



A Brief History

of the Federal Columbia River Power System
And Power Planning in the Northwest

1. Background

The development of the Federal Columbia River Power System in the Pacific Northwest began in the 1930s under a program of regional cooperation to meet the needs of electric power production, land reclamation, flood control, navigation, recreation, and other river uses. From the beginning, the federal government has played a major role in the development of one of the largest multiple-use river systems in the world. The U.S. Army Corps of Engineers and the Bureau of Reclamation built 31 hydropower dams (many have other purposes in addition to power generation) in the Pacific Northwest, 29 of them on the Columbia River and its tributaries.

Investor-owned and publicly owned utilities also built a major system of dams and generating facilities, beginning in the late 1800s.

Congress directed the Bonneville Power Administration, in the Bonneville Project Act of 1937, to build and operate transmission lines to deliver the power from dams, and to market electricity from federal generating projects on the river at rates set only high enough to repay the federal investment over a reasonable period of time.

Today, the Federal Columbia River Power system includes these dams:

Name	River, State	In-service year	Capacity
Albeni Falls	Pend Oreille, ID	1955	43 MW
Anderson Ranch	Boise, ID	1950	40 MW
Big Cliff	Santiam, OR	1953	18 MW
Black Canyon	Payette, ID	1925	10 MW
Boise River Diversion	Boise, ID	1912	3 MW
Bonneville	Columbia, OR/WA	1938	1,077 MW
Chandler	Yakima, WA	1956	12 MW
Chief Joseph	Columbia, WA	1958	2,458 MW
Cougar	McKenzie, OR	1963	25 MW
Detroit	Santiam, OR	1953	100 MW
Dexter	Willamette, OR	1954	15 MW
Dwarshak	Clearwater, ID	1973	400 MW
Foster	Santiam, OR	1967	20 MW
Grand Coulee	Columbia, WA	1942	6,795 MW
Green Peter	Santiam, OR	1967	80 MW
Green Springs	Rogue, OR	1960	16 MW
Hills Creek	Willamette, OR	1962	30 MW
Hungry Horse	Flathead, MT	1953	428 MW
Ice Harbor	Snake, WA	1962	603 MW
John Day	Columbia, OR/WA	1971	2,160 MW
Libby	Kootenai, MT	1975	525 MW
Little Goose	Snake, WA	1970	810 MW
Lookout Point	Willamette, OR	1953	120 MW
Lost Creek	Rogue, OR	1977	49 MW
Lower Granite	Snake, WA	1975	810 MW
Lower Monumental	Snake, WA	1969	810 MW
McNary	Columbia, OR/WA	1952	980 MW
Minidoka	Snake, WA	1909	28 MW
Palisades	Snake, WA	1958	176 MW
Roza	Yakima, WA	1958	11 MW
The Dalles	Columbia, OR/WA	1957	1,808 MW

Total: 31 dams, 20,460 megawatts of capacity. The U.S. Army Corps of Engineers operates 21 of the dams, and the Bureau of Reclamation operates 10.

The Columbia River Treaty with Canada*

As demand for power grew, the United States and Canadian governments recognized a need for development of water storage sites in the upper reaches of the Columbia River Basin. The governments of both nations negotiated a treaty in the early 1960s for the cooperative use of dams that would be built by both countries. Four dams were built under the treaty. Three are on the Columbia River or a tributary in Canada—Keenleyside, Duncan and Mica—and the fourth, Libby, is on a major Columbia tributary, the Kootenai River, in Montana. The Canadian dams were completed by 1973, and Libby was completed in 1975. The administrator of the Bonneville Power Administration and the Division Engineer of the Northwestern Division of the U.S. Army Corps of Engineers together comprise the U.S. Entity under the treaty. The Canadian entity is BC Hydro.

The Canadian dams provide flood control and water storage for the purpose of additional power generation at dams downstream in the United States. The power-generating capability of downstream dams increased by the following percentages as a result of the treaty storage: Grand Coulee, 13 percent; Chief Joseph, 14 percent; the five mid-Columbia public utility district dams, 18 percent; and dams farther downstream on the Columbia, 11 percent collectively. In return, Canada received two payments: one from the U.S. Treasury for flood control benefits and the other a cash lease payment for the first 30 years of the additional power generation. Known as the downstream benefit, the additional power is divided equally between Canada and the United States. Following the 30-year lease/sale by Canada to U.S. parties, in the late 1990s Canada's share of the downstream benefit was returned to Canada.

The arrangement obligates the United States to deliver the power to B.C. Hydro at the U.S.-Canada border, most of it at Blaine in western British Columbia and a small portion at Selkirk in the Columbia River Basin, where transmission connections already exist. But delivery at Blaine and Selkirk may be at times a formal fiction. Instead, B.C. Hydro finds a buyer for the power or service and notifies Bonneville where to deliver. Even if delivered at Blaine, B.C. Hydro still largely

markets the power rather than use it for its local firm-power customers.

Since 1964, when the treaty was ratified, the United States and Canada have enjoyed significant benefits through coordinated river management by the two countries. When the treaty was negotiated, its goals were to provide significant flood-control and power-generation benefits to both countries. The treaty contains two provisions, however, each of which may significantly change these benefits as early as the year 2024.

First, in 2024 the 60 years of purchased flood control space in Canadian treaty dams expires. Instead of a coordinated and managed plan to regulate both Canadian and U.S. projects for flood control, the treaty calls for a shift to a Canadian operation under which the United States can call upon Canada for flood control assistance. The United States can request this “called upon” assistance as needed but only to the extent necessary to meet forecast flood control needs in the United States that cannot adequately be met by U.S. projects. When called-upon is requested, the United States will then have to pay Canada for its operational costs and any economic losses resulting from the called upon flood control operation.

Second, while the treaty has no specified end date, it does allow either Canada or the United States the option to terminate most of the provisions of the treaty on or after September 16th, 2024, with a minimum of 10 years advance written notice. Thus, the year 2024 is the first year a notice of termination would take effect assuming written notice of termination is given by the Canadian or U.S. governments by 2014. Unless the treaty is terminated or the federal governments elect to modify the treaty, its provisions continue indefinitely, except for the changes in flood control discussed above.

Given the significance of both of these provisions, it is important that the parties to the treaty understand the implications for post-2024 treaty planning and Columbia River operations. The U.S. Army Corps of Engineers and the Bonneville Power Administration, the agencies that implement the treaty in the United States, began a multi-year effort in 2009 to understand these implications. This effort is called the 2014/2024 Columbia River Treaty Review.

**Parts of this section are taken verbatim from the 2014/2024 Columbia River Treaty Review website, www.crt2014-2024review.gov*

Operations under the treaty are complex and affect millions of people and a wide variety of issues on both sides of the border. Implementing the required specified treaty changes in flood control provisions in 2024 and considering the consequences of possible treaty termination will be a major challenge for both countries. Due to the scope and complexity of these issues, the U.S. Entity is taking a phased approach to studying the treaty and the issues related to its future. Each phase will provide valuable information, building toward a comprehensive and informed picture for evaluating the future of the treaty.

Phase 1 of the 2014/2024 Columbia River Treaty Review, the initial modeling and analysis phase, is a joint effort between the U.S. and Canadian Entities. Its purpose is to provide fundamental information about post-2024 conditions both with and without the current treaty and only from the limited perspective of power and flood control. These initial studies are not designed to establish future operating strategies, alternatives to the treaty, or government policies, but simply to begin the learning process. The initial Phase 1 studies were completed in August 2010, followed by additional modeling to show how requirements in the Biological Opinion affect treaty operations.

Once Phase 1 is complete, the U.S. Entity and the U.S. Department of State will work together to coordinate next steps and additional phases, including developing the appropriate level of consultation and involvement with other U.S. parties, such as affected states, tribes, and other stakeholders.

More on Columbia River Treaty history is on the Council's Columbia River history website at www.nwcouncil.org/history/ColumbiaRiverTreaty.asp. The website for the 2014-2024 Treaty Review is www.crt2014-2024review.gov.

Interties between the Northwest and Southwest

Also in the 1960s, Congress authorized construction of three major power lines linking the Columbia River hydropower dams with power markets in California and the rest of the Pacific Southwest. The interties benefit the Pacific Northwest in several ways. They allow the sale of hydropower from the Columbia when it is not needed here and would otherwise be lost in the form of water spilled over dams without generating electricity, and they permit

this region to buy power from California when power is needed here during shortages and periods of heavy use. In the first instance, sales of surplus Northwest hydropower to California has saved the equivalent of some 200 million barrels of oil. In the second case, California utilities sold power to Pacific Northwest utilities in the drought years of 1973, 1977, 1979, 1992, 1993, 1994 and 2001.

To protect Northwest access to the federal hydropower, Congress authorized regional preference provisions in 1964. Bonneville must offer any surplus power to utilities in the Northwest before selling it to California. Sales to California can be called back if the power is needed in the Northwest. Sales of firm energy can be recalled with 60 days notice; sales of peaking capacity can be recalled in five years.

The Hydro-Thermal Power Program

With the dams developed in Canada as well as in the United States, the river system provided virtually all the electricity needed by the region until the early 1970s. But by that time, all dam sites on the mainstem of the Columbia that were economically feasible and environmentally acceptable either were developed or were under development, and the region was looking for other ways to meet electric load growth. Bonneville and the region's utilities were predicting shortages of electricity unless thermal generating plants were built in response to increasing demand.

The region's publicly owned utilities and investor-owned utilities turned mainly to coal-fired and nuclear plants to meet growth throughout the Pacific Northwest. Utilities believed the development of such plants was the most economical and environmentally acceptable option available at the time. Bonneville helped the utilities respond to these needs by participating in the Hydro-Thermal Power Plan for the continued development of electricity resources in the Pacific Northwest.

Under the plan, Bonneville agreed to acquire electricity by entering into "net billing" agreements with its utility customers. These agreements made it possible for the publicly owned utilities, which owned shares of power plants, to sell to Bonneville all or part of the generating capacity of new thermal projects. Bonneville credited, and continues to credit, the wholesale power bills of these utilities in amounts sufficient to cover the costs of their

shares in these plants. Bonneville then sells the output of the plants, melding the higher costs of the thermal power with the lower costs of hydropower for the benefit of all customers. The plants were cooperative efforts of both publicly owned and investor-owned utilities, but Bonneville purchased only the shares of generating capacity owned by publicly owned utilities.

Under the Hydro-Thermal Power Program (Phase I), Pacific Power & Light Company (today known as Pacific Power) and other investor-owned utilities built the twin Centralia, Washington, coal-fired plants with the co-ownership of several publicly owned utilities. Portland General Electric Company built the Trojan nuclear power plant, with 30-percent co-ownership by Eugene Water and Electric Board (EWEB) covered by a net-billing agreement. And the Washington Public Power Supply System (WPPSS), under net-billing agreements, completed one nuclear plant (WNP 2) and partially constructed two other nuclear plants (WNP 1 and 3) in Washington state. The Hanford N-reactor turbine generator, built by WPPSS, also came on line just prior to the formal initiation of the Hydro-Thermal Power Program, and before its closure in 1987 was considered a part of the overall effort. Bonneville became the agent for integrating these resources so the consumers of the region could benefit from the greatest efficiency and lowest costs from operation of the regional electric system. Under the plan, the thermal power plants would run continuously to meet the baseload, or constant, power needs. The hydroelectric dams would be operated to follow the fluctuation of energy needs throughout the day.

In spite of the efforts of utilities and Bonneville to continue developing the region's generating resources in a systematic way, the region continued to lose ground to rapidly growing demands for electricity. The Hydro-Thermal Power Program failed to meet the region's expectations for two basic reasons. A revision of regulations by the Internal Revenue Service denied tax-exempt status to bonds sold by publicly owned utilities to finance their plants if power from the facilities was sold to Bonneville, a federal agency. And, Bonneville's financial ability to participate in net-billing agreements reached its limit far sooner than expected because of the climbing costs of new thermal plants.

In 1973, Bonneville and the region's utilities initiated Phase II of the Hydro-Thermal Power Program, in which the utilities would finance their own plants without net-billing participation by Bonneville. Thus, WPPSS nuclear plants 4 and 5, now terminated, were not covered by net-billing

contracts. Nonetheless, Bonneville expected to provide electric load management and power integration services and to supply peaking power and reserves from federal facilities in order to bring about the most efficient mix of resources possible. Bonneville's participation in this program was enjoined by a federal court in 1975. The court required that Bonneville complete an environmental impact statement on the impact of the Hydro-Thermal Power Program.

The environmental impact statement, which was not completed until 1980, found that fluctuation in the use of hydroelectric dams would have to be limited to protect shore structures along the river. Bonneville put the Hydro-Thermal Power Program on hold while the impact statement was being prepared, and during those five years a number of events occurred that led to the demise of plants 4 and 5. These included construction delays at all five of the WPPSS nuclear plants, cost increases for those plants as the result of overruns and mismanagement, decreasing regional demand for power, growing public interest in energy efficiency as a low-cost alternative to the extraordinarily expensive nuclear plants, and court decisions that relieved the participating utilities of their obligation to pay for the plants.

Bonneville continues to pay for the net-billed plants, even though construction was suspended on plants 1 and 3 in 1983 and never restarted. (More on the Hydro-Thermal Power Program is on the Council's Columbia River history website at www.nwccouncil.org/history/HydroThermal.asp).

Public power preference

The Bonneville Project Act of 1937 directed that the electric cooperatives and other publicly owned utilities of the region be given highest priority for the available federal power. They consequently came to be called "preference customers." In 1964, Congress authorized the Pacific Northwest Consumer Power Preference Act, which directed that only surplus energy from the Columbia River system could be sold outside the Northwest. Firm power from the system was reserved for the Northwest, except under conditions specified in the Act. Until the 1970s, the legal preference of public customers was unchallenged, largely because there had been enough electricity for everyone. In 1973, when Bonneville's firm-power contracts with investor-owned utilities expired, Bonneville could not offer new ones if



preference customers were to continue to have first call on federal resources. So the firm power contracts with the investor-owned utilities were not renewed.

However, Bonneville continues to sell some peaking power to the investor-owned utilities—power the utilities need during periods of heavy use in the winter heating season. Bonneville also sells power to the investor-owned utilities and utilities outside the region when electricity surplus to the needs of the preference customers is available.

In 1976, Bonneville's power demand and supply projections showed that federal power supplies were running short for preference customers, and that Bonneville would no longer be able to guarantee preference customers that their load growth could be met beyond 1983. Bonneville issued a notice of insufficiency to the utilities in June of 1976. The following month, 88 public utilities signed contracts with WPPSS to build nuclear plants 4 and 5. The WPPSS nuclear construction program proved to be a debacle, but it also prompted changes in regional energy policy. Mismanagement and cost overruns at the five WPPSS plants were at the root of the financial problems, but the WPPSS debacle also was a failure of electricity demand forecasting. The impetus for the nuclear construction effort lay in demand forecasts produced by the region's utilities, through the Pacific Northwest Utilities Conference Committee, and Bonneville. The forecasts proved to be too high.

Rate disparities

With PNUCC and Bonneville warning of future power shortages, with the investor-owned utilities relying on their own hydro and thermal power resources to meet the demand of their customers, and with the prices of federal hydropower remaining much lower than that of new thermal generation, a divisive struggle developed for

access to the limited federal hydropower. Sixty percent of the residential and farm customers of the region were served by investor-owned utilities. These customers were paying, on average, twice as much for electricity as customers of publicly owned utilities receiving wholesale power from Bonneville. The city of Portland sued Bonneville, claiming a right to a share of hydropower resources for its residents. The Oregon Legislature passed a law authorizing formation of a statewide public utility—the Domestic and Rural Power Authority—to seek service as a preference customer from Bonneville so that all residential customers of private utilities could receive the rate benefits of federal resources. Elected officials of other states talked of forming their own statewide public utilities.

Stimulated by rate disparities, the public power movement also experienced a renaissance. A strong public power move to buy out investor-owned utility service areas by means of elections in accordance with state law was revived in Oregon. All votes to form new PUDs failed in the November 1980 elections, but one long inactive PUD, the Columbia Peoples Utility District west of Portland, won voter approval for issuing bonds to buy out utility properties in Columbia County.

Meanwhile, planning for more resources to meet demand was hamstrung by uncertainty over the allocation of low-cost federal power among competing claimants, existing and new. For example, Bonneville's contracts with its direct-service customers, which are large industrial firms that purchase power directly from Bonneville, were to expire in the 1980s. The power sold to these industries would have to be sold to public utilities under the preference clause. If they were to survive in the Northwest, these industries needed an assured source of electricity.

2. Declining salmon runs

Finally, by the late 1970s it became clear that our regional prosperity, which resulted in large measure from inexpensive hydropower from the federal dams, had extracted a price on fish and wildlife in the Columbia River Basin. Just a century earlier, for example, between 10 million and 16 million salmon and steelhead returned to the Columbia each year. But by the late 1970s the annual returns had dwindled to about 2.5 million fish,

and most of those returned to hatcheries. Environmental groups and other advocates for fish and wildlife considered filing petitions to protect dwindling fish populations under the federal Endangered Species Act.

These pressures on our regional electric power supply, which once seemed inexhaustible, caused Pacific Northwest residents to question the institutions governing the development, sale, and distribution of generating

resources. Should new preference agencies be formed to replace private companies in given areas? How would the needs of new preference customers be met? Should private utilities undertake new generating projects in a hostile atmosphere of rapidly rising rates and the threatened shift to public power? How would large industrial customers in the region be served? How should the public, and their elected representatives, participate in decisions that were critical to the region's economy and environment? Who ultimately would be responsible for

planning and acquiring new resources to avoid impending electricity shortages? How would our region protect the fish and wildlife that had been damaged over the years by the construction and operation of hydropower dams?

The region continued to work for a cooperative solution that preserved local options while obtaining regional efficiencies of an integrated electric system. Several alternatives were explored, but no agreement was reached. To avoid a court battle over allocation issues, the region turned to Congress for a solution.

3. Toward a Congressional solution

Revisions to the Bonneville Project Act were considered as early as 1975. The legislation was prompted by Bonneville's Notice of Insufficiency in June 1976, coupled with the threat posed by Oregon's Domestic and Rural Power Authority. However, it was not until 1977 that Bonneville and its customers, through the Pacific Northwest Utilities Conference Committee (PNUCC), drafted legislation to solve the region's energy problems. U.S. Senator Henry M. Jackson of Washington introduced the PNUCC bill in September 1977, but neither that bill, nor a less complex successor drafted a year later, managed to progress very far by the time the 95th Congress adjourned in late 1978.

When the 96th Congress convened in 1979, a coalition of Bonneville customers was solidly behind a legislative solution to the Northwest's power crisis. Neither Bonneville nor its customers wanted an administrative allocation of limited power supplies, although Bonneville

did propose an allocation scheme in October of 1979. Bonneville and its customers, however, maintained that such an allocation would be subjected to protracted litigation. They alleged that Congress could avoid the uncertainties accompanying administrative allocation by devising a legislative allocation scheme and equipping Bonneville with the authority to purchase power from non-federal sources on a long-term basis. Supplying Bonneville with purchase authority was, they claimed, the key to implementing any legislative allocation scheme. Congress apparently agreed. The Senate passed the regional legislation on August 3, 1979; the House passed an amended bill on November 17, 1980, which the Senate agreed to two days later. On December 5, 1980, President Carter signed the Pacific Northwest Electric Power Planning and Conservation Act into law as Public Law 96-501.

4. Northwest Power Act

After four years of deliberation, Congress devised methods for protecting the preference that existing federal law gives publicly owned utilities, while at the same time providing the benefits of federal hydropower to residential and small farm customers of private utilities. It should be noted that the Act passed largely because it seemed to benefit all the interest groups that lobbied for it.

The Act directs that Bonneville should continue its traditional role of transmitting and marketing power, but also carry out additional responsibilities. Under the Act,

Bonneville must acquire all necessary energy resources to serve public utilities that choose to apply to Bonneville for wholesale power supplies. The Act contains checks and balances to insure that all customers of Bonneville are treated equitably.

Bonneville remains accountable to the people of the Pacific Northwest for the actions it takes to meet the needs of residents and industry. By creating a regional planning council consisting of two members from each of the four Northwest states to develop a regional plan,



Congress provided a regional decision-making system. It emphasizes local control of resource development and power planning.

Here are some of the major provisions of the Act:

- The states of Idaho, Montana, Oregon, and Washington were authorized to form the Council (in the Act, Section 4.(a)(2)(A), it is called the Pacific Northwest Electric Power and Conservation Planning Council) with two representatives from each state, appointed by the governors. The Act directed the Council to draw up a plan for meeting the electrical needs of the region at the lowest possible cost. The plan must give highest priority to cost-effective conservation to meet future demand for electricity. Renewable sources of energy must be given next-highest priority in the region's power planning, to the extent that they are cost-effective, ranking ahead of conventional thermal generating resources. Among thermal options, fuel-efficient methods of producing energy, such as cogeneration, must be given priority.
- Bonneville became responsible for meeting loads of customers and managing the regional electrical system to achieve the purposes of the Act relating to fish and wildlife, system efficiency, and experimental projects. The plan adopted by the Council, which is amended periodically, is the basis for Bonneville's actions in meeting loads of its customers. Congress exercises budget review of all proposed Bonneville expenditures. If Bonneville decides to acquire resources not consistent with the Council's plan, specific Congressional approval is required prior to any commitment by Bonneville. Bonneville must give priority to cost-effective conservation and renewable resources in meeting the region's needs. Bonneville may also purchase the generating capabilities of new thermal projects, but only after determining that they are required in addition to all cost-effective conservation and renewables that can be achieved or developed in time. Such projects must also be found reliable and compatible with the regional electric system. Bonneville must spread the benefits and the costs of resources among all of its customers through its rates.
- The supply preference and resulting price advantage to co-ops and publicly owned utilities by federal law was protected and enhanced. Bonneville was given the responsibility of meeting the full future requirements of preference customers -- something Bonneville was not previously authorized to do.
- Residential and farm customers of investor-owned utilities received rate relief. The utilities sell to Bonneville an amount of electricity equal to their residential and farm loads at their cost. In return, Bonneville sells to them enough energy at Bonneville's standard rates to cover these residential and farm loads. The rate advantages cannot enhance company profits, but must be passed on directly to the customers.
- Direct service industries received new 20-year contracts for power from Bonneville, but at a higher price than they paid under previous contracts. In effect, they paid the cost of rate relief to residential and small farm customers of investor-owned utilities during the first four years, and a substantial portion thereafter, which they agreed to do in exchange for assurances of long-term supplies.
- Bonneville sells electricity at a rate that reflects the melded cost of federal hydropower and more expensive thermal resources, conservation, and renewable sources of energy. The Act contains incentives, as well, to encourage conservation and renewables. Bonneville may credit utilities for their individual actions to implement conservation and renewables.
- The Council is to prepare, and periodically amend, a program to protect, mitigate, and enhance fish and wildlife, and related spawning grounds and habitat, that have been affected by the construction and operation of any hydroelectric project on the Columbia River or its tributaries. This applies to anadromous (ocean-going) fish as well as to resident (non-ocean-going) fish, and terrestrial and aquatic wildlife. The Act directs the Bonneville administrator to use the Bonneville fund to protect, mitigate, and enhance fish and wildlife affected by hydropower dams in a manner consistent with the program developed by the Council. A 1996 amendment of the Power Act authorized the Council to create the Independent Scientific Review Panel to review projects proposed for funding by Bonneville through the Council's program. The ISRP is discussed in the section of this briefing book that addresses fish and wildlife planning.

- All planning for electric resources and fish protection must involve the public. State and local control of land use and water rights is protected under the Act and the decision to allow construction of new resources is left with utilities and state siting authorities.
- The Council must provide a method for balancing environmental protection and the energy needs of the region. For each new energy resource, the provisions of the National Environmental Policy Act must be followed.
- The Council is required to seek the recommendations of the region's tribal, state and federal fish and wildlife agencies. In addition, the Council's measures must be consistent with the legal rights of the region's tribes.

5. Challenges for the future

Since 1996, the electricity industry in the United States has been in the midst of a significant restructuring. This restructuring is the product of many factors, including national policy to promote a competitive electricity generation market and state initiatives in California, New York, New England, Wisconsin, and elsewhere to open retail electricity markets to competition. This transformation is moving the industry away from the regulated monopoly structure of the past 75 years. Today we are served by individual utilities, many of which control everything from the power plant to the delivery of power to our homes or businesses. In the future, we may have a choice among power suppliers that deliver their product over transmission and distribution systems that are operated independently as common carriers.

There is much to be gained in this transition, as electricity consumers can benefit from competition, but also much to lose from volatile wholesale power markets and illegal marketing activities, as the region learned during the energy crisis of 2000/2001. On the optimistic side, not too many years ago competition in the natural gas industry helped lower the cost of electricity produced by gas-fired generating plants. On the negative side, completion of a new pipeline linking the gas fields of northern Alberta with the American Midwest increased competition between that region and the Northwest and contributed to higher gas prices here in the early 2000s. During the energy crisis of 2000/2001, natural gas prices tripled in a year, and then subsided as the electricity supply rebounded. Competition among manufacturers and developers of combustion turbines contributed to the availability of less expensive, more efficient power plants that can be built relatively quickly, and many new plants were added to the Northwest and West Coast

power supply during the energy crisis, when stratospheric prices -- well over \$200 per megawatt-hour -- meant that construction debt for the plants could be paid down quickly. Generally speaking, surplus generating capacity on the West Coast, combined with increasing competition among wholesale suppliers, reduces the price utilities must pay for power on the open market, as long as supplies are adequate. Broad competition in the electricity industry can result in lower prices and more choices about the sources, variety and quality of their electrical service, but competition also can lead to price escalations, as the region learned during the energy crisis.

Electricity markets can be benign as long as supply and demand remain somewhat aligned. But as the experience of 2000/2001 made abundantly clear, competitive markets can be volatile. In a competitive energy marketplace, prices can explode to unheard-of levels in a matter of months when demand increases and the supply decreases. Coupled with rapidly increasing costs for natural gas, the advantages of competition can turn quickly to disadvantages.

If nothing else, the absurdly high West Coast prices for wholesale electricity in late 2000 and the first five months of 2001 showed there are risks inherent in the transition to more competitive electricity services. Merely declaring that a market should become competitive will not necessarily achieve the full benefits of competition or ensure that they will be broadly shared -- particularly when the weather, power plant outages, regulatory rules, and natural gas prices don't cooperate.

It is entirely possible to have deregulation without true competition. Similarly, the reliability of our power supply could be compromised if care is not taken to ensure that



competitive pressures do not override the incentives for reliable operation. How competition is structured is important.

It is also important to recognize the limitations of competition. Competitive markets respond to consumer demands, but they do not necessarily accomplish other important public policy objectives. The Northwest has a long tradition of energy policies that support environmental protection, energy-efficiency, renewable resources, affordable services to rural and low-income consumers, and fish and wildlife restoration. These public policy objectives remain important and relevant. Given the enormous economic and environmental implications of energy, these public policy objectives need to be incorporated in the rules and structures of a competitive energy market, and not abandoned in the face of escalating demand and tight supplies of power.

In some respects, the transition to a competitive electricity industry is more complicated in the Northwest than elsewhere in the country because of the presence of the Bonneville Power Administration. Bonneville is a major factor in the region's power industry, supplying, on average, 40 percent of the power sold in the region and controlling more than 70 percent of the region's high-voltage transmission. Bonneville benefits from the fact that it markets most of the region's low-cost hydropower. It is hampered by the fact that it has comparatively high fixed costs, including the cost of past investments in nuclear power and the majority of the cost of fish and wildlife recovery in the Columbia River Basin.

As a wholesale power supplier, Bonneville already is fully exposed to competition, and Bonneville struggles when market prices are above its own cost-based rates. The transition to a competitive electricity industry raises many issues for Bonneville and the region. For example, can Bonneville continue to meet its financial and environmental obligations in the face of intense competitive pressure? When market prices rise and some of Bonneville's debt obligations have been retired, how can the Northwest retain the economic benefits of its low-cost hydroelectric power when the rest of the country is paying market prices? And finally, what is the appropriate role of a federal agency in a competitive market? The question is not only whether Bonneville can compete in the near term, but also, should it be a competitor?

In the mid 1990s, Bonneville struggled in a low-cost market. During the energy crisis of 2000 and 2001, when wholesale market prices shot up to 10 times the usual price, and higher at times, federal power was the envy of every utility facing marketplace sticker shock.

The drought of 2001, which reduced Columbia River runoff to the second-lowest level in 73 years of record-keeping, reduced the region's hydropower capacity by 4,000 megawatts, and Bonneville, which at that time normally purchased about 3,000 megawatts in the market in order to meet its customers' demand, spent nearly \$3 billion on power in a single year, 2001.

Largely because of Bonneville's experiences in 2001, a group of Bonneville customers proposed a fundamental change in Bonneville's power marketing role in the future, a proposal to limit Bonneville to selling only the output of the federal Columbia River Power System -- this is called Tier 1 -- essentially ending its role in the marketplace and making its customers responsible for meeting their own load growth beyond their guaranteed share of the federal system (Tier 2), which Bonneville would supply. That proposal, known as the Joint Customer Proposal (JCP), initiated a multiple-year-long process, known as the Regional Dialogue, by Bonneville to define its future role in power supply. This process culminated in 2007 and its principles were embodied in power-sales contracts in 2008.

The Council strongly supported and participated in these processes and offered a number of recommendations. Bonneville adopted a Regional Dialogue Policy, which defined its potential resource-acquisition obligations for power sales after 2011, whether at Tier 1 or Tier 2 rates. The administrator's potential future obligations also include additional firm energy, capacity, and flexibility for integrating wind power into Bonneville's balancing area. Its obligations to provide flexibility for wind-power balancing also are driven by its obligations under NERC standards as the host balancing authority for wind-power resources that are meeting load elsewhere, primarily in California.

The size of these obligations is not well understood because the obligations will be driven by choices of Bonneville's customers and the amount of wind power located in Bonneville's balancing area. Moreover, the supply of resources available to meet these obligations, particularly for additional flexibility to deal with wind integration, is uncertain. There are, for instance, a number of regional and West-wide discussions underway about institutional and business-practice changes to help balancing authorities deal with these issues.

Because of these uncertainties, the Council adopted several general principles in the Sixth Plan to guide Bonneville should it need to acquire resources to meet any of these several kinds of obligations. They are, briefly:

- Aggressively pursue the Council's conservation goals first
- Aggressively pursue the various institutional and business-practice changes to reduce the demand for flexibility and to use the existing system more fully
- Look broadly at the cost-effectiveness and reliability of possible sources of new capacity and flexibility, such as gas or other generation types, and take into account synergies in meeting several types of needs with single resources

The federal power system in the Pacific Northwest has conferred significant benefits on the region for more than 60 years. The availability of inexpensive, cost-based electricity has supported strong economic growth and helped provide for other uses of the Columbia River, such as irrigation, flood control, and navigation. The renewable and non-polluting hydropower system has helped maintain a high quality environment in the region.

But while the power system has produced significant benefits, these benefits came at a substantial cost to the fish and wildlife resources of the Columbia River

Basin. Salmon and steelhead populations were reduced to historic lows (some of these have rebounded in the 10 years between 2001 and 2010), and 12 populations of salmon and steelhead, plus bull trout and Kootenai River white sturgeon, are listed for protection under the federal Endangered Species Act. Resident fish and wildlife populations also have been affected. Native Americans and fishery-dependent communities, businesses and recreationists have suffered substantial losses due in significant part to construction and operation of the power system.

It is important that the region sustain its core industries, support energy efficiency and renewable resources, and restore salmon runs. As John Volkman comments in his book on Columbia River water policy, excerpted at the beginning of this briefing book, fish and wildlife mitigation requires a healthy hydropower system capable of generating sufficient revenues to finance energy and fish and wildlife measures -- neither fish and wildlife conservation nor power development can proceed without the other.

6. Energy-efficiency accomplishments

Since the 1980s, improvements in the efficiency of electricity use met 40 percent of the new demand for power in the Northwest, and the same—or more—is possible over the next 20 years. Importantly, the future cost of energy efficiency—also known as energy conservation—is less than the cost of building new generating plants.

Since 1982, when the Council issued its first Northwest Power Plan, energy efficiency improvements have topped 4,000 average megawatts—enough power for four cities the size of Seattle or, put another way, enough for all of the present-day power use of Idaho and western Montana combined.

In the Sixth Power Plan, issued in February 2010, the Council predicts that up to 85 percent of the new demand for electricity over the next 20 years in the Northwest can be met through energy efficiency. The anticipated demand growth is about 7,000 average megawatts. The plan's target for the first five years, 1,200 average megawatts, is the energy equivalent of the power use of a city the size of Seattle. Over time, the energy-efficiency target in the plan

—5,900 average megawatts over 20 years—would be the most aggressive regional target in the nation.

Investments in energy-efficient equipment and products will cost less than half as much as buying electricity from new power plants, saving consumers millions of dollars. Additionally, investments in energy efficiency will reduce greenhouse gas emissions from the region's power supply by 17 million tons per year by 2030 and create as many as 47,000 new jobs in the Northwest according to calculations by the Council staff.

The Council's analysis in the Sixth Plan shows that efficiency gains are available in a number of new places over the next 20 years compared to the Fifth Plan, which was completed in 2004. These include, for example, 954 average megawatts in consumer electronics, particularly flat-screen television sets, which are more energy-efficient than older sets that have cathode ray tubes. Industrial lighting and motors and more efficient electricity distribution equipment also contribute large savings in the plan.



