, changes in precipitation patterns, changes in ocean currents, inundation of coastal land as the mean sea level rises, and increased intensity and frequency of storms. The potential for damage from these effects has led to intense scientific research and international discussions to understand what sort of response might be appropriate.

Measures to mitigate damage from climate change could include reductions in greenhouse gas emissions by using different fuels for energy

[19] Economists define externality as a byproduct of an economic activity that is not borne by the parties involved in that activity. Environmental externalities are the environmental effects that we impose on others, which are not included in the direct cost of our actions to us.

[20] Greenhouse gases include carbon dioxide (CO_2), which is the most important,and methane (CH_4), nitrous oxide (N_2O), low-altitude ozone (O_3) and chloroflourocarbons (CFCs).

production, reducing transportation fuel use, increased efficiency of energy use, removal of greenhouse gases from the atmosphere and direct responses to damage, such as building higher seawalls.

While the Council focuses primarily on the issue of possible global climate change in this draft plan, this focus is not because other environmental effects are not significant. This focus was chosen because:

Control efforts of other emissions have already made a difference: Many effects, such as emissions of sulfur dioxides of nitrogen (NO_x) and particulates, are already controlled to levels such that taking them into account does not change the preferred portfolio of new resources. In addition, market mechanisms, such as tradable emission rights or offset requirements, account for some of these effects (SO_2 and in some areas NO_x) as operating costs of existing resources. To the extent that resource operators are expected to cover the cost of their emissions with amounts that approximate the damage resulting from emissions, they will make operating decisions that take proper account of the environmental damage.

Many effects are project-specific: Many environmental effects are specific to unique qualities of resource design and location that can only be evaluated when specific projects are evaluated. The Council, in a long-term, regionwide plan, can generally describe these effects, but it cannot quantify impacts of actual projects. This evaluation is most appropriately done when specific projects are proposed. The Council recognized this in the 1991 Power Plan and committed to work with the state and local bodies responsible for establishing siting criteria that take into account localized environmental effects.

The Council's fish and wildlife program also addresses impacts of the power system: The hydroelectric system has had very significant impacts on fish and wildlife, particularly anadromous fish. The Council was given special direction to deal with these environmental effects through its Columbia River Basin Fish and Wildlife Program. The Council's power planning analysis takes into account the effects on the power system of fish and wildlife recovery efforts, but leaves the determination of what these recovery efforts should be to the fish and wildlife program process.

Global climate change could significantly change the power system: The steps that might be taken to mitigate climate change have the potential to change significantly the region's choice of energy resources. The potential damage from climate change ranges from disruption of agriculture, natural vegetation and wildlife from changed temperatures and rainfall patterns, to inundation of islands and coastlines because of higher sea level, to damage from more-intense storms. Estimates of possible damage costs from global climate change cover a wide range, but values at the upper end of the range would justify changing our generation and use of electricity, as well as other uses of energy (e.g., transportation).

Special Difficulties of the Climate Change Issue

The issue of global climate change has features that make it even more difficult to deal with than other environmental issues. First, while scientific consensus appears to be emerging that human activity is affecting the global climate,[21] there is still great uncertainty regarding the degree of climate change we face, its costs and the effects of efforts to mitigate such change. Scientists disagree about the mechanisms at work and the damage that may result.

Second, the *global* nature of the problem means climate change is an "externality" to our region, as well as to the individuals in the region. Whatever damage is caused by our region's greenhouse gas emissions is distributed globally; that is, it is experienced by people and ecosystems throughout the world. Likewise, any damage that our region suffers from global climate change is determined by greenhouse gas emissions throughout the world. This means that even if scientific uncertainty were eliminated, the region could not secure a stable climate by its own decisions and efforts. As is typical in situations with externalities, there would be inadequate

[21] See the "IPCC Second Assessment Synthese of Scientific-Technical Information Relevant to Interpreting Article 2 of the UN Framework Convention on Climate Change 1995." (http://www.unep.ch/ipcc/syntrep.html on the Worldwide Web)

incentive for each individual and each region to take actions that were in the global interest.

Because global climate change is an externality to each individual country, a response to climate change (if scientific consensus develops to justify a response) would be most effective if it were a cooperative international effort, with mutual commitments from most of the world's nations. Preliminary diplomatic negotiations are under way to make such cooperation possible if it turns out to be necessary.

Managing Risk to the Power System

Given the uncertainties surrounding the climate change issue, the inability of the region to control its climate by its own action and the difficulties implied by the ongoing transition to competitive electricity markets, the Council has approached the issue as a problem in managing risk to the power system. The region faces the risk that greenhouse gas emissions will have to be controlled and/or offset in the future. Such control would likely require policies such as a carbon tax or emission caps with tradable allowances. The risk to the region, then, is that fossil fuel burning may become more costly in a discrete step sometime in the future.

The size of this risk is determined by the magnitude and timing of this increase in cost, the probability that it will occur, and the cost of adjusting to the increase should it occur. The region cannot reduce the probability that global climate change will require future actions to control it — scientists will eventually come to a consensus, one way or another. The region may, however, be able to reduce the cost and disruption of a carbon tax, if global climate change turns out to warrant one.[22]

Measures to accomplish this reduction fall into two categories. First are measures that affect the production and use of electricity in the region, such as investments in increased efficiency or changes in generating fuel. The Council has reasonably good information about the first category. The cost of increased efficiency and the relative costs of generation by fossil, renewable and nuclear fuels in our region have been the subjects of Council analysis for every power plan.

Second are measures to offset emissions in this region by actions elsewhere; for example, investment in efficiency or fuel switching in the power system of a developing country, or the absorption of carbon by forestry practices in the United States or overseas. Measures in this "offset" category show promise of being some of the cheapest ways to respond to a need to control greenhouse gas emissions. These measures, unfortunately, are not nearly so well-studied as those in the first category.

In preparation for this plan, the Council commissioned an analysis of measures to offset carbon dioxide emissions.[23] While the offset potential appears promising, the quality of the data does not allow the development of a "supply curve" of offsets with much confidence. For example, incentives to invest in offsets to emissions depend on legal and institutional steps, such as the definition of new kinds of property rights. Such rights might be obtained by party A for reforestation work and sold to party B to satisfy party B's carbon tax obligations. The definition of these new property rights will need to deal with conceptual problems, such as assurance that a reforestation project is truly an increase in sequestered carbon, not merely a relocation of timber-cutting activity. Many of the measures that offer promise of inexpensive control of climate change (e.g., carbon sequestration in forests) are not completely inventoried. The size and cost of this inventory will depend in part on the definition of offset rights.

Analytical Approach

In the past, the Council has been able to estimate the costs and benefits of reducing other kinds of risk using its computer model, ISAAC (Integrated System Analysis of Acquisitions).[24] ISAAC would be the preferred tool for analyzing strategies to deal with the risk of a carbon tax as well. Unfortunately, the quality of available data

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[22] Though control policies could take several forms, we use a carbon tax as a representative example. Other policies, such as tradable emissions under a cap, will have roughly equivalent effects on utilities' incentives at the margin.

[23] Trexler and Associates, Inc., "Considerations in the Construction of a CO_2 Mitigation Cost Curve for the Next Northwest Power Plan," August 1995.

[24] See Appendix H for a further description of ISAAC.

means that we could have little confidence in the results.

The fundamental information necessary for an analysis using ISAAC is some sort of probability distribution of the outcomes (e.g., the level and timing of a carbon tax) that present risk to the region, and estimates of costs of the measures being considered to respond to the risk. While our understanding of global climate is improving, it does not yet support the estimation of a credible distribution of global climate change outcomes. The estimation of the cost of strategies to control emissions of greenhouse gases also faces serious difficulties.

Because of these problems, this draft plan does not treat the risk of global climate change with the kind of quantitative analysis applied to other issues. Instead, it provides illustrations of how much potential impact a control policy for greenhouse gases might have on:

- The cost of the power system;
- The value of conservation that is cost-effective on the basis of energy savings alone, but at some risk of not being acquired; and
- The net cost of maintaining some acquisition of renewables.

For purposes of illustration, carbon tax levels of $10, $25 and $40 (in January 1995 dollars) per ton of carbon dioxide were used. These values are illustrative of the range of values commonly cited.[25]

Power System Cost Analysis

To illustrate the potential impact of a carbon tax on the overall cost of the region's power system, the Council estimates that supplying the region's electricity in 1996 will result in the emission of 11.6 million tons of carbon dioxide. If a tax of $10-per ton of carbon dioxide were in force and no changes were made to the operation of the power system, the region's total carbon tax payment would be $116 million, a 1.7 percent increase in the total regional bill for electricity. Under the same assumptions, a $40-per ton tax would cost four times as much.

The region appears likely to rely increasingly on fossil-fueled generation in the future, making it potentially more vulnerable to a carbon tax. If current acquisition patterns hold, the Council's forecasts project an expected level of carbon dioxide emissions of 27.3 million tons in 2005. If a tax of $10 per ton of carbon dioxide were imposed in that year, in the absence of adjustments to the operation of the power system, the tax payment would be $273 million, or a 3.7 percent increase in the expected regional electricity bill. A tax of $40 per ton would impose a proportionately larger tax bill and a proportionately larger increase in the total electricity bill, $1.1 billion and 14.7 percent, respectively.

Of course, even in the short run, changes in the operation of the power system to reduce this impact are possible. Generating units that are heavily affected by a carbon tax (such as coal-fired or high heat-rate gas-fired units) would be used less, and other units that are less affected by the tax (such as nuclear, renewable and high-efficiency gas-fired units) would be used more. Purchases from outside the region, to the extent their prices were affected by a carbon tax, could also be adjusted. The Council estimates that such short-run changes in the operation of the power system existing in 2005 could reduce the net impact of a $10 per ton tax to $245 million, and the net impact of a $40 per ton tax to $849 million (in 1995 dollars). In the longer run, as new generating units are added to the system, there is more scope for adjustment to the tax.

Effect of a Carbon Tax on Resource Choice

The imposition of a carbon tax could affect new resource acquisition choices. Table 6-3 shows estimates of the impact of a tax on the cost of various generating alternatives. These generating alternative costs are estimated assuming acquisition in the year 2000, and assuming medium forecast prices for natural gas. The generation making up

[25] See Table 1 of "Accounting for Environmental Externalities in the Power Plan," Northwest Power Planning Council Issue Paper 94-50, October 1994.

Table 6-3
Comparative Impact of Carbon Tax on Power Costs

Resource	Fuel Carbon & CO_2 Releases			Cost of Power (cents/kWh)				
	Taxable Fuel Carbon (lb/MMBtu)	Heat Rate (Btu/kWh)	Power Plant CO_2 Releases (lbCO2/kWh)	Base	\$10/ton CO_2 Tax	\$20/ton CO_2 Tax	\$30/ton CO_2 Tax	\$40/ton CO_2 Tax
Conservation (average)	0.0	0	0.00	1.7	1.7	1.7	1.7	1.7
SW Market - Gas Boilers	31.4	9,260	1.07	2.5	3.0	3.6	4.1	4.6
SW Market - Coal	55.1	9,560	1.93	2.5	3.5	4.4	5.4	6.4
Pulp Liquor Cogeneration	0.0	16,500	0.00	2.3	2.3	2.3	2.3	2.3
Landfill Gas Recovery	0.0	11,000	0.00	3.2	3.2	3.2	3.2	3.2
Clean MSW Combustibles	0.0	14,400	0.00	4.2	4.2	4.2	4.2	4.2
Forest Thinning Bioenergy	0.0	14,400	0.00	7.3	7.3	7.3	7.3	7.3
New PNW Natural Gas CC	31.4	7,215	0.83	3.1	3.6	4.0	4.4	4.8
Wind (First block)	0.0	0	0.00	4.1	4.1	4.1	4.1	4.1
New PNW Coal (PRB)	55.1	8,970	1.81	4.0	4.9	5.8	6.7	7.7
New Hydropower (Average)	0.0	0	0.00	3.2	3.2	3.2	3.2	3.2
New LWR	0.0	0	0.00	4.9	4.9	4.9	4.9	4.9
Ind. Gas Cogen (LM-5000)	31.4	8,000	0.92	3.7	4.1	4.6	5.1	5.5
Geothermal (First block)	0.0	0	0.00	5.0	5.0	5.0	5.0	5.0
Total Solar Thermal	0.0	0	0.00	12.0	12.0	12.0	12.0	12.0
Solar Photovoltaics	0.0	0	0.00	17.8	17.8	17.8	17.8	17.8

our region's purchases from the West Coast market is represented by "SW Market - Gas Boilers" and "SW Market - Coal" and assumes purchases based on winter prices for these resources. A comparison of these impacts shows that coal plants are affected most heavily by a carbon tax, gas plants are less affected, and conservation and generation fueled by renewable or nuclear fuels are not affected at all. For example, a $10-per ton tax increases the cost of power from coal-fired plants in the Southwest ("SW Market - Coal") by 1.0 cent per kilowatt-hour, from 2.5 cents to 3.5 cents. The same tax increases the cost of power from a new gas-fired combined-cycle combustion turbine in the Northwest ("New PNW Natural Gas CC") by only 0.5 cents per kilowatt-hour, from 3.1 to 3.6 cents.

Table 6-3 shows that the conservation resource and pulp liquor cogeneration are the least expensive resources even without a carbon tax. These resources become more attractive if a carbon tax is imposed, becoming more attractive yet as the tax level increases. The size of the conservation resource would increase with higher tax levels; marginal measures become cost-effective as the avoided cost of power generation increases.

Currently, two of the most common resource choices by the region's utilities are purchases from existing resources from outside the region and new gas-fired combined-cycle turbines. It's useful to examine the impacts of a carbon tax on the attractiveness of each of these alternatives in turn.

Table 6-3 shows that a tax of $10 per ton of carbon dioxide makes building new gas-fired combined-cycle turbines (at 3.6 cents per kilowatt-hour) competitive with the cost of power purchases (at 3.5 cents per kilowatt-hour based on operating costs only) from coal-fired plants in the Southwest. With higher taxes, coal-fired plants are more heavily penalized, and they become less competitive. The cost of power from conservation and renewable resources is not affected by a carbon tax, so these resources become more attractive relative to fossil-fueled plants at higher levels of carbon tax. As the carbon tax increases, landfill gas recovery, municipal solid waste combustibles, wind and hydropower all become competitive with purchased power from coal and natural gas generation in the Southwest.

Some renewables also become competitive with new gas-fired combined-cycle combustion turbines at higher levels of carbon tax. The high efficiency of the new turbines means higher taxes are necessary before the renewables are the cheaper resources. Landfill gas and new hydropower plants are competitive with new combined-cycle gas turbines at tax levels of $10 per ton or less, while municipal solid waste and wind require taxes above $20 per ton to be competitive.

These results suggest that carbon taxes could lead to adjustments in the resource mix across the range of taxes considered here. At low levels of tax, we might see substitution of a lower-carbon fossil fuel, natural gas for coal for example, while at higher tax levels renewable generation could be substituted for fossil fuel-fired generation.

Value of Conservation

The value of conservation was estimated by assuming the imposition of a $10-per ton tax in 2005 and simulating the development of the power system with and without the conservation resource identified earlier in this chapter. The value of this conservation is the difference between the two cases in the expected present value of the cost of providing electricity to the region. Without the carbon tax, the estimated value of the conservation is $2.3 billion. With the assumed carbon tax, the value of conservation increases to $3.2 billion, $4.6 billion and $6.1 billion for the three levels of tax, respectively. This increased value includes the value of extra conservation measures that become cost-effective as the tax raises the avoided cost of power.

Non-Power System Responses

Changing generating resources and acquiring conservation are responses to a carbon tax that we might expect, and that we understand reasonably well — measures affecting the production and use of electricity in our region. It is very likely that a number of other measures would be part of any sensible policy for controlling greenhouse gas emissions. These other measures would include reduction of emissions in other sectors of our economy (for example, transportation) or in other economies (for example, in developing countries), and they would include absorption of greenhouse gases (for example, in reforestation). It is very likely that some of the measures not analyzed here would turn out to be some of the most cost-effective in controlling global climate change.

Regional Actions While Climate Change is Uncertain

The foregoing discussion has described some of the responses we could expect from the imposition of a carbon tax if it occurs, but offers no strategy to pursue while the imposition of a tax is uncertain. As explained earlier in this chapter, the information is not available to evaluate such strategies quantitatively, using the tools the Council has used in similar situations in the past. We can, however, make some qualitative recommendations:

Avoid investments in vulnerable resources: Investments in resources that emit greenhouse gases are at risk of becoming stranded investments if a carbon tax is imposed. In the evaluation of alternatives that are "close calls" based on costs and other resource characteristics, taking account of the risk of a carbon tax tips the balance toward low-fixed-cost, short-term commitment alternatives, such as operating existing resources or purchasing from spot or short-term markets.

In most cases, operating existing resources does not increase a utility's exposure to the risk of a carbon tax. Most operating decisions commit the utility for a short time only (a year or less). The utility faces little risk that something as significant as a carbon tax will be imposed before the utility can reconsider its operating decision. The risk-avoiding advantages of existing resources hold whether the existing resource is owned and operated in the region, or the output of an existing out-of-region resource is being purchased.

When investment is unavoidable, recognize risk: Exposure to the risk of a carbon tax should be recognized when new investments are considered. New investments include the acquisition of new resources, of course, but they also include investments in existing resources. Examples of the latter are the replacement of the steam generator at a nuclear plant, installation of emission-control equipment at a coal-fired generating plant, or life-extension of a high heat-rate gas-fired plant. If investments are made in new or existing plants that are vulnerable to a carbon tax, and if a carbon tax were imposed before the investments are recovered, they could become "stranded." Many factors influence such investment decisions, and other factors might outweigh the risk of a carbon tax in the final decision, but the risk should be recognized, and taken into account.

In contrast, with decisions that commit utilities to the continued operation of a resource that is *not* vulnerable to a carbon tax, such as WNP-2 or a renewable energy resource, recognition of the risk of carbon tax would weigh in favor of continued operation. In these cases, too, other factors will be weighed and may outweigh carbon tax risk in the final decision, but carbon tax risk should be recognized.

Secure cost-effective conservation: Cost-effective conservation measures reduce the region's exposure to the risk of a carbon tax with "no regrets." That is, these measures are worth taking based on the direct costs alone, their risk-reducing benefits come without imposing any extra cost. Some conservation resources may be at risk because of market imperfections or gaps in the new utility industry structure. The risk of a carbon tax only increases the incentive to make sure the region takes advantage of all its opportunities for cost-effective conservation.

Gain experience in offsets: While the uncertainty about global climate change's impact on power system economics persists, utilities, regulators and others can monitor scientific developments, both in the area of extent and damage of warming and in the area of the economics and law of mitigation activities.

Utilities can also carry out pilot-scale efforts to get experience in the practical problems of acquiring offsets. Utilities in our region, most notably PacifiCorp, are pursuing this strategy with a variety of projects ranging from reforestation on private land in our region, to preservation of forests in Central America. The Oregon Energy Facility Siting Council is encouraging independent power producers to gain the same sort of experience as part of their license agreements. Such projects prepare the region to move quickly to larger-scale offset acquisitions if needed. The projects can be entered in a registry created by the Energy Policy Act of 1992 (see Box) and may qualify for credits against a carbon tax or equivalent policy if one is adopted.

Some offset projects, for example, reforestation, result in a combination of carbon sequestration and production of other products that have value, for example, lumber. The net cost of the offset is the total cost of the project less the value of the non-offset products. The value of the offsets themselves, however, is speculative while national and international policy on climate change is uncertain. Because it is not certain the offsets are worth anything, however, they may be available at low cost. If a carbon tax (or equivalent policy) is imposed, the value of acquired offsets would equal the tax avoided due to the offsets. If a tax is not imposed, the offsets would have no value.

Acquiring offsets after a tax is imposed would be less risky, but more expensive. The owners of potential offsets will attempt to extract as much value as possible. Unless there are enough offsets to avoid any tax payments at all, the net cost of offsets should rise to approach the level of the tax.

INTERNATIONAL RESPONSE TO THE CLIMATE CHANGE ISSUE

There is not yet agreement that the earth's climate is changing in response to human activities. Nonetheless, the international community has taken several steps to improve global understanding of the issue and to make it possible to take cooperative action if it is found to be necessary:

New York, 1988

In response to increasing interest in the issue of climate change, the United Nations created the Intergovernmental Panel on Climate Change in 1988. The Intergovernmental Panel is made up of working groups of experts from many countries, and is managed by representatives of the member governments. Its task is to "provide internationally coordinated assessments of the magnitude, timing and potential environmental and socioeconomic impacts of climate change and realistic response strategies." The Panel issued an assessment of the state of the science in 1990, and again at the end of 1995.

Rio de Janeiro, 1992

In 1992, the United Nations Conference on Environment and Development in Rio de Janeiro, Brazil, resulted in the adoption and signing of the United Nations Framework Convention on Climate Change. The Convention took effect as an international treaty in 1994 after ratification by 54 countries. The Convention is intended to prevent "dangerous anthropogenic interference" with the global climate. The treaty specified the Intergovernmental Panel as the Convention's scientific advisory body.

Berlin, 1995

The first "conference of the parties" of the treaty took place in Berlin in 1995. The conference resulted in the "Berlin Mandate," which calls for the developed countries to set quantified targets for control and reduction of greenhouse gas emissions. These targets are to be negotiated by 1997. No targets are being set for developing countries.

Washington, D.C.

The United States is participating in the Intergovernmental Panel and the Framework Convention on Climate Change. The United States is formally committed to return its greenhouse gas emissions to their 1990 levels by the year 2000, under the terms of the treaty. The United States has a National Climate Change Action Plan intended to achieve these emissions reductions, although it is widely believed the plan will fall short. The United States also, in the Energy Policy Act of 1992, established a registry of greenhouse gas offsets. The registry is intended to make it possible for parties to take action now to reduce or offset greenhouse gas emissions, and receive credit later if, for example, a carbon tax or compulsory reductions take effect.

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CHAPTER 7

THE ROLE OF THE BONNEVILLE POWER ADMINISTRATION

This chapter focuses on the role of the Bonneville Power Administration in an increasingly competitive electricity market. The reason for this focus is at least four-fold. First, as a wholesale utility, competition is already here for Bonneville, and it can probably be counted upon to become more intense. Second, Bonneville markets the output of a public resource. As a consequence, Bonneville's governance is more an issue of public policy than is the governance of other utilities. Third, Bonneville is a major and integral part of the region's power system. In an average year, it controls the marketing of almost 40 percent of the electricity sold in the region, most of which is relatively low-cost federal hydroelectric power, and it owns and operates the majority of the region's electricity transmission system.[1] Bonneville, or its successor, will continue to be a major factor in the region's electricity markets, its economy and its environment. Finally, the federal system has other purposes, public and private, besides power production. As a result, the issues surrounding Bonneville seem more complex.

The subject of the Comprehensive Review is the entire Northwest energy system, but a primary focus of the review is the role of the federal power generation and transmission assets in a competitive power marketplace. A number of alternatives are being discussed for Bonneville. They range from a somewhat scaled-back version of the current federal agency to privatization. The emerging competitive electricity market raises a number of issues for any alternative. Some of the questions and issues that may be addressed in the Comprehensive Review are discussed below.

[1] Depending on how regional transmission is defined, Bonneville owns between 50 and 80 percent of the region's transmission system.

7-A. ALTERNATIVES FOR THE FEDERAL COLUMBIA RIVER POWER SYSTEM

The advent of the competitive market and Bonneville's recent financial difficulties have caused many to ask whether Bonneville should continue to be a federal agency. They point out that federal agencies do not typically compete with the private sector. Advantages such as tax exempt status, greater regulatory autonomy and access to financing from the federal Treasury could be interpreted as giving Bonneville an unfair competitive advantage.

Counterbalancing these advantages, however, are a number of statutory requirements that could hamper Bonneville's competitive position. These include the mandate to serve the requirements of Bonneville's public agency customers, regional preference, prohibition on resale of federal power, cumbersome rate processes and several cost transfers such as the residential exchange, the low density discount and the Bureau of Reclamation's irrigation pumping rate. Several of these are requirements that Bonneville has either recently been successful in removing or modifying or that the agency's representatives have mentioned as in need of relaxation.

Supporters of a less-constrained Bonneville continuing in its present federal status argue that Bonneville must be competitive to meet its responsibility to repay the Treasury and fulfill its "social" responsibilities. Opponents argue that Bonneville may become so competitive that it will be in a position to exercise undue market power.

This chapter considers several alternatives for the Federal Columbia River Power System. These alternatives were chosen to illustrate some of the issues. This is not an exhaustive list. The alternatives are:

- A continuation of Bonneville as a federal agency, but with limitations. For example, it might be limited to marketing the output of the existing system;

- A continuation of Bonneville as a federal agency free to compete in the electricity market with as many constraints as possible removed;

- Sale of the rights to market the output of the Federal Columbia River Power System to a public regional entity;

- Sale of the rights to market the output to a private entity or entities; and

- Leasing the rights to market the output to public or private entities.

Sale of Assets vs. Sale or Lease of Marketing Rights

The list of alternatives is limited to the rights to market the output of the federal power system, not sale of the dams or other generating assets. This does not mean that sale or transfer of the physical assets might not be desirable under certain circumstances or that it cannot be accomplished. However, the multi-owner, multipurpose nature of the Columbia River system greatly increases the complexity associated with a sale of assets compared to a sale or lease of marketing rights.

For example, ownership requires responsiveness to the requirements for a number of public or quasi-public purposes (e.g., flood control, recreation, fish and wildlife, navigation) as well as commercial purposes (e.g., power and irrigation water). This is not an absolute obstacle to selling the assets, since a number of dams in the Northwest were constructed by non-federal utilities for power generation only, with the other requirements imposed as a license condition. However, because of their 50-year term, license conditions are not necessarily as flexible as public ownership in ensuring public purposes are met.

Moreover, political opposition could be increased by a sale of the assets, as opposed to sale of the marketing rights, at least if a proposed sale is to a private buyer. The Federal Columbia River Power System is built on an important natural resource for four states, two nations and many Indian tribes. Giving up public ownership of the dams is not an action that will be undertaken lightly. Apparently the non-power beneficiaries of the Southeastern Power Administration joined the power beneficiaries in opposing the recently proposed sale of that agency, in large part because it was a sale of the dams as well as of the power output. The proposal was killed in Congress.

A sale of marketing rights does involve a number of complexities. An important issue that would need to be resolved with a transfer of marketing rights is the degree of control afforded over the output of the dams. This is an issue for two reasons. The first reason is that the non-power constraints still allow flexibility, although not as much as in the past, in the decision to generate electricity or store water for later generation or other purposes. This flexibility is economically valuable. Bonneville currently uses this flexibility to maximize power value, within the constraints of the Coordination Agreement, dam operations requirements under the Endangered Species Act, and the Canadian Treaty. Any transfer of marketing rights will require a mechanism that can balance the ability to operate the system to maximize the value of power, versus operation of the system for non-power obligations.

A second reason degree of control is important is because of the "upstream/downstream" question. Storage releases from upstream dams usually constitute the bulk of the water flowing past downstream dams. The federal projects dominate the upstream storage capability. Coordination with downstream non-federal parties, primarily the mid-Columbia utilities, is essential both to optimizing the power output of the total system and to retaining the current rights of the downstream parties. The Coordination Agreement was developed, in large part, to resolve this potential for conflict. The issue is one of constraining the purchaser of the federal assets, especially if the purchase were of the dams or other assets themselves, but also if it were of marketing rights that include the flexibility to store water or generate electricity.

The complexities related to a transfer of marketing rights, however, appear much more manageable than those associated with a sale of assets. As a consequence, further discussion of non-federal alternatives will be limited to the sale or lease of marketing rights rather than the sale of generating assets.

Issues in Considering Alternatives

Whatever alternative is considered, it will be necessary to confront a number of issues. Some of the issues derive from the principles, characteristics and limitations of competitive markets discussed in Chapter 3. If Bonneville, or its successor, is to operate in a competitive electricity market, the principles, characteristics and limitations of that market will either apply, or the result will be a less effective market. Among the issues that should be considered in Bonneville's case are:

- The degree of separation of generation and transmission required to ensure that Bonneville, or its successor, cannot restrict competitors' access to the market;

- The degree of market power Bonneville, or its successor, might exercise as a result of its control of generation; and

- The ability to absorb competitive risks and rewards and the degree of congruence between those who take risks and those who reap rewards.

Related to the question of risk and reward are the terms of any sale or lease of the marketing rights and contractual constraints on any transfer of liability for the debt on the Washington Public Power Supply System nuclear projects.

Other considerations derive from Bonneville's historic role in the region, the public and quasi-public purposes Bonneville has fulfilled, and whether these purposes can be fulfilled in the future. These considerations include:

- Allocation of the benefits of the Federal Columbia River Power System through public and regional preference. The benefits are in the form of power sold at cost.

- Other public purposes, such as irrigation subsidies, mitigation of higher costs to serve low-density rural customers, access to the benefits of federal power for the residential customers of investor-owned utilities, and so on.

These issues are discussed in the following sections.

7-B. Consistency with the Principles, Characteristics and Limitations of Competitive Markets

Should Bonneville's Transmission and Generation Assets Be Separated?

Does the ownership by Bonneville, or its successor, of a very large percentage of the high voltage transmission in the region, combined with the rights to market the output of the Federal Columbia River Power System, give Bonneville market power inconsistent with a fair and effective competitive market? Functional separation of generation and transmission has been proposed as a requirement by the Federal Energy Regulatory Commission in its open access notice of proposed rulemaking for utilities under its jurisdiction. In its current form, Bonneville is not under FERC jurisdiction. Nonetheless, Bonneville is undertaking functional separation of transmission and generation within its existing organization. However, many fear that with pressure to repay the Treasury and at the same time keep power prices low, Bonneville will be tempted to exercise monopoly power over the federal transmission system to maximize the value of its power sales. If Bonneville's transmission system were sold along with the marketing rights to the output of the federal power system, it is likely there would still be similar concerns.

Setting up an independent, FERC-regulated grid operator for the region could insulate Bonneville, or its successor, and other transmission owners from monopolistic temptations. However, as long as Bonneville retains responsibility for marketing federal power, it cannot function as grid operator without facing the temptation to exercise undue market power. The conflict of interest between Bonneville as marketer of federal power and Bonneville as grid operator is unfortunate, given Bonneville's obvious strengths in the area of transmission.

Setting up a separate federal transmission agency with control over Bonneville's transmission assets is another option. Establishing FERC jurisdiction over this entity's transmission tariffs identical to its jurisdiction over investor-owned utility transmission tariffs could go far toward limiting Bonneville's market power. This separate federal entity might be able to play the role of independent grid operator, as well.

The idea of privatizing the transmission grid has also been raised. The resulting private transmission company would be regulated by FERC and would be allowed to earn a rate of return on its investment. It is not clear what benefits would be associated with private ownership compared to continued federal ownership. For example, could private ownership and operation of the system result in sufficient efficiencies compared to federal ownership to offset the higher return on investment a private owner would receive? If not, the result would be a net increase in the cost of transmission in the region.

Some have also suggested that it would be possible to sell the transmission system for more than its remaining debt, with the "profit" used to buy down the debt on Bonneville's high-cost generation. Since many of the users of the transmission system are not firm power customers of Bonneville, such a sale might be a mechanism for spreading the cost of Bonneville generation more broadly. This would undoubtedly raise issues of fairness and might not pass FERC scrutiny on the ground it would result in recovering generating costs in transmission charges.

Market Power

A fundamental question that will have to be resolved, whether Bonneville continues as a federal agency or whether its right to market federal power are sold to another entity, is that of market power. Does the entity have market power in any important electrical product as a result of its control over a large portion of the hydropower system? If so, what remedies are appropriate?

Bonneville, for example, clearly has the ability to influence spot market prices, at least at some times of the year. There may be other power products — storage and load following, for example — that the hydropower system is particularly able to provide. Competitive markets for these products may not exist. If not, some degree of regulation of their prices may be necessary.

If Bonneville, or its successor, is to be a full participant in the competitive power market, it may be necessary to sell the marketing rights to more than one party. This raises issues of how the output of the system would be allocated. These issues are probably manageable. Limiting Bonneville's role to an allocation of power to its customers, with limited ability for Bonneville to market any residual power, probably accomplishes the same end. If the structure of the wholesale electricity market in the region evolves toward a mandatory pool, it may be possible to mitigate the market power associated with Bonneville power marketing. In such a pool, prices are set by the marginal bid price in any period. Experience in the United Kingdom, however, indicates it is possible to exercise market power through a mandatory pool if there is sufficient concentration of ownership or the rules for operation of the pool are poorly set. The interaction between market structure and market power should be investigated.

Markets, Risks and Rewards

Competitive markets imply the risk of business failure and loss. Conversely, they also imply the possibility of success and profits. Whatever form Bonneville, or its successor, takes in the future, it will have to be able to accommodate the possibility of either profit or loss.

Risk, Reward and Federal Ownership

The risk of long-term loss poses a problem for Bonneville as a federal agency in the transition to competitive electricity markets. Bonneville has long been subject to the risk of year-to-year fluctuations in hydropower output, risks of fish and wildlife restoration costs and risks associated with treaty obligations to the region's Indian tribes. In the past, Bonneville has been able to absorb these risks because its costs have been consistently below market. The advent of competition poses the possibility and, in recent months, the reality that market competitors may undercut Bonneville's prices for extended periods of time.

As a federal agency, Bonneville has no stockholders to absorb the business losses that are bound to happen, to a greater or lesser extent, in a competitive environment. Instead, the federal Treasury ultimately bears the burden of losses in excess of what can be covered by Bonneville's financial reserves. Bonneville has not yet incurred any long-term losses, and past missed Treasury payments were subsequently brought up to date, with interest. However, one of the mechanisms by which Bonneville has lowered its proposed 1996-2001 rates is a reduction of the probability of full, on-time repayment of its Treasury obligations. On the other hand, recent agreements to limit fish recovery costs have raised the probability of meeting the Treasury payment.

As electricity generation evolves toward a fully competitive industry, the possibility of long-term loss needs to be addressed. Stranded costs due to the competitive transition represent one form of loss, but dealing with the current level of stranded costs, difficult as it may be, will only require a one-time solution to a one-time problem. It should not be assumed that losses could not recur due to changes in technology, customer choices, and so forth. Bonneville's financial problems are generally considered short term (over the next three to five years, for instance), but that is not guaranteed. In a competitive market, prices are independent of a company's own costs. Generally, customers cannot be expected to bear any of the burden of either short-term or long-term losses, since they will simply find a different supplier if the current supplier tries to raise prices above market levels.

If Bonneville is to continue as a federal agency, there are at least two risk-related questions that must be answered. First, with the greater risk exposure associated with a competitive market, will the federal Treasury continue to fulfill the risk-bearing function? If not, what are the options for bearing that risk? Second, should the Treasury be exposed to additional risk as a result of new resource development by Bonneville? The Northwest Power Act obligated Bonneville to meet the requirements of its preference customers and authorized Bonneville to acquire resources to meet those requirements. Those customers, however, are under no obligation to purchase power beyond the periods established in their contracts.

Under the Power Act, Bonneville was granted the authority to acquire resources because, at the time, new resources were large, required long lead times and were very expensive. Small public utilities and even investor-owned utilities were not expected to be able to shoulder the risks of such huge investments without federal backing. This is much less the case in today's utility world. New combustion-turbine technologies, for example, are smaller in scale, less expensive and require far shorter lead times to develop. The risks to utilities from resource development are more manageable, and other entities can develop and market these resources. Consequently, if Bonneville is to continue as a federal agency, there may be reason to limit its role to marketing the output of the existing system. Bonneville no longer needs to take on the risks associated with new resource acquisitions because the utilities themselves are more financially able to manage those risks.

Just as a competitive market implies risks, it also implies the possibility of rewards or profits. It is possible to construct scenarios in which Bonneville's costs are once again below market prices. For example, when the debt on the Washington Public Power Supply System nuclear plants is retired beginning in 2011, it appears likely that Bonneville's costs would be well below market prices. When and if this occurs, will the federal government be willing to allow the region to retain the reward in the form of either profits or below-market prices, or will it want to appropriate some or all of the benefit for the Treasury?

Risk, Reward and Regional Public Ownership

One set of alternatives to continued federal ownership of the marketing rights of the federal power system involve some form of regional public lease or ownership. Regional public ownership is a mechanism for ensuring that potential benefits are retained by the region, at least to the extent that the terms of the sale or lease leave room for benefits.

Risk, however, is still an issue. For a general-purpose government entity (e.g., a state or municipal government), shortfalls are managed by shifting budget accounts or raising taxes. For a non-taxing public entity (e.g., a wholesale generation-only analog of a public utility district), probably neither is possible. If market prices fall below costs, and customers have access to the market, there is no entity to absorb the loss. The same holds true for a non-profit, non-governmental entity purchasing Bonneville's marketing or generation assets. One alternative is federal government guarantees of the debt of such an entity. However, as demonstrated by the savings and loan problem of the 1980s, such backing can substantially distort investment incentives and become a major problem for taxpayers, although it is often perceived to be without cost when it is proposed.

Risk, Reward and Private Ownership

In the private corporate economy, stockholders bear the business risks and incur whatever profits or losses result from taking those risks. Stockholders lose if there are stranded costs. They win if their firm is more efficient than its competitors. Privatization of Bonneville's power marketing function would resolve the allocation of risk and reward in a manner that is consistent with the private economy. This includes transferring any return that might be earned by the regional system to the participants in the sale — the federal government and the private purchaser.

What is an Appropriate Price for the Rights to Market the Output of the Federal System?

Any sale or lease of the marketing rights for the federal power system involves determining a price. The process of determining a price is one of assessing potential risk and potential reward. Under most circumstances, no one should pay more than market value, and the Treasury should not accept less than embedded cost, unless it is greater than the expected market value. Of course, in this instance, the assessed market value is not certain. Market value depends on the relationship between future costs and the future market price of electricity, both of which can be estimated, but not known. Consequently, there is a great deal of room for negotiation of the price. Because of this uncertainty and the possible desire for immediate deficit reduction, the government could accept a price lower than embedded cost.

In trying to establish market value, it is important to specify the operative time horizon. With a short time horizon (the next five-year rate period, for example), there may be little difference between the market value of the output and embedded cost. Over a longer term (a permanent sale, for example), a buyer might expect there to be more market value in a system that is dominated by fixed costs and low variable costs when the environment is one of variable gas prices. On the other hand, the fixed-cost burden might be considered a liability in an environment in which generating costs and efficiencies are being improved, and fuel prices are stable or declining.

There are, therefore, two basic conceptual choices for the term of the transfer: permanent or limited term. A permanent transfer might be the simplest, but it has the greatest possibility of deviations from subsequently observed market values, primarily because of uncertainty-related discounting by the purchaser.

The alternative is a limited-term transfer, for example, an auction every five or ten years. The shorter the term, the closer the result will be to the observed market value of the system output.

The duration of the transferred rights will affect the perceived value of those rights. Uncertainty about future value might be reduced by shorter-term sales. A series of shorter-term auctions may produce higher prices for the sale of marketing rights than a one-time long-term sale if system value rises over time.

Purchasers of a longer-term right would take into account the potential net value above cost in the out years, but that net value would be discounted because of timing and (most likely) uncertainty below a simple sum of the forecast net values. A longer-term sale will produce more revenue up front than a series of shorter-term sales, depending on how purchasers perceive future risks. The relative values of a long-term sale compared to a series of short-term sales would have to be explored further using various parties' discount rates and expectations about net value of the system in future years.

Contract Constraints on Transfer of Nuclear Power Plant Assets and Liabilities

The Bonneville Power Administration assumed responsibility for paying the principal and interest on the bonds for the construction of the Washington Public Power Supply System's nuclear plants 1, 2 and 3. A transfer of the marketing rights of the federal system would have to address this responsibility. A preliminary examination of this question was conducted more than a decade ago. This analysis was focused on sale of the physical assets. The same issues would appear to be relevant to a lease or sale of the marketing rights.

The examination concluded that the various WPPSS-related contracts (bond resolutions, project agreements, net-billing agreements) appear to severely constrain the ability to assign the WPPSS marketing authority and financial liability away from Bonneville without, ultimately, the consent of the bondholders. The only alternative that offered a clear transfer path was to pay off the bonds at the time of transfer. Other approaches that did not require immediate payment were considered possible, but are affected by legal ambiguities that would need to be resolved or do not meet the test of completely transferring the assets away from Bonneville. Resolution of these questions would be a necessary condition for any sale of marketing rights.

7-C. ALLOCATION OF BENEFITS

How the possible benefits of the Federal Columbia River Power System are allocated is an important and difficult question for the region. Any change in the status quo has the potential to alter that allocation of benefits.

The Basis of the Benefits — the Hydropower System

The essential "regional benefit" provided by Bonneville is financial — the difference between a free-market price of electricity and the low historic costs of the hydropower system and its associated transmission system, largely constructed by the federal government. While much of that benefit has been diluted by past nuclear investments and by the general lowering of the market price level in recent years, that benefit was substantial at times in the past and could be substantial in the future, depending on changing electricity generating technologies and fuel markets.

Distribution of Regional Benefits

The benefits of the federal hydropower system were widely distributed in the region prior to 1973, when Bonneville's existing 20-year firm power contracts with investor-owned utilities were not renewed. Between 1974 and 1981, customers of investor-owned utilities had no access to firm power from the federal hydropower system. In 1981, as a result of the Power Act's residential exchange provisions, the financial benefits of federal hydropower were again made available to residential and small farm customers of investor-owned utilities. In 1985, Bonneville revised its average system cost methodology, and the residential exchange benefit to investor-owned utility customers was reduced. It is expected to be reduced even more after 1997, with the phase-out of the residential exchange. Although there have been changes over time, the primary beneficiaries of the hydropower system have historically been a wide spectrum of public and investor-owned utilities, and direct-service industrial customers.

The distribution of whatever future benefits can be produced by the system will be, at least in part, a function of the ownership of the rights to market the output of the system and the risk that goes with that ownership. One possible outcome might be continued federal ownership and continued willingness on the part of the federal government to be the ultimate bearer of risk, ensuring that the benefits of the power system go to some or all of Bonneville's traditional regional customers. Bonneville was created to achieve such public purposes as regional development, which go well beyond market risk and reward relationships. Whether the federal government will be willing to maintain the current allocation of risks and benefits in a world of competitive wholesale electricity transactions is a question the region must confront.

If some sale of the marketing rights is undertaken, the terms of the sale will, as discussed earlier, result in some distribution of risk and potential benefits between the Treasury and the buyer. Who the buyer is will determine who receives the buyer's share of potential benefits and risks. A private buyer will take the risks and return whatever future benefits can be produced to its investors. If the buyer is a consortium of Bonneville's current customers, then the risks and the potential benefits would be allocated to those customers. If the buyer is some entity created by the Northwest states, the benefits as well as the risks would go to the states to be further allocated as determined by the states, perhaps to taxpayers or to specific customers.

Marketing and Pricing

Historically, Bonneville has been constrained in its marketing of power from the Federal Columbia River Power System to giving preference first to its public agency customers and second to the region. The restrictions on out-of-region sales have recently been relaxed, but not eliminated. The term of out-of-region surplus sales is limited to seven years, and regional customers retain a right of first refusal on surplus sales (regional customers are given the opportunity to match the price offered by an out-of-region customer).

The marketing restrictions on Bonneville may not be as vital an issue for Bonneville customers today as they once were. The approximate convergence of increasing Bonneville costs and falling market prices have effectively eliminated the price advantage that Bonneville's power once carried. Some Bonneville customers have been willing, at least temporarily, to leave the federal system and the risks associated with that system in order to buy from the market. However, Bonneville's costs may be below market prices in the future. How should the power from the Federal Columbia River Power System be marketed now, when its costs are close to market prices, and in the future, when the costs may be below market prices? Should it be marketed on a preferential basis, with any surplus made available to the broader market, or should its marketing be unconstrained?

A corollary question has to do with the pricing of the power from the Federal Columbia River Power System. The below-market pricing of Bonneville power has historically been the mechanism by which benefits have been delivered to Bonneville's regional constituencies. The marketing of Bonneville power at cost has been a major reason why many Northwest utilities and their consumers have enjoyed rates well below the national average. This raises the question of how possible future benefits, to the extent they can be retained for the region, are to be returned — in the form of prices that are again below market or in some other form, for example, cash dividends.

However, below-market pricing was one of the main inefficiencies that led to the dramatic over-investment in the region's nuclear plants in the late 1970s. This problem might or might not recur in the future. If the dividend is continued in the form of below-market prices, but Bonneville is no longer in the resource acquisition business (or is in it on the basis of specific acquisitions at market prices), then this distortion will be eliminated. If, however, Bonneville acquires new resources to meet its customers' load growth and sets its prices by averaging the costs of existing resources with those of the new acquisitions, it will be reinstating the price distortions of the 1970s. A better method of conveying the dividend to regional beneficiaries needs to be designed.

7-D. PUBLIC PURPOSES

The Federal Columbia River Power System has historically supported a number of "public purposes" beyond that of providing power to its customers at cost. These have included cost transfers that benefit different classes of customers, such as reduced rates for irrigation and low-density rural customers and the residential exchange that benefits the residential customers of investor-owned utilities. Some would also include centralized funding of conservation, activities to encourage renewable resource development, and other forms of research, development and demonstration. Fish and wildlife costs are a cost of producing power and are among the purposes for which the hydropower facilities are operated. Without attempting to sort out which costs truly cover public purposes, the question for the region is which of the public purposes should be maintained and how the region can best accomplish those purposes in the context of a competitive power market.

The principles of competitive markets suggest that subsidized rates are not the way to accomplish public purposes. Such rates are both inefficient and, because they cause the unsubsidized customers' rates to be higher, they create an opportunity for competitors to exploit. To the extent the power system can earn a profit, public purposes can be supported from those profits. To accomplish this, however, dividends for other purposes must be reduced. How to balance profits and public purposes is a legitimate policy decision that will have to be addressed in the course of the Comprehensive Review.

However, competitive markets don't guarantee profits. It may be that the power system cannot be counted upon to earn a profit or one that is sufficient to support both public purposes and the return requirements of the risk-bearing owners, whether public or private. If that is the case, other non-market mechanisms to support those public purposes may be required. These mechanisms could include a regulatory requirement applied to the monopoly elements of the business, a general tax or a charge for use of the transmission or distribution system, a tax on generation or fuel use, or development standards for new energy facilities.

7-E. CONCLUSIONS

Many argue that the Bonneville Power Administration, as currently configured, violates several of the principles for a competitive market. Bonneville combines generation and transmission in one entity. It has substantial market power. Market risk is ultimately borne by the Federal Treasury. And it carries out several public purposes that may be difficult to support in a competitive wholesale power market. At the same time, Bonneville is at the heart of the regional power system and embodies many of the values of the region. Deciding the future role of Bonneville is a key task of the Comprehensive Review of the Northwest Energy System. Successful resolution of the Bonneville question will set the stage for an efficient and competitive regional power system.

CHAPTER 8

THE FUTURE ROLE OF THE NORTHWEST POWER PLANNING COUNCIL

The Council was established to respond to a very different world than the region faces today. Some of the Council's past roles are less important, or even unnecessary, in this new world. Other roles seem to have continuing relevance during the transition to a new industry structure and, possibly, beyond.

In developing this draft power plan, the Council faced challenges that are far more significant than any it has faced in the past. Technological and regulatory changes are sweeping the energy industry and are certain to affect the industry's basic structure. To the extent that effective electricity markets can be facilitated, the Northwest stands to gain greater economic efficiency in its power system more quickly than could be accomplished by regional planning. Regulation and planning are, at best, approximations of what can be achieved by a well-functioning market. Thus, the focus of this plan is on understanding the coming changes, explaining them to the public, and opening a discussion of ways that the region might facilitate an orderly transition to an effective competitive market.

At the same time, new approaches need to be identified to achieve some of the goals of the Northwest Power Act that may not be achievable in a competitive marketplace. Energy efficiency, renewable resource development and environmental protection are all goals of the Act that are unlikely to be strongly supported by a competitive industry.

8-A. GOALS OF THE NORTHWEST POWER ACT

As the Pacific Northwest Electric Power Planning and Conservation Act (the Act) was being debated, it was thought that the region was facing impending power deficits. The resources that utilities planned and began to build to meet those deficits were large, expensive, environmentally controversial and took many years to site and construct. Those on which construction was begun had the consequence of raising power rates from the federal system by more than 500 percent, even though most were never completed.

The Power Act put in place an ambitious experiment in regional planning. It was a balancing of interests that integrated power generation, system reliability, environmental concerns, energy efficiency, and the costs of new and existing resources. It sought to involve the public in making decisions about the composition of electricity resources that would meet the region's future electricity needs.

The specific purposes of the Act are, among others:

- To encourage conservation and efficiency in the use of electric power;
- To encourage the development of renewable resources;
- To assure the region of an adequate, efficient, economical, and reliable power supply;
- To provide for the participation and consultation of the states, local governments, consumers, customers, users of the Columbia River system and the public at large in:
  - — the development of regional plans and programs related to energy conservation, renewable resources, other resources, and protecting, mitigating and enhancing fish and wildlife resources;
  - — facilitating the orderly planning of the region's power system;
  - — providing environmental quality; and
  - — the protection, mitigation and enhancement of the fish and wildlife, and their habitat, of the Columbia River Basin.

To carry out the power-related purposes of the Northwest Power Act, Congress gave the Council explicit responsibilities. The Council is to develop and periodically revise a regional, long-term conservation and electric power plan. That plan is to incorporate:

- Priority for cost-effective resources with first priority given to conservation, second to renewable resources, third to resources using waste heat or that have high conversion efficiency, and fourth to all other resources;
- An energy conservation program including model conservation standards;
- Recommendations for research and development;
- A methodology for determining quantifiable environmental costs and benefits;
- A demand forecast of at least 20 years and a forecast of the resources required to meet Bonneville's obligations;
- An analysis of reserves and reliability requirements; and
- The Columbia River Basin Fish and Wildlife Program.[1]

In developing this plan and in regional power policy generally, the Council is to ensure "widespread public involvement."[2]

The acquisition of conservation and other resources by the Bonneville Power Administration is to be consistent with the Council's plan. The Council can choose to subject proposals for major resources (over 50 megawatts for five years or more) to a test of consistency with its plan. If the Council finds a resource inconsistent with its plan, and Bonneville still wishes to acquire it, the administrator must get specific congressional authorization.[3] This is the Council's most important authority over Bonneville's resource acquisition, and even this authority is indirect.

When the Act was passed, it was anticipated that Bonneville would back the acquisition of resources for the whole region — for investor-owned utilities as well as for publicly owned utilities. As a consequence, although the authority of the Council's planning is limited to Bonneville, it was anticipated that it would influence the resource acquisitions of investor-owned utilities. As it turned out, investor-owned utilities did not place significant loads on Bonneville. Nonetheless, the adoption of integrated resource planning rules by the region's state utility regulators and the involvement of the Council in the development of utility integrated resource plans meant that the Council has had significant influence beyond the limits of its direct authority.

8-B. The Council's Power Planning Innovations

The region's first electricity plan was completed by the Council in April 1983, just a year and a half after the Council was formed. That first plan was probably best known for its planning innovations. The 1983 plan set the standard for utility least-cost integrated resource planning. In it, the Council developed a number of planning methods that continue to be prominent in utility integrated resource planning today.

- The Northwest's power plans are developed from the perspective of the entire regional society. The costs that the plans sought to minimize were *all* costs of power, whether paid by utilities, their customers, or environmental costs that are not actually paid in dollar terms.
- The planning process relies heavily on the participation of both direct stakeholders and the general public. Advisory committees provide a means for interest groups to provide input to and review the work of the Council and its staff. Extensive public hearings provide the opportunity for the public to review and influence the directions of the Council's plans.

[1] 16 USC §839 b(e)-(f).

[2] 16 USC §839 b (g).

[3] 16 USC §839 d(c).

- At the heart of integrated resource planning is the consistent evaluation of both generating resources and improved efficiency of energy use. The Council fully integrates efficiency resources into the planning process. Conservation supply estimates are developed to be consistent with energy demand forecasts. Conservation resources compete directly with generating resources in developing a least-cost mix of choices. The costs of resources, both supply-side and demand-side, affect the forecasted price of, and demand for, electricity.

- The Council's plans focus on the inherent uncertainty of the future. In the Council's first plan, there was no medium or best-guess forecast of future electricity use, but rather a range of four forecasts with an assumed probability distribution. This focus on uncertainty shifts planning objectives from meeting a best-guess forecast of electricity requirements to developing a risk-averse strategy for meeting an uncertain future requirement.

- The concept of resource "options" was introduced as an important opportunity to reduce the lead time of electricity resources and, thus, help respond to uncertain future resource needs without making huge investments in new power plant construction. The most familiar form of an option would be a pre-designed and pre-sited power plant, that is not completed until the time the plant is needed. This concept was ground-breaking in an era when the lead time for new generation was as long as 10 years.

- An "action plan" was included to chart an explicit course for the plan's implementers to follow for the first couple of years following the plan's adoption. The action plan is critical to achieving the goals of the plan, and it provides a means of tracking progress and identifying problems.

8-C. The Future Role of the Council

The Council's direct authority over the operation of the region's power system has always been limited, and is likely to be applied even more rarely in the future. For example, if Bonneville is not acquiring new resources, the Council's review authority under the Act will never be exercised. Bonneville currently has a surplus of electricity. As a consequence, it may not be acquiring resources in the near term. Any guidance the plan provides for Bonneville's resource acquisition is thus essentially moot for the time being.

In the past, the Council's plans have not relied on regulatory authority for their impact. With respect to the region's investor-owned utilities, the role of the Council's plan has always been indirect and, at best, limited. Wholesale competition and the potential for retail competition appear to be weakening what have been the primary vehicles for Council influence — the state utility commissions' requirements for integrated resource planning and conservation. As the utility industry evolves in the direction of greater competition, it is quite possible those requirements will not be retained.

Similarly, the plan's influence over the public utilities also has been indirect. In large part it has been exercised through Bonneville, although in several instances the Council has worked with the utilities themselves. Many publicly owned utilities actively embraced integrated resource planning and conservation and worked with the Council in their own planning processes. Some did not. In the future, integrated resource planning and conservation may be problematic for the publicly owned utilities for most of the same reasons that affect the investor-owned utilities.

More fundamentally, in a competitive market, is there still a need for the kind of long-term, regionwide planning and broad public involvement that have typified the Council's work? In the future, the development of new resources will likely be the function of an unregulated, competitive wholesale market in which integrated resource planning, as we have known it, will not play a major role. Planning will most certainly take place, but it will be the kind of planning carried out by competitors seeking a market niche in which they can be successful.

The authority of the Council's plan and the relevance of traditional planning will probably be much more limited than has been the case in the past. Some of the mechanisms that enabled the Council and its plan to influence the actions of regional power actors may be less effective. However, there may still be activities the Council can carry out that will be of value to the region. The questions for the Council and the region are:

- Are there power-related functions that the Council already performs or could perform under its current mandates that will be useful to the region in a more competitive electricity industry? In particular, are there functions the Council can fulfill that can provide appropriate public policy guidance for the transition to a more competitive electricity industry?

- Are there new functions that the Council should be authorized to carry out?

Council Functions under the Northwest Power Act

There are a number of activities the Council carries out or could carry out with no changes in the Northwest Power Act that may be of value in a competitive electricity industry. In most instances, these are activities the Council and its staff already perform in the course of developing and, subsequently, trying to facilitate implementation of the regional power plan. They include:

- Providing up-to-date information on future electricity demands, new generating and efficiency technologies, system operations and market forecasts;

- Serving as a broker for information exchange among utilities and others;

- Working at federal and state levels to resolve legal and institutional barriers to accomplishing regional goals;

- Providing impartial analysis of issues with a long-term regional perspective;

- Serving as a focus for analysis of the interactions between power and fish;

- Representing the interests of states and the public in power issues; and

- Being a regional convener of forums to resolve issues.

Providing Energy Information

The information the Council develops in the course of its planning — forecasts of electricity demand, analysis of new resource costs and availability, and so forth — has been useful to the utility industry and others for their own planning and decision-making. This information could continue to be useful in the future. Some in the industry will be deciding whether to purchase electricity from the market. Others may be developing resources for the power market and facing considerable risk in the process. Everyone will need to know the rules they face and which resources would be the best choices. Futures markets and other financial instruments can distribute financial risk, they cannot eliminate it. The efficient functioning of markets depends on quality information and accurate interpretation of that information.

The Council could focus its information activities to facilitate the transition to and operation of the market. To be of value in a fast moving competitive market, information will have to be produced and revised more frequently than has been the case in the past.

There will, of course, be other providers of such information. Consultants, for example, will produce resource assessments and forecasts, but business imperatives will lead them to restrict access to their information, if they can. Is there value in having an independent entity, such as the Council, develop this sort of information and disseminate it broadly?

Brokering Information

The Council has frequently functioned as an information broker — facilitating the exchange of information among utilities and others about problems and solutions of mutual concern and bringing together potential participants in transactions. Some of this brokering the Council has carried out through its publications, meetings and conferences, or through financial support of similar functions carried out by others. The Council's brokering has frequently been most effective in bringing together those who might not otherwise talk to one another on a regular basis — utilities and local governments, for example. This kind of information exchange may remain valuable, but may also become more difficult, if competition between utilities and other participants in the market for electricity becomes prevalent.

Again, others can and do perform this function. The Public Power Council, the Northwest Public Power Association and the Pacific Northwest Utilities Conference Committee, for example, have also performed this role for their members and will probably continue to do so to some degree. As the market becomes more competitive, market intermediaries will likely emerge who will perform some broader information brokering functions. Nonetheless, there may be a continuing role for the Council, with its regionwide reach, to bridge the inevitable communication gaps.

Facilitating Regional Goals at Federal and State Levels

The Council has frequently worked at federal and state levels to resolve legal and institutional barriers to the accomplishment of regional goals. The Council's status as representative of the governors of the four Northwest states gives its recommendations unique weight, both within the region and at the federal level, where the region's congressional delegation has been generally supportive.

The Council was the catalyst for the adoption, implementation and enforcement of energy-efficient building codes in several Northwest states and local communities. The Council facilitated conservation activities, such as the Manufactured Housing Acquisition Program, which helped establish more efficient federal standards for manufactured housing. The Council also supported action on national appliance efficiency standards.

These kinds of activities, which helped transform industries and markets to become more efficient, are likely to continue to be important in the future.

Impartial, Long-term Analysis of Issues

One of the Council's primary strengths has been its ability to focus relatively impartial analytical attention on power issues the region faces. The Council takes a long-term perspective on the region's energy system, a focus that is more likely to be neglected by competitors preoccupied with near-term concerns. The Council also takes the perspective of the region as a whole, which can identify issues and solutions that might be missed by parties whose private interests are more narrowly focused. The need for the Council to continue to provide a long-term, regional perspective was voiced repeatedly by a wide range of interested parties during consultations the Council held in the course of developing this draft plan.

As the region makes the transition to a more competitive electricity industry, there will be many issues about that transition on which an independent analytical perspective will be valuable to the region. One might question the continued usefulness of the Council's analysis once the competitive electricity market has matured; commodity markets, such as those for shoes or corn flakes, raise few issues of public policy that require independent analysis.

However, the electricity industry will not be completely deregulated. The areas that are regulated will continue to be public concerns. Moreover, the importance of electricity to the economy and environment of the Northwest, and the fact that so much of the region's electricity is generated by a public resource — the Columbia River system — make it likely that there will be continued value in an independent source of analysis of the region's energy system.

Analyzing the Interaction Between Fish and Power

The significance of the operation of the Columbia River hydropower system to the Northwest's overall power system, as well as to the region's fish and wildlife resources, would argue for an ongoing role for an organization like the Council, which is required to balance these resources. Given the contentiousness of the issues, the high stakes involved and the technical sophistication of the analysis required, the Council's ability to analyze the effects of different hydropower system operational regimes should continue to be of value for the foreseeable future. There has also been the suggestion that the Council should undertake an even broader analysis of the multiple uses of the Columbia and its watershed.

Representing the Interests of the States and the Public

The Council was established in part to give the Northwest states and the public a greater voice in decisions about the region's power system. This was largely because electricity is so important to the economy and environment of the Northwest. In addition, the fact that much of the Northwest's power industry is federally owned and has monopoly status has given the public a particular interest in decisions that affect the industry. This public interest is likely to continue while the industry makes the transition to competition. There will be many issues in that transition about which the states and the public will want to have a voice. In such cases, the Council's regional perspective can make a significant contribution.

In the longer run, the Council's role in representing the states and public will depend on the nature of the market that evolves. A fully competitive market should enable consumers to influence industry decisions through customer choices. As noted above, however, a continued public policy content seems likely. In addition, a continued significant federal presence in some form in the regional power system seems likely, although not certain. This in itself would argue for some vehicle like the Council to represent the interests of the four states and the public.

Convening Forums to Resolve Regional Issues

The Council, representing the governors of the Northwest states, has the ability to convene regional forums to work for the resolution of regionally important issues. This ability will be particularly important in the transition to a competitive electricity industry. How the structure and regulation of the electricity industry evolve will, determine in large part, the degree to which the benefits of competition are achieved and how they are distributed. And while the Northwest is clearly part of a wider electricity market, a vital element of that market will be supplied by the resources of this region. There will be many issues of importance to the region that will have to be resolved on the way to more widespread competition. The Council is well situated to convene the stakeholders for the resolution of such issues. In the longer run, the ultimate nature of the market for electricity and the degree of public policy content of issues will dictate the need for this kind of activity. It seems likely there will be some continuing need for such a function.

New Roles for the Council?

New roles for the Council will depend, in large part, on how the region and the electricity industry adapt to the emergence of competition. For example, will the region find that new mechanisms to fund and implement conservation and renewables are necessary? If so, some entity may be needed to plan and possibly administer those mechanisms. Whether the Council is the appropriate entity is another question, but its expertise and regional purview have significant advantages.

There will inevitably be new needs that arise as the industry's transition proceeds. When these needs align with the Council's strengths — strong analytical capability, regional purview, multipurpose scope, the influence of the governors of the Northwest states — the Council should be a candidate for accomplishing them. Many of the new power-related roles for the Council would require legislation at the federal level and/or in the states. For that reason, the validity of potential roles will appropriately be subjected to intensive public scrutiny.

No Role for the Council?

It would be disingenuous to suggest that the power system of the Northwest could not function without the Northwest Power Planning Council. No other region has an equivalent institution. The power systems in those regions appear to function reasonably well, although in few others is there a *public* resource equivalent to the Columbia River's power system.

Inevitably, the move to a competitive electricity industry will lessen the influence of regional planning in favor of entrepreneurial strategy. The transition is also likely to lessen consideration of public values in decision-making and possibly even diminish the sense of the Northwest as a region. The policy question the Northwest must resolve is whether there needs to be a continuing means for reflecting the region's values in power decisions and, if so, whether the Council is the appropriate institution to facilitate that process.

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