90-18A

Draft

1991 NORTHWEST CONSERVATION and ELECTRIC POWER PLAN

VOLUME II

Group 2

Includes:

Chapter 2: Background and History of the Northwest Power System

Chapter 3: The Council's Planning Strategy

Chapter 4: The Existing Regional Electric Power System

JAMES A. GOLLER
CHAIRMAN
Idaho

Robert (Bob) Saxvik
Idaho

John C. Brenden
Montana

Stan Grace
Montana

NORTHWEST POWER PLANNING COUNCIL

851 S.W. SIXTH AVENUE • SUITE 1100
PORTLAND, OREGON 97204-1348 • (503) 222-5161

Toll free number for Idaho, Montana & Washington: 1-800-222-3355
Toll free number for Oregon: 1-800-452-2324

R. TED BOTTIGER
VICE CHAIRMAN
Washington

Tom Trulove
Washington

Angus Duncan
Oregon

Ted Hallock
Oregon

November 1990

To Interested Parties:

The attached document is a specific part of a larger document entitled, the "Draft 1991 Northwest Conservation and Electric Power Plan--Volume II." If you are interested in ordering any other parts of this plan, you may do so by writing or calling the Council's public involvement division (address and toll-free phone numbers are listed above). Volume I is the basic power plan. It contains all of the plan's major policies, directions and actions. Volume II is the technical, supporting documentation. A complete listing of Volume II is described below for your ordering convenience.

The Council is accepting public comment on this draft plan through 5 p.m., March 15, 1991. Please send comments to the Council's central office at the address above. Comments should be clearly marked. If you are commenting on Volume I, refer to document number 90-18. If you are commenting on Volume II, refer to document number 90-18A. Public hearings also are scheduled in each state. Please call your state at the following numbers for times, locations and to sign up to testify: Idaho: 208-334-2956, Montana: 406-444-3952, Oregon: phone numbers are listed above, and Washington: 509-359-7352.

- Volume I (40 pages)
- Volume II, Group 1 (60 pages)--Chapter 1: Recommended Activities for Implementation of the Power Plan; Chapter 11: Resource Acquisition Process
- Volume II, Group 2 (80 pages)--Chapter 2: Background and History of the Northwest Power System; Chapter 3: The Council's Planning Strategy; Chapter 4: The Existing Regional Electric Power System
- Volume II, Group 3 (210 pages)--Chapter 5: Economic Forecasts for the Pacific Northwest; Chapter 6: Forecast of Electricity Use in the Pacific Northwest
- Volume II, Group 4 (190 pages)--Chapter 7: Conservation Resources; Chapter 12: Model Conservation Standards and Surcharge Methodology
- Volume II, Group 5 (360 pages)--Chapter 8: Generating Resources: Chapter 9: Accounting for Environmental Effects in Resource Planning; Chapter 16: Confirmation Agendas for Geothermal, Ocean, Wind and Solar Resources
- Volume II, Group 6 (120 pages)--Chapter 10: Resource Portfolio; Chapter 13: Financial Assumptions; Chapter 14: Resource Cost-Effectiveness; Chapter 15: Risk Assessment and Decision Analysis

A:[DM]Letters.AS5 vol. II

CHAPTER 2

BACKGROUND AND HISTORY OF THE NORTHWEST POWER SYSTEM

Chapter 2
Table of Contents

Page No.

Introduction

For well over half a century, electrical power has been a cornerstone of the Pacific Northwest economy. Thanks to the nation's most productive hydropower system, abundant, low-cost electricity has made the Northwest attractive to business and industry, despite the fact that the region is a long way from major markets.

Electricity has lighted and powered the farms of the region and turned deserts and sparse grasslands into highly productive cropland. Aluminum smelting, pulp and paper production, and industrial chemical manufacturing have all benefited from abundant and cheap electrical supplies. Sales of electricity have provided the revenues that made the damming of the Northwest's rivers possible, thus multiplying economic growth through increased navigation, irrigation and flood control.

Now, however, products from other regions are competing strongly with the region's products. As a result, maintaining low-cost electricity is more vital than ever to the Northwest economy. The goal of the 1991 Northwest Power Plan is to preserve and enhance this valuable asset by identifying the steps that need to be taken to ensure the lowest cost electrical energy future for the Pacific Northwest.

This new age poses major new challenges for the region.

All new sources of power are much more expensive than the region's existing electric power system. Conservation costs about double Bonneville's current wholesale power costs, and new coal plants cost four times as much. As a result, electricity prices will go up as the region adds new resources.

The region's industries have divergent needs. The Northwest's traditional industries--pulp and paper, wood products, chemicals, agriculture, transportation equipment and metals--represent the backbone of the region's economy. These industries employ over 400,000 people and produce much of the economic activity in the region. These basic industries rely on low-cost power to remain competitive with other parts of the country and the world. New industries, such as high technology and consumer services, are not as dependent on low-cost power because power costs represent a smaller portion of their overall operation costs. As these new industries grow, new resources will be needed. The dilemma is that new additions to the power system will raise electricity costs and thereby threaten the traditional industries.

The Last 50 Years: A History of Northwest Electrical Power Development

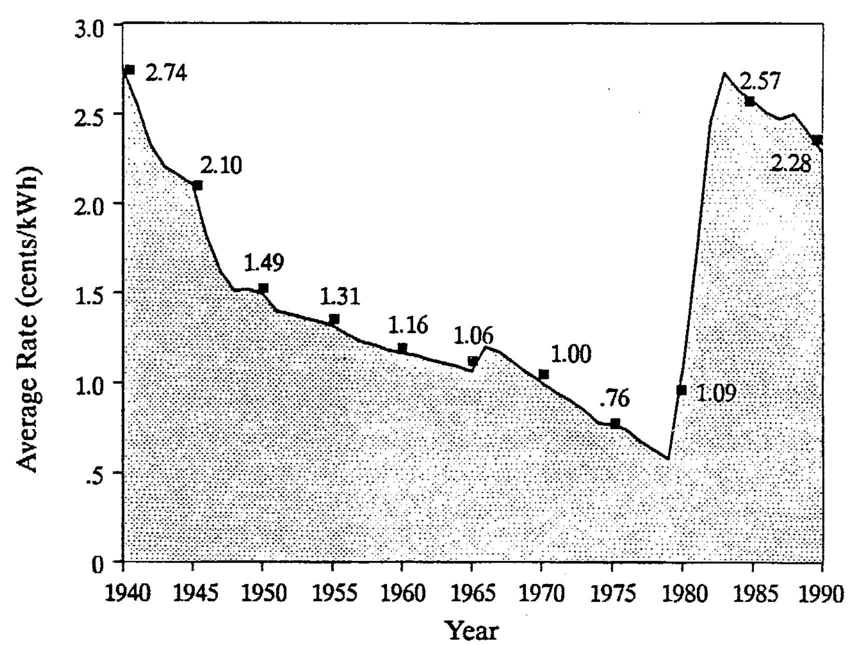
The Hydropower Era

Today's electric energy choices reflect a reversal from yesterday's economics of power. For years, the region had been blessed with low-cost electricity from the seemingly inexhaustible Columbia River system. The rapid economic growth of the region created a steady demand for more and more power. Because of economies of scale and growing sales of electricity to pay the costs, each new dam actually brought the cost of electricity down.

From 1940 to 1979, the wholesale rate for Bonneville Power Administration public utility customers dropped, when adjusted for inflation, from 2.7 cents to 0.6 cents per kilowatt-hour (see Figure 2-1). The region's huge hydropower system on the Columbia River, built when inflation and interest rates were low, provided the nation's cheapest electricity. From farm to factory, the region prospered during this hydropower era. With the cost of power dropping, "living better electrically" became the axiom of the times. Power planning in the 1950s and 1960s involved minimal risk of being wrong. If the supply of electricity exceeded demand, demand was certain to catch up soon. The far greater risk, or so it was perceived at the time, was to underbuild, to have demand for electricity exceed the supply.

Bonneville Power Rates

Figure 2–1
Bonneville Power Administration Preference Rate—1940–1990
(All Figures in 1990 Dollars, Adjusted for Inflation)



By 1960, the region's power system had grown to 6,000 megawatts of average energy. Figure 2-2 shows both the growth in electric load and the additions to the Northwest power system. During the 1960s and 1970s, electric load growth averaged 5.2 percent per year. The region added 10,000 megawatts of new resources during this period.

Loads and Resources

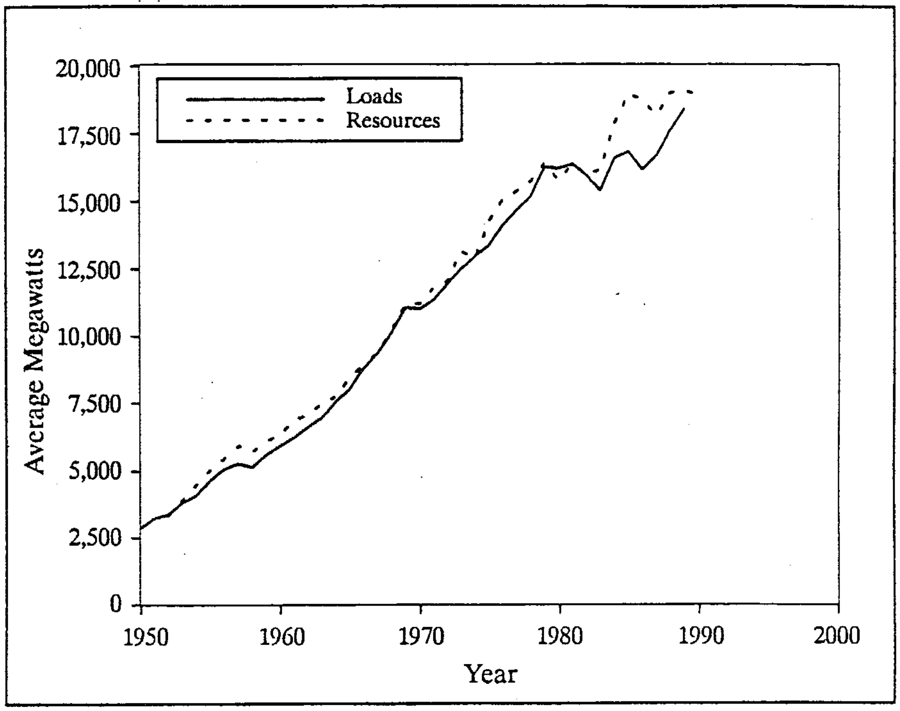


Figure 2-2
Firm Electricity Loads and Resources

The Hydro-Thermal Power Program

During the 1960s, it became obvious that hydropower alone could not supply all the Northwest's electrical needs. For one thing, the region was running out of new river sites that could be developed. The Hydro-Thermal Power Program was conceived as an answer to this problem in the late 1960s. As the name suggests, it was an effort to mesh new thermal resources with the existing hydropower system. A major goal of this program was to allow construction of large generating plants, while preserving the basic roles of Bonneville and its customers. Bonneville would supply energy peaking needs, and utilities would build large base-load[1] generating resources.

Rapid growth was projected to continue for years ahead; therefore, the Hydro-Thermal Power Program was based on the energy economics of the day. Nuclear reactors appeared to be cheaper to operate as base-load facilities because so much of their cost is in the building of the physical plant, not in the cost of fuel. Once a reactor is running, it makes little economic sense to operate it to follow the daily

1./ Base-load resources run continuously except for maintenance and forced outages.

fluctuations in power demand. The hydropower system, on the other hand, could follow the hour-to-hour demand for electricity in the region.

By law, Bonneville could not construct or own generating plants. Therefore, public utilities would finance, construct and operate the plants, and Bonneville would acquire their output by crediting the owner utilities for the cost of those plants when it billed the utilities. The arrangement was called net billing. An adverse Internal Revenue Service ruling and high costs ended the original Hydro-Thermal Power Program in 1973.

The second phase of the program followed, with the region's utilities taking power from their own shares of the generating plants, while Bonneville provided transmission and "shaping" of the generation to fit power loads. Washington Public Power Supply System nuclear plants 4 and 5 were the principal products of this phase. Bonneville's participation in this phase effectively ended in 1975 with adverse court decisions which required the agency to prepare lengthy environmental impact statements on its role.

Few had anticipated the cost of the thermal era transition. The cost of new coal or nuclear plants escalated by billions of dollars with power from these plants costing many times more than power from the existing Northwest dams.

As the cost of the new thermal plants increased, so did the value of the hydropower system. Although its output varies with annual rainfall and snowpack conditions, during high-water years there is enough low-cost hydropower to allow other, more expensive resources to be shut down, thus saving ratepayers some of the cost of running thermal plants. Given today's cost of building and operating any new plant, economics point toward getting maximum use out of the hydropower system while planning new resources that complement that system.

Congress Addresses the Region's Problems

By 1977, the forces which were leading to the Northwest Power Act of 1980 were becoming clear. Regional utility planners were frustrated with a plethora of increasingly difficult problems. These led regional decision-makers to look to Congress for a comprehensive solution to a set of linked problems.

First, hold-ups in siting and licensing and delays in plant construction had become commonplace. Utilities began projecting they would be unable to meet the region's power needs in the early 1980s. Deficits of more than 3,000 megawatts were projected by the mid-1980s in the event of low-water years. A mechanism was needed to speed new resources into the system.

Second, while Bonneville and several utilities were promoting construction of large thermal plants, a number of critics were arguing that the region's power needs could be met by conservation programs at substantially less cost. State siting agencies began to consider conservation as an alternative to thermal plants. However, at the time, conservation was a new and unfamiliar resource to most utilities.

Third, with the end of federal dam construction and the limiting of net billing, Bonneville could no longer acquire additional resources to meet new loads.

Investor-owned utilities, which traditionally had relied on surplus Bonneville power to meet their growing loads, found in 1973 that they could be cut off from cheap federal hydropower by the "preference clause" of the Bonneville Project Act, which granted public utilities first access to federal hydropower. The investor-owned utilities then began turning to expensive thermal generation, a step which was reflected in their rates by the mid-1970s. Many of the region's public utilities are small, serving only one county or a sparsely populated rural area. But even the larger investor-owned utilities were limited in their ability to move into the thermal age. It was not unusual for an investor-owned utility to have half its assets tied up in construction of generating plants that could not bring in revenue until they were completed.

Fourth, by 1977, investor-owned utility rates, which historically had been comparable to public utility rates, skyrocketed to two or three times those of public utilities. Growing pressure to correct this rate disparity prompted the state of Oregon to enact the Domestic and Rural Power Authority, which was to lay claim as a publicly owned utility to federal hydropower for the benefit of all the state's citizens.

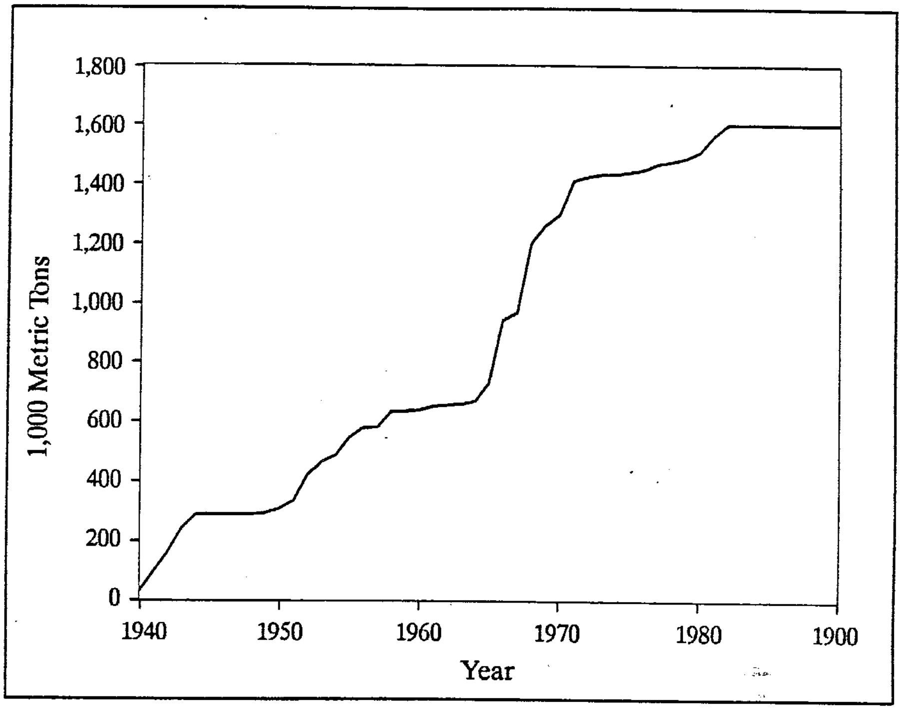
Fifth, with limited power supplies and growing customer loads, Bonneville foresaw a day when it could no longer meet all the power needs of its customers. On July 1, 1976, it issued a Notice of Insufficiency informing its customers that after seven years it could no longer meet all their needs. Bonneville then began a lengthy proceeding to develop a formula to allocate its available power supplies. This effort was expected to be extremely difficult and controversial.

Sixth, the direct service industries' contracts were to expire in the 1980s. The power supplied to these industries would have to be sold to the public utilities under the preference clause. If they were to survive in the Northwest, these industries needed an assured source of power. Some of these plants are old, but Figure 2-3 shows that approximately 60 percent of the region's aluminum capacity was built after 1965.

And seventh, concerns over the decline of the famed Columbia River salmon and steelhead runs were drawing regional attention. Since the first dams went up in the 1930s, the annual salmon catch had declined 70 percent. While hydroelectric development was not the only cause for the decline, there was widespread agreement that the dams had been a major factor and that remedial measures were needed. Getting a coordinated response was a problem. The river and its tributaries flowed through all the Northwest states and a number of jurisdictions, including Indian tribal lands.

Aluminum Capacity

Figure 2–3
Growth in Regional Aluminum Capacity



The Northwest Power Act Ushers in a New Power Era

By 1980, it was clear that not only was a comprehensive solution needed for the region's electrical power problems, but a mechanism for addressing that part of the fish and wildlife problem resulting from the power system was needed as well. That comprehensive solution resulted in the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act, Public Law 96-501) passed by the 96th Congress in December 1980.

Among other things, the Act gave Bonneville an expanded role, allowing it to acquire resources, including the development of conservation programs, and to help restore fish and wildlife. The Act also created a public process for future electrical power planning by allowing the creation of a state-appointed Northwest Power Planning Council to make the judgments about future electrical energy demand and resources, including conservation, to be developed to meet the region's needs. It also gave the Council the authority to plan the actions and investments to be undertaken to rescue the fish and wildlife resources, particularly salmon and steelhead, affected by the Columbia River power system dams.

Bonneville received broad new authorities. In return, the Northwest states, whose ratepayers fund Bonneville, received an increased role in directing their own energy future through the Council. All of the Council's business and decision making are conducted in public, and the Council maintains a broad public information and involvement program to stimulate public participation.

Bonneville's expanded role allowed it to acquire new power supplies through a mechanism where Bonneville would acquire the power generated by a power plant and pledge to pay the costs of building and operating it. This "guaranteed purchase" was intended to give financially strapped utilities better access to financial markets to get funds for new conservation programs and thermal plants, and was designed to spread the financial risks of developing new resources across the region.

With the ability to acquire new resources, Bonneville could execute new contracts as well as continue to supply the non-generating utilities and the growing needs of all other utilities. The Act also authorized Bonneville to sign residential "exchange" contracts with utilities, allowing them to buy power to serve their residential and agricultural customers at the same rate that Bonneville charges public utilities. In turn, the generating utilities would sell Bonneville power at their own average system cost. This exchange gives residential and small farm customers of utilities participating in the exchange access to the Northwest's cheap hydropower and has saved these customers approximately $1.7 billion since the passage of the Act.

The Act also authorized Bonneville to enter into new long-term contracts with the direct service industries. These industries gave up existing contracts, most of which were scheduled to expire in the 1980s, for higher-priced contracts of 20 years' duration. The direct service industries also agreed to absorb a large portion of the costs to Bonneville for the exchange program described above.

Finally, the Act also set up a system of "rate pools" to assist Bonneville in determining what the various classes of customers would pay for power.

The Northwest Power Planning Council

In the past, dams had been built and transmission lines constructed with relatively little public participation. However, new coal and nuclear plants were seen as affecting both the economy and environment of the Northwest. Electricity rates had begun to climb dramatically in many parts of the region prior to the Act, and the impacts of the dams and thermal generating plants on the environment had become matters of intense public controversy. The public at large, as well as state and local governments, needed and demanded a voice to express their interest in energy issues.

Public opinion on electrical energy issues had become so strong that future power development seemed stymied. To propose a new generating unit in the atmosphere of the late 1970s was to subject a utility to what appeared to be an endless process before public bodies and a largely uncertain outcome. The lack of consensus was counterproductive to planning. While energy plants were being stalemated, the conservation programs that would be necessary if the plants were not built were not being undertaken either. The need for regional consensus building was a primary impetus for the formation of the Northwest Power Planning Council.

The creation of the Council took place in the framework of an interstate agreement under the "compacts clause" of the U.S. Constitution. The principal duties of the Council under the Act are to: 1) develop a 20-year regional power plan (the plan) to ensure the Northwest an adequate and reliable electrical power supply at the lowest cost; 2) develop a fish and wildlife program (the program) to "protect, mitigate and enhance" the fish and wildlife affected by hydroelectric development in the Columbia River Basin; and 3) provide for broad public participation in these processes.

According to the Act, Bonneville implements actions consistent with both the plan and the program. The Act requires Bonneville to seek the Council's approval for any resource acquisition over 50 megawatts and five years in duration. If the Council finds that any proposed resource acquisition is not consistent with its power plan, Bonneville would have to secure congressional approval before acquiring the resource.

1980-1985: A Changing Power Picture

As the Council worked to develop its first plan, the Northwest electrical power picture had already begun to change dramatically. Much of the impetus for the Act had been the projection of large deficits in power supply. Because many utility planners in the 1970s assumed they could predict the most likely future, the result was a single energy forecast for the region that led to the start of construction of 17 coal plants and 10 nuclear plants. In 1980, there were predictions of blackouts and severe regional shortages.

But between 1981 and 1983, it became apparent to the Council that the mid-1980s would not be characterized by deficits but by an expensive surplus of uncertain duration. This signaled the emergence of a new and different set of problems.

Uncertainties inherent in forecasts of energy needs had led the region to build large expensive generating plants that were not needed, at least not on their schedules for completion. The high electricity rates resulting from these expensive new plants were leading to consumer unrest and even some shutdown of industrial processes in the region. Figure 2-1 also shows that Bonneville's wholesale rates increase by 500 percent between 1980 and 1983, primarily as a result of the cost of the Washington Public Power Supply System plants.

Other factors also cast a new cloud on the regional power picture. The region entered its deepest economic recession since the depression of the 1930s. At the same time, due to low world aluminum prices, a significant portion of the aluminum production capacity in the Northwest shut down, temporarily exacerbating power surpluses. Other traditionally reliable, large industrial power loads, such as the wood products industry, also dropped off. As a result, electric load during this period actually declined. Bonneville and the region's utilities suddenly found themselves with more power than they could sell.

The Northwest Power Plan: Planning for Flexibility

In April 1983, the Council adopted its first 20-year power plan. That plan spelled out a new kind of planning strategy and set significant new directions for the Pacific Northwest.

The plan addressed the surplus of electricity in the region and focused on preventing lost opportunities to the region. Lost opportunity resources are cost-effective resources which, if not secured , could be lost forever to the region. The primary example is incorporating energy-efficient features into new buildings when they are constructed, since many of these measures cannot be installed later, and the building will consume energy long after the surplus is over.

The plan called for few new resources to be acquired. Instead, it emphasized the need to develop the capability to deliver energy conservation in the commercial, industrial, governmental and agricultural sectors. The plan also called for continued capability in the residential sector with an emphasis on programs to reach low income and renter households.

In accordance with the statutory priorities established in the Act, the plan relied primarily on conservation, because improving energy-efficiency costs considerably less than building new thermal resources.

Like the 1983 plan, the 1986 plan emphasized lost-opportunity conservation and called for no near-term development of new resources except those which are cost-effective and could be lost to the region if they are not secured. In addition, that plan emphasized the following priorities: a stronger regional role for Bonneville; development of conservation on a regional basis; strategies to make better use of the hydropower system; building conservation capability in all sectors; demonstration of the cost effectiveness of renewable resources so they are available before the region has to build new thermal generating resources; development of an acquisition process to secure resource options and demonstrate the purchase of conservation and generating resources so they can be available when needed; equitable allocation of costs for two unfinished nuclear plants and elimination of barriers to their completion; and study of electrical power sales and purchases between regions. These efforts were designed to prepare the region to meet future electric energy needs.

Key to most of the priorities in the 1986 plan was cooperation among power organizations, both public and investor-owned.

1985-1990: The Region Prepares for the Future

Since the Council adopted its 1986 plan, the region's economy has boomed and electric load growth has averaged 4.4 percent. In 1986, the regional surplus was approximately 2,500 megawatts. Today, the region has just enough firm resources to meet its current energy needs. The region is facing major decisions on investments in new conservation and generating resources to meet its future needs.

During the past five years, Bonneville, the region's utilities, and state and local governments have made significant strides in preparing the Northwest for the challenges we face.

Bonneville and utility programs have saved an estimated 350 megawatts of energy at less than half the cost of the same amount of power from a coal plant. If the same amount of power was produced from a coal plant, the Northwest would spend $1.4 billion more than the cost of conservation over the life of the plant.

The federal, state and local governments, in cooperation with Bonneville and the utilities, have adopted new efficiency standards for new buildings and appliances. Over the next 20 years, these actions will save an estimated 800 megawatts in the high demand forecast. State governments also have implemented energy-efficiency programs that have saved an additional 200 megawatts of electricity.

The Council developed model conservation standards in 1983, at the direction of the Northwest Power Act. All of the Northwest's utilities now promote efficiency through practical programs and incentives. In addition, approximately 120 local governments throughout the Northwest have adopted the standards as part of their building codes, and in February 1990, Washington became the first state in the Northwest to adopt the full model conservation standards for residential construction.

Idaho also recently adopted a statewide energy code that will improve building practices substantially. After the code takes effect on January 1, 1991, Idaho utilities will be prohibited from serving new homes that have not obtained permits guaranteeing compliance with the new code.

The state of Oregon amends its statewide building code through an administrative process every three years. A code providing energy savings equivalent to the model conservation standards currently is proposed for adoption in 1992. The proposal already has received approval from two of the three agencies involved.

In 1989, Montana used an administrative procedure to adopt a more energy-efficient residential building code. In addition, Montana is conducting a statewide education program to move construction practice toward the level required by the model conservation standards.

The Northwest has been a leader in the country and the world in integrated least-cost planning. The Council, Bonneville, utilities and other regional interests have worked together to develop common analytical tools and improve information on energy use, forecasting, and new resources. For the past two years, the Council and Bonneville have developed a joint forecast of future electricity needs and joint estimates of the cost and future supply of conservation and generating resources.

The utility regulatory commissions in Idaho, Oregon and Washington now require the investor-owned utilities they regulate to prepare resource plans similar to the general outlines of the Council's plan. All of the region's investor-owned utilities have completed or are developing such plans. Several utilities are working on their second plan.

In addition, a number of public utilities have developed integrated least-cost plans and participate in the development of Bonneville's Resource Program. All of the public utilities have developed conservation plans as part of Bonneville's programs.

As a result of all these efforts, there appears to be a general consensus on the data and analysis, and the focus has shifted to implementation of the region plan.

Also, during this period, the costs of electricity have generally stabilized and Bonneville's rates have actually declined after adjusting for inflation.

All of these accomplishments will help the region meet the challenges of the 1990s. Unfortunately, there also are areas where the Northwest fell short of achieving the objectives of the past plans.

One of the objectives was to test and perfect conservation programs that could be ready for aggressive implementation when the region needed more power. Bonneville and the region's utilities have run pilot programs in the commercial, industrial and agricultural sectors. But more work is needed before the region has the capability to capture all the cost-effective energy efficiency in all sectors of the Northwest economy.

Another objective of previous plans was to build up an inventory of resources with short lead times that could be used to meet future load growth. The Creston coal project has successfully completed siting and licensing, and the Washington Energy Facility Site Evaluation Council has extended the site certificate for the project. No other large generating projects have completed the pre-construction phase, although several hydroelectric sites have been licensed and could be developed within several years.

State siting organizations in Montana, Oregon and Washington have modified their procedures to allow resource developers to delay construction of a resource after receiving permits, site certification and licenses. However, a number of significant contractual, legal regulatory and institutional issues must be resolved before decisions to site, license and design a resource can be separated from decisions to begin construction.

Some of the legal barriers surrounding the Washington Public Power Supply System plants have been resolved, but a number of significant issues remain that raise questions about whether those two plants could be completed if they were needed.

Finally, little progress has been made in demonstrating the cost-effectiveness of renewable resources in the Northwest. Bonneville has proposed to cosponsor a geothermal demonstration project. The Council, working with broadly representative advisory committee, has proposed a research, development and demonstration agenda for geothermal, wind and solar powered resources.

Given the status of the region's conservation programs and the current inventory of resources with short lead times, the region can only support about one percent annual growth in electricity use over the next five years. If electricity growth is higher than that, the region will have a deficit of firm resources and it will need to rely on less reliable nonfirm power and purchases from outside the Northwest.

The lessons from the 1980s are clear: the future is very uncertain and it is very important to invest in activities that will prepare the region to meet whatever happens. The Council's planning strategy and Action Plan respond to these lessons.

CHAPTER 3

THE COUNCIL'S PLANNING STRATEGY

Chapter 3
Table of Contents

Page No.

The Council's Goals

Because the future is uncertain and conditions are likely to change, flexibility and risk management are underlying concepts throughout the Council's planning strategy.

The overall goal of the power plan is to ensure that the region can provide reliable electrical energy services at the lowest cost, while at the same time minimizing the risk of future uncertainties in the cost and supply of energy services in the Northwest.

The plan would achieve that goal by planning for sufficient resources to meet the region's future energy needs under varying conditions of growth and service requirements.

The Council seeks to balance the sometimes competing attributes of lowest cost, highest reliability, and least exposure to risk. The Council believes this plan, if fully implemented, will meet the region's electric energy needs at the lowest cost and lowest risk to the economy and environment of the Northwest.

The Council developed this electrical power plan with the following specific goals in mind:

- provide the region an adequate and reliable supply of electrical energy service at the lowest possible cost;
- select resources following the cost-effectiveness principles and priorities in the Northwest Power Act;
- develop a flexible strategy so that the plan can be modified as conditions change and new information becomes available;
- encourage the greatest rate predictability and stability for the region;
- evaluate all resources from a total regional system perspective and ensure their compatibility with the existing power system;
- select resources with the least adverse impacts on the environment, or those with adverse environmental impacts which can be mitigated; and
- select resources that are consistent with protecting and enhancing fish and wildlife, and that mitigate power system impacts on fish and wildlife.

Integrated Least-Cost Planning

Integrated least cost planning means ordering resource acquisitions in such a way as to result in the lowest overall total societal cost to the region. But it means much more than the cost to build and operate a resource. It also means lowest cost in terms of environmental consequences, and lowest cost in terms of risk management. That is, lessening the risk of overbuilding or underbuilding resources when you have to deal with an uncertain future.

Economic and Load Projections

The Council begins its planning process with a thorough analysis of the region's demographic trends, economic development potential and existing energy demands. It uses these patterns of use and predicted growth to develop ranges of power demand for the next 20 years, rather than the single-point prediction used historically.

Resource Analysis

The Council then compares alternative resources on a consistent basis to determine which ones can most reliably and cost-effectively meet the region's energy needs. Electricity saved through efficiency improvements is considered a resource comparable to any generating resource.

Taking into account energy supplies already in the system, the Council then projects what mix of new resources might need to be acquired across the 20-year planning horizon to meet the region's energy future at the lowest cost to society. This mix, called the resource portfolio in the Council's plan, reflects an effort to reduce the risks of overbuilding or underbuilding to an acceptable level. Finally, the Council develops a plan of specific actions that should be taken in the near term to meet the region's long-term energy needs.

The keystone of the Council's planning philosophy, is the expressed recognition of the uncertainty surrounding virtually every aspect of energy planning. Instead of fixing on a single-point prediction of the region's energy future, the Council's methodology embraces a range of possible futures, as described in more detail below.

Public Review

An important reality check in the Council's least-cost planning process is public involvement. The Council forms broadly representative advisory committees to review the forecasts and resource assessments. The details of this analysis are published and circulated, and public comment is taken at the Council's regular meetings as well as in writing. This preliminary analysis encourages organizations and individuals to challenge the assumptions and methodology used by the Council and improves the quality of the final product.

The Council works with all interested organizations in the region to develop commonly accepted analytic tools. As a result, regional debates can focus on important policy considerations rather than on differences in the computer models used by various organizations. In addition to improving the quality of information and focusing policy debates, the Council's public process helps ensure that all interested parties share the same set of factual assumptions. This enhances communication and helps build a consensus for action.

The Council's Planning Process

In selecting the resources described in this plan, the Council followed the directions of the Northwest Power Act. The Act sets many guidelines for the Council's planning process. First, it requires the Council to produce a plan for developing resources, including conservation measures. The Council must consider environmental quality, compatibility with the existing regional power system, as well as protection, mitigation and enhancement of fish and wildlife. The Act also specifically requires that the Council develop and include model conservation standards designed to make electrically heated residences and new commercial buildings use electricity efficiently.

In accordance with the Act, the Council selects resources that are cost-effective. The Act defines a "cost-effective" measure or resource as one that is forecast to be reliable and available within the time it is needed, at an estimated incremental system cost[1] no greater than that of the least-cost similarly reliable and available alternative. Cost-effectiveness is a function of need, relative cost, reliability and availability. The plan is based on the premise that the region should buy only the resources that it needs. When the region needs power, it should buy the lowest-cost resources, counting all the costs involved on a consistent basis. And, the region should only depend on resources that are reliable and available when they are needed.

The Act requires the Council to give first priority to conservation, second to renewable resources, third to generating resources using waste heat or generating resources of high fuel conversion efficiency, and last to all other resources. Finally, the Act provides a 10-percent advantage in calculating the estimated incremental system costs for conservation measures.

1./ System cost is defined to be an estimate of all direct costs of a measure or resource over its effective life, including, if applicable, costs for distribution and transmission, waste disposal, end of cycle, fuel, and quantifiable environmental measures. The Council also is required to take into account projected resource operations based on appropriate historical experience with similar measures or resources.

Step One: Dealing with an Uncertain Future

The planning process starts with the recognition that the future is uncertain, and that electrical energy needs cannot be predicted with any precision. The Council has chosen to deal with this uncertainty by defining plausible boundaries for the region's energy growth. To do this, the Council develops a range of high, medium-high, medium, medium-low and low electrical load growth scenarios over the next 20 years. The region's actual demand for electricity is most likely to be between the medium-high and medium-low boundaries.

The high forecast in the Council's range projects an average annual growth rate of 2.5 percent. This outcome would be the result of record regional economic growth relative to the nation over the next 20 years. In fact, it is based on assumptions that would produce relative economic growth over 20 years at a higher rate than any previous 20 year period in the Northwest's history. Employment in the region would grow 115 percent faster than projections for a fast-growing national economy.

The Council selects a high upper bound to ensure that the region has the ability to supply electricity for any potential need. While the Council develops an inventory of actions which would permit acquisition of resources to meet this upper bound, the region will not build all these resources unless high growth actually occurs.

The lower boundary of the range forecast is an average annual rate of growth of -0.6 percent. It is based on assumptions that the region might grow more slowly than the rest of the nation, with employment growing significantly slower than a low national forecast. The economic assumptions in this forecast would be well below what the region has experienced historically.

The Council translates economic assumptions into corresponding electricity requirements using the best available demand forecasting models. Please see Volume II, Chapter 5 for details of the economic forecast and Volume II, Chapter 6 for the demand forecast.

The range forecast represents the prudent span of future energy use patterns and defines the magnitude and schedule of actions needed to meet that range of use.

The Council produces its best estimate of the existing resource base, including any known additions or reductions (e.g., resources nearing completion or retirement, and power contracts that expire or begin within the next 20 years). The existing resources and power transactions are described in Volume II, Chapter 4. Existing resources then are subtracted from the range of future electricity demands to determine the amount of conservation and generating resources needed.

Step Two: Comparing all Resources

Concurrent with development of the range of energy-use forecasts, the Council examines the availability, reliability and costs of all generating and conservation resources.

This approach explicitly recognizes that there is no demand for electricity per se, but rather for services, such as heating and lighting, which can be met either by improving the efficiency of electricity use or increasing supply. Measures that improve the energy efficiency of a building provide the same service (a comfortable place to live or work) and free up electricity that can be used to provide other services.

Environmental impacts are also assessed, and costs are included for adapting technologies to avoid or reduce to acceptable levels the impacts of each resource on the environment and on fish and wildlife. The Council also developed a method for analyzing other environmental costs and benefits. The Council also used judgment in weighing the non-quantifiable effects of each resource alternative.

The products of this analysis are "supply curves" for each resource. These curves estimate how many megawatts of a resource are available across a range of costs. In order to evaluate all resources on a comparable basis, all costs are calculated on a levelized life-cycle basis using 1988 levelized nominal dollars.

Resources are divided into "cost-effective" and "promising" categories. Cost-effective resources must use commercially available technology, have predictable and competitive costs and performance, and must use a demonstrated resource base. Development of the resource must not have institutional constraints (legal, financial or regulatory), and the resource must be environmentally acceptable according to current policies, laws, regulations and the Council's Columbia River Basin Fish and Wildlife Program. Promising resources may be considered for use in future resource portfolios if their availability, reliability or costs improve. The plan includes research, development and demonstration activities to promote the development of promising resources.

Volume II, chapters 7, 8 and 9 describe the conservation and generation resource analysis and environmental considerations used by the Council. Volume II, Chapter 16 describes the Council's research, development and demonstration recommendations.

Step Three: Selecting Least-Costly, Least-Risky Resources

The Council then analyzes the lowest cost combination of all resources that would be needed to meet the entire range of potential energy needs.

State-of-the-art computer models are used to simulate how each resource would operate within the existing power system to determine the actual costs the region is likely to incur. This analysis also determines the compatibility of each resource with the existing power system. Alternative resources are evaluated against hundreds of different load scenarios to simulate the uncertainty and volatility of future energy needs.

Non-discretionary resources (sometimes called "lost-opportunity" resources) are the first added into the Council's actual portfolio--the mix of resources included over the planning period. These are cost-effective resources whose timing cannot be scheduled or controlled by the power system. For example, the opportunity for incorporating energy-saving measures in new residential and commercial buildings will occur when the buildings are built. If the resources are not installed, the opportunity to save the energy will be lost. The power system cannot control the timing of these potentially lost opportunities, but it can take action to secure all cost-effective electrical energy savings at the time of construction. Next, discretionary resources--either conservation or supply--are scheduled to be acquired when they are needed.

Several resource characteristics have been identified as important in providing the flexibility to adapt to uncertainties. For example, the Council recognizes that resources with short lead times, small plant sizes and low capital costs can reduce risk. Resources that can be constructed and brought into operation quickly and in small increments give the region a much better chance of matching supply to energy needs. Resources that are correlated to load growth, such as conservation from building and appliance efficiency standards, also help reduce uncertainty by supplying increased energy savings as the population and economy grow.

Volume II, Chapter 15 provides a description of the risk assessment and decision analysis used by the Council.

Conservation: The Flexible Resource

The Council has found that conservation is a flexible resource that also can reduce uncertainty and risk. The Northwest has a large supply of potential conservation measures which cost much less than building a new thermal power plant.

Conservation programs to improve the efficiency of new buildings tend to track load growth. During rapid growth, more buildings are built and the energy that is saved reduces the need for generating resources. During periods of slow growth, fewer buildings are built and thus less money is expended on these programs.

Programs to improve the efficiency of existing buildings and other electricity uses also are flexible. Once a program has been developed and tested, it can create savings relatively quickly. These savings can be developed in small units and can be timed to match growing power needs. If the region's electrical energy needs grow rapidly, the conservation programs can be accelerated. If slower growth occurs, they can be maintained at a minimum level. While conservation programs are capital intensive, the expenditures are usually simultaneous with the savings. Conservation programs can be paced to deliver the needed amount of savings much more easily than new central station power plants.

An added benefit to conservation is that it helps reduce uncertainty. Because more savings are available in high load growth, conservation actually reduces the range of future energy needs. In addition, well insulated buildings and energy-efficient industrial plants are more resistant to changes in energy prices. Therefore, they are less likely to contribute to fluctuations in power demand or switching to another fuel.

Shortening the Lead Time for Generating Resources

It is likely that the Pacific Northwest will need resources in addition to conservation. The Council has been working to improve the flexibility of generating resources in order to reduce the risk they pose for utility systems and ratepayers. The key element of the concept is the explicit recognition of at least two decision points for a long lead-time resource. The first is a decision to initiate engineering and siting. The second decision point is to begin construction.

Under this two-step approach, a resource would move through the time-consuming but relatively inexpensive siting, design and licensing stages, after which it can be placed in a "ready condition." In that condition, the project could be constructed, placed on hold, or terminated, depending on the demand for electricity. For this concept to be successful, the Bonneville Power Administration or a utility would need to provide financial assistance to a resource sponsor in exchange for the right to decide when conditions warrant beginning construction. This concept is similar to an option contract for a piece of land. The developer pays for the future right to develop the land. In power planning, such options would provide a relatively low-cost inventory that would allow the region to be ready for high growth rates without prematurely committing to build to those rates.

The cost of design, siting and licensing is typically very small compared to the costs associated with constructing a resource. Completing these pre-construction activities can substantially reduce the lead time of resources. By having a licensed or readily licensable resource effectively "on hold," the period over which electricity needs must be forecast could be reduced to the resource construction period, which may be as little as half of the total time that is now needed. Figure 3-1 shows the cumulative costs of the pre-construction and construction phases for several resources. For example, the total lead time to site, license, design and construct a new coal plant is about 11 years. The activities of siting, licensing and detailed design would take four years and cost $24 per kilowatt, compared to the $1,325 per kilowatt for the construction phase. It then would then take another six years to complete construction. Thus, the effective lead time of a coal plant can be reduced by four years for approximately 2 percent of the total potential cost.

Resource Cost and Timing

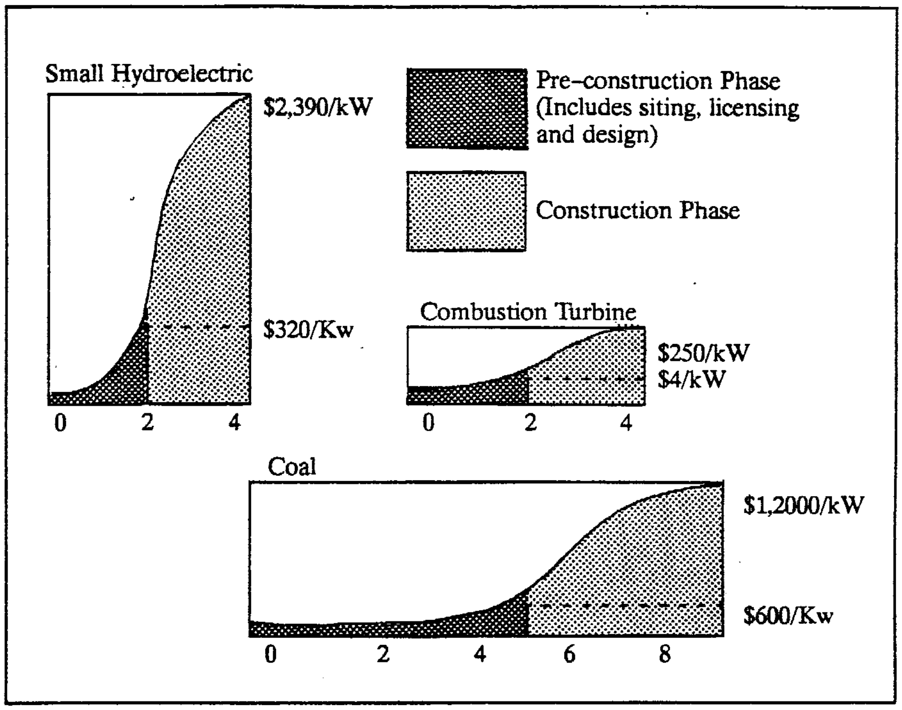


Figure 3–1
Cost and Timing of Resource Pre–Construction and Construction

Separating the decisions related to construction from those of pre-construction is critical. The objective of an effective risk management strategy is to move decisions involving the commitment of large sums of capital as close as possible to the anticipated time power will be needed. This will significantly reduce the likelihood of beginning construction on a project that is not needed. Another benefit of this approach is its potential for reducing environmental degradation. For example, if generating plant construction can be postponed until need is more certain, the accompanying environmental impacts also can be postponed and, if the plant is not needed, they can be avoided. This approach will have less effect on the environment than building and operating resources that may not be needed.

The Council believes that the region needs to secure projects that have been sited, licensed and designed. These resources would be needed to meet a very high level of economic growth. If the region actually experiences lower growth rates, some of these projects would be delayed or even abandoned at a minimal cost to the region. This concept is comparable to an insurance policy--paying low-cost premiums to be prepared for a high-cost event. It improves the region's ability to match energy supply to actual demand and reduces the chance of overbuilding resources, an event which historically has been very costly.

Utilities need to be able to recover the costs for siting, licensing and design activities to make a second decision point possible. These changes in existing regulations would allow a utility to be relatively indifferent about whether the plant is actually constructed. Without changes in utility regulation, the utility cannot recover the pre-construction costs until the plant is built and operating, thus precluding a second decision point.

The Council has identified three specific ways to reduce lead time, each of which provides the region with ways to limit future power costs:

- Resource banking: A resource could be sited, licensed and designed. At the end of the pre-construction process, a second decision would be made to construct the resource or put it on hold until it is needed.

- Callback provisions on power sales: Another way to provide flexibility would involve the sale of surplus power from a new or existing resource. Contract provisions would allow the power to be called back with some notice. These kinds of transactions could provide a regional benefit by generating revenue that reduces power costs in the Northwest. At the same time, they would avoid situations where resources are sold for their entire lifetime, potentially forcing the region to build new resources to meet its own needs.

- Use of existing resources: In response to temporary resource needs, the output of an existing resource could be acquired by paying for its operating costs (e.g., existing combustion turbines inside the region or excess generation in California or British Columbia).

It is important to note that, even with no additional ability to hold a resource over what current regulations allow, the explicit recognition of a significant second decision to begin construction has value to regional power planning. The Council has analyzed the value to the region of being able to option resources. It found that a two-stage decision-making process could save the region $700 million across the range of future load growth. Separate decision points in resource development will improve the region's ability to minimize the cost and risk associated with matching resources to load growth.

The Council believes that shortening resource lead-times has great promise to provide the region additional flexibility in meeting its resource needs at the lowest risk and cost. To establish the practicality of this concept, the Council, Bonneville, utilities and other resource developers have been working to identify and resolve institutional, regulatory and legal barriers to its successful operation. The state energy siting organizations in Montana, Oregon and Washington have incorporated this concept into their procedures. Unfortunately, there are still significant contractual, legal, regulatory, and institutional issues that need to be resolved before this concept can be fully implemented. The Action Plan includes a number of activities to address these problems.

Step Four: Policy Considerations

In evaluating the cost-effectiveness of both non-discretionary and discretionary resources, there are other significant attributes that must be included concerning the cost-effectiveness and appropriateness of each resource included in the plan. In deciding on the cost-effectiveness of individual actions, the Council included environmental concerns such as indoor air quality, acid rain, mining impacts, transportation, employment, and fish and wildlife, and the potential for global warming. In addition, some of the resources included in the Council's plan will help reduce future load growth uncertainty, and some resources are particularly flexible and, therefore, will help the region adapt to the wide range of uncertainty it is facing. The Council also made judgments about fuel diversity and the risks of fuel cost escalations. Finally, due to the significant uncertainty over the cost and availability of each resource included in the Council's portfolio, the Council must decide whether enough valid cost and performance information is available on which to make an informed judgment.

The Council has relied upon its demand forecasting, system analysis and decision models as aids to decision-making. It is important to emphasize, however, that the models are used to analyze decision alternatives and not to make decisions. The Action Plan and resource portfolio analysis presented in this plan outlines a program for managing the uncertainties and minimizing the risks faced by the region in its energy future. The Action Plan and resource portfolio reflect prudent judgments that necessarily go beyond the Council's analytic models.

Step Five: Designing the Final Resource Portfolio

Through its integrated resource analysis, the Council identifies a portfolio of all the resources that may be needed to meet the range of future loads, and ranks them so that the most cost-effective overall will be developed first. Similar to a financial investments portfolio, the Council selects a balanced mix of resources that will meet energy service needs at low cost over a broad range of future events. The portfolio provides a schedule, as well as a sequence, for making resource decisions. The costs associated with the portfolio are reinserted into the forecasting system to develop the final forecasts of electricity needs, which are used to fine-tune the final amount of resources needed.

The Council's planning strategy continues to be based on what has come to be known as a societal perspective. The objective of the Council's plan is to minimize the total present value system costs, whether those costs are borne by utilities, and thus reflected in electric rates, or by individuals, businesses and governments acting in their own self interest--in other words, the total "society" served. This approach does not necessarily result in the lowest electricity rates in the short term, but, rather, minimizes the total long-term cost of providing energy services for all ratepayers in the region.

This approach assures that all costs of resources are considered when comparing two or more resources, whether they are conservation or generation. Conservation resources can be acquired through financial assistance, regulatory standards or rate designs. In many cases, financial payments will be needed to acquire all cost-effective conservation. Bonneville and utilities should require conservation at costs up to the region's marginal cost. These payments should not be diluted simply to avoid rate impacts.

The resource portfolio is described in Volume II, Chapter 10.

Step Six: Action Plan

Based on the final portfolio of resources to meet potential energy needs over the next 20 years, the Council determined which actions are required in the next few years to prepare the region to meet its future needs. These actions are described in Volume I and Volume II, Chapter 1. Since these actions require significant effort and investment, the Action Plan is the most important part of the plan.

Although the plan is based on the best available information, the Council realizes that circumstances change, some cost-effective resources are not included in the plan and other resources may become cost-effective. Therefore, the Council carefully monitors electrical load growth and the cost and availability of resources to determine when modification of the plan and Action Plan is needed. The Council also expects that conservation and generating resources will be developed through a variety of competitive acquisition processes. These processes should identify resources that are cost-competitive with the resources included in the plan.

The Role of Conservation in Least-Cost Planning

The objective of integrated least-cost planning is to minimize the total societal cost of meeting whatever future energy needs may materialize, providing electric energy services in the most economically efficient manner. Because conservation's total cost to society is less than the cost of many other resources and because it can respond flexibly to changes in loads, conservation plays a major part in the Council's plan to achieve this objective. This section discusses some of the issues addressed by the Council in treating conservation as a resource.

The Council believes a least-cost plan should establish the value of conservation in order to select the conservation measures that will lead to a least-cost solution for society. It is of paramount importance that conservation and generation compete on a level playing field. Failure to provide a level field will result in society shifting scarce capital from other more productive economic development to the construction of inefficient resources.

Conservation as a Resource

The Council recognizes the possibility that purchasing conservation in lieu of generation can create inequity in the rates of participants versus non-participants in conservation programs. However, the Council believes that equity is best dealt with through rate design and ratemaking. Acquisition of virtually every type of resource has an impact on rates. Rate impacts that could result from acquiring conservation can be minimized through program design and by offering comprehensive conservation programs to all customers. Comprehensive programs reduce all customers' electricity bills. The Council believes that rates are important, but if rates are allowed to become the overriding objective of least-cost planning, the costs imposed on all society can be enormous.

One of the most significant issues addressed by the Council is the effect of conservation on non-participants. Some argue that conservation programs should not increase the electric rates of individuals who do not directly participate in the program. This is sometimes referred to as the "no-losers test." Conservation can affect rates because conservation programs do not increase the amount of power a utility sells. Therefore, even though conservation programs may cost less than generation, because its costs are spread over a smaller base, it can raise rates relative to generation.

The Council reviewed this issue and found that strict adherence to a no-losers test leads to a higher total cost for all ratepayers than the economic decision rules used by the Council. In choosing between conservation and generating resources, the Council selects all conservation measures that have a total societal cost[2] that is expected to be less than or equal to the expected marginal cost of all resources needed to meet forecast load growth. The following example compares the total system costs and rate impacts of an all-generation strategy, conservation under the no losers test, and the Council's approach. It shows that the Council's treatment of conservation results in the lowest present value cost to all ratepayers with minimal effects on electric rates.

An Analysis of Three Approaches to Meet Load Growth

Remembering that the planning goal is to provide energy service at the lowest total cost to society, this section provides a simple numerical example of how a growing power system could pursue several distinct resource acquisition paths. This example will show how different acquisition strategies affect total societal costs and also how non-participants (in conservation acquisition) are affected. These strategies are shown in Table 3-1. In this example, the base power system has an existing load of 100,000 gigawatt-hours[3] and is expected to grow by 10,000 gigawatt-hours.

2./ The total societal cost of conservation measures includes the direct costs of any equipment or materials that are required to achieve the efficiency gain, the labor required to install the improved equipment or materials, and the overhead and administrative costs required to manage and direct programs to acquire the measures.

3./ A gigawatt-hour is 1,000 megawatt-hours, or one million kilowatt-hours. The system used for this example has a total load of 11,400 average megawatts. For comparison purposes, the Pacific Northwest system has a current load of about 20,000 average megawatts or 175,000 gigawatt-hours.

Table 3-1
Alternative Resource Strategies

	Base Power System	Case I Generation Strategy	Case II Conservation Strategy "No-Losers Test"	Case III Marginal Conservation up to Marginal Generation
Existing load (gWh)	100,000	100,000	100,000	100,000
Load growth (gWh)	--	10,000	10,000	10,000
Conservation (gWh)	--	--	1,667	10,000
Generation (gWh)	--	10,000	8,333	0
Total load (gWh)	100,000	110,000	108,333	100,000
Existing rate (cents/kWh)	5.0	--	--	--
Existing annual revenue requirement ($ billion)	5.0	5.0	5.0	5.0
New generation (gWh)	--	10,000	8,333	0
Generation cost (cents/kWh)	--	6.0	6.0	--
Conservation cost (cents/kWh)	--	--	0.5	3.0
Generation revenue requirement ($ billion/year)	--	0.6	0.5	--
Conservation revenue requirement ($ billion/year)	--	--	.008	0.3
Total annual revenue requirement ($ billion/year)	5.0	5.6	5.508	5.3
Average rate (cents/kWh)	5.0	5.09	5.08	5.3
Total present value revenue requirement @ 8.15% ($ billion)	55.5	62.2	61.1	58.8

Three distinct strategies are analyzed to meet this load growth. The first involves the all-generation strategy. This proposal is to meet the entire 10,000 gigawatt-hour load growth with new generation estimated to cost 6 cents per kilowatt-hour. The second strategy involves a conservation strategy based on adherence to the "no-losers test" described later. The third strategy chooses all conservation up to the point at which the marginal conservation measure is estimated to cost the same as the marginal generation resource.

If the base power system serves its 100,000 gigawatt-hour total load at an average rate of 5 cents per kilowatt-hour, the annual revenue requirement is $5 billion per year. The present value of this annual requirement, using an 8.15-percent nominal discount rate[4] over a 30-year period, is $55.5 billion.

4./ The Council uses a 3-percent real discount rate and an assumed long-term inflation rate of 5 percent. These combine to a nominal discount rate of 8.15 percent.

Strategy 1: All Generation

Assuming the system grows by 10,000 gigawatt-hours and load growth is met with new generation costing 6 cents per kilowatt-hour, the annual revenue requirement will increase by $600 million to a total of $5.6 billion per year. This means that the average rate for all customers, under the generation strategy, would increase to 5.09 cents per kilowatt-hour. The total present value revenue requirement of the generation strategy increases to $62.2 billion. Acquiring new generation to meet the increased load, in other words, results in a $6.7 billion increase in the total present value revenue requirement.

Strategy 2: No Losers Test

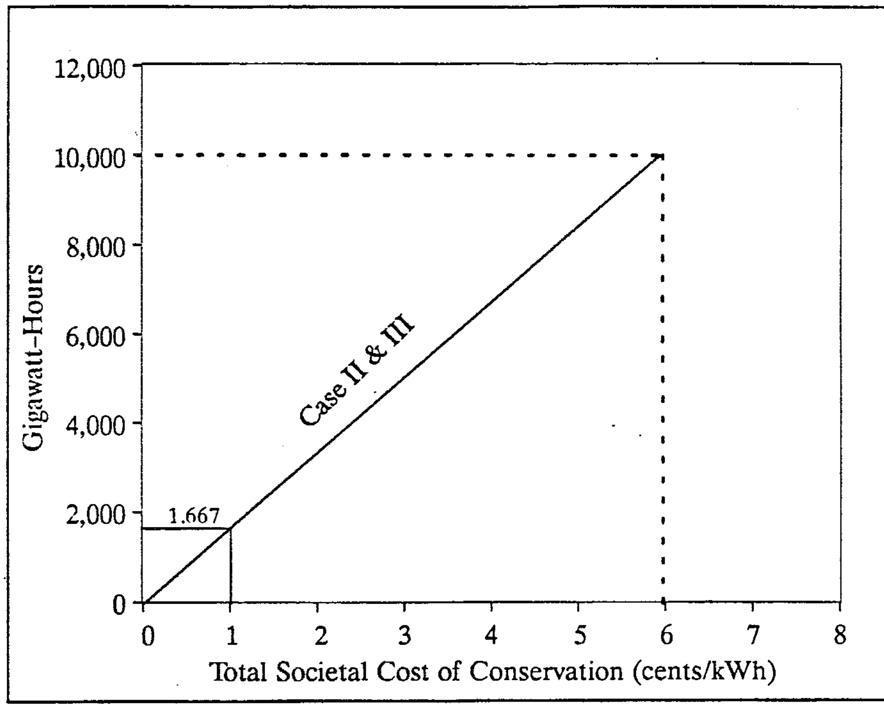
The second strategy involves selecting all conservation measures that do not violate the decision rule known as the "no-losers" test. This test, in its simplest form, limits conservation programs so that electric rates are no higher than if the same amount of power came from new generating resources. This test would restrict payment for new conservation measures to no more than the difference between the marginal cost of new generation and the current rate for the existing system. As in the previous example, the average rate of the existing system is 5 cents per kilowatt-hour. Subtracting this average rate from the marginal cost of new generation of 6 cents per kilowatt-hour leaves a maximum payment of 1 cent per kilowatt-hour for conservation measures.

Advocates of this rule base their position on two specific reasons. The first reason is to provide for equity among all the ratepayers of a utility. The second is that they have adopted-explicitly or implicitly-the objective of minimizing rates, as opposed to minimizing the total cost of energy services.

To demonstrate how conservation fits into utility planning, it is necessary at the outset to estimate the potential for energy savings available in any given system. One such conservation supply curve or function is shown in Figure 3-2. This curve shows the amount of load reduction that can be achieved through the purchase of energy-efficiency improvements at various cost levels. The main point of the hypothetical curve in Figure 3-2 is that the average cost of conservation is significantly less than the cost of the last measure selected. This characteristic of conservation is frequently ignored by those engaged in the "no-losers" debate. The supply function in Figure 3-2 shows that by purchasing all conservation measures with an expected total societal cost of less than 6 cents per kilowatt-hour, a total savings of 10,000 gigawatt-hours can be achieved.

Conservation Supply Functions

Figure 3-2
Assumed Conservation Supply Functions



For Strategy 2, the conservation achievable for less than 1 cent per kilowatt-hour is estimated to be 1,667 gigawatt-hours. Therefore, an additional 8,333 gigawatt-hours of generation are needed at 6 cents per kilowatt-hour. Since the supply function is assumed to be linear, the average cost of all conservation measures under 1 cent per kilowatt-hour is 0.5 cents per kilowatt-hour. The increase in the total annual revenue requirement for generating and conservation resources is $0.5 billion and $0.008 billion per year respectively. This means that the total annual requirement of the combined system is $5.508 billion per year with an average rate of 5.08 cents per kilowatt-hour. In comparison with the rate of 5.09 cents per kilowatt-hour found in Strategy 1, Strategy 2 has preserved a situation with a lower rate for all customers after the acquisition of conservation measures. With respect to the objective of minimizing the total present value cost of energy services, Strategy 2 has a lower present value system cost of $61.1 billion, $1.1 billion less than Strategy 1. Therefore, it appears that Strategy 2, involving the acquisition of all conservation measures which do not violate the "no-losers" test, helps both to reduce rates and to reduce the total present value cost of all energy services, in comparison with the "all-generation" strategy.

Strategy 3: The Council's Approach

Strategy 3 is to acquire all conservation measures with a marginal cost up to the marginal cost of new generation. The supply function in Figure 3-2 shows that it is possible to acquire 10,000 gigawatt-hours of energy-efficiency improvements at less than 6 cents per kilowatt-hour. Since the marginal cost of new generation was assumed to be 6 cents per kilowatt-hour, and the total amount of load growth was assumed to be 10,000 gigawatt-hours, it is possible to meet the entire load growth through conservation. Again, assuming a linear supply function, the average cost of all conservation measures that are less than 6 cents per kilowatt-hour is estimated to be 3 cents per kilowatt-hour. This means that the annual revenue required for the purchase of such measures is $300 million. The total annual revenue requirement of the system, therefore, increases to $5.3 billion and, since there has been a reduction of the total system load, the average rate increases to 5.3 cents per kilowatt-hour. Significantly, the total present value system cost for providing exactly the same energy services, as were provided in Strategy 1, has declined to $58.8 billion. By acquiring all conservation measures up to the marginal cost of generation, the present value of the total cost of meeting society's energy service requirements has been reduced by $3.4 billion when compared with the all-generation strategy in Strategy 1, and by $2.3 billion when compared with Strategy 2, which uses the "no-losers" test decision rule.

Conclusion of this Example

If a least-cost plan calls for the acquisition of all conservation measures with a total societal cost less than the cost of alternative resources, it is possible to significantly reduce the total present value cost of meeting society's energy service requirements. This may, in fact, lead to a higher electricity rate. As discussed below, the Council has adopted strategies to limit the effects of rate increases on utility customers.

In the examples shown above, a relatively large power system was assumed to grow by 10 percent. When this growth was met entirely through conservation measures that are cost-effective to society, rates increased by 4 percent. The reduction in the total present value system cost of $3.4 billion reduces the average consumer's electricity bill and is sufficiently large to compensate all ratepayers for the increased rates. A substantial amount of ratepayer capital is also freed up to be spent on other goods and services. Saving $3.4 billion in present value utility bills will have a substantial impact on the region's economy, to the benefit of all ratepayers.

Some people are concerned that if utilities offer to purchase conservation savings up to the avoided cost of new generation, consumers will invest in conservation measures that are not cost-effective from a total societal perspective. If utilities offer to pay up to 6 cents for every kilowatt-hour of efficiency improvement, then consumers may be expected to invest in measures that are forecast to cost much more. This happens because their bills are reduced by the current utility rate of 5 cents for each kilowatt-hour conserved and with utility financial assistance, they could invest in conservation measures up to the sum of the utility payment and the savings in their electricity bills. This would mean consumers might invest in conservation measures that cost up to 11 cents per kilowatt-hour (6 cents offered by utility financial assistance and 5 cent reduction in utility rates). Such an outcome would not be economically efficient and would divert significant resources from other uses. For this reason, great care must be taken to design conservation programs so only those measures that have met strict societal cost-effectiveness criteria are included in utility conservation programs.

Design of Conservation Programs

The Council's cost-effectiveness test first evaluates the total societal cost of all conservation measures. Conservation measures are evaluated in incremental steps, and each incremental improvement in efficiency is evaluated to determine its total societal costs. When these incremental improvements are ordered from lowest to highest cost, a supply function for each sector or subsector is created. These supply functions estimate the cost and performance of all efficiency improvements that are available for inclusion in a least-cost plan.

Conservation measures that cost more than the avoided cost limits established by evaluating the mix of all available resources are excluded from further consideration. The Council calculates the expected present value costs of all resources included in the resource mix. Any conservation measure that increases the expected present value costs above the minimum achievable level is excluded from the plan. For a more detailed discussion of resource cost-effectiveness, see Volume II, Chapter 14.

Substantial efficiency gains are possible by selecting only those individual conservation measures that cost less than the expected cost of other available and similarly reliable resource alternatives. There is a significant distinction between the identification of cost-effective conservation measures and the design of conservation programs to acquire these measures. The Council approaches these two issues sequentially.

In the design of conservation programs, the Council recognizes that many consumers are likely to understand and appreciate the benefits of the efficiency improvements that are cost-effective to the regional power system. These consumers are willing to participate financially in the installation of such efficiency improvements. To determine the effectiveness and cost of various conservation programs, the Council, the Bonneville Power Administration and the region's utilities have been developing and testing many alternative conservation program designs. This activity has demonstrated that many conservation measures can be acquired at substantially less than the estimated total cost of the measures.

Some have argued that conservation programs are not necessary--that the free market will promote economically justified efficiency improvements. This might be true if electricity rates were set at the true marginal cost of new resources and if consumers had access to information and capital.

In actual practice, electric rates are usually based on the average costs of the utility. Also, utilities generally have access to large amounts of low-cost capital and have historically invested in energy producing facilities and recovered their costs over the 30- to 40-year life of the plant. Consumers, on the other hand, have much less access to discretionary capital, and when they invest, they have a much shorter payback criteria. Research into consumer behavior indicates that consumer actions to invest in energy conservation generally reflect an implicit consumer discount rate that ranges from 20 to 100 percent. This translates to simple payback requirements of five to one years, respectively. High discount rates indicate the difficulty consumers face in evaluating energy conservation investments. Embodied in the high implicit discount rates are the consumer's time value of money, lack of information, inability to process information, riskiness of future returns versus known current costs, and other market barriers.

The Council has been careful to identify the barriers to efficient decision-making and has concentrated a major part of its efforts toward removing these barriers.

Bidding Strategies for the Acquisition of Conservation Measures

The Federal Energy Regulatory Commission and many states allow outside contractors to bid to secure conservation measures as a way of meeting a utility's load growth.

There does not appear to be any significant conceptual difference between soliciting bids for new generation or for conservation. The major concern is that only those measures judged to be cost-effective (on a societal cost basis) be allowed in a bidder's proposal. To accomplish this, the utility would need a comprehensive least-cost plan, with specific cost-effectiveness criteria for conservation measures available in each of the sectors in its service territory. Other conservation measures that have not been anticipated or included also could be submitted; however, the bidder should be required to include estimates of the total societal cost of these measures and to illustrate that they meet the overall cost-effectiveness criteria.

Since each conservation resource and generation resource has different characteristics and will probably be evaluated based on those characteristics, it makes no difference whether the bidding system is integrated or separate. The important point is that conservation be treated on a level playing field with generating resources and that the bidding system not inadvertently acquire resources with higher societal costs than other available resources.

Bidding for conservation measures would require detailed specification of the technical and economic characteristics that are desirable from the utility's perspective. These specifications should require that programs be designed to capture all cost-effective conservation so that bidders do not "cream-skim" only the low-cost conservation and create lost opportunities. If cost-effective conservation measures can be secured through bidding, it is possible that competition will drive the total costs of those measures down. For this reason, the Council believes that a wide variety of conservation delivery mechanisms should be investigated. Through bidding and increased competition, the process of acquiring conservation resources should become more efficient, and both the utility system and society will benefit.

The Council's goal in including efficiency improvements in its plan is to acquire all cost-effective conservation measures that have a total societal cost that is expected to be less than or equal to the expected marginal cost of resources needed to meet load growth. The process of establishing cost-effectiveness is an open competition among all resources. This establishes a clear and structured economic competition for all resources, and thereby encourages the development of those resources that can meet the region's collective needs at the lowest present value system cost.

A:EX/ED.DD9 Volume II, Chapter 3

CHAPTER 4

THE EXISTING REGIONAL ELECTRICAL POWER SYSTEM

Chapter 4
Table of Contents

Page No.

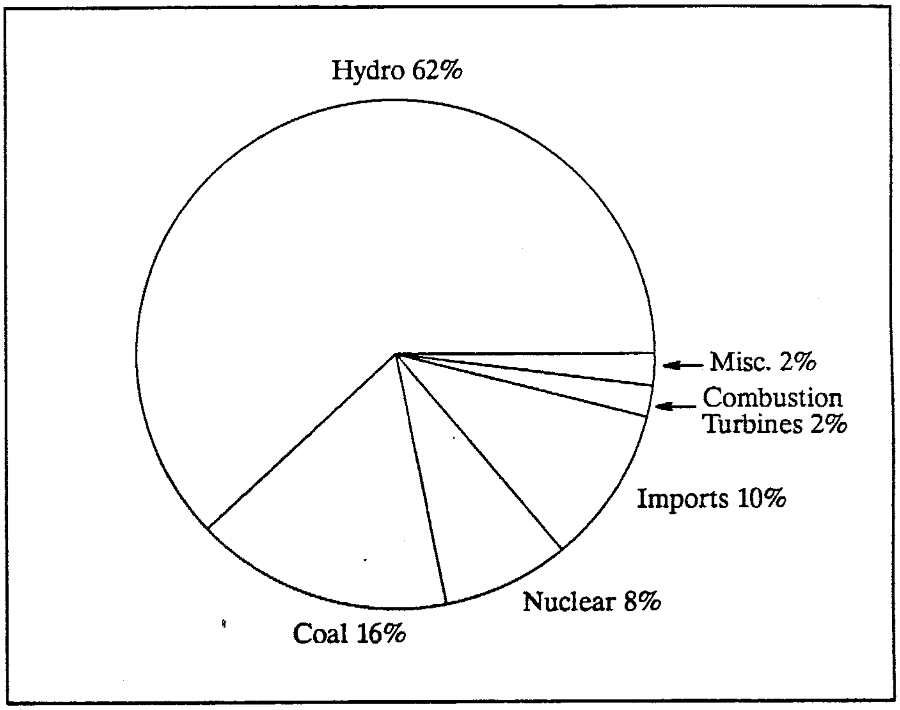
Regional Generating Resources

Currently, the Pacific Northwest electrical power system is capable of delivering about 20,100 average megawatts of guaranteed (firm) energy. Of that total, about 12,500 megawatts, or 62 percent, come from the region's network of hydropower dams. Coal plants account for a little over 3,200 megawatts, or 16 percent, and nuclear plants account for a little less than half that amount, or about 8 percent. Gas-fired turbines can produce about 1,250 average megawatts of energy,[1] but they are relied upon to produce only 456 megawatts of firm energy, representing about 2 percent of the region's total.

The region's utilities also have access to energy from resources outside of the Northwest. These utilities are either co-owners of out-of-region generating resources or have the contractual rights to part of their output. Firm energy imports, primarily from out-of-region coal-fired plants, supply about 10 percent of the region's total needs. The remaining 2 percent comes from smaller resources including cogeneration and renewable sources. Figure 4-1 illustrates the diversity in the region's firm energy generating capability.[2]

Firm Energy Resources

Figure 4–1
Existing Firm Energy Resources in the Northwest



1./ This is estimated by taking the peaking capacity of 1,468 megawatts and multiplying by an assumed availability factor of .85 which yields approximately 1,250 megawatts.

2./ Source: *Northwest Regional Forecast of Power Loads and Resources*, Pacific Northwest Utilities Conference Committee, March 1990.

Investor-owned utilities have access to about 45 percent of the firm resources in the region, followed by the Bonneville Power Administration, the region's Federal power marketing agency, with 43 percent and the public utilities with 12 percent. The breakdown of resource types by group is illustrated in Figure 4-2. Bonneville and the public utilities have access to about 76 percent of the region's hydropower, while private utilities own 90 percent of the coal generation.[3]

Energy Resources by Subgroup

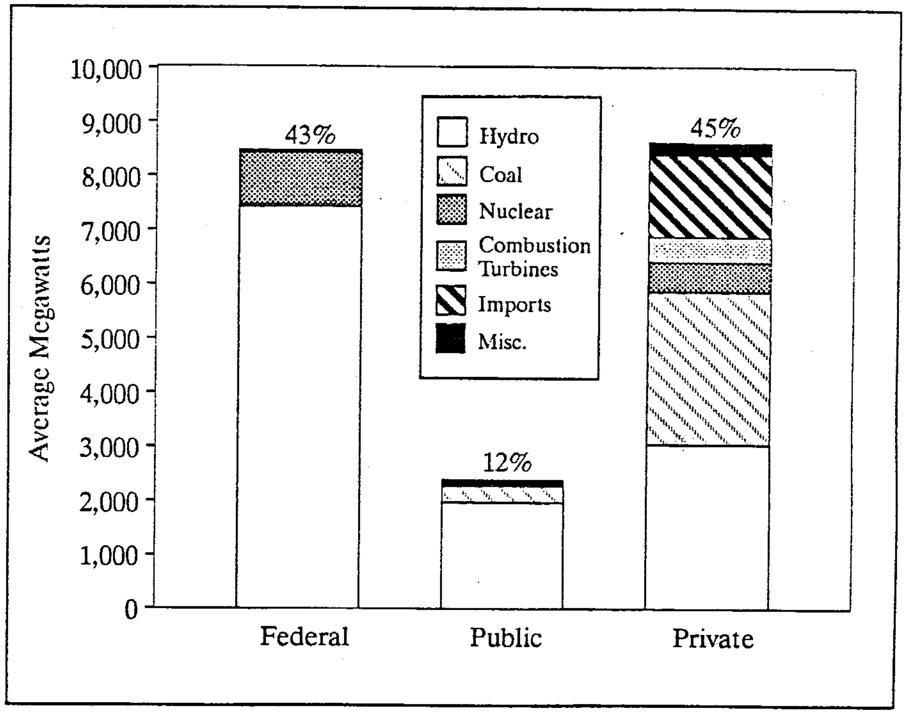


Figure 4-2
Firm Energy Resources by Subgroup

Utilities must plan to have enough resources, on average, to meet their annual energy needs. They must also have enough resources to meet their daily peak demand. This measure of a utility's resources is referred to as peaking capability. The hydropower system in the Northwest has an inherently large peaking capability. For any given peak demand hour, the hydropower system can provide almost 30,000 megawatts of capacity, which represents about 75 percent of the total for the region. Total peaking capacity for the region is a little over 40,000 megawatts. Bonneville has estimated that the region currently has about 2,600 megawatts of surplus capacity, most of which is on the federal system.[4]

3./ For more information on individual resources see Appendix 4-A.

4./ Marketable surplus capacity is calculated based on sustaining a 50 hours per week peak delivery and is limited by monthly and daily variations in water flow. See *1989 Pacific Northwest Loads and Resources Study*, Bonneville Power Administration, November 1989.

Hydropower

Hydropower is the cornerstone of the Northwest's energy system. The regional hydropower system includes the Columbia River, its tributaries and the coastal streams of Washington and Oregon. The Columbia River dominates the area, stretching over 1,200 miles from its source, Columbia Lake in Canada's Selkirk Mountain Range, to the Pacific Ocean. The basin covers about 260,000 square miles, of which 15.2 percent lies in Canada.[5] In Canada, the system includes the operation of the Duncan, Keenleyside and Mica reservoirs.

The Columbia River Treaty between the United States and Canada and the Pacific Northwest Coordination Agreement provide that the Columbia River hydroelectric system operate as one system in order to maximize the energy output. The operation at the Canadian reservoirs is designed to increase power generation downstream in the United States and to aid in the control of flooding. Storage at the Canadian projects is considered an element in the Columbia Basin power system and the downstream power benefits from this operation are shared equally between the United States and Canada.

The natural flow of the Columbia River peaks in spring and early summer, when the snowpacks melt. Energy production from the hydropower system depends on this flow of water. If reservoirs were not available to store water for later use, the energy derived from the hydropower system would rise and fall with the natural flow of the river. This would not be a very reliable or valuable source of energy especially since the peak in river flow does not coincide with peak electricity demand.

Reservoir storage, however, is limited to about 40 percent of the average January to July volume of water that flows down the river system. Thus, energy derived from the hydropower system still depends somewhat on fluctuations in the natural river flows. Guaranteed (firm) energy from that system must be based on the lowest annual runoff expected. In that way, planners can expect at least that much energy in any given year. This sequence of worst water conditions is commonly referred to as the critical period or critical water and is represented by the historical water conditions that occurred from 1929 to 1932. Based on this sequence, the amount of firm energy available from the hydropower system is estimated to be about 12,500 average megawatts.

Annual energy generation from the hydropower system varies widely, depending on annual rainfall and snowpack accumulation. Because water conditions for most years will be better than critical flows, the hydropower system typically will produce more than its firm energy generating capability. In good water years it can produce as much as 20,000 megawatts, but on average it generates about 16,600 megawatts. The approximately 4,100 megawatt difference[6] between firm energy capability and average energy production is referred to as nonfirm energy and is used to serve interruptible loads, to displace the generation from high-operating cost thermal resources and to sell to utilities in California.

5./ *Columbia River System Power Operation*, Pacific Northwest River Basins Commission, September 1981.

6./ Based on a 102-year water record.

Because of the availability of nonfirm energy, the hydropower system generates about 75 percent of the region's electricity, on average. Nonfirm energy often displaces generation from coal plants (because it is cheaper) so that actual electricity produced by coal plants is only about eight percent of the region's total requirements. Nonfirm energy also displaces the operation of gas-fired combustion turbines. In fact, turbines usually run only during the worst water conditions, thus providing less than one percent of the region's electricity, on average.

The amount of firm energy derived from the hydroelectric system also depends on the characteristics and operating constraints for each dam. When any of those constraints or characteristics are changed, the firm energy generating capability of the system changes. For example, the regional hydropower capability has been adjusted to take into consideration the effects of the Council's fish and wildlife program. An important element of this program is the water budget, which is a volume of water released in the spring to improve streamflows for downstream migration of salmon and steelhead. The water budget operation reduces the firm energy generating capability of the hydropower system by about 300 average megawatts.

Other constraints on the hydropower system include the fish bypass spill program, irrigation, navigation and other at-site operating constraints. All of these factors have been taken into account in determining the hydropower system's firm energy generating capability. Effects of the current fish bypass spill program reduce the firm energy capability by about 100 average megawatts.[7] The loss due to the spill program, however, is only temporary. Once mechanical bypass systems are in place, the spill program should no longer be needed, and the hydropower system firm energy generating capability will increase by about 100 average megawatts.

Large Thermal Resources

The character of the Northwest's power system has changed over the years. Between 1937 and 1960, hydropower was the only large-scale resource in the region. Since 1960, the region has built 14 coal plants and two nuclear plants, making what was once almost exclusively a hydroelectric system into one that now receives about one-quarter of its energy from thermal plants.

Large thermal resources currently available to the region include the Washington Public Power Supply System nuclear project 2 (WNP-2) and the Trojan nuclear plant. The combined generating capability of these two units is 1,493 average megawatts.

Of the 14 coal plants that supply the region with electricity, only three are located in the region; the Boardman plant in eastern Oregon and the two Centralia plants in Washington. The remaining coal plants are only partially dedicated to serving Northwest loads. These plants are generally located near coal sources to minimize fuel transportation costs. Four Colstrip coal plants are

---

7./ *Balancing the Uses of the River*, Programs in Perspective, Bonneville Power Administration, September 1989.

located in Colstrip, Montana, four Jim Bridger coal plants are near Rock Springs, Wyoming, two Valmy coal plants are in Nevada and the Corette coal plant is in Montana. The total generating capability of these 14 coal plants is almost 7,000 average megawatts but firm energy available to the region amounts to only 3,203 average megawatts. More information about the existing thermal plants can be found in Appendix 4-A.[8]

Combustion Turbines

Because combustion turbines have low capital costs and high operating costs, they are best used as peaking resources; that is, resources that are used only during times of exceptionally high electricity demand. Because of the hydropower system in the Northwest and its inherently large peaking capacity, turbines are rarely used as peaking resources, although areas exist within the Northwest that have peaking limitations.

As firm base-load resources, existing turbines would not be cost-effective unless used in conjunction with the hydropower system.[9] In that mode of operation, turbines are often displaced by cheaper hydro nonfirm energy, lowering the overall operating costs of the turbines. The Council has recommended the use of combustion turbines as one method of better using the hydropower system.[10]

The region's gas-fired combustion turbines have a peaking capacity of 1,468 megawatts. If no restrictions were placed on turbine operation and assuming an unlimited supply of fuel, they could provide about 1,250 average megawatts of energy to the region. In 1978, the Powerplant and Industrial Fuel Use Act limited the use of turbines. Combustion turbines could be run for peaking purposes or for system reliability, but, in general, were limited to 1,500 hours of operation per year. Taking these and other limitations into account, the net energy available to the region was about 200 average megawatts.

The Fuel Use Act has since been amended to allow unrestricted operation of combustion turbines under certain conditions. Utilities can declare that their turbines could be run with alternate fuels if natural gas becomes unavailable or too expensive. Utilities then could use turbines as base-load plants. With the exception of Portland General Electric's Bethel plant, all gas-fired turbines in the region have applied for and received unrestricted status.[11]

8./ Some of the generation from out-of-region coal plants that serves regional demands is categorized as imported energy.

9./ Actually, in terms of cost-effectiveness, newer technology combined-cycle plants are very competitive with coal plants at low gas prices.

10./ *1986 Northwest Conservation and Electric Power Plan*, Volume Two, Chapter 7 and *Better Use of the Hydropower System*, Staff Issue Paper #89-37, October 16, 1989.

11./ Bethel's operation is limited to 2,000 hours per year during specified hours of the day only.

Assuming no limitations on fuel supply and an average availability of 85 percent, the net firm energy available to the region is a little more than 1,250 average megawatts. Currently, utilities are declaring only 456 average megawatts as firm combustion turbine energy. Utilities have been reluctant to rely on combustion turbines as firm energy resources primarily due to the volatility of gas prices and the uncertainty in gas availability. By counting too heavily on turbines, a sharp increase in gas prices accompanied by poor water conditions could have a drastic effect on rates.

Out-of-Region Transactions

Due to interconnecting transmission lines between regions, utilities can look outside of this region to sell energy in times of surplus or to purchase energy during times of need. The total firm resources available to this region include the net effect of these transactions. Transmission interconnections also support sales of nonfirm energy to other regions. Nonfirm energy sales, however, do not affect firm regional resources.[12]

Interregional transactions involve the transfer of energy and/or the sharing of generating capacity between utilities in different regions. Capacity is defined as the maximum power output that a generating plant is designed to produce continuously. A utility may purchase the rights to this capacity from an out-of-region utility system in order to ensure that it will have adequate generation to meet its daily peak demands. The purchasing utility may never call upon that resource for power, but it pays a fee for the right to the generation, even if no energy is ever delivered. If energy is delivered during peak hours, an equivalent amount of energy is then returned to the selling utility during the off-peak hours. This type of transaction is more predominant for utilities whose firm resource mix is made up primarily of thermal resources. Most transactions combine capacity purchases with energy transfers.

Although interregional transactions involve only two basic commodities--energy and capacity--they may be packaged in many forms. Typically, transactions fit into five basic categories:

- Capacity Sales. Payment is made in dollars for capacity guaranteed during the peak demand hours of the day. If energy is delivered, an equivalent amount of energy is returned to the sending utility during the lightly loaded hours of the night and on weekends. No net energy is transferred between regions over the specified period, usually a week.

- Capacity/Energy Exchanges. This transaction is similar to a capacity sale, but payment for capacity is made in energy instead of dollars. As in a capacity sale, capacity is provided during the peak demand hours of the day. If energy is delivered, an equivalent amount of energy is returned to the sending utility. Payment for the capacity provided is made in the form of

---

12./ For further information about out-of-region sales, see the Western Electricity Study paper *Interregional Transactions*, Northwest Power Planning Council, December 28, 1987 and *Adequacy of the Northwest's Electricity Supply*, Northwest Power Planning Council, April 13, 1989.

additional energy returned by the purchasing utility to the sending utility. This additional energy may be returned during the same week or during a different part of the year. This type of transaction represents a net energy import for the region.

- Seasonal Exchanges. Capacity and/or energy is provided to a utility during a specified part of the year. An equivalent amount of capacity and/or energy is later made available to the sending utility during a different part of the year. Usually, in these arrangements, no money is exchanged. This type of transaction is most beneficial for two regions that have system loads that peak in different seasons.

- Firm Energy Sales. Energy is purchased on a guaranteed basis. Firm energy sales can be either long-term or short-term. Transactions that span periods of time greater than 18 months are typically referred to as long-term sales. Energy may be delivered 24 hours a day or during the peak demand hours only. Sometimes energy is delivered only during a specified season of the year. Often these types of transactions also specify a maximum amount of capacity to be provided along with the equivalent energy amount.

  Long-term firm energy sales represent a net loss of energy to the selling region. Without recall provisions, these types of sales could force a region to acquire or develop new resources sooner than expected. If, however, the energy from these sales can be recalled when needed, the schedule for new resources would not be affected. By structuring long-term energy sales with recall provisions, a region can sell surplus energy without increasing the risk that new energy supplies will be needed any sooner.

  Long-term energy sales can also be structured so that, upon recall, they convert to capacity/energy exchanges (defined above). Under that type of contract, the selling region would realize a net energy gain.

  Recall provisions are only one way to protect a region from higher long-run marginal costs. Another way that is built into some current contracts is to price those sales so that if and when higher marginal cost resources are required, the extra-regional buyer bears the brunt of those costs.

- Economy Sales. Energy is delivered on an hour-by-hour and as-available basis, usually scheduled one day in advance. These transactions take advantage of the diversity that exists in short-term operating costs due to different fuel sources in different regions and the short-term variability in water supply in a hydroelectric system. These types of transactions are also referred to as nonfirm energy sales because the energy cannot be guaranteed.

Ever since the interregional transmission lines were built, Bonneville and other Northwest utilities have successfully marketed energy and capacity to California utilities under both short-term and long-term contracts. For the 1991 operating year, long-term energy contracts to out-or-region utilities add up to 598 average megawatts, increase to almost 800 average megawatts by the mid-1990s and then decline to about 300 average megawatts by 2010.[13]

13./ These values do not include the return of Canadian Entitlement energy to Canada. See Table 4-B-1 in Appendix 4-B.

Recallable contracts make up 270 average megawatts of the firm exports. The Bonneville Power Administration has three recallable contracts (totaling 237 average megawatts) and Pacific Power and Light has one (108 average megawatts). The two Bonneville contracts convert to capacity/energy exchanges upon recall. Bonneville has recalled the energy from these contracts for the 1990 operating year due to poor water conditions and the unexpected outages of thermal units. These contracts could revert to firm energy sales in subsequent operating years.

Most of the region's imported energy comes from out-of-region coal plants that are owned, in part by regional utilities. Imported energy for the 1991 operating year amounts to 2,047 average megawatts[14] and declines to 1589 average megawatts by 2010. Appendix 4-B summarizes all existing out-of-region transactions.

The Columbia River Treaty

The Columbia River Treaty signed in 1961 and ratified in 1964 by the United States and Canada provided for increased storage on the Columbia River. The downstream power benefits were shared equally between the two countries. The Canadians sold their share of the downstream power benefits to utilities in the Pacific Northwest because, at the time, Canada did not need the energy. That share of benefits, known as the Canadian Entitlement, is scheduled to be returned to Canada beginning in 1998. Under that agreement, the energy to be returned amounts to under 100 average megawatts in the first year and increases to over 500 average megawatts by 2004.

Uncertainty in the Existing Power System

The amount of electricity that the existing power system produces is not static. It depends on certain conditions and assumptions. It depends on the weather--on how much rain and snow falls. It depends on how different agencies and organizations operate the region's network of hydropower dams, on how much water they keep in reservoirs; on how much they release for fish migration, for irrigation or for other uses. It depends on the price and availability of coal, natural gas and other fuels. And it depends on federal and state regulations governing pollution and waste disposal at coal, nuclear and gas-fired plants. A change in any of these factors may alter the amount of power the region can expect out of its existing system.

This section provides a discussion of some of the factors that can alter the amount of energy available from the region's existing generating resources. This is not intended to be an exhaustive list. Many of the problems discussed here are not easily resolved, yet it is important to point out that uncertainty surrounds the existing system just as it does predictions of future demand and potential future resources.

14./ These totals do not include all out-of-region coal generation that serves regional demands.

Potential Effects of Endangered Species Proceeding

On April 2, 1990, the Shoshone-Bannock Tribe filed a petition under the Endangered Species Act seeking the designation of upper Snake River sockeye salmon as a threatened or endangered species. On June 7, four additional petitions were filed by other parties, seeking the designation of Snake River spring, summer, and fall chinook salmon and lower Columbia River coho salmon as threatened or endangered species.

The National Marine Fisheries Service has found that these five petitions present substantial information indicating that listing may be warranted. A decision on whether to propose listing of these salmon is expected within one year of the dates on which the petitions were filed. If the National Marine Fisheries Services proposes listing, a final decision on the listing, and a recovery plan, are expected within approximately one year of the notice of proposed listing.

At the invitation of Senator Hatfield of Oregon, a working group of interested parties, including federal agencies, has been convened and is working with the assistance of professional mediators to develop measures to improve the salmon runs and, if possible, avert a listing of the five stocks which are under consideration for threatened or endangered status. The Council is participating in this process.

It is not now possible to estimate the likely impact on the power system of additional measures to improve the salmon runs, and therefore this description of the existing regional electrical power system does not reflect any reductions in available hydropower which might result from such measures. In the event that better information about likely impacts becomes known before final adoption of this power plan, the Council will include this information in this plan and will adjust the resource estimates accordingly.

Potential Effects of Hydropower Relicensing

Non-federal hydropower projects are licensed for construction and operation by the Federal Energy Regulatory Commission. Approximately 70 of the 155 hydropower projects in the Northwest will require relicensing between 1990 to 2010. These projects represent approximately 2,950 average megawatts of firm energy.

A key aspect of the Commission's relicensing regulations is that renewed licenses will not automatically be issued to the current licensee. The relicensing procedures mandate extensive consultation with relevant resource management agencies. The procedures also extend consideration of project-related environmental effects to those that may occur outside the project's boundaries. These factors are expected to lead to in-depth consideration of project-related environmental effects and implementation of additional mitigation, especially at older projects, during the relicensing process.

The relicensing process would involve a re-evaluation of the use of the hydro project and a potential lowering of its generating capability due to non-power constraints such as fish survival. On the other hand, the relicensing process provides an opportunity for making efficiency improvements, which could lead to increased generation.

In addition to the factors on which competing applications will be judged, all applicants are required to submit adequate plans to protect, mitigate damages to, and enhance fish and wildlife. The rule treats this mitigation plan as a threshold requirement; that is, no applicant can receive a license unless the applicant fully satisfies this requirement, regardless of how the mitigation proposed by an applicant compares to that proposed by other applicants.

This may have significant effects on the cost and energy capability of older projects built at a time when environmental concerns were not as important as at present. Environmental mitigation measures may require additional capital investment or operating and maintenance costs, and may require additional in-stream flow, reducing the energy production of a project. In rare cases, license renewal might be denied for projects found to be unacceptable by contemporary standards.

Figure 4-3 illustrates the timing and amount of energy subject to relicensing. (Appendix 4-C contains more information.)

Firm Energy Capability

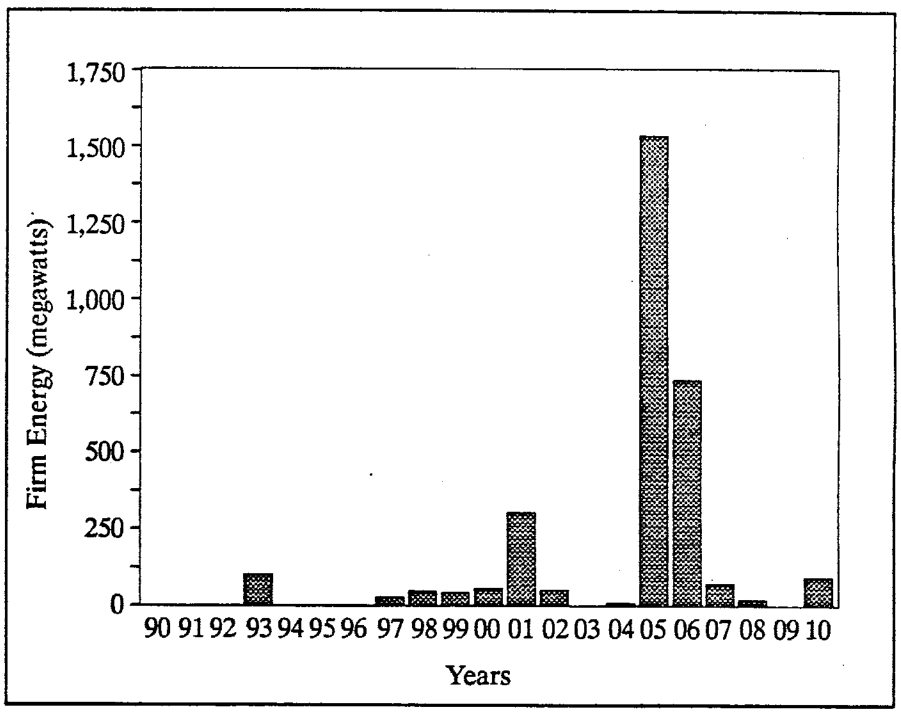


Figure 4-3
Firm Hydropower Energy Capability Subject to Relicensing 1990–2010

In previous plans, no assumptions were made concerning loss or gain in firm energy due to the relicensing process. Since the magnitude of any potential change is impossible to predict, the most reasonable action is to assume no change until more information is available.

Nuclear Spent Fuel Storage and Disposal

Spent commercial nuclear power plant fuel contains highly radioactive fission products and long-lived radioactive transuranic isotopes. The disposal of spent fuel must be managed carefully to prevent the release of these materials into the environment. Spent fuel may be reprocessed to remove the radioactive isotopes for recycling or special disposal; placed unprocessed in a permanent repository; or placed in interim retrievable storage pending the selection and development of permanent storage options.

Originally, the nuclear industry and the federal government planned to develop commercial reprocessing plants for the separation of fission products and transuranic materials from commercial spent fuel. Materials with no commercial use would be placed in permanent disposal facilities, while unburned uranium and transuranic isotopes would be recycled as refabricated nuclear fuel.

In the late 1970s, the United States abandoned the reprocessing option because of nuclear proliferation concerns, and chose to dispose of spent commercial fuel in permanent repositories. In 1982, Congress passed the Nuclear Waste Policy Act, making the federal government responsible for the ultimate disposal of high-level nuclear wastes, including spent nuclear fuel. Operators of nuclear plants were required to contract with the federal government for spent fuel disposal services as a condition of maintaining the operating license for their plants. Payment for this service was set at one mill per kilowatt-hour, with adjustments to be made as the costs of the program were better defined. The contract specifies that the U.S. Department of Energy will take title to the spent fuel and begin disposal operations not later than January 31, 1998.

Significant delays have occurred in the program, however, and progress continues to be disappointing. Opening of a national repository has been delayed until 2010. In the past, the Council has not had to act on this issue since both Trojan and WNP-2 have adequate on-site storage to last through 1998, the date when the U.S. government was to assume responsibility for the spent fuel. (WNP-2 can store spent fuel through 1998 and Trojan through 2007.)

It is unlikely that this issue will force the shutdown or derating of the existing nuclear plants. Temporary storage facilities, such as above-ground dry storage casks, have proven to be technically feasible and cost-effective. The cost of such actions is relatively small compared to other nuclear costs and is likely to be in the range of 1 mill per kilowatt-hour or less. The Council assumes, therefore, that some kind of on-site storage through the year 2010 will be utilized for both Trojan and WNP-2 and that the cost of such storage will be added to their respective operating costs.

Clean Air Act

The combustion of coal produces several airborne pollutants of concern. These include sulfur dioxide and oxides of nitrogen, precursors of acid rain. The Clean Air Act of 1970, along with the 1977 amendments, established federal controls on the release of these pollutants for new power plants. However, prior to 1990, existing power plants were generally exempt from any federal restrictions on emissions of sulfur dioxide and nitrogen oxides.

In late October, Congress passed the Clean Air Act Amendments of 1990. Title IV of the Act establishes for power plants a two-phase pollution control program which is intended to reduce sulfur dioxide emissions by 11 million tons annually in the year 2000, and to reduce emissions of oxides of nitrogen beginning in 1995. The 1990 Amendments are expected to affect 111 existing power plants, but it appears that only two affected plants, Centralia (in Washington) and Corette (in Montana) are located within the region. The other coal-fired plants within the region already are achieving emissions within the limits of the 1990 Amendments.

Under Phase I, by 1985 existing power plants must reduce emissions to not more than 2.5 pounds of sulfur dioxide per million Btu multiplied by the plant's annual average baseline fuel consumption in 1985-1987. During Phase II, which begins in the year 2000, the limit drops to 1.2 pounds. As of 2000, sulfur dioxide emissions from power plants are permanently capped at 8.9 million tons per year.

The Clean Air Act Amendments of 1990 contain a complex set of mechanisms for allocating emissions allowances. The emissions allowances can be applied to existing plants, banked, marketed, or used for capacity expansion. It is possible for a non-complying plant to continue in service without installing additional pollution control equipment if the utility acquires sufficient emissions allowances. Emissions allowances can be purchased from others or earned in a number of ways. For example, bonus allowances can be earned by reducing emissions below the required levels, or by meeting load growth with conservation or solar, geothermal, wind or biomass resources.

It is too early to predict how the region's utilities will choose to meet these new emissions requirements for their existing coal-fired power plants, and it is likely that the means of achieving compliance will vary among the plants. In order to provide some estimate of the cost of compliance for the region's two affected power plants in this power plan's modelling of existing resources, two assumptions were included in the cost of power expected to be produced by the Centralia and Corette plants: 1) that the plants will use a very low-sulfur coal or a high heat value low-sulfur coal beginning in 2001, and 2) that, starting in 1992, the plants will need to set aside one-half mill per kilowatt hour to purchase emissions allowances or pollution control equipment.

The costs of controlling nitrogen oxide emissions to current new source performance standards are relatively low compared to the cost of controlling emissions of sulfur dioxide. The Electric Power Research Institute has estimated that, for a new plant, flue gas desulfurization represents about 17.4 percent of the cost of the plant, compared to 1.3 percent for control of oxides of nitrogen. For this reason, it is unlikely that the revised nitrogen oxide release limits will significantly affect future operating costs or performance characteristics of existing coal-fired plants in the region, and no additional costs are assumed in the modelling of these resources. Nitrogen oxide control could be a more significant problem at combustion turbine and combined-cycle power plants, but it is too early to estimate what the costs of control might be at such plants.

Control of Carbon Dioxide Releases

Carbon dioxide releases from fossil fuel-fired power plants may be one of the major factors leading to an increase in atmospheric carbon dioxide and possible global warming. It may be necessary to control the production of carbon dioxide and other greenhouse gases to constrain global warming. The National Energy Policy Act, recently passed by the U.S. Senate, requires the United States to develop strategies for reducing emissions of carbon dioxide up to 20 percent by 2005. Also, the state of Oregon Senate Bill 576 requires state agencies to develop a strategy for reducing the emission of gasses that add to global warming by 20 percent by 2005.

In fossil fuel power plants, carbon dioxide is formed by combustion of the carbon contained in the fuel. Carbon combustion is one of the two principal chemical reactions (the other is combustion of hydrogen to form water) involved in the release of chemical energy of fossil fuel to produce heat. As such, the carbon reaction is inherent to the use of fossil fuels. It is more important for coal, with its high carbon-to-hydrogen ratio, than for oil or natural gas, which are progressively richer in hydrogen.

The release of carbon dioxide from fossil fuel power plants could be controlled by switching to hydrogen-rich fuels, such as natural gas; increasing plant efficiency; recapturing carbon dioxide using reforestation; reducing plant operation through conservation or substitution of other generating resources; or by use of flue gas recovery systems for carbon dioxide. Carbon dioxide recovery systems, while used in some industrial applications, have not been used for power plant applications. Power plant applications would be of far larger scale than any existing carbon dioxide recovery systems and, moreover, would present significant problems relative to the transport and disposal of the recovered carbon dioxide.

As in the case with sulfur and nitrogen oxides, any attempt to reduce these emissions will force the price of electricity to rise. Since no regulations currently exist governing the emission of carbon dioxide, no assumptions will be made concerning the potential effects to plant operation. The regional cost of increasing fuel cost by 25 percent, to simulate a carbon tax, is $350 million. More information on this analysis can be found in Volume II, Chapter 10.

APPENDIX 4-A

EXISTING REGIONAL GENERATING RESOURCES

KEY TO TABLES IN APPENDIX 4-A

Utilities/Operators

Baker	City of Baker
Bonners Ferry	City of Bonners Ferry
BPA	Bonneville Power Administration
Centralia	City of Centralia
Chelan	Chelan County PUD #1
Clark	Clark County PUD #1
Cowlitz	Cowlitz County PUD #1
CPN	CP National
Douglas	Douglas County PUD #1
EWEB	Eugene Water and Electric Board
GECC	General Electric Credit Corporation
Grant	Grant County PUD #1
Idaho Falls	City of Idaho Falls
IPC	Idaho Power Company
Lower Valley	Lower Valley Power and Light Company
MPC	Montana Power Company
Pend Oreille	Pend Oreille County PUD #1
PGE	Portland General Electric Company
PNGC	Pacific Northwest Generating Cooperative
PP&L	Pacific Power and Light Company
PSPL	Puget Sound Power and Light Company
Seattle	Seattle City Light
Snohomish	Snohomish County PUD #1
SPPC	Sierra Pacific Power Company
Tacoma	City of Tacoma Light Division
USBI	U.S. Bureau of Indian Affairs
USBR	U.S. Bureau of Reclamation
USCE	U.S. Corps of Engineers
USTC	United States Trust Company
WPPSS	Washington Public Power Supply System
WWP	The Washington Water Power Company

Status

PP	Preliminary Permit
LC	Licensed
EX	Exempted (from Federal Energy Regulatory Commission license)
POL	Power on Line (In-service)
UNC	Under Construction
PND	Pending
GTD	Granted

Table 4-A-1
Federal Hydropower Projects

	Operator	Nameplate Capacity (MW)[a]	Peak Capacity (MW)[b]	Average Energy (MWa)[b]	Critical Energy (MWa)[b]	In-Service Year
Federal Columbia River Power System:						
Albeni Falls	USCE	43	39	34	32	1955
Anderson Ranch	USBR	40	c	c	c	1950
Big Cliff	USCE	18	6	12	10	1954
Black Canyon	USBR	8	c	c	c	1986
Boise Diversion	USBR	2	c	c	c	1912
Bonneville	USCE	1,093	1,147	711	555	1938
Chandler	USBR	12	4	10	6	1956
Chief Joseph[f]	USCE	2,457	2,614	1,470	1,167	1955
Cougar	USCE	25	6	17	13	1964
Detroit	USCE	100	99	46	36	1953
Dexter	USCE	15	8	10	8	1955
Dworshak	USCE	400	460	239	177	1974
Felt	USCE	1	2	1	1	N/A
Foster	USCE	20	10	14	13	1968
Grand Coulee	USBR	6,494	6,678	2,321	1,916	1941
Green Peter	USCE	80	73	28	22	1967
Hills Creek	USCE	30	30	18	15	1962
Hungry Horse[g]	USBR	285	306	109	97	1952
Ice Harbor	USCE	603	693	324	215	1961
John Day	USCE	2,160	2,484	1,279	927	1968
Libby	USCE	525	492	218	175	1975
Little Goose	USCE	810	932	339	214	1970
Lookout Point	USCE	120	67	36	26	1954
Lost Creek	USCE	49	18	35	23	1977
Lower Granite	USCE	810	932	339	214	1975
Lower Monumental	USCE	810	932	320	202	1969
McNary	USCE	980	1127	831	654	1953
Minidoka	USBR	13	c	c	c	1909
Palisades	USBR	119	122	74	61	1957
Roza	USBR	13	10	7	5	1958
The Dalles	USCE	1,807	2,074	1,018	737	1957
Other Federal Hydropower:						
Big Creek	USBI	N/A	d	d	d	1916
Green Springs[e]	USBR	16	18	7	7	1960
Savage Rapids Diversion	USBR	N/A	N/A	<1	<1	1955
Wapato Drop 2	USBI	2	N/A	1	1	1942
Wapato Drop 3	USBI	1	N/A	<1	<1	1932

a From PNUCC, *Northwest Regional Forecast,* March 1990.

b Operating years 1991 through 2010 from PNUCC, *Northwest Regional Forecast,* March 1990. Peak capacity is for January.

c Joint peak capacity, average energy and critical period energy for Anderson Ranch Black Canyon, Big Cliff and Minidoka are 55 megawatts, 41 average megawatts, and 30 average megawatts, respectively.

[d] Totals for Flathead Irrigation Projects: 1-megawatt peak capacity; 0-megawatt average energy; and 0-megawatt critical period energy.

Contracted to Pacific Power and Light Company.

[f] Includes uprating, scheduled for completion by September 1986.

[g] Includes uprating, scheduled for completion by August 1992.

Table 4-A-2
Investor-Owned Utility Hydropower Projects

Project	Utility	Nameplate Capacity (MW)[a]	Peak Capacity (MW)[b]	Average Energy (MWa)[b]	Critical Energy (MWa)[b]	In-Service Year
Albany	PP&L	1	c	c	c	1923
American Falls	IPC	92	0	46	32	1978
Bend Power	PP&L	1	c	c	c	1913
Big Fork	PP&L	4	c	c	c	1910
Black Eagle	MPC	17	k	k	k	N/A
Bliss	IPC	75	75	50	45	1949
Brownlee	IPC	585	675	309	223	1958
Bull Run	PGE	21	22	12	10	1912
C.J. Strike	IPC	83	85	61	55	1952
Cabinet Gorge	WWP	200	230	124	100	1952
Cascade[j]	IPC	12	5	6	4	1926
Cochrane	MPC	48	k	k	k	N/A
Clear Lake	IPC	3	d	d	d	1937
Clearwater 1	PP&L	15	e	e	e	1953
Clearwater 2	PP&L	26	e	e	e	1953
Cline Falls	PP&L	1	c	c	c	1913
Condit	PP&L	10	c	c	c	1913
Copco 1	PP&L	20	f	f	f	1918
Copco 2	PP&L	27	f	f	f	1925
Eagle Point	PP&L	3	h	h	h	1957
East Side	PP&L	3	f	f	f	1924
Electron	PSPL	26	i	i	i	1904
Fall Creek	PP&L	2	c	c	c	1903
Faraday	PGE	35	43	23	17	1907
Fish Creek	PP&L	11	e	e	e	1952
Hauser	MPC	17	k	k	k	N/A
Hell's Canyon	IPC	392	450	247	177	1967
Holter	MPC	38	k	k	k	N/A
Iron Gate	PP&L	18	f	f	f	1962
John C. Boyle	PP&L	80	f	f	f	1958
Kerr	MPC	168	k	k	k	1938
Lemolo 1	PP&L	29	e	e	e	1955
Lemolo 2	PP&L	33	e	e	e	1956
Little Falls	WWP	32	g	g	g	1910
Long Lake	WWP	70	g	g	g	1914
Lower Baker	PSPL	64	63	45	38	1925
Lower Malad	IPC	14	d	d	d	1911
Lower Salmon Falls	IPC	60	68	34	29	1910
Madison	MPC	9	k	k	k	N/A
Merwin	PP&L	136	128	64	52	1931
Meyers Falls	WWP	1	1	1	1	1915
Milltown	MPC	4	k	k	k	1906
Monroe Street	WWP	7	g	g	g	1890
Moroney	MPC	45	k	k	k	N/A
Mystic Lake	MPC	10	k	k	k	N/A
Naches	PP&L	6	c	c	c	1909
Naches Drop	PP&L	1	c	c	c	1914
Nine Mile	WWP	12	g	g	g	1908
Nooksack	PSPL	2	i	i	i	1906
North Fork	PGE	38	54	26	19	1958
Noxon Rapids	WWP	467	536	210	148	1960
Oak Grove	PGE	51	49	30	26	1924
Oxbow	IPC	190	220	124	91	1961
Pelton	PGE	97	108	40	34	1957
Post Falls	WWP	15	g	g	g	1906

Powerdale	PP&L	6	c	c	c	1923
Prospect 1	PP&L	4	h	h	h	1912
Prospect 2	PP&L	32	h	h	h	1920
Prospect 3	PP&L	7	h	h	h	1932
Prospect 4	PP&L	1	h	h	h	1944
Rainbow	MPC	37	k	k	k	N/A
River Mill	PGE	19	23	13	10	1911
Round Butte	PGE	247	300	100	82	1964
Ryan	MPC	48	k	k	k	N/A
Shoshone Falls	IPC	12	13	11	10	1907
Slide Creek	PP&L	18	e	e	e	1951
Snoqualmie Falls 1	PSPL	12	i	i	i	1898
Snoqualmie Falls 2	PSPL	29	i	i	i	1910
Soda Springs	PP&L	11	e	e	e	1952
Stayton	PP&L	1	c	c	c	1937
Swan Falls	IPC	10	12	9	9	1910
Swift 1	PP&L	204	182	76	52	1958
T.W. Sullivan	PGE	15	16	14	14	1985
Thompson Falls	MPC	30	k	k	k	1915
Thousand Springs	IPC	9	d	d	d	1912
Toketee	PP&L	43	e	e	e	1950
Twin Falls	IPC	8	10	8	7	1935
Upper Baker	PSPL	94	92	42	35	1959
Upper Falls	WWP	10	g	g	g	1922
Upper Malad	IPC	8	d	d	d	1948
Upper Salmon A	IPC	18	20	18	18	1937
Upper Salmon B	IPC	17	18	16	16	1947
Wallowa Falls	PP&L	1	c	c	c	1921
West Side	PP&L	1	f	f	f	1908
White River	PSPL	70	62	36	27	1912
Yale	PP&L	108	112	65	52	1953

[a] From PNUCC, *Northwest Regional Forecast,* March 1990.

[b] Values for operating years 1991 through 2010 from PNUCC, *Northwest Regional Forecast.* Peak capacity is for January.

[c] Totals for Pacific Power and Light small projects: Peak, 33; Average, 27; Critical 26.

[d] Totals for Idaho Power Company Spring projects: Peak, 30; Average, 28; Critical, 29.

[e] Totals for Pacific Power and Light Umpqua River projects: Peak, 175; Average, 129; Critical, 97.

[f] Totals for Pacific Power and Light Klamath projects: Peak, 92; Average, 41; Critical, 22.

[g] Totals for Washington Water Power Spokane River projects: Peak, 155; Average, 117; Critical, 92.

[h] Totals for Pacific Power and Light Rogue River projects: Peak, 25; Average, 43; Critical, 35.

[i] Totals for Puget Sound Power and Light small projects: Peak, 72; Average, 55; Critical, 49.

[j] Includes 1984 expansion.

[k] Approximately 40 percent of the capability of Montana Power Company projects is available to serve regional load. In accordance with Northwest power planning convention, the output of these resources used to serve regional load is treated as import to the region.

Table 4-A-3
Publicly Owned Utility Hydropower Projects

Project	Utility	Nameplate Capacity (MW)[a]	Peak Capacity (MW)[b]	Average Energy (MWa)[b]	Critical Energy (MWa)[b]	In-Service Year
Alder	Tacoma	50	39	26	20	1945
Boundary[f]	Seattle	1,034	845	502	360	1967
Box Canyon	Pend Oreille	60	81	49	51	1955
Calispel Creek	Pend Oreille	1	c	c	c	1920
Carmen-Smith	EWEB	80	34	17	16	1963
Cedar Falls	Seattle	20	d	d	d	1905
Chelan	Chelan	48	56	48	42	1928
City	Idaho Falls	8	e	e	e	1982
Cushman 1	Tacoma	43	29	12	11	1926
Cushman 2	Tacoma	81	88	25	24	1930
Diablo	Seattle	122	159	97	83	1936
Gorge	Seattle	171	177	113	95	1924
Henry M. Jackson	Snohomish	112	103	53	41	1984
Idaho Falls Lower	Idaho Falls	11	e	e	e	1904
Idaho Falls Upper	Idaho Falls	8	e	e	e	1938
LaGrande	Tacoma	64	65	41	33	1912
Leaburg Dam	EWEB	14	14	13	12	1930
Mayfield Dam	Tacoma	162	172	78	64	1963
Mossyrock	Tacoma	300	309	118	93	1968
Moyie Falls 1-Upper	Bonner's Ferry	<1	c	c	c	1921
Moyie Falls 2-Lower	Bonner's Ferry	2	c	c	c	1941
Newhalem Creek	Seattle	2	d	d	d	1921
Packwood Lake	WPPSS	26	30	11	7	1964
Priest Rapids	Grant	789	896	580	482	1959
Rock Island	Chelan	620	613	404	339	1933
Rocky Reach	Chelan	1,212	1,284	723	582	1961
Ross	Seattle	360	357	90	70	1952
Strawberry Creek	Lower Valley	2	e	e	e	1951
Swift 2	Cowlitz	70	76	25	20	1958
Trail Bridge	EWEB	10	4	4	4	1963
Walterville	EWEB	8	9	8	7	1911
Wanapum	Grant	831	910	536	428	1963
Wells[g]	Douglas	774	820	426	345	1967
Yelm	Centralia	10	10	9	9	1930

a From PNUCC, *Northwest Regional Forecast,* March 1990.

b Values for operating years 1991 through 2010 from PNUCC, *Northwest Regional Forecast,* March 1990. Peak capacity is for January.

c Totals for Big Creek, Calispel Creek, Moyie Falls 1 and 2 (Flathead Irrigation Projects) are: Peak, 4 megawatts; Average, 2 average megawatts; Critical, 2 average megawatts.

d Totals for Cedar Falls and Newhalem Creek are: Peak, 30 megawatts; Average, 13 average megawatts; Critical, 9 average megawatts.

e Totals for City, Idaho Falls Upper, Idaho Falls Lower, and Strawberry Creek are: Peak, 21 megawatts; Average, 21 megawatts; Critical, 16 megawatts.

f Includes Units 55 and 56.

g Includes upgrades scheduled for completion by 1989.

C:[JF.DOCUMENT]90PLAN.AA3 Appendix 4-A T1-T3

Table 4-A-4
Contracted Resources[a]

Project	Fuel	Contracting Utility	Nameplate Capacity (MW)	Average Energy (MW)	In-Service Year
Wind:					
Whiskey Run		PP&L (R&D Contract)	1.25	0.01	1981
Subtotal, Wind			1.25	0.01	
Thermal: (* = cogeneration; ? = not known whether project is cogeneration)					
AEM Corporation (?)	Coal	MPC	12.0	N/A	1985
Afton Generating Company (*)	Wood	IPC	6.0	5.8	N/A
Big Horn Energy (?)	Coal	MPC	15.0	N/A	1986
Biomass One (*)	Wood	PP&L	25.0	18.3	1986
Biosolar (*)	Biomass	PP&L	25.0	17.5	1987
Blue Mountain Forest Products (*)	Wood	OTEC	6.0	2.6	1986
Boeing (Auburn) (*)	Gas	PSPL	9.0	8.0	N/A
Boise Cascade (Emmett, ID.) (*)	Wood	IPC	14.0	N/A	1985
Boise Cascade (Medford)	Wood	PP&L	8.5	0.3	pre-1961
Bozeman Woodwaste (?)	Wood	MPC	12.0	N/A	1985
Champion International (Libby)	Wood	PP&L	13.3	1.8	pre-1960
Cristad Enterprises (*)	Wood	OTEC	7.0	2.7	1986
Daw Forest Products	Wood	PP&L	10.0	0.9	pre-1960
Gorge Energy[c] (*)	Wood	PP&L	8.5	2.9	N/A
Great Western Malting (*)	Gas	Clark	20.0	17.9	1983
Husky Industries (*)	Biomass	PP&L	5.0	3.8	1989
D. R. Johnson (CPN) (*)	Biomass	CPN	7.5	5.6	1986
D. R. Johnson (PP&L) (*)	Biomass	PP&L	7.5	5.7	1987
Kinzua (*)	Wood	PGE	10.0	7.4	1985
Lakeview Power Company (*)	Biomass	PP&L	15.0	11.3	1987
Lane Plywood (*)	N/A	EWEB	0.8	N/A	N/A
Longview Fibre (*)	Pulp Liquor	BPA	71.3	35.9	pre-1970
Metro West Point (*)	Sewage Methane	Seattle	3.9	1.2	1982
Ogden-Martin	MSW	PGE	15.0	7.6	1986
Pacific Crown (Woodpower, Inc.) (*)	Wood	WWP	6.3	4.5	1983
Perkins Power (?)	Coal	MPC	12.0	N/A	1985
Pine Products	Wood	PP&L	5.75	N/A	1987
Potlatch (Lewiston #1) (*)	N/A	WWP	36.5	9.1	N/A

Table 4-A-4 (cont.)
Contracted Resources[a]

Project	Fuel	Contracting Utility	Nameplate Capacity (MW)	Average Energy (MW)	In-Service Year
Red Lodge (?)	Coal	MPC	10.0	N/A	1986
Roseburg Lumber	Wood	PP&L	45.0	26.0	1983
Simplot Fertilizer	Sulphur	IPC	15.0	9.0	1986
Tamarack Energy (*)	Wood	IPC	6.3	4.1	1983
Vaagen Brothers Lumber (*)	Wood	WWP	4.0	4.0	1980
Warm Springs Forest Products	Wood	PP&L	9.0	0.5	pre-1960
Weyco (*) ,	Pulping Liquor	EWEB	51.2	14.0	1976
Weyerhauser (Everett) (*)	N/A	Snohomish (Negotiating)	12.5	10.0	N/A
Subtotal, Thermal			540.85	238.4	

Table 4-A-4 (cont.)
Contracted Resources[a,b]

Project	FERC Permit No.	Contracting Utility	Nameplate Capacity (MW)	Average Energy (MWa)	Status	In-Service Year
Hydropower:						
Amy Ranch	08700-01		0.00	0.00	EX-GTD	1986
Barber Dam	04881-17	Idaho Power Co	3.70	1.88	LA-GTD	
Barney Creek	07754-02	Park Electric Co-op	0.07	0.04	EX-GTD	1986
Big Sheep Creek	05118-03		4.00	1.83	EX-GTD	1985
Billingsley Creek	06208-01	Idaho Power Co	0.14	0.13	EX-GTD	1986
Birch Creek	07194-05	PacifiCorp	2.85	0.34	LA-GTD	1987
Birch Creek	06458A01	Idaho Power Co	0.02	0.02	EX-GTD	1984
Birch Creek	06458B01	Idaho Power Co	0.04	0.04	EX-GTD	1984
Black Canyon #3	06137-00	Idaho Power Co	0.15	0.07	EX-GTD	1983
Blind Canyon	08375-02	Idaho Power Co	1.30	0.65	EX-GTD	
Box Canyon	06543-01	Idaho Power Co	0.56	0.51	EX-GTD	
Briggs	08083-02	PacifiCorp	0.25	0.20	EX-GTD	1983
Briggs Creek	04360-02	Idaho Power Co	0.75	0.54	EX-GTD	1986
Brunswick Creek	06564-01	PGE	0.04	0.25	EX-GTD	1985
Bull Run No 1	02821A05	PGE	23.75	7.31	LA-GTD	1982
Bull Run No 2	02821B05	PGE	12.00	5.25	LA-GTD	1981
Burnham Creek	09654-10	PUD 2/Pacific County	0.02	0.00	LA-GTD	1982
Burton Creek	07577-00		0.80	0.40	EX-GTD	
Bypass Site	09070-00	Idaho Power Co	9.90	3.42	EX-GTD	1988
Canal Creek	05572-00		1.10	0.47	EX-GTD	1984
Canyon Creek	06414-00	PGE	0.12	0.06	EX-GTD	1985
Cascade Creek	06629-00	Montana Power Co	0.08	0.04	EX-GTD	1983
Cedar Draw Creek	08278-04	Idaho Power Co	2.92	1.23	LA-GTD	1986
Cereghino	05865-00	Idaho Power Co	1.10	0.73	EX-GTD	1987
Cowiche Hydroelectric Proj	07337-02	PacifiCorp	1.35	0.58	LA-GTD	1986
Deep Cr Micro Hydro Proj	05991-01		0.27	0.06	EX-GTD	1983
Denny Creek	07350-00		0.05	0.04	EX-GTD	1985
Dietrich Drop	08909-11	Idaho Power Co	4.80	2.54	LA-GTD	1988
Doug Hull	06676-01	Idaho Power Co	0.25	0.13	EX-GTD	1983
Dry Creek	09134-00		3.60	2.02	EX-GTD	
Dry Creek	02907-00		0.01	0.00	LC-GTD	1980

Table 4-A-4 (cont.)
Contracted Resources[a,b]

Project	FERC Permit No.	Contracting Utility	Nameplate Capacity (MW)	Average Energy (MWa)	Status	In-Service Year
Hydropower (cont.):						
Ebey Hill	10428-00	Snohomish Cty PUD 1	0.10	0.07	EX-GTD	
Elk Creek	03503-09	Idaho Power Co	2.20	0.67	EX-GTD	1984
Eltopia Branch Canal 4.6	03842-03	Cities of Sea/Tac	2.40	0.98	LA-GTD	1983
Falls Creek	06661-04	PacifiCorp	4.00	1.70	EX-GTD	1984
Falls Creek Small Hydro Proj	05497-04		0.20	0.16	EX-GTD	
Farmers Irr Dist Proj No 2	07532-00	PacifiCorp	3.00	1.48	EX-GTD	1985
Faulkner Lnd & Lvstk Co	07592-03	Idaho Power Co	0.40	0.02	EX-GTD	1987
Felt	05089-18	BPA	1.87	0.00	LA-GTD	1985
Ferguson Ridge	06621-00		1.66	0.63	EX-GTD	1984
Fid Project #3	06801-03	PacifiCorp	1.80	0.85	EX-GTD	
Fisheries Development 1	07885-01	Idaho Power Co	0.31	0.23	EX-GTD	
Ford	07986-00	Wash Water Power	1.50	0.84	LA-GTD	1987
Galesville	07161-15	PacifiCorp	1.80	0.68	LA-GTD	1987
Geo-Bon 2	07548-02	Idaho Power Co	0.81	0.47	EX-GTD	1986
Georgetown	06445-00	PacifiCorp	0.45	0.21	EX-GTD	1985
Ground Water Pumping Station	07052-00	Inter Water Sup Sys	4.50	2.50	EX-GTD	1985
Hailey	07016-02	Idaho Power Co	0.05	0.05	EX-GTD	1985
Hecla Power Proj	06965-06		0.50	0.23	EX-GTD	
Hettinger	03041-00		0.01	-0.00	LC-GTD	1960
Ingram Warm Springs Ranch	08498B09		1.70	1.26	LA-GTD	1986
Ingram Warm Springs Ranch	08498A09		0.90	0.66	LA-GTD	1986
James E White	03922-00	PacifiCorp	0.24	0.11	EX-GTD	1981
Jim Boyd	07269-07	PacifiCorp	1.10	0.48	LA-GTD	
Jim Knight	07686-01	Idaho Power Co	0.29	0.18	EX-GTD	1984
Kasel-Witherspoon	06410-00	Idaho Power Co	1.00	1.24	EX-GTD	1983
Kaster Riverview	04608B01	Idaho Power Co	0.16	0.16	EX-GTD	1983
Kaster Riverview	04608A01	Idaho Power Co	0.16	0.16	EX-GTD	1983
Koyle Ranch	04052-03	Idaho Power Co	1.41	0.77	EX-GTD	1983
Lacomb	06648-00	PacifiCorp	0.96	0.63	EX-GTD	1986
Kake Creek No 1	06595-01	PacifiCorp	0.05	0.04	EX-GTD	1984

Table 4-A-4 (cont.)
Contracted Resources[a,b]

Project	FERC Permit No.	Contracting Utility	Nameplate Capacity (MW)	Average Energy (MWa)	Status	In-Service Year
Hydropower (cont.):						
Last Chance Canal	04580-00	PacifiCorp	1.66	0.94	EX-GTD	1982
Lateral #10	06250-02	Idaho Power Co	3.00	1.16	EX-GTD	1985
Leishman Irrigation System	07684-00		0.03	0.01	EX-GTD	
Lemoyne	04563-02		0.04	0.03	EX-GTD	1985
Lilliwaup Falls	03482-03		1.20	1.20	EX-GTD	1983
Little Gold	08660-04		0.45	0.22	LA-GTD	
Little Mac	06443-00	Idaho Power Co	0.25	0.24	EX-GTD	1984
Little Wood R	07427-01	Idaho Power Co	1.93	0.52	EX-GTD	1988
Little Wood R Ranch	07530-00	Idaho Power Co	0.66	0.34	EX-GTD	1986
Low Line Canal Drop	03216-01	Idaho Power Co	9.00	3.59	EX-GTD	1984
Lower Low Line	08961-00	Idaho Power Co	2.35	0.27	EX-GTD	
Lucky Peak	02832-14	Seattle City Light	101.60	32.19	LA-GTD	1988
Macks Creek	06631-03	Local Sys-Applic Will Use PW	0.01	0.00	EX-GTD	1984
Magic Dam	03407-27	Idaho Power Co	9.00	3.17	LA-GTD	
Main Canal Headworks	02849-12	Cities of Sea/Tac	26.00	9.86	LA-GTD	1986
Middle Fork Irr District 1	04458A04	PacifiCorp	2.10	1.72	EX-GTD	1987
Middle Fork Irr District 2	04458B04	PacifiCorp	0.60	0.47	EX-GTD	1987
Middle Fork Irr District 3	04458C04	PacifiCorp	0.60	0.39	EX-GTD	1987
Mill Creek	05390-02	CP National	0.63	0.29	EX-GTD	1905
Mill Creek	04949-00		0.50	0.27	EX-GTD	1983
Mink Creek	08646-07	PacifiCorp	2.75	1.07	LA-GTD	1988
Mirror Lake	07747-00	Puget Sound P&L	1.00	0.71	EX-GTD	1985
Mitchell Butte	05357-08	Idaho Power Co	1.68	0.60	LA-GTD	1989
Mt. Tabor	06957-00		0.17	0.13	EX-GTD	1985
Mud Creek	04769A01	Idaho Power Co	0.44	0.14	EX-GTD	1982
Mud Creek	04769B01	Idaho Power Co	0.22	0.07	EX-GTD	1982
N-32 Canal	06778-01	Idaho Power Co	0.55	0.27	EX-GTD	1985
Nichols Gap	08704-00	PacifiCorp	0.80	0.30	EX-GTD	1986
Nicholson	07865-01	PacifiCorp	0.35	0.31	EX-GTD	1986
North Willow Creek	07804-13	Montana Power Co	0.40	0.40	LA-GTD	

Table 4-A-4 (cont.)
Contracted Resources[a,b]

Project	FERC Permit No.	Contracting Utility	Nameplate Capacity (MW)	Average Energy (MWa)	Status	In-Service Year
Hydropower (cont.):						
O.J. Power Company	07719-03	PacifiCorp	0.15	0.15	EX-GTD	
Odell Creek	06057-01	PacifiCorp	0.07	0.05	EX-GTD	1984
Opal Springs	05891-03	PacifiCorp	1.25	2.66	LA-GTD	1920
Orchard Avenue	07338-02	PacifiCorp	1.44	0.64	LA-GTD	1986
Oregon City	02233C21	Power Used Intern	1.50	-0.00	LA-GTD	
Owyhee Dam	04354-04	Idaho Power Co	4.34	1.82	LA-GTD	1985
Owyhee Tunnel No 1	04359-11	Idaho Power Co	8.00	2.28	LA-GTD	
PEC Headworks	02840-16	Cities of Sea/Tac	6.50	2.27	LA-GTD	
Philipsburg (a)	06639A00		0.09	0.08	EX-GTD	1981
Philipsburg (b)	06639B00		0.07	0.00	EX-GTD	1981
Pickell	02794-03		0.00	0.00	LC-GTD	1953
Pine Creek	08546-20	Park Rec or MPC	0.37	0.21	LA-GTD	1975
Ponds Lodge	01413-05	Internal Use	0.25	0.11	RL-GTD	1936
Port Townsend Mill	05411-00		0.40	0.31	EX-GTD	1982
Potholes E Canal 66 Power Pl	03843-03	Cities of Sea/Tac	2.30	1.35	LA-GTD	1985
Preston	05892-00		0.41	0.34	EX-GTD	1987
Project No 1	08865-03	Idaho Power Co	0.12	0.07	LC-GTD	1979
Project No 2	08866-03	Idaho Power Co	0.09	0.06	LA-GTD	1980
Quincy Chute	02937-03	BPA	7.80	3.34	LA-GTD	1984
Reynolds Irrig District	06229-00	Idaho Power Co	0.35	0.15	EX-GTD	1985
Rock Creek	06450-00	Idaho Power Co	2.54	1.35	EX-GTD	1983
Rock Creek	06015-37	Idaho Power Co	1.90	1.35	LA-GTD	
Rocky Brook	03783-03	Mason County PUD 1	1.50	0.80	EX-GTD	1985
Rocky Mtn. Embryos	05731-02	Idaho Power Co	0.18	0.18	EX-GTD	1984
Russell D Smith	02926-02	Sea/Tac PUDs	6.10	2.59	LA-GTD	1982
Sagebrush Project	08046-02	Idaho Power Co	0.32	0.24	EX-GTD	1985
Salmon Falls Creek	07211-11	Idaho Power Co	0.27	0.20	LA-GTD	
Schaffner Project	08438-01	Idaho Power Co	0.25	0.20	EX-GTD	1986
Shingle Creek	04025-03	Idaho Power Co	0.12	0.12	LA-GTD	1984
Shoshone	09967A20	Idaho Power Co	0.33	0.68	LA-GTD	1982

Table 4-A-4 (cont.)
Contracted Resources[a,b]

Project	FERC Permit No.	Contracting Utility	Nameplate Capacity (MW)	Average Energy (MWa)	Status	In-Service Year
Hydropower (cont.):						
Skyview Ranch Power	09179-00	Coos Curry Co-op	0.04	0.01	EX-GTD	1983
Slaughterhouse Gulch	06375-00	Idaho Power Co	0.12	0.06	EX-GTD	1983
Smith Creek	08436-68	EWEB	38.15	9.76	LA-GTD	1989
Snake River Pottery	05651-03		0.09	0.06	EX-GTD	1984
Soda Creek	07959-00	City of Soda Springs	0.71	0.22	EX-GTD	1987
South Dry Creek	08831-00		1.80	0.81	EX-GTD	1985
South Willow Creek	07856B10	Montana Power	0.03	0.01	LA-GTD	1980
South Willow Creek	07856A10	Montana Power	0.29	0.16	LA-GTD	1986
Spencer Lake Hydro	06625-01		0.04	0.02	EX-GTD	1983
Spring Creek	07214-01		0.01	0.01	LA-GTD	
Summer Falls	03295-10	Cities of Sea/Tac	92.00	37.10	LA-GTD	1984
Sunshine	09907-02	Idaho Power Co	0.11	0.06	LA-GTD	
Sygitowicz Creek	05069-01		0.19	0.10	EX-GTD	1986
Telford	05637-00	PacifiCorp	0.15	0.12	EX-GTD	1984
Thompson's Mills	09169-00	PacifiCorp	0.10	0.07	EX-GTD	1986
Trinity	00719-03		0.29	0.29	RL-GTD	1923
Tuttle Ranch	04055-05		1.06	0.38	EX-GTD	1983
Twin Reservoirs	10376-00		0.00	0.00	EX-GTD	1988
Upper Indian Creek	07405-01	CP National	0.08	0.07	EX-GTD	
Upper Little Sheep Creek	05573-00		4.25	1.69	EX-GTD	1984
Upper Pine Creek	08727-01		0.01	0.00	EX-GTD	1985
Water Street	06943-01	PacifiCorp	0.16	0.11	EX-GTD	1985
Weeks Falls	07563-08		3.40	1.55	LA-GTD	1985
West Linn	02233A21	Power Used Intern	3.60	0.00	LA-GTD	
White Ranch	04115-04	Idaho Power Co	0.15	0.10	EX-GTD	1986
White Water Ranch	06271C00	Idaho Power Co	0.10	0.06	EX-GTD	1983
White Water Ranch	06271A00	Idaho Power Co	0.18	0.04	EX-GTD	
Whitefish	06941-01		0.19	0.11	EX-GTD	1985
Wisconsin-Noble	09482-07	Montana Power Co	0.66	0.29	LA-GTD	
Wolf Creek	07058-00	PGE	0.12	0.06	EX-GTD	1987
Woods Creek	03602-01		0.60	19.41	EX-GTD	1982
Y-8 Hydroelectric Project	06630-02		0.08	0.09	EX-GTD	1983
	Subtotal, Hydropower				479.15	205.57
Total, Contracted Resources			1,021.25	443.98		

a Exclusive of projects of less than 1-megwatt capacity.

b From various sources compiled by the Council including PNUCC, *Cogeneration Compendium,* April 1990; PNUCC, *Northwest Regional Forecast,* March 1990; Pacific Northwest Hydropower Data Base; Idaho Public Utility Commission, Oregon Public Utility Commissioner, Montana Power Company, Washington State Energy Office.

Table 4-A-5
Large Thermal Units

Project & Unit	Fuel	Utility	Nameplate Capacity (MW)[a]	Peak Capacity (MW)[b]	Average Energy (MWa)[b]	In-Service Year
Boardman	Coal	PGE-65%; IPC-10%; PNGC-10%; GECC-15%	560	455	341[f]	1980
Centralia 1	Coal	PP&L-47.5%; WWP-15%; PSPL-11% Snohomish-8%; Tacoma-8%; Seattle-8% PGE-2.5%	730	640	543	1971
Centralia 2	Coal	PP&L-47.5%; WWP-15%; PSPL-11%; Snohomish-8%; Tacoma-8%; Seattle-8% PGE-2.5%	730	640	543	1972
Colstrip 1	Coal	MPC-50%; PSPL-50%	358	158[c]	123[c]	1975
Colstrip 2	Coal	MPC-50%; PSPL-50%	358	158[c]	123[c]	1976
Colstrip 3	Coal	MPC-30%; PSPL-25%; PGE-20%; WWP-15%; PP&L-10%	778	504[c]	392[c]	1984
Colstrip 4	Coal	USTC-30%; PSPL-25%; PGE-20%; WWP-15%; PP&L-10%	778	504[c,g]	392[c,g]	1986
J.E. Corette	Coal	MPC	172	[c]	[c]	1968
Jim Bridger 1	Coal	PP&L-66-2/3%; IPC-33-1/3%	509	167[d]	137[d]	1974
Jim Bridger 2	Coal	PP&L-66-2/3%; IPC-33-1/3%	509	167[d]	137[d]	1975
Jim Bridger 3	Coal	PP&L-66-2/3%; IPC-33-1/3%	509	167[d]	137[d]	1976
Jim Bridger 4	Coal	PP&L-66-2/3%; IPC-33-1/3%	509	167[d]	137[d]	1979
Valmy 1	Coal	IPC-50%; SPPC-50%	254	121	98	1981
Valmy 2	Coal	IPC-50%; SPPC-50%	267	121	98	1985
Trojan	Nuclear	PGE-67.5%; EWEB-30%; PP&L 2.5%	1,216	1,152	726	1976
WNP-2	Nuclear	WPPSS	1,154	1,095	711	1984
Kettle Falls	Wood	WWP	51	47	40	1983

Table 4-A-5 (cont.)
Large Thermal Units

---

[a] From 1990 PNUCC, *Northwest Regional Forecast,* March 1990.

[b] Declared (by sponsors) to be available to the region (from PNUCC, *Northwest Regional Forecast,* March 1990).

[c] Approximately 40 percent of the capability of Montana Power Company resources is available to meet regional load. In accordance with Northwest power planning convention, the output of these resources used to serve regional load is treated as import to the region.

[d] The portion of the Pacific Power and Light Company share of Jim Bridger is treated as an import to the region in accordance with Northwest power planning convention.

[e] Operation of the N-reactor for plutonium production has priority over production of steam for electricity. Therefore, the firm capacity of Hanford Generating Project is zero.

[f] General Electric Credit Corporation share to be sold to San Diego Gas and Electric on a 25-year contract beginning in 1989.

[g] United States Trust Company share of Colstrip 4 is leased back to Montana Power Company.

Table 4-A-6
Other Thermal

Project and Unit	Primary Fuel	Utility	Nameplate Capacity (MW)[a]	Peak Capacity (MW)[b]	Firm Energy (MWa)[c]	In-Service Year
Combustion Turbine						
Bethel 1	Gas	PGE	56.7	58.0	26.0	1973
Bethel 2	Gas	PGE	56.7	58.0	26.0	1973
Frederickson 1	Gas	PSPL	85.0	89.0	2.0	1981
Frederickson 2	Gas	PSPL	85.0	89.0	2.0	1981
Fredonia 1	Gas	PSPL	123.6	123.5	3.0	1984
Fredonia 2	Gas	PSPL	123.6	123.5	3.0	1984
Northeast	Gas	WWP	61.2	68.0	54.0	1978
Point Whitehorn 1	Oil	PSPL	61.0	68.0	13.0	1974
Point Whitehorn 2	Gas	PSPL	85.0	89.0	13.0	1981
Point Whitehorn 3	Gas	PSPL	85.0	89.0	13.0	1981
Whidbey Island	Oil	PSPL	27.0	29.0	1.0	1972
Wood River	Gas	IPC	50.0	50.0	1.0	1974
Diesel						
Bonners Ferry 1	Oil	Bonners Ferry	0.2	0.0	0.0	1930
Bonners Ferry 2	Oil	Bonners Ferry	1.1	1.0	1.0	1930
Bonners Ferry 3	Oil	Bonners Ferry	1.1	1.0	1.0	1973
Crystal Mountain	Oil	PSPL	2.8	3.0	0.1	1969
Summit 1	Oil	PGE	2.8	3.0	0.5	1970
Summit 2	Oil	PGE	2.8	3.0	0.5	1973
Steam-Electric						
Shuffleton 1	Oil	PSPL	35.0	43.0	1.0	1930
Shuffleton 2	Oil	PSPL	35.0	43.0	1.0	1930
Steam Plant 2	Coal/MSW/Wood	TPU	50.0	38.0	32.0	1990
Willamette Steam Plant	Wood	EWEB	25.0	25.0	20.0	N/A
Combined Cycle						
Beaver	Gas	PGE	586	534	299	1977
TOTALS:				1,628	513	

a/b From PNUCC, *Northwest Regional Forecast,* March 1990.

c Declared by sponsor to be available as firm energy. From PNUCC, *Northwest Regional Forecast,* March 1990.

Table 4-A-7
Thermal Resource Operating Costs[a]

Project and Unit	Primary Fuel	Heat Rate (Btu/kWh)	Fixed Fuel Cost ($/kW/yr)	Variable Fuel Cost ($/MMBtu)	Average Fuel Real Escalation (%)	Fixed[b] O&M ($/kW/yr)	Variable[b] O&M (mills/kWh)
Boardman	Coal	10,800	1.14	2.18	-0.4	22.30	0.10
Centralia 1	Coal	10,240	0.00	1.66	3.9	13.90	1.24
Centralia 2	Coal	10,240	0.00	1.66	3.9	13.90	1.24
Colstrip 1	Coal	11,250	5.39	0.62	3.5	19.70	1.76
Colstrip 2	Coal	11,250	5.39	0.62	3.5	19.70	1.76
Colstrip 3	Coal	10,390	5.70	0.73	3.4	20.53	2.39
Colstrip 4	Coal	10,390	5.70	0.73	3.4	20.53	2.39
Corette	Coal	11,030	0.00	1.04	1.1	12.03	1.56
Jim Bridger 1	Coal	9,985	0.00	1.14	3.7	21.26	1.76
Jim Bridger 2	Coal	9,985	0.00	1.14	3.7	21.26	1.76
Jim Bridger 3	Coal	9,985	0.00	1.14	3.7	21.26	1.76
Jim Bridger 4	Coal	9,985	0.00	1.14	3.7	21.26	1.76
Valmy 1	Coal	9,556	0.00	1.76	0.5	22.81	1.45
Valmy 2	Coal	9,515	0.00	1.76	0.5	22.81	1.45
Beaver	Gas	8,800	0.21	3.16	2.3	6.43	1.35
Point Whitehorn 1	Gas	11,850	0.00	3.16	2.3	9.75	8.30
Point Whitehorn 2	Gas	10,320	1.04	3.16	2.3	15.14	8.30
Point Whitehorn 3	Gas	10,320	1.04	3.16	2.3	15.14	8.30
Bethel	Gas	13,300	0.31	3.16	2.3	6.22	0.00
Frederickson 1	Gas	10,320	2.90	3.16	2.3	1.35	8.30
Frederickson 2	Gas	10,320	2.90	3.16	2.3	1.35	8.30
Fredonia 1	Gas	10,485	5.19	3.16	2.3	1.04	8.30
Fredonia 2	Gas	10,485	5.19	3.16	2.3	1.04	8.30
Trojan	Nuclear	10,339	30.20	0.45	0.24	38.00	1.50[c]
WNP-2	Nuclear	10,310	25.70	0.10	0.69	49.10	1.00[c]

a January 1988 dollars.

b O&M real escalation for coal and gas is zero.

c O&M escalation for Trojan and WNP-2 is 3 percent real in 1988 and declines linearly to 0 percent by 2000.

APPENDIX 4-B

REGIONAL IMPORTS AND EXPORTS

Abbreviations

(Tables 4-B-1 through 4-B-4)

BC Hydro	British Columbia Hydro Power Authority
BPA	Bonneville Power Administration
EWEB	Eugene Water and Electric Board
Longview	Longview Fiber
MPC	Montana Power Company
MPC Restoration	Due to coordination agreement
PGE	Portland General Electric
PG&E	Pacific Gas and Electric
PP&L	Pacific Power and Light
S.Diego	San Diego
SCE	Southern California Edison
SCL	Seattle City Light
SCM	Southern California Municipalities
SW	Southwestern Utilities
TPU	Tacoma Public Utilities
WAPA	Western Area Power Agency
WWP	Washington Water Power
Wyo	Wyoming

Table 4-B-1
Summary of Firm Energy Exports
(Average Megawatts)

Parties Involved	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
BPA To BC Hydro	0	0	0	0	0	0	0	14	121	318	315	311	368	548	542	536	531	525	519	513
BPA To BGP[a]	25	25	28	28	28	28	28	28	0	0	0	0	0	0	0	0	0	0	0	0
BPA To MPC #1	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
BPA To MPC #2	65	65	65	65	65	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BPA To MSR[a]	0	0	9	50	50	50	73	75	0	0	0	0	0	0	0	0	0	0	0	0
BPA To SCE[a]	134	134	134	134	134	134	134	134	0	0	0	0	0	0	0	0	0	0	0	0
BPA To Utah	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Idaho To MPC	13	13	13	13	13	13	13	6	0	0	0	0	0	0	0	0	0	0	0	0
PGE To SCE	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
PGE To SCE	8	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	25
PGE To WAPA	37	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
PGX To Burbank #1	7	7	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
PGX To Burbank #2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PGX To Glendale #1	13	13	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
PGX To Glendale #2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PP&L To PG&E #1	17	17	17	17	17	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PP&L To PG&E #2	11	11	11	11	11	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PP&L To SCE	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	27	0	0	0
PP&L To SMUD	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Puget To PG&E	0	12	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	35	0	0
SCL To PG&E	0	0	0	7	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
TCL To WAPA #1	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
TCL To WAPA #2	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18	18
TCL To WAPA #3	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
WWP To PG&E	7	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
TOTAL	598	669	716	764	787	773	717	726	590	787	784	780	837	1,017	1,011	1,005	919	874	833	818

Th[illegible] Pow[illegible] [illegible]dmi[illegible]tion [illegible]mes [illegible] th[illegible] ontr[illegible] will [illegible]ert[illegible] apac[illegible] nerg[illegible] char[illegible] in [illegible]

Table 4-B-2
Summary of Firm Energy Imports
(Average Megawatts)

Parties Involved	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
BC Hydro To PSP&L	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
BC Hydro To SCL	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
BC Hydro To WWP	17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BGP To BPA	0	0	0	0	0	0	0	0	10	10	10	10	10	10	10	10	10	9	0	0
BPA To MPC	29	29	29	29	29	29	29	29	29	29	29	0	0	0	0	0	0	0	0	0
Burbank To PGX	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Glendale To PGX	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MPC To Idaho	12	12	12	12	12	12	12	12	0	0	0	0	0	0	0	0	0	0	0	0
MPC To Puget	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
MSR To BPA	0	0	0	0	0	0	0	0	25	25	25	25	25	25	25	25	25	25	25	25
MT Power Co.	326	330	333	337	340	321	296	296	298	302	302	302	312	312	312	312	312	312	312	312
PG&E To Puget	0	24	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	24	0	0
PG&E To SCL	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
PG&E To WWP	0	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
PP&L (Wyo) To PP&L	1,179	1,179	1,119	1,121	1,116	992	974	963	894	895	896	813	836	826	752	754	756	675	698	690
SCE To BPA	0	0	0	0	0	0	0	0	36	35	34	33	32	30	29	28	28	28	28	0
SCE To PGE	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Utah Power Co.	339	344	349	346	350	350	352	353	354	354	355	356	357	357	358	359	361	361	363	365
TOTAL	2,047	2,088	2,056	2,089	2,091	1,948	1,904	1,897	1,890	1,894	1,895	1,703	1,816	1,804	1,730	1,732	1,736	1,631	1,623	1,589

Table 4-B-3
Summary of Peaking Capacity Exports
(Megawatts)

Parties Involved	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
BPA To BC Hydro	0	0	0	0	0	0	0	0	126	768	768	768	768	1,400	1,400	1,400	1,400	1,400	1,400	1,400
BPA To BGP	36	36	36	36	36	36	36	36	25	25	25	25	25	25	25	25	25	25	0	0
BPA To MPC #1	77	77	77	77	77	77	0	0	0	0	0	0	0	0	0	0	0	0	0	[illegible]
BPA To MPC #2	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0	0	0	[illegible]
BPA To MSR	0	0	0	100	100	100	150	150	150	150	150	150	150	150	150	150	150	150	150	150
BPA To SCE	250	250	250	250	250	250	250	250	0	0	0	0	0	0	0	0	0	0	0	0
Idaho To MPC	50	50	50	50	50	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0
PGE To SCE	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
PGE To WAPA	0	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
PGX To Burbank	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PGX To Glendale	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
PP&L To PG&E	100	100	100	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PP&L To SCE	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	0	0	0	0
PP&L To SMUD	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
TCL To WAPA	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41
TOTAL	1,059	1,124	1,124	1,224	1,224	1,124	1,097	1,047	912	1,554	1,554	1,454	1,454	2,086	2,086	2,086	1,886	1,886	1,861	1,861

Table 4-B-4
Summary of Peaking Capacity Imports
(Megawatts)

Parties Involved	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
BC Hydro To PSP&L	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
BC Hydro To SCL	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156	156
Burbank To PGX	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Glendale To PGX	20	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MPC To Idaho	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MPC To Puget	94	94	94	94	94	94	94	94	94	94	94	94	94	94	94	0	0	0	0	0
MT Power Co.	489	493	497	501	503	502	476	476	460	460	460	460	425	425	425	94	94	94	94	94
PG&E To SCL	0	0	0	200	200	200	200	200	200	200	200	200	200	200	200	425	425	425	425	425
PG&E To WWP	0	150	150	150	150	150	150	150	150	150	150	150	150	150	150	200	200	200	200	200
PG&E To Puget	0	300	300	300	300	300	300	300	300	300	300	300	300	300	300	150	150	150	150	150
PP&L (Wyo) To PP&L	1,570	1,565	1,550	1,518	1,490	1,347	1,313	1,275	1,252	1,223	1,192	1,163	1,133	1,104	1,078	300	300	0	0	0
SCE To PGE	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	1,051	1,024	998	971	944
Utah Power Co.	219	219	220	218	218	218	219	219	219	221	222	224	226	227	229	225	225	225	225	225
TOTAL	2,787	3,236	3,196	3,366	3,340	3,196	3,137	3,099	3,060	3,033	3,003	2,976	2,913	2,885	2,861	2,836	2,812	2,488	2,464	2,440

C:JF.DOCUMENT/90PLAN.AA7 Appendix 4-B

APPENDIX 4-C

PACIFIC NORTHWEST HYDROPOWER PROJECT LICENSE EXPIRATIONS: 1990-2010

Table 4-C-1
Pacific Northwest Hydropower Project License Expirations: 1990-2010

Project	Licensee	FERC Project Number	License Status[a]	Peak Capacity (MW)	Average Energy (MWa)	Firm Energy (MWa)	Lic Exp Year
Walterville	Eugene Water & Elect Bd	2510	LA-GTD	9.0	8.0	7.0	1993
Leaburg Dam	Eugene Water & Elect Bd	2496	LA-GTD	14.0	13.0	12.0	1993
Meyers Falls	Washington Water Power Co	1393	LC-GTD	1.0	1.0	1.0	1993
Snoqualmie Falls No 1	Puget Sound Power & Light	2493A	LA-GTD	29.0	22.8	N/A	1993
Snoqualmie Falls No 2	Puget Sound Power & Light	2493B	LA-GTD	12.0	9.0	N/A	1993
Condit Dam	Pacificorp	2342	LA-GTD	10.0	9.7	N/A	1993
La Grande	City of Tacoma DPU	1862A	LA-GTD	65.0	41.0	33.0	1993
Alder	City of Tacoma DPU	1862B	LA-GTD	39.0	26.0	20.0	1993
Newhalem Creek	City of Seattle	2705	LA-GTD	1.8	1.6	N/A	1994
Rock Creek	Oregon Trail Elec Coop	1986	LA-WDN	.8	0.6	.8	1996
Soda Springs Dam	Pacificorp	1927A	LC-GTD	11.0	8.2	N/A	1997
Slide Creek Dam	Pacificorp	1927B	LC-GTD	18.0	11.1	N/A	1997
Fish Creek Dam	Pacificorp	1927C	LC-GTD	11.0	7.2	N/A	1997
Bend	Pacificorp	2643	LC-GTD	1.1	.88	N/A	1993
Clearwater No 1	Pacificorp	1927F	LC-GTD	15.0	6.9	N/A	1997
Clearwater No 2	Pacificorp	1927	LC-GTD	26.0	7.5	N/A	1997
Toketee Dam	Pacificorp	1927	LC-GTD	43.0	9.5	N/A	1997
Lower Salmon	Idaho Power Company	2061	LC-GTD	68.0	34.0	29.0	1997
Bliss	Idaho Power Company	1975	LA-GTD	75.0	50.0	45.0	1998
Moyie River	City of Bonners Ferry	1991A	LA-GTD	2.0	2.0	2.0[b]	1998
Moyie River	City of Bonners Ferry	1991B	LA-GTD	0.4	N/A	N/A[b]	1998
Moyie River	City of Bonners Ferry	1991C	LA-GTD	1.5	N/A	N/A[b]	1998
Missouri-Madison	Montana Power Co	2188	LA-GTD	60.0	N/A	N/A	1998
Upper Salmon Falls A	Idaho Power Co	2777A	LA-GTD	20.0	18.0	18.0	1999
Upper Salmon Falls B	Idaho Power Co	2777B	LA-GTD	18.0	16.0	16.0	1999
Shoshone Falls	Idaho Power Co	2778	LA-GTD	13.0	11.0	10.0	1999
Powerdale	Pacificorp	2659	LA-GTD	6.0	2.4	N/A	2000
C J Strike	Idaho Power Co	2055	LC-GTD	85.0	61.0	55.0	2000
Cabinet Gorge	Washington Water Power Co	2058	LA-GTD	230.0	124.0	100.0	2001
Big Fork	Pacificorp	2652	LA-GTD	4.2	3.3	N/A	2001
Pelton Dam	Portland General Electric	2030A	LA-GTD	108.0	40.0	35.0	2001
Pelton Reregulating	Warm Springs Power	2030B	LA-GTD	11.0	10.0	8.0	2001
Mayfield Dam	City of Tacoma DPU	2016A	LA-GTD	172.0	78.0	64.0	2001
Mossyrock Dam	City of Tacoma DPU	2016B	LA-GTD	337.0	118.0	97.0	2001
Box Canyon Dam	Pend Oreille PUD No 1	2042	LC-GTD	81.0	54.0	51.0	2002
Lower Malad	Idaho Power Company	2726A	LA-GTD	13.5	11.6	N/A	2004
Upper Malad	Idaho Power Company	2726B	LA-GTD	7.2	7.4	N/A	2004
Bull Run	Portland General Ele	4770	LA-GTD	22.0	12.0	10.0	2004

Project	Licensee	FERC Project Number	License Status[a]	Peak Capacity (MW)	Average Energy (MWa)	Firm Energy (MWa)	Lic Exp Year
Oregon City	Smurfit Newsprint Co	2233C	LA-PND	1.5	N/A	N/A	2004
T W Sullivan	Portland General Electric	2233B	LA-PND	16.0	14.0	14.0	2004
West Linn	James River Corp	2233C	LA-PND	3.6	N/A	N/A	2004
Noxon Rapids Dam	Washington Water Power Co	2075	LA-GTD	536.0	210.0	148.0	2005
Prospect 2	Pacificorp	2630A	LA-GTD	32.0	31.6	N/A	2005
Prospect 1	Pacificorp	2630C	LA-GTD	3.8	3.9	N/A	2005
Prospect 4	Pacificorp	2630B	LA-GTD	1.0	0.9	N/A	2005
Oxbow	Idaho Power Company	1971B	LA-GTD	220.0	124.0	91.0	2005
Brownlee	Idaho Power Company	1971C	LA-GTD	675.0	309.0	223.0	2005
Hells Canyon	Idaho Power Company	1971A	LA-GTD	450.0	247.0	177.0	2005
Wanapum Dam	PUD No 2 of Grant Co	2114B	LA-GTD	910.0	536.0	428.0	2005
Priest Rapids	PUD No 2 of Grant Co	2114A	LA-GTD	896.0	563.0	482.0	2005
Rocky Reach	PUD No 1 Chelan Co	2145	LA-PND	1,284.0	723.0	582.0	2006
John C Boyle	Pacificorp	2082	LC-GTD	80.0	N/A	N/A	2006
West Side	Pacificorp	2082G	LC-GTD	0.6	N/A	N/A	2006
East Side	Pacificorp	2082H	LC-GTD	3.2	N/A	N/A	2006
Lower Baker	Puget Sound Power & Light	2150A	LA-GTD	63.0	45.0	38.0	2006
Upper Baker	Puget Sound Power & Light	2150B	LA-GTD	92.0	42.0	35.0	2006
Swift No 1	Pacificorp	2111	LA-GTD	182.0	76.0	52.0	2006
Pickell	???????????????????	2794	LC-GTD	<1.0	<1.0	<1.0	2006
River Mill Dam	Portland General Electric	2195A	LA-GTD	23.0	13.0	10.0	2006
North Fork Dam	Portland General Electric	2195C	LA-GTD	54.0	26.0	19.0	2006
Post Falls	Washington Water Power Co	2545	LA-GTD	16.0	11.0	8.0	2007
Upper Falls	Washington Water Power Co	2545	LA-GTD	10.0	9.0	8.0	2007
Monroe Street	Washington Water Power Co	2545C	LA-GTD	6.0	6.0	5.0	2007
Nine Mile	Washington Water Power Co	2545B	LA-GTD	18.0	13.0	10.0	2007
Long Lake	Washington Water Power Co	7065	LA-GTD	71.0	54.0	42.0	2007
Sullivan Creek	???????????????????	2225	LA-PND	20.4	26.8	N/A	2008
Trail Bridge Dam	Eugene Water & Elect Bd	2242A	LA-GTD	4.0	4.0	4.0	2008
Carmen-Smith	Eugene Water & Elect Bd	2242B	LA-GTD	34.0	17.0	16.0	2008
Mystic Lake	Montana Power Co	2301	LA-GTD	10.0	6.0	N/A	2009
Packwood Lake	Wa Pub Power Supply Sys	2244	LA-GTD	30.0	11.4	7.0	2010
Round Butte Dam	Portland General Electric	2259	LC-GTD	300.0	100.0	82.0	2010
Hettinger	Mackay Bar Corp	3041	LC-GTD	<1.0	<1.0	<1.0	2010

[a] FERC license status: LC - license; LA - license amendment; GTD - granted; PND - pending (application accepted); WDN - withdrawn.

[b] All Moyie energy included in listing for 1991A.

C:JF.DOCUMENT/90PLAN.AA5 Appendix 4-C